Loads of Loads

Electricity Demand Growth and Forecasting in a Time of Change

UNITED STATES ASSOCIATION FOR ENERGY ECONOMICS
NEW ENGLAND CHAPTER LUNCHEON

PRESENTED BY

T. Bruce Tsuchida

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Brattle

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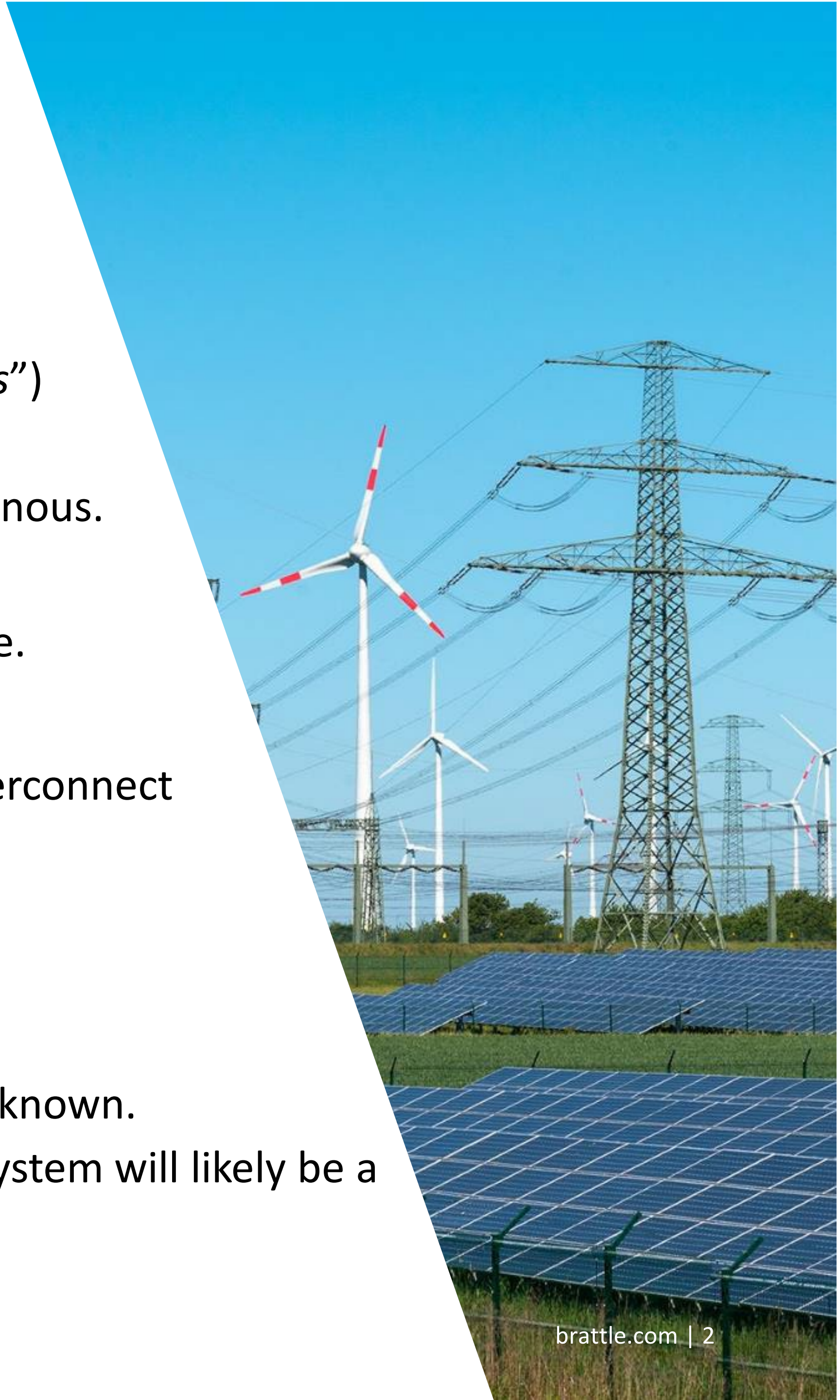
Outline

The Report (2024):

- The U.S. electricity industry is seeing an upsurge in new loads (“*Loads of Loads*”) trying to interconnect and put into service.
- There are various types of new loads and their characteristics are not homogenous.
  - 5 load drivers identified and categorized into 2 types.
- Associated load forecasts are evolving and some are recognizing the difference.

Since the Report:

- Much of the discussion to date has been centered around large loads that interconnect at the transmission level.
  - Specifically designed Tariffs.
  - Investment needs for Generation and Transmission.
  - Policies for better planning.
- Whether large loads lead to higher utility bills for existing customers in still unknown.
  - The potential impact of Type B loads that interconnect to the Distribution system will likely be a new kind of challenge.



Two Years Ago

Electric forecasting entities of all types should be evolving their forecasts to incorporate major changes in electricity use in the coming decades.

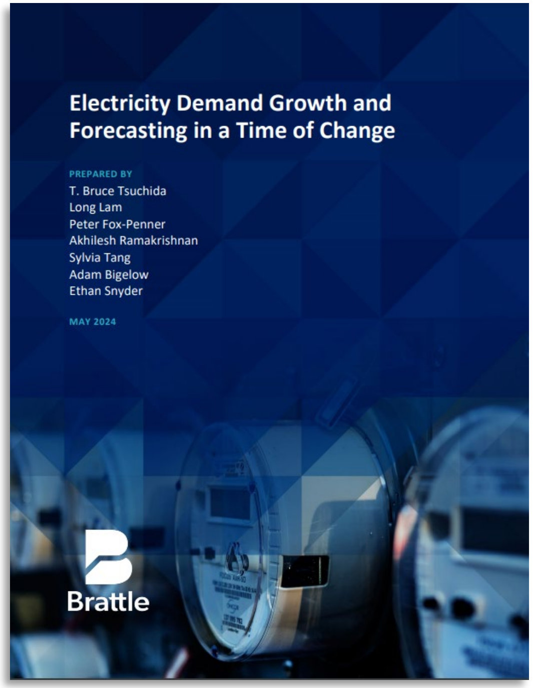
- Five major load drivers (data centers, onshoring and industrial electrification, cryptocurrency mining, building electrification, transportation electrification) identified.
- New load categorized as "large, discrete, and lumpy" Type A loads, or "smaller and distributed" Type B loads.
- Observed that many forecasters have made substantial progress updating their forecasting methods, but overall there is still much progress urgently needed.

High potential cost of under-forecasting indicating the need for proactive electric system planning (infrastructure is already lagging), especially with significant upturn in the next few years.

- Recent industry conversation has also evolved to risks of over-forecasting, as evidence suggests data centers queue shopping/being double counted.

Explicit consideration and evaluation of expansion optionality in all generation and transmission plans to address the forecasting risks.

- Optimize usage of existing infrastructure (e.g., via the adoption of grid-enhancing technologies).
- Incorporate the full effects of demand-side resources (including flexibility) and non-wire alternatives.



Scan for link to the full report

Two Types of New Load Drivers

	Type A	Type B
Description	• Large discrete and "lumpy" loads.	• Small and more distributed load; gradual growth.
Grid Impacts	• Impacts are highly regional/at specific locations, typically at Gen/Trans level. • Shorter planning horizon.	• Impacts are regional but more spread out at the distribution level. • Longer planning horizon.
Forecast Challenges	• Some loads can be speculative. • Less able to be forecasted in advance.	• Can be forecasted with greater foresight due to similar planning experience, but sharp load increase after a certain adoption level (assuming S-curve profile).
Potential Solutions	• Traditional Gen and Trans capacity expansion to ensure resource adequacy. • Use surplus Gen and Trans capacity. • Create capacity with load flexibility. • Leverage onsite generation. • Transparent interconnection processes.	• Execute system buildout under the assumption of steady expansion. • Leverage load flexibility tools to optimize Dist grid usage. • Offset with increased energy efficiency.
Examples	• Data centers, hydrogen electrolyzers, manufacturing plants.	• Electric vehicles, heat pumps.

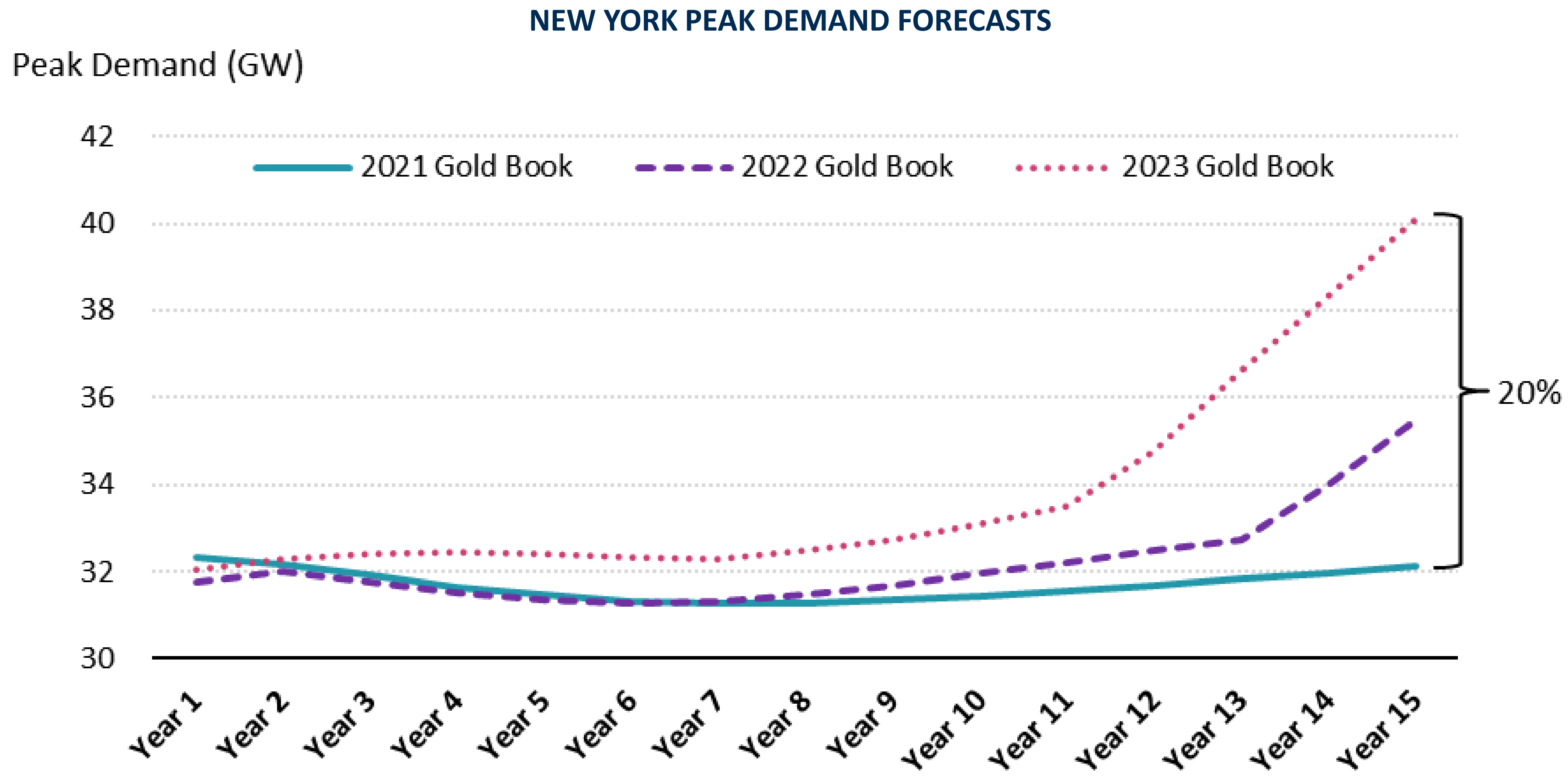
How Electric Forecasts Are Changing

- Electricity forecasters from many different types of organizations (utilities, RTOs/ISOs) are starting to adapt their forecasting methods.
- These efforts vary widely in terms of improvement techniques and the level of maturity of the effort.
- Several utilities and RTOs/ISOs have made changes to their forecast approaches to incorporate new demand drivers, resulting in sometimes substantial changes in their load forecasts over the course of a few vintages.
- Only a few entities include forecasts of these Type B drivers at the distribution level.

INCORPORATION OF SELECTED MAJOR DEMAND DRIVERS BY VARIOUS FORECASTING ENTITIES

		Demand-Side Resources			Type B Load		Type A Load			
		EE	DR	DG	EVs	Electric Heating	Data Center	Indoor Agriculture	Electrolyzer	Industrial Onshoring
AZ	Arizona Public Service (APS)	✓	✓	✓	✓		✓			✓
AZ	Salt River Project (SRP)	✓	✓	✓	✓	✓	✓			
CA	City of Palo Alto	✓	✓	✓	✓	✓				
CA	CleanPowerSF	✓	✓	✓	✓	✓				
CA	Los Angeles Department of Water and Power	✓	✓	✓	✓	✓				
CA	Pacific Gas & Electric (PG&E)	✓	✓	✓	✓	✓				
CA	Southern California Edison (SCE)	✓	✓	✓	✓	✓				
CA	San Diego Gas & Electric (SDG&E)	✓	✓	✓	✓	✓				
CA	Sacramento Municipal Utility District (SMUD)	✓	✓	✓	✓	✓	✓	✓*		
CO	Black Hills	✓	✓	✓			✓*			
CO	Colorado Springs Utilities (CSU)	✓	✓	✓	✓	✓				
CO	Public Service Company of Colorado (PSCO)	✓	✓		✓	✓				

Change in Forecast Assumptions: New York Example



Evolving forecasting techniques and drivers considered in forecasting led to a 20% difference in the 15 years-out projections.

Topics on the Streets Since Then

There are many large load interconnection requests and the electricity industry cannot respond fast enough.

2. Who should pay for all the new equipment and upgrades needed?

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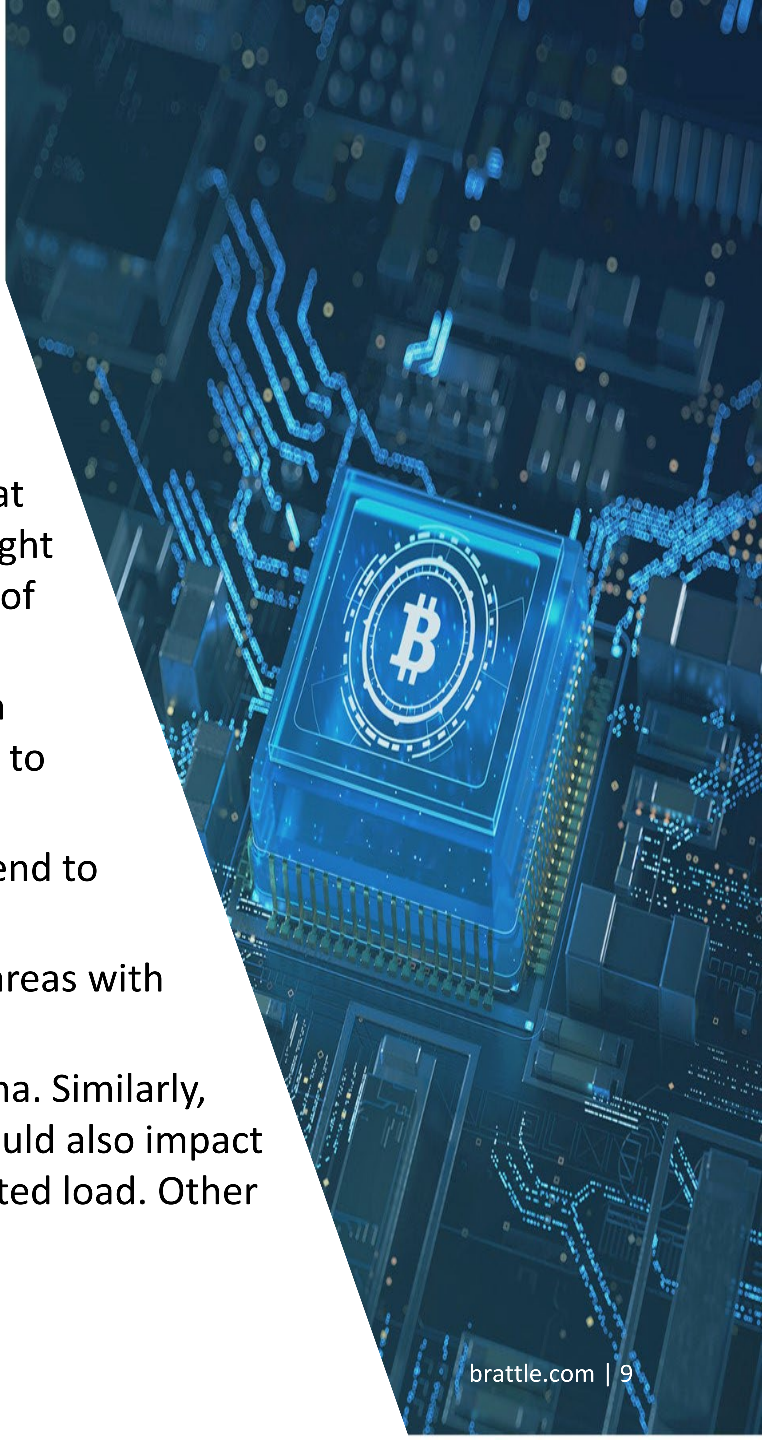
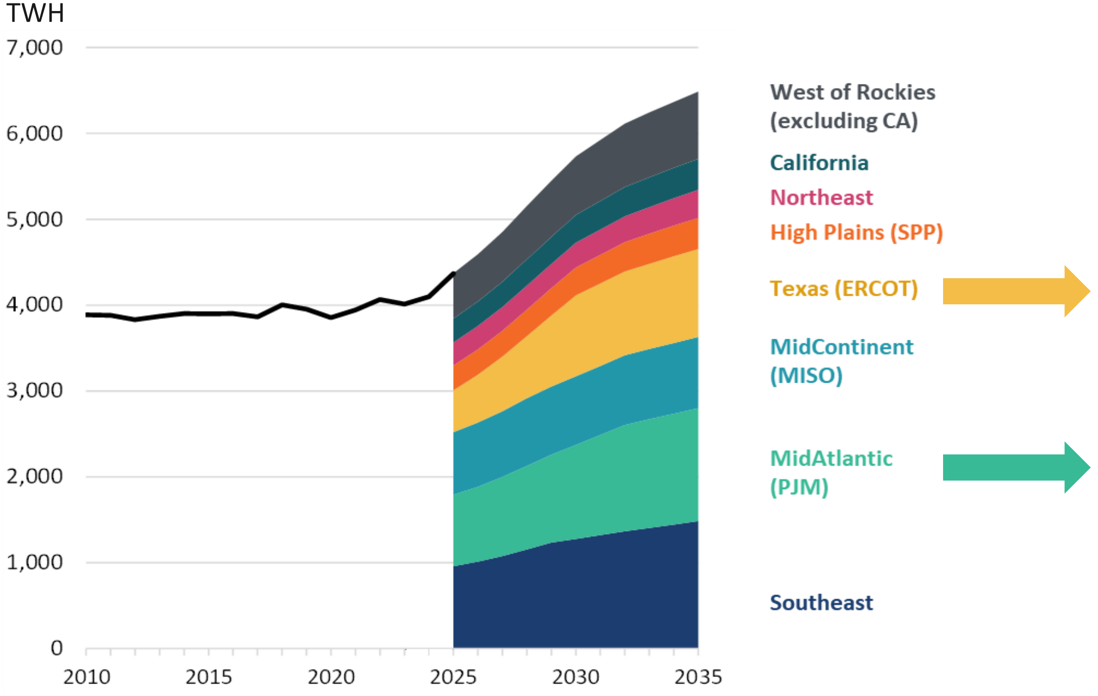
Emerging New Loads

- Emergence of newer load types, such as cryptocurrency mines, and cannabis grow houses, can be highly cyclical, depending on various external factors (e.g., macroeconomic and regulatory policies).
  - **Size**: Bigger can be either more or less risky, depending on the type of load. A large load that suddenly exits could result in *stranded assets* for the utility. Larger loads are generally thought to be less risky than small ones because they are more established and less likely to go out of business, or leave.
  - **Timing**: Many newer loads require power as soon as possible. This can lead to challenges in determining and securing the capacity (MW), energy (MWh), and ancillary services needed to serve the new load. Who pays for the costs?
  - **Growth rate**: Compared to traditional loads, many of the newer loads (regardless of size) tend to have higher and yet unpredictable growth rates.
  - **Location**: Many of the new loads are seeking lower cost power, and try to interconnect to areas with excess capacity (G, T, and D).
  - **Regulatory policies**: Cannabis load will be in areas (e.g., states) that have legalized marijuana. Similarly, crypto loads are likely to gravitate toward areas with less regulatory restrictions. Policies could also impact the markets and values of crypto currencies, which could alter crypto activities and associated load. Other policies, such as tax breaks, impact large loads.

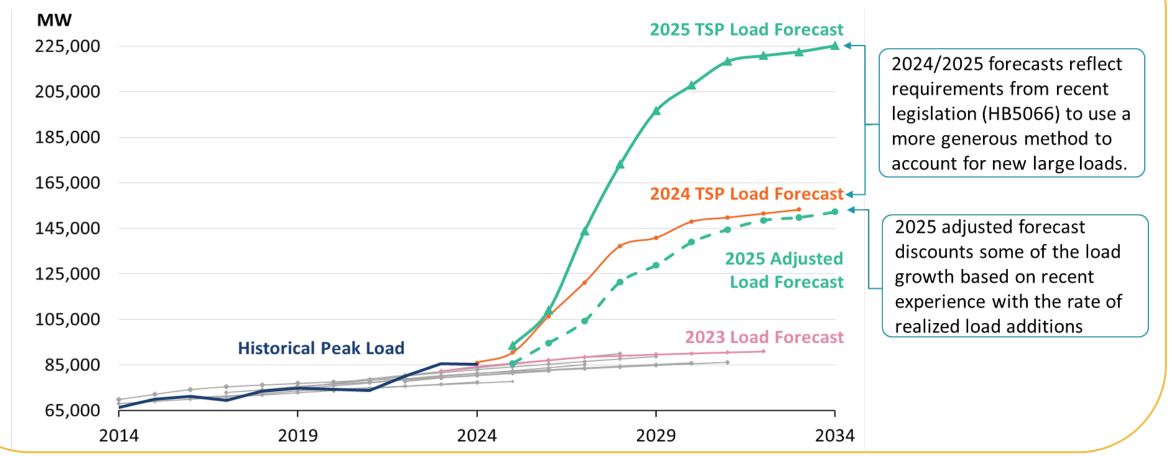


Recent Forecasts Herald an Era of High Electricity Growth

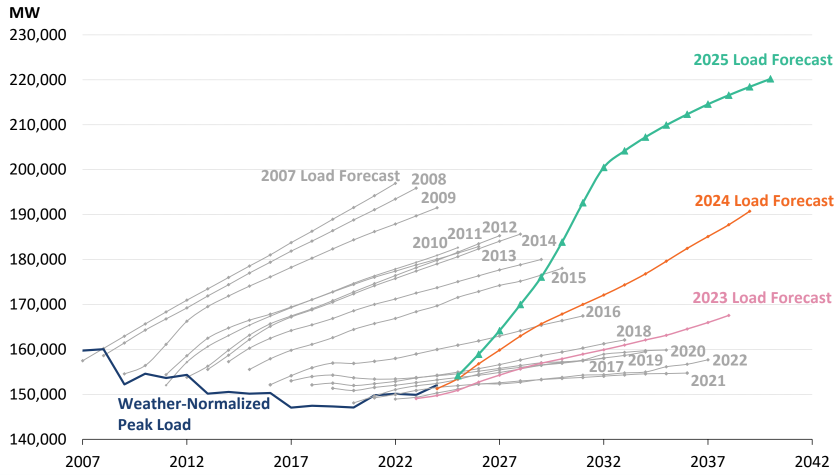
ANNUAL ELECTRIC ENERGY CONSUMPTION FORECAST



ERCOT PEAK SUMMER LOAD FORECASTS



PJM PEAK SUMMER LOAD FORECASTS



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Recent Large Load Tariffs-Associated Activities

Pre-2023

Cheyenne Fuel Light & Power *(Aug 2016)*: WY commission approves CFLP's Large Load Tariff
NY Municipal Power Authority *(Jun 2018)*: NY commission approves NYMPA's Cryptocurrency Tariff
Entergy MS *(Dec 2018)*: MS commission approves new Large Load Tariff
Xcel MN/Northern States Power *(May 2019)*: MN commission approves proposed changes to Xcel MN's Competitive Response Rider
Dominion *(Mar 2020)*: VA commission approves market-based rate, an optional tariff available to large load customers

2023

Idaho Power *(May)*: ID commission approves Large Load Tariff
Entergy AR *(Dec)*: AR commission approves Large Load Tariff

2024

Duke IN *(Apr)*: Special retail service agreement for a data center in IN is approved by commission
Tucson Electric Power *(Jun)*: AZ commission approves special contract (ESA) for large battery manufacturing facility
PacifiCorp *(Dec)*: OR commission approves proposal to penalize data centers for inaccurate forecasting

PG&E *(Nov)*: Proposes Rule 30, requiring large loads to pay for electric grid upgrades in advance

Basin Electric (ND) *(Aug)*: FERC rejects Basin Electric data center & cryptocurrency tariff

2025

Georgia Commission *(Jan)*: Approves rules to protect other customers from cost increases from data center investment
AEP/Indiana & Michigan *(Feb)*: IN commission approves new "Large Load Tariff"
Salt River Project *(Feb)*: Board approves changes to E-67 rate for Large Load General Service
AEP/Appalachian Power and Wheeling Power *(Mar)*: WV commission approves new "Large Load Tariff"
NV Energy *(Mar)*: NV commission approves Clean Transition Tariff
Georgia Power *(Apr)*: GA commission approves revised TOU-SC-15 tariff for >100 MW customers
AEP Ohio *(Jul)*: OH commission approves "Data Center Power" tariff addressing data centers and crypto mining facilities with >25 MW load

Evergy (MO/KS) *(Feb)*: Proposes Large Load Power Service tariff
Florida Power & Light *(Feb)*: Proposes new large load contract service rates
Wisconsin Electric *(Mar)*: Files new "Very Large Customer" tariff
Dominion *(Apr)*: Files revised GS-5 rate addressed at large loads and data centers
East KY Power Cooperative *(Apr)*: Files new "Data Center Power" tariff; later suspended by KY commission to allow for a longer review
Ameren MO *(May)*: Proposes revisions for large load customers in LPS rate
ComEd *(Jun)*: Files changes to General Terms & Conditions that increase the upfront costs for large load customer applications
APS *(Jun)*: Files proposed changes to its Extra High Load Factor rate to more clearly address data centers

Source: Brattle analysis.

Commission Approval
Application
Commission Rejection

Large Load Tariff Design Considerations

1	**Cost recovery approach**	**Direct assign:** Transparent demonstration of cost causation; customer-specific flexibility.	**System average:** Reduced risk of disallowance if customer exits; consistent with philosophy of power system as a shared resource.	
2	**Basis for recovered costs**	**Marginal/incremental costs:** Ensures no cost shift to other ratepayers; may attract load if marginal cost < embedded cost.	**Embedded costs:** Consistent with pricing basis for most existing customers; benefits ratepayers if marginal cost < embedded costs.	**Hybrid option:** Recover incremental cost for all demand above a threshold level.
3	**New or existing tariff**	**Propose new tariff:** Provides more flexibility in rate design; avoids "baggage" associated with existing rates.	**Leverage existing tariff:** Potentially less regulatory and administrative burden; less "fear of the unknown".	**Hybrid option:** Update existing rate and introduce new option.
4	**Standardized or special contract**	**Special contract:** Provides customer-specific flexibility.	**Standardized approach:** Streamlined negotiations and approval.	**Hybrid option:** Default to standardized approach, with special contract option.
5	**Available Customer Programs**	Optional customer programs include: **clean energy program** to help customers achieve their decarbonization goals, **load flexibility programs** and **behind-the-meter generation** to accelerate interconnection, support resource adequacy, and reduce power system costs.		
6	**Risk Mitigation**	Tools to reduce stranded cost and cost shifting risks include: collateral requirements, minimum charges, exit fees, minimum term lengths, and "hold harmless" provisions.		

Source: Brattle analysis.

Emerging Trends on Tariff Design

Non-Discriminatory Tariff Design	Utilities are mostly moving away from tariffs that single out data centers and instead establish eligibility criteria that focus on large customers, including data centers (e.g., using minimum load requirements).
Risk Mitigation Mechanisms	Utilities rely on a multi-prong approach to mitigate stranded cost risks: high credit ratings and collateral requirements, minimum (demand) charges, exit fees based on minimum charges, and longer contract terms (10-15 years). State legislation is beginning to impose these requirements as well.
Premium	Some tariffs require customers to pay a premium to reflect the cost of accelerating new energy supply procurement. Customers can also pay a premium to be supplied by more expensive clean energy.
Cost-Recovery	Generation charges reflect the market structure and how the energy resource is procured (e.g., from an organized market, utility-owned, customer-owned), while **transmission costs** are typically recovered in the same manner as in the "standard rate", with some customer-specific costs directly assigned.
BTM Resources and Load Flexibility	Surveyed tariffs typically allow **BTM generation** as backup or to offset contract capacity, by incorporating elements of **standby rates** (e.g., customers contract for their remaining capacity needs). **Load flexibility** is typically addressed through demand response programs or BTM generation.

Source: Brattle analysis.

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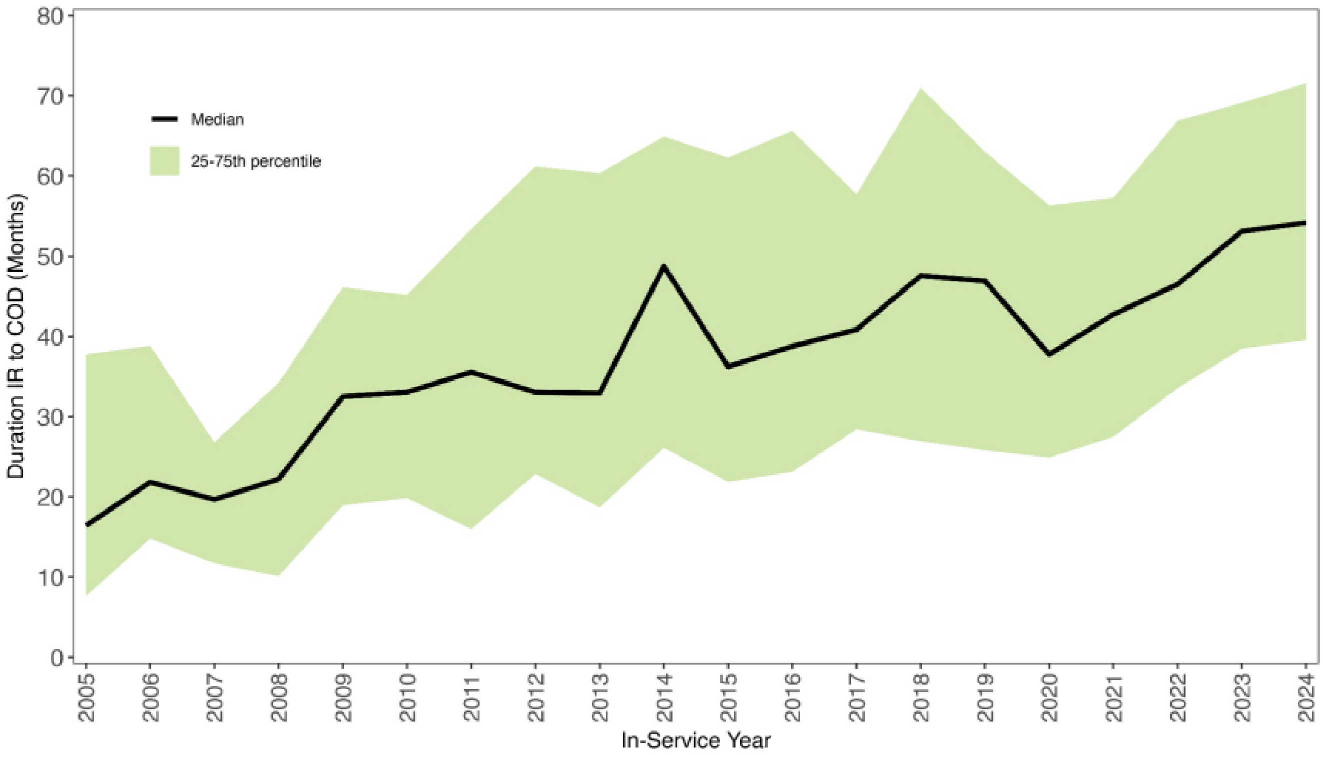
Generation Timeline

Duration from Interconnection Request to Commercial Operations Date

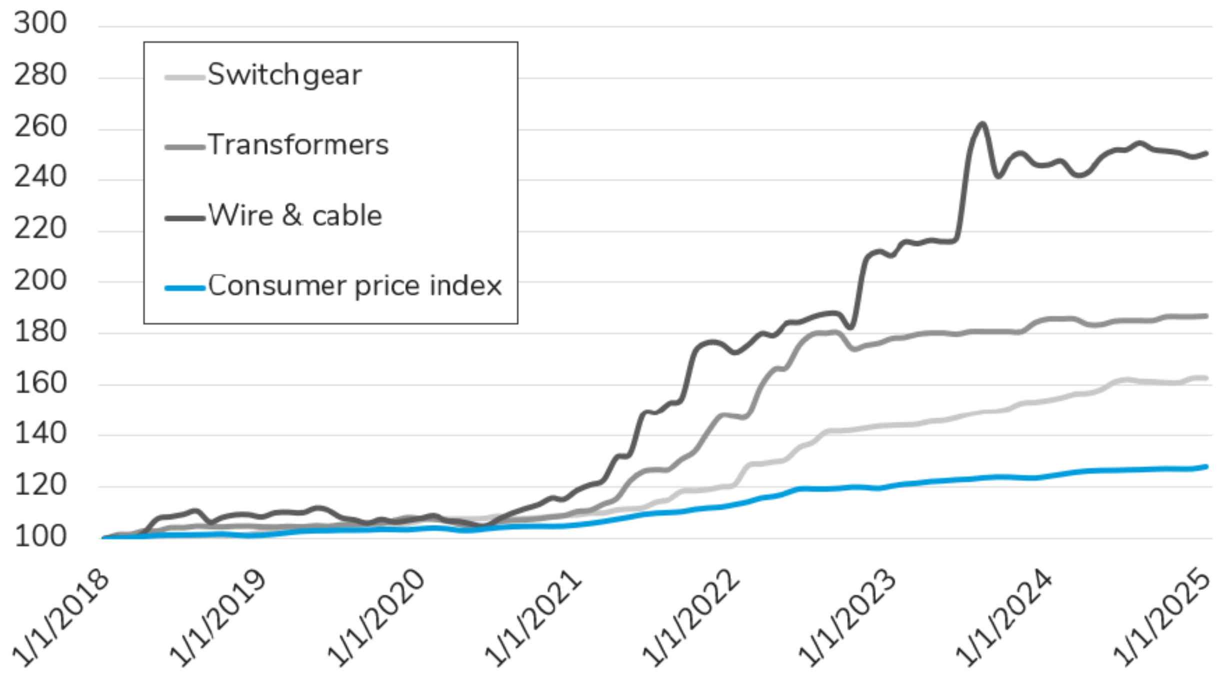


- The typical project built in 2024 took 55 months from the interconnection request to commercial operations, compared to 36 months in 2015 and 22 months in 2008.
- About 19% of projects (13% of capacity) requesting interconnection from 2000-2019 reached commercial operations by the end of 2024.
- These trends raise concerns for meeting growing electricity demand and resource adequacy needs.

Source: Lawrence Berkeley National Laboratory, Queued Up: 2025 Edition, December 2025, available at: https://eta-publications.lbl.gov/sites/default/files/2025-12/queued_up_2025_edition_12.15.2025.pdf.

Equipment Cost and Lead Time

Producer Price Index for Critical Power System Equipment, St Louis Fed



Source: Andy Lubershane, Steel for Fuel, 2025. Data from St. Louis Federal Reserve FRED databased, Producer Price Indices Accessed April 29, 2025.

- Rising costs for critical power infrastructure in recent years have outpaced inflation.
- $/kW cost of generation is expected to increase by 20% or so between 2025 and 2030.

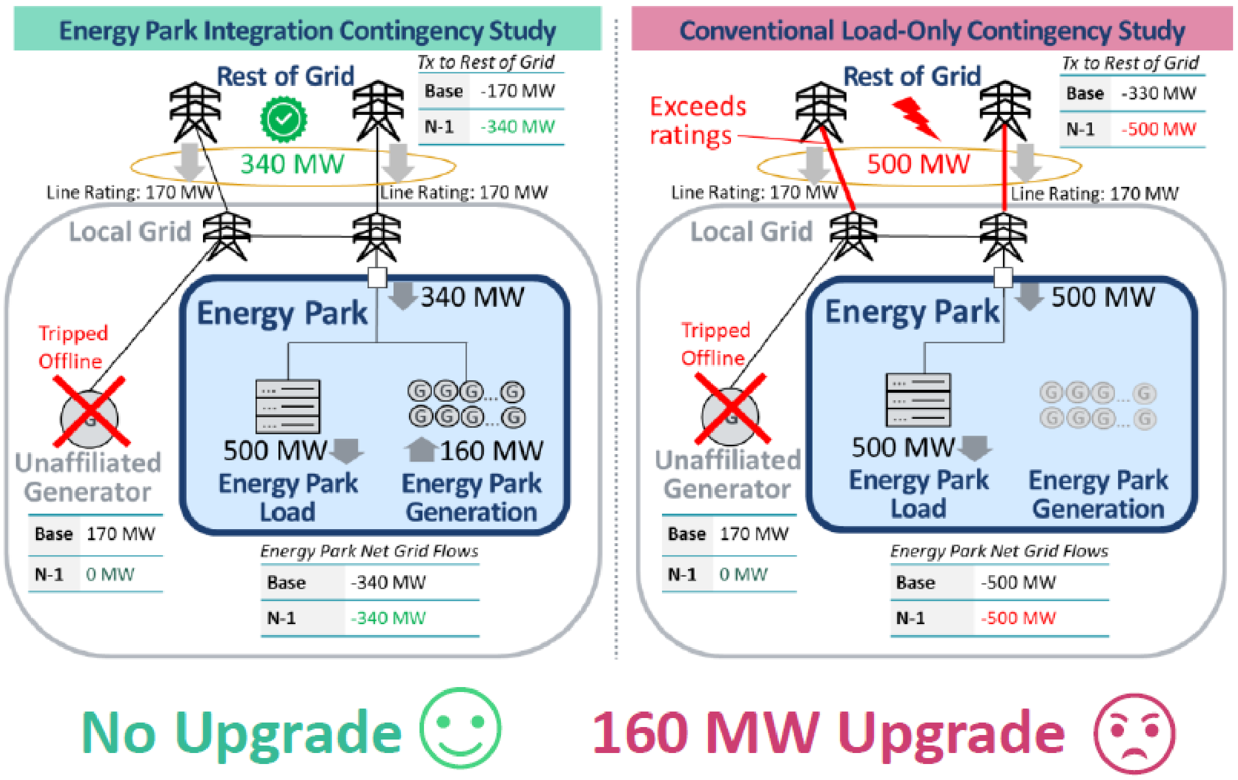
Estimated Change in Gas Turbine based Power Plant Costs between 2025 to 2030 ($/kW)

Configuration\ Technology Type	Frame	Aeroderivative
Combined Cycle	$2,100 -> $2,400	$2,400 -> $2,700
Simple Cycle	$1,750 -> $2,100	$2,100 -> $2,500

- Equipment require longer lead time as well.
  - Transformers: 2.5 to 3 years
  - Gas Turbines: 3 to 6 years

Potential Solution: Energy Park

Energy Park Reducing Upgrade Needs



- When the new load is asked to cover incremental costs (especially Generation costs), the new load may consider building its own resource.
  - The load may ask the utility to be the off-taker of power (and then sleeve it to the load) to reduce the cost of capital.
- An Energy Park is one form of such outcome. Benefits include:
  - Reduces transmission upgrade needs.
  - Provides some flexibility in interconnection schedule (e.g., develop generation as behind the fence first, then interconnect to the grid later).

Source: A. Levitt, et al., Accelerating the Integration of New Co-located Generation and Loads, prepared for Bloom Energy, April 2025, available at: Accelerating the Integration of New Co-located Generation and Loads - Brattle.

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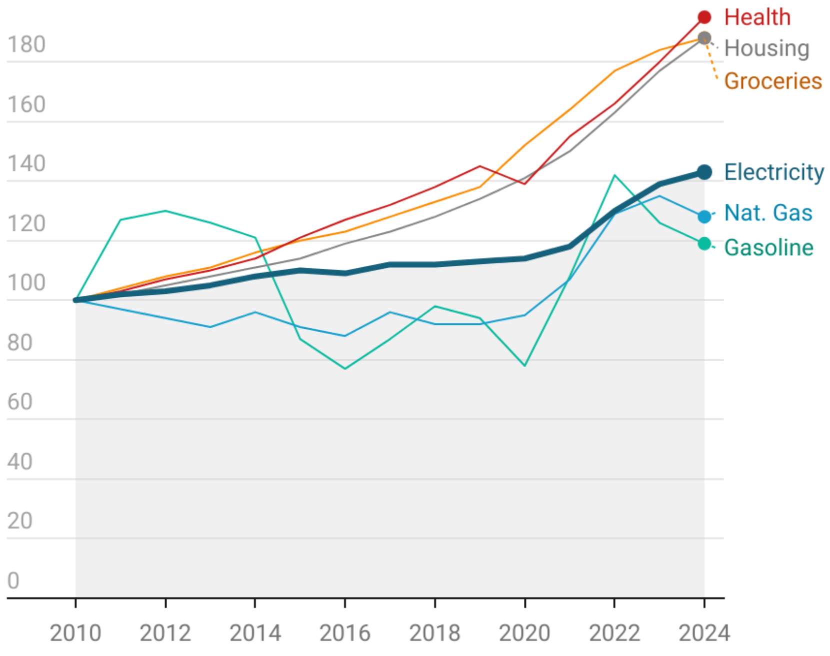
Are Electricity Prices High?

Indexed Residential Electric Prices vs. Other Household Expenditures (since 2010 and 2019)

Indexed Prices of Household Expenditures

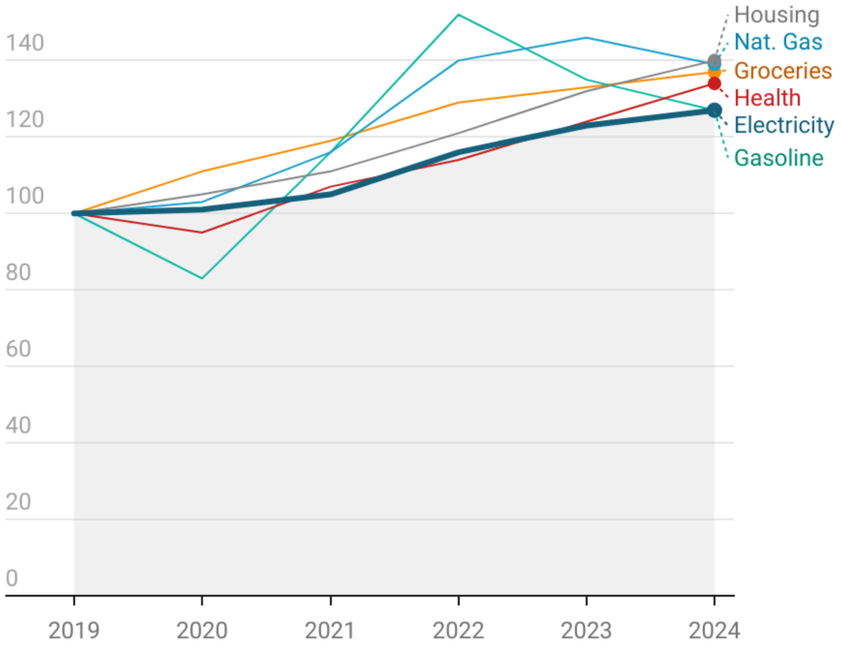
Nominal price index relative to prices and expenditures in 2010



Source: EIA, BEA • Created with Datawrapper

Indexed Prices of Household Expenditures

Nominal price index relative to prices and expenditures in 2019



Source: EIA, BEA • Created with Datawrapper

- Residential electricity bills in 2024 was at 1.23% of personal expenditure and 0.98% of income.
  - Both were at or near all-time lows since data became available in 1970.
  - In 2010, these values were almost 2.5% of personal expenditure and above 1.6% of income.

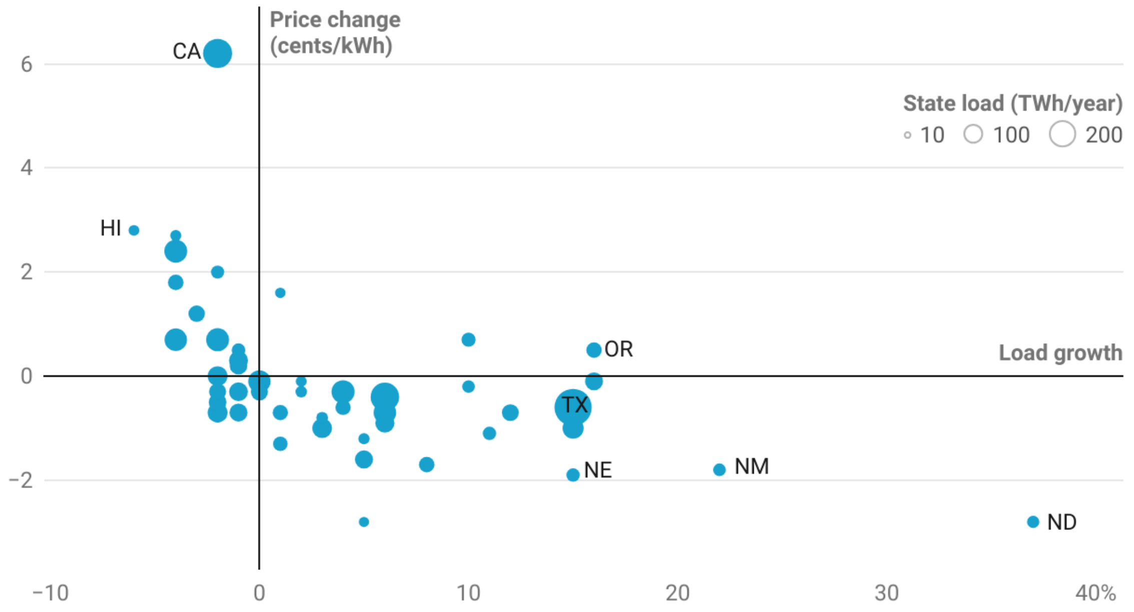
Source: Lawrence Berkeley National Laboratory and The Brattle Group, Recent Retail Electricity Price Trends: *What Do We Know… or Think We Know?, October 2025*, available at: https://eta-publications.lbl.gov/sites/default/files/2025-10/full_summary_retail_price_trends_drivers.pdf.

Will Electricity Prices Be Higher?

- Forecasted load growth from data centers, manufacturing, and other drivers has created concerns that increasing load might place upward pressure on wholesale prices and T&D delivery infrastructure, and thus also retail electricity prices.
- Historical data over the last 5 years show counterintuitive results.
  - States with the highest load growth generally saw average prices <u>decline</u> in inflation-adjusted terms.
  - States with load contraction (via economic trends, energy efficiency, etc.) generally experienced <u>increased</u> prices.
- Importantly, this relationship need <u>not</u> always exist.

Load Growth vs. Retail Price Changes from 2019 to 2024

Price change in cents/kWh, inflation adjusted to 2024$. Load growth in percentage terms from 2019 to 2024.



Source: EIA • Created with Datawrapper

Note: Graphic shows prices in real 2024$; relationships are the same if shown in nominal terms

Source: Lawrence Berkeley National Laboratory and The Brattle Group, Recent Retail Electricity Price Trends: *What Do We Know… or Think We Know?, October 2025*, available at: https://eta-publications.lbl.gov/sites/default/files/2025-10/full_summary_retail_price_trends_drivers.pdf.

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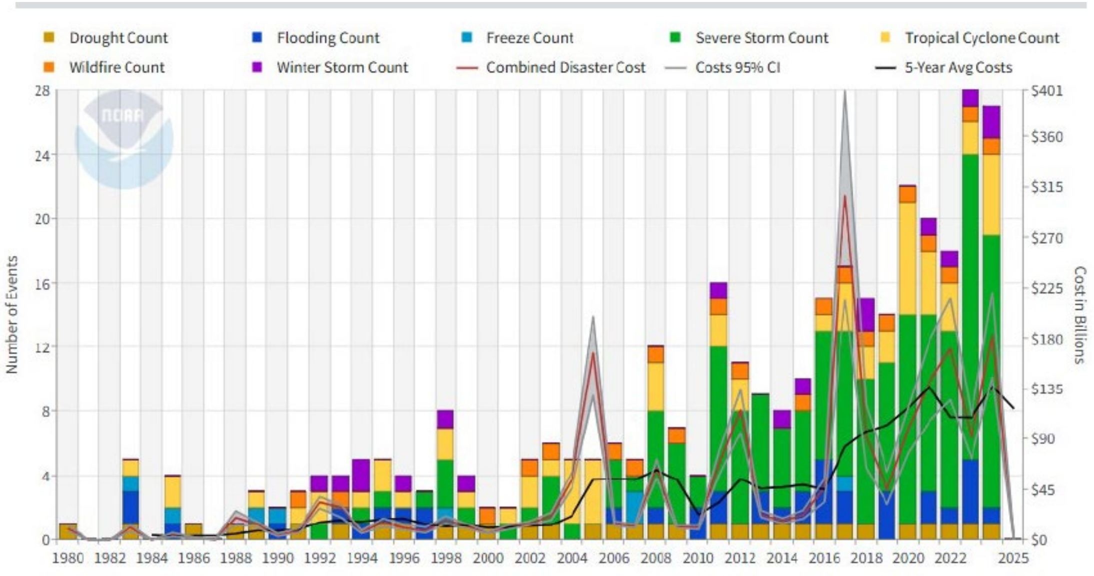
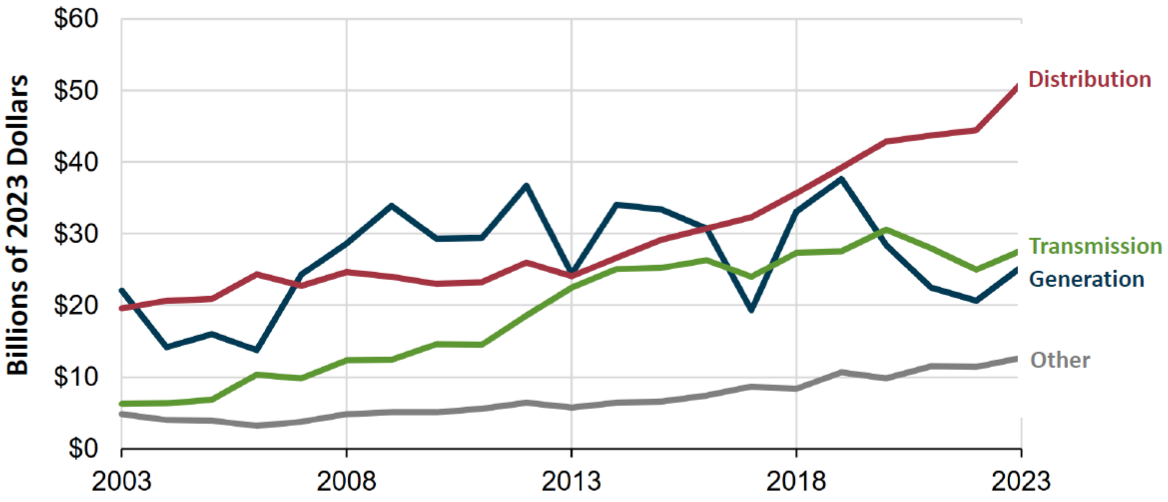
What do We Need to Prepare for?: 1/2

Count and Cost of U.S. Billion Dollar Disaster Events



Source: All dollar values reported in nominal dollars; see NOAA, Billion-Dollar Weather and Climate Disasters, accessed April 22, 2025.

Annual US Capital Additions by Sector (2003-2023)



Sources and notes: Data from US Energy Information Administration and Federal Energy Regulatory Commission (FERC) financial reports, accessed by Ventyx Velocity Suite. See EIA, Grid infrastructure investments drive increase in utility spending over last two decades, accessed April 30, 2025

- The increasing frequency and magnitude of extreme weather events poses challenges for the electricity infrastructure. They drive capital spending to restore the damaged infrastructure and improve system resilience (in addition to higher insurance, litigation, and other associated expenses.)
- The Edison Electric Institute estimates that over half of utility transmission and about two-thirds of distribution CapEx is not for expansion but rather for replacements and resiliency needs.

What do We Need to Prepare for?: 2/2

- Most of the large loads in the past few years were those that interconnect at the transmission level (Type A).
- The impact of potential surges of Type B loads that would likely require more distribution upgrades is unknown.

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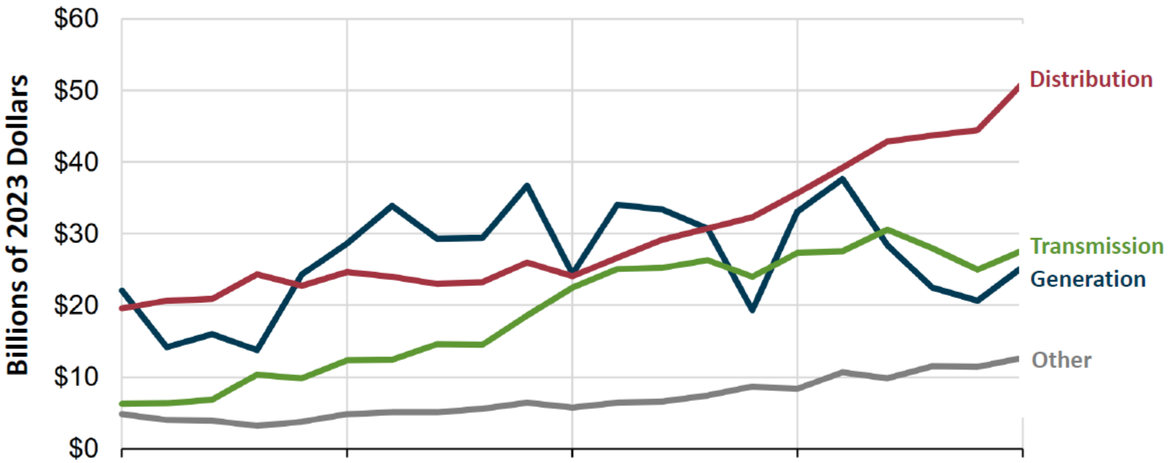

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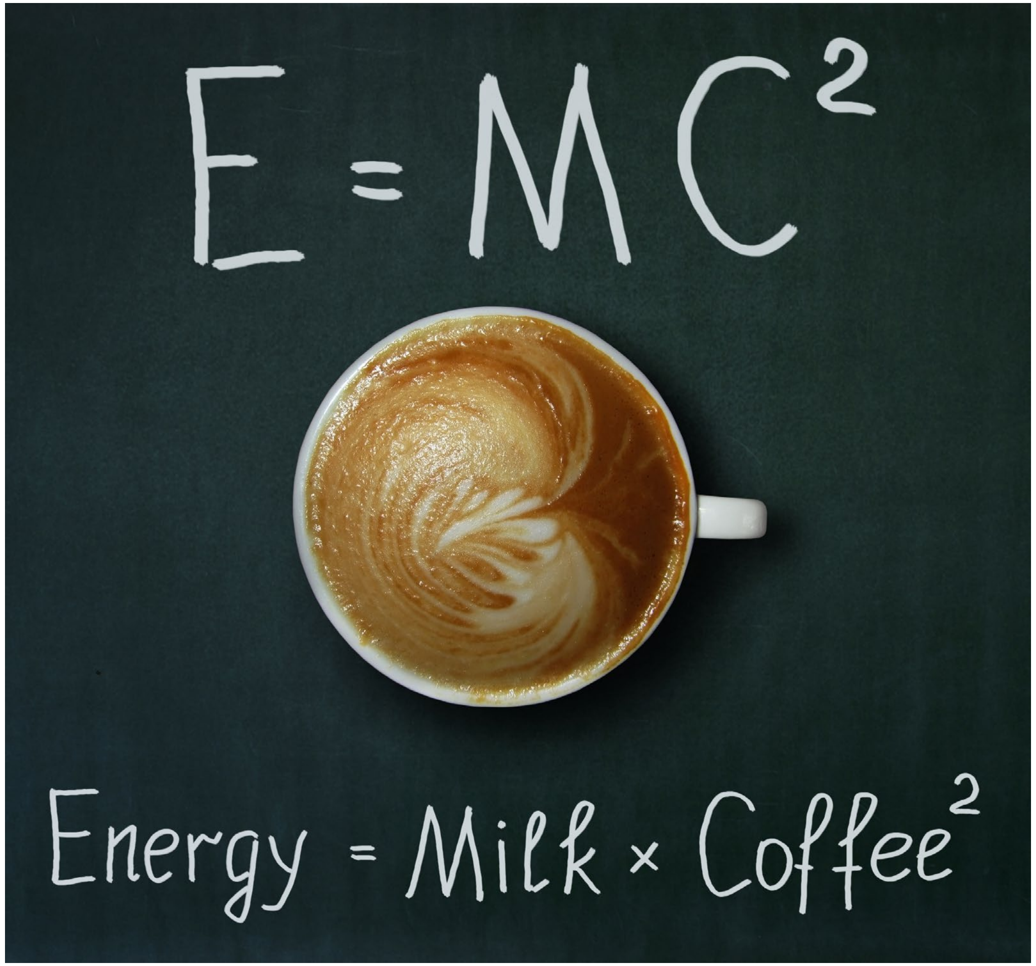
Potential Solutions	• Execute system buildout under the assumption of steady expansion. • Leverage load flexibility tools to optimize distribution grid usage. • Offset with increased energy efficiency.
Examples	• Electric vehicles, heat pumps.

+ = ???

Discussion



Presented By

T. Bruce Tsuchida
Principal, Boston

+1.617.234.5686
Bruce.Tsuchida@brattle.com

Mr. T. Bruce Tsuchida is a Principal of The Brattle Group with over thirty years of experience in domestic and international power generation development, utility operation, and power market analysis. He specializes in bridging technology, economics, and regulatory policy, particularly in assessing the impact of new technologies and regulatory changes. This includes modeling of evolving wholesale and retail electricity markets, impact of renewables, storage, and other new technologies' on system operations, utility business, and various valuations (including the engineering and technical capabilities) of transmission, generation, and distribution assets, deliverability, and contracts.

Prior to joining Brattle, Mr. Tsuchida was a Principal at Charles River Associates, and previously a Project Manager at the Tokyo Electric Power Company where he oversaw international generation development projects and was the lead engineer for Southeast Asia generation units.

Mr. Tsuchida earned his M.S. in Technology and Policy, and M.S. in Electrical Engineering and Computer Science from the Massachusetts Institute of Technology in Cambridge, Massachusetts, and a B.S. in Mechanical Engineering from Waseda University in Tokyo, Japan.

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