AMERICAN CLEAN POWER

U.S. National Power Demand Study

March 2025

Credit: Enel

The Following Study from S&P Global Commodity Insights was commissioned by

The American Clean Power Association (ACP), with the support of its partners: the American Petroleum Institute, Alliance to Save Energy, Clean Energy Buyers Association, Nuclear Energy Institute, the U.S. Chamber of Commerce, and the National Electrical Manufacturers Association.

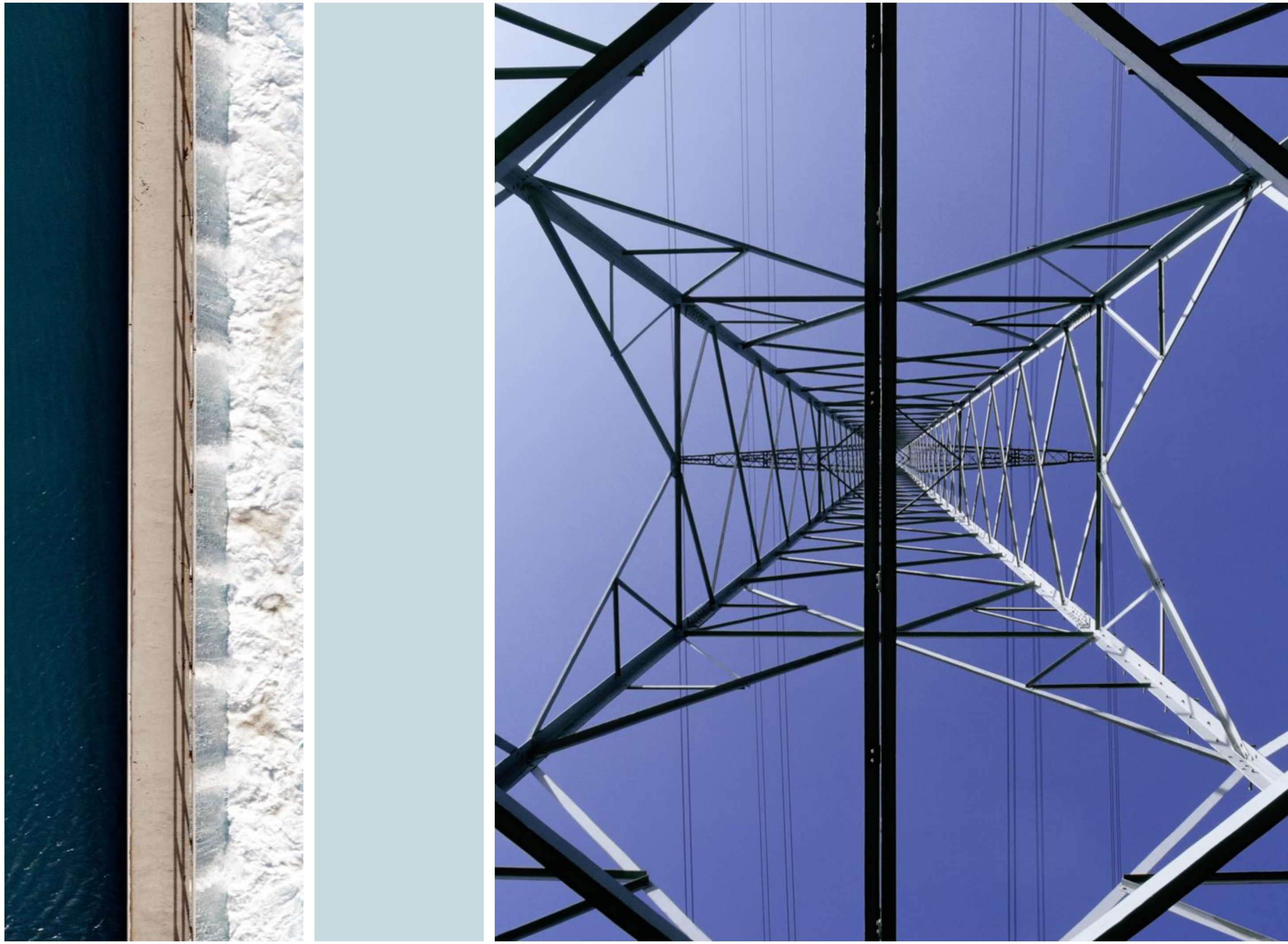
S&P Global
Commodity Insights

CI Consulting

US National Power Demand Study

- Final Report

Electricity Demand Returns to Growth



Prepared for The American Clean Power Association (ACP)

March 31, 2025

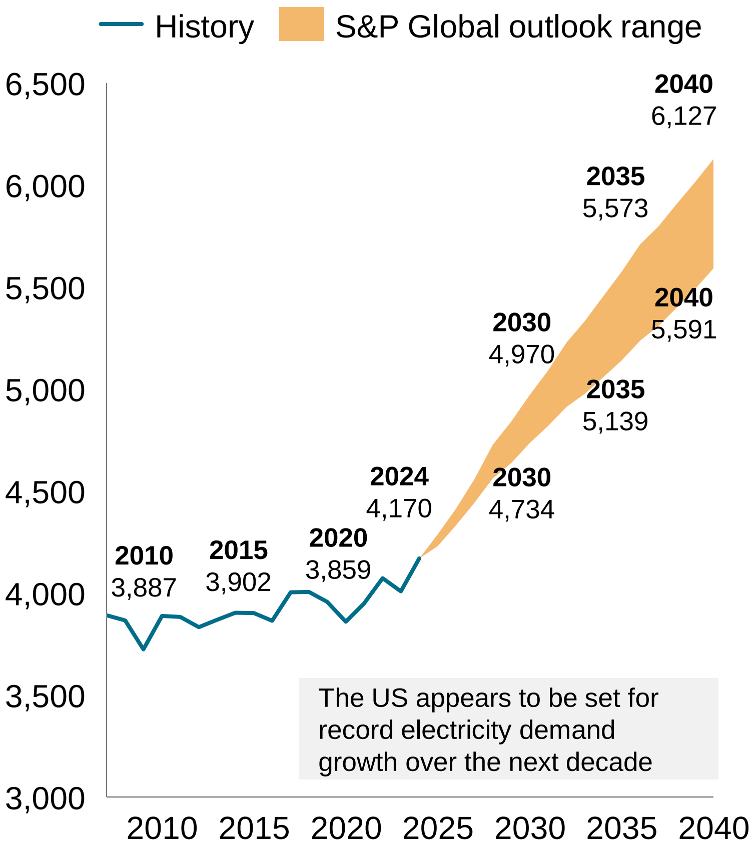
After two decades of nearly stagnant power demand, growth has returned to the sector

Key takeaways from the US National Power Demand Study

- Sustained power growth is driven by manufacturing and data centers in the near-term, and electrification of heating and transportation in the long-term. General economic and population growth underpin the outlook along the way
- The next five years pose a major risk of supply and demand imbalance, as datacenter buildout is expected to go through major development, while near-term supply response is constrained. Load flexibility and co-location stand out as the few options to help meet rising demand in the short-term
- The supply pathways involve renewables providing the bulk of energy volume, while natural gas-fired capacity and other firm resources like batteries will be critical to provide capacity and balancing support
  - By 2040, the US will require net additions of between 60 and 100 GW of gas, and over 900 GW of renewables and batteries, while continuing to support energy efficiency savings remain essential to maintain reliability
  - All current generation technologies face differing challenges in deployment, and load profiles across the grid are diverse, therefore, a diversified portfolio of generation technologies will be needed to ensure planning reserve margins are met and grid reliability is maintained
  - Additionally, there is a role for clean firm technologies not currently deployed at scale (advanced nuclear and geothermal), especially if carbon emission mitigation is prioritized
- Significant challenges remain to quickly bring online large amounts of generation, as the supply response is constrained by outdated interconnection processes, local opposition, siting/permitting delays, supply chain constraints, ongoing challenges in developing economic transmission projects, and other limitations to deploying energy delivery infrastructure
  - Thoughtful and timely policy reforms and a diversified supply response portfolio will be needed to reduce the demand/supply tension
- The stakes are high. Successfully navigating these challenges will unlock economic growth (e.g., generative AI, expansion of industrial base) and efficient, lower carbon emission trajectories for the sector. Electricity supply shortfalls in the near term could translate into longer-term missed economic opportunities

US Lower 48 net on-grid electricity demand

TWh



Source: S&P Global Commodity Insights

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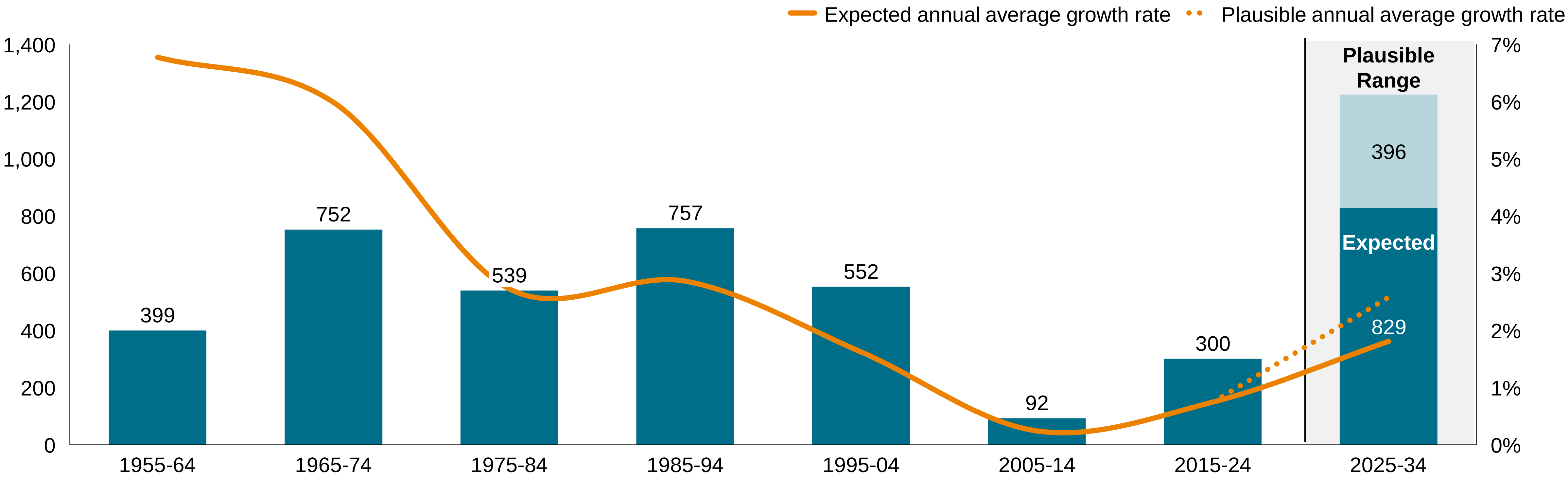
US power demand has gone through periods of slow and rapid growth, but the coming decade will see more absolute electricity demand growth than ever before in US history

Growth in US electricity consumption, 10-year periods

10-year growth (TWh)



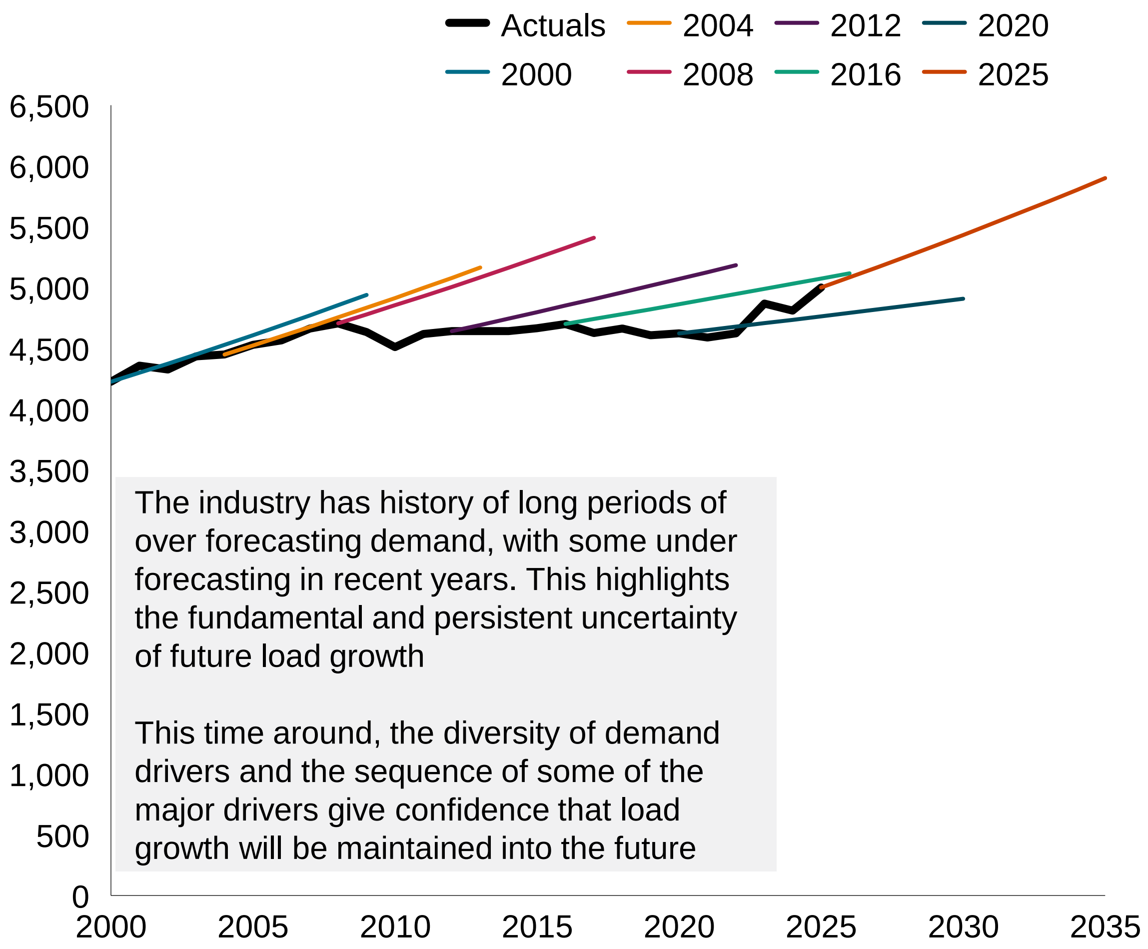
- The US appears to be set for record electricity demand growth over the next decade, driven by large loads and widespread electrification
- Confidence in these loads materializing is driven by supportive electrifications policies, corporate commitments, technological advancements, and significant infrastructure investments
- Additional upside potential stems from large loads coming from the rapid expansion of datacenters needed to support generative AI and the revitalization of US manufacturing

Source: Energy Information Administration (July 2024); S&P Global Commodity Insights

Diversity of drivers and early data give confidence to the bullish load growth forecast

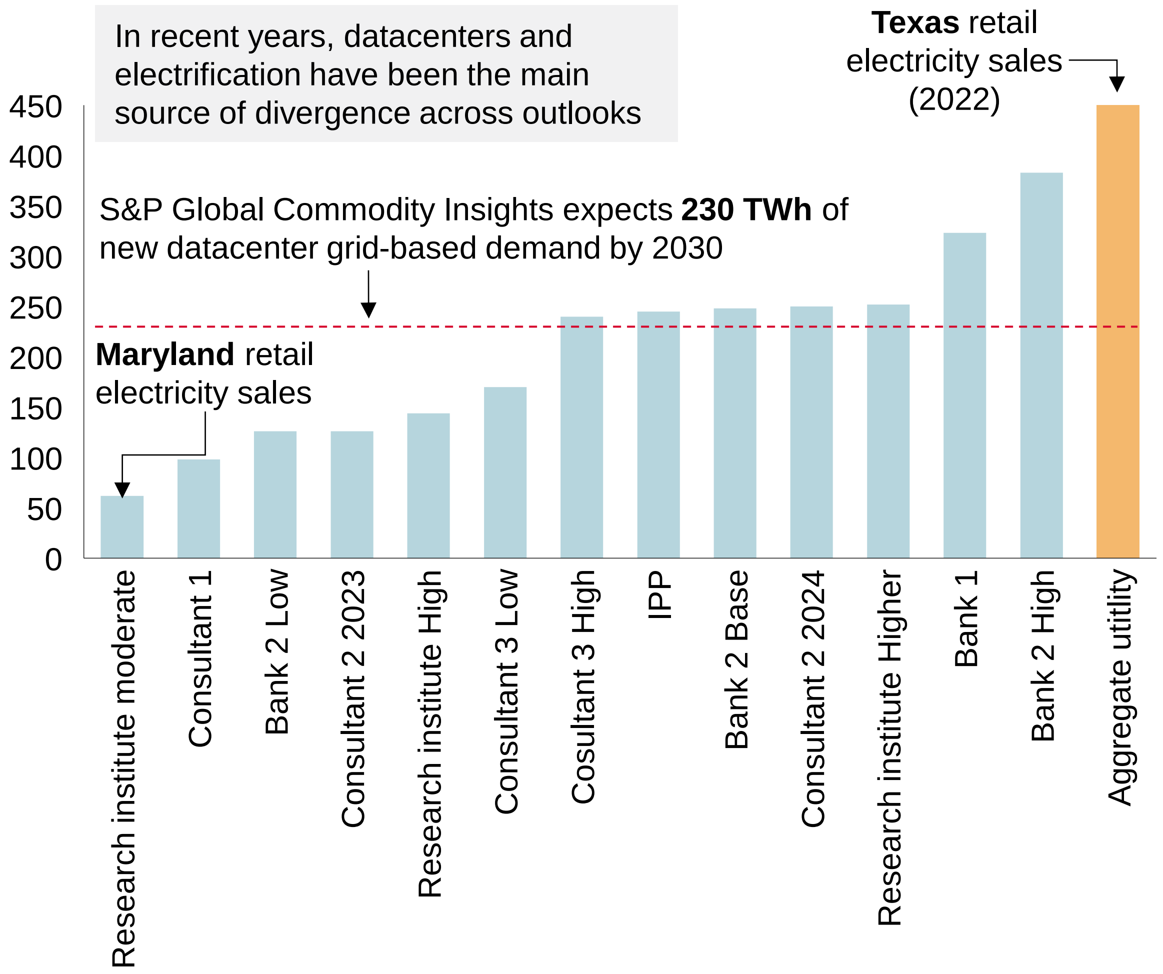
NERC net energy load forecast by LTRA

TWh



Estimates for new US datacenter demand from 2023–30

TWh

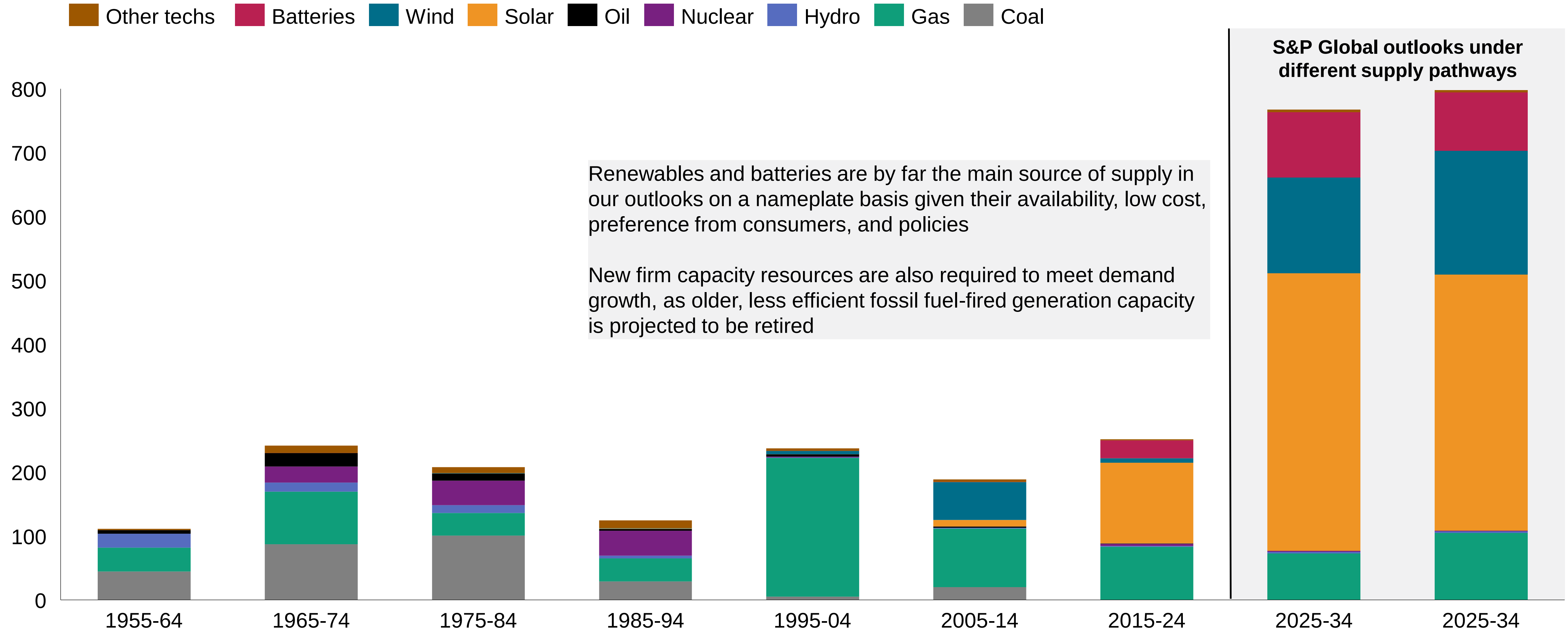


LTRA: Long Term Reliability Assessment. Aggregate Utility: Sum of individual utility forecasts of data center load growth expectations.
Source: North American Electric Reliability Corporation's (NERC) Long Term Reliability Assessment, S&P Global Commodity Insights

Decades of substantial coal/gas capacity expansion are giving way to solar and wind, which S&P Global expects to account for over 75% of all capacity additions in the next 10 years

US capacity additions by technology type (nameplate), 10-year periods

GW



"Other techs" includes geothermal and biomass.
Source: S&P Global Commodity Insights

With an increasing risk of undersupply, planning reserve margin targets remain one of the key metrics to follow for grid planners

Planning Reserve Margins are a key metric to assess energy adequacy

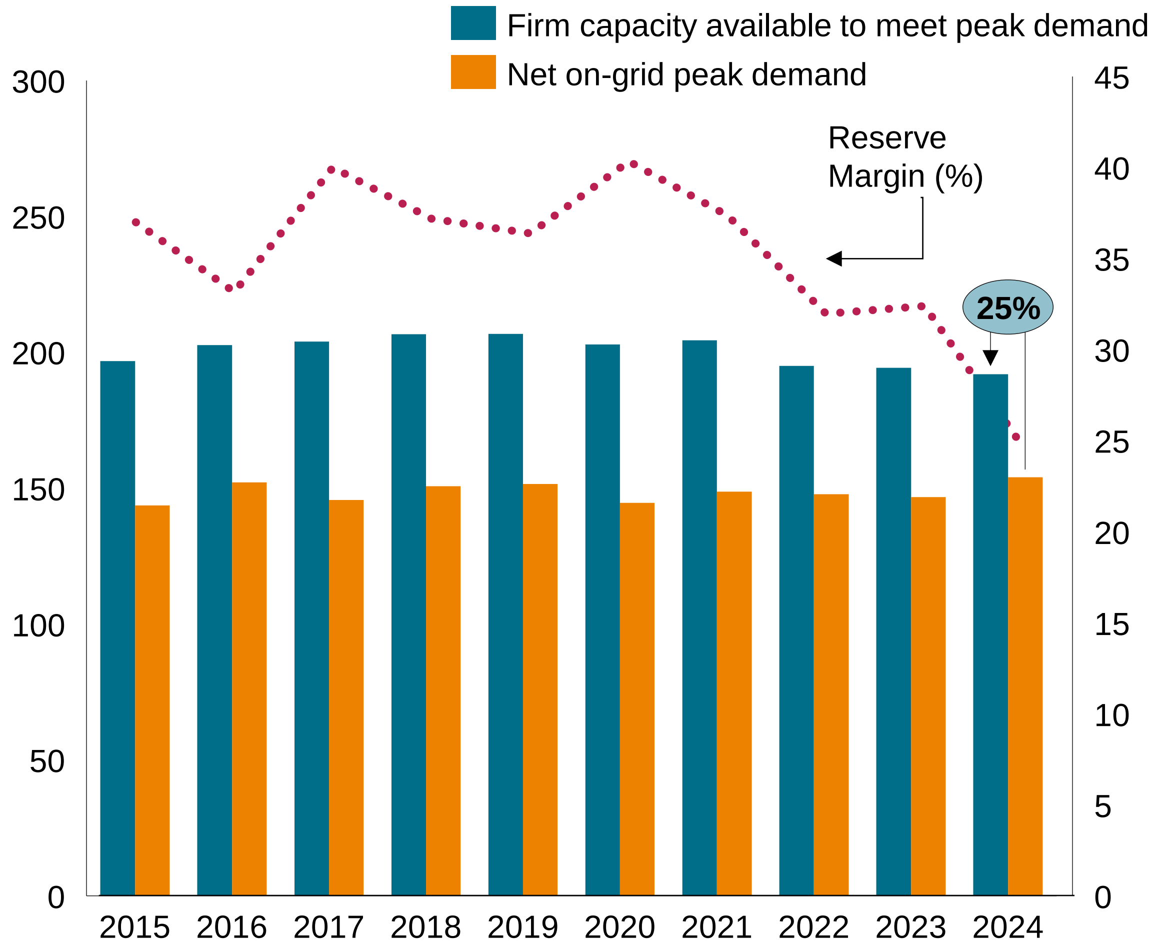
- Planning reserve margin targets are a critical component in the planning and operation of electricity grids, determining the acceptable buffer between available supply and expected demand. They represent the percentage of required extra capacity that exceeds the anticipated peak demand
- Falling reserve margins are an early indicator of the need for new supply. Reserve margins had already begun dropping in some markets like PJM leading to rising concerns about supply-demand balance. Upward revisions to near-term demand forecasts starting in late 2023 exacerbated these concerns
- Going forward, reserve margin values also represent evolving assessments of how different resources are expected to contribute to reliability over time given specific market conditions

Relation between reserve margins and loss of load

- Planning reserve margins help grid operators and policymakers anticipate and prepare for future electricity needs. They are typically set to achieve a specific Loss of Load Expectation (LOLE), which quantifies the likelihood that the demand for electricity will exceed available supply over a given period. A frequently used LOLE target is 0.1 Loss of Load Events per year
- A lower LOLE indicates a higher level of reliability, meaning that the grid is less likely to experience shortages or system outages. By setting planning reserve margins to meet a particular LOLE, planners can balance the cost of installing and maintaining additional capacity with the need for reliable service and the societal costs associated with system outages

Peak demand and firm capacity available for PJM

MW

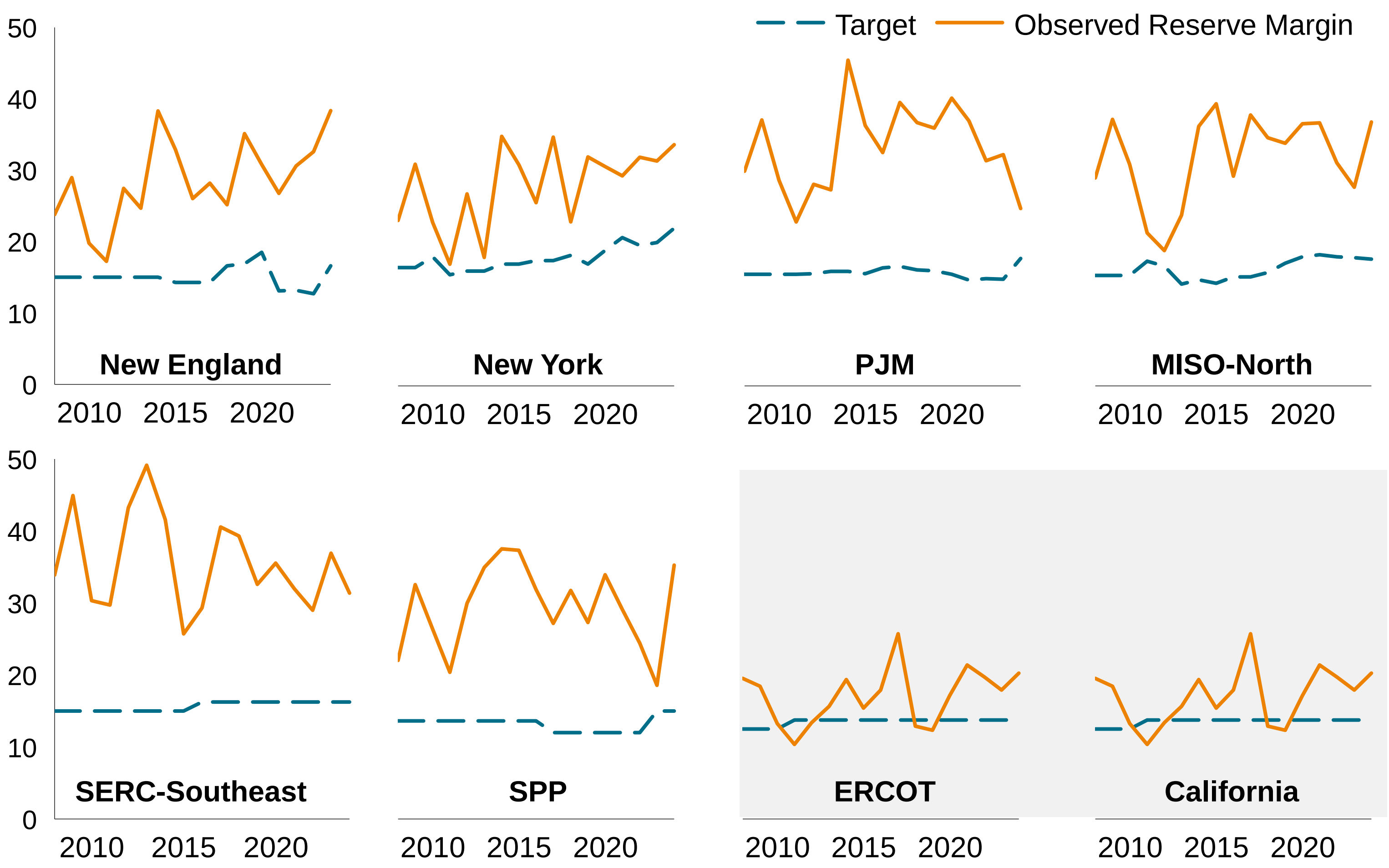


Source: S&P Global Commodity Insights

In the past two decades we have seen above-target reserve margins for most US regions, due to the combination of substantial gas-fired capacity additions + modest demand growth

Planning reserve margins for select markets

%



Recent Trends in Planning Reserve Margins

- Over the past two decades, reserve margins in many U.S. regions have generally remained above target levels, largely due to the significant expansion of natural gas-fired power plants during the 2000s and the relatively modest growth in electricity demand
- In contrast to the national trend, the Electric Reliability Council of Texas (ERCOT) has maintained reserve margins closer to target levels due to its unique market design and specific regional dynamics. ERCOT operates an energy-only market without a capacity market, relying on shortage pricing to incentivize new entry
- California has also faced challenges in maintaining adequate reserve margins over the past decade. However, recent years have seen a reversal of this trend, largely driven by the substantial deployment of battery energy storage systems (BESS)

Source: S&P Global Commodity Insights

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This study is based on three S&P Global North American Power and Gas market outlooks through 2040

Planning Case

Our view of the **most likely** evolution of US and Canadian power markets.

Power Crunch

Examines major Planning Case uncertainties around demand growth and renewable development costs.

Power Crunch (w/ CO_2 emissions adjusted)

Examines the clean firm power required to mitigate approximately half of the additional emissions from the Power Crunch Case over the Planning Case.

The Planning and Power Crunch cases presented herein are recent but different vintages; therefore, some discrepancies in scenario design may exist. Such discrepancies are not critical to the key messages in this Study.

Planning Case reflects our ‘most likely’ future for US power markets

Factors under consideration

Technology costs and performance	Reflect S&P Global latest expectations for the cost and performance of wind, solar photovoltaic (PV), battery energy storage and natural gas-fired technologies.
Commodity pricing	Incorporates commodity price outlooks, particularly for natural gas (in both short and long terms), into the outlooks for both capacity and generation mix.
Policy trends	Reflects assumed implementation of most existing policies and some further policy developments where supporting trends or significant momentum exist (e.g., state and corporate clean/renewable energy ambitions, net energy metering reform, state/city support to electrify residential and commercial heating).
Transportation electrification	Reflects the latest national outlook from experts across Commodity Insights, notably Mobility and Energy Futures and the Hydrogen and Renewable Gas Forum. US outlook is translated to state outlooks based on state-level vehicle fleet and usage metrics and broad trends in facilitating EV deployment and then mapped to power markets.

Power Crunch is a sensitivity case to the Power Planning Case that explores potential disruptions and deviations from trend

Factors under consideration

Higher demand growth	Higher-than-expected growth in datacenter-driven and new manufacturing power demand, especially in the near term. New industrial load growth disproportionately higher in markets like PJM and ERCOT.
Higher cost to develop new large-scale wind and solar	Challenges around interconnection, siting and permitting of onshore renewables persist and raise development costs. Major differences across states and technologies create a complex patchwork.
Larger role for fossil fuels	Increased gas-fired generation development, expansion of natural gas pipeline infrastructure, higher utilization of the fossil generation fleet.
Higher utilization of existing power infrastructure	Accelerated repowering timelines for wind and solar, incremental coal and gas retirement delays, restarting recently retired nuclear, higher utilization of the existing fossil generation fleet.

Power Crunch with CO_2 emissions adjusted is a sensitivity case to the Power Crunch that examines clean firm additions needed to keep emissions closer to the Planning Case levels

Adjustment to the Power Crunch Case

New clean firm capacity	▪ 28 GW of new clean firm power is added by 2050 to mitigate approximately half of the additional emissions from the Power Crunch Case over the Planning Case ▪ Incremental additions of clean firm capacity begin in 2035 ▪ Incremental additions start higher and then slow down by the mid-2040s until 28 GW is reached
- New nuclear capacity	▪ 25.5 GW of new nuclear capacity is added by 2050, most of which is sited at existing nuclear facilities — primarily in PJM, SERC and MISO — that previously applied for a combined license (COL) or early site permit (ESP) ▪ The successful restart of the recently retired Three Mile Island, Palisades and Duane Arnold plants and expansions at two other sites (Columbia and Joseph M. Farley) is assumed ▪ Most sites assume sufficient space for three SMR units (900 MW total) and 25.5 GW total by 2050
- New geothermal capacity	▪ 2.5 GW of incremental geothermal capacity is added to the California and NWPP markets by 2050

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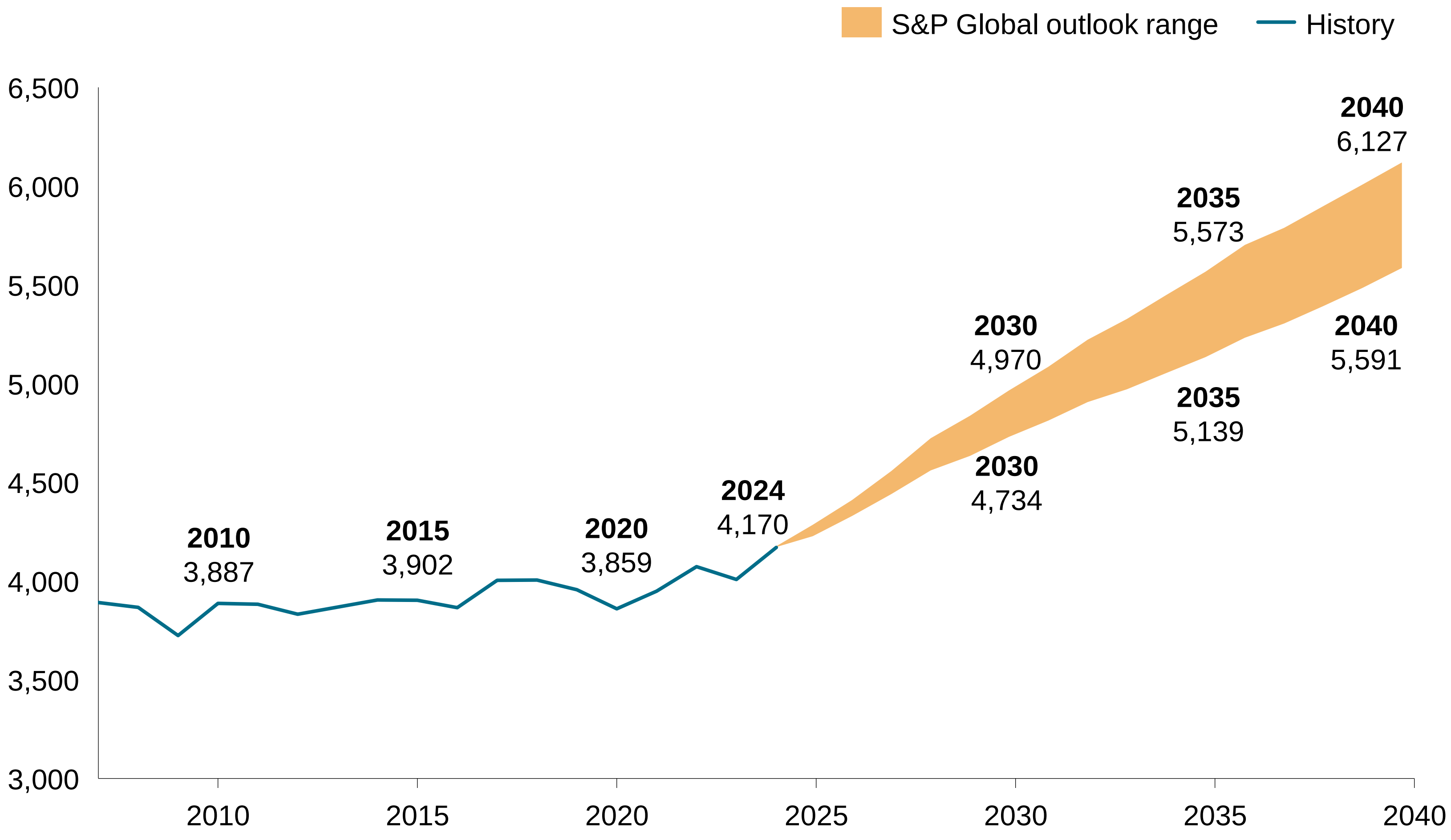
Summary of demand growth drivers

- The next decade is projected to demand more new electricity than any ten-year period in the nation's history. The diversity and sequence of the major drivers point to sustained growth in the sector
  - Between 2024 and 2040, electricity demand in the US is expected to grow by 35-50% driven by a combination of underlying economic growth, large industrial loads like datacenters and manufacturing, and the electrification of transport and heating
- Up to 2030, large loads are the main source of growth, driven by datacenters and manufacturing. These loads are significantly concentrated in the Eastern Interconnection regions (PJM, MISO, Southeast) and Texas (ERCOT)
- Electrification of transportation and heating are main drivers of demand growth over the long-term
  - Electric vehicles (EVs) reach 10% of total energy demand by 2040. Regions with the most EV demand are PJM, Southeast and California
  - Electrification of heating is projected to comprise 3% of total demand by 2040. Supported by state policies, a rising share of new residential and commercial customers across all states adopts electric space- and water-heating rather than natural gas
  - Electrification increases winter peak demand, with some regions in the US becoming winter peaking around 2040. This has implications for resource planning, as the reliability contributions of different supply technologies differ in the winter versus the summer
- The heterogeneous load profiles emerging from evolving demand drivers emphasizes the need for a diversified generation portfolio to sustain grid reliability and resilience
- Energy efficiency emerges as a crucial factor in mitigating demand growth, effectively offsetting increases by optimizing energy use across sectors
  - Energy Efficiency Resource Standards (EERS) are assumed to be achieved in most states due to their track record of compliance. By 2040, cumulative savings after 2024 will go up to 431 TWh, a level comparable to 8% of total energy demand
  - Roughly half of U.S. states have a rate-payer-funded EERS policy designed to slow electricity demand growth. Efficiency savings will vary regionally, influenced by specific targets and historical performance in implementing efficiency measures

Total US electricity demand is projected to grow approximately 35-50% between 2024 and 2040

US Lower 48 net on-grid electricity demand, 2007–40

TWh



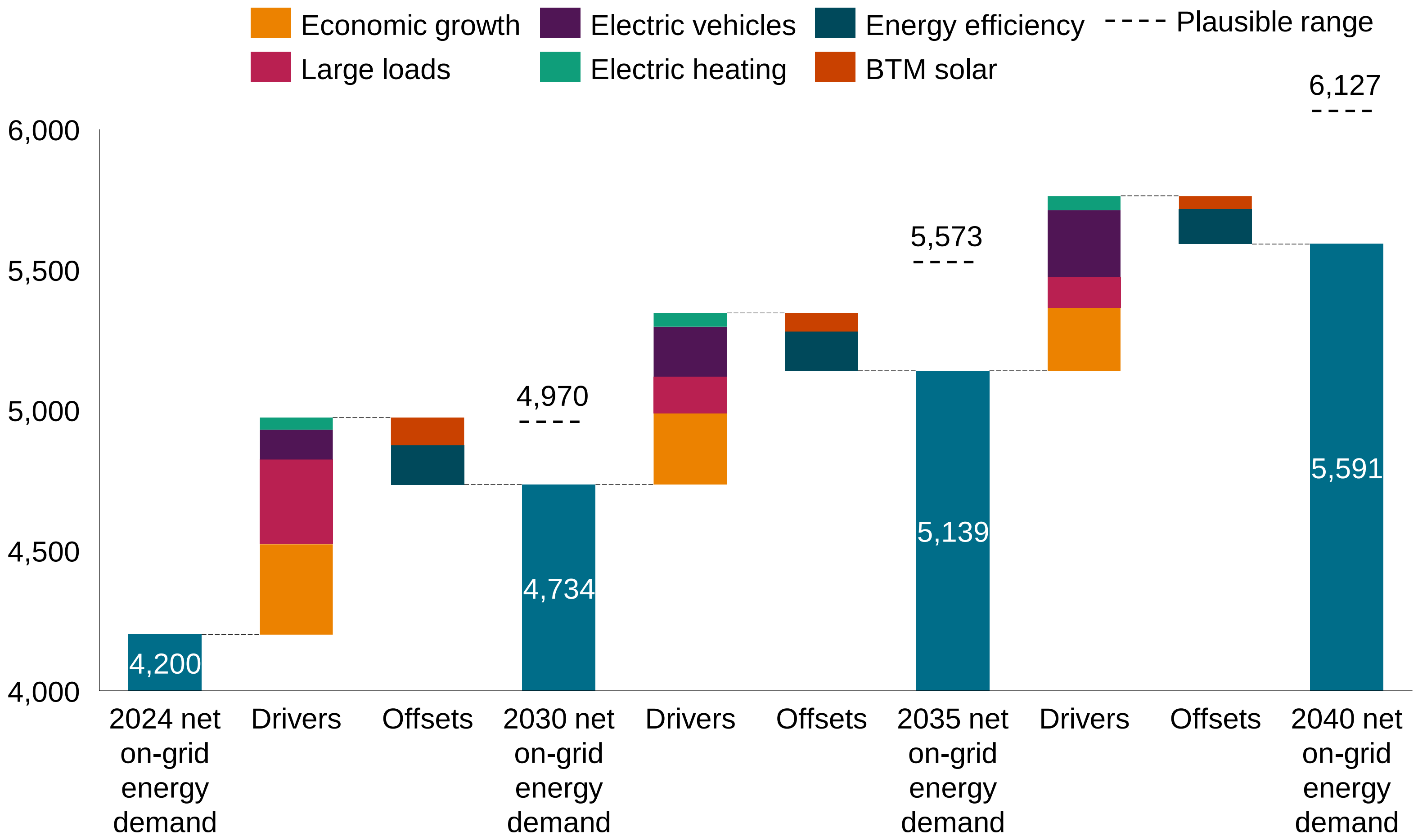
- Electricity demand across the US grows by 1.9-2.7% per year from 2024 to 2034
  - Between 890-1,300 TWh of new demand is expected during this period – an equivalent of adding another US Western Interconnection to the grid
  - In the near term, the primary drivers of energy demand are large industrial loads, such as datacenters and new battery and chip manufacturing facilities, and the electrification of the Permian Basin (especially in ERCOT and SPP)
- The pace of growth in electricity usage moderates slightly post-2034. From 2035 to 2040, the annual increase in load growth averages 1.7-1.9%
  - An additional 450-550 TWh of demand is anticipated between 2035 and 2040 – on par with the current energy demand in ERCOT
  - Electrification becomes the main driver of new electricity loads
- The boost in electricity demand in the upside case is primarily attributed to higher load projections from datacenters, with additional demand coming from other large industrial loads

Source: S&P Global Commodity Insights

Large loads drive energy demand growth over the next decade before electrification takes over

Drivers and offsets of growth in US Lower 48 net on-grid electricity demand, 2024–40

TWh



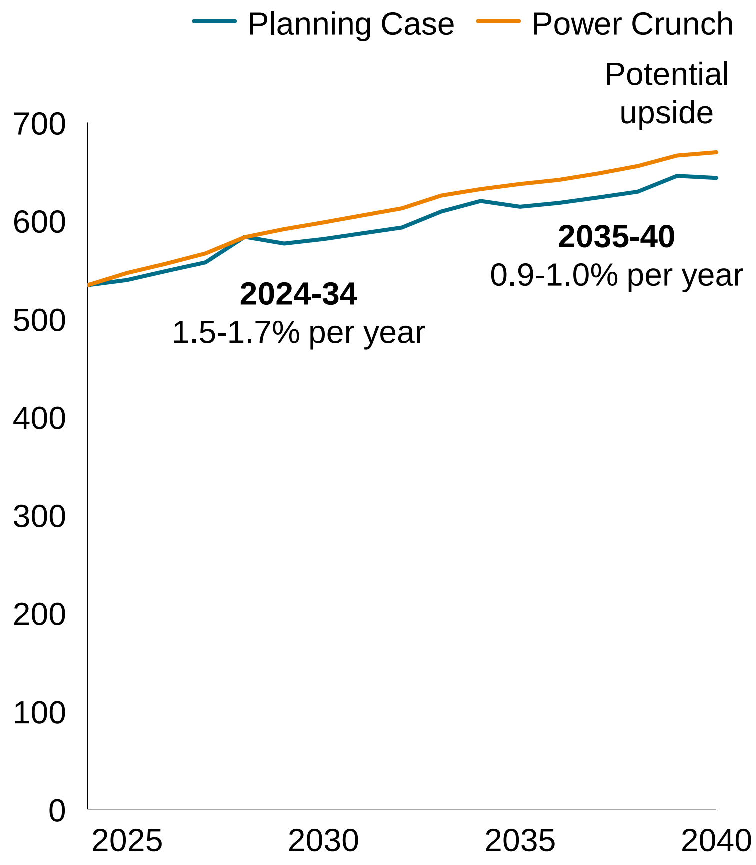
- **Large industrial loads,** including datacenters and manufacturing facilities, play an outsized role in demand growth over the next 5 years
- **EV adoption** accelerates in the latter part of the outlook as falling battery costs make EVs more economically attractive
- **Large flexible loads** are driven by cryptocurrency in the near term and hydrogen electrolyzers in the long term. Electrolyzer demand picks up steam later in the outlook as hydrogen use cases become more cost effective
- **Energy efficiency gains** offset on-grid demand throughout the outlook, particularly before 2035
- **Behind-the-meter (BTM)** solar continues strong growth over the next decade, offsetting on-grid demand from other sectors. After 2035, many regions reach thresholds expected to trigger net energy metering reforms that significantly curb BTM solar growth, like California's NEM 3.0. This slower growth combined with retirements means incremental reductions in demand from BTM decrease in the latter part of the outlook

Economic growth is based on economic and demographic inputs. Energy efficiency reflect cumulative incremental growth relative to 2024.
Large load includes large industrial load (datacenters and manufacturing) and large flexible load (electrolyzer and cryptocurrency mining).
Source: S&P Global Commodity Insights

Large loads and electric vehicles drive electricity demand growth in the Eastern Interconnection

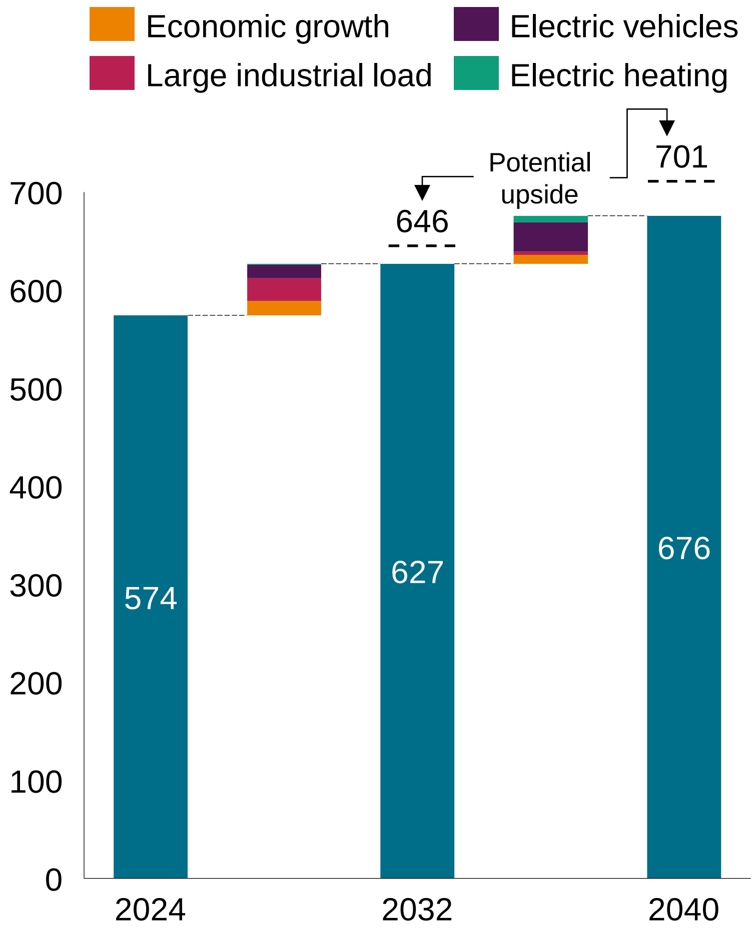
Net on-grid peak demand, Eastern Interconnection

GW



Growth in net on-grid peak demand

GW

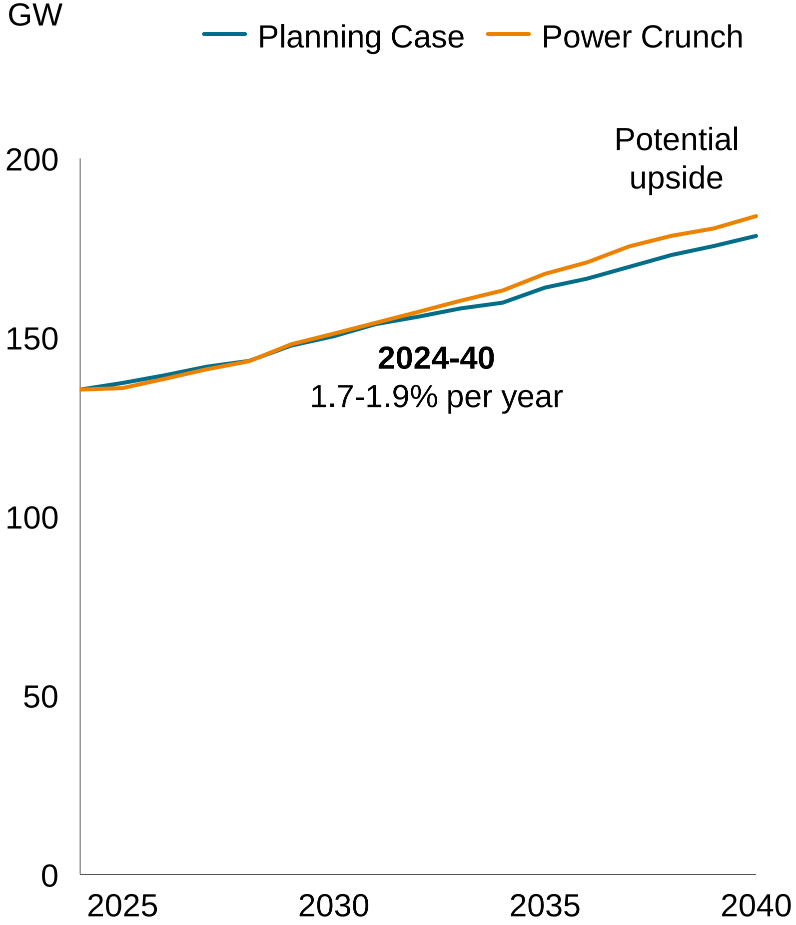


- Large loads such as datacenters and manufacturing in PJM, the Southeast, MISO, and SPP drive appreciable growth through the late 2020s and early 2030s but growth tails off later in the outlook
- EV adoption is expected to be moderate in the near-term. However, EV adoption picks up in the latter half of the outlook
- Economic growth in the region contributes a moderate portion of the increase in demand by 2040, particularly in the Southeast, MISO, and SPP
- Tax credits and various forms of incentives are provided for energy efficiency programs and BTM solar generation in most states in the region, helping alleviate some of the pressure on the grid.
- Potential upside is driven by a combination of manufacturing and datacenter load growth, while potential downside risks stem from demand for electrolytic hydrogen, EV adoption rates, and also the uncertainty range in datacenter power demand and manufacturing expansion

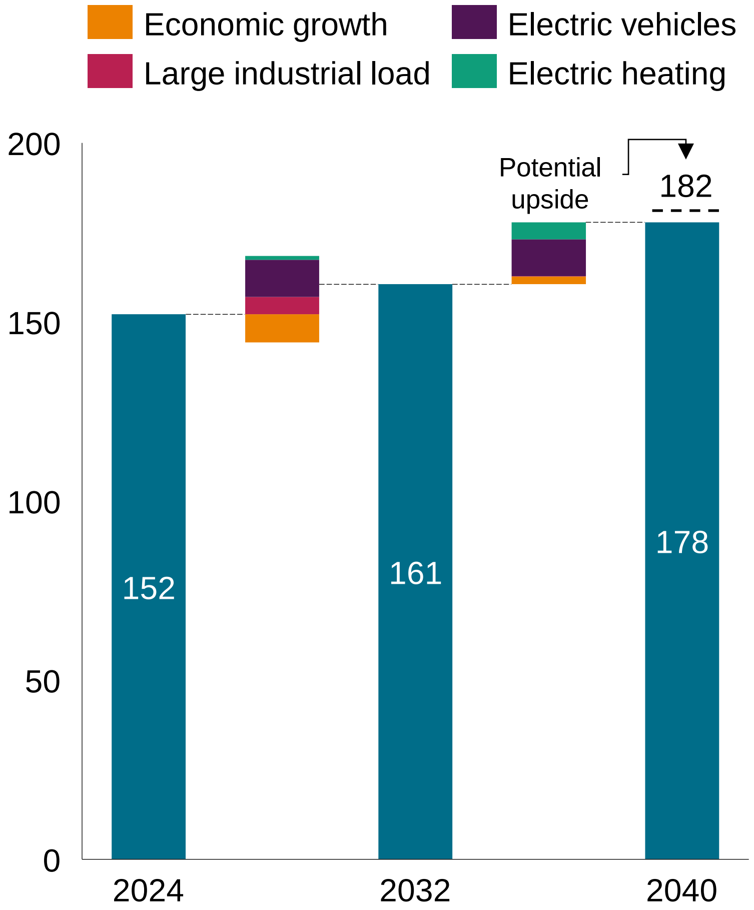
Note: (L): Annual coincident peak demand in the Eastern Interconnection. (R): Annual non-coincident peak demand in the Eastern Interconnection. Large industrial load includes datacenters and manufacturing. Large flexible load includes electrolyzer and cryptocurrency mining. Economic growth is based on microeconomic and demographic inputs reconstituted for expected energy efficiency savings.
Source: S&P Global Commodity Insights

Demand growth in the US Western Interconnection is largely driven by electrification

Net on-grid peak demand, Western Interconnection
GW



Growth in net on-grid peak demand
GW

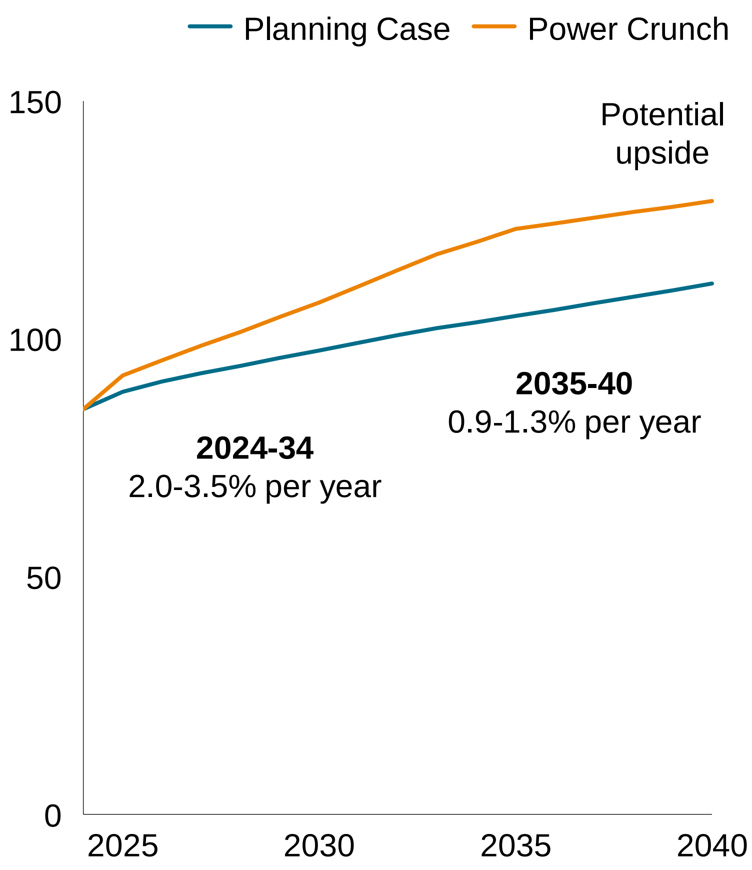


- Electric vehicles are the largest contributor to peak demand growth in the region. California, Washington, Oregon, Nevada, Colorado and New Mexico all have some form of zero emission vehicles mandates in place, driving EV demand. In addition, many states and utilities across the west have enacted EV incentives and rebate programs to spur adoption
- Electrification of heating is a key driver of demand in California and the Pacific Northwest beginning in the 2030's
- Upside in the outlook is attributed to additional datacenter load in the region, while potential downside risks stem mostly from EV adoption rate uncertainty
- In California, behind-the-meter (BTM) solar continues to grow and offset demand growth through the 2030s despite the less supportive Net Billing Tariff (NEM 3.0) policy

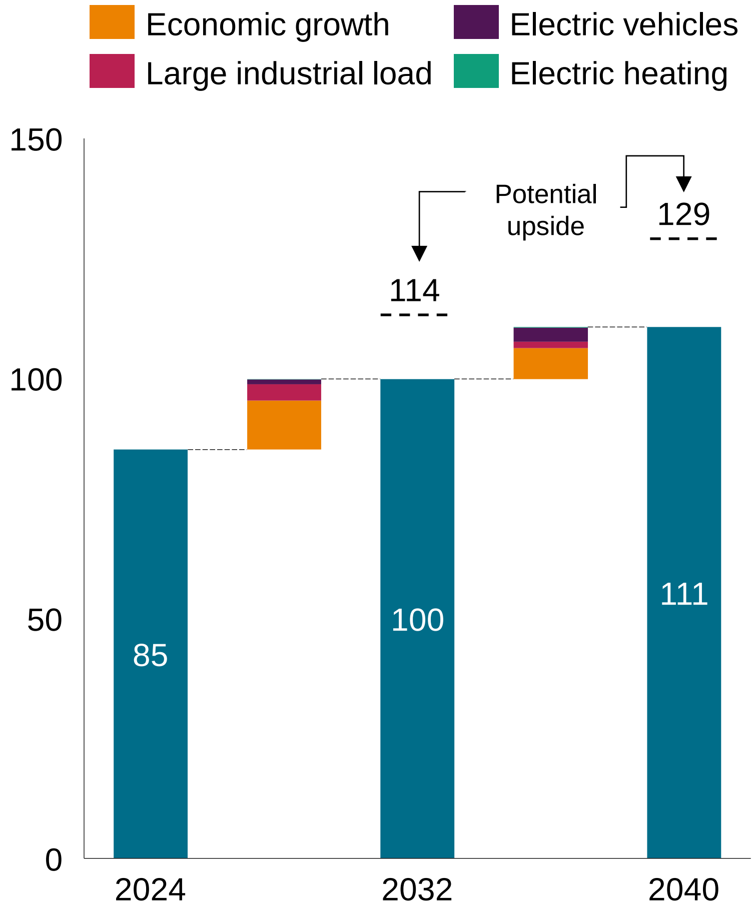
Note: (L): Annual coincident peak demand in the Western Interconnection. (R): Annual non-coincident peak demand in the Western Interconnection. Large industrial load includes datacenters and manufacturing. Large flexible load includes electrolyzer and cryptocurrency mining. Economic growth is based on microeconomic and demographic inputs reconstituted for expected energy efficiency savings.
Source: S&P Global Commodity Insights

Economic growth, large loads, and electrification drive higher electricity demand in ERCOT through 2040

Net on-grid peak demand, ERCOT
GW



Growth in net on-grid peak demand
GW



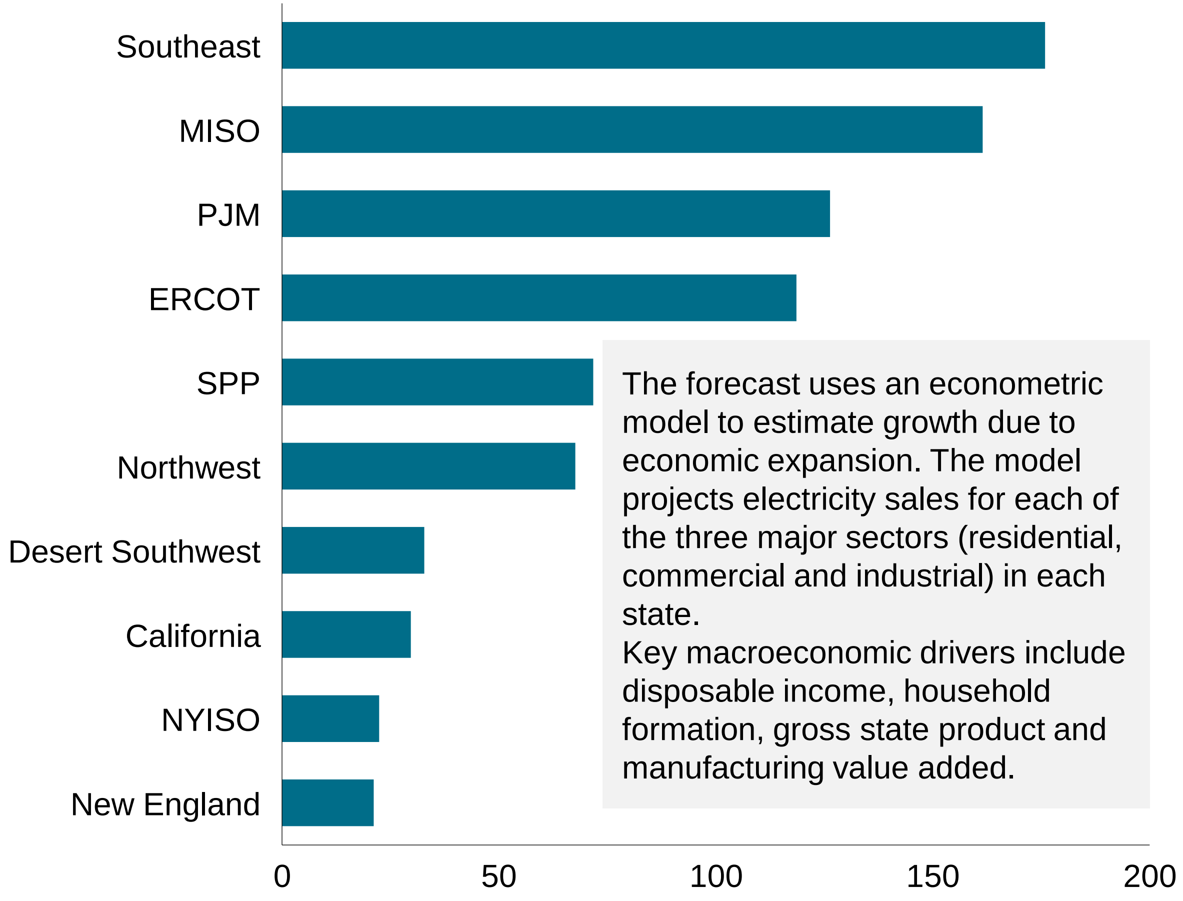
- Economic growth is the largest driver of new electricity demand in ERCOT. Texas's economy and population are projected to grow at a faster rate than the rest of the nation
- Large industrial loads and large flexible loads are the second largest contributor to higher electricity demand. Datacenters, cryptocurrency mining facilities, and other large electric customers drive higher electricity demand through 2035, while flexible hydrogen facilities drive higher demand later in the outlook. Permian electrification drives demand both in the near- and long-term
- Electrifying the transportation sector accelerates in the mid-2030s, leading electric vehicles to account for 5% of net on-grid demand by 2040
- Investments in state energy efficiency programs and behind-the-meter solar slightly slow net on-grid electricity demand growth
- Potential upside in the outlook comes entirely from large industrial loads, while potential downside risks relate to the uncertainty range in datacenter power demand and manufacturing expansion

Large industrial load includes datacenters and manufacturing. Large flexible load includes electrolyzer and cryptocurrency mining. Economic growth is based on microeconomic and demographic inputs reconstituted for expected energy efficiency savings.
Source: S&P Global Commodity Insights

Economic growth expected to drive 828 TWh increase in US electricity demand between 2024 and 2040

Net change in economic growth energy demand, 2024–40

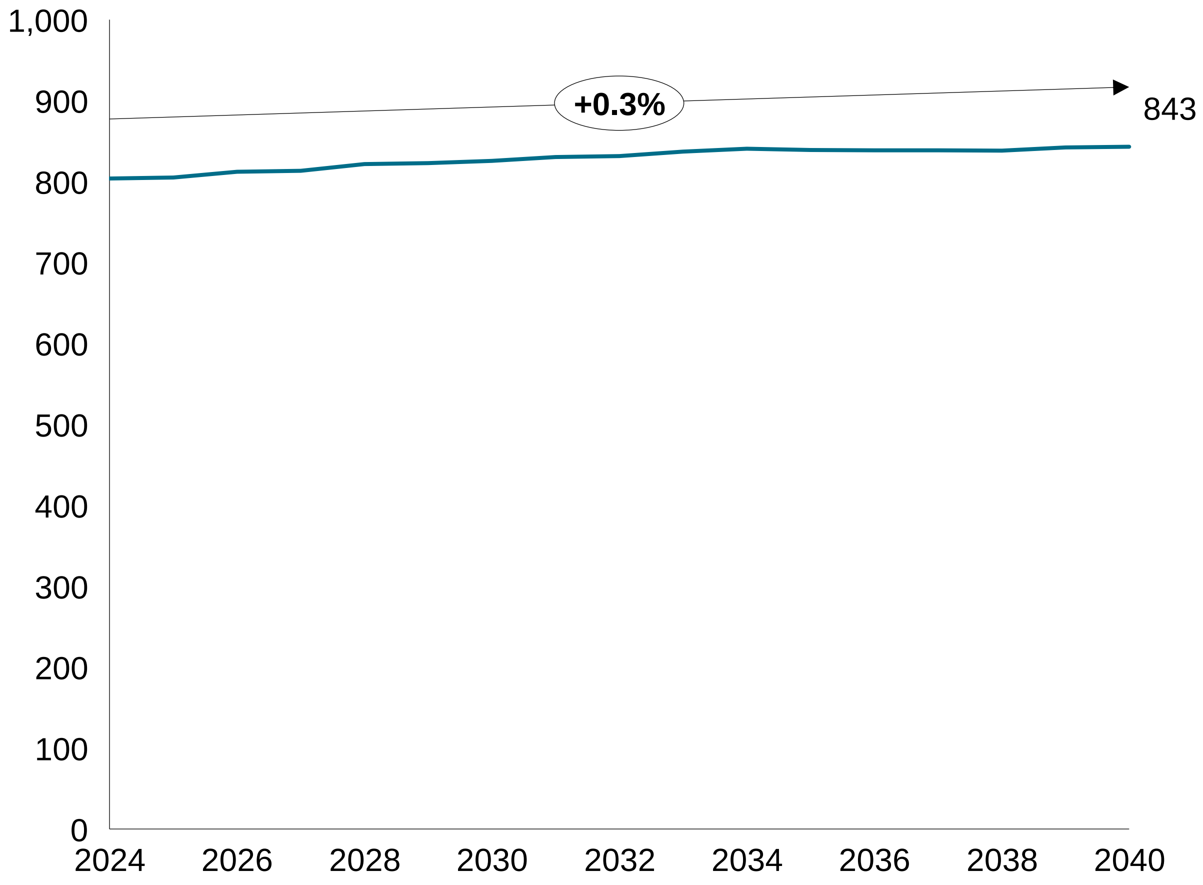
TWh



The forecast uses an econometric model to estimate growth due to economic expansion. The model projects electricity sales for each of the three major sectors (residential, commercial and industrial) in each state.
Key macroeconomic drivers include disposable income, household formation, gross state product and manufacturing value added.

Economic growth peak demand, 2024–40

GW

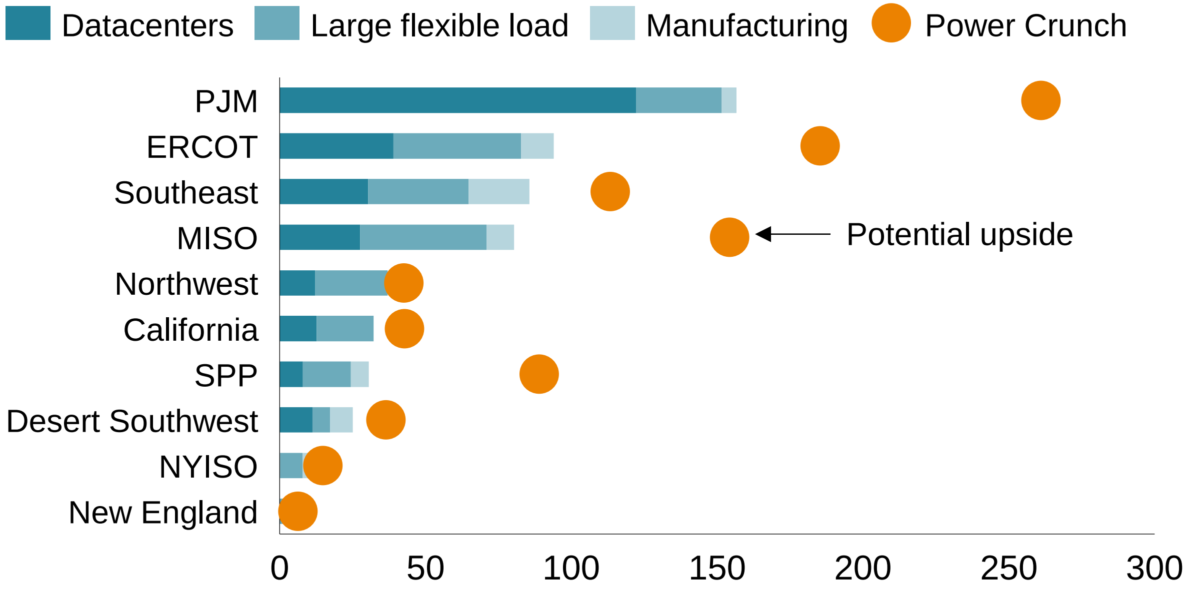


Corresponds to S&P Global econometric demand forecast reconstituted for expected energy efficiency savings. Does not include EV, heating electrification, large flexible load, or incremental large industrial demand.
Source: S&P Global Commodity Insights

Incremental electricity demand from datacenters, manufacturing facilities, and large flexible loads drives significant load growth, especially through the early 2030s

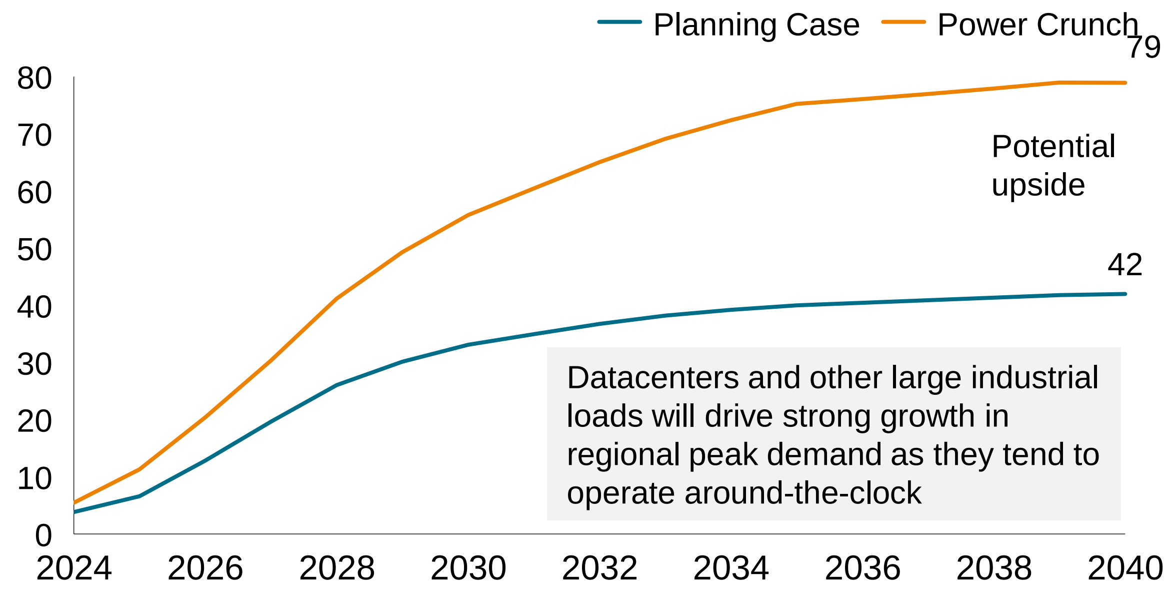
Net change in large load energy demand, 2024–40

TWh



Large industrial load peak demand, 2024–40

GW

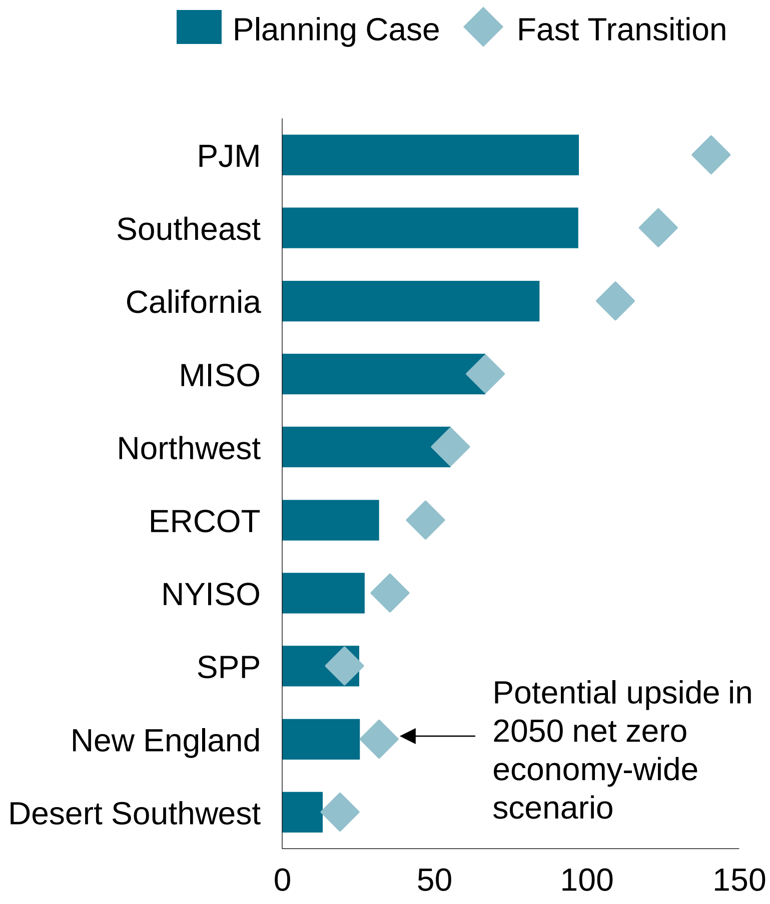


- In PJM, growth in new industrial loads is dominated by the expansion of datacenters in Northern Virginia and along major high-voltage transmission corridors through Indiana, Ohio and Illinois. In ERCOT, new industrial load growth in the upside case is primarily driven by the electrification of oil and gas operations in the Permian Basin.
- The upside case assumes over 400 TWh of additional large industrial load by 2040, with 70% of it concentrated in ERCOT, PJM, and MISO. While datacenters represent the primary upside to load forecasts, incremental load growth is also driven by new battery and chip manufacturing facilities and electrified oil and gas operations. Many of these new loads rely on the continued but uncertain success of policy-driven efforts to revitalize US manufacturing
- Interest in the potential of load flexibility coming from datacenters has risen recently. In the S&P Global cases, datacenters are not expected to exhibit significant load flexibility given their low participation in demand response programs currently, and their high value on uptime due to their economic incentives. However, increasing ability of datacenters to operate flexibly in response to power prices or system operator signals is a development to follow

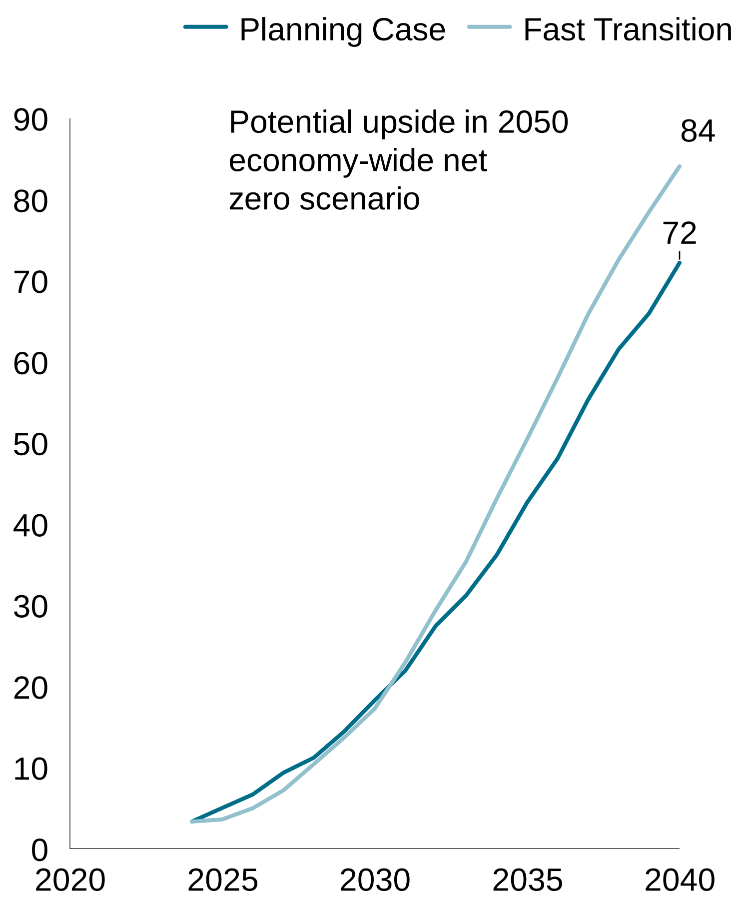
Note: Large load includes large industrial load (datacenters and manufacturing) and large flexible load (electrolyzer and cryptocurrency mining).
Source: S&P Global Commodity Insights

EV-driven demand load – both from BEVs and PHEVs – is expected to make up ~10% of the total net on-grid electricity demand by 2040

Net change in EV energy demand, 2024–40
GW



EV peak demand, 2024–40
GW



- EV load rises to over 554 TWh by 2040, around 10% of total net-on-grid demand in the US
  - EV peak demand grows to 72 GW, which will be defined by factors around charging infrastructure, behaviors and policies (see next slide)
  - EVs constitute around a third of all LDV sales in the US by 2030, a significant increase from 2023 levels (9%). Regions with the most EV demand are PJM, Southeast and California
- In a case that presents a pathway to achieving economywide carbon net neutrality by 2050 (called the Fast Transition case), 100% of on-road transportation is expected to be electrified by 2050
  - EV electricity demand reaches over 684 TWh in the US.
  - By 2040, EVs constitute roughly two-thirds of the LDV fleet in the US
  - EV demand constitutes over 15% of net on-grid demand in California, New York, New England and PJM Mid-Atlantic

LDV = light- duty vehicles.
Electricity demand and peak demand are associated with light, medium, and heavy-duty battery electric vehicles (BEVs) and plug in hybrid electric vehicles (PHEVs).
Potential upside is shown for Fast Transition, an outlook that presents a pathway to achieving economywide carbon net neutrality by 2050 in the US.
Source: S&P Global Commodity Insights

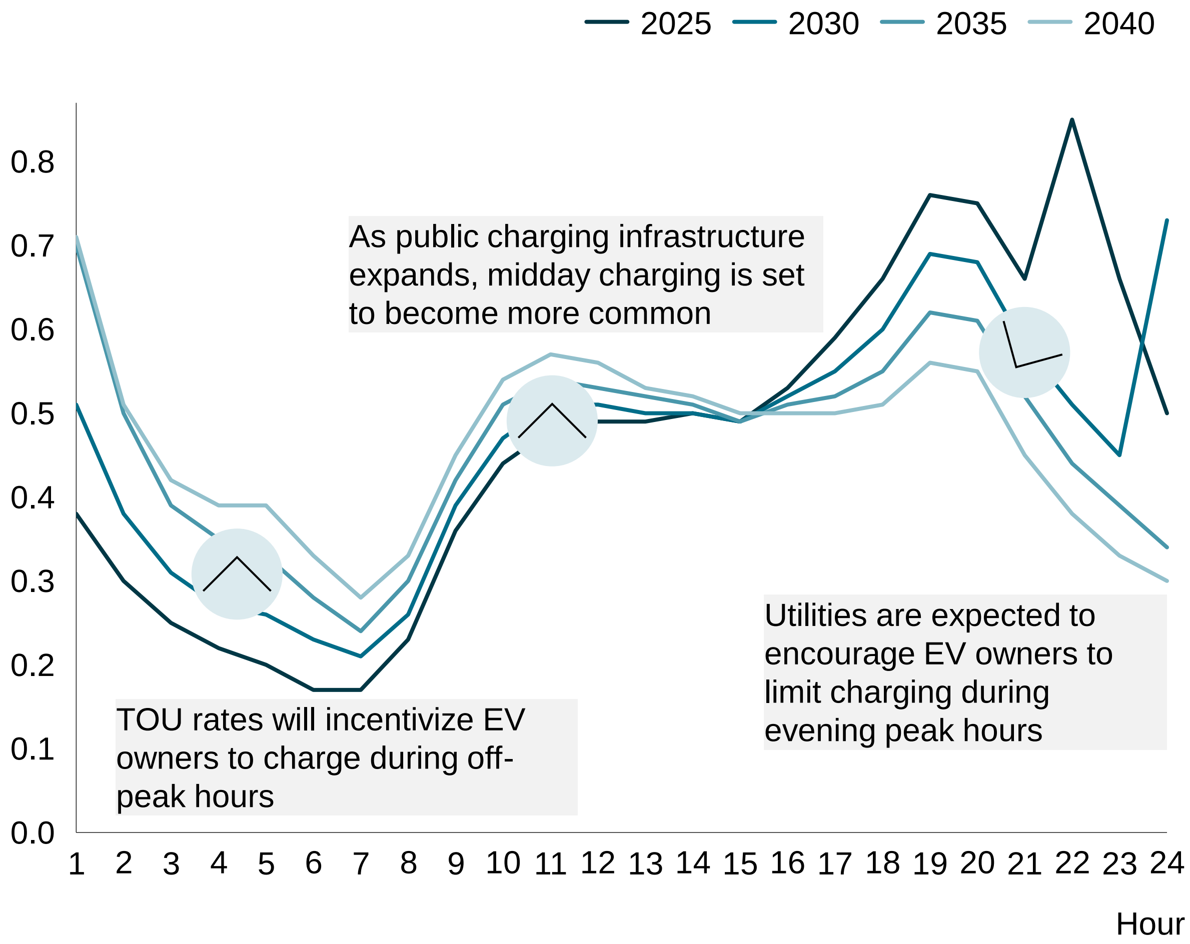
The peak impact of EVs is strongly affected by charging behavior evolution and policy; over time, EV charging during the evening is expected to be managed/shifted into other hours

Key trends impacting the load shape

- Due to lower access to home charging as a share of total, EV owners will increasingly charge in the middle of the day at the workplace/public chargers
- Evolution of time-of-use (TOU) rates will nudge people not to charge immediately as they get home in the evening
- As more people adopt managed charging, they will increasingly charge either overnight or early morning before departure
- Hourly load shapes are also affected by factors such as seasonality of driving and weekday/weekend driving, while total EV load is determined by vehicles in operation (VIO) and vehicles miles traveled (VMT)

PJM light duty EV average weekday charging

kW

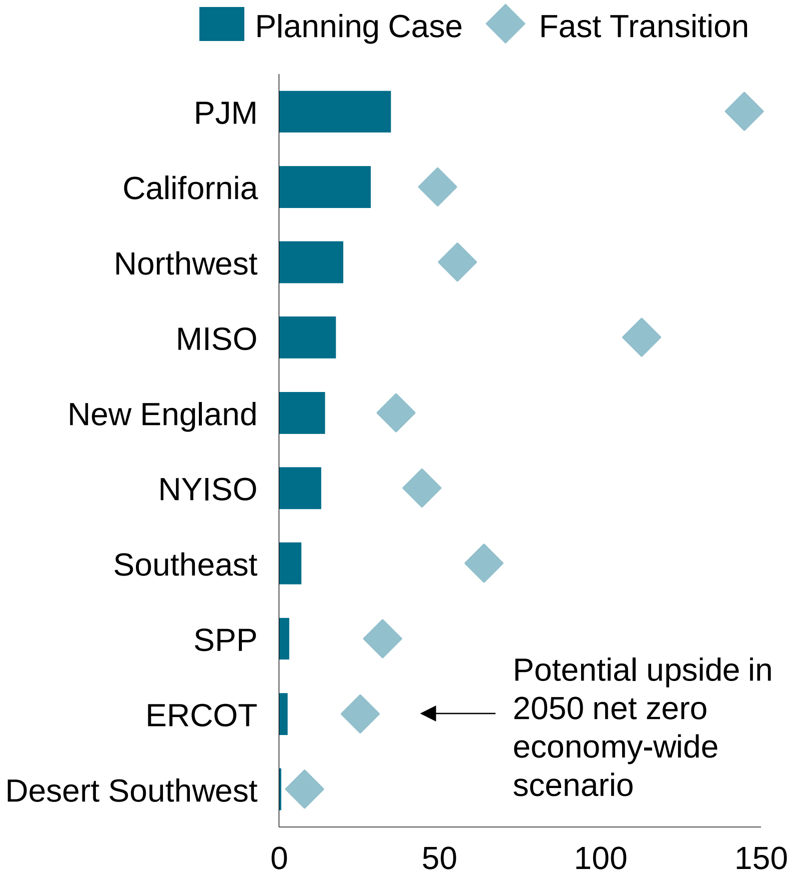


Note: Assuming 34 miles per day driven and no mileage loss from temperature
Source: PJM Electric Vehicle Charging Power Demand Forecast, S&P Global Commodity Insights

Residential and commercial building heating electrification demand is projected to exceed 150 TWh by 2040, accounting for nearly 3% of US energy demand

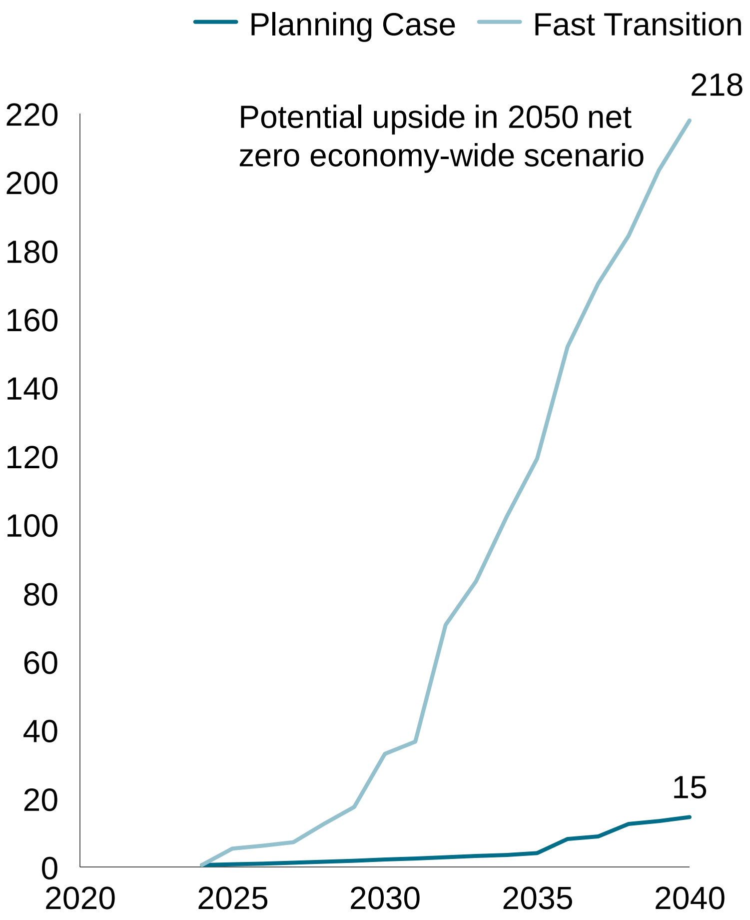
Net change in heating electrification energy demand, 2024–40

GW



Heating peak demand, 2024–40

GW



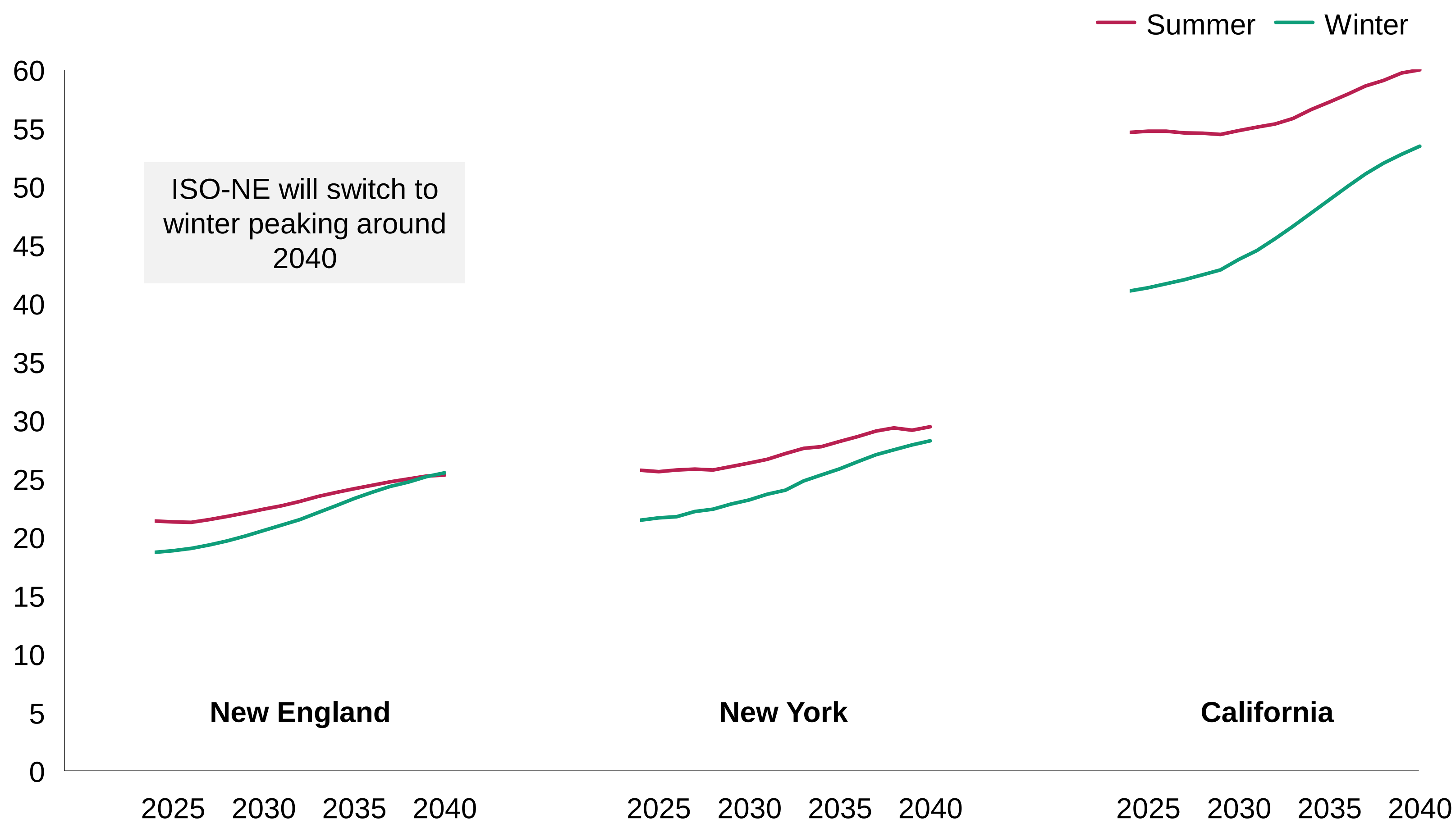
- **Our outlook assumes that subnational policies will promote increased electrification of heating systems**
  - **New all-electric residential and commercial customers**. A rising share of new residential and commercial customers across all states adopts electric space- and water-heating rather than natural gas
  - **Conversion of existing fossil heat customers to all-electric space- and water-heating systems or hybrid fossil-electric space heating**. Beginning in 2025, a rising share of existing residential and commercial gas customers partially or fully converts to electric-based heating systems. Building heat electrification in colder regions involves a higher share of partial electrification (gas-electric hybrid space heating) than in warmer regions
  - In 2040, PJM is projected to have the largest share of heating electrification load (23%), followed by California (21%) and the Northwest (14%)
- **Heating electrification plays a larger role in a case (called Fast Transition) involving a net-zero carbon US economy by 2050.** The net-zero scenario projects that energy demand from heating electrification reaches 635 TWh by 2040 – a fourfold increase from the base case projection – driven by aggressive subnational programs for electrification of space heating and water heating.

Potential upside is shown for Fast Transition, an outlook that presents a pathway to achieving economywide carbon net neutrality by 2050 in the US
Heating electrification energy demand reflects cumulative impact of incremental heating electrification compared to 2024 levels including heat pumps and other electric space and water heating
Source: S&P Global Commodity Insights

Electrification is expected to shift the seasonal peak in some power markets, with material implications for resource planning

Seasonal peak demand, 2024–40

GW



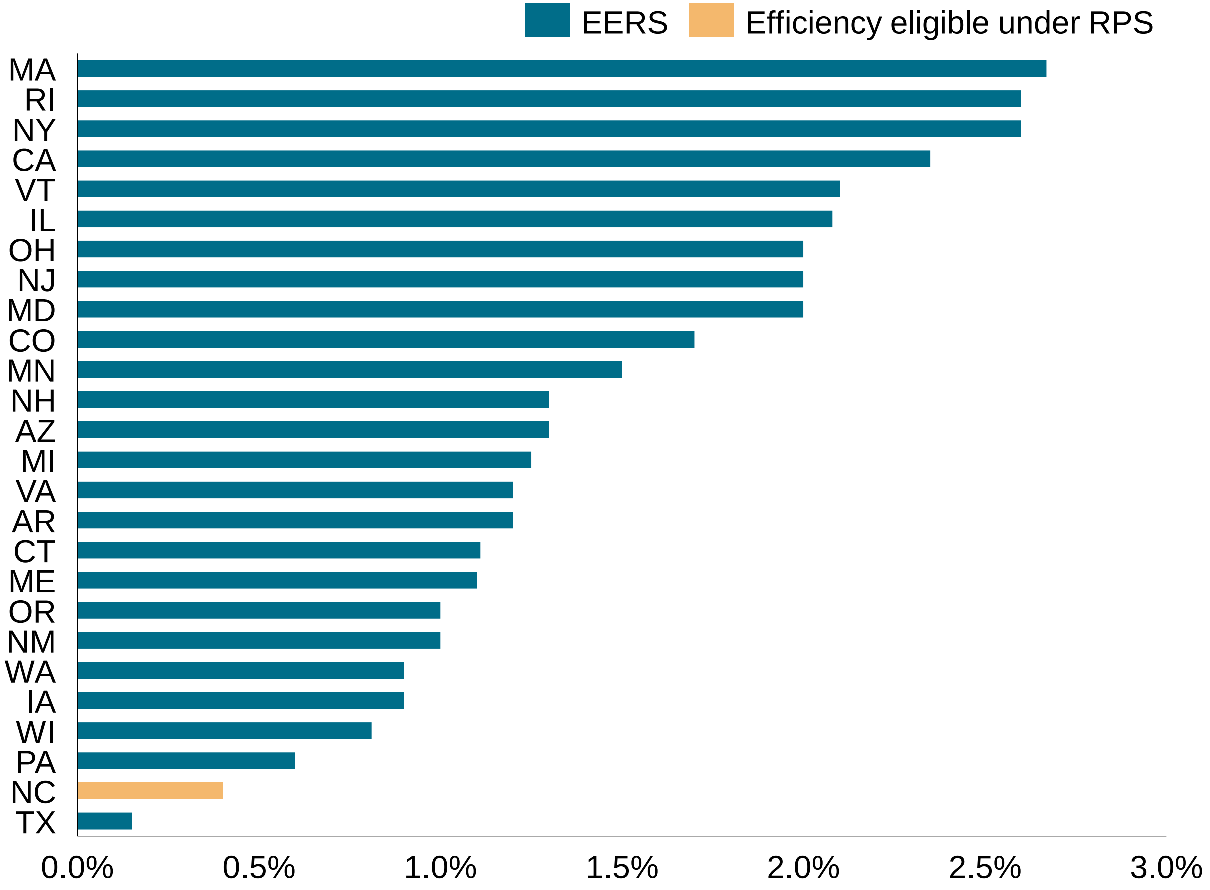
- **The combined impact of heating electrification during winter cold snaps and increased EV demand during cold months will tighten the gap between seasonal peaks**
  - In several markets heating electrification will emerge as a major contributor to peak load beginning in the mid-2030s. Regions such as New England and New York are expected to become winter peaking within the next two decades
- **Traditional resource planning has often focused on summer peaks. Now planners must reassess capacity requirements to accommodate increased heating loads and ensure sufficient resources are available during colder months**
  - The transition to winter peaking highlights the need for a diversified energy portfolio, as the reliability contributions by technology vary by season. For example, solar generation is typically lower in winter compared to summer. In addition, higher gas demand from heating needs puts pressure on gas supplies in some markets
  - Market design will have to adjust market structures and incentives to encourage the development of resources that can address winter peaks. This includes revising capacity market rules and introducing incentives for technologies that provide reliable winter capacity

Source: S&P Global Commodity Insights

Energy Efficiency Resource Standards (EERS) in most states are assumed to be achieved due to their track record of compliance

State annual average avoided electricity sales targets, 2023

Avoided sales as a percent of prior year's total sales



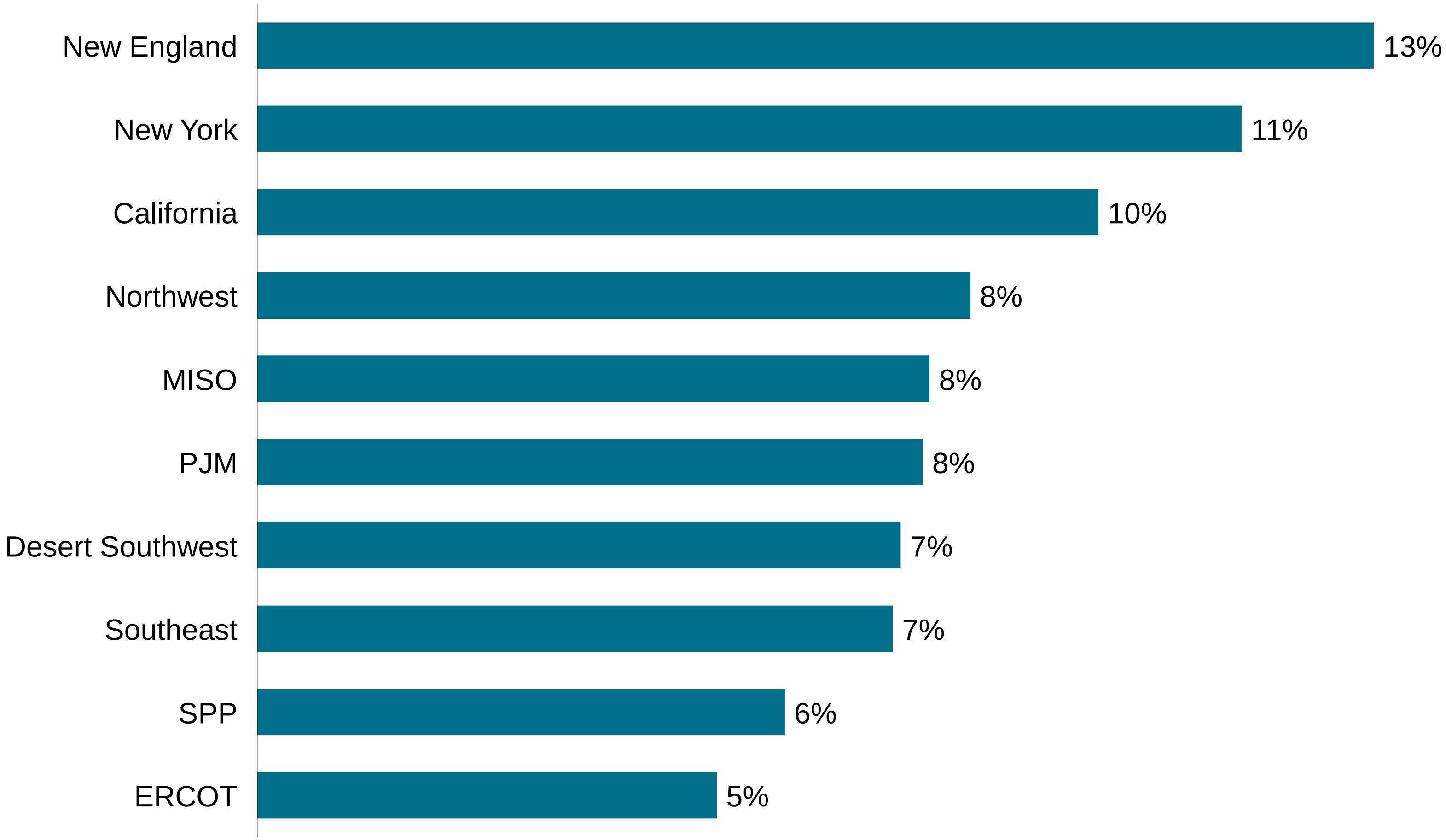
End-use energy efficiency estimates in our outlook are based on states' EERS policies

- Roughly half of US states have a rate-payer-funded EERS policy designed to slow electricity demand growth. EERS policies vary in their structure and ambition but typically target a level of avoided electricity sales (or energy efficiency savings) each year over a specified period. The target level is expressed as a percent of the prior year's total electricity sales. The more ambitious EERS policies target avoiding an average of at least 2% per year in electricity sales
- Many individual utilities in states without EERS policies also have rate-payer-funded energy efficiency programs that drive savings, albeit more modestly
- We assume existing EERS policy targets are achieved. We also assume existing policies are extended and achieve comparable savings up to a maximum of 1.5% per year. Underpinning these assumptions is the track record of EERS compliance and relatively stable year-over-year costs of incremental efficiency savings
- For states without an EERS policy, we assume states achieve savings levels equal to their recent past performance
- Beyond 2030, we assume that states with less aggressive or no EERS policy ramp up avoided sales to roughly 0.5% per year on average[1]

1 The rate of annual avoided sales assumed is applied to demand exclusive of electrification.
The electric saving target is calculated as the average electric saving as a percent of total sales based on each state's policy. NC denotes a state with RPS policies that include energy efficiency. The average avoided electricity sales target is an estimate from the efficiency cap within the RPS.
Source: S&P Global Commodity Insights

By 2040, the US is expected to achieve average energy efficiency savings of 8% relative to the nation's energy demand

Cumulative energy efficiency savings as a share of energy demand, 2024–40



- Cumulative energy efficiency savings between 2024 and 2035 will exceed 300 TWh, an equivalent of 6% of the nation's energy demand in 2035. By 2040, cumulative savings after 2024 will exceed 400 TWh, a level comparable to 8% of total energy demand
- New England, New York, and California lead in energy efficiency savings, in line with their strong track record in implementing and enforcing EERS polices
- In contrast, energy efficiency savings in ERCOT and SPP lag at 6% and 5%, respectively

Represents cumulative energy efficiency savings beginning 2024 from measures that are implemented as a result of rate-payer funded programs. Energy efficiency measure effectiveness is assumed to degrade linearly over time and to have a median lifetime of 10 years.
Source: S&P Global Commodity Insights

Contents

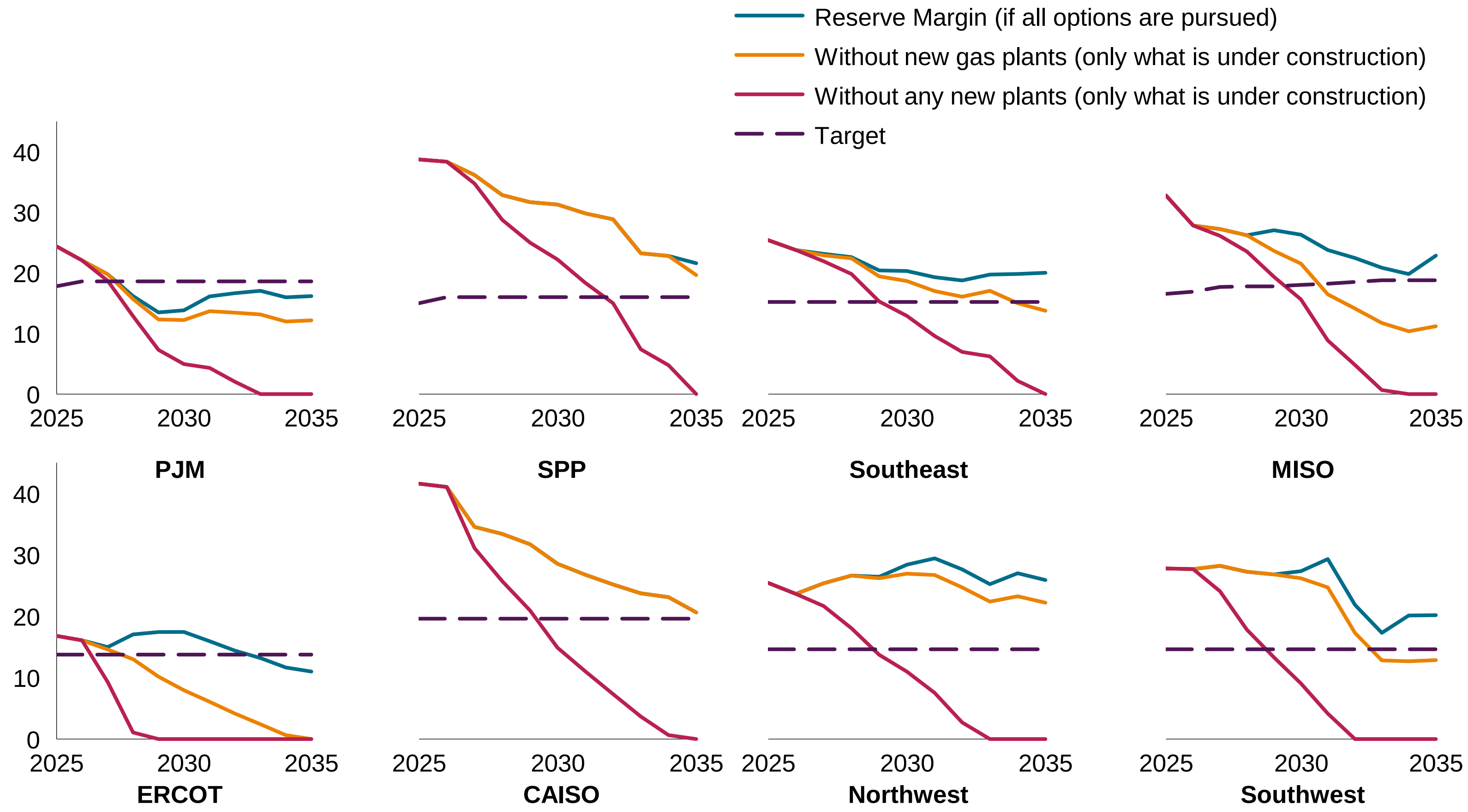
Summary of supply pathways

- US nameplate capacity is projected to almost double over the next 15 years in three examined supply pathways
  - This study is built around three S&P Global cases: (1) Planning Case, (2) a case with faster demand growth and increased supply constraints, and (3) and a variation on the second case where more clean firm capacity is added.
- Adding above 900 GW to the supply mix through 2040, renewables and batteries are by far the main source of supply in all three cases on a nameplate basis given their availability, low-cost, preference from consumers, and policy support.
  - However, the ability of renewables to respond to new demand growth in the short-term is constrained. While an increased outlook for power demand and price signals improves economics, bottlenecks (interconnection queue backlog) and headwinds (local opposition) significantly constrain the scope to increase the pace of additions in the near term
- New firm capacity resources are required to meet peak demand growth, as 140 GW of older, less efficient fossil fuel-fired generation capacity is projected to be retired.
  - Natural gas-fired generation capacity grows by 60 GW, supporting growing loads and providing needed capacity to balance non-dispatchable resources
  - Deployment of gas-fired generation faces constraints, however, as the equipment supply chain adjusts to increased demand and gas delivery infrastructure bottlenecks are addressed. This pushes substantial new growth of unplanned natural gas plants to early next decade
  - 40 GW of additional gas could be needed with further constraints to the ability to build renewables and higher-than-expected load growth materializes.
- Advanced nuclear and other clean firm technologies remain an important part of the resource mix. A stronger emphasis on emissions reductions or a constrained ability to build renewables is expected to increase the role of nuclear, though the technology will not be ready at scale until next decade.
- Other tools like demand response and energy efficiency remain essential to meet peak requirements

Renewables, battery energy storage, and gas-fired capacity build beyond *what is under construction* are required to meet planning reserve margin targets

Planning reserve margins by market

%



Through 2030, some markets are at risk of demand growing faster than timelines for new supply

- Incremental near-term demand is likely to rely heavily on increased utilization of existing resources given questions around the pace and scale of bringing on incremental new supply in the near term
- In an era of rapidly rising demand and renewable additions, many of the processes that were put in place to maintain reliability in the past (the structure of interconnection queues and system studies, static transmission line ratings, transmission expansion planning, siting and permitting, etc.) are ripe for reform

Large loads concentration in PJM and ERCOT

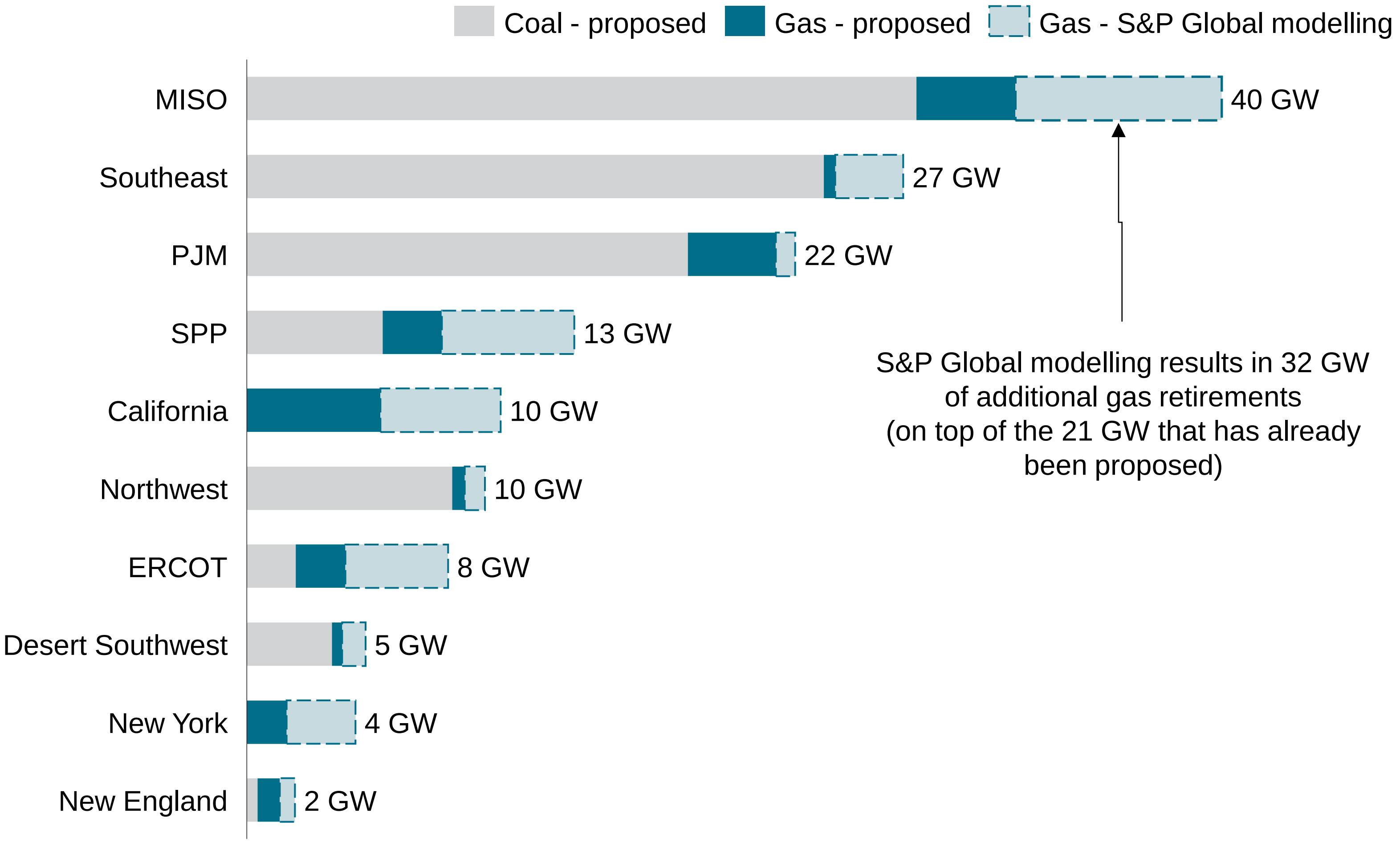
- Reserve margins in most markets stay above target in the short-term, however, PJM and ERCOT combine for above half of the planned large industrial load growth. These two markets face a major risk of demand and supply imbalance over the next five years

1. The target reserve margin is typically calculated with a 0.1 Loss of Load Events (LOLE) per year criterion
Source: S&P Global Commodity Insights

Over the next ten years, around 140 GW of coal and gas capacity is projected to be retired due to age-based decisions, compliance regulations and economics

Coal and gas retirements, 2025-35, US Lower 48

GW



Proposed includes units that have applied for approval or planned for retirement in plant owner's Integrated Resource Plan.
Source: S&P Global Commodity Insights

By 2035, a total of 88 GW of coal capacity is proposed for retirement

- The retirement analysis considers individual coal unit compliance with federal and state environmental regulations, including the Cross-State Air Pollution Rule (CSAPR), Mercury and Air Toxics Standard (MATS) and Effluent Limitation Guidelines
- Most coal retirements, over 80%, are concentrated in the PJM, Southeast, and midcontinent regions (SPP and MISO)
- With no new coal additions expected during this period, the installed coal capacity will decrease significantly from 180 GW to 80 GW by 2035

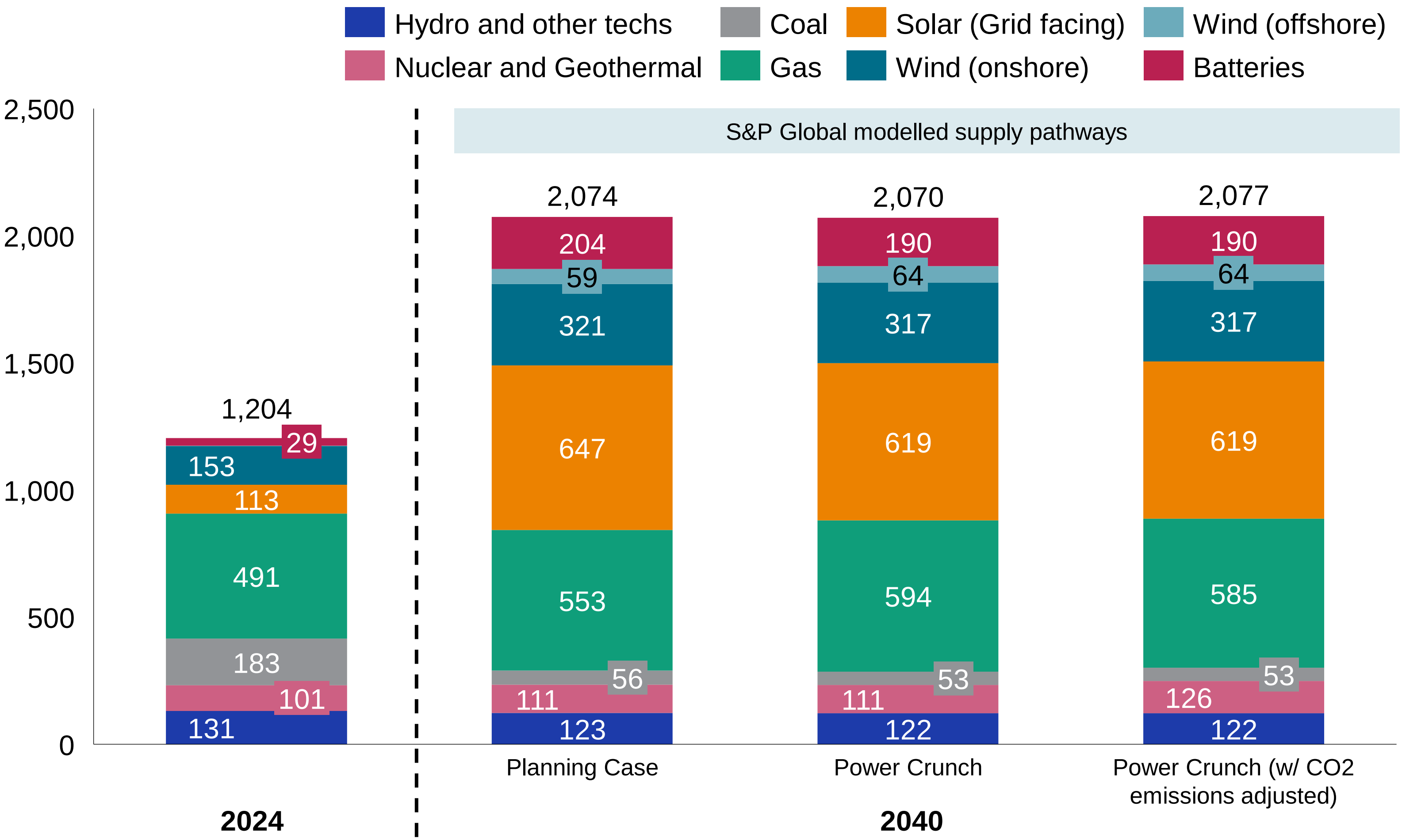
S&P Global's modeling results in additional 32 GW of retirements, leaving some room for retirement delays if market conditions justify it

- Over the past 18 months, a quarter of all announced coal plant retirements through 2050 have either been delayed by an average of 3-4 years or announced new plans to convert to gas-fired generation
- Most near-term gas-fired proposed retirements are aging steam turbines with low utilization rates.

US installed capacity is expected to almost double over the next 15 years, with renewables becoming the main source of added supply

Operating/nameplate capacity (all technologies), US Lower 48

GW



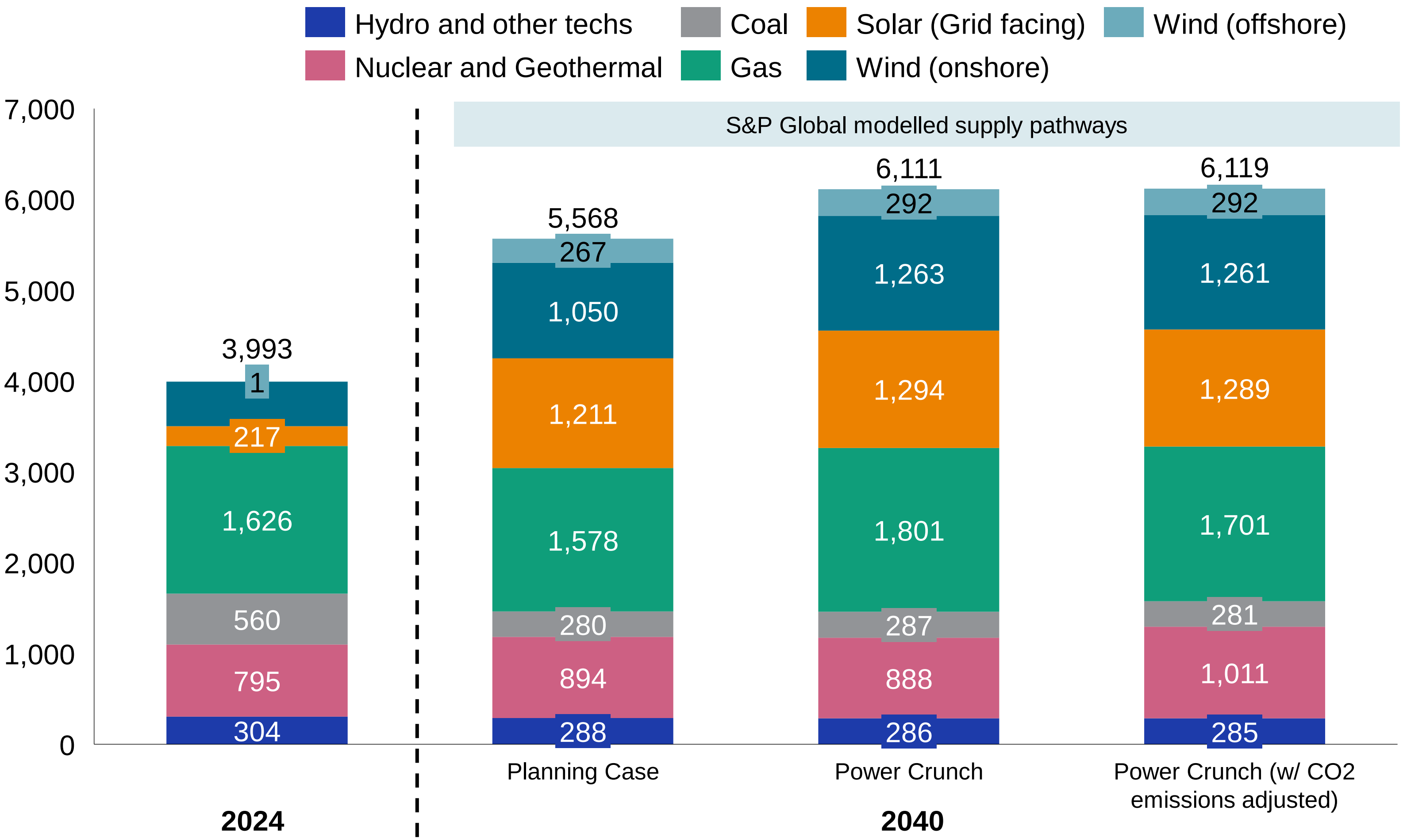
Others include Oil, Geothermal, Biomass and Pumped Storage.
Source: S&P Global Commodity Insights

- **Renewable and battery capacity increases to see a net increase of 900 GW, reaching 60% of total capacity**
  - Renewable energy sources are the primary drivers of nameplate capacity expansion with solar capacity leading, growing to 647 GW
  - Battery energy storage capacity is expected to grow nearly fivefold, reaching 204 GW, a key technology in supporting grid reliability and integrating variable renewable energy sources
  - Wind energy more than doubles reaching to 380 GW, where 59 GW is reached by offshore wind
  - In the Power Crunch case, onshore renewable capacity and batteries are limited to respond to higher demand due to increased challenges around interconnection, siting and permitting
- **Natural gas capacity reaches 553 GW, and up to 594 GW under higher load and constrained renewables**
  - Natural gas-fired capacity sees a net increase of 62 GW from 2024 to 2040.
  - While in the Power Crunch Case there is an additional need for 41 GW, due to higher load and constrained onshore renewables
- **Clean firm technologies (nuclear and geothermal)**
  - In the Power Crunch (w/ CO2 emissions adjusted) case, 15 GW of clean firm capacity is added (14 GW of it nuclear), reducing the need for additional gas capacity by about 10 GW

Under three different supply pathways to 2040, the US generation mix is a balanced portfolio of renewables, clean firm power, and natural gas-fired generation

Generation (all technologies), US Lower 48

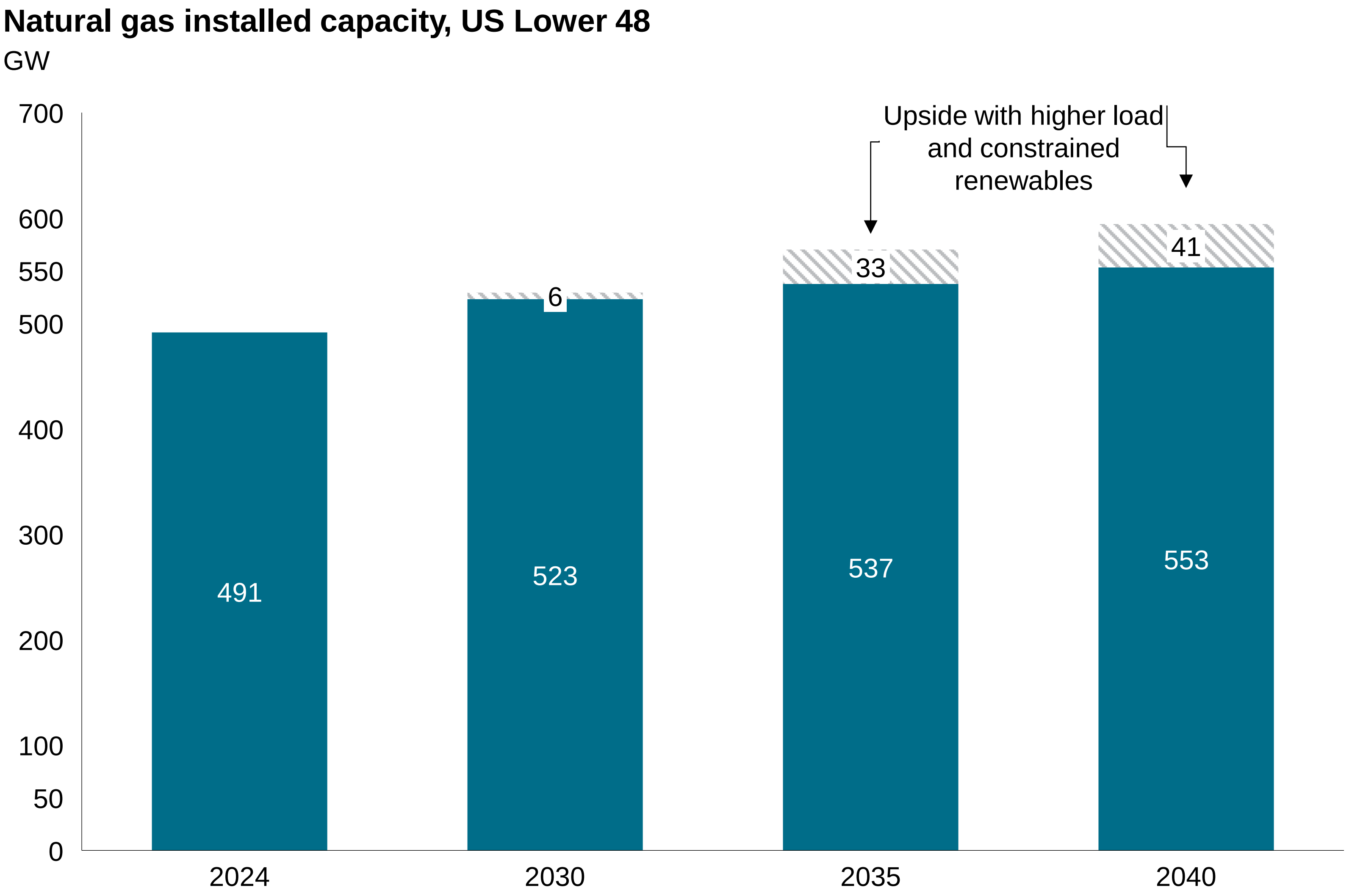
TWh



Others include Oil, Geothermal, Biomass and Pumped Storage.
Source: S&P Global Commodity Insights

- **Renewable combine to reach almost half of total generation**
  - As the primary driver of new energy supply, wind and solar combined become the main source of generation in the US
  - In the Power Crunch case, developers respond to persistent challenges with siting and permitting new projects by accelerating plans to repower existing ones. This helps to offset restrictions and support a modest growth of generation
- **Natural gas-fired generation remains near current levels through the outlook**
  - As load grows and coal generation decreases, natural gas generation holds mostly steady through 2040
  - Additional upside of around 200 TWh in the Power Crunch case, due to higher load and constrained onshore renewables development
- **Clean firm technologies (nuclear and geothermal)**
  - These technologies combine to about 20% of generation currently. There is a modest increase of around 100 TWh by 2040
  - The Power Crunch (w/ CO2 emissions adjusted) case results in an additional 120 TWh

Demand growth and aging coal fleet help natural gas-fired capacity additions to rebound after recent years of slow growth



Renewed interest in developing gas projects

- In 2024, the US installed the least amount of new gas-fired capacity since 1998. However, there is an uptick in interest in gas-fired generator investment and development owing to soaring demand growth projections
- With substantial gas-fired capacity currently under development in the US, 32 GW (net) is expected to come online by 2030

Gas installed capacity grows over 60 GW (net) by 2040

- About half of the gas additions (by 2040) occurs between 2028 and 2033
  - Given the aging coal fleet, by the early 2030s new resources are needed to replace the energy and capacity contributions from retiring coal and to supply incremental load growth
- In a scenario of higher load and constrained renewables (Power Crunch), there is further upside for a net increase in total US gas-fired generation capacity of 101 GW

Source: S&P Global Commodity Insights

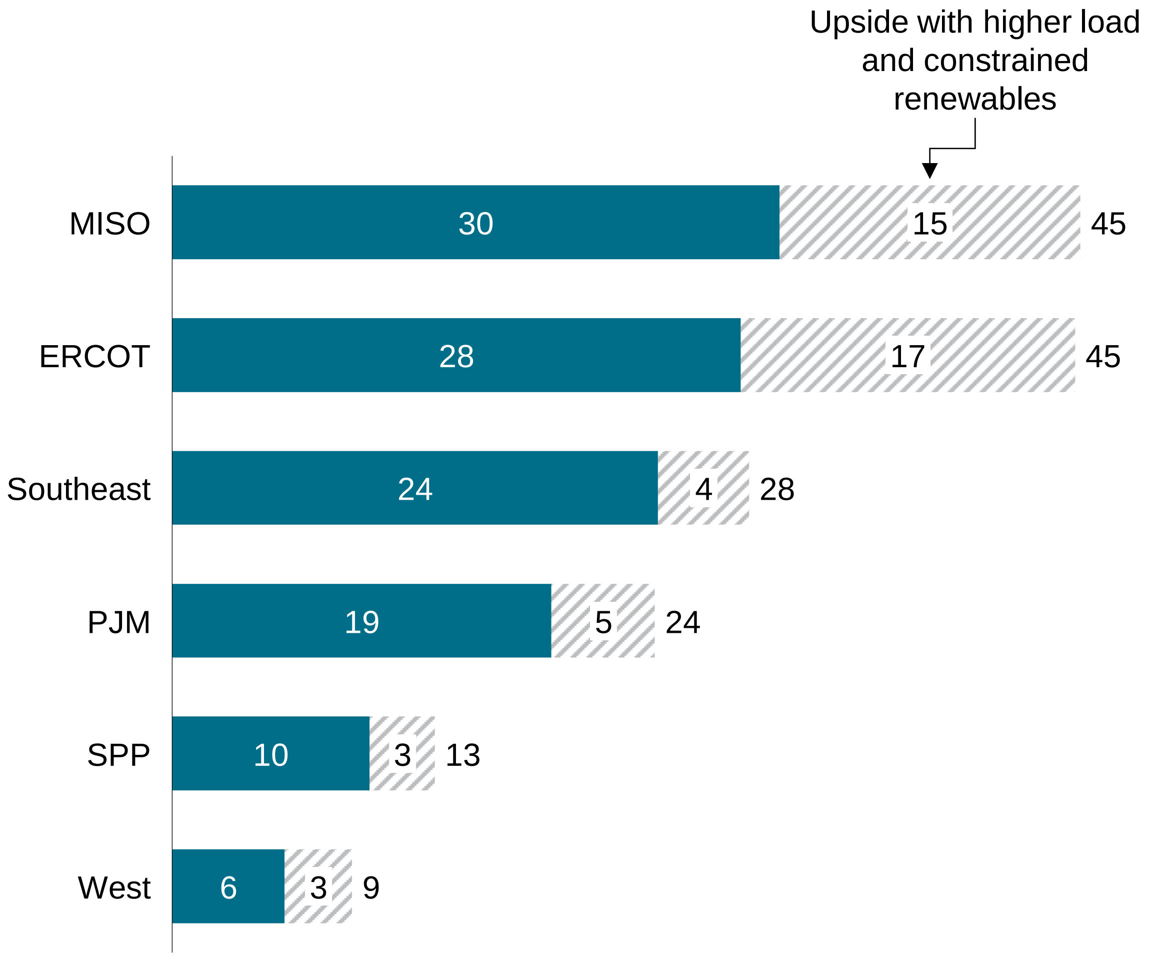
Natural gas-fired capacity additions are expected to occur in regions of high demand growth

New gas-fired capacity additions are concentrated in the Eastern Interconnection and Texas

- Natural gas-fired gross additions total 120 GW between 2025 and 2040. An additional 40 GW is required in the case of higher-than-expected demand
- ERCOT, MISO and the Southeast lead the US in planned gas-fired projects, each with over 14 GW of projects. These regions exhibit need for new capacity owing to a combination of high near-term load growth and limited opportunity for incremental coal retirement delays
  - The Texas Energy Fund has boosted the number of proposed projects this year. The Texas regulator’s is set to provide financial support for almost 10 GW of new, primarily gas capacity by 2029. The Texas legislature is contemplating additional policy measures to support gas-fired capacity additions
  - Projects in MISO and the Southeast are mostly being developed by regulated utilities which rate-base new gas-fired projects
  - However, there are still numerous projects being planned by independent power producers in competitive markets

Natural gas-fired gross additions by region, 2025–40

GW



Source: S&P Global Commodity Insights

Going forward corporate demand and competitive economics are the main drivers of renewable additions

Over 900 GW of combined solar photovoltaic, wind and battery storage are expected to be added to the US grids in the next decade, driven by clean energy targets from states and corporations, competitive costs of renewables, Inflation Reduction Act (IRA) tax credits and rising demand for power overall

Renewable portfolio standards (RPS) have been important drivers of wind and solar PV development as the industry has evolved

- Demand for renewable energy attributes could outpace supply in in the near term in regions with strong RPS and CES policies
- However, as renewable buildouts continue and demand growth slows, a surplus of renewables emerges, supported by merchant profitability

Corporate renewable energy procurement provides a significant amount of demand for renewable energy as companies look to meet their climate goals

- Corporate demand accounts for more than 30% of renewable supply by 2035 (see next slide)
- Corporate demand can be for either wind and solar or nuclear and geothermal, depending on the targets of a given company. However, since most corporate targets reflect decarbonization ambitions, companies can consider clean generation instead of renewables if there is a significant price difference

Although the majority of renewable generation helps satisfy governmental and corporate energy policies, renewables' competitive economic position also drive its development

- Renewables' competitive costs combined with tax credits underly their rapid development
- The option to take the production tax credit (PTC) improves the economics of already low-cost utility-scale solar
- Additionally, the investment tax credit (ITC) to stand-alone storage improves the economics of stand-alone batteries in many new applications

Source: S&P Global Commodity Insights

Corporate procurement is driving substantial onshore renewables development, becoming the largest counterparties for renewable power purchase agreements (PPAs)

Corporates have procured near 120 GW of project-specific renewable capacity

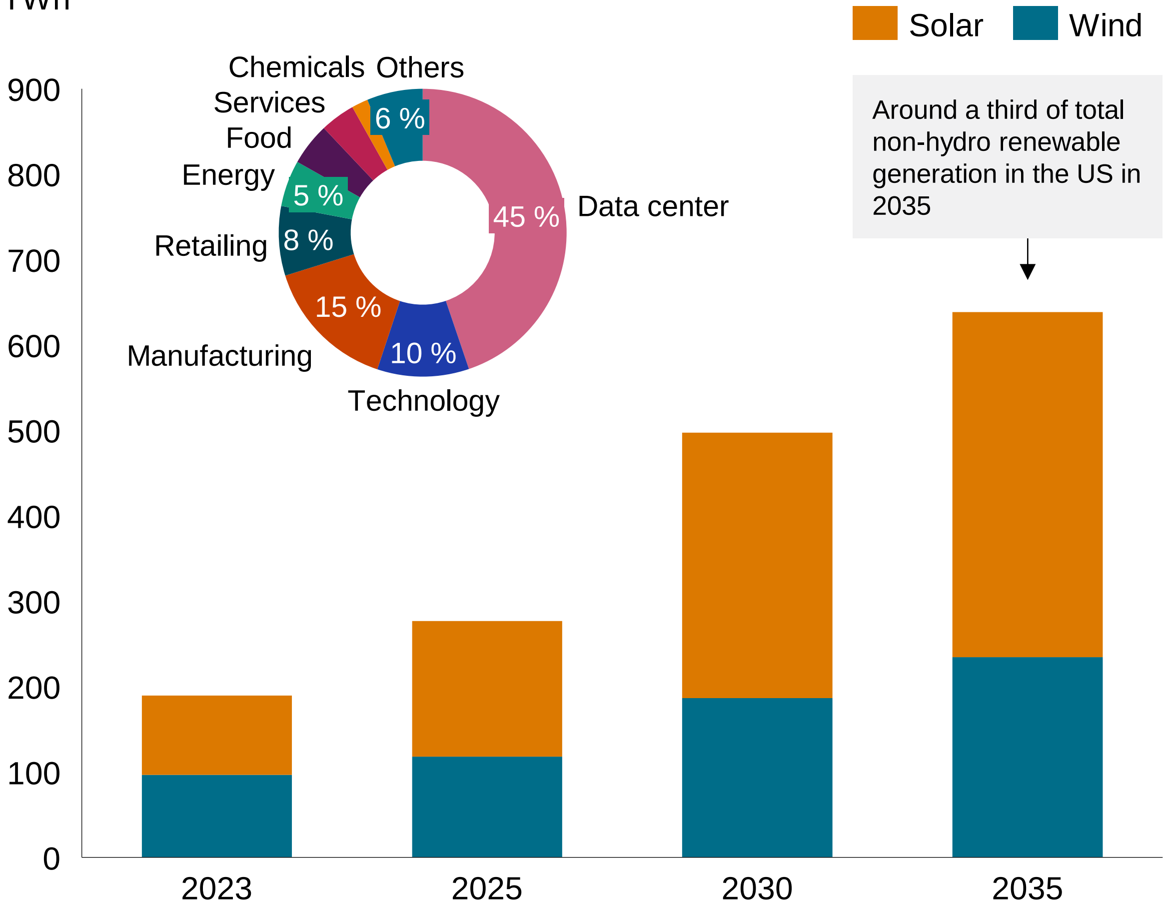
- With clean energy procurement expanding globally and self-imposed carbon reduction efforts by corporations maintaining strong momentum, annual corporate renewable purchases are expected to remain aggressive for the foreseeable future

The technology sector continues to lead renewable procurement, while new buyers emerge from a diversified range of sectors

- Of the top 30 datacenter companies, 14 have set 100% renewable targets. Most of these companies set targets before 2030, which boosts demand in the near term
- Within datacenter companies, the technology giants (hyperscalers) will continue to spearhead clean energy procurement. They will comprise over 80% of the datacenter demand today through 2035
- Demand from the manufacturing sector is poised for substantial expansion, with many automobile makers and electrical equipment suppliers committing to 100% renewables
- Demand from key industries like steel, cement and mining within the manufacturing sector is expected to surge by over five-fold in the next decade

Outlook of US cumulative project-specific corporate renewable demand

TWh



Analysis does not include most on-site corporate renewable capacity such as rooftop solar systems.
The S&P Global corporate demand outlook is based on 2,370 companies operating in the US. This includes the top 30 datacenter companies and 2,340 companies that have exhibited climate ambition, either by setting procurement targets or disclosing their emissions.
Source: S&P Global Commodity Insights

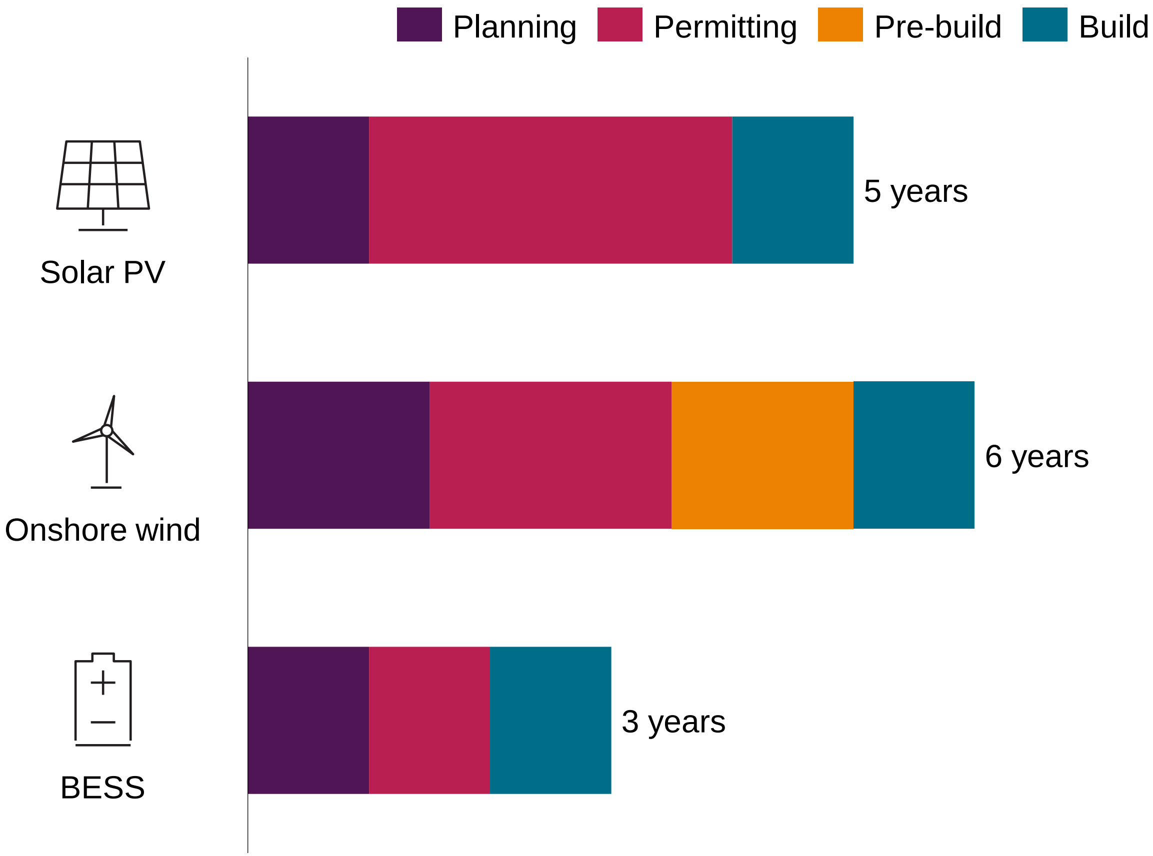
However, the ability of renewables to respond to incremental demand growth is challenged by siting and permitting barriers

The time to develop new capacity continues to be a barrier to renewable development across the US

- While an increased outlook on demand improves economics, bottlenecks (interconnection backlog) and headwinds (local opposition) significantly reduce the ability to increase the pace of additions in the near term
- Land access and grid connections are bottlenecks that can drive up development costs and uncertainty as investors look to deploy capital quickly and are willing to pay large premiums for construction-ready projects
- Efforts are being made at the state and federal levels to reduce the time required for permitting, but local opposition has continued to grow in some parts of the country (see next slide)

Indicative average time to market by technology

Years



Planning = The project is in early planning stages. It has not obtained approvals from the relevant authorities.
Permitting = The project is in its permitting process. Planning documentation (for environmental permits, interconnection rights, etc.) are being prepared or are submitted to the relevant authorities for approval.
Pre-build = The project has its required permits and is preparing for construction. Financing is being finalized, tenders for equipment and construction contracts are being awarded, and site preparations and front-end engineering and design studies are being completed.
Build = The project is under construction or in testing/commissioning phase.
Source: S&P Global Commodity Insights

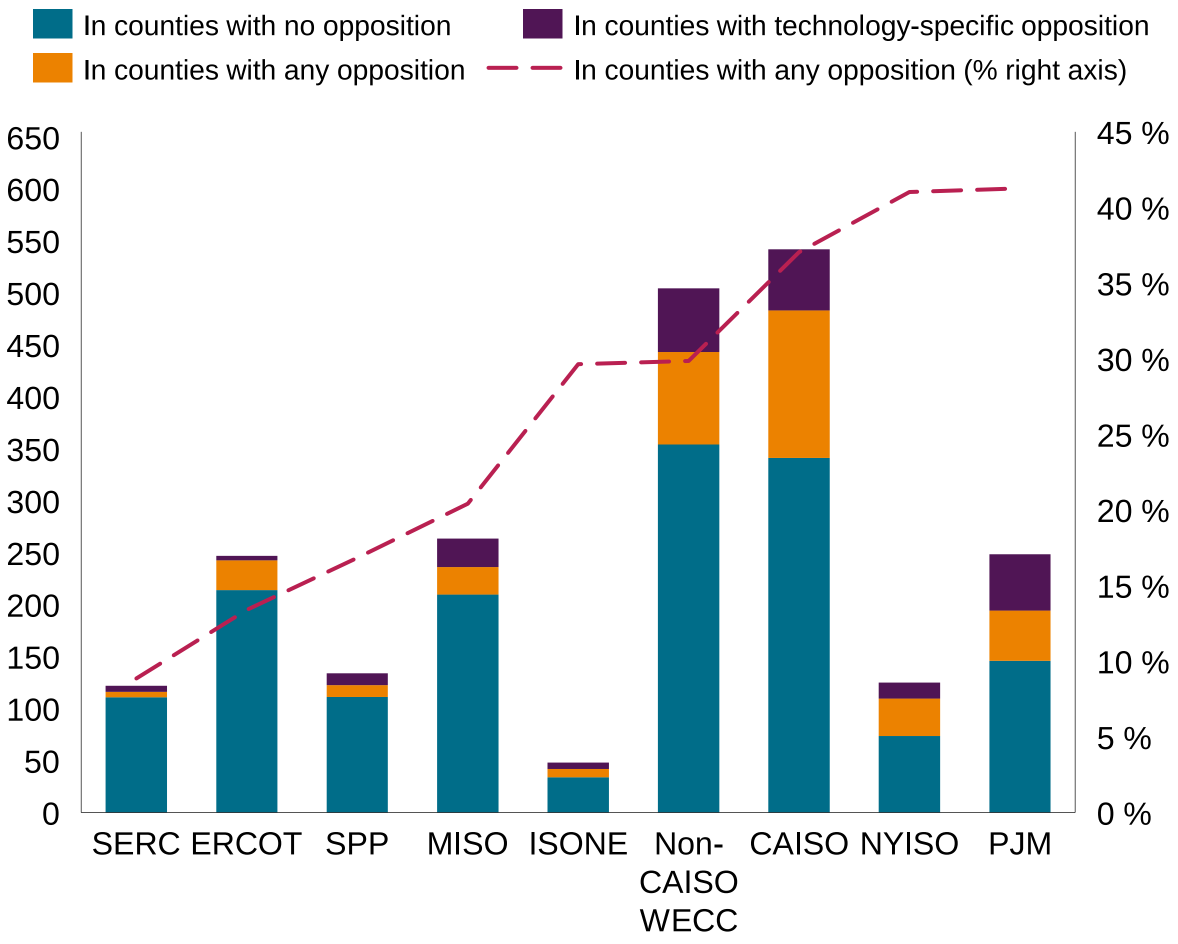
Headwinds like local opposition can limit the ability of renewables to meet their potential pace of growth

Opposition to renewable development at the local level has emerged as an important risk to the cost and pace of renewables

- Most land-based renewables are sited in rural areas where surveyed measures of “favorability” for wind and solar have been declining between 2016 and 2024[1]. This decline has coincided with a sharp rise in local challenges to siting and permitting of renewables in predominantly rural areas
- These challenges may also contribute indirectly to higher costs by pushing projects into less cost-effective areas (e.g., lower-quality resources and/or greater transmission investment needs). For instance, local siting restrictions for onshore wind, which is much more location-sensitive than solar, may be contributing to the recent underperformance of onshore wind capacity factors compared with technological advances
- **PJM Case Study:** S&P Global Commodity Insights found that around 40% of onshore renewable queue capacity in PJM is in counties with local opposition as of 2023
  – Onshore wind and solar interconnection queue capacity and local opposition to renewables was analyzed at the county-level in PJM from 2020 to 2023. The key metric analyzed is the annual share of onshore wind, solar, and hybrid solar queue capacity in counties that have imposed restrictive zoning amendments, bans, moratoria or successful challenges to new onshore wind or solar projects

Interconnection queue capacity facing local opposition, 2023

GW



Sources: Pew Research Center (2024). Graph based on data from Lawrence Berkeley National Laboratory (LBNL) and Columbia Sabin Center for Climate Change Law

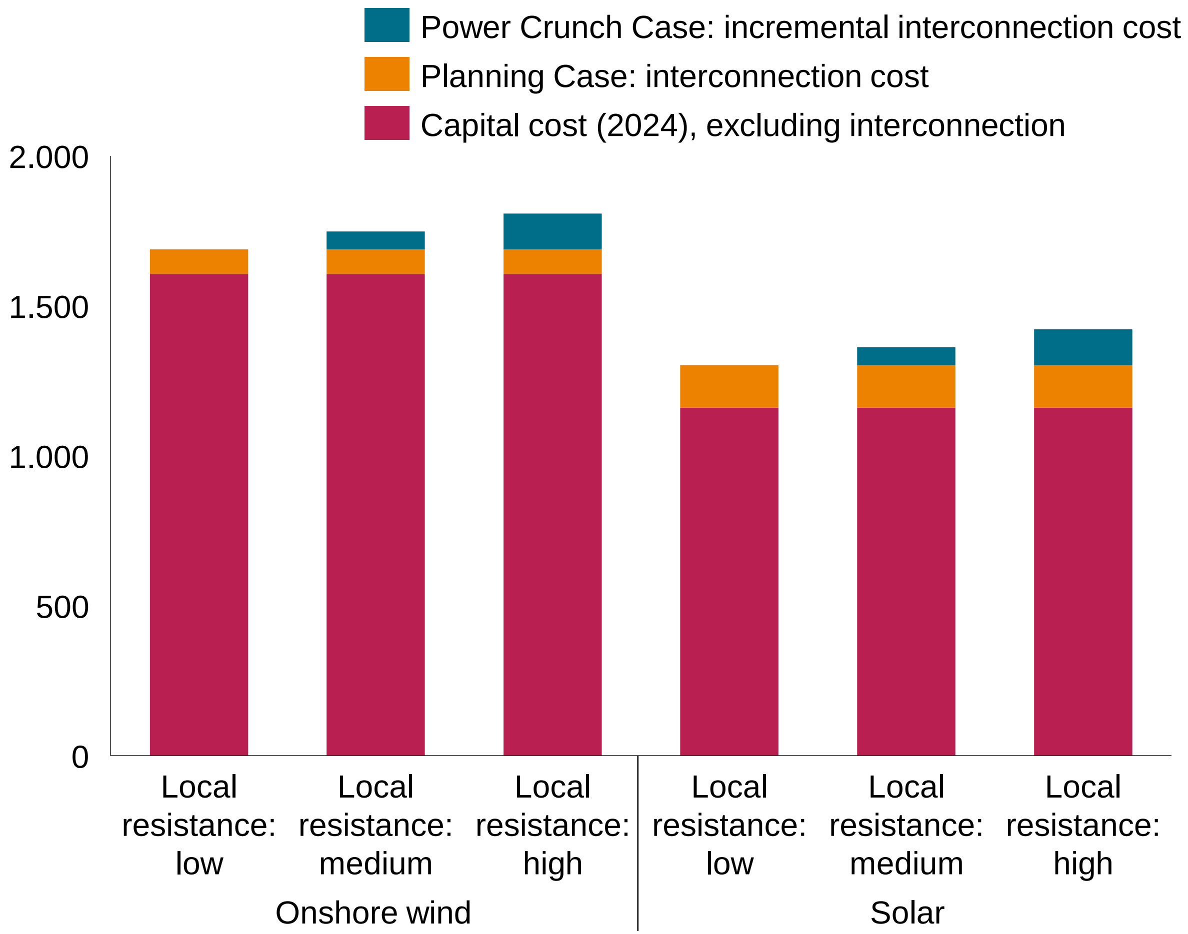
The persistence of local siting and permitting challenges reduces the development potential of most cost-effective locations by up to 60%

Local siting and permitting challenges contribute directly to higher development costs by increasing the chance of cancellations and delays

- In a less optimistic case for development, the potential for these challenges to persist is represented by assuming higher development costs and limiting development potential in the most cost-effective locations
- Renewable development costs are increased by up to $120/kW, or 10% higher than our central expectations, and the development potential in the most cost-effective locations is reduced by up to 60%
- Local siting and permitting challenges can not only constrain the overall trajectory of development but also reshape the regional development trends of onshore wind and solar. Increases to development costs and restrictions are likely not uniform across states and can be lower where:
  - Local challenges to siting and permitting are less common
  - State policymakers, motivated by state clean energy mandates, are expected to take action to mitigate local challenges to development through “stick” and/or “carrot” measures
  - Primary siting and permitting authority for solar and onshore wind is held at the state level
  - Federal land accounts for a large share of state land. Given the strategic nature and importance of datacenters to US economic competitiveness on the global stage, it is assumed that the federal government will continue to take action to support power infrastructure development where it has the most influence

Onshore renewable interconnection costs by case

$/kW



Source: S&P Global Commodity Insights

There is potential for a nuclear renaissance in the US given its renewed long-term relationship with the datacenter construction trend, however challenges exist

Recent trends in nuclear deals

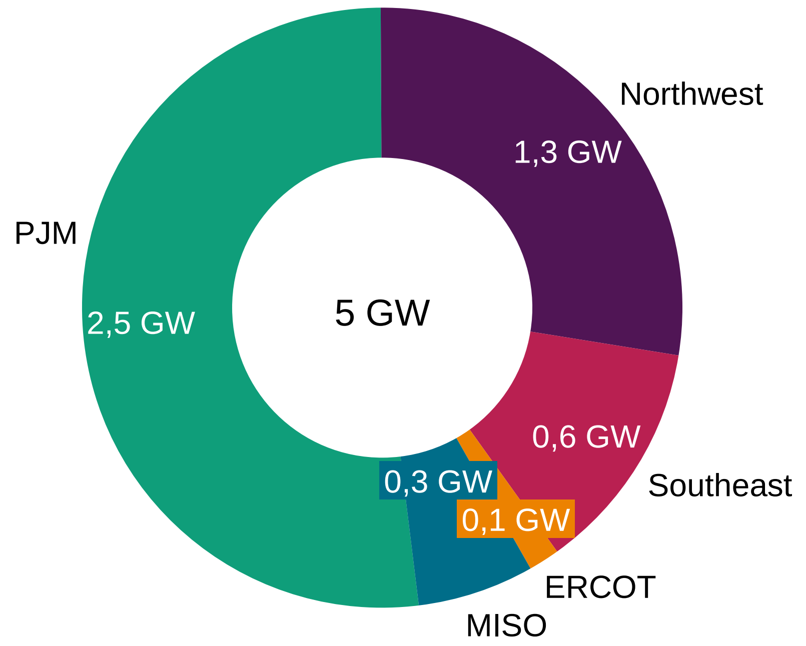
- 2024 saw the announcement of multiple high-profile deals and partnerships between Big Tech and nuclear energy providers and developers. Most of the announced projects involve the development of small modular reactors (SMRs)
- New US nuclear development is concentrated in the eastern interconnection, a geography with a large operating and planned datacenter footprint

Long lead times will make it challenging for nuclear to be a solution for short-term capacity needs

- It would take an average of six years for nuclear SMRs and light water reactors, according to the EIA — an optimistic view of development timelines considering the recent past for the US nuclear sector and the general consensus around announced projects
- Furthermore, with the deployment of the first commercial-scale small modular reactors (SMRs) 10-15 years away, the cost of electricity produced from these facilities must still be considered highly uncertain

Announced SMR and Micro nuclear projects in the US by region

GW



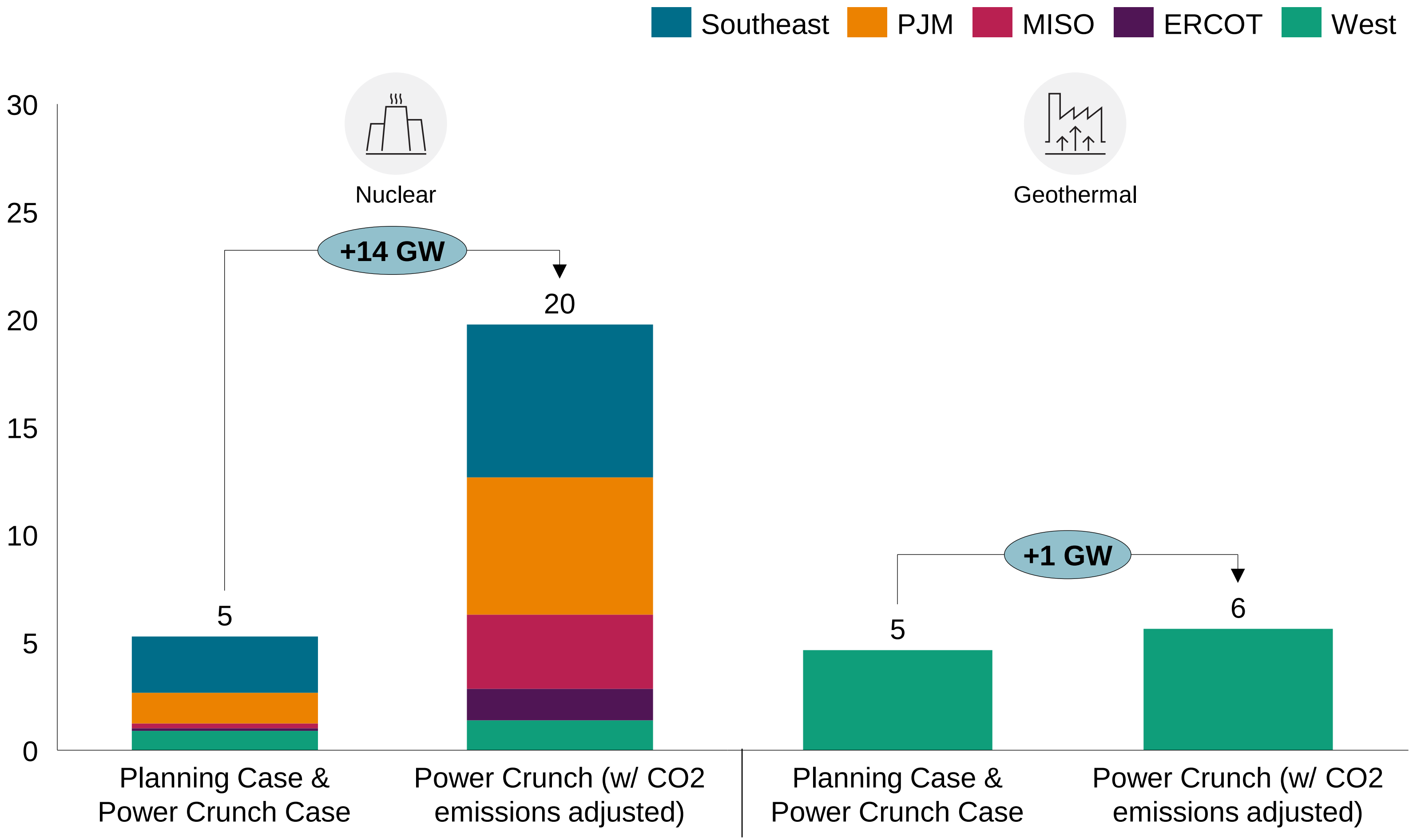
An additional 2 GW of conventional nuclear restarts are underway (Palisades and Three Mile Island)

Source: S&P Global Commodity Insights

A coordinated effort and investment to establish a new layer of “clean firm” power would be needed to offset CO2 emissions increases associated with a power crunch

Clean firm additions by region, 2025–40

GW



The Power Crunch (w/ CO2 emissions adjusted) case examines the effects of a plausible 15 GW of incremental clean firm capacity by 2040

- Most of this incremental clean firm capacity is sited at existing nuclear facilities — primarily in PJM, SERC and MISO — that previously applied for a combined license (COL) or early site permit (ESP). New nuclear is concentrated in the East, which aligns with future large loads
- It is assumed that it will take a decade or more for new technologies like SMRs to begin scaling up, owing to the time needed to go through the regulatory licensing process and technology evaluation; for supply chains to scale up; and for financing challenges to be overcome

Significantly higher additions would be needed to keep emissions at Planning Case levels

- To return to emissions levels trajectory of the Planning Case, 26 GW of additional new nuclear or geothermal capacity would be required in the next 15 years. Which is significantly above the modelled case, as it would require a significant lift from the nuclear industry

Source: S&P Global Commodity Insights

Discussion around assumptions which alleviate energy constraints in higher demand cases

Reliance on higher-cost gas plays increases, but limited greenfield expansions are needed

- Stronger-than-expected power sector gas demand compared to the Planning Case is expected to intensify market tightness, necessitating higher production from costlier gas resources and leading to higher gas prices

In a scenario of higher-than-expected demand, basis differentials would encourage midstream players to advance additional pipeline infrastructure projects:

- As Haynesville (East Texas) and Permian (West Texas) production decline due to resource depletion, the primary low-cost resource base in the US will shift back to the Marcellus/Utica (Appalachia), exacerbating existing pipeline takeaway constraints
- Since pipeline capacity constraints will limit the flow of lower-cost Marcellus/Utica gas from Appalachia to demand located outside of the region, power market gas demand growth in the Southeast and Gulf Coast will be served by higher cost plays in Texas and Oklahoma.
- Persistently large basis differentials between Appalachia production regions and key gas demand centers in the Gulf Coast and Southeast will make additional pipeline infrastructure projects competitive, despite costly legal challenges and regulatory uncertainties

EPA GHG regulations would require additional flexibility

- *EPA finalized regulations in April 2024, which cover new natural gas-fired and existing coal fired power plants. Due to the ongoing substantial uncertainty around this regulation, it <u>is not</u> a constraint included in the Planning Case*
- The EPA's new standards require that existing coal plants and new "baseload" gas-fired power plants operating above a 40% capacity factor reduce CO2 emissions by 90% by 2032
- Compliance with the April 2024 EPA GHG emissions regulations for existing coal- and new gas-fired power plants is even more challenging under a higher demand case. The assumed gas additions operate at an average capacity factor well above 40% each year, thereby violating the EPA's emissions standards
- Compliance with EPA standards would require a significant portion of the 100+ GW of new gas-fired capacity and the remaining coal fleet to install CCS or for new gas to limit capacity factors to 40% or less
  - Widespread adoption of CCS by 2032 is highly unlikely due to the high technical and financial risks, along with uncertainties regarding the development of the CCS infrastructure at the necessary pace and scale and in suitable locations
  - The alternative — limiting new gas plant capacity factors to less than 40% and retiring the remaining coal fleet — would require a minimum expansion of the gas combustion turbine fleet by roughly a third, or over 50 GW

Demand response remains an essential tool that meets around 5% of the peak load requirements in the outlook

Firm demand response resource capacity is expected to keep pace with the markets' net on-grid peak demand growth

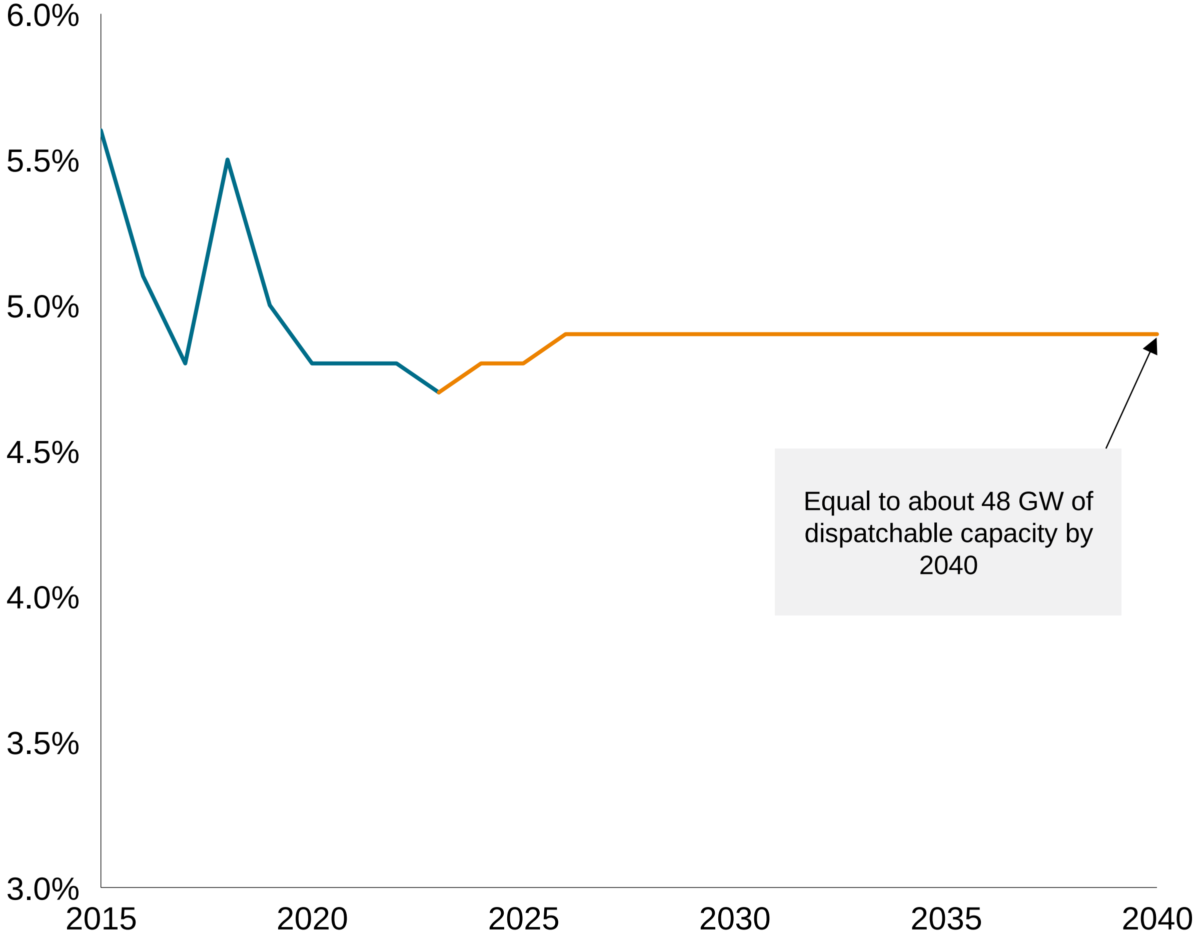
- Firm demand response (DR) resource capacity in North America has modestly declined as a percentage from 2015 to 2024, largely owed to the tightening of market rules and participation requirements for emergency DR resources following major grid emergencies.
- In the last decade, grid emergencies exposed vulnerabilities in emergency DR market participation requirements that did not ensure the expected levels of emergency DR availability. Over the last decade, PJM, MISO and CAISO responded to major grid emergencies by tightening participation requirements for emergency DR resources, thereby increasing participation costs for these resources.

Outlook

- Interest in flexibility of large loads has risen in recent months, which to an extent, can help with near-term capacity needs. However, through 2030, both incremental capacity and energy are needed to meet large industrial load growth, especially in markets expecting the most load growth.
- For the US, S&P Global cases assume the addition of roughly 8 GW of firm DR capacity by 2040. Firm DR climbs to 48 GW by 2040 in the base case. This view reflects an expectation that the tightening of market rules for DR resources will be balanced by a rising need for flexible, non-emitting energy resources.

North American firm DR capacity to peak load ratio, 2015–40

Percentage



48 GW equals to 4.7% of total peak requirements in the US by 2040.
Sources: S&P Global Commodity Insights; NERC, MISO, ISO-NE, NYISO, PJM and CAISO for historical data

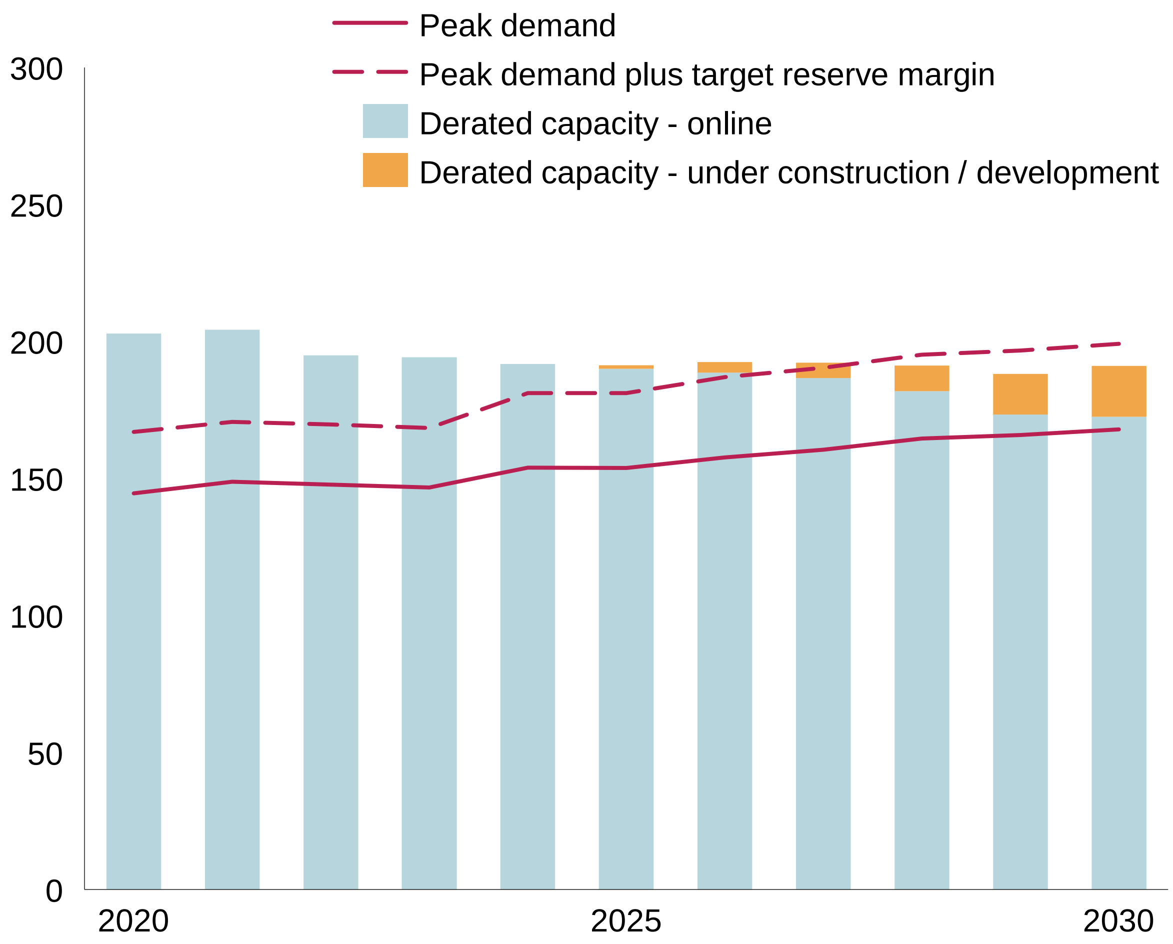
Regional supply challenges: PJM

PJM recent developments

- Around 19 GW (mostly coal and gas) of retirements are expected to take place over the next five years and with the rising demand from large loads and electrification, the need for capacity available to meet peak demand is acute in PJM
- PJM saw historically high clearing prices for capacity in its 2025/2026 delivery year, an outcome serving as a market signal for new entry
- With the risk of undersupply in mind, PJM has proposed several market design changes recently
  - Capacity market changes: PJM required a delay of the upcoming capacity auction, originally set for December-2025, in response to complaints raised following record-setting clearing prices in its last auction. Additionally, lower price caps have been filed after pushback from stakeholders
  - Proposal to extend the capacity must-offer requirement to all existing generator capacity resources: The extension would sunset exemptions for intermittent resources, capacity storage resources and hybrid resources beginning with the 2026/2027 capacity auction
  - Reliability Resource Initiative (“RRI”) proposed to speed up the process for getting shovel-ready generation projects added to the grid
  - A plan to expedite studies for Surplus Interconnection Service (“SIS”): which would streamline existing tariff details allowing new generators that do not require transmission system upgrades to use an existing generator's unused interconnection capacity

Peak demand vs derated capacity in PJM, 2020–30

GW



Source: S&P Global Commodity Insights

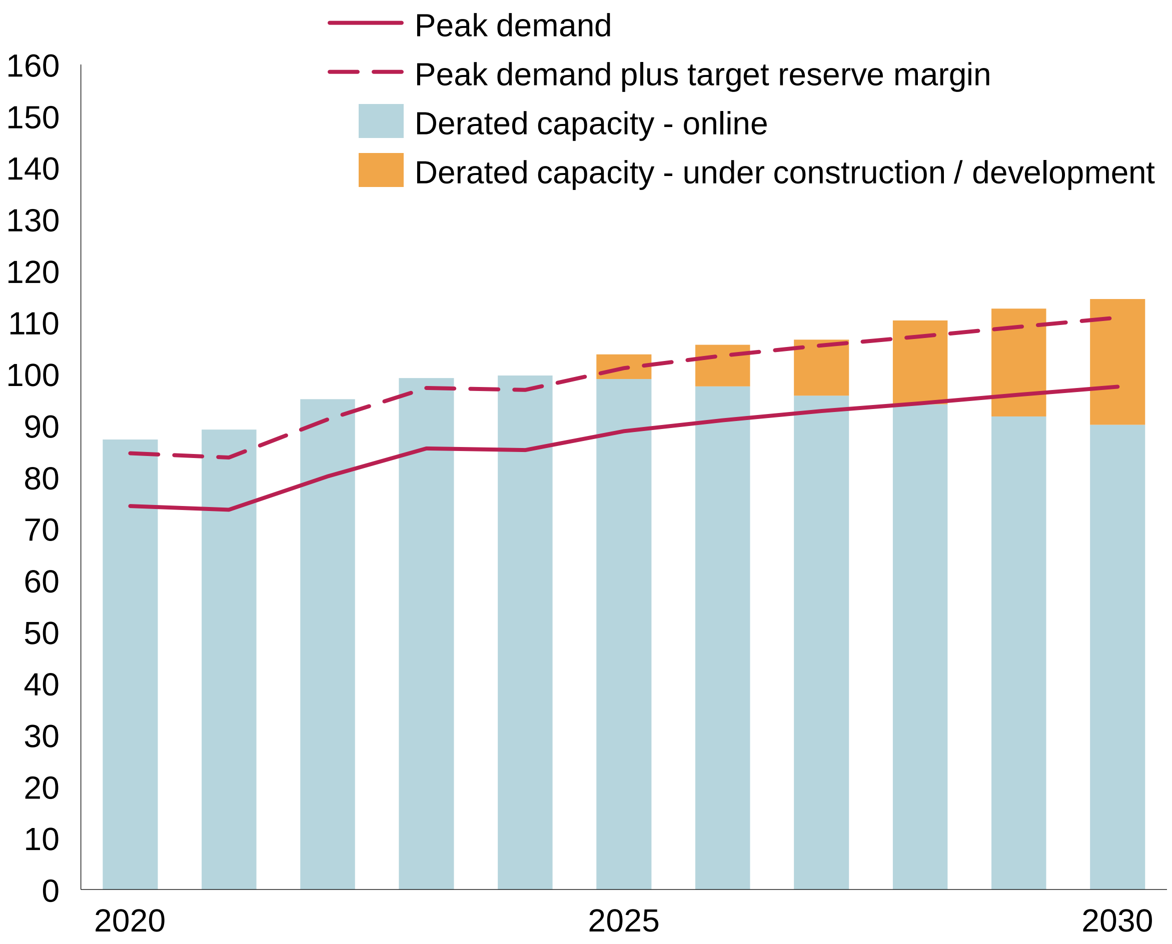
Regional supply challenges: ERCOT

ERCOT recent developments

- ERCOT relies on shortage pricing within an energy-only market design to incentive new entry. The demand for operating reserves during shortage periods is established administratively via the Operating Reserve Demand Curve (ORDC)
- ERCOT has experienced reliability challenges, exacerbated by extreme weather
- Several changes are underway to mitigate the risk of undersupply
  - As a political response to these reliability challenges, the Texas legislature established the Texas Energy Fund (TEF) during the fall of 2023, subsidizing new, firm resources. The legislature is currently considering additional measures to support firm capacity additions.
  - Also in 2023, ERCOT introduced the first new A/S product to be procured in 20 years, known as ECRS. This product is intended to improve grid reliability, requiring the resource to ramp up to a specified level within 10 mins and have a sustained output of typically 2 hours
  - ERCOT employs a relatively efficient interconnection process known as “connect and manage” whereby a new generator’s owner takes on more market/local pricing risk in exchange for a lower burden of system studies and system upgrade investments prior to receiving an interconnection agreement

Peak demand vs derated capacity in ERCOT, 2020–30

GW



Source: S&P Global Commodity Insights

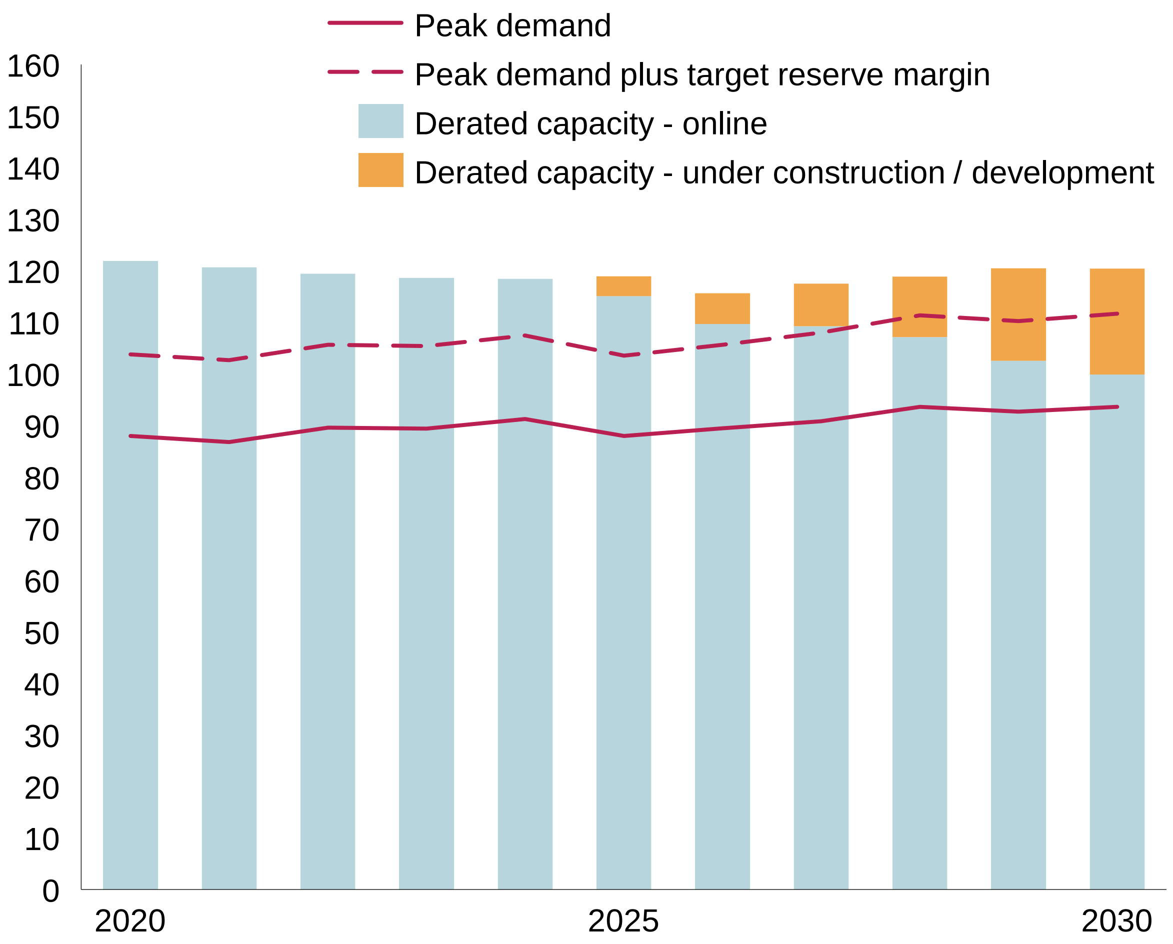
Regional supply challenges: MISO

MISO recent developments

- With over 17 GW of retirements planned over the next five years, MISO members and states may need to add capacity at an unprecedented rate to meet future demand and policy goals
- The situation called the attention of NERC in its latest report, labeled as the only "high risk" area of the 11 at-risk assessment regions, that its resource additions are not keeping up with generator retirements and demand growth
- With solar and batteries just ramping up in MISO, gas-fired generator additions are poised to be the main source of firm capacity additions in the system over the short term
- MISO has several market design changes underway
  - New capacity framework for MISO's seasonal reliability auctions
  - Interconnection queue reforms: Increased milestone payments, automatic withdrawal penalties
  - Additionally, MISO approved the $30 billion 2024 Transmission Expansion Plan, which called the largest portfolio of transmission projects in US history

Peak demand vs derated capacity in MISO North, 2020–30

GW



Source: North American Electric Reliability Corporation's (NERC) 2024 Summer Reliability Assessment. S&P Global Commodity Insights

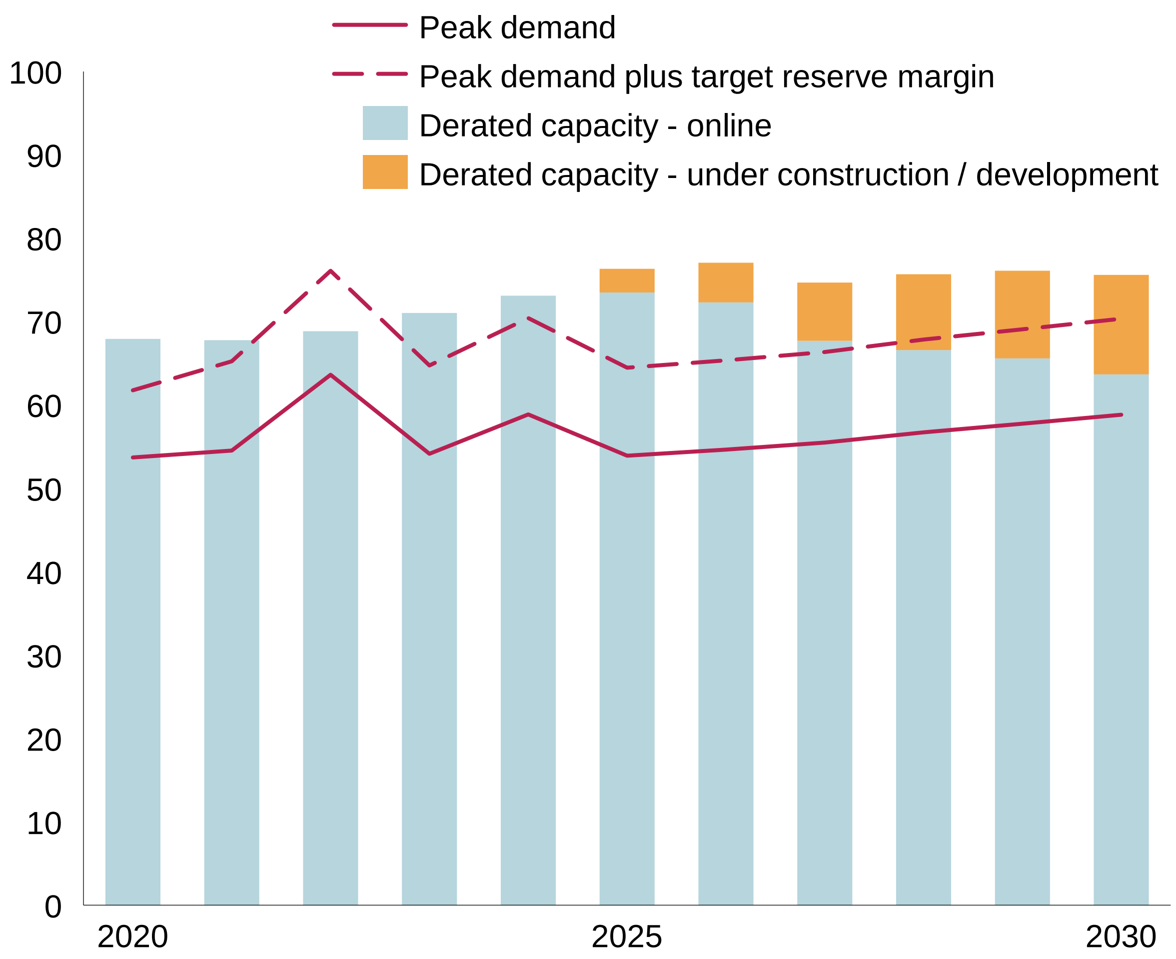
Regional supply challenges: California

California recent developments

- California has faced challenges in maintaining adequate reserve margins over the past decade. However, recent years have seen a reversal of this trend, largely driven by the substantial deployment of battery energy storage systems (BESS)
- Going forward, retirements driven by the state's Once-through Cooling rule, which affects coastal generators, will tighten capacity conditions. However, some thermal retirement dates are being postponed as part of the governor's strategic reliability reserve program
- The state is averse to building new gas-fired resources and is relying on new battery storage resources to meet incremental capacity needs. However, there has been recent regulatory headwinds for batteries in California including the CPUC's proposal for enhanced battery safety standards in response to a recent series of fires at battery storage facilities and FERC's approval of changes to battery storage bid-cost recovery rules.

Peak demand vs derated capacity in California, 2020–30

GW



Source: North American Electric Reliability Corporation's (NERC) 2024 Summer Reliability Assessment. S&P Global Commodity Insights

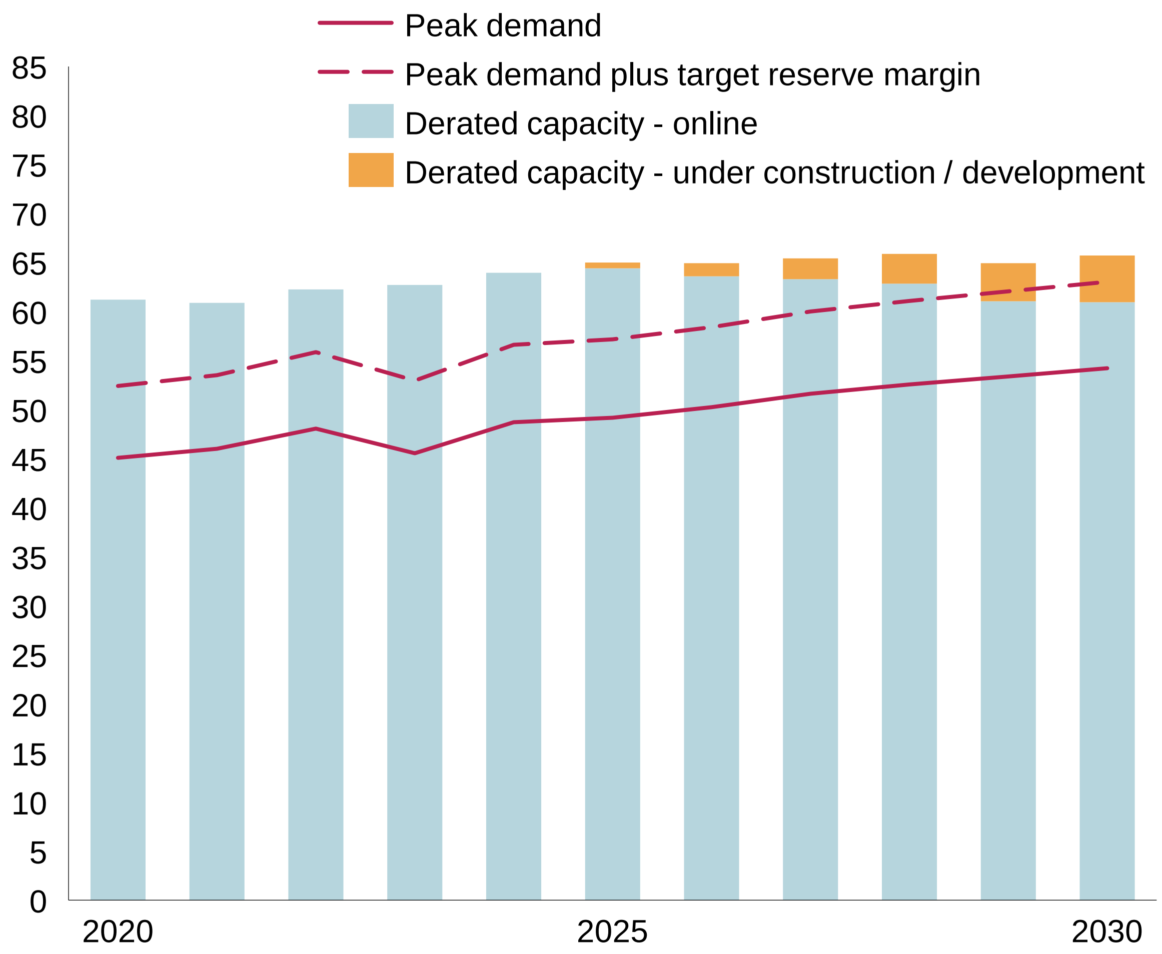
Regional supply challenges: Southeast

Southeast recent developments

- Large industrial loads are driving demand forecast growth in the region. While metro areas are experiencing a high demographic growth compared to the rest of the country.
- Generator retirements are carefully managed by entities in the SERC-Southeast assessment area. Entities perform studies to determine the impacts of confirmed or unconfirmed retirements
- Georgia Power filed their proposed 2025 integrated resource plan with Georgia state officials. The plan calls for adding more capacity at existing gas and nuclear sites through uprates and delaying retirement at three coal-fired units as the utility faces growing demand.
- Fellow Southern Company subsidiary Mississippi Power also announced delayed retirements at a coal-fired unit and a gas-fired unit with the objective to meet large-load demand.

Peak demand vs derated capacity in SERC: Southeast, 2020–30

GW



Source: North American Electric Reliability Corporation's (NERC) 2024 Summer Reliability Assessment. S&P Global Commodity Insights

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Wholesale power prices are around 20% higher in Power Crunch, whereas regional price differentials are largely influenced by the degree of renewable penetration

Power prices by RTO/ISO

RTO/ISO	Annual average price (2025-30), nominal $/MWh	Percent change in Power Crunch (%)
PJM	$47	18 %
MISO	$43	18 %
ERCOT	$38	56 %
SPP	$34	20 %
California	$52	26 %
ISONE	$51	18 %
NYISO	$49	19 %

- Higher gas prices and higher load could put upward pressure on power prices
- On average, power prices could be around 20% higher in the short term, except for ERCOT that sees a higher increase due to tightening margins and increased frequency of scarcity pricing

Source: S&P Global Commodity Insights

Near-term capacity prices remain elevated despite higher energy prices

Capacity prices for key markets

RTO/ISO	Summer year average price (2025-30), nominal $/kW-year	Percent change in Power Crunch
PJM - RTO	$115	5
PJM - DOM	$123	12
MISO North	$41	160
MISO South	$27	241
ISONE	$35	6
NYISO	$28	10

- Higher gas and power prices, especially in the near term, could increase expected energy margins of new units, which, during “normal” times, lowers the net cost of new entry (net CONE) and therefore would typically (all else equal) exert downward pressure capacity prices
- However, in Power Crunch, not enough supply can enter the market in the near term to avoid the capacity markets clearing at a higher price. MISO is an example of this dynamic where capacity prices more than double compared to the Planning Case
- PJM capacity prices do not see much variation as the Planning Case prices were already high and near price cap levels
- NYISO and ISONE see modest increases due to limited large load increases in those areas

Source: S&P Global Commodity Insights

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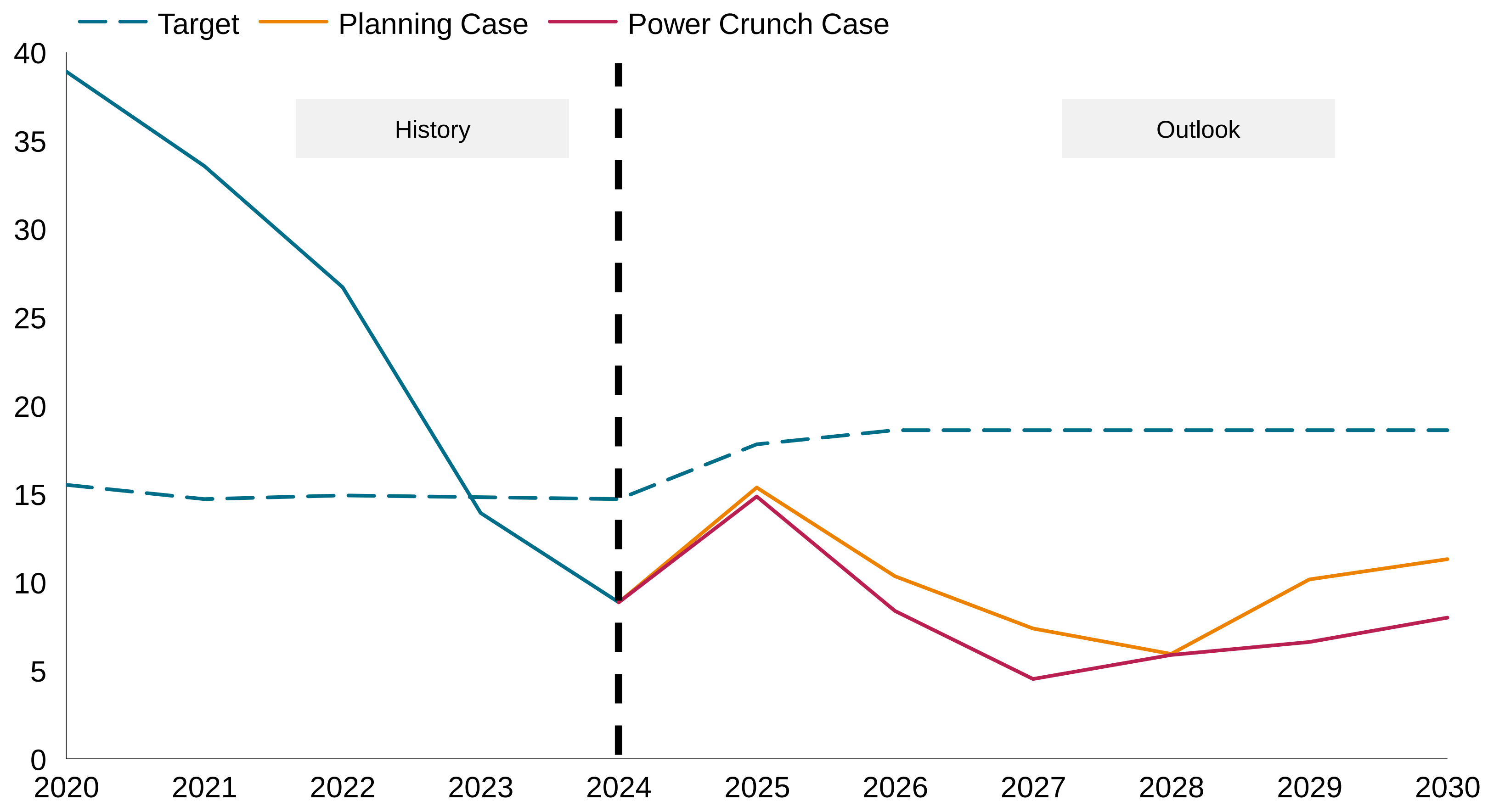
PJM South is expected to have reserve margins below target, as demand growth continues to outpace supply expansion

Planning Reserve Margin, PJM South

Percentage



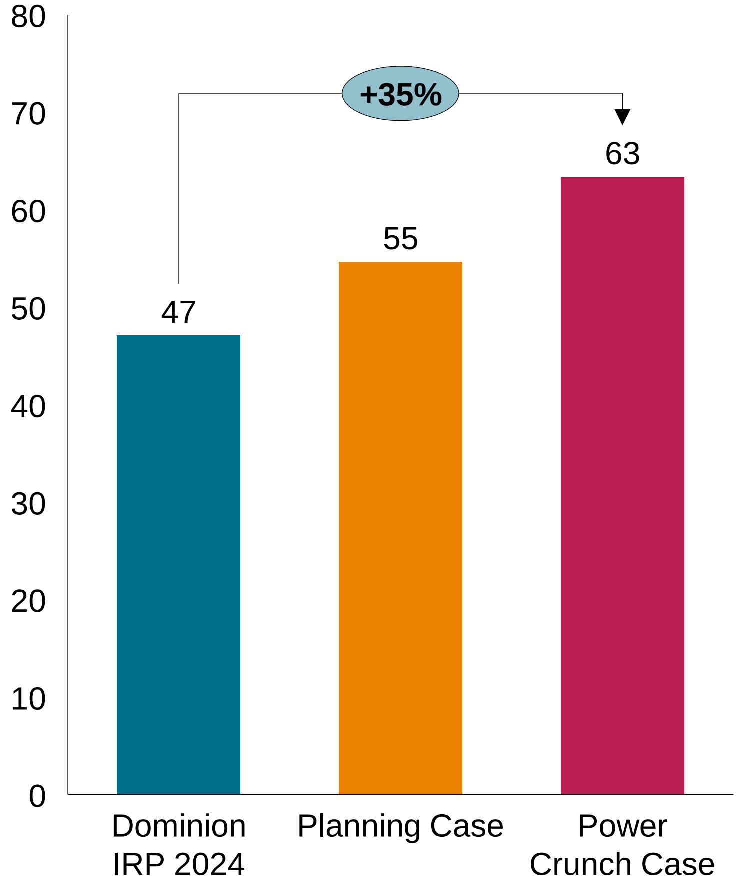
- With the passage of the Virginia's Clean Economy Act, the transition of the supply mix in PJM South is expected to accelerate
- However, supporting datacenter-driven load growth while maintaining reliability will be challenging under current market conditions
- Historically, reserve margins in PJM South have exceeded targets. However, since 2023, these margins have tightened due to increased demand and the retirement of 3 GW of aging thermal capacity over the past five years
- Looking ahead, reserve margins are projected to remain below target levels as demand growth continues to outpace supply expansion efforts

Source: S&P Global Commodity Insights, Virginia Electric And Power Company 2024 Integrated Resource Plan

Higher wholesale energy and capacity prices translate to higher costs for Dominion, which ultimately is expected to put pressure on retail rates

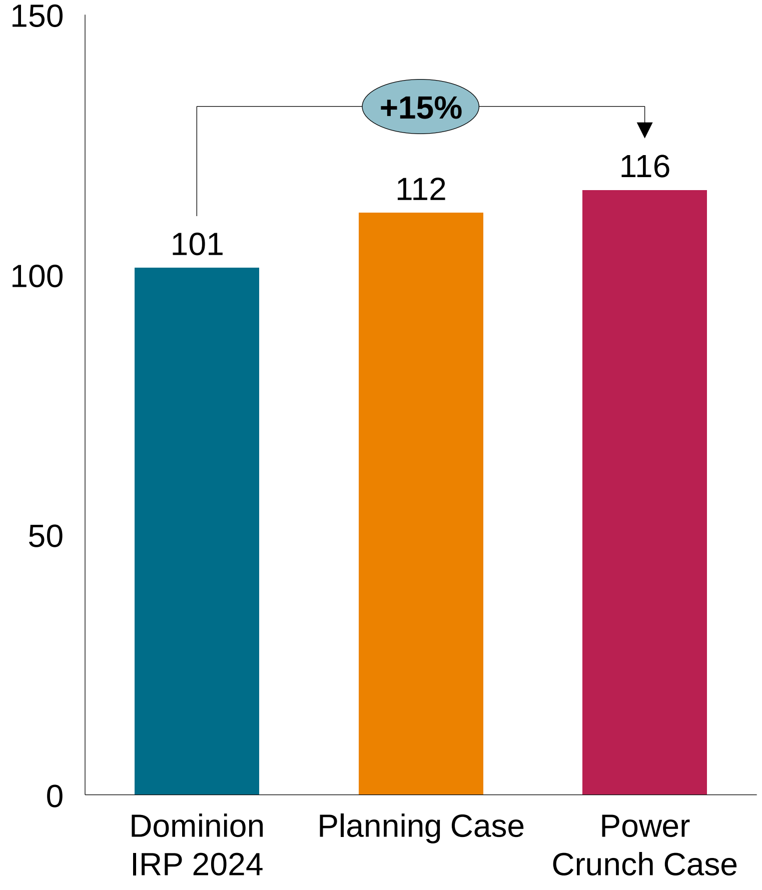
2025-30 average on-peak energy price, PJM South

$/MWh



2025-30 average capacity price, PJM South

$/kw-year



- The S&P Global cases project higher energy and capacity prices compared to Dominion's Integrated Resource Plan (IRP). This difference is largely attributed to our expectation of higher load growth driven by datacenters, which contributes to increased market demand and price volatility
- Dominion, despite owning generation assets, has increasingly relied on power purchases from the market to meet its energy needs. In 2023, it purchased 22% of its energy requirements from the wholesale market
- This dependency on wholesale price fluctuations can exert pressure on retail rates, as wholesale market transactions represent a cost that the utility recovers through increased prices to customers

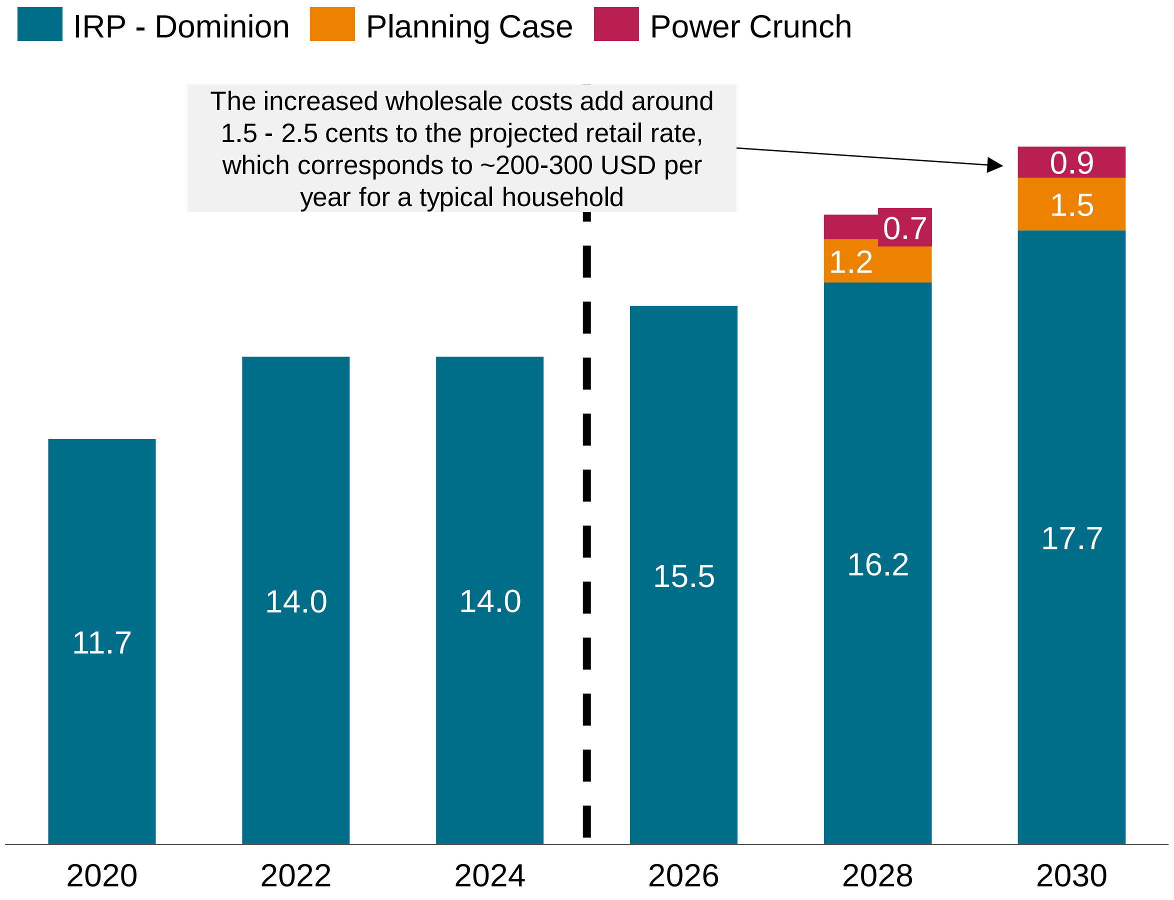
Source: S&P Global Commodity Insights, Virginia Electric And Power Company 2024 Integrated Resource Plan

As higher energy and capacity costs get translated into higher retail rates, residential customers can see their bill increased by around 10-15% by 2030

- The projected increase in wholesale costs could result in an additional 2-3 cents per kilowatt-hour (kWh) by 2030. For a typical household, this translates to an estimated increase of approximately $200 to $300 per year in energy bills
- This analysis does not make further assumptions regarding potential changes in Dominion's procurement strategy. Dominion has the capability to mitigate exposure to wholesale market fluctuations by entering into Power Purchase Agreements (PPAs) or other hedging mechanisms. Such strategies could potentially shield consumers from the full impact of rising wholesale prices
- Additionally, the estimation assumes that the additional costs are allocated to residential customers based on their share of total energy consumption. However, the actual impact on consumer bills could vary significantly, depending upon rate case outcomes. The commission’s rulings will play a crucial role in determining the extent to which residential customers bear the brunt of increased demand and wholesale costs, a topic being discussed as load growth projections (mostly coming from large loads) have soared

Residential all-in retail rate, household consuming 1000 kWh per month

Cents per kWh



Source: S&P Global Commodity Insights, Virginia Electric And Power Company 2024 Integrated Resource Plan

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The increasing difficulty to pass through the interconnection queue adds uncertainty to the deployment of new generation projects

Interconnection Queues Explained

- Interconnection queues are lists of projects awaiting approval to connect to the grid. For approval, the RTO/ISOs conduct various studies (some requiring complex power flow analysis) to determine how the resource will affect grid stability
- The studies determine the cost and timeline of network upgrades associated with enabling the resource. Outside of ERCOT, RTO/ISOs also analyze deliverability, which means whether the power can get to load under peak/contingency conditions, a major driver of network upgrades

Recent trends

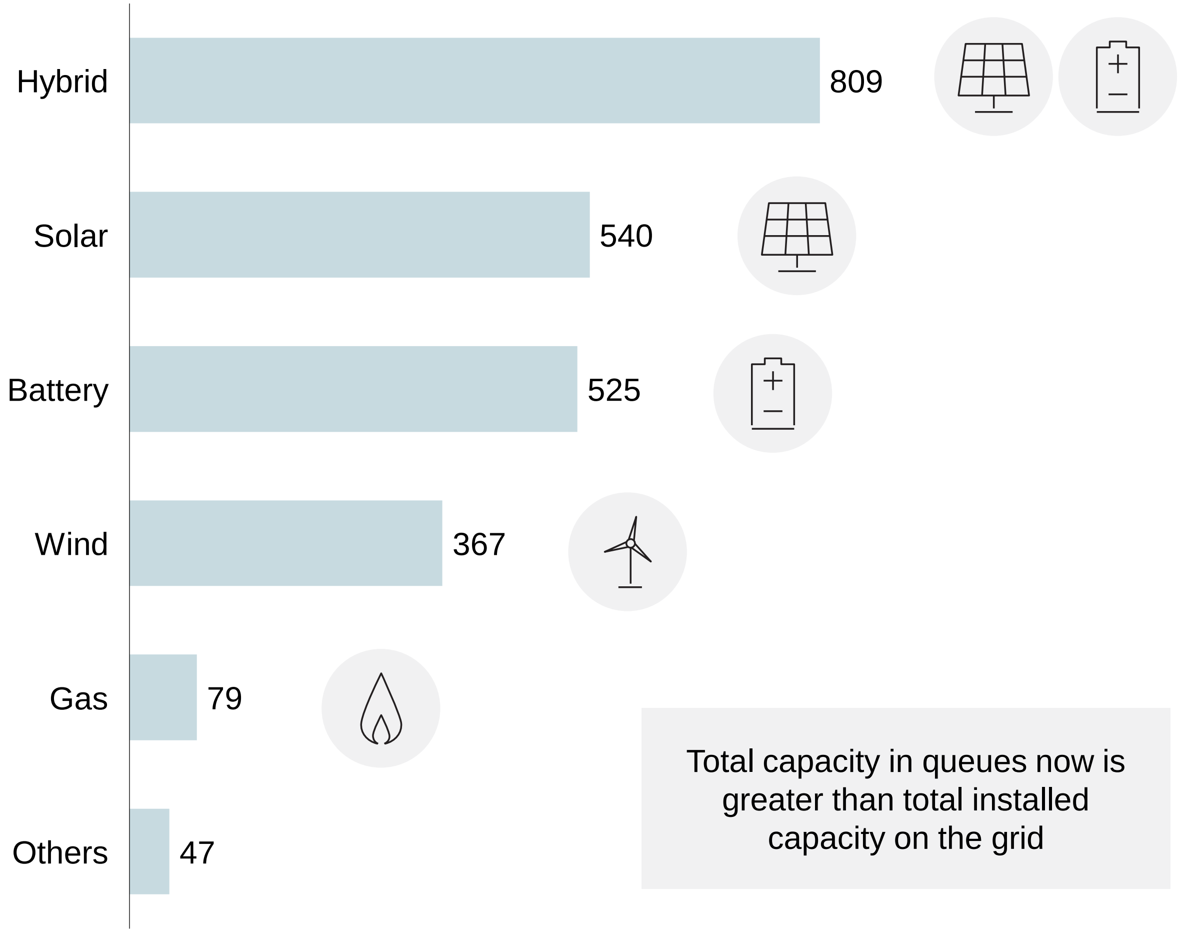
- Interconnection queues for all seven independent system operators and 19 major utilities in the non-ISO regions of the Western and Southeastern US combine to show nearly 2,400 GW of capacity requesting grid interconnection.
- Most of this queue capacity has been added over the last five years. The shift from large generators to smaller generators has intensified queue pressures, as processes were not designed to keep up with this rate of project study

Uncertainty to the deployment of energy projects

- Developers submit many applications but only intend to build the cheapest, which cannot be known until studies are run. This creates inefficiency as RTO/ISOs spend resources studying projects with a very small likelihood of ever getting built (and the list is dynamic)
- As transmission grids run out of spare capacity, the network upgrades required to interconnect new projects tends to rise. This has created significant cost uncertainty for developers, adding to their incentive to submit speculative projects, creating a vicious cycle

Interconnection queue capacity breakout as of April 2024

GW



Total capacity in queues now is greater than total installed capacity on the grid

Data as of April 2024. Hybrids are defined as Solar + Batteries. Others include Coal, Geothermal, Hydro, Nuclear, Pumped-hydro storage.
Source: Lawrence Berkeley National Laboratory: Queued Up 2024 Edition

However, the response of new supply to quickly address demand growth is challenged by several factors

- With a broad consensus about continued near-term demand growth, there are pressing questions about how to meet this new demand while maintaining reliability
  - These questions arise amid uncertainties about the long-term trajectory of rapid demand growth and the challenges of building supply against the backdrop of often conflicting policy, economic, and reliability considerations
- Gas-fired additions have seen a surge in interest but given how additions were at a two-decade low in 2024, the industry faces challenges to quickly ramp up supply chains. Some coal retirement delays are likely, but technical and regulatory limits will prevent some coal plants from remaining online much longer
- Battery energy storage has the potential to expand quickly, but battery project economics are exposed to ongoing changes in capacity and ancillary markets
- Other technologies like advanced nuclear and geothermal have long lead times, reducing their relevance to addressing the coming power supply crunch
- The increasing difficulty, in nearly every jurisdiction, around siting, permitting and getting projects through interconnection queues adds uncertainty to the deployment of new generation projects
  - Local opposition has emerged as a major risk to the cost and pace of renewables deployment
  - As transmission grids run out of spare capacity, the network upgrades required to interconnect new projects tends to rise. This has created significant cost uncertainty for developers, adding to their incentive to submit speculative projects
- Transmission development will also be key to supporting grid reliability – but without major reforms the lack of new transmission expansion projects could turn into a significant barrier, particularly after 2030

Selected recent transmission and interconnection reforms and updates

Level	Description
FERC	▪ **Order 2023:** reform processes used by transmission providers to study and connect generating facilities, including a "first ready, first served" approach, which groups projects by location and queue dates. ▪ **Order 1920:** requiring all transmission providers to conduct long-term planning — a minimum of 20 years into the future — to ensure adequate transmission capacity is planned to reflect changes in future demand and supply.
ISO/RTO	▪ **MISO:** Increase milestones payments, automatic withdrawal penalty; cap on total queue size ▪ **CAISO:** Prioritize requests where transmission system has available existing or planned capacity ▪ **PJM:** First-ready, first-served clustered cycle approach, grouping projects into three-phase cluster cycles for interconnection costs studies and allocations ▪ **ERCOT:** “Connect and manage” approach to interconnecting new resources; Interconnection cost cap (HB 1500)

Although these reforms aim to alleviate backlogs, it is unclear if they will have a major impact for near-term supply response. Additionally, local opposition remains as a major risk that is difficult to address

Note: FERC orders do not apply to ERCOT, non-FERC-jurisdictional utilities, and vertically integrated utilities in non-FERC-jurisdictional states
Source: Lawrence Berkeley National Laboratory: Queued Up 2024 Edition, S&P Global Commodity Insights

Transmission will be key to supporting grid reliability – but without major reforms lack of new transmission expansion projects could turn into a significant barrier, particularly after 2030

- **Major US investor-owned utilities are planning to spend nearly $400 billion on transmission and distribution upgrades over the next five years,** with a large share of investments allocated toward distribution projects. Despite this substantial spending, the US transmission grid is not expanding fast enough, particularly in long-range, high-voltage infrastructure. The outdated transmission network poses growing risks to grid reliability, delaying the development of new energy projects, and limiting the efficient use of existing assets during dispatch

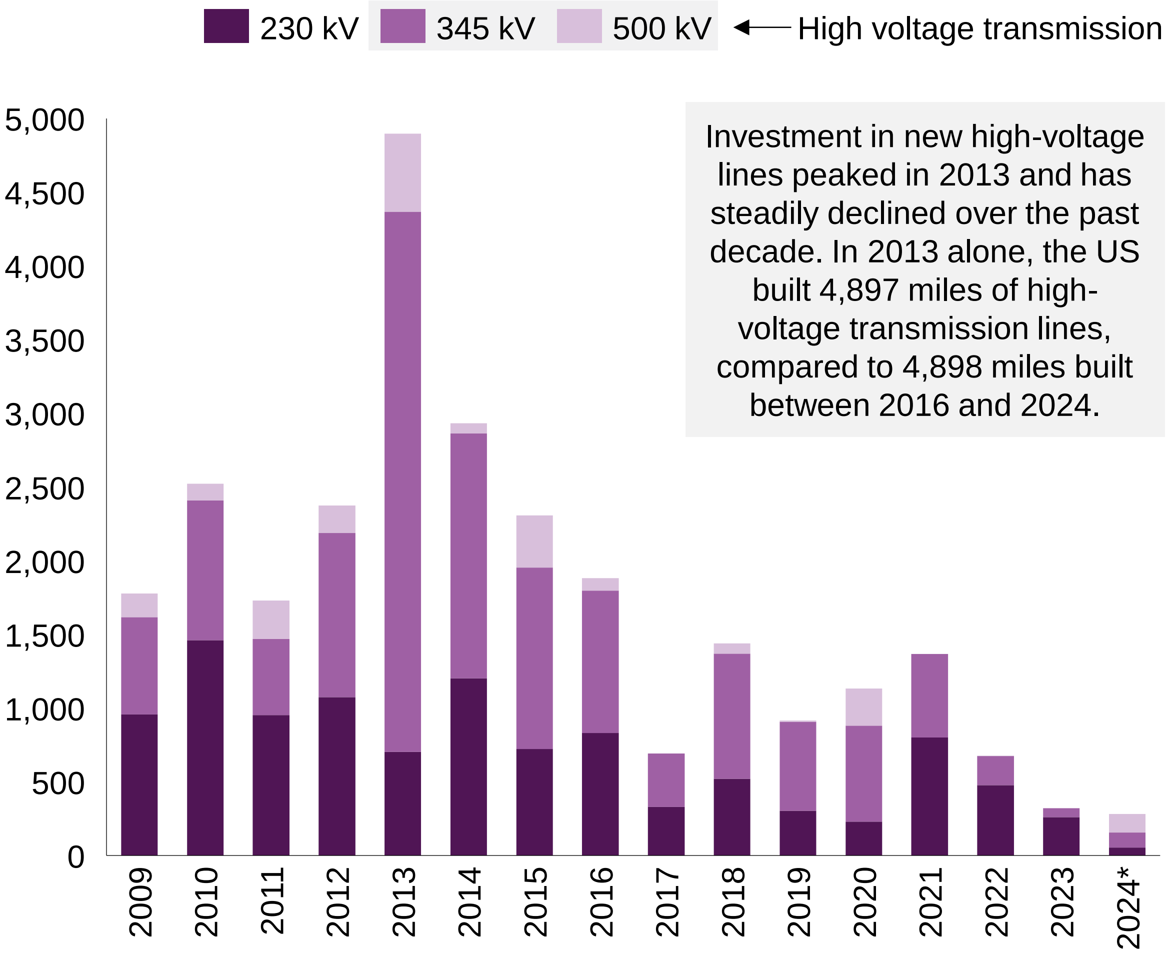
- **Transmission development involves a complicated regulatory process.** Progress has been made over the past several years via a series of FERC orders, which may result in important changes in the transmission system that could ease many of the key problems facing the electric sector. The implementation of these recent orders may begin to ease some of the transmission roadblocks. However, absent a high level of success associated with these orders, transmission development could become a major impediment to clean energy expansion, particularly after 2030
  - FERC's requirements under Order 881 for the use of ambient line ratings and the possibility of direct line rating technology is expected to assess more accurately the carrying capacity of the US grid, potentially reducing some generator curtailments and postponing the need for new transmission in some areas
  - Reforms to the interconnection process through FERC Order 2023, issued in July 2023, may improve the speed of processing generator applications to connect to the grid. Order 2023 transitions the "serial first-come, first-served" study process to a "clustered first-ready, first-served" process. Order 2023 also contains provisions to encourage co-location of generation resources
  - In the spring of 2024, FERC issued Order 1920, requiring all transmission providers to conduct long-term planning — a minimum of 20 years into the future — to ensure adequate transmission capacity is planned to reflect changes in future demand and supply. This order requires a robust, transparent process for planning and selecting regional long-term transmission projects. Additionally, transmission providers must file with FERC a cost allocation methodology that has been reviewed with states in advance. Finally, this order requires that local transmission projects be coordinated with regional planning processes to ensure local projects are "right sized" and represent the most efficient option

High voltage transmission is considered to start at 345 kV.
Source: S&P Global Commodity Insights

Significant transmission investment needs to take place to keep up with future power demand

Added transmission miles by voltage, 2009–24

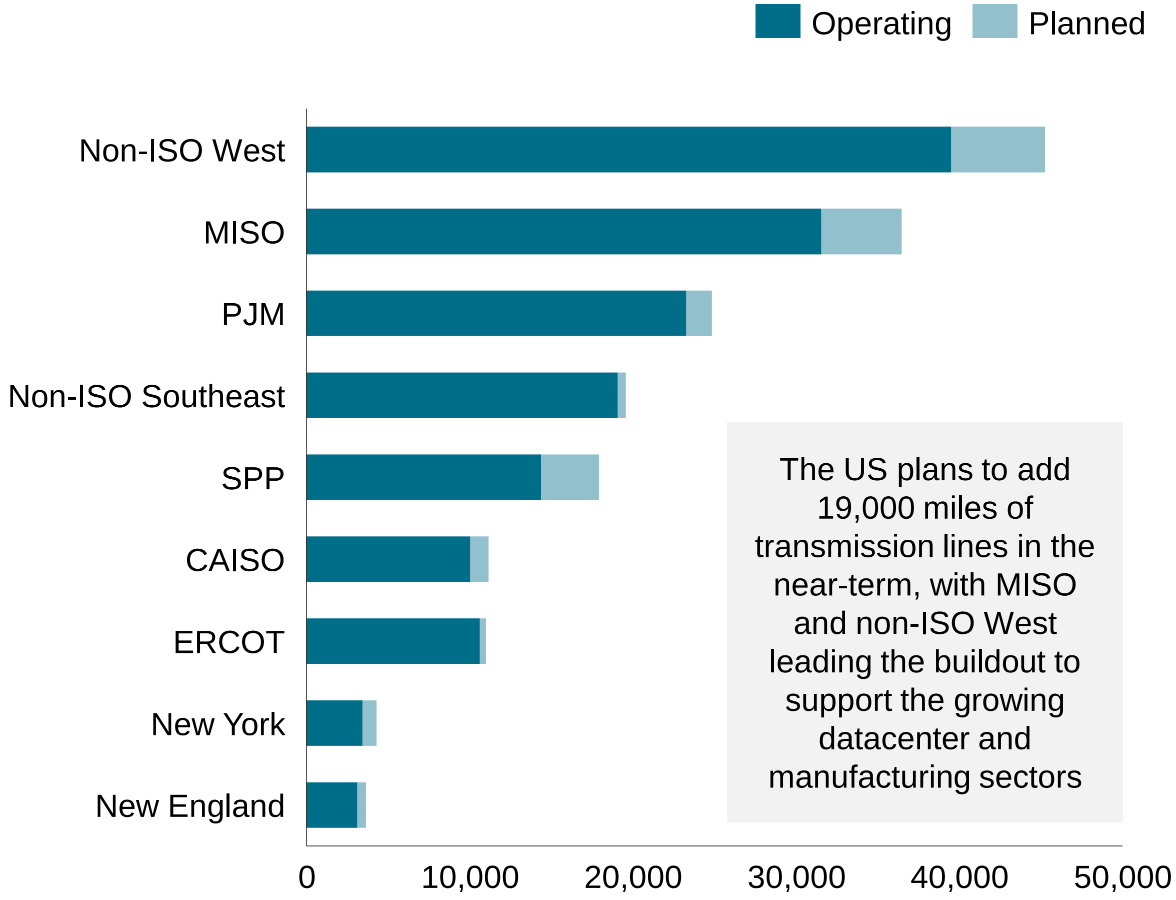
Miles



Investment in new high-voltage lines peaked in 2013 and has steadily declined over the past decade. In 2013 alone, the US built 4,897 miles of high-voltage transmission lines, compared to 4,898 miles built between 2016 and 2024.

Transmission miles by originating region, 2024

Miles



The US plans to add 19,000 miles of transmission lines in the near-term, with MISO and non-ISO West leading the buildout to support the growing datacenter and manufacturing sectors

Note:*Data for 2024 completed transmissions project length is presented for January-September.

Non-ISO West includes the Desert Southwest, Rockies and the Northwest Power Pool-US; Non-ISO Southeast includes the SERC regions and FRCC. Source: (L) Federal Energy Regulatory Commission (2024), (R) S&P Global Commodity Insights

Adding supply to meet surging electricity demand growth is challenging, but policy options exist that could make it easier

Optimize interconnection study process

- Standardize interconnection study process across ISO/RTOs
- Employ cluster studies where multiple interconnection requests are grouped together and studied collectively rather than individually
- Shift some of the responsibility for conducting interconnection studies from RTO/ISOs to developers
- Employ digital technologies/AI to expedite interconnection studies

Prevent speculative behavior in the queue

- Charge upfront interconnection entry fees commensurate with likely upgrade costs and project size
- Require developers to demonstrate capability in executing the proposed project
- Introduce penalties for withdrawal from the queue
- Introduce a mechanism to remove nonviable projects from the queue

Improve interconnection access and flexibility

- Increase transparency on queue position, project ownership, location, and size
- Delink interconnection from deep network upgrade decisions
- Allow generators to initially gain ERIS access, but later obtain NRIS access
- Offer educational resources for stakeholders to better manage risks

Conduct grid upgrades

- Improve reporting on the transmission project construction phase
- Reduce supply chain bottlenecks for key equipment
- Streamline permitting and siting for high-voltage, long-distance transmission lines

Explore co-location of supply with large loads

- Expedite approvals for projects that integrate generation and large loads on the same site
- Support microgrids and off-grid solutions to serve large loads

Enhance energy efficiency as a grid resource and strengthen demand-side management to reduce grid strain

- Use fast track processing for flexible and high-efficiency loads
- Incentivize load flexibility and demand response capabilities for large loads

NRIS = Network Resource Interconnection Service. ERIS = Energy Resource Interconnection Service.

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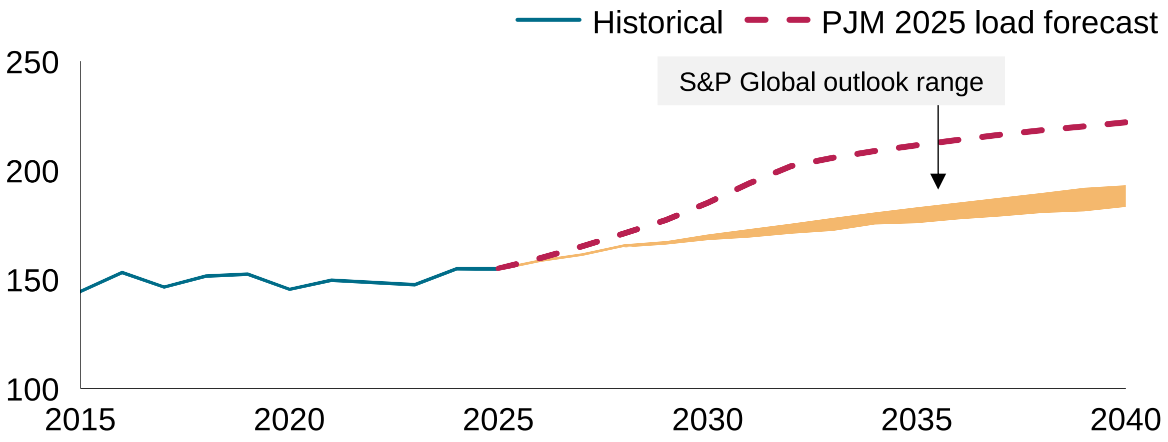
PJM

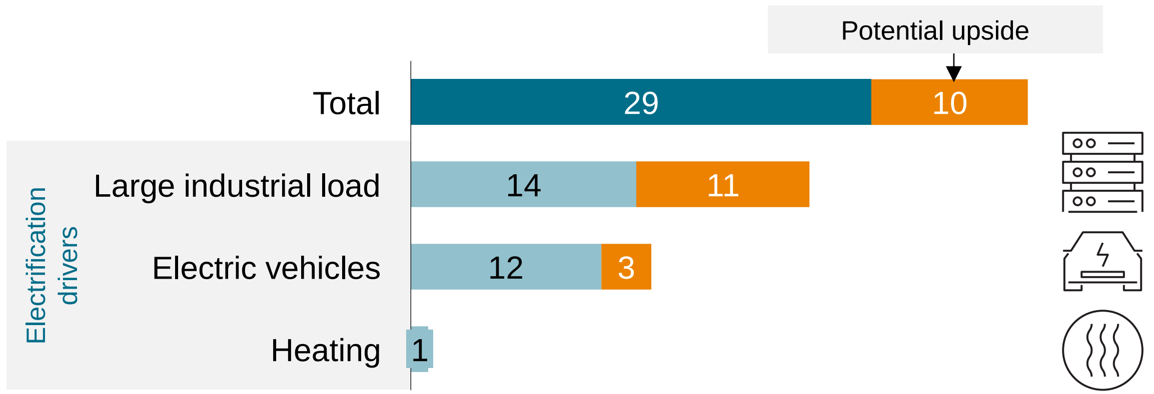
Net peak demand for PJM, 2015–40

GW



Main drivers of peak demand, net change (2024–40)

GW



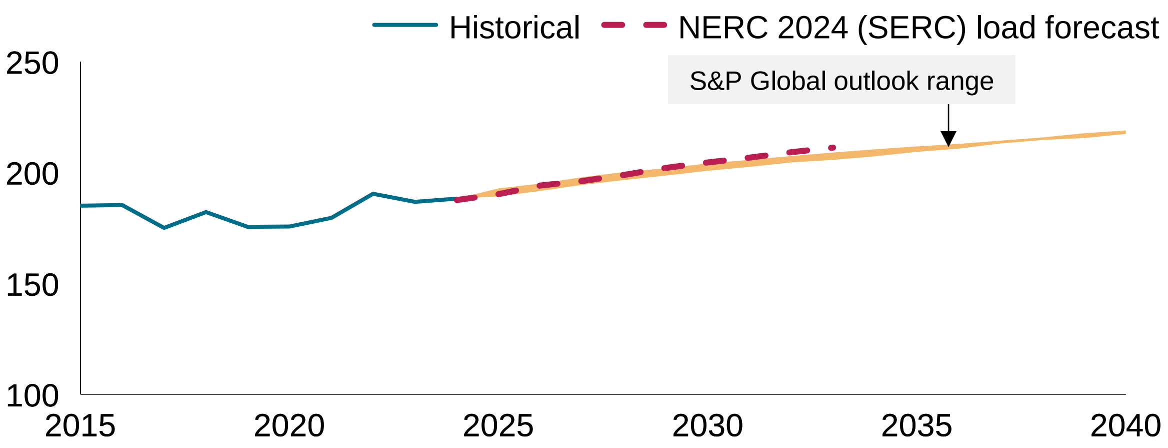
Electric vehicles include light duty battery electric vehicles (BEVs) and plug in hybrid electric vehicles (PHEVs).
Source: S&P Global Commodity Insights, 2025 PJM Long-Term Load Forecast

- Peak demand in PJM has inched up over the last ten years despite modest economic growth. Datacenters, electric vehicles and heating electrification are key drivers of electricity demand growth over the long term
- Large industrial loads are the main driver of peak demand growth in PJM. This growth is primarily attributed to the expansion of datacenters in Northern Virginia – home to the largest datacenter hub in North America – and along major high-voltage transmission corridors through Indiana, Ohio and Illinois. Datacenter load presents a high upside risk, particularly in PJM South and PJM West
- EV adoption is expected to be moderate in the near-term and pick up in the later half of the outlook.
- The region sees economic growth slightly below the national average. This modest growth, coupled with stagnant population levels and a sluggish annual increase in households, suggests that demand driven by economic/demographic growth will be minimal

Southeast

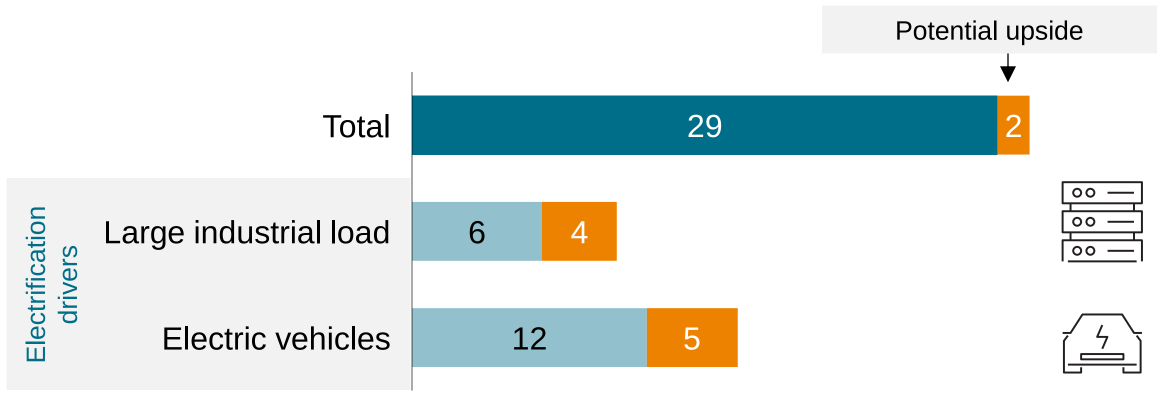
Net peak demand for Southeast, 2015–40

GW



Main drivers of peak demand, net change (2024–40)

GW



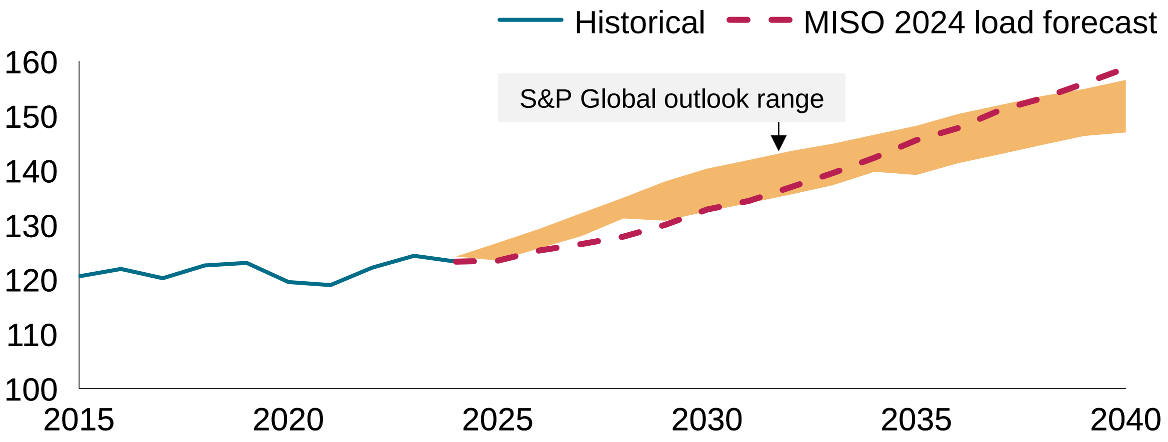
Electric vehicles include light duty battery electric vehicles (BEVs) and plug in hybrid electric vehicles (PHEVs).
Source: S&P Global Commodity Insights, 2024 NERC Long-Term Reliability Assessment

- Demographic and economic trends are set to significantly shape electricity demand in the Southeast, driven by its dynamic growth landscape. With an annual economic growth rate slightly above the national average, the region is experiencing robust expansion. Population and the number of households both surpassing U.S. averages. Notably, the Southeast is the region that adds the most population and households in absolute terms, reflecting its attractiveness for new residents and businesses
- Electric vehicle adoption begins at a slower rate due to lack of strong policy support in the Southeast but picks up later in the outlook. The region is expected to reach 17 million of EVs in operation by 2040
- Large load, split roughly evenly between the datacenter and manufacturing load, drive growth in the region in the near term

MISO

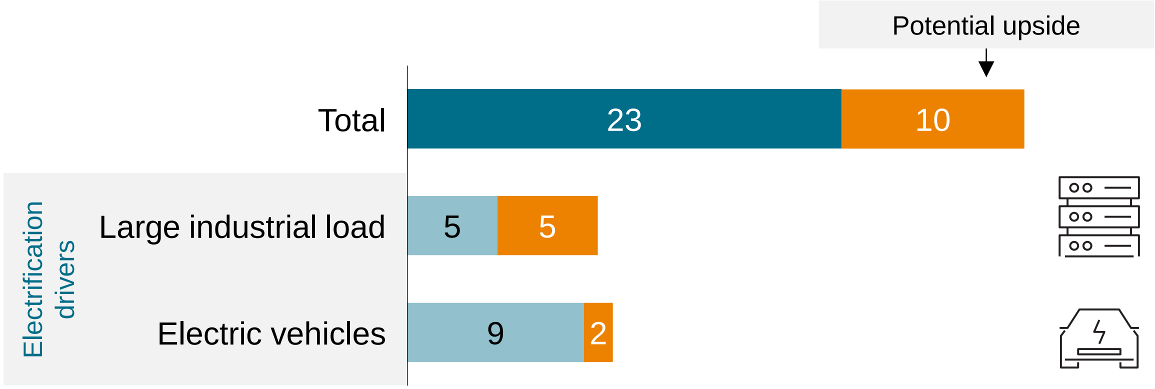
Net peak demand for MISO, 2015–40

GW



Main drivers of peak demand, net change (2024–40)

GW



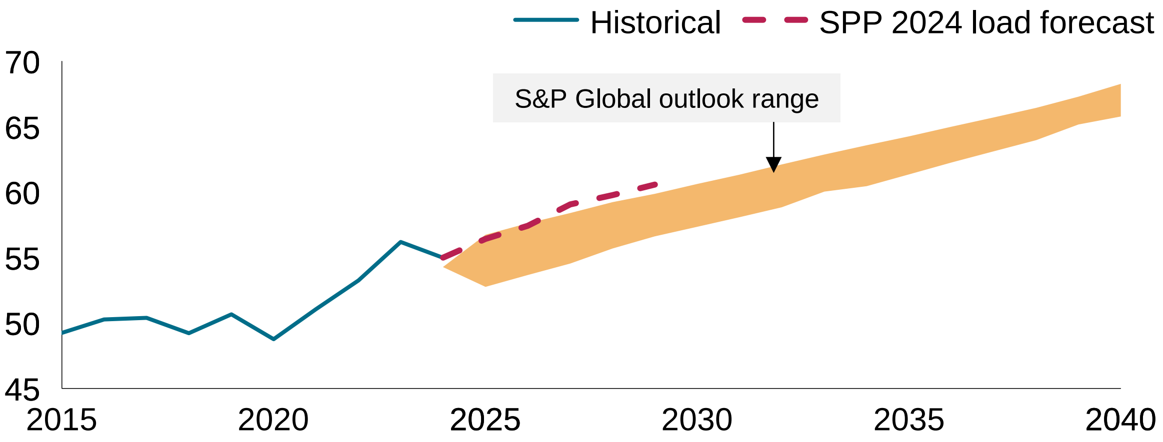
Electric vehicles include light duty battery electric vehicles (BEVs) and plug in hybrid electric vehicles (PHEVs).
Source: S&P Global Commodity Insights, 2024 MISO Long-Term Forecast

- In the MISO region, economic and demographic factors are a major driver of power demand. The region's economic growth is projected closely aligns with the national average. While population growth remains stagnant, the number of households is expected to increase slightly below the U.S. average of. A key factor influencing demand is the modest growth anticipated in the manufacturing sector, particularly among manufacturers of transportation equipment. The announcement of several large projects focused on building electric vehicles (EVs) and their components over the past few years underscores the region's potential for increased electricity demand, driven by industrial advancements and the transition to electric mobility
- Electric vehicles adoption is expected to be moderate in the near-term. However, in the later part of the outlook, EV adoption accelerates, with vehicles in operation to reach over 11 million by 2040
- Large industrial load growth is predominantly driven by datacenter expansion in the base case, while the sensitivity case projects an uptick in manufacturing additions

SPP

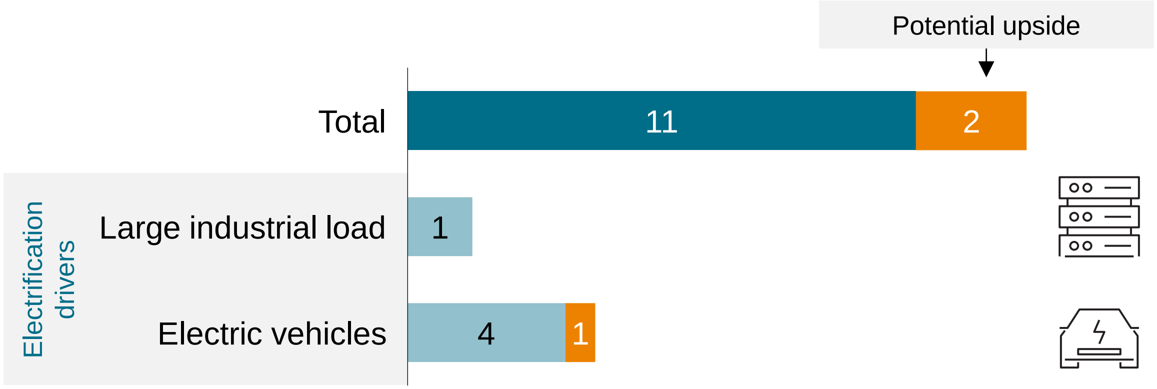
Net peak demand for SPP, 2015–40

GW



Main drivers of peak demand, net change (2024–40)

GW



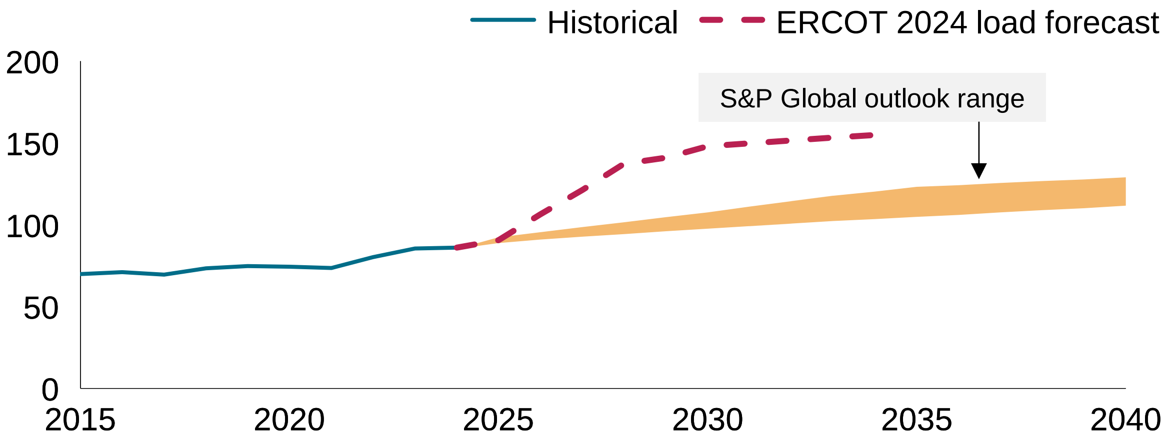
Electric vehicles include light duty battery electric vehicles (BEVs) and plug in hybrid electric vehicles (PHEVs).
Source: S&P Global Commodity Insights, 2024 SPP Resource Adequacy Report

- In the SPP region, economic growth is projected to align with national averages. Both population and household growth mirror U.S. levels. Although the region's economic growth has lagged the national pace since the pandemic, the mining and agricultural sectors present opportunities for economic revitalization, as they expand operations and increase production activities
- Electric vehicles are the single largest source of electrification demand. As vehicles in operation are expected to reach nearly 5 million by 2040
- Large industrial loads – predominantly datacenters – see modest growth, adding just 1 GW to the peak demand over the next 15 years
- SPP remains a summer peaking system through the outlook, where heating contribution is not significant

ERCOT

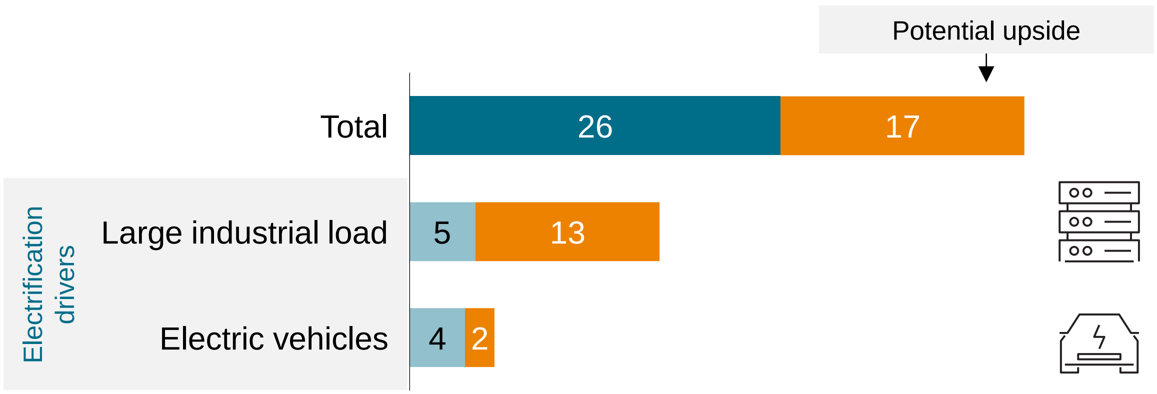
Net peak demand for ERCOT, 2015–40

GW



Main drivers of peak demand, net change (2024-40)

GW



Electric vehicles include light duty battery electric vehicles (BEVs) and plug in hybrid electric vehicles (PHEVs).

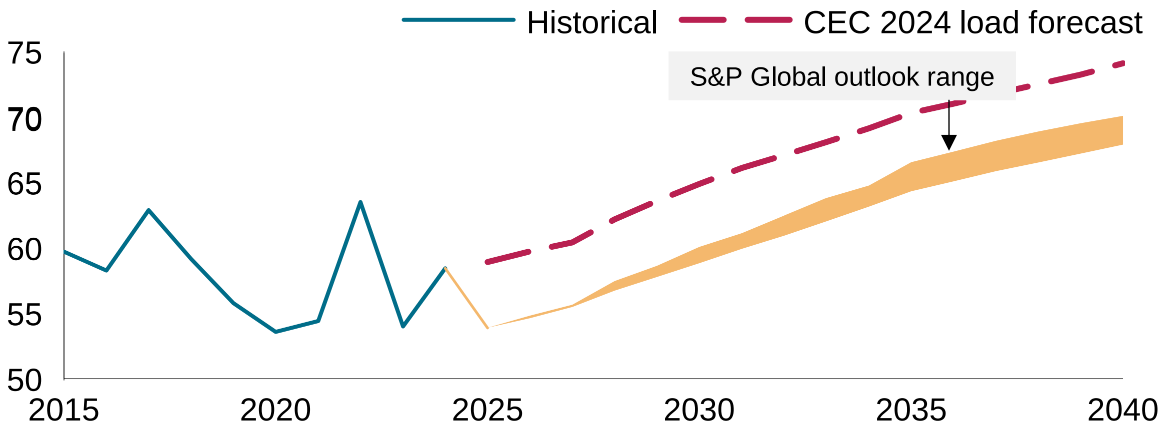
Source: S&P Global Commodity Insights, 2024 ERCOT Long-Term Load Forecast

- In Texas, robust economic growth and demographic expansion is the primary driver of increasing power demand. With an annual economic growth rate surpassing the national average, Texas is poised for significant expansion. Texas's appeal as a destination for new residents and businesses bolsters the state's population, while the growth in the number of households is also well above U.S. averages
- Large industrial load drives peak demand growth in ERCOT, attributed almost entirely to datacenter growth in the base case. Manufacturing capacity additions push peak demand significantly higher in the sensitivity case
- Large load growth reflects tremendous upside risk — the potential for a near doubling of peak load by 2030, according to the system operator
- Transportation is a modest contributor to the grid's peak requirements, as EV load demand adds around 4 GW to the peak requirements by 2040

California

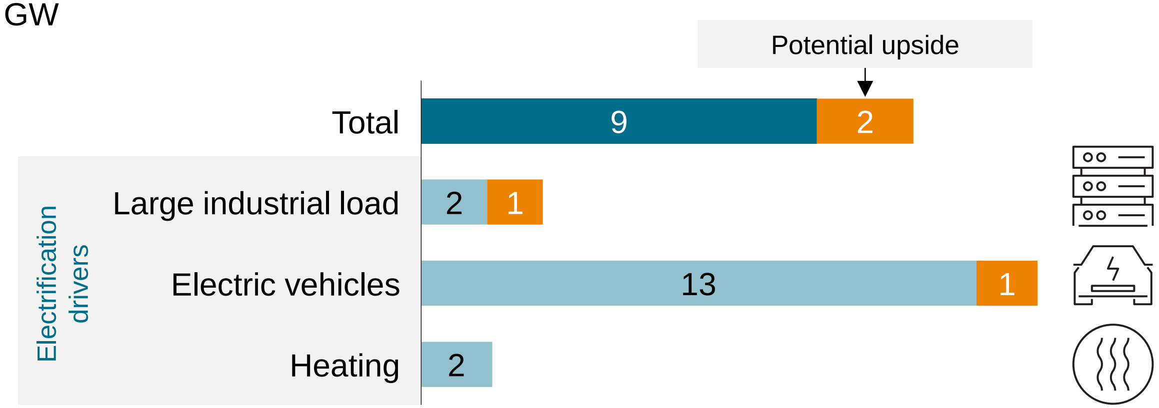
Net peak demand for California, 2015–40

GW



Main drivers of peak demand, net change (2024–40)

GW



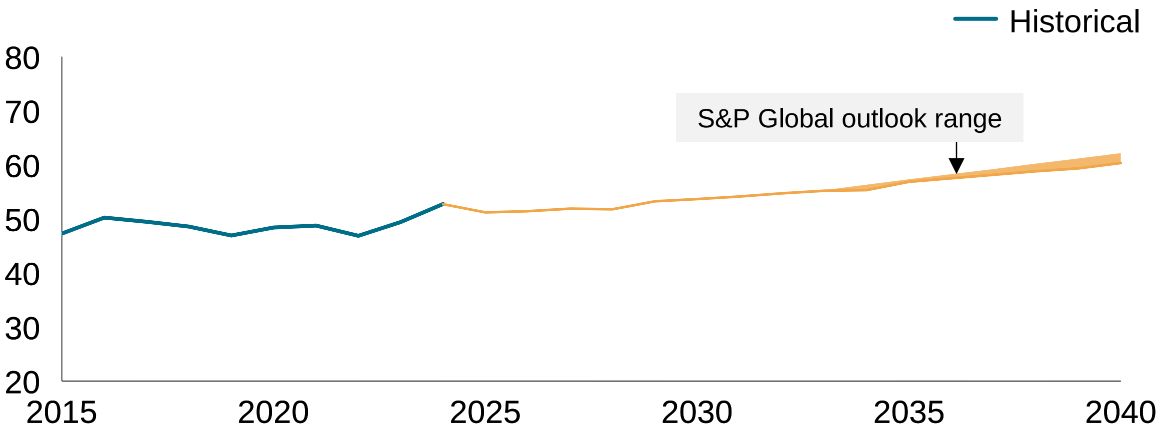
- Large scale electrification of vehicle fleet in California is the main driver of demand growth. The state has set a target of 100% zero-emission vehicles by 2035. EV sales are also propped up by infrastructure policies such as rebates for battery replacement and new sales and charging spot requirements for parking lots. Vehicles in operation are expected to surpass 16 million by 2040
- Aggressive building standards and electrification targets also drive demand growth throughout the outlook. New residential and commercial buildings are required to install a heat pump and must include electric heating and appliances by 2026. All heating equipment sold after 2030 must be zero emissions, leaving new heating to be heavy on heat pumps with gas and water heating equipment no longer sold
- As a leader in energy efficiency, California's advancements in reducing energy consumption further mitigate any potential increases in power demand from economic and demographic expansion. The state is projected to have no significant population growth, and household growth is projected to be slightly under the U.S. average. Economic growth aligns with national trends, but with very modest gains in the manufacturing sector

In the lower graph the sum of components is lower than the total, as demand coming from non-electrification components is expected to decrease due to modest economic/demographic growth and strong energy efficiency measures
Electric vehicles include light duty battery electric vehicles (BEVs) and plug in hybrid electric vehicles (PHEVs).
Source: S&P Global Commodity Insights; CED 2024 Baseline Forecast, California Energy Commission

Northwest

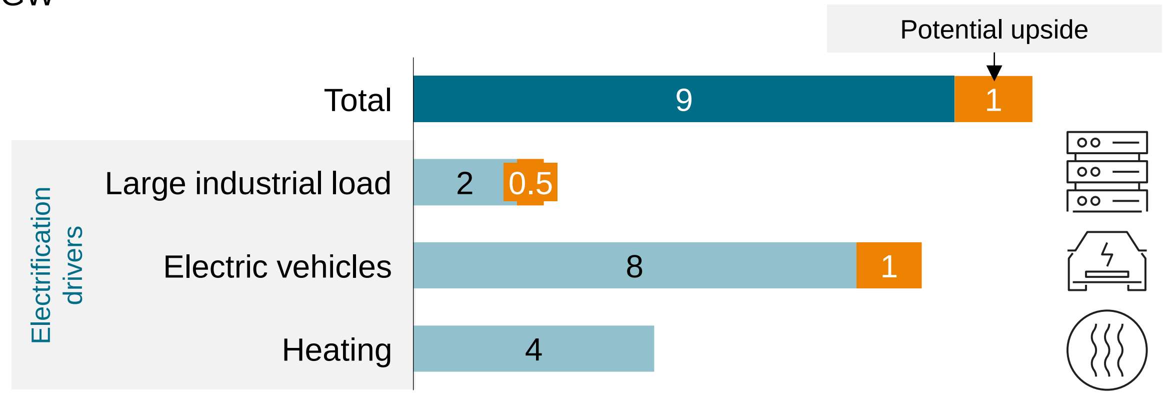
Net peak demand for Northwest, 2015–40

GW



Main drivers of peak demand, net change (2024–40)

GW



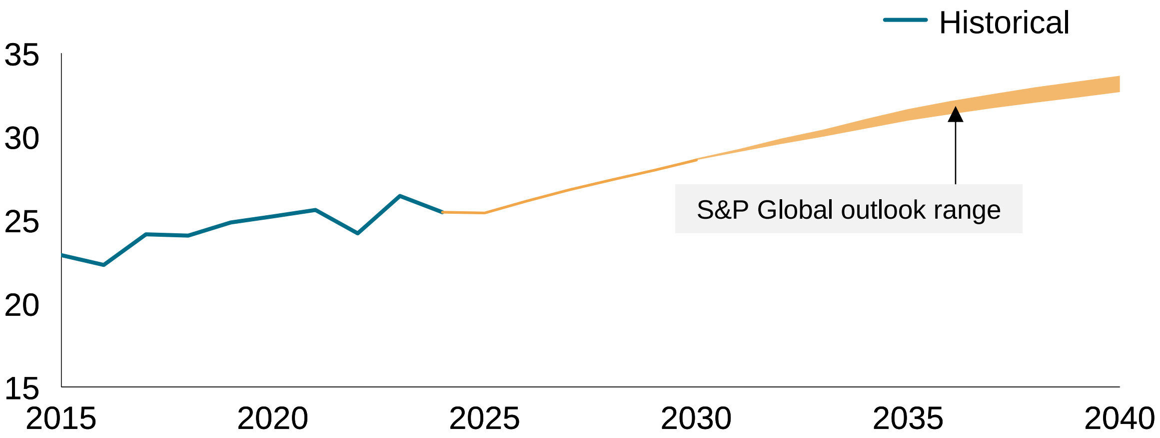
- Many states and utilities across the Northwest have enacted electric vehicle incentives and rebate programs to spur adoption. As such, EV demand is the largest demand driver of peak demand growth in the region adding 8 GW to the peak demand by 2040
- Electrification of heating is also a key driver of demand in the Northwest beginning in the 2030's, which adds around 4 GW by 2040
- Large load is a modest contributor to load growth, coming entirely from datacenters
- The region is poised for strong economic and demographic expansion; however, energy efficiency measures neutralize growth coming from non-electrification components of demand

In the lower graph the sum of components is lower than the total, as demand coming from non-electrification components is expected to decrease due to modest economic/demographic growth and strong energy efficiency measures.
Electric vehicles include light duty battery electric vehicles (BEVs) and plug in hybrid electric vehicles (PHEVs).
Source: S&P Global Commodity Insights

Southwest

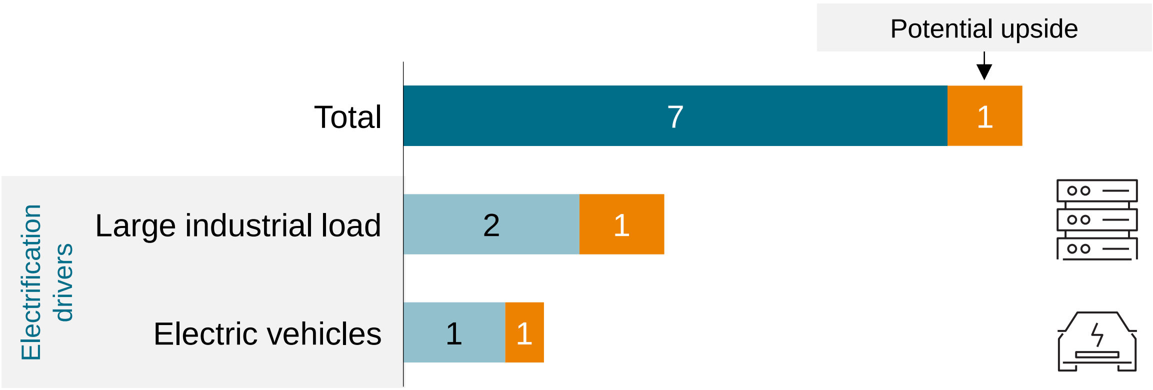
Net peak demand for Southwest, 2015–40

GW



Main drivers of peak demand, net change (2024–40)

GW



Electric vehicles include light duty battery electric vehicles (BEVs) and plug in hybrid electric vehicles (PHEVs).

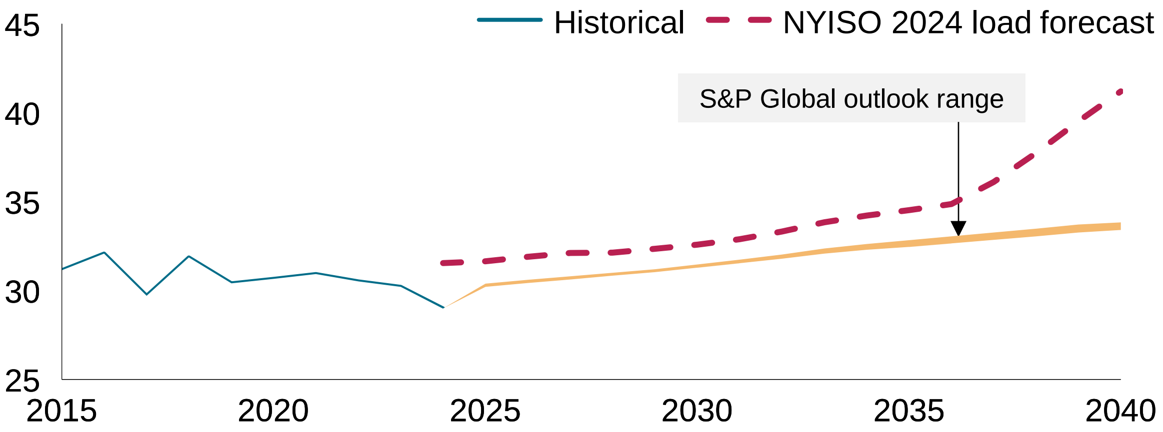
Source: S&P Global Commodity Insights

- The Southwest has seen particularly strong demand growth in the residential sector as the population continues to grow at a pace well above the US average. Its robust economic and demographic expansion drives the majority of power demand growth. With an economic growth rate well above the national average and electric intensive homes, the region is poised for substantial demand growth
- Arizona stands out as a key area of growth due to its strong population increase and strategic location near Mexico, making it an attractive destination for companies seeking to establish new strategic facilities and regional headquarters. Meanwhile, New Mexico's economy is receiving an extra boost from its thriving energy industry, further enhancing its economic landscape and contributing to increased electricity demand
- Over two-thirds of demand from large loads is expected to originate from datacenters
- Electric vehicle have a modest contribution to the Southwest electricity demand

NYISO

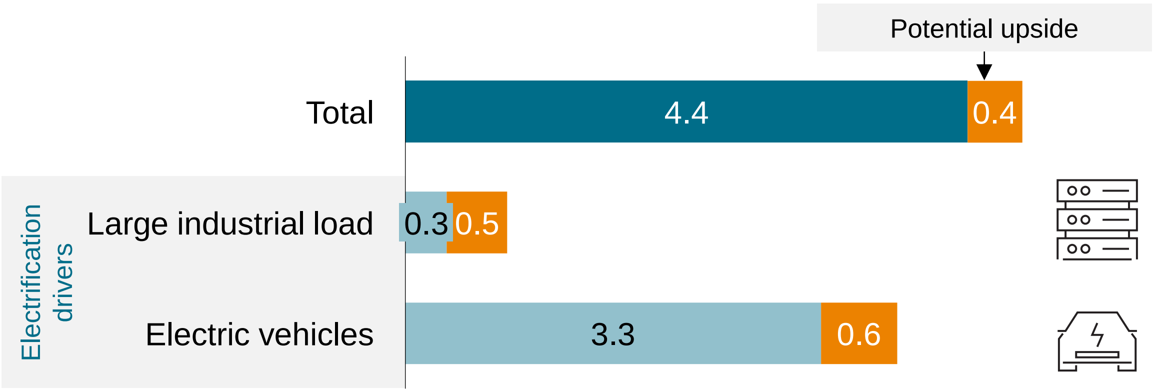
Net peak demand for NYISO, 2015–40

GW



Main drivers of peak demand, net change (2024–40)

GW

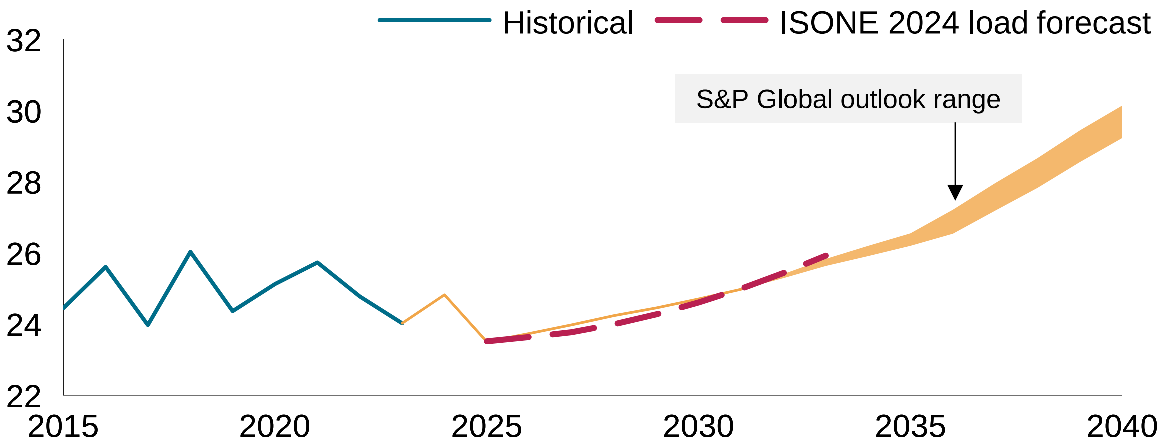


- New York electricity demand has steadily declined in the past ten years; however, the trend is expected to change owing largely to the electrification of the economy as the state seeks to reduce greenhouse emissions by 85% by 2050 as mandated by the Climate Leadership and Community Protection Act
- Electric vehicles are by far the largest electrification driver in New York. All sales of new light-duty passenger vehicles in New York must be zero emission vehicles (ZEVs) by 2035. As such, vehicles in operation expected to reach over 5 million by 2040
- However, economic growth is projected to be below the national average, compounded by stagnant population levels and household growth. Any additional demand coming from limited economic growth and demographic expansion is offset by strong energy efficiency measures
- Peak demand growth from large industrial loads is minimal, driven almost exclusively by manufacturing

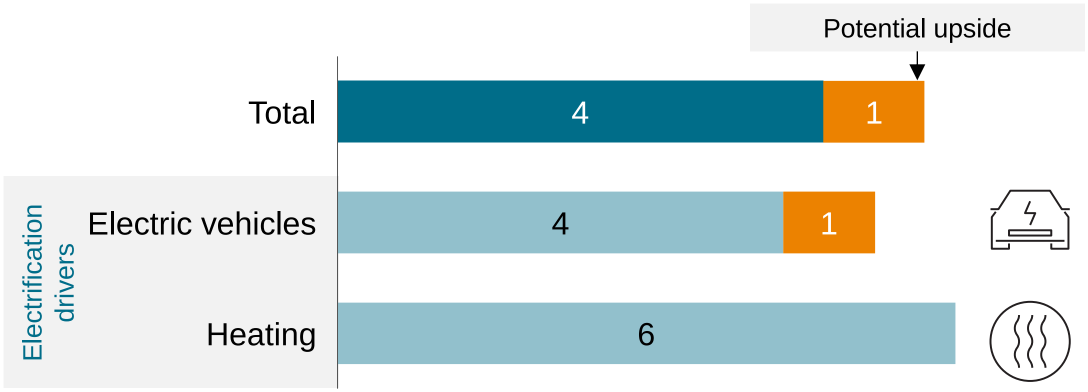
Electric vehicles include light duty battery electric vehicles (BEVs) and plug in hybrid electric vehicles (PHEVs).
Source: S&P Global Commodity Insights, 2024-2054 NYISO Long Term Forecast

ISONE

Net peak demand for ISONE, 2015–40
GW



Main drivers of peak demand, net change (2024–40)
GW



- After more than a decade of declining energy demand, policy-driven electrification is expected to set New England on a path of electricity demand growth
- Heating is the primary driver of peak demand, as New England is expected to shifted to winter peaking in the near term
- Electric vehicles are also a significant contributor to electricity demand, as vehicles in operation are forecasted to reach almost 5 million by 2040
- Any additional demand that will come from limited economic growth and demographic expansion is offset by strong energy efficiency measures. Economic growth is projected to be below the national average, compounded by stagnant population levels and household growth

In the lower graph the sum of components is lower than the total, as demand coming from non-electrification components is expected to decrease due to modest economic/demographic growth and strong energy efficiency measures.
Electric vehicles include light duty battery electric vehicles (BEVs) and plug in hybrid electric vehicles (PHEVs).
Source: S&P Global Commodity Insights, 2024 ISO-NE Long-Term Load Forecast

Contents

Supply chains are exposed to risks around trade policies and minerals shortage

Tariffs and Trade Issues

- The ongoing antidumping and countervailing duties (AD/CVD) investigation into solar modules imported from Southeast Asia adds further uncertainty to the U.S. solar industry. With 80% of solar modules installed in 2023 projects sourced from countries under investigation, the potential impact on the industry is substantial. In response to these uncertainties, some developers are postponing projects slated for 2025 and 2026, opting to explore alternative supply sources
- The upcoming increase in Section 301 tariffs on non-EV lithium-ion batteries imported from China—from 7.5% to 25% by January 1, 2026—poses a significant financial burden. While these tariffs are intended to stimulate the diversification of supply chains and bolster domestic manufacturing capabilities, they also present immediate cost challenges. The heightened costs are expected to temporarily contract the renewable energy market size, posing a short-term hurdle that may stabilize over time as supply chains adjust

While clean energy manufacturing in the US is nascent, growing demand and import tariffs are driving more domestic production across the supply chain

- With federal incentives, U.S. solar manufacturers using more domestic components and vertically integrated facilities will better compete with Chinese firms. New manufacturing facilities are set to come online across the US in the coming years but very few are vertically integrated across the value chain

Metals shortage challenge

- The transition to renewable energy and battery storage systems necessitates increasing volumes of metals such as lithium, cobalt, and nickel. These materials are essential for achieving the scale required to meet global energy demands. However, a significant challenge lies in the lengthy lead times and substantial resources needed to transition from mineral exploration to full-scale mining production. This delay can hinder the timely expansion of renewable technologies
- Moreover, the concentration of critical mineral processing and manufacturing in China raises national security concerns. This dependency could lead to geopolitical tensions, trade wars, and protectionist measures, potentially disrupting global supply chains and impacting the availability of essential materials

Source: S&P Global Commodity Insights

There is a challenge to build a skilled workforce that the industry requires to face growing demand

Workforce Gap Challenge

- The renewable industry continues to face a shortage of skilled workers, highlighting the urgent need for comprehensive workforce development strategies. The challenge of finding, recruiting, and hiring qualified employees remains persistent according to surveys, compounded by the rapid pace of technological advancement and the increasing complexity of solar installations. This shortage is particularly acute in areas requiring specialized skills, such as system design, installation, and maintenance
  - The National Renewable Energy Laboratory (NREL) estimates a deficit for nearly 124,000 additional workers by 2030 to meet deployment goals for both land-based and offshore wind energy. This gap poses a significant barrier to the industry's growth, particularly in achieving ambitious capacity expansion targets. The shortage is most pronounced in technical roles such as turbine maintenance, project management, and grid integration

Measures have been developed with the aim to address the issue

- The federal incentives for registered apprenticeships and prevailing wage requirements, are designed to help bridge the workforce gap. These measures aim to attract workers by offering structured training programs and competitive compensation
- There is a growing emphasis on developing targeted education and training programs to equip workers with the necessary skills for renewable energy jobs. Collaborations between industry, educational institutions, and government agencies are crucial for creating curricula that align with industry needs and technological advancements
- Engaging communities and raising public awareness about the potential career opportunities in renewable energy can stimulate interest and attract new talent to the field. Community outreach programs and public information campaigns can highlight the benefits and opportunities of working in renewable energy, encouraging more individuals to consider it as a viable career path

Source: NREL National Wind Energy Workforce Assessment (March 2024), Department of Energy: United States Energy & Employment Report 2024. IREC: National Solar Jobs Census 2023

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