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Greenwheel Insights

Prospects for US natural gas power: Will the boom become bust?

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Executive Summary

- **Electricity demand in the USA is set to grow, but with uncertain pace and shape**. Data centres are likely to spearhead this growth, but some forecasts may be significantly overestimating their demand.

- Despite official forecasts, **data centre flexibility could avoid substantial peak load additions, and the need for new gas capacity** to maintain reserve margins, even with large total load growth.

- **Of existing capacity, only the gas fleet may be able to accommodate significant additional demand** outside peak periods. Headroom in other capacity is limited.

- **Where capacity additions are needed,** supply chain constraints mean **new gas units will be slow and expensive to build and operate.**

- **By contrast, renewables and batteries are easily available, quick to install and cheap** - even under a reoriented federal policy environment.

- **Renewables, batteries and existing gas generators together offer the quickest, cheapest route to market for large loads** – particularly when coupled with flexibility.

- **Captive gas capacity for data centres** may be installed, but over time may **serve primarily as back-up.**

- **Developers of new grid-connected gas capacity face significant risk** from: (a) overbuild to satisfy peak load growth that is unlikely to materialise, (b) gas price volatility, and (c) displacement by near-zero marginal cost renewable generators, and batteries.

- **Rapid development and deployment of alternatives,** such as distributed solar, nuclear or geothermal, and demand response options, **adds further risk of redundancy** to new gas plants in the medium-term.

Preface: The Investor Need

*"**US power demand has inflected back to growth** for the first time in almost 20 years, **providing opportunities across the entire generation and electrification value chains. Incumbent power generation capacity**, including nuclear and gas power, **are set to be clear beneficiaries**.*

*The **profile of new capacity is contingent on evolving technology costs, availability and speed to market, as well as the role of demand-side flexibility** – particularly for large loads like data centres"*

Max Slee

Portfolio Manager, Redwheel-Ecofin Energy Transition Strategies

Following a long period of stability, an electricity-intensive AI revolution is expected to spearhead electricity demand growth in the USA. Many expect natural gas to take the lead in meeting this demand growth. This paper examines this proposition.

How has gas power in the USA developed?

Electricity from natural gas has rapidly grown over the last decade to over 40% of total US generation, rising across almost all markets. **Renewables have grown by almost as much**, both at the expense of coal. **Around 10GW of new gas capacity is under construction**, but around 15 GW is planned for retirement by 2030. By **contrast, around 65 GW of renewables and battery storage is under construction**. **Renewables and batteries also dominate the pre-construction pipeline**.

Gas power has grown significantly in the USA since the late 2000s. It now exceeds 40% of generation, from less than 25% in 2010 (Figure 1).

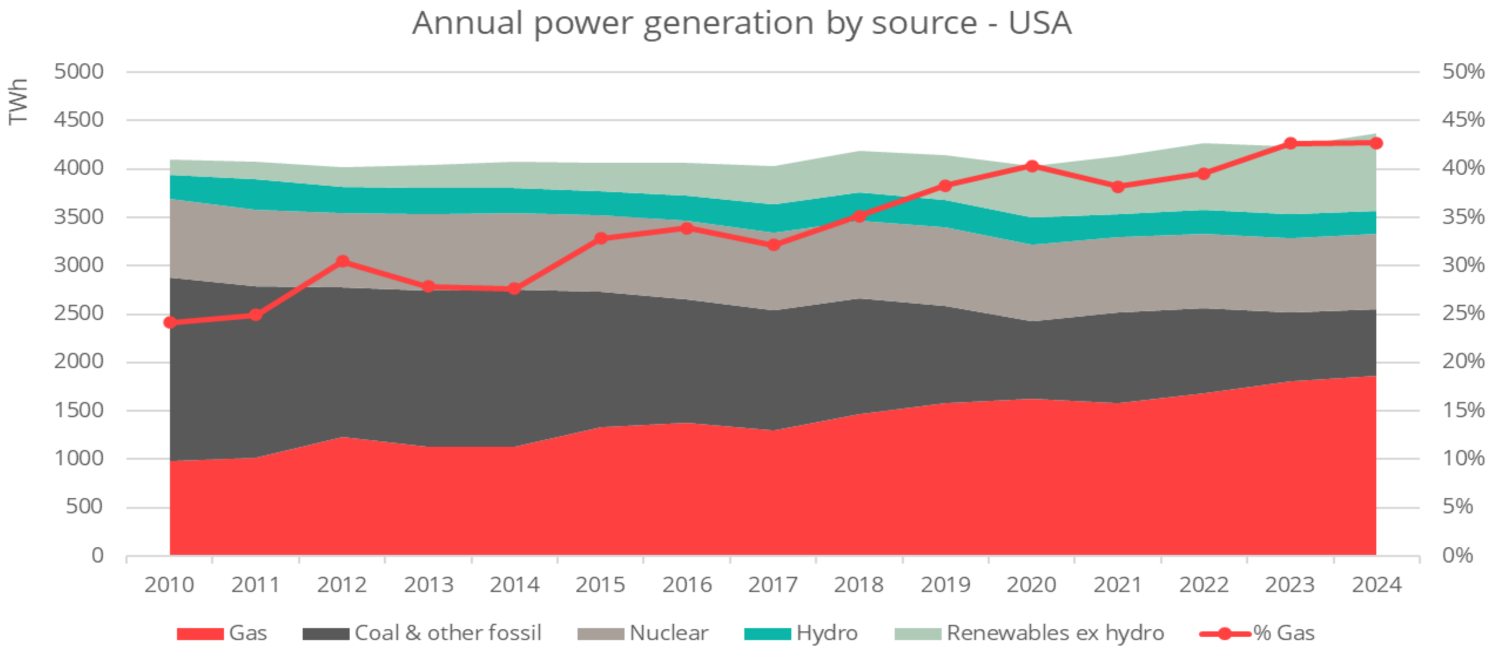

Figure 1 – Annual power generation by source – USA. Data source: Ember (2025). Graphic created by Greenwheel. The information shown above is for illustrative purposes.

This growth was driven by declining gas prices produced by the shale revolution, displacing coal generation over a period of largely flat electricity demand.[i] Variable renewables (solar PV and onshore wind) have also grown rapidly, delivering additional generation equivalent to three-quarters of the growth in natural gas power since 2010. This also worked to displace coal from the mix (Figure 2).

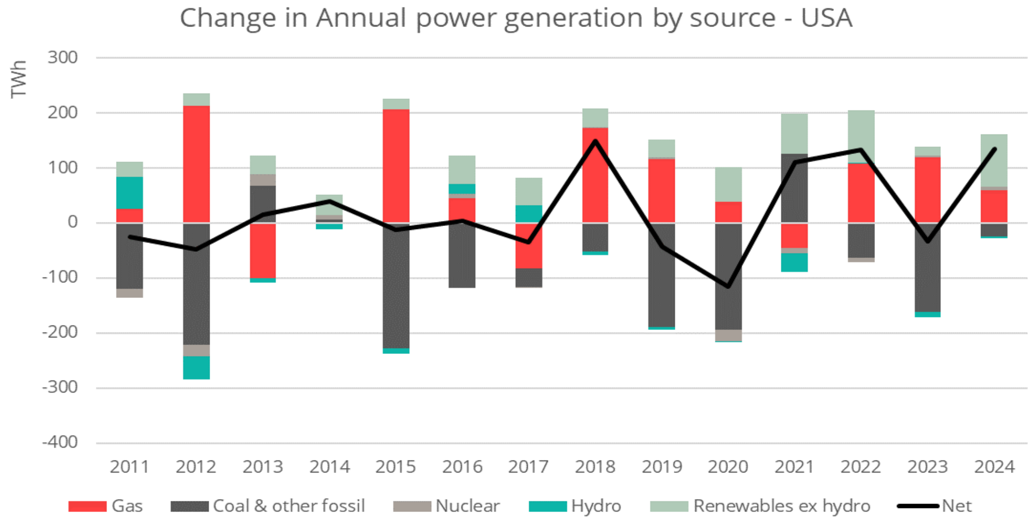

Figure 2 – Change in annual power generation by source – USA. Data source: Ember (2025). Graphic created by Greenwheel. The information shown above is for illustrative purposes.

Gas power generation differs significantly across the ten Regional Transmission Organisations (RTOs) and Independent System Operators (ISOs)[1], collectively referred to as 'markets' in this paper. Three-quarters of gas generation in 2023 (the latest year

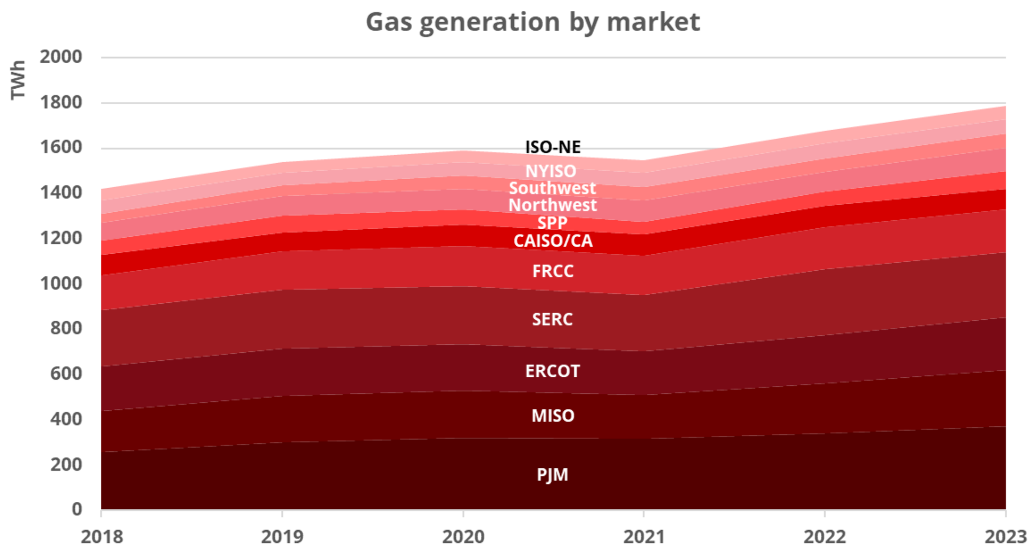

Figure 3 – Gas generation by market. Data source: EPA (2025). Notes: Data aggregated from individual generators by prime mover, then matched to and aggregated by Balancing Authority and subsequently market. Graphic created by Greenwheel. The information shown above is for illustrative purposes.

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[1] Since 2019, when FRCC and SERC merged for form the Southeast market (neither an ISO or an RTO). In this paper data for FRCC and SERC will be presented separately, giving 11 markets.

comprehensive data is available) was across five markets: PJM, SERC, MISO, FRCC and ERCOT (Figure 3).

The most gas-reliant market is FRCC, with the Northwest and SPP market least reliant (Figure 4). All markets except CASIO grew the share of gas power over the five years to 2023, with PJM, MISO and Southwest registering double-digit percentage point growth.

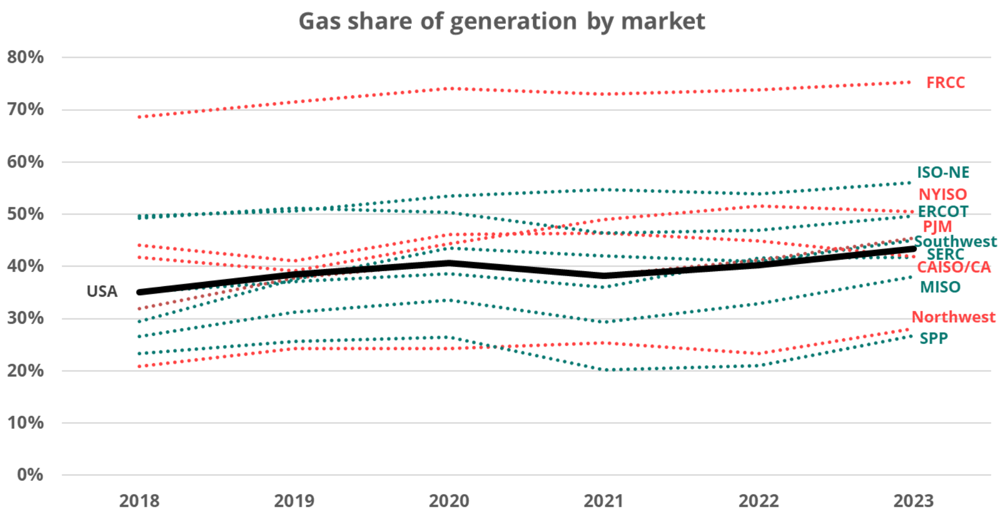


Figure 4 – Gas share of generation by market. Data source: EPA (2025). Notes: Data aggregated from individual generators by prime mover, then matched to and aggregated by Balancing Authority and subsequently market. USA value is weighted average. Graphic created by Greenwheel. The information shown above is for illustrative purposes.

Combined cycle gas turbine (CCGT) units accounted for around 60% of gas capacity in 2023. Peaking generators (mainly OCGTs) accounted for the remainder. Between 2010 and 2023, CCGT capacity grew by over 40% (nearly 100GW), focused in PJM, SERC and FRCC. CCGT retirements, and changes to peaking gas capacity, were negligible.[ii]

The newest, most efficient CCGT units are delivering most generation growth. In 2023 they had a weighted average capacity factor of over 60%, with 36% for the oldest units (>25 years). Average capacity factors for non-CCGT peaking units were 11-19% (Figure 5).

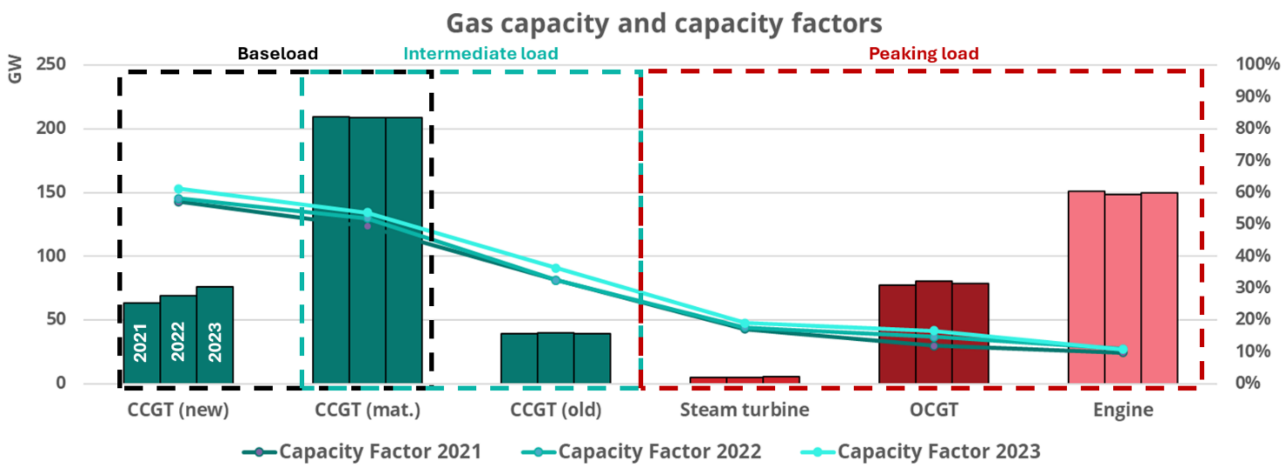
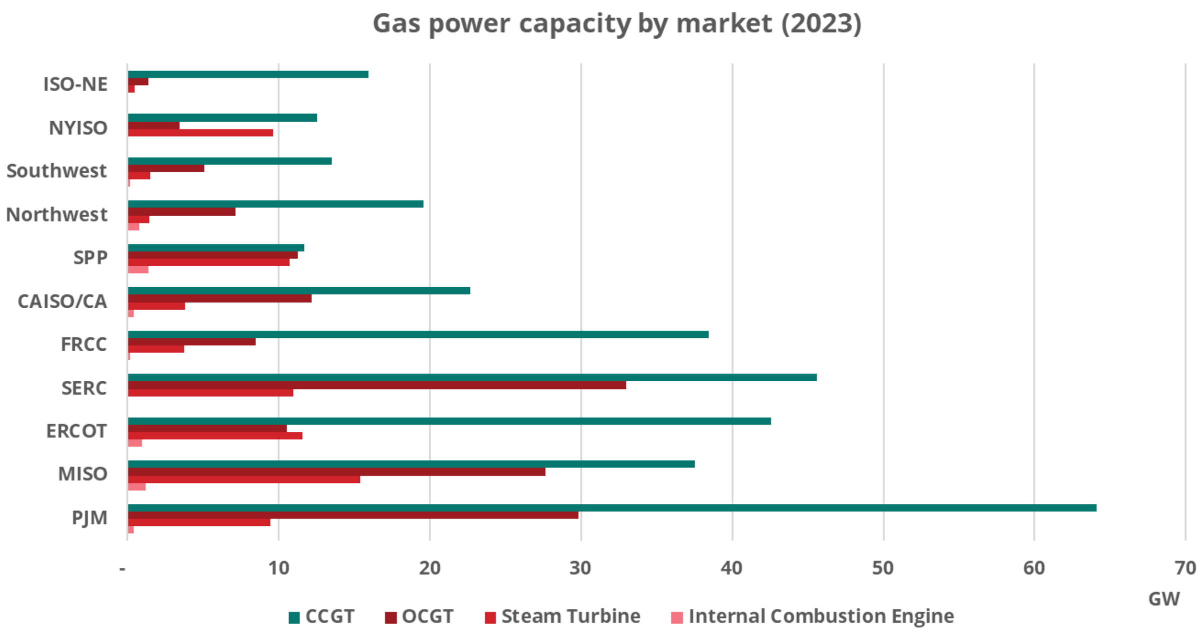


Figure 5 – US gas capacity and capacity factor by technology. Data sources: EPA (2025); EPA (2024). Notes: Notes: CCGT vintage = commissioning dates: >2014 (new), 1999-2013 (mature), <1998 (old). Data aggregated from individual generators by prime mover. Capacity factors are weighted average. Lower 48 only. Graphic created by Greenwheel. The information shown above is for illustrative purposes.

CCGTs had by far the greatest capacity and utilisation across gas technologies in most markets in 2023 (Figure 6), while the profile for peaking generators varied significantly - driven by differences in reserve margins, actual demand and the penetration of intermittent renewables.[iii]



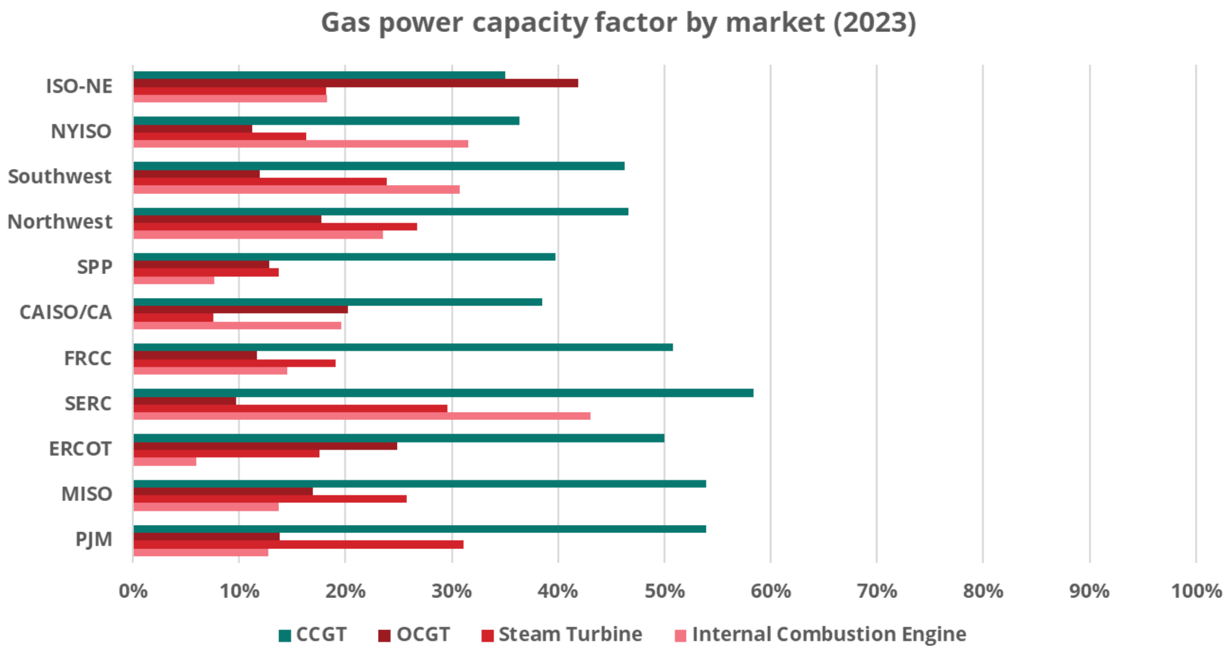


Figure 6 – Gas power capacity and capacity factor by market. Data source: EPA (2025). Notes: Notes: Data aggregated from individual generators by prime mover, then matched to and aggregated by Balancing Authority and subsequently market. Operational capacity only. Graphic created by Greenwheel. The information shown above is for illustrative purposes.

As of May 2025, just under 9 GW of new gas power capacity was under construction across these markets, with over 15GW scheduled to retire by 2030. Over half of the capacity under construction were CCGTs, while 90% of retirements are peaking units.

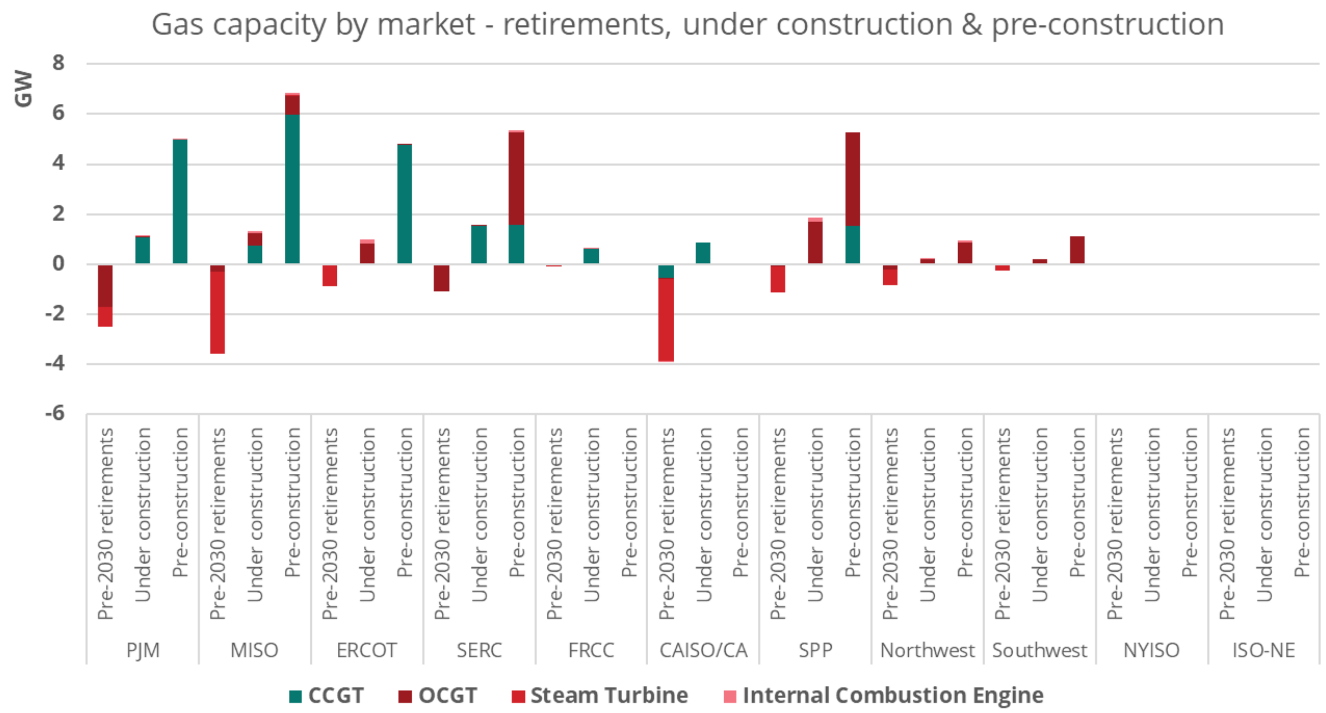


Figure 7 – Gas capacity by market – retirements, under construction & pre-construction. Data source: [EIA (2025)](). Notes: Data aggregated from individual generators by prime mover, then matched to and aggregated by Balancing Authority and subsequently market. Graphic created by Greenwheel. The information shown above is for illustrative purposes.

New construction is distributed across markets, while retirements are significantly concentrated in CAISO, MISO and PJM and SERC. Another 31 GW is in active pre-construction development, of which two-thirds are CCGTs (with around 5 GW having received regulatory approval). This potential capacity is focused in MISO, SERC, SPP, SERC and ERCOT (Figure 7).

Of other generators, 47 GW of solar and wind capacity is under construction with broad distribution across markets, plus 18GW of battery storage concentrated in ERCOT and CAISO. Nearly 35GW of coal capacity is scheduled for retirement by 2030, also concentrated in MISO, PJM and SERC (Figure 8).

Around 100 GW of solar and wind, and 50 GW of battery storage, are in pre-construction stages. Around 17 GW and 4 GW, respectively, have received regulatory approval.[iv]

If all capacity under construction and with regulatory approval comes online and all scheduled retirements happen by 2030, total net generation may grow by around 90 TWh if all units approximate current capacity factors – a roughly 2% increase on 2024 generation. This involves a 190 TWh growth in wind and solar generation offset by 130 TWh reduction from coal. Generation from gas would grow by just 30 TWh. However, there would be significant variation between markets (Figure 9).

Figure 8 – Planned retirements, new capacity under construction and pre-construction. Data source: EIA (2025). Notes: Data aggregated from individual generators by prime mover, then matched to and aggregated by Balancing Authority and subsequently market. Graphic created by Greenwheel. The information shown above is for illustrative purposes.

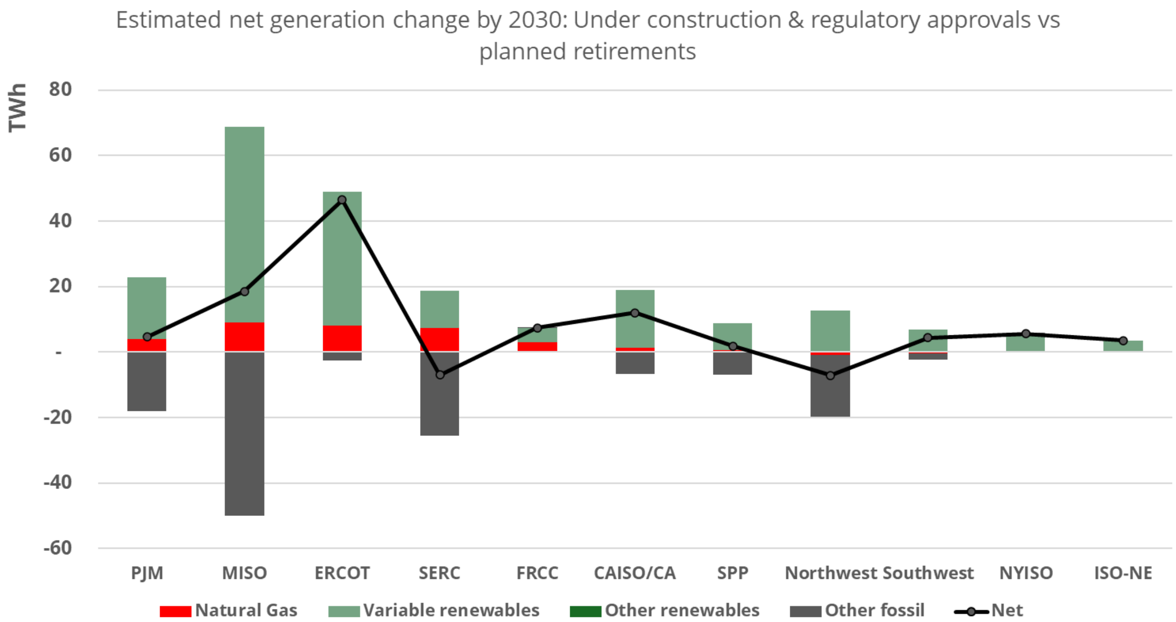


Figure 9 – Estimated net generation change by 2030. Data sources: EIA (2025); EPA (2025). Notes: Average capacity factors for each technology in each market in 2023 is assumed for new capacity and retirements (split by new and old capacity values for natural gas CCGTs). Excludes storage technologies and curtailments. Graphic created by Greenwheel. The information shown above is for illustrative purposes.

What role for gas power moving forward?

Recent policy actions broadly seek to improve conditions for fossil fuel production and demand and impair them for renewables and electrified energy demand. Overall, **the core determinants of changes to the US electricity generation profile are likely to be**: **(a) total electricity demand; (b) demand for new generation capacity; (c) cost and (d) non-cost drivers and barriers to alternatives.**

There has been a recent flurry of changes to the energy policy landscape at the federal level, driven largely by Executive Orders and provisions in the One Big Beautiful Bill Act (OBBBA), signed into law in July 2025.

Key policy actions are summarised below (Table 1). These actions broadly seek to improve conditions for fossil fuel production and demand and impair them for renewables (particularly solar and wind) and electrified energy demand (particularly electric vehicles).

Fossil Fuels	Supply	• **Leases and royalties.** Mandated increase in rate of leases on federal lands and waters. Reduced royalty rates. Streamlined approach for environmental reviews and impact statements. • **Methane emissions tax.** Deferred from 2025 to 2035. • **LNG exports.** Pause lifted on new export permits for countries without a free trade agreement with the USA.
	Demand	• **Federal power plant emissions standards**. The EPA has proposed (but not yet enacted) removal of emissions standards for GHGs, which would otherwise have required most new gas plants to be fitted with carbon capture and storage technology by 2035 (and coal plants from 2032). • **Federal vehicle fuel economy and emissions regulations**. Stated intention to rollback current standards. Penalties for non-compliance with fuel economy standards removed. California's vehicle emissions waiver rescinded.
Clean technologies	Supply	• **Wind and solar**. 48E ITC & 45Y PTC terminated for facilities placed in service after 2027 (previously phase-out beginning 2032), with exemptions for facilities under construction before 6th July 2026 (must be in service by end of 2030). Thresholds for "under construction" changed to require "significant physical work" (non-quantified). Projects on Federal land must be personally approved by Secretary of the Interior, but signalled approval will not be given. "Stop work" orders issued for key offshore wind projects under construction. • **Other renewables**. No change. Technologies including hydropower and geothermal retain 48E ITC & 45Y PTC with phaseout starting in 2034. • **Battery storage**. No change to tax credits (as above) • **Nuclear.** No change to tax credits. Four executive orders to reduce barriers to nuclear construction, with a target to quadruple capacity by 2050. • **Green hydrogen**. PTC (45V) terminated for projects beginning construction after 2027 (previously 2032). • **Advanced manufacturing.** No change to 45X credit, except removing eligibility of wind components sold after 2027 (from 2030-2032 phase-out), and bringing critical minerals into the phase-out schedule (from permanent). Domestic content adder thresholds for ITC and PTCs are also increased. • **Foreign Entities of Concern (FEOC) restrictions.** Expanded definition and application, tightening thresholds for FEOC involvement in ownership and supply chain, and 'material assistance' for access to tax credits across most categories.
	Demand	• **Tax credits.** A range of credits have had their termination dates brought forward to 2025/26 from 2033-35, including for electric and other clean vehicles, and domestic energy efficiency and clean energy installations. • **State-level vehicle emissions regulations and zero-emission vehicle mandates**. The Federal government have moved to revoke California's ability to set vehicle emission regulations under the Clean Air Act, and for other states to follow them (currently subject to legal action).

Table 1 – Key recent changes to the Federal policy environment (as of August 2025). Information sources include: Reuters (2025), Kimball (2025), Sidley (2025), Brasher et al (2025), King et al (2024), Crooks (2025)

Two core determinants of changes to the electricity generation profile are likely to be: (a) the rate of electricity demand growth, and (b) the strength of policy support for clean technologies (particularly renewables). Combining these two factors produces four stylised scenarios, illustrated in Figure 10.

These two factors can be further divided into: (a) total electricity demand; (b) demand for new generation capacity; (c) cost and; (d) non-cost drivers and barriers to alternatives. The following sections examine these subfactors to assess prospects for gas power in the short-term (to 2030) and medium-term (2030).

This paper focuses on utility-scale solar PV, onshore wind and battery storage as the most important near-term alternatives to gas power. Other alternatives such as new large- and small-scale nuclear power, offshore wind, hydropower or geothermal, are not likely to represent alternatives at significant scale before 2040.

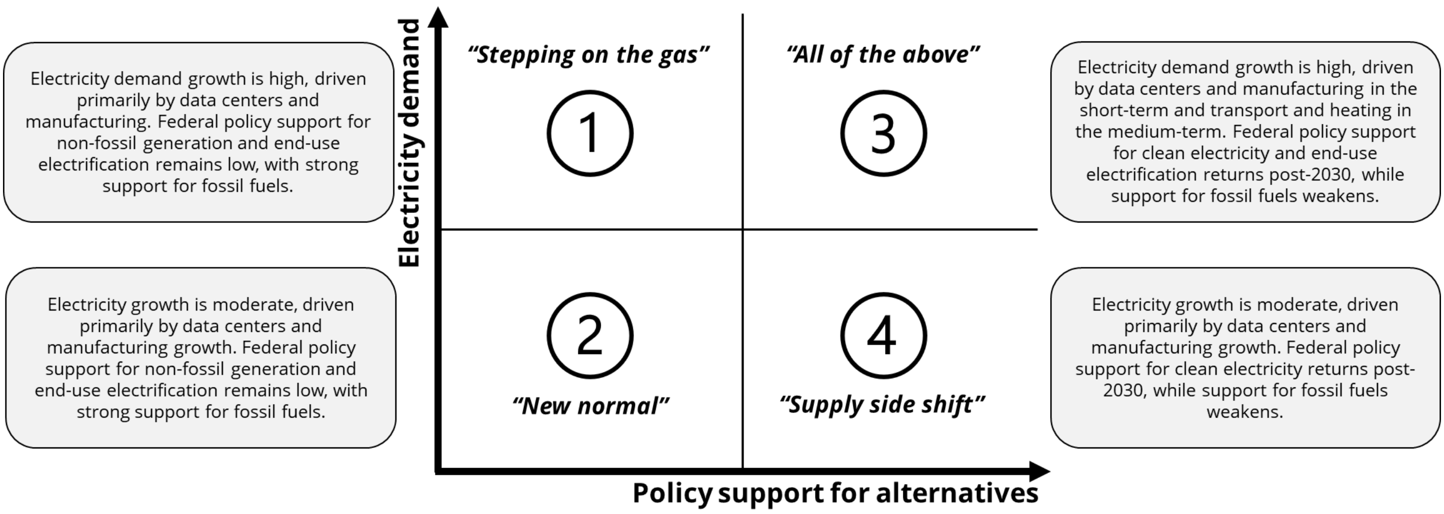


Figure 10 – Four stylised scenarios for electricity demand and technology policy support in the USA to 2040. Graphic created by Greenwheel. The information shown above is for illustrative purposes.

Electricity demand projections vary significantly, ranging between 5-25% growth to 2030 from 2024 levels, extending to 25-45% by 2040. **Data centres are the most significant driver of projections**, **but materialisation of this demand is highly uncertain** and driven by the evolution compute demand, compute and cooling efficiency, and electricity system constraints - but also on the feedbacks between them.

Total electricity demand

Electricity demand projections vary significantly with most estimates ranging between 5-25% growth to 2030 from 2024 levels (1.5-2.5% CAGR), extending to 25-45% by 2040 (Figure 11).

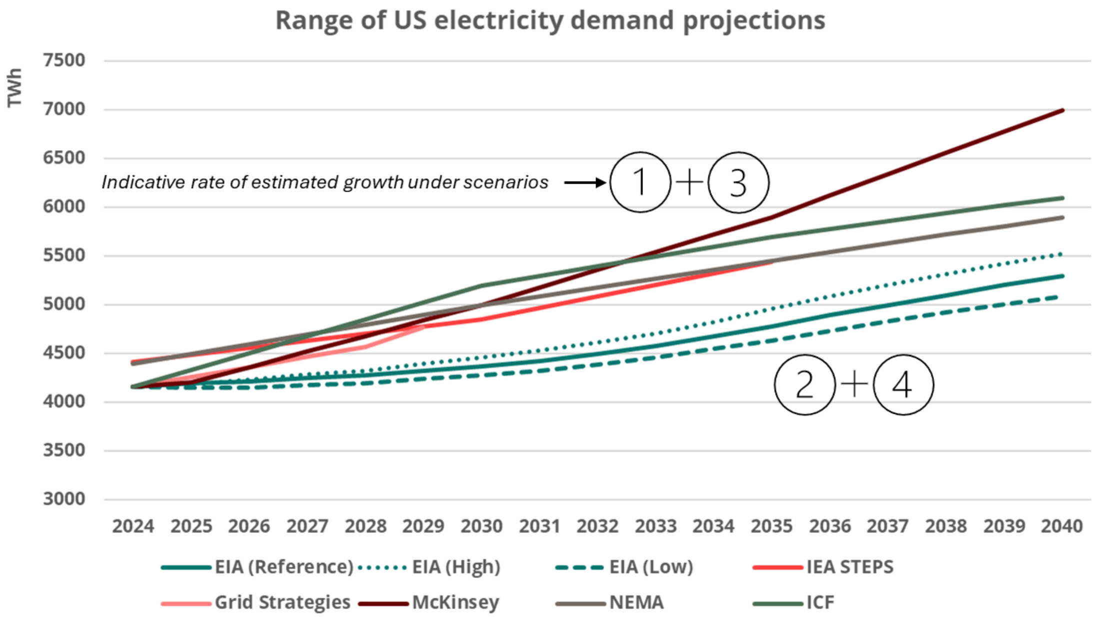


Figure 11 - Range of US electricity demand projections. Data Sources: EIA (2025), Wilson et al (2024), Barth et al (2025), NEMA (2025), Batra et al (2025), IEA (2024). Notes: Some projections report different values for their base years. Graphic created by Greenwheel. Forecasts and estimates are based upon subjective assumptions.

Data centres drive one-third of growth to 2040 under higher-end projections (and more to the early-2030s), followed closely by electrified transport. Steady growth in the commercial, industrial and residential sectors account for the remainder.[v,vi,vii,viii] The EIA projections largely reflect historical trends (with ‘Low’ and ‘High’ reflecting economic growth sensitivities), resulting in lower demand growth by design.[ix]

Data centre electricity demand is highly uncertain, particularly beyond the next few years. It will be driven by the evolution of three factors: compute demand, compute and cooling efficiency, and electricity system constraints (Figure 12) - but also on the feedbacks between them.

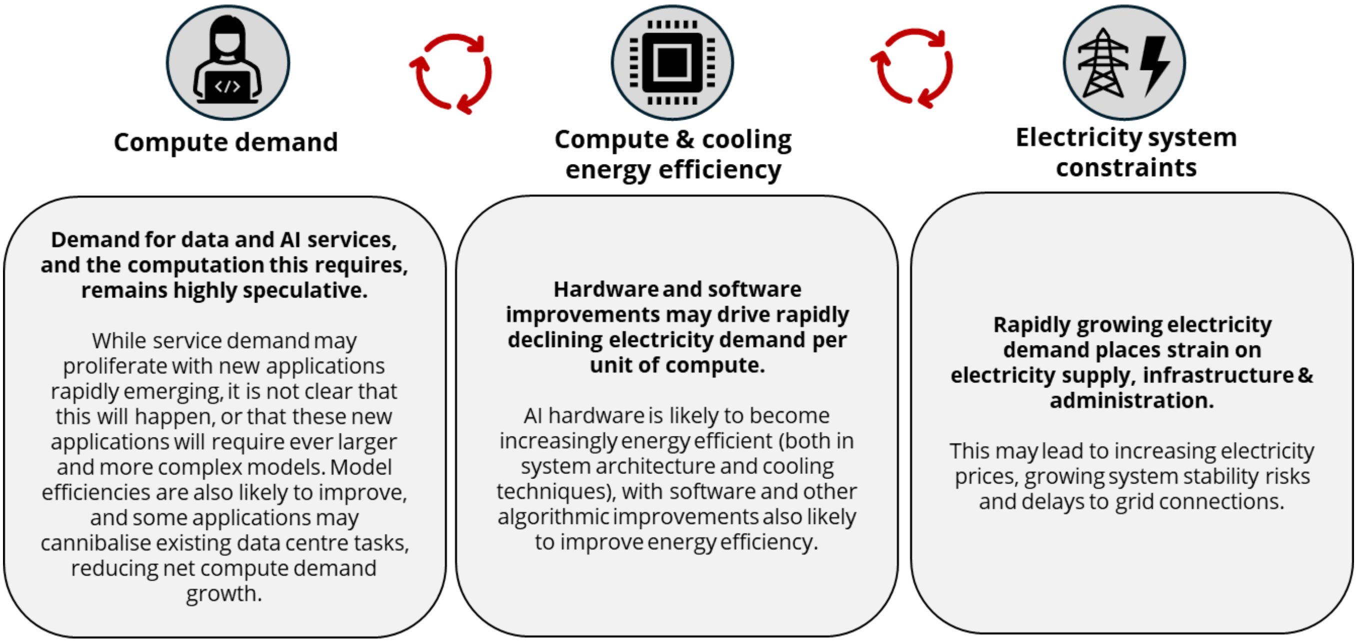


Figure 12 – Key factors and feedbacks influencing future data centre electricity demand. Graphic created by Greenwheel. Forecasts and estimates are based upon subjective assumptions.

These feedbacks are likely to be a rate limiter for electricity demand growth from data centres, particularly due to electricity system constraints. Large load interconnection queues are now several years in some markets due to their volume, transmission incapacity, and outdated planning tools and processes[x] - including an inability to identify speculative requests and consider real-world operational profiles (see below).

Additionally, the projections in Figure 11 were produced prior to most recent policy changes, which are likely to reduce total electricity demand growth. For example, BNEF now project passenger electric vehicles to reach 27% of US sales in 2030, down from 48% previously projected.[xi] Even if support for electrification returns after 2030 (Scenarios 3 & 4), electricity demand by 2040 is likely to be structurally lower than previously projected.

Regardless, as generation from net capacity additions (Figure 9) is not enough to satisfy even the lowest growth projections to 2030 in Figure 11, greater use of the existing and committed generation fleet, additional capacity build-out, or both, will be needed.

Demand for new supply capacity

The North American Electric Reliability Corporation (NERC) projects around 80GW of peak load growth by 2030, growing another 40 GW by 2035. However, **utilities have significantly over-forecast average peak load growth in the past, with this risk now even greater** due to recent policy changes, the likely number of purely speculative load connection requests, and unfounded assumptions that data centres will operate constantly at full electrical capacity.

At just 1% annual demand curtailment, over 120 GW of data centre load may be added to the US grid, with no increase in peak demand and no change in generation capacity. This is larger than all peak load additions projected by NERC, which does not consider such flexibility. **Outside of peak hours, existing gas capacity is most able to satisfy growing electricity demand**, although technical and other practical system constraints mean **some new electricity supply capacity is likely to be needed**.

Whether new capacity is required depends on where and when new demand is likely to arise, the size and flexibility of this demand, and the profile of existing supply. The North American Electric Reliability Corporation (NERC) project around 80GW of peak load growth by 2030 across the contiguous US, growing another 40 GW by 2035 (a 10% and 14% growth from likely 2025 peak load, respectively).

Five markets account for most growth – ERCOT, PJM, SERC, MISO and Northwest (Figure 13).[xii] For most markets data centres are the single largest driver. Industrial growth and demographic change are also significant in ERCOT, and electric vehicles and heat pumps in PJM. For SERC, industrial growth and electric vehicles are primary drivers.[xii]

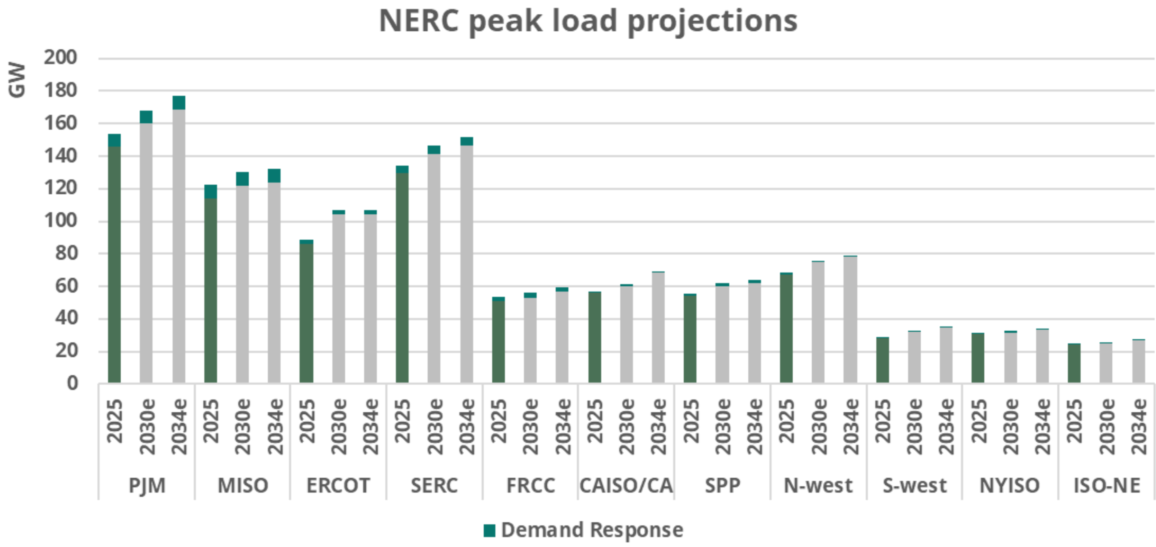


Figure 13 - NERC peak load projections. Data source: NERC (2024). Graphic created by Greenwheel. Forecasts and estimates are based upon subjective assumptions.

Under these projections, anticipated reserve margins (ARM) remain healthy in most markets to 2030, but drop significantly to the mid-2030s, mostly falling under reference margin levels (RML) (Table 2).[2]

[2] The amount of reserve capacity in the system above the forecasted peak demand that is needed to ensure sufficient supply to meet peak loads, accounting for long-term factors of uncertainty involved in system planning, such as unexpected

	2025$_e$	2026$_e$	2027$_e$	2028$_e$	2029$_e$	2030$_e$	2031$_e$	2032$_e$	2033$_e$	2034$_e$
PJM	34.9%	35.7%	30%	27.9%	24.6%	23.1%	21.6%	20%	18.5%	16.8%
MISO	17%	17.3%	19.8%	16.8%	14.5%	10.6%	8.2%	7.5%	4.2%	4.2%
ERCOT	31.2%	34.7%	32.4%	28.8%	28.5%	27.8%	28%	28.3%	28.8%	27.7%
SERC[1]	29.3%	27.9%	25.9%	25.4%	22%	19.8%	17.7%	16.5%	16.5%	14.4%
FRCC	27.1%	26.8%	24.9%	23.7%	22.5%	22.7%	22%	20.4%	18.2%	16%
CAISO/CA[2]	45.8%	45.2%	38.4%	43.1%	28.8%	29.6%	23.3%	25%	15.2%	11.1%
SPP	29.7%	31.8%	31.2%	31.6%	29.7%	26.7%	24.9%	23.5%	22.4%	21.6%
Northwest[3]	38.7%	37.7%	34.1%	29.3%	23.3%	17%	10.8%	8.9%	6.7%	4.6%
Southwest[4]	36.9%	35.6%	31.8%	24.2%	17.4%	11.3%	7.7%	0.2%	-4.7%	-8.7%
NYISO	17.1%	21.4%	22.5%	22.4%	21.6%	20.7%	18.3%	16.7%	14.9%	13.6%
ISO-NE	25%	25%	26.3%	25.1%	23.7%	22%	20.1%	19.7%	17.1%	14.8%

Relative to Reference Margin Level (RML): >10pp 5-10pp 0-4.9pp <RML

Table 2 - Anticipated Margin Levels (AMLs) vs Reference Margin Levels (RMLs). Data source: NERC (2024). Notes: [1]Average of SERC Central, East and Southeast. [2]Reflects the WECC-CA/MX region. [3]Reflects WECC-NW region. [4]Reflects WECC-SW region. Graphic created by Greenwheel. Forecasts and estimates are based upon subjective assumptions.

However, US utilities have significantly over-forecast average peak load growth in the past – by 8% over a five-year horizon, and 17% over a ten-year horizon over 2006-2023.[xiii] Current forecasts risk even greater overestimation, for three reasons.

Firstly, these projections were also made before recent policy changes, which are likely to reduce peak demand growth, particularly from electric transport and heating (even if federal support returns under Scenarios 3 and 4).

Secondly, there is evidence that data centre developers place speculative loads in the queue in multiple markets as they shop around for the quickest interconnection opportunities and the lowest prices.[xiii] Potentially fewer than 20% of current data centre interconnection requests are firm[xiv], and those that materialise may distribute to markets with the fewest electricity system constraints as far as other constraints allow (e.g. access to water for cooling and access to high-speed fibre optic networks).

Thirdly, system planners often assume that data centres will operate near their nameplate electrical capacity at almost all times.[xv] This is likely not to be the case.

Some developers likely request grid connection sizes well above their near-term needs to avoid upgrades if they expand. There is also a common misunderstanding of the 'five nines' uptime guarantee (i.e. data centre services must be always available except five minutes a year), which refers to *availability* rather than *utilisation* of compute capacity.[xv]

There is little public data, but LNBL estimate that current hyperscale servers operate at around 50% utilisation on average. For AI model training this rises to 80% but drops to just 40% for inference operations[xvi] (although others estimate ~60%).[xv]

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generator outages and extreme weather impacts. An RML is established by a state, provincial authority, ISO/RTO, or other regulatory body. In some cases, the RML is a requirement. NERC (2024)

Server utilisation may be much lower than capacity to allow redundancy for maintenance, unexpected outages and future demand growth, and time-varying compute demand. Demand for inference workloads tend to peak in the middle of the working day.[xvii]

Inherent to an assumption of full utilisation is that data centres have little scope for flexibility. However, there are three ways data centres could flex their electricity load (Figure 14).

A first-order estimate finds that even if data centres were to operate at full nameplate electrical capacity, annual load curtailment of 0.25% (less than one day a year of full load-equivalent) would allow the integration of 76 GW of new data centre interconnection capacity across the contiguous US – *with existing power capacity*.[xviii]

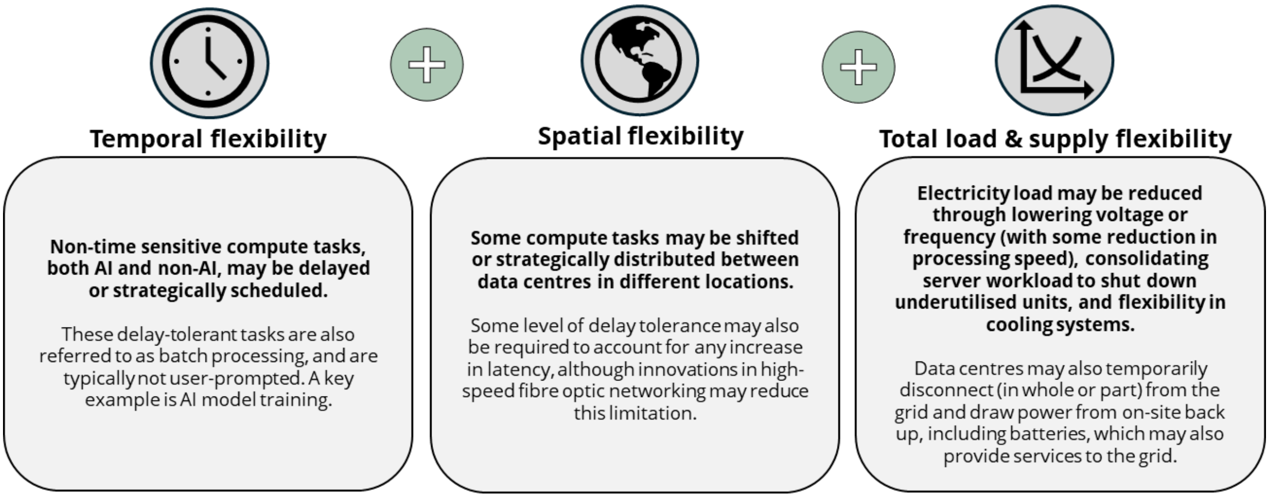

Figure 14 - Options for flexibility in data centres. Information sources include: Numata et al (2025), Norris et al (2025); Lovins (2025). Graphic created by Greenwheel. The information shown above is for illustrative purposes.

This is roughly equivalent to all peak load growth projected to 2030 by NERC, from all sources. An annual curtailment rate of 1% would allow integration of 126 GW of new load, equivalent to the aggregate additional peak load projected to 2035.[xviii] Almost all curtailment events would be under two hours, and require just 50% load reduction.[xviii]

Figure 15 maps this potential against net NERC peak demand growth projections. In three of the four largest markets, headroom exceeds total estimated peak load additions by the mid-2030s at 1% curtailment.

These estimates have limitations. For example, they don't consider constraints in the transmission network,[xviii] or the suitability of market structures and incentives to deliver flexibility in practice. Regardless, they indicate a significant potential which is beginning to be realised.

In August 2025 Google announced first-of-a-kind deals with US utilities to integrate flexibility with inference workloads into resource adequacy planning, explicitly recognising the benefits for quicker interconnection, infrastructure requirements, grid reliability and cost savings.[xix]

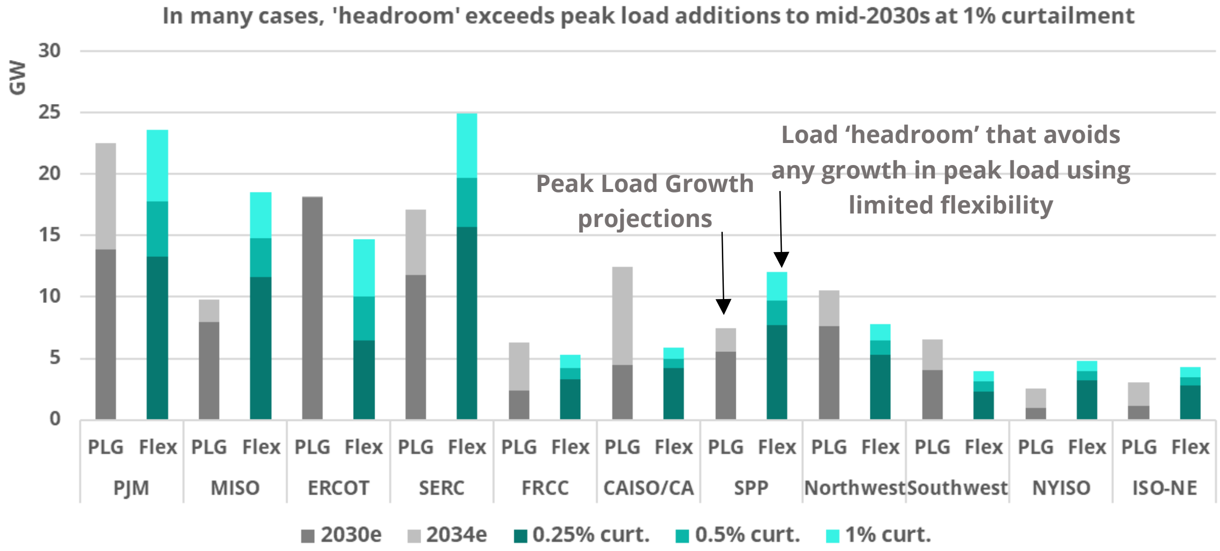

Figure 15 – NERC peak load additions compared to potential 'headroom' from data centre flexibility. Data sources: NERC (2024); Norris et al (2025). Graphic created by Greenwheel. Forecasts and estimates are based upon subjective assumptions.

This means that even if total electricity demand grows significantly, peak load in many markets may not. This reduces the need for new supply capacity to boost reserve margins. Some authorities are exploring methods to improve peak load forecasts to minimise the construction of underutilised assets.[xx]

However, any electricity demand growth must be met by generation growth. The above analysis implies a significant volume could be satisfied by making greater use of existing capacity.

The US nuclear fleet operates at 93% capacity on average[xxi] and variable renewables generate 'as available'. This means neither can be materially called on to supply more electricity (except through batteries, discussed below).

The lifetime of coal capacity is likely be extended, but aging coal plants are expensive to maintain, relatively inflexible and increasingly unreliable,[xxii]. Planned retirements are also heavily concentrated in just four markets, and under Scenarios 3 & 4, re-introduced regulations may also force them to close or limit generation.

Only gas has potentially significant underutilised capacity outside periods of peak demand. The newest CCGT plants operated at an average 60% capacity in 2023. If this were to raise to 70%, total electricity generation would increase around 3%. If mature CCGT capacity were to increase average utilisation from 54% to 65%, total US electricity generation would increase by another 9%.

Although the potential utilisation may be lower due difficulties in maintaining higher capacity factors (particularly for older generators), gas and electricity transmission constraints and implications for system resilience, it likely remains significant.

Building out transmission infrastructure, particularly between markets, may loosen supply constraints. Current inter-market transmission constraints are significant and costly[xxiii], and are likely to become more so with new construction significantly slowing over the last decade.[xxiv] Building new short-distance transmission lines (<150 miles) can take 5-10 years, with longer distance lines taking 10-20 years,[xxv] limiting its likely contribution even over the medium-term.

These constraints mean that some new generation capacity is likely to be needed, particularly beyond 2030 and if more rapid demand growth materialises (Scenarios 1 & 3). What this additional capacity is likely to look like will depend on their relative characteristics and the evolving needs and governance of the system.

New electricity supply capacity – costs

Supply chain constraints mean **new gas capacity costs >3x the cost over the last decade, while gas prices are set for structural growth**. **Renewables,** either standalone or collocated with battery storage, **are often cheaper – even without tax credits in many cases**. Under all four scenarios examined, **in the medium-term it is likely that the cost of renewables and batteries will continue declining, while gas capacity and operational costs will remain elevated or increase further**.

Natural gas prices in the USA declined significantly from the mid-2000s to around 2020 (Figure 16), with the development of shale formations with significant resources and oil co-production.[xxvi] Coupled with stable construction costs for new gas capacity, this drove rapid growth in gas power and the displacement of coal in key markets.

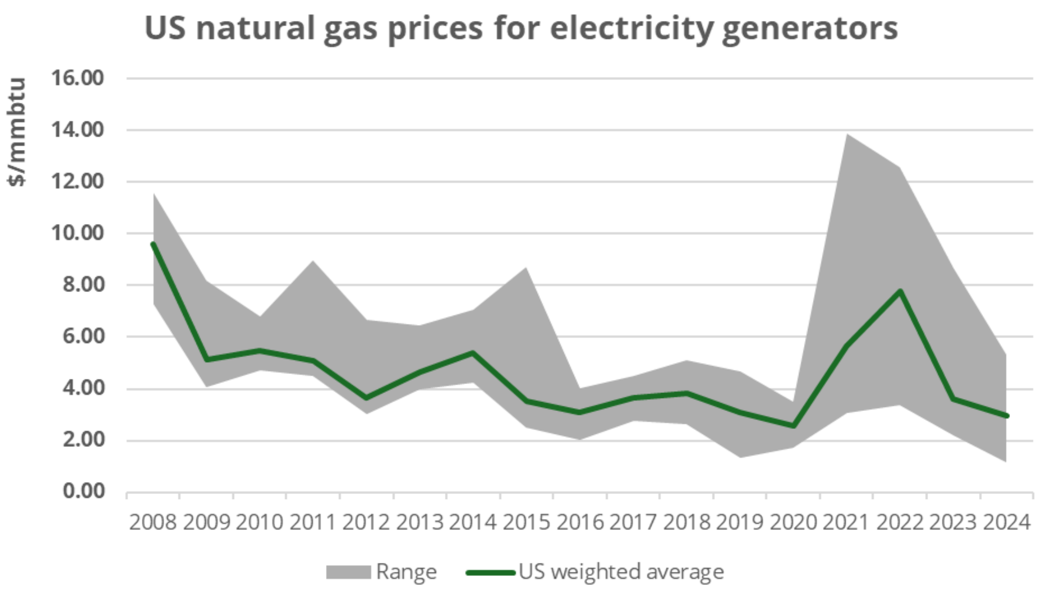

Figure 16 – US natural gas price for electricity generators – weighted average and range. Data source: EIA (2025). Notes: Available data for different states varies significantly over time, with the range typically reflecting prices across 20-30 states. Prices in some states are not available due to commercial sensitivities. Graphic created by Greenwheel.

The average Henry Hub spot price in 2024 was $2.2/mmbtu, with a weighted average price to electricity generators of just under $3/mmbtu. The EIA project average Henry Hub spot prices to rise to $3.6/mmbtu in 2025 and $4.3/mmbtu in 2026[xxvii], driven by a dip in gas extraction, a rise in LNG exports, and strong domestic demand.[i] This means the weighted average price available to generators could nearly double over 2024-26.

The average electricity wholesale price in the USA was around $45/MWh in 2024.[xxviii] Each $1/mmbtu rise in gas prices may increase electricity wholesale prices by $7-12/MWh with gas as the marginal generator.[xxix]

Average construction costs for new CCGTs were under $800/kW in 2023, having remained relatively stable across the previous decade.[xxx] Estimates for new capacity have increased to $2,400-2,700/kW, with delivery not likely before 2030.[xxxi] This is due to strong demand, supply chain constraints and inflationary pressures.[xxxii] New peaking capacity costs have also grown, although lead times are slightly shorter.[xxxiii]

The average levelised cost of energy (LCOE) from solar PV and wind in the USA dropped by around 70% and 75%, respectively, over the last decade.[xxxiv] These rapid cost reductions, supported by long-running federal tax credits, drove the significant growth in renewable capacity and generation since the late 2000s.[xxxv]

ITCs for new solar and wind are due to expire by the end of 2027, except for those beginning construction before 2026, or which begin 'significant physical work' before July 2026 and are generating within four years.[xxxvi] Around 14GW with regulatory approval is scheduled for commissioning by the end 2027, with 29 GW scheduled for commissioning by 2027 but yet to receive approval (half of which is solar PV in CAISO and ERCOT).

This means up to around 45 GW of solar and wind is planned for commissioning with unchanged ITC eligibility. Although the final value is likely be significantly smaller due to regulatory, supply chain and other constraints, a proportion that miss the end-2027 deadline are still likely to receive safe harbouring protection.

Figure 17 illustrates estimated levelised costs of energy (LCOE) and storage (LCOS) for new units in the USA, both with and without ITCs, where relevant. New renewables, either standalone or collocated with battery storage, are highly competitive with new CCGTs on an LCOE basis – even without tax credits in many cases. As ERCOT and CAISO are two of the lowest cost markets for solar[xxxvii], much of the solar PV capacity due for commissioning in the next couple of years is likely to remain economically attractive even if they are delayed and are not safe-harboured.

This is emphasised by the rise in gas capacity costs and in gas prices, the latter of which is not reflected in Figure 17, and which would increase LCOE estimates (~$7/MWh per $1/mmbtu for new CCGTs, or more for peakers).

The average cost of turnkey battery storage systems in the US halved over 2022-2024.[xxxiv] Although the ITC remained untouched, Foreign Entity of Concern (FEOC) requirements have been introduced,[3] which may increase costs in the near term due to supply chain reconfiguration or growing ineligibility for ITCs.

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[3] An entity is a FEOC if it is "owned by, controlled by, or subject to the jurisdiction or direction of a government of a foreign country that is a covered nation." Covered nations are China, Russia, Iran, and North Korea [(DOE, 2025)](). For projects beginning construction in 2026, at least 55% of the total system cost must come from non-FEOC entities. This rises by 5pp annually to 75% from 2030 onwards.

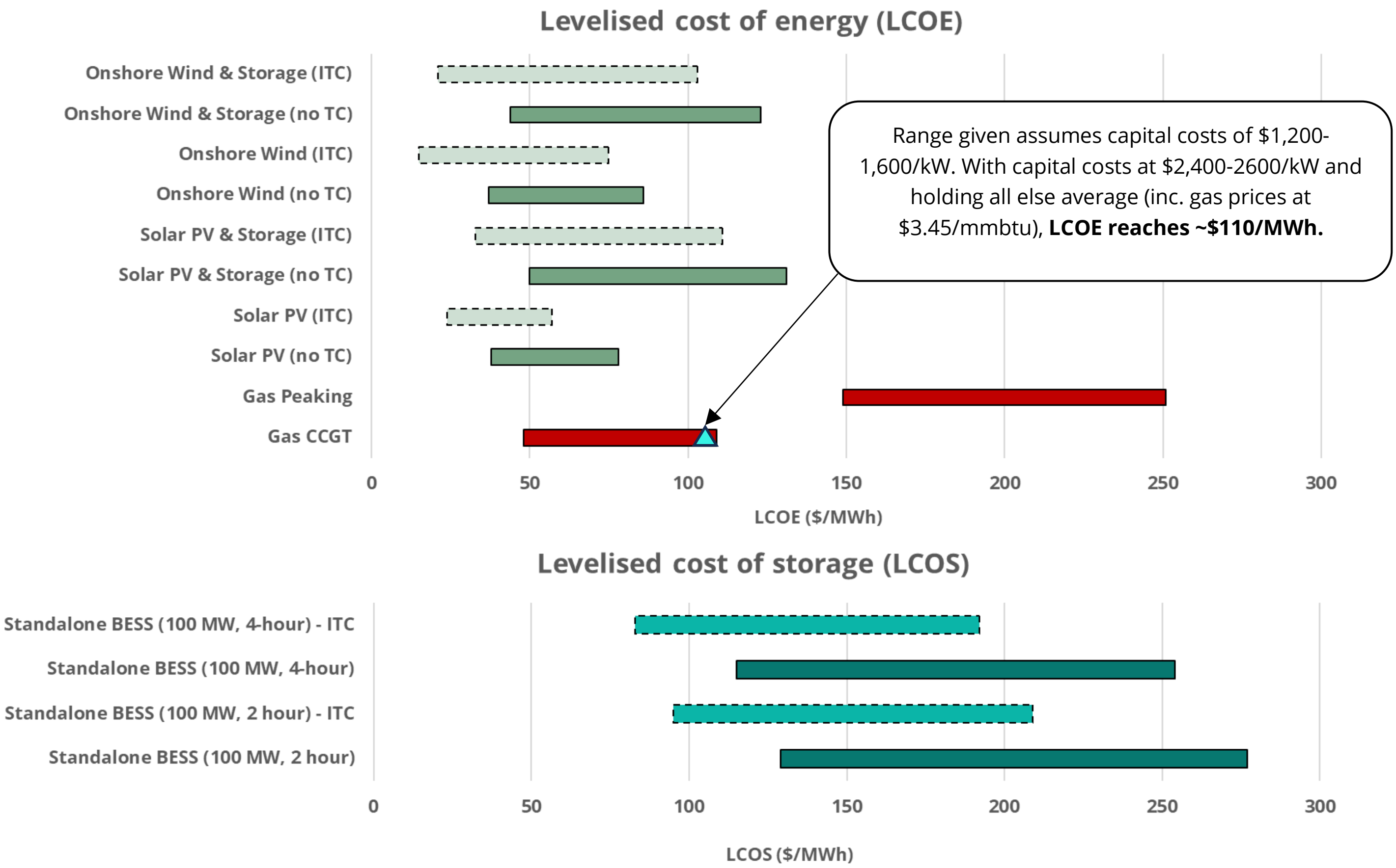

Figure 17 - Levelised cost of energy (LCOE) and storage (LCOS). Data source: Lazard (2025). Graphic created by Greenwheel. The information shown above is for illustrative purposes.

Despite short term headwinds, the cost of new renewables and batteries are likely to continue declining in the medium-term under each of the four scenarios examined, while the cost of gas generation is likely to remain high or increase further (Table 3).

Technology costs – potential direction & magnitude

Scenario (2030-2040)		Natural gas	Alternatives	
	->2030			**By 2030 solar costs may hover near current levels** with pressure from removed tax credits and trade measures largely offset by declining technology costs and supply chain rerouting. **Onshore wind costs may be elevated** due to slower technology cost declines and dependence on higher cost domestic supply chains. **Battery costs may also hover near current levels**, as upward pressure from trade measures and FEOC rules is largely offset by declining technology costs from imports and an expanding domestic supply chain. **New gas power costs are likely to grow to 2030** with pressure from constrained supply chains (manufacturers are investing in new production capacity but remain cautious due demand uncertainty[1]), growing gas prices, and trade measures on key inputs (e.g. steel).
1	Stepping on the gas			**Over 2030-2040, renewables and battery costs may steadily decline** as deployment grows, innovation proceeds and supply chains – domestic and international – mature and reform. **New gas power costs may grow further**, with pressure on supply chains remaining strong even with growing manufacturing capacity, and on gas prices with tight production and high demand.
2	New normal			**Over 2030-2040, renewables and battery costs may steadily decline** as deployment grows, innovation proceeds and supply chains – domestic and international – mature and reform. **New gas power costs may grow further**, although supply chain pressure amd costs may ease, while gas prices may continue to increase with tight production and high demand. but to a lesser degree than Scenario 1.
3	All of the above			**Over 2030-2040, renewables and battery costs may decline significantly** with policy support returning and significant demand driving scale. **New gas power costs may grow further**, although supply chain and cost pressure may ease with greater deployment of other technologies. Gas prices may continue to increase with tight production and high demand. but to a lesser degree than Scenario 1.
4	Supply side shift			**Over 2030-2040, renewables and battery costs may decline relatively significantly** with policy support returning. **New gas power costs may grow further**, although supply chain and cost pressure may ease with greater deployment of other technologies. Gas prices may continue to increase with tight production and moderate demand. but to a lesser degree than Scenarios 1 & 3.

Table 3 - Potential direction and magnitude of natural gas, renewable and battery costs Notes [1]GE Vernova are investing to increase global turbine output by 20 GW/year (focused in the USA). Siemens and Mitsubishi also have US expansion plans but the impact on production capacity is unclear. Graphic created by Greenwheel. The information shown above is for illustrative purposes. Forecasts and estimates are based upon subjective assumptions.

A key uncertainty is the size and scope of trade measures. Proposed and realised import tariffs have been volatile in recent months and have impacts across the power sector and its supply chains. Although tariffs are most significant on clean energy technologies and components, duties on imported steel, for example, also raise costs for new gas capacity and other infrastructure (e.g. grids).

For developers, the cost profile of renewables is largely known when the investment decision is taken. For developers and operators of new gas capacity, rising gas prices are a long-term risk. In the first half of 2025 growing gas prices supported a significant switch from gas to coal capacity use,[xxxviii] reversing dominant trend of the last decade.

Consumer electricity prices have been steadily increasing, driven by demand, transmission constraints and gas prices. This trend is set to continue, with projected residential prices 2026 at 30% above 2020 levels. [xxxix] Scenarios with the greatest reliance on gas (1&2) are likely to maintain the greatest pressure into the medium-term.

Pressure may also come from additional system costs associated with large loads such as data centres. Several states have developed or are actively developing rules and rate structures to shield other ratepayers from these costs.[xl] With appropriate rate design and planning, flexible large loads may allow greater use of new and existing assets, reducing the required rate of capital recovery per unit of electricity delivered.[xli]

New electricity supply capacity – other drivers & barriers

Gas supply chains are heavily constrained and may remain so, while renewables and batteries are readily available, quick to install and highly flexible in siting and sizing. Gas capacity can suffer less from electricity network constraints and its dispatchability means individual units are more able to address system reliability, but batteries can substantially improve the case for renewables across both factors. **Growing renewables capacity that generate 'as available' at near-zero marginal cost act to displace gas at a given level of demand, pushing gas toward lower average utilisation**.

For new large loads, co-locating with new renewable and battery capacity and existing gas generator may offer the quickest route to market with firm power at relatively low cost.

Different technologies have varied characteristics and modes of compatibility with the wider electricity system and are often dealt with differently by the policy landscape. Tables 4-6 describe these key characteristics and implications for the prospects of natural gas and key alternatives (renewables and battery storage).

Gas supply chains are currently heavily constrained and may remain so under scenarios where electricity demand remains strong (particularly Scenario 1). They must also be built with access to gas pipelines with sufficient capacity. In contrast, renewables and batteries are readily available, quick to install and highly flexible in siting and sizing. Speed to market is a key priority for data centres in particular.[xlii]

		Natural gas	Alternatives	Technology characteristics
Technology availability	2030			**Lead times for gas turbines are 3-7 years**[1], **with new orders unlikely to be delivered before 2030. Construction contractors are also at capacity until the early 2030s.**[2] Limited manufacturing expansion plans mean **constraints remain beyond 2030 under scenarios with high demand growth** (1) and (3), **but ease with more moderate growth** (2) and (4), particularly where policy support for alternatives is reinstated (4).
	1			**Global solar PV manufacturing capacity is in significant oversupply**, although steep tariffs are planned on major US suppliers (e.g. Vietnam, Thailand, Malaysia).[3] Stockpiling means **there is likely at least a year's worth of capacity in US inventories.**[4] **Domestic module manufacturing capacity exceeds current deployment**[5], but significant cell import dependency remains. **Beyond 2030 availability will remain high under all four scenarios,** even if supply chains vary.
	2			**Around 90% of US battery storage supplies are from China,** with South Korea also significant. **Global battery manufacturing capacity – dominated by China - is double global demand.**[6] **US manufacturing capacity exceeds domestic demand, with 3x current capacity under construction**[7], although tariffs on components, FEOC requirements and export controls on critical minerals from China may increase costs, slowing build-out. As with solar PV, **availability beyond 2030 is likely to remain high under all four scenarios**, even if supply chains and costs vary.
	3			
	4			Wind supply chains are generally localised due to transport costs**,** meaning **most key components for wind capacity deployed in the USA is manufactured domestically**, **with nacelle and tower production capacity 2-3x current demand**. Domestic blade manufacturing capacity largely equals demand, despite significant imports from Mexico and Canada. There is little new manufacturing capacity in the pipeline.[8] **Beyond 2030, wind technology availability is likely to be more limited than solar and batteries, but sufficient to meet demand under all four scenarios.**
Time to build *(excl. regulatory approval)*	2030			**A new CCGT plant typically takes 3-4 years from site preparation to operational readiness,** assuming limited supply chain delays. **For large utility-scale solar and onshore wind, this timeframe is 12-18 months, and 6-18 months for battery storage**. Smaller and less complex installations may take less than a year[9], with more complex installations – including renewable and storage co-locations – typically falling toward the upper end of the range.
	1			
	2			
	3			
	4			
Deployment flexibility	2030			**New gas capacity must be sited near gas pipelines with sufficient gas supply capacity**. Around 20-40 acres of land is required[10], **with a moderate ability to customize and change plant capacity** (with smaller units tending to be peaking generators), and associated investment and network requirements over time. Although they require significantly more land for comparable capacity, **solar and battery systems are highly flexible in siting and sizing due to their modularity** (including co-location), while **wind generators have moderate flexibility**.
	1			
	2			
	3			
	4			

Prospects: Good Moderate Poor

Table 4 – Characteristics of natural gas and alternative technologies. Sources: [1]Anderson (2025); [2]Martin (2025); [3]IEA (2025); [4]Bloomberg (2025); [5] Pickerel (2025) [6]McKerracher (2024); [7]IEA (2025); [8]CIM (2025); [9]EDF (2024); [10]Stevens (2017) . Graphic created by Greenwheel. The information shown above is for illustrative purposes. Forecasts and estimates are based upon subjective assumptions.

Gas capacity can suffer less from electricity network constraints, and its dispatchability means individual units are more able to address system reliability. However, in many cases batteries can substantially improve the case for renewables across both factors.

In ERCOT, over a quarter of renewable generation in 2024 was curtailed, equivalent over 10% of all ERCOT load.[xliii] In CAISO, just 6% was curtailed,[xliv] due to high inter-market connectivity and battery capacity. Batteries supplied almost a fifth of California's evening peaks in June 2024 and has exceeded one third.[xlv] Further deployment of batteries improves the systemic value of renewables and reduce the need for new dispatchable capacity and transmission infrastructure.

The baseload capability of CCGTs is a key reason for their match with data centres in commentary. Around a third of current slot reservations for new gas turbines with GE Vernova (the largest manufacturer) are for captive data centre generators, but a negligible volume of confirmed orders.[xlvi] Of those on order or reserved a significant number are peaking units,[xlvii] and most data centres with captive gas capacity are also still seeking a grid connection[xlviii], indicating they may be primarily used for back-up.

System characteristics

	Scenario	Natural gas	Alternatives	
Electricity network constraints	2030	Moderate	Moderate	**Large volumes of variable renewables require significant network capacity to transmit power to users, or face connection delays or curtailment** when producing strong output. This capacity requires time and significant investment to deliver. **Variable renewable generators have more expensive and longer interconnection approval processes** than firm power generators (e.g. gas), due to network upgrade requirements and varying processes between markets.[1] **Batteries can actively help reduce pressure on electricity networks** by firming variable renewables and smoothing supply and demand profiles.
	1	Moderate	Poor	
	2	Good	Moderate	
	3	Moderate	Poor	
	4	Good	Moderate	
Value to the system *(inc. dispatchability)*	2030	Good	Good	**Gas generators are dispatchable**, with peaking generators able to ramp up quickly to meet changes in demand or alternative supply. **Solar and wind generate 'as available'. The marginal value of solar or wind generators may decline with increasing penetration**, with growing price cannibalization, particularly in deregulated markets – although **solar and wind capacity can be complementary** with different temporal generation profiles. By flattening supply profiles, **batteries can significantly improve the system value of variable renewables and can provide a range of ancillary services** to the grid.
	1	Good	Moderate	
	2	Moderate	Good	
	3	Good	Moderate	
	4	Moderate	Moderate	

Prospects: Good Moderate Poor

Table 5 – System characteristics related natural gas and alternative technologies. Information sources: [1]LBNL (2025). Graphic created by Greenwheel. The information shown above is for illustrative purposes. Forecasts and estimates are based upon subjective assumptions.

Current lead times, the continued need for a grid connection and the technical challenges involved in operating CCGTs in a back-up or peaking role[xlviii] means the construction of captive CCGT capacity is unlikely to materialise a widespread strategy for data centres.

An alternative is to co-locate data centres (or other large loads) with new renewable and battery capacity, and an existing gas generator. This allows the gas generator to meet marginal demand when renewable and battery supply is insufficient, and for excess renewable generation to feed into the grid using the existing interconnection. This also allows fast-track approval for and reduces the strain on the grid by avoiding new large load interconnection. [xlix]

The RMI estimate that over 50 GW of new large loads could be powered this way across the US, at less than \$100/MWh for 30 GW and less than \$200/MWh for the remainder. [xlix] The value of this approach may increase significantly when employing load flexibility.

The greatest value of dispatchable capacity is in its availability rather than use. Growing renewables that generate 'as available' at near-zero marginal cost act to displace gas at a given level of demand, particularly as coal plants retire (and particularly in deregulated markets). This may push gas toward lower average utilisation.

Permitting & state-level characteristics

		Natural gas	Alternatives	
Permitting	**2030**			**Gas power plants may now receive expedited federal review** with protection against judicial review,[1] with **fast-track approval in some states and markets** (e.g. PJM)[2]. **Renewable projects on Federal land must be personally approved by Secretary of the Interior**, which by default will not be given (although only 4% of installed renewable capacity is on federal land)[3]. **State and market-level permitting procedures vary significantly**, but ~30 states have defined permitting timelines of <1 year, and **some (e.g. Texas) are actively accelerating timelines for renewables and batteries**.[4] Under Scenarios 1 & 2 current trends may continue, while under Scenarios 3 & 4 more supportive federal permitting procedures for renewables and batteries remerges.
State-level & company energy policy	**2030**			**More than half of US states have binding state-level clean electricity or renewable portfolio standards with stringency increasing over time**. Although many standards have derogations or exemptions they have been a significant driver for renewables deployment in some regions (Northeast, mid-Atlantic and the West), and become so elsewhere as stringency grows or compliance deadlines near.[5] **There are few state level emissions standards on gas power that exceed Federal limits, although limits in CAISO, for example, are highly restrictive**.[6] There is little indication of potential changes to state-level standards, although pressure to reduce their stringency may rise under scenarios with high electricity demand growth (1 & 3). **Most major hyperscale data centre operators have ambitious clean energy goals**. For example, Google, Microsoft and Amazon all aim to use 100% carbon-free energy by 2030 and are broadly on track to achieve these aims[7]. Satisfying growing power demand under Scenarios 1 & 3, in particular, may emerge as a challenge to these goals.

Prospects: Good Moderate Poor

Table 6 – Permitting & state-level characteristics related to natural gas and alternative technologies. Information sources:[1]S&P Global (2025) [2]Skidmore (2025); [3]Energy Global (2025) [4]LBNL (2025); [5]LBNL (2024); [6]Ankura (2024); [7]Weller (2025). Graphic created by Greenwheel. The information shown above is for illustrative purposes. Forecasts and estimates are based upon subjective assumptions.

State and market-level policies can hold significant influence over the ability and time to permit new generation capacity, with many seeking to accelerate the deployment of all forms of capacity. In the longer term, particularly under scenarios with lower electricity demand growth (2 & 4), clean electricity and renewable portfolio standards may begin to further restrict the prospects for new gas capacity.

Endnotes

[i] IEA (2023)
[ii] EPA (2025)
[iii] S&P Global (2025)
[iv] EIA (2025)
[v] Wilson et al (2024)
[vi] Barth et al (2025)
[vii] NEMA (2025)
[viii] Batra et al (2025)
[ix] EIA (2025)
[x] Case (2025)
[xi] BNEF (2025)
[xii] NERC (2025)
[xiii] Numata et al (2025)
[xiv] Martucci (2025)
[xv] Norris (2025)
[xvi] LBNL (2024)
[xvii] Aurora (2025)
[xviii] Norris et al (2025)
[xix] Google (2025)
[xx] Lam (2025)
[xxi] EIA (2023)
[xxii] Tosado et al (2025)
[xxiii] Ham et al (2025)
[xxiv] Shreve et al (2025)
[xxv] Paolella (2024)
[xxvi] Brick (2018)
[xxvii] EIA (2025)
[xxviii] EIA (2025)
[xxix] NBER (2018)
[xxx] EIA (2025)
[xxxi] Anderson (2025)
[xxxii] Seiple et al (2025)
[xxxiii] Shenk (2025)
[xxxiv] IRENA (2025)
[xxxv] Bartlett (2023)
[xxxvi] IRS (2025)
[xxxvii] NREL (2025)
[xxxviii] IEA (2025)
[xxxix] EIA (2025)
[xl] Satchwell et al (2025)
[xli] Long & Lee (2025)
[xlii] McKinsey (2024)
[xliii] Dutton (2024)
[xliv] CAISO (2025)
[xlv] Ember (2025)
[xlvi] Storrow (2025)
[xlvii] DIN (2025)
[xlviii] Seiple & Hertz-Shargel (2025)
[xlix] Engel et al (2025)

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