WHEN TRUST MATTERS

ENERGY TRANSITION OUTLOOK NORTH AMERICA 2025

A regional forecast to 2060

FOREWORD

Welcome to our 2025 forecast of the energy transition in North America to 2060. It's been two years since we launched our first North American *Energy Transition Outlook*, and our customers in the US and beyond have requested an updated forecast.

This report sets out our revised outlook, which considers large policy changes in the US and smaller reversals in otherwise consistent Canadian energy policy. The overall long-term trend is that an energy transition is still underway in North America that will see fossil's share of final energy demand fall from 72% in 2024 to 45% by 2050, and 31% by 2060.

The policy changes in the US this year are intended to reassert the use of US oil and gas at home, and abroad through exports, and to boost nuclear developments. Compared with our previous forecast, we find that North American renewable generation buildout is indeed slower, EV uptake more muted, the role of oil in transport prolonged, and the use of natural gas in electricity generation extended. The net effect of all of this is that at least five years will elapse before North America returns to the decarbonization trajectory we previously forecast.

Though slowed by policy changes, the energy transition in North America is still underway. Managing demand growth and affordability are emerging challenges.

A very consequential development since our 2023 forecast is, however, not policy related: the rapid rise of generative AI and the surging power needs from new data centers. Current evidence points to data centers accounting for at least 5% of total North American electricity demand by 2030, increasing to 16% by 2040. By then, rising EV uptake and the electrification of other end-uses will have driven the demand for electricity up by one third relative to 2024 levels.

Where is the new generation going to come from to satisfy this surging demand? Despite policy changes, solar and onshore wind remain the fastest and cheapest way to generate new electricity. Solar and wind will expand from 19% of electricity generation today to 55% by 2040. However, their contribution is hampered in the near term by underinvestment in grid upgrades and newbuild and long wait times for new connections to the grid.

New natural gas plants will be built but there is a backlog for new gas turbines of between one and seven years, and costs are increasing. With gas being the price setter in tight power markets over at least the next decade, power prices are likely to continue to rise. We estimate that between now and 2035, average household energy costs will increase 22% after adjusting for inflation.

Tackling energy affordability will not be easy. However, policymakers, utilities, and energy companies can make important progress if they work together to get more out of the existing electricity system by pursuing flexibility options around storage and demand management, efficiency options like reconductoring and grid enhancing technologies, as well as policy reforms to connect new generation projects to the grid more rapidly.

Remi Eriksen
Group President and CEO
DNV

HIGHLIGHTS

1. **Fossil for longer**
   Policy changes in 2025 prolong the use of fossil fuels in the North American energy system.
2. **Renewables: resilience then resurgence**
   Despite short-term policy friction, solar and wind will expand from 19% of electricity generation today to 55% by 2040.
3. **Decarbonization delayed**
   Continued use of fossil fuels delays decarbonization by five to eight years.
4. **(Un)affordable energy**
   Retail electricity prices are likely to increase by 22% before inflation in the next ten years.

HIGHLIGHTS

1. Fossil for longer

Policy changes in 2025 prolong the use of fossil fuels in the North American energy system.

– Before the 2025 policy reversals, we forecast fossil fuels would cover 45% of North American final energy demand in 2050. Our new forecast sees that share increase to 50% by mid-century.

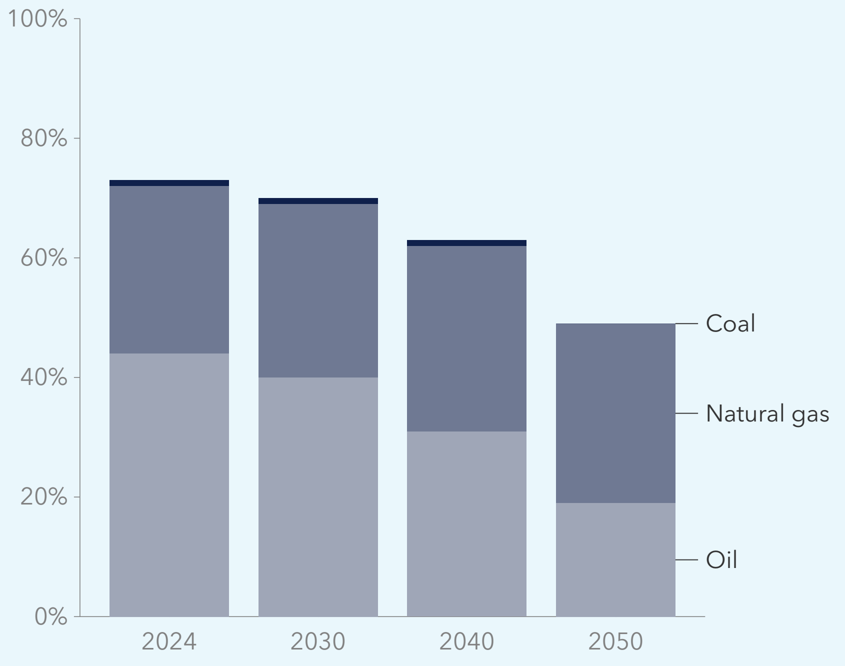
– US policy changes have eliminated federal subsidies for EVs, cut short support for renewables, rolled back carbon regulations, and introduced regulatory barriers for renewables. At the same time, oil and gas now enjoy favorable tax treatment, rolled back environmental regulations, and federal land opened up for drilling.

– Fossil fuels currently represent 80% of North American primary energy (40% is natural gas, 34% oil, and 6% coal). Despite the present support for these sources, they are subject to the global decarbonization megatrend. In absolute terms, by 2050, coal will reduce to negligible levels, oil will decline by almost two thirds, and gas by one third.

– While we previously predicted oil would supply 67% of transport demand in 2040, we have now revised that share up to 76%. However, its share of the transport energy mix then falls to 53% in 2050 and 30% by 2060.

– Natural gas remains dominant – supplying a third of electricity by 2035, a third of building energy by 2044, and 40% of manufacturing energy by 2060. Gas exports have spiked by 22% over the last two years and will remain at those elevated levels until 2040 before declining.

Fossil share of final energy demand



HIGHLIGHT 1

2. Renewables: resilience then resurgence

Despite short-term policy friction, solar and wind will expand from 19% of electricity generation today to 55% by 2040.

– Renewables installations will grow until the IRA stimulus window closes early. After this, the rate of growth in installations flatlines for four years and then picks up again as renewables begin soaking up more of the growth in electricity demand. Renewables start to replace natural gas-fired power in the North American grid from 2034.

– Overall, we forecast electricity demand will increase 50% by 2040, with more than a third of the increase being for AI-computing and data centers.

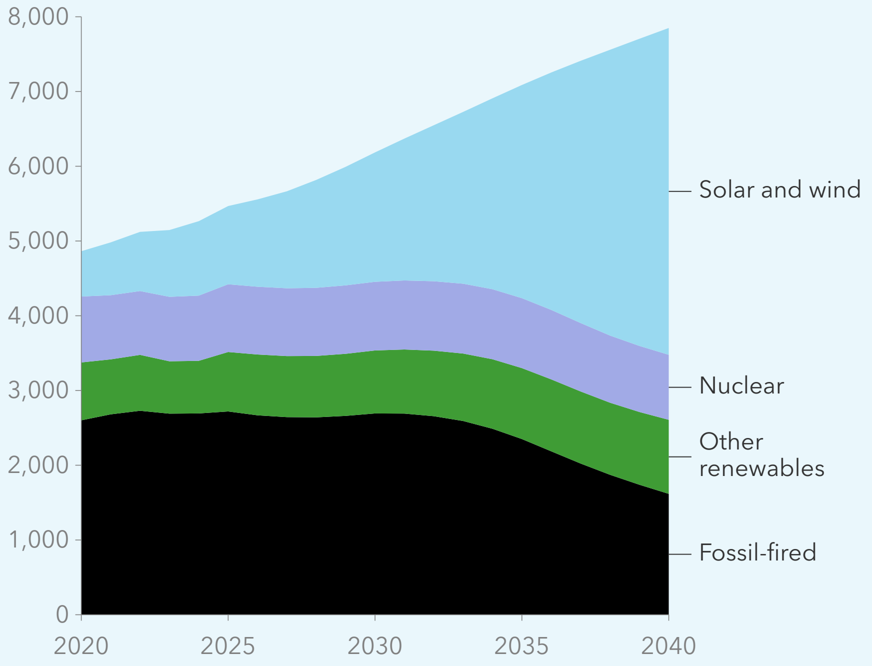
– Despite the reversal of policy support, solar and onshore wind continue being the cheapest sources of electricity. The levelized cost of energy (LCOE) of solar is 62% of the LCOE of gas-fired turbines in 2025 and the LCOE of onshore wind is 75%.

– By 2040, we forecast 1.8 TWh of grid-connected batteries on the North American grid, growing 25x from 0.07 TWh in 2024, and enhancing the dispatchability of solar and wind. Almost 60% of these batteries will be co-located with solar generation.

– Interconnection and permitting bottlenecks will continue to constrain renewables more than natural gas-fired power plants.

– By 2040, we forecast the fraction of self-generated electricity to reach 10% in commercial buildings in North America, from a scant 1% in 2024. Long inter-connection wait times will incentivize investment in behind-the-meter (BTM) solar and batteries.

Grid-connected electricity generation (TWh/yr)



HIGHLIGHT 2 | Historical data source: IEA WEB (2025)

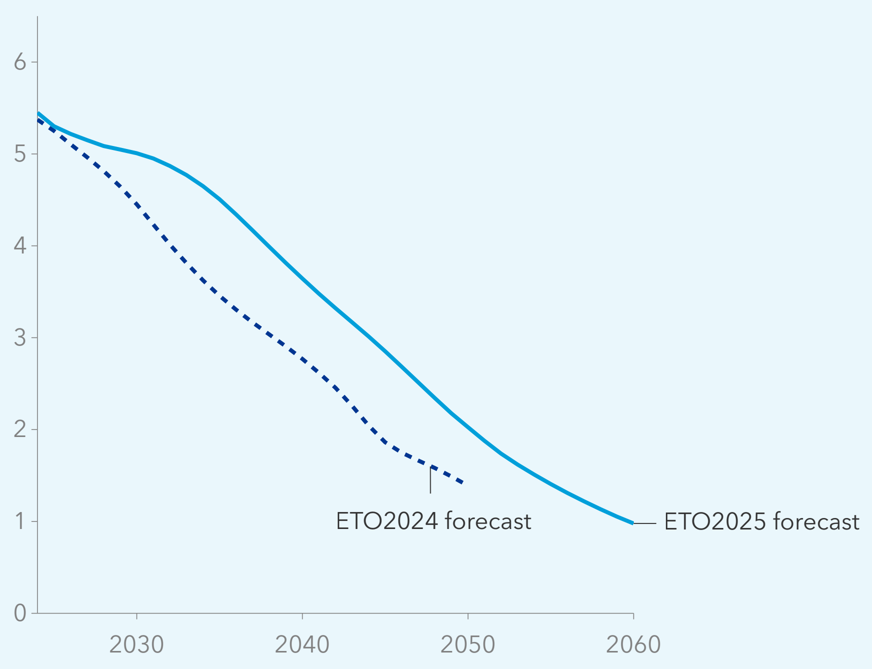
HIGHLIGHTS

3. Decarbonization delayed

Continued use of fossil fuels delays decarbonization by five to eight years.

- We have been modelling the transition of North America's energy systems for the past decade. Comparing our present forecast with our 2024 forecast enables us to assess the impact of the policy changes that have occurred over the last year.
- North American energy-related CO_2 emissions are 33% higher in 2040, compared to the ETO 2024 forecast. Within the 2024-2050 timeframe, the delayed transition translates to 19 $GtCO_2$ of additional cumulative energy-related emissions.
- 99% decarbonization of the electricity mix is achieved 8 years later: 2058 instead of 2050 as we forecast last year.
- The 50:50 split between fossil and non-fossil primary energy is delayed by 5 years, from 2042 to 2047, due to the sustained prevalence of fossil fuels spurred on by 2025 policy changes.
- Maintaining support for carbon capture, storage, and utilization leads to more than 425 $MtCO_2$ (28% of energy-related emissions) captured in North America in 2060. However, the emissions remain well above net zero by 2060.
- Investments in natural gas infrastructure, such as LNG terminals, in the current period run the risk of becoming stranded assets after 2040, with the demand for North American natural gas declining due to faster decarbonization in regions such as Europe, OECD Pacific, and China.

Energy-related CO_2 emissions ($GtCO_2$/yr)



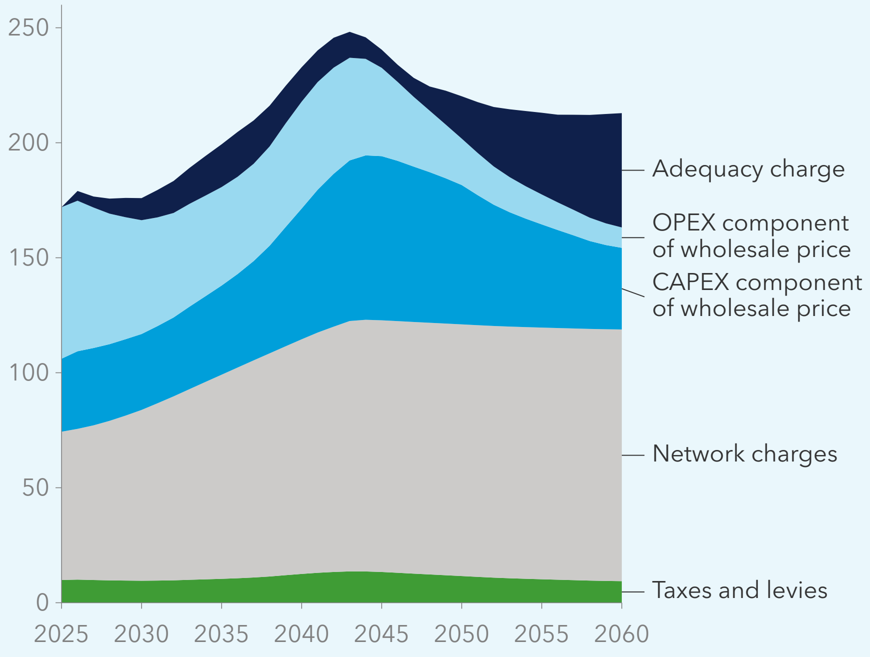
HIGHLIGHT 3

4. (Un)affordable energy

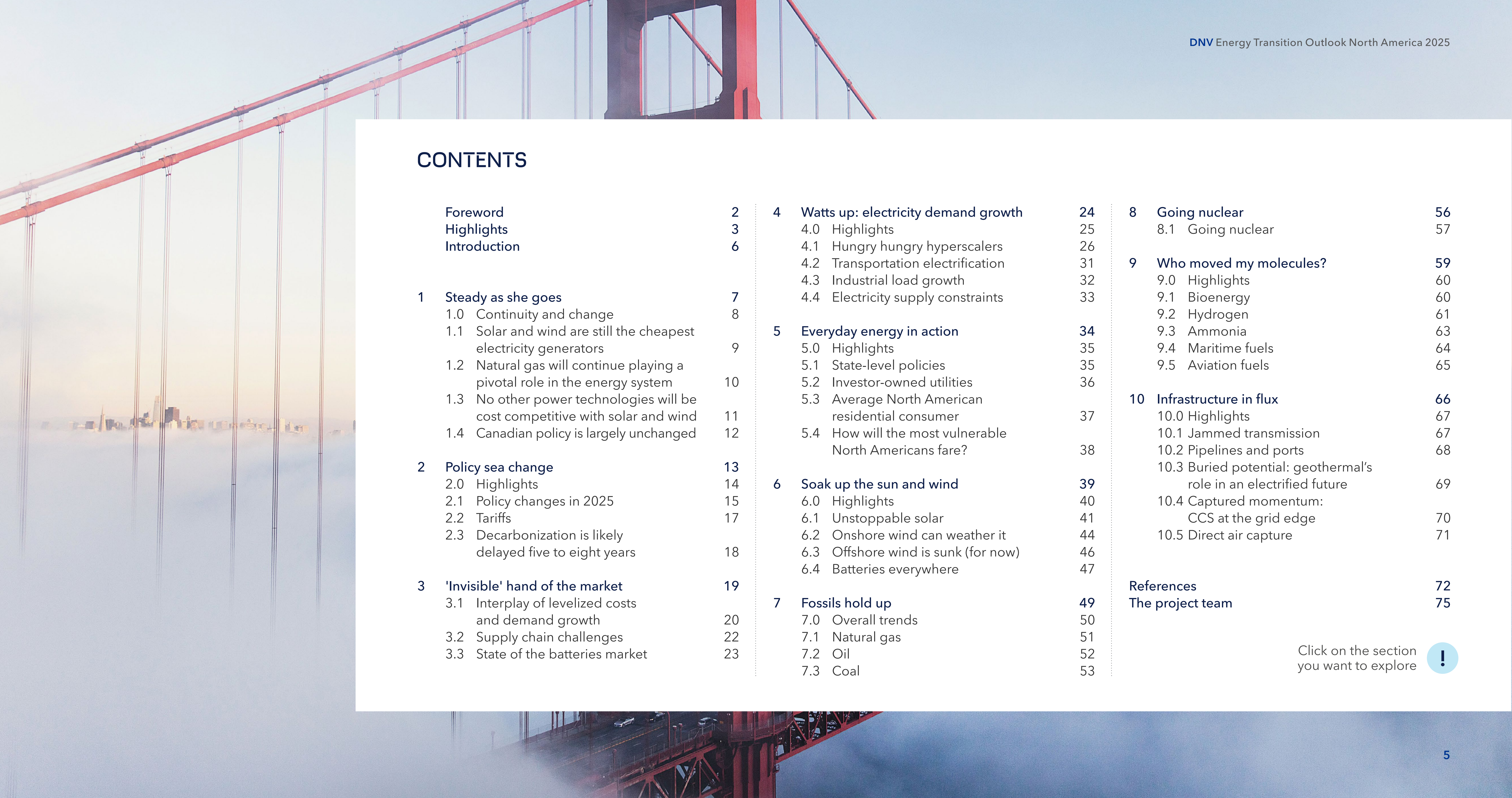
Retail electricity prices are likely to increase by 22% before inflation in the next ten years.

- After jumping 17% in the last five years, we forecast residential electricity prices will rise another 22% to 2035 (before inflation). The average household is thus likely to see a 50% higher USD/kWh rate in nominal terms between 2024 and 2035.
- Prices for other energy inputs like gasoline and natural gas are likely to increase more gently. Thus, we project total energy costs per household will rise by 15% in real terms by 2040.
- The main reason for the near-term electricity rate increase relates to grid costs: maintenance, hardening against climate events, and new build.
- Trade tariffs and foreign entity of concern (FEOC) provisions will put some upward pressure on the cost of solar, batteries, and grid expansion.
- Policies inhibiting the rate of expansion of cheaper renewable energy in the power mix start to add to rising costs by the 2030s, while data center demand pressure intensifies.
- Natural gas will continue to set the price in many tight power markets well into the 2030s. This also pushes wholesale electricity prices up, on average.
- To combat affordability issues in the near term, policymakers, utilities, and energy companies should work together to get more out of the existing electricity system by pursuing flexibility and storage options, grid enhancing technologies, and policy reforms around new connections.

Total electricity price (USD/MWh)



HIGHLIGHT 4



CONTENTS

Click on the section you want to explore

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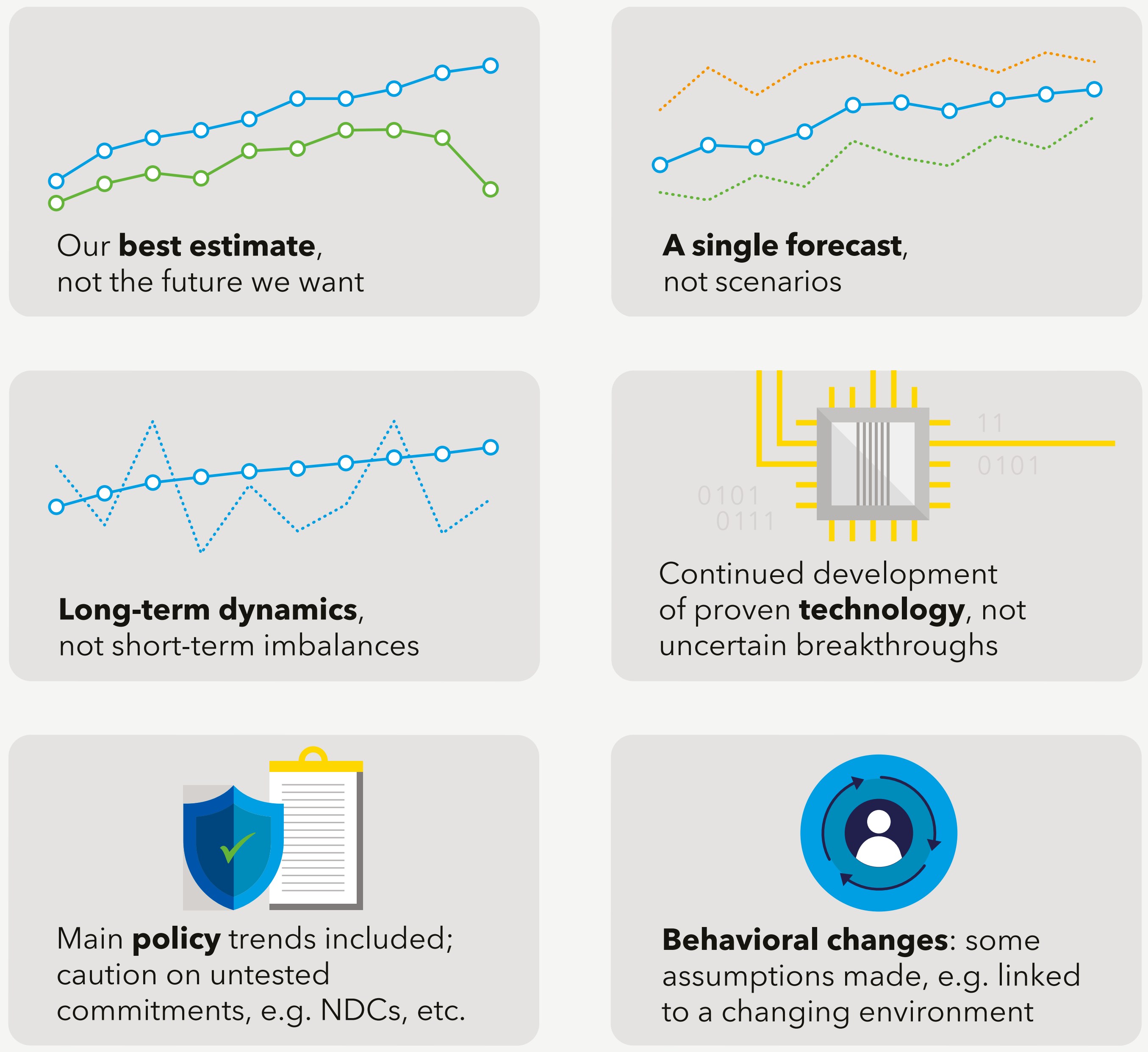
INTRODUCTION

About this Outlook: This is the second edition of our *Energy Transition Outlook North America* forecast, which explores the energy future of the US and Canada through 2060. The analysis, underlying model framework, methodology, and assumptions – and consequently the results – are closely aligned with our global forecast, *Energy Transition Outlook 2025* (ETO 2025) (DNV, 2025).

North America's energy system operates within a global context where technology learning rates, costs, market dynamics, and policies are shaped by developments in other regions. The ETO model captures this interdependence by representing North America as an integrated yet distinct region within the broader global energy system.

Unlike approaches that rely on multiple scenarios, we publish a single, independent forecast – representing our best assessment of the most likely energy future. We believe this clarity of view provides greater value to decision-makers than a range of equally weighted possibilities that can obscure rather than illuminate the path ahead.

Our approach is based on the following tenets:



Modeling the energy transition in North America in 2025

We have undertaken this modeling exercise to assess the 2025 energy transition in the US and Canada amid exceptional uncertainty and significant policy upheaval. As an organization with an independent view on the energy system and the global energy transition, we recognize the importance of providing a clear and evidence-based view of the most likely energy future for North America.

Developing an independent understanding and forecast of North America's energy transition is strategically important for both DNV and our customers. This Outlook reflects the collective expertise of more than 40 DNV professionals, whose names are listed on the final page of this report. In addition, we are very grateful for the assistance provided by external experts and organizations, listed here:

Steve Nadel
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Smart Energy Consumer Collective

Photo by, Josh Bauer and Bryan Bechtold, NREL 84129

1 STEADY AS SHE GOES

1.0 CONTINUITY AND CHANGE

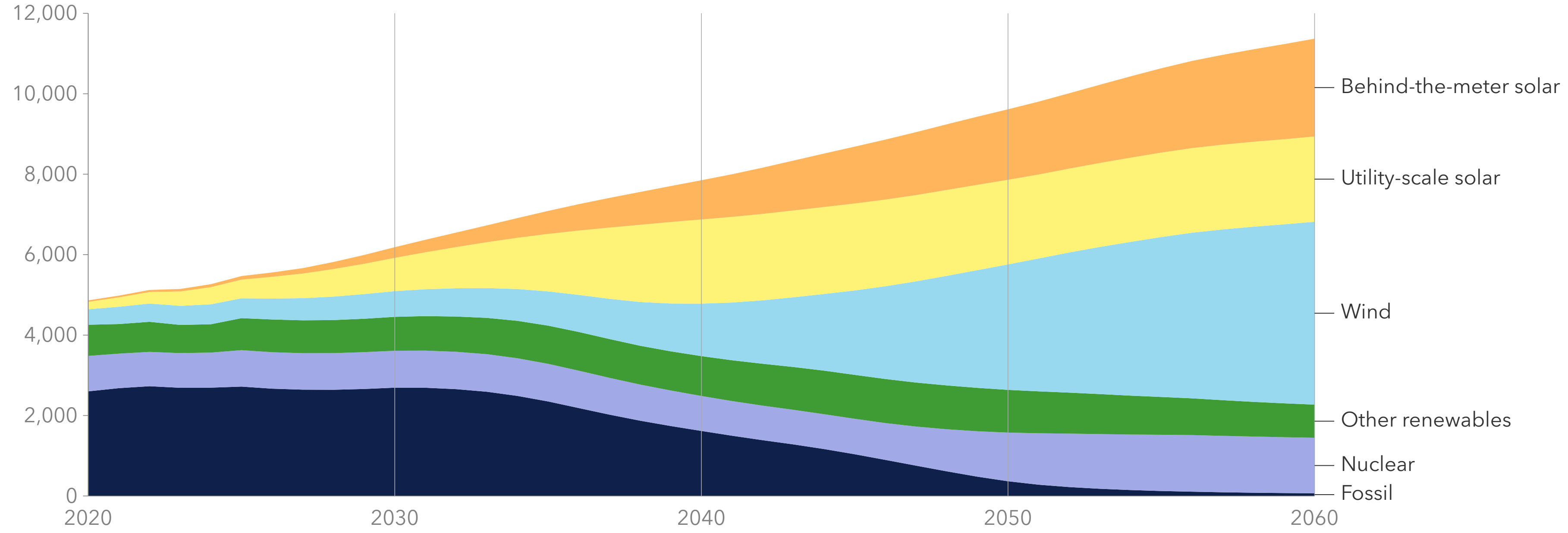
There has been a major shift in US federal policy and a rapid increase in electricity demand growth – driven primarily by the power needs of data centers and AI computation – since we last published a dedicated *North America Energy Transition Outlook* in 2023. Nevertheless, a few commonalities remain from that forecast to this one. We will first examine areas of continuity here before addressing what has changed in our forecast in later chapters.

- Solar and onshore wind are the cheapest electricity generators in North America, and will continue to be so in the future as well.
- Natural gas will continue to play a significant role in the North American energy system, due to rising electricity prices.
- No other power technologies will compete with solar and onshore wind in the near term on cost.
- Canadian energy policy is largely unchanged, despite the policy changes in US.

Photo by Joe DelNero, NREL 80597

Solar and wind garner an ever-growing share of electricity from 2030

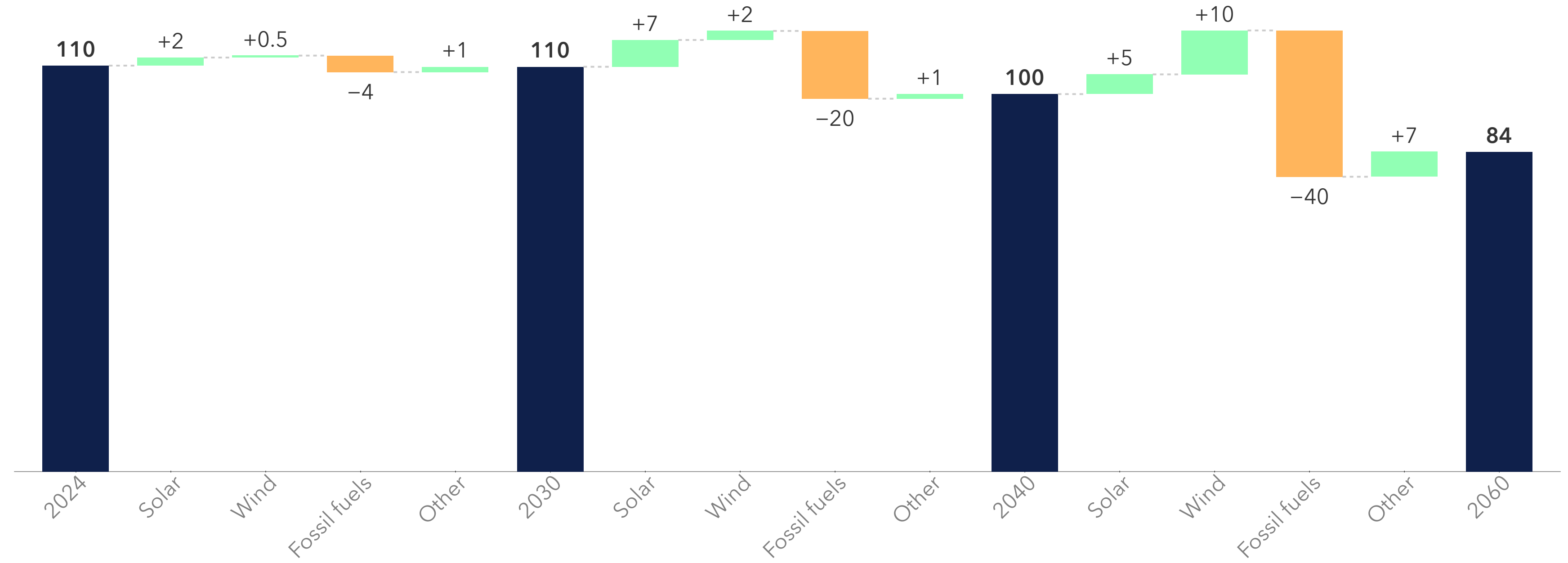
Grid-connected electricity generation (TWh/yr)



Historical data source: IEA WEB (2025)

Solar, wind, and the ensuing electrification reduce energy consumption

Primary energy consumption by source (EJ/yr)



Historical data source: IEA WEB (2025). Numbers may not sum due to rounding.

1.1 SOLAR AND WIND ARE STILL THE CHEAPEST ELECTRICITY GENERATORS

In 2025, it costs less to generate electricity with solar and onshore wind in North America than with any other source, even when factoring in regional deviations in cost of generation, short-term cost increases for equipment and capital, and the impact of tariffs.

This is because:

- Capacity costs (total cost of installation per unit of power capacity) of solar and onshore wind have reduced so much that they are the least-cost options on a levelized cost basis.
- Solar and onshore wind resources are plentiful in the US, with vast, still-untapped potential. While solar resources are not as abundant in Canada, onshore wind resources are plentiful there.

In this forecast, we calculate the average solar and onshore levelized cost of energy (LCOE) across the entire North America region. In reality, this LCOE varies across projects located in different parts of the region based on the level of insolation and wind regimes at each site and fixed costs like labor, capacity, and land. Thus, the LCOE is a range (based on the costs and capacity factors) across the region and spread around the average LCOE. Different electricity generation options across North America have different average LCOE and spreads (Figure 1.1).

In 2025, even the most expensive solar and onshore wind generation costs about the same as average gas-fired electricity.

The lower cost of solar and onshore wind electricity generation makes these sources attractive for investors, developers, and utilities. Solar and wind projects waiting to come online have dominated the interconnection queues in many US and Canadian electricity markets (Rand et al., 2025).

Over the next decade, the profitability of solar and wind projects will increasingly depend on energy storage. As renewable penetration rises, electricity often becomes abundant during sunny or windy periods, requiring excess generation to be transmitted or stored. With grid expansion in North America constrained, more storage capacity will be needed to absorb this surplus.

We expect the LCOE for solar+storage power plants in North America to remain elevated between 2025 and 2040 due to several factors:

- Rising energy-to-power ratios: The current average energy-to-power ratio of 2–2.5 hours is increasing as developers seek higher value capture from solar generation. Many new solar+storage projects now feature ratios around 4 hours, raising both system costs and LCOE.
- Higher solar-to-battery capacity ratios: Historically, battery capacity was sized at roughly 0.7 GW for every 1 GW of solar. Recent projects are approaching a one-to-one ratio, further increasing capital costs and LCOE.
- Tariff-driven cost pressures: While most batteries slated for installation in the next 2 to 3 years were procured before new tariffs took effect, we expect costs to rise once existing inventories are depleted. Although some manufacturers and developers have diversified their supply chains away from high-tariff regions, average battery system costs are still likely to increase.

So, in the medium term, we do not anticipate a complete halt in renewables deployment, but rather a slowdown driven by policy headwinds. In the long term, after 2040, we forecast that the cost of natural gas-fired electricity will rise rapidly and become more expensive than renewable sources. By 2045, even solar+storage will have a lower LCOE than natural gas, leading to a faster transition away from gas-fired electricity after the 2040s.

Solar PV and onshore wind remain the cheapest sources of electricity

Levelized cost of energy at FID (USD/MWh)

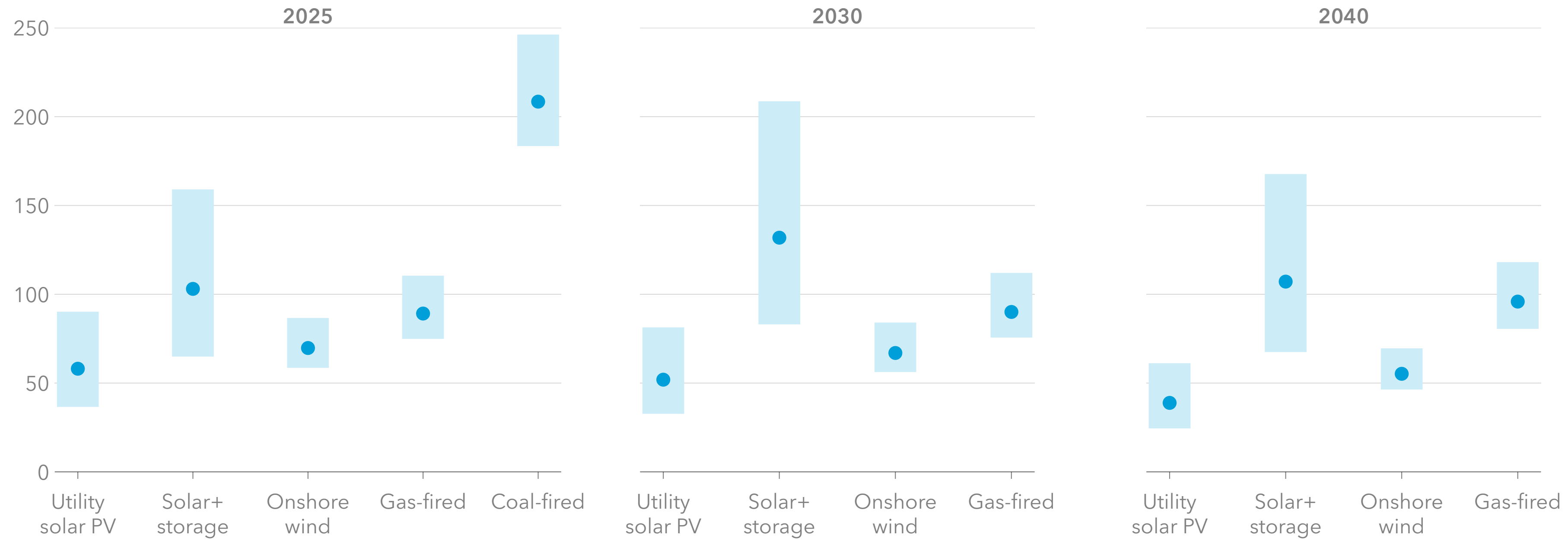


FIGURE 1.1 | No new coal-fired electricity generation is expected to come online in the forecast period.

1.2 NATURAL GAS WILL CONTINUE PLAYING A PIVOTAL ROLE IN THE ENERGY SYSTEM

Both the US and Canada have abundant natural gas resources that currently play a substantial role in the region's energy system. Natural gas-fired electricity accounts for 41% of on-grid electricity and 29% of the region's final energy demand in 2025.

Despite this abundance, we expect electricity prices in North America to keep rising until 2040 due to:

- Insufficient renewable growth: solar and wind expand, but not quickly enough to meet rising demand.
- Higher-cost generation: new gas-fired plants fill the supply gap, pushing wholesale prices upward.
- Continued coal use: ongoing coal-fired generation adds further upward pressure.
- Storage integration: batteries are required to make renewables dispatchable, adding costs.
- Grid investment needs: an aging grid requires major capital expenditure for maintenance, climate resilience, expansion, and renewables integration, all of which increase end-use prices.

Although we expect natural gas prices to rise for the end consumer, the rate of increase is lower than for electricity price rises.

This implies that over the next 15 years, electricity will be a more expensive energy carrier than natural gas before considering the energy efficiency gains it brings. Some demand sectors that currently use natural gas heavily may not be incentivized to transition. Thus, we forecast that natural gas will continue to be a key energy carrier in both buildings and industrial sectors in North America well into the 2040s. Natural gas-fired electricity generation will fall by 2040 but will still be significant.

Manufacturing will continue to use natural gas at near-current levels. Buildings slowly transition away from natural gas as an energy carrier while power stations make a sharp transition in the 2030s.

Electricity prices rise at a faster rate than natural gas

Industrial energy prices (Indexed to 2024)

Residential energy prices (Indexed to 2024)

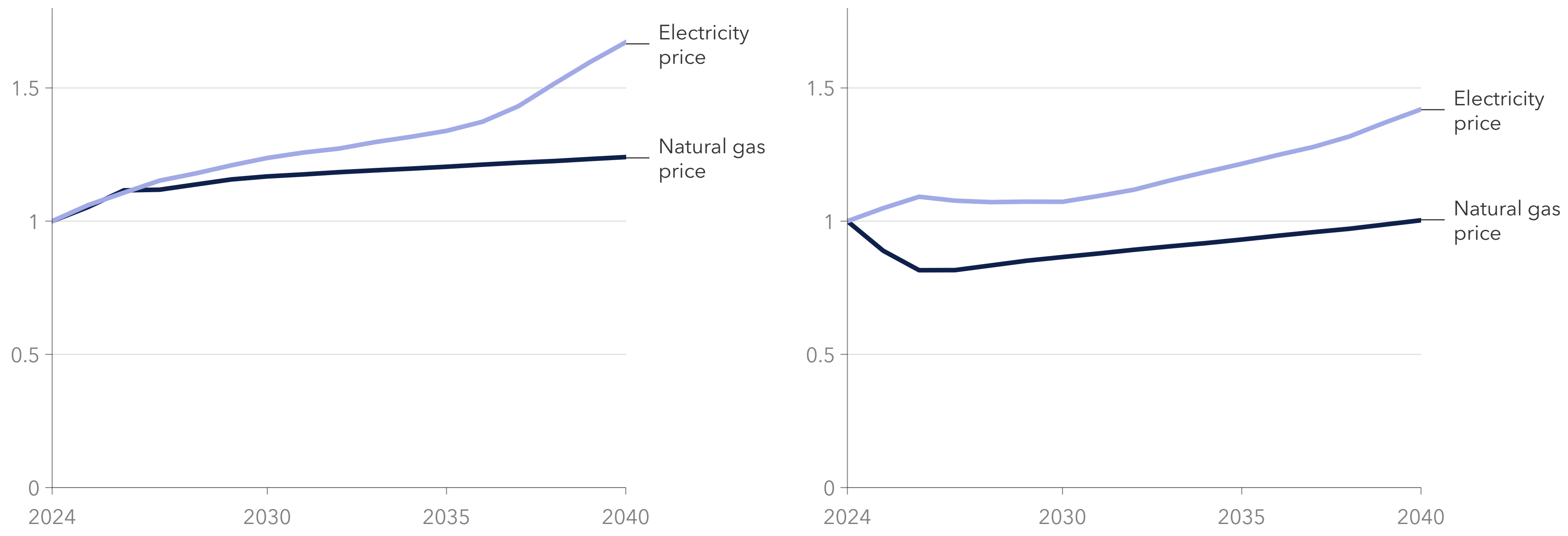


FIGURE 1.2 |

Natural gas use is steady for 15 years

Natural gas demand by sector (PWh/yr)

Natural gas share of energy demand by sector

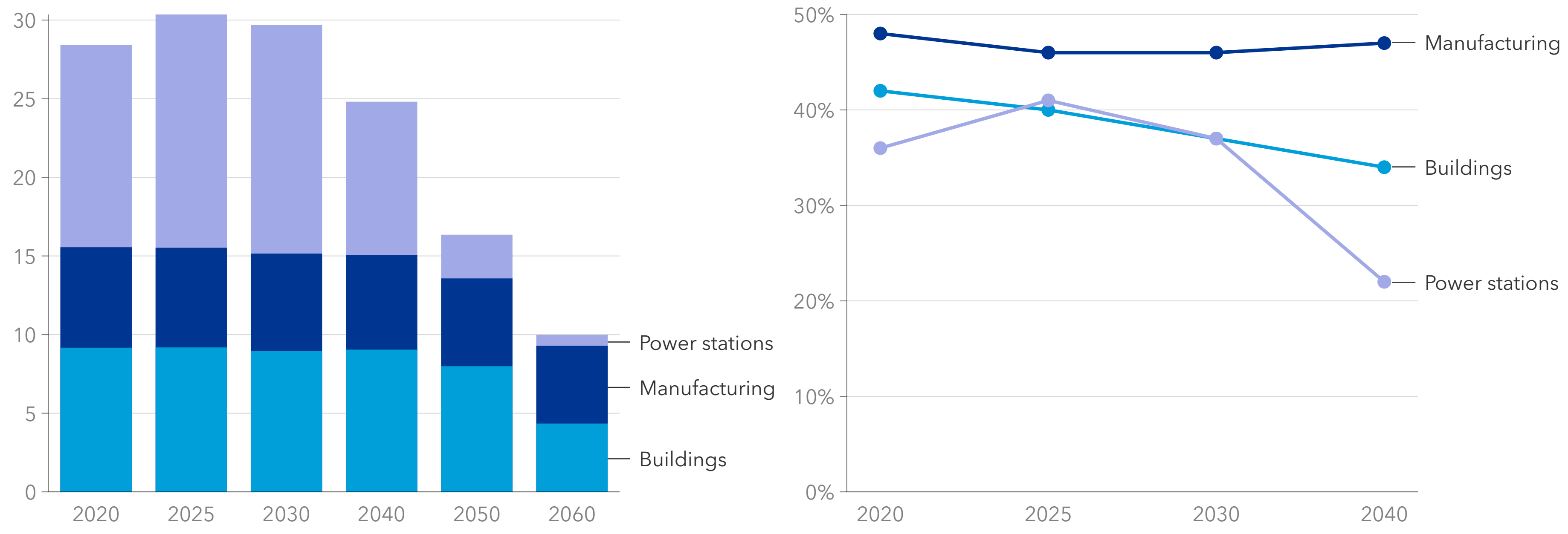


FIGURE 1.3 | Historical data source: IEA WEB (2025)

1.3 NO OTHER POWER TECHNOLOGIES WILL BE COST COMPETITIVE WITH SOLAR AND WIND

The LCOE of coal, nuclear, geothermal, and bioenergy is already substantially higher than for solar or onshore wind. We forecast that none of these technologies will become cheaper than solar or onshore wind in the foreseeable future. The LCOE for nuclear will decrease slightly in the late 2040s as small modular reactors (SMRs) become commercially viable, but even then, we expect costs to be double that of solar or wind.

When factoring in network charges or grid expansion costs, biomass and geothermal can become cost competitive with renewables, but coal and nuclear cannot. However, biomass and geothermal are a very small proportion of the current energy mix and will remain marginal.

Wind and solar outcompete other technologies on price

Average levelized cost of energy before support (USD/MWh)

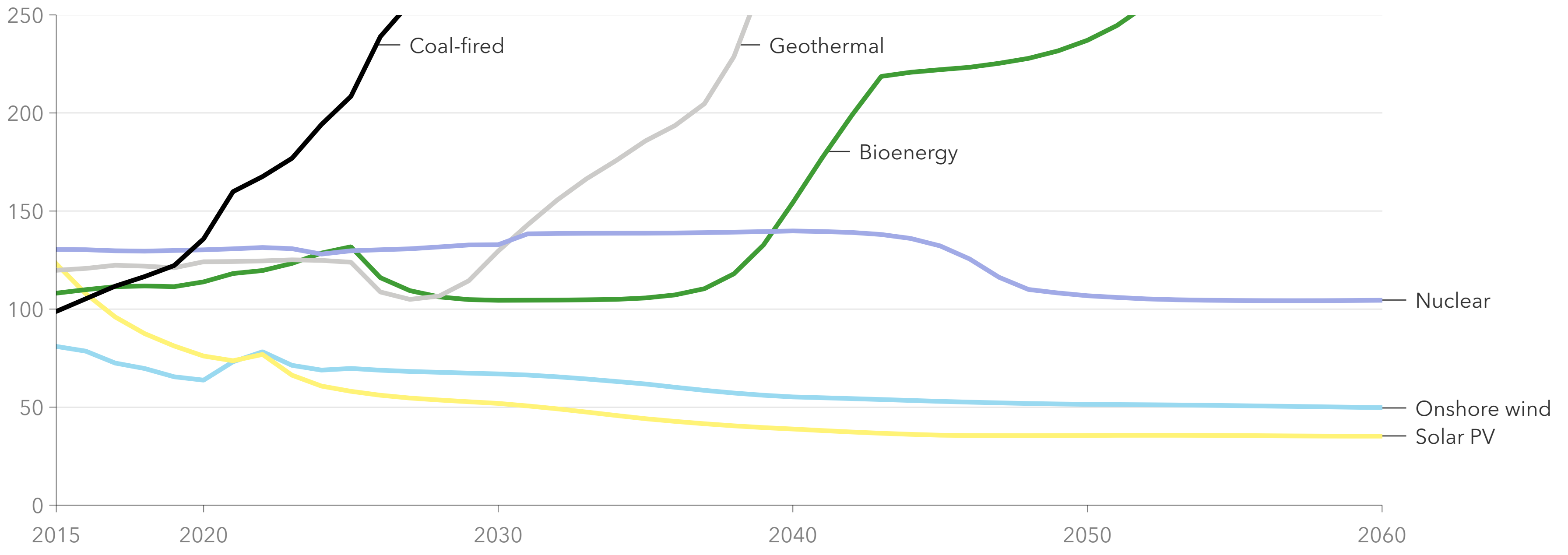


FIGURE 1.4 | Historical data source: GlobalData (2025) and DNV analysis

Photo by Werner Slocum, NREL 65600

1.4 CANADIAN POLICY IS LARGELY UNCHANGED

While US energy policy has undergone significant shifts, Canada's policy trajectory has been comparatively stable. Canadian policy has not been static since 2023 though; like any country, it has had to adapt to evolving market dynamics and geopolitical pressures. Areas of uncertainty remain as Canada has maintained or strengthened a core set of energy policies while other policies have experienced reversals or setbacks.

Canada's transition away from fossil fuels has been slow

Power generation by source (TWh/yr)

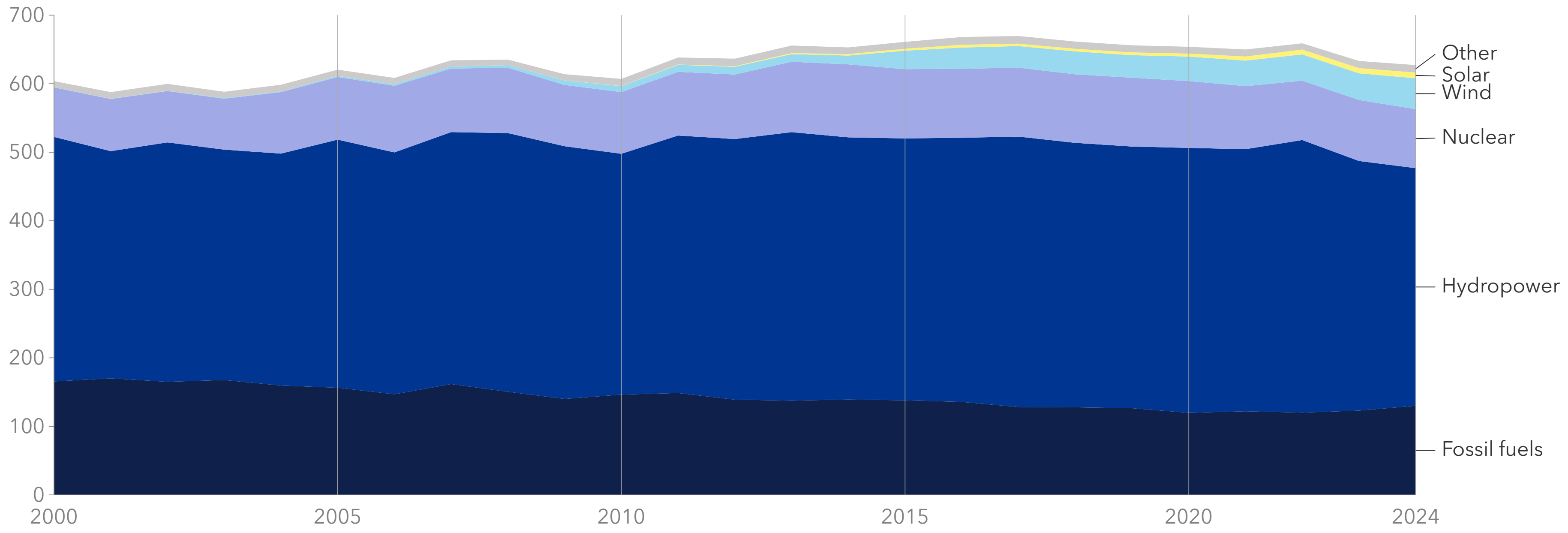


FIGURE 1.5 | Data source: Our World in Data (2025)

Where there is continuity in the Canadian energy policy:

- Federal commitment to **100% non-emitting electricity by 2035** (renewables, hydropower, nuclear) remains (Government of Canada, 2022)
- **Investment Tax Credits (ITCs) for clean technologies remain in effect**. This also includes ITCs for grid enhancements and expansion, and for storage technologies. Furthermore, new incentives were introduced in ITCs for capital costs of buildings employed in the EV supply chain.
- **Industrial carbon pricing** remains a core decarbonization tool (Government of Canada, 2025).
  - Despite rescinding the *Consumer Carbon Tax* in April 2025, industrial carbon pricing remains intact at the federal level.
  - The current price on emissions above threshold allowances is CAD 95/ton.
- The *C-5 One Canadian Economy Act*, reacting to US tariff policies, aims to further support the energy transition by **removing federal barriers to interprovincial trade**.
  - This bill expands federal powers to fast-track critical energy infrastructure projects, such as transmission lines, critical mineral mining, nuclear power development, and LNG infrastructure development.

Delays and reversals in Canadian energy policy include:

- **The suspension of the consumer carbon tax** in April 2025 by Canada's Prime Minister, Mark Carney, citing affordability concerns, is a step back.
- **Regional divergence of energy policy** from Canadian federal energy policy, with more regions choosing to delay or rescind policies that favor decarbonization.
  - British Columbia rescinded the consumer carbon tax earlier than the federal stoppage.
  - The province of Alberta enacted legislation hindering deployment of wind and solar in 2024.
  - The province of Alberta froze its industrial carbon price in May 2025, further diverging from federal policy.
- **EV policy setbacks** such as:
  - Consumer rebates for EVs expired and have not yet been renewed.
  - The *Zero-Emission Vehicle* mandate was delayed, partly due to the expiration of consumer rebates.
  - Delays and cancellations of EV manufacturing and supply chain installation in Canada.

Uncertainty remains in:

- Long-term stability of **industrial carbon pricing** under provincial pressure.
- Designing policies to attract data centers to Canada and the effectiveness of such policies.
- Direction of **US–Canada relations** and implications for energy and affiliated commodity trade.
  - Trade tariffs have placed a strain on steel exports from Canada to the US.

2 POLICY SEA CHANGE

2.0 HIGHLIGHTS

The current US administration has substantially changed federal policy by reversing many of the previous administrations' efforts. The new policies benefit oil and gas development and create headwinds for renewables. The new administration has created a general environment of uncertainty that affects even nonrenewable capital projects. The net effect of these policy changes is to slow the energy transition in North America by five to eight years.

The current administration is using the power of the executive branch to deny climate change, emphasize fossil fuel expansion and the continued use of coal, expand nuclear development, and deregulate. Executive actions have rolled back the federal carbon emission authority put in place by previous administrations and have attempted to curtail clean energy and climate initiatives at the state level. They have defunded and significantly cut jobs in federal agencies such as the Department of Energy. On the international stage, the present administration has used the threat of tariffs to hinder international efforts to combat climate change, for example scuttling the IMO's *Net-Zero Framework* in London in mid-October (Stallard, 2025).

The key piece of legislation passed by Congress so far in 2025 is the *One Big Beautiful Bill Act* (OBBBA). This act rolls back several energy industry incentives put in place in the *Inflation Reduction Act* (IRA), retains selective incentives, and adds incentives for oil and gas.

OBBBA provisions affecting energy developments

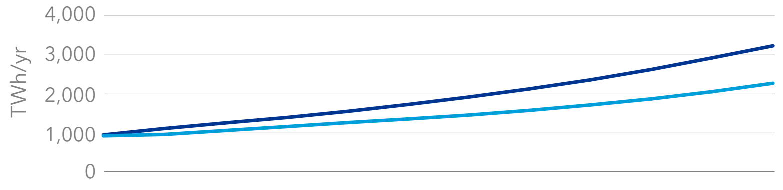
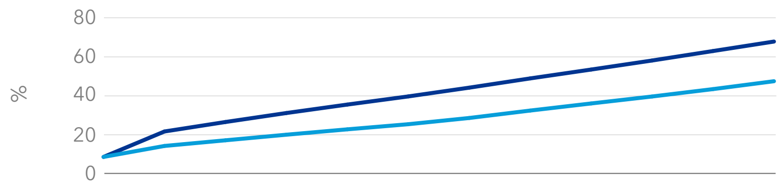
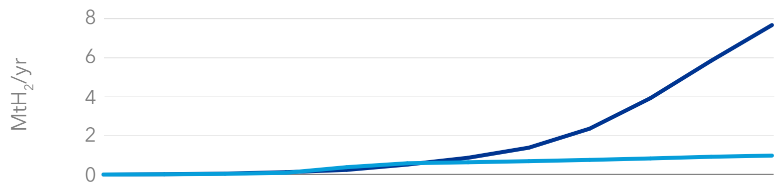
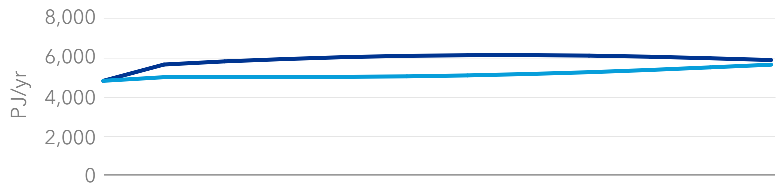
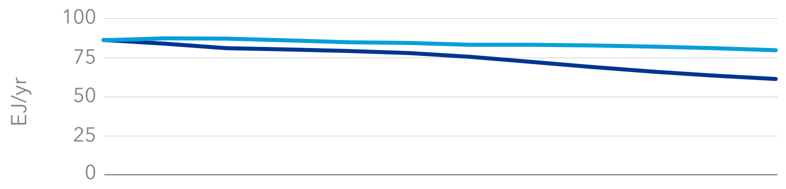
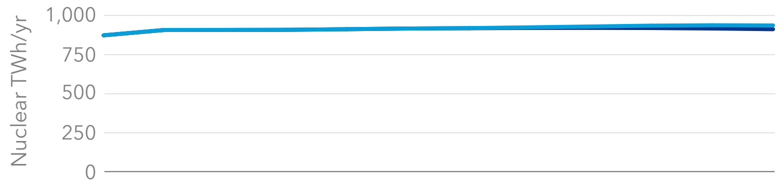
Technology	Effect of OBBBA on IRA incentives	Changes to our forecast (from 2024 to 2035) — 2024 — 2025
Solar and wind generation	↓ 48E and 45Y credits phased out after 2027; tightened FEOC rules	
Electric vehicles sales share	↓ 30D, 25E, 45W, and 30C credits phased out by 2026	
Green hydrogen production	↓ 45V credits phased out by 2028	
Biofuels supply	↓ 45Z credits capped and extended to 2029; feedstock rules tightened	
Oil and gas production	↑ Tax breaks, public land access, and regulatory rollbacks	
Energy storage, nuclear, geothermal, carbon capture	– No major changes	

TABLE 2.1 | Adapted from: Castaño et al. (2025)

2.1 POLICY CHANGES IN 2025

The energy transition in the US is unfolding within a dramatically altered policy environment. Donald Trump's return to the presidency in 2025 has brought a sharp reversal of many Biden-era climate and clean energy policies. This shift has not only redefined the federal government's stance on energy and climate, but has also introduced a level of policy instability that is unhelpful for CAPEX-heavy new energy investment. In this context, states have emerged as increasingly central actors in shaping the trajectory of the nation's energy future.

A new administration, a reversal in federal energy policy

The previous administration's energy and climate agenda was anchored in a commitment to decarbonization, clean energy innovation, and environmental justice. Signature legislative achievements such as the IRA and the *Bipartisan Infrastructure Law* (BIL) directed hundreds of billions of dollars toward renewable energy, EVs, grid modernization, and climate resilience. These policies were supported by a regulatory framework that tightened emissions standards and promoted clean technology deployment.

In contrast, the current administration has moved swiftly to undo many of these initiatives. The US has once again withdrawn from the *Paris Agreement*, and the White House has declared a national energy emergency, citing concerns over grid reliability and energy affordability. Offshore wind leases have been suspended and permits withdrawn, while key IRA clean energy funding streams have been paused, cancelled, or redirected, including cutbacks to Department of Energy programs affecting the prospects of less mature technologies (carbon capture and storage, hydrogen, and direct air capture). Funding for solar development has also been cut. Instead, the new administration is prioritizing domestic fossil fuels and nuclear while continuing previous support for batteries and geothermal.

Additionally, the current administration has proposed rescinding the US Environmental Protection Agency's *2009 Endangerment Finding*, arguing that it lacks statutory authority to regulate greenhouse gases for climate-change purposes, and thereby providing legal justification for rolling back fuel-efficiency and power-plant emission standards. Thus, US energy policy has moved from one favoring renewables, curtailing coal, and vacillating on gas and fracking, to a policy favoring baseload power, disfavoring renewables, and eliminating offshore wind.

In the US Congress, Republicans won control of both chambers in the 2024 election, but their narrow majorities and internal ideological divisions have constrained their ability to fully exercise power. Republicans had aimed to dismantle the IRA, but only partially succeeded – curtailing several clean energy tax credits through a sweeping budget bill (the OBBBA; see Table 2.1). Their lack of a filibuster-proof Senate majority also requires bipartisan support to pass broader energy legislation, including permitting reforms and regular annual budget appropriations.

Meanwhile, the US courts are being drawn into legal battles over executive authority, including the suspension of clean energy funding, the rollback of environmental regulations, and the cancellation of clean energy project permits. Energy-related lawsuits have escalated since January 2025 due to regulatory changes and climate policy conflicts, with lower courts addressing state laws and environmental claims against energy firms even as federal authorities seek to restrict such cases.

Uncertainty is the new certainty

What distinguishes the current federal approach is not merely its policy content but a way of wielding power that creates uncertainty. The current administration has given us regulatory ambiguity, vacillating trade policy, and abrupt reversals, all of which disrupt long-term planning across the energy sector. Permitting processes have been paused without clear timelines and executive orders have introduced sweeping changes with little advance notice.

This uncertainty has had paradoxical effects. While it has created headwinds for some clean energy developers, it has also galvanized others to accelerate investment to hedge against future policy shifts. Private capital continues to flow into renewables, driven by global market trends, investor pressure, and the declining cost of clean technologies. Despite rhetorical support from the administration, the uncertainty has also negatively affected the oil and gas sector. This uncertainty is likely to continue for the rest of the current administration, and will reshape risk calculations and investment strategies across the energy sector.

Contradictions in federal energy policy goals vs actions

The current administration has outlined three primary energy policy goals: ensuring a secure and abundant energy supply, maintaining affordability for consumers, and enhancing grid reliability. However, several recent federal actions appear to undermine these stated objectives, particularly in light of the rapidly evolving energy demand landscape.

One of the most significant contradictions lies in the administration's response to the surge in electricity demand, driven largely by the rapid growth of data centers. Despite this demand trajectory, some federal actions have not aligned with the infrastructure needs required to meet such a surge. The administration has suspended offshore wind projects and withdrawn transmission permits, two critical components for expanding clean energy generation and delivering power to high-demand regions. Federal actions have attempted to delay the planned retirement of existing infrastructure (e.g. coal-fired plants). Keeping legacy coal plants open may help with supply but undermines affordability, as they were slated for retirement due to high costs and cheaper alternatives. Rhetoric and policy have promoted the construction of new fossil, nuclear, and geothermal assets. However, constructing new power generation involves long lead times – either because of very long wait times for conventional equipment like natural gas turbines or because of technology immaturity in the case of new nuclear designs – which does little to address short-term load challenges.

The contradiction is further compounded by the rollback of clean energy incentives under the IRA. These incentives had begun to lower costs for consumers through tax credits for energy-efficiency upgrades and distributed solar. Their removal risks increasing energy costs over time, particularly as demand outpaces supply and utilities are forced to rely on more expensive or less efficient generation sources.

There are also countervailing forces in grid policies: with support for batteries, but opposition to transmission. The administration has declared a national energy emergency, citing risks to grid reliability, but has not advanced a comprehensive grid modernization strategy. Instead, the focus has shifted toward preserving legacy fossil infrastructure, which may not be capable of handling the dynamic loads (from seconds to hours or days) introduced by, for example, AI data centers. Different grid reliability strategies are needed to handle different time periods of change, from adding dispatchable power assets to improving demand flexibility.

Moreover, the administration's skepticism toward wind and solar – labeling them as unreliable – ignores both market trends and technological advancements. Intermittency challenges are increasingly being addressed through battery storage, demand-response programs, hybrid generation systems, and in the longer term, the expansion of transmission. Yet federal support for these solutions has waned, leaving states and private developers to fill the gap.

In sum, many of the federal government's current energy actions appear misaligned with its stated goals. The contradiction is most acute in the context of rising electricity demand, where policy decisions risk exacerbating supply shortages, increasing costs, and undermining reliability. Unless reconciled, these contradictions could hinder the US's ability to meet its economic and technological ambitions, particularly in sectors like AI and advanced manufacturing that depend on abundant, affordable, and reliable power.

States step up: A decentralized energy transition

In the face of federal retrenchment, states remain the primary laboratories of energy innovation. While the political landscape varies widely, a growing number of states are advancing ambitious clean energy agendas tailored to their unique economic and environmental contexts. Twenty-four states in the US Climate Alliance remain committed to their climate goals (Segal, 2025).

- As of October 2025, 17 states, Puerto Rico, and the District of Columbia have enacted laws requiring a shift to 100% carbon-free or renewable electricity by 2050 or sooner. Another five states have issued executive orders for 100% clean energy (Clean Energy States Alliance, 2024). Vermont recently joined by overriding a gubernatorial veto to pass its clean energy mandate, while New Jersey may follow as Governor Phil Murphy seeks to codify his executive order targeting 100% clean electricity by 2035.
- California remains a leader in both ambition and complexity. The state is grappling with high electricity prices, permitting bottlenecks, and grid constraints, yet continues to push forward with policies such as the *Pathways Initiative*, a regional electricity market proposal aimed at integrating western states into a more resilient grid.
- Texas presents a more nuanced picture: despite Republican leadership and strong fossil fuel interests, it has attracted over USD 62bn in clean energy investments since 2022, including projects in solar, wind, hydrogen, and carbon capture. Texas's regulatory framework regarding batteries has allowed a big increase in storage capacity. With 130 battery projects under construction and 234 operational, Texas shows how market forces can drive the energy transition even in conservative states.
- Other states are also making significant strides. Illinois has enacted reforms to streamline permitting for solar and wind projects, while New York and Massachusetts are investing heavily in upskilling workforces through clean energy training programs. In total, 48 states and Puerto Rico took nearly 400 actions related to power decarbonization in the second quarter of 2025 alone.

These efforts are not merely symbolic; they are backed by substantial capital. Since the passage of the IRA, over USD 321bn has been invested in clean energy projects across the US, with southern and western states – many of them Republican-led – receiving the lion's share. On a per capita basis, Wyoming, Nevada, and New Mexico have seen some of the highest levels of investment, underscoring the broad geographic reach of the energy transition.

Conclusion: A fragmented but forward-moving transition

The US energy transition is a fragmented, multi-level process shaped by divergent political ideologies and goals, market dynamics, and regional priorities. At the same time, nuclear and geothermal – and to a lesser extent, battery storage – are emerging as rare areas of bipartisan consensus that offer prospects for greater policy stability. While the current administration has introduced significant policy volatility, the underlying trajectory toward decarbonization in power systems (and other sectors) has substantially slowed but remains intact – driven by state leadership, private investment, and technological innovation.

In this environment, uncertainty is not merely a challenge; it is a defining feature of the policy landscape. For stakeholders, the imperative is to remain agile, informed, and engaged across multiple levels of governance. The energy transition is happening – but slower than before, and not from Washington alone.

2.2 TARIFFS

2025 has seen the highest average US tariff rates since 1935, far exceeding levels in recent decades. According to economic analyses, the overall average effective tariff rate was 15% at the end of October 2025 and reached a peak of 28% for a week in mid-April (Figure 2.1). Most industries, including the clean-energy industry in the US, depend heavily on imported goods and raw materials. Consequently, high tariffs raise costs for nearly every business, forcing companies to pay significantly more for the inputs they need to operate. For businesses unable to pass on these increased costs to consumers due to competitive pressures or price sensitivity, the direct result is reduced profit margins or even operating losses.

More importantly, the tariffs directly impact the energy transition by increasing capital costs, reducing access to materials, and inviting reciprocal negative trade actions on the part of US trade partners.

The evolution of US tariffs

Average US tariff rate on imports

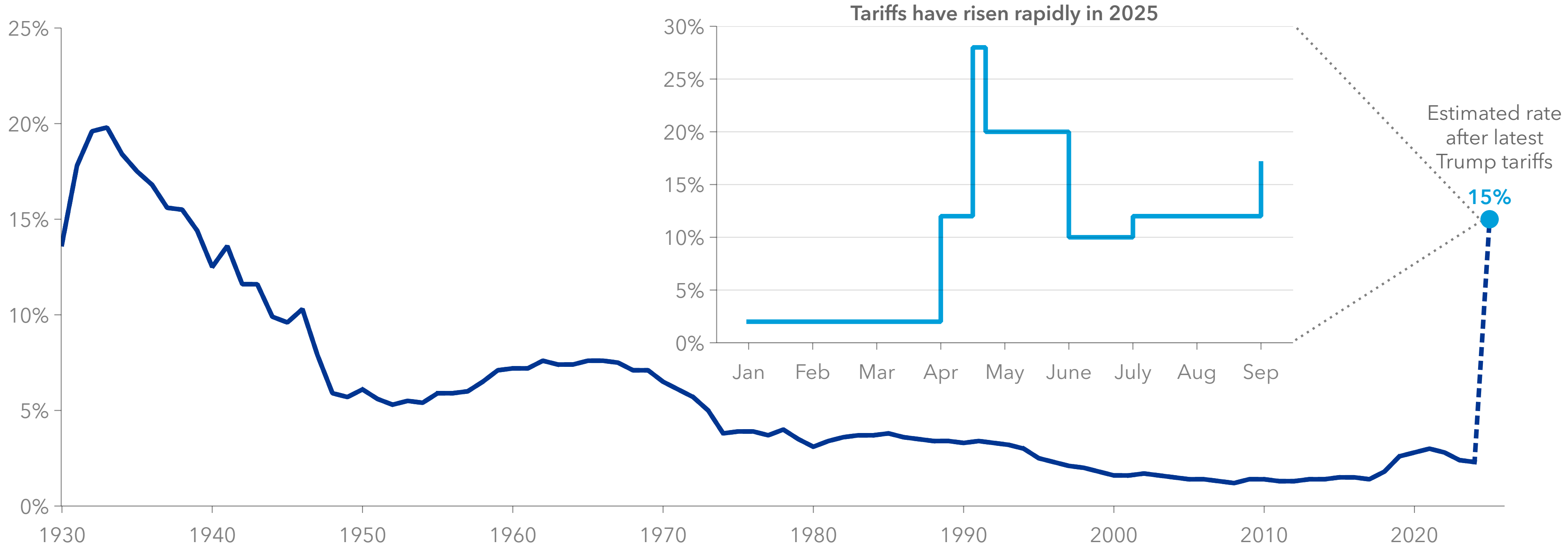


FIGURE 2.1 | Average tariff rate is calculated as a percentage of total import value.
Data source: US International Trade Commission (2024), The BudgetLab at Yale (2025)

Some specific tariff examples are:

- Steel, aluminum, and copper tariffs – the US has imposed imports tariffs of around 50% on these materials, which are critical for grid components like wires and transformers (Howland, 2025).
- Battery components and batteries – tariffs on batteries and their components are additive across the entire supply chain; the critical minerals used in batteries (such as lithium, cobalt, etc.) face an 'unfair competition' tariff; battery cells and packs from China face an additional tariff under Section 301 (Attarwala, 2024).
- Electric vehicles – In addition to the tariffs on EV batteries, finished EV imports from China face an additional 100% tariff, raising the price of imported EVs.
- Solar cells and modules – tariffs are additive across the solar panel supply chain from China under Section 301 for solar wafers and polysilicon (nearly finished or unfinished raw material), solar cells, and solar modules.
- China's retaliatory policies have included reciprocal tariffs, halting import of US fossil fuels, and restricting exports of critical minerals needed for battery manufacturing and other energy infrastructure projects.
- Moreover, the administration's frequent adjustments of tariff rates have introduced substantial uncertainty into the economic environment. This persistent unpredictability complicates decision making for companies and makes it difficult to plan for future expenses, supply chains, and pricing strategies (Andrade et al., 2025). Tariff uncertainty also complicates investment decisions (Gerring et al., 2025).

2.3 DECARBONIZATION IS LIKELY DELAYED FIVE TO EIGHT YEARS

The most significant consequence of the 2025 policy changes in North America – particularly in the US – is a marked slowdown in decarbonization. We now expect the region will emit nearly 600 Mt more energy-related CO_2 in 2050 than we forecast in last year's ETO (DNV, 2024). After 2040, the deviation or difference in energy-related CO_2 emissions does become narrower, signaling that the decarbonization is not reversed, but rather only delayed five to eight years.

Decarbonization is slower compared to last year's forecast

Energy-related CO_2 emissions ($GtCO_2$/yr)

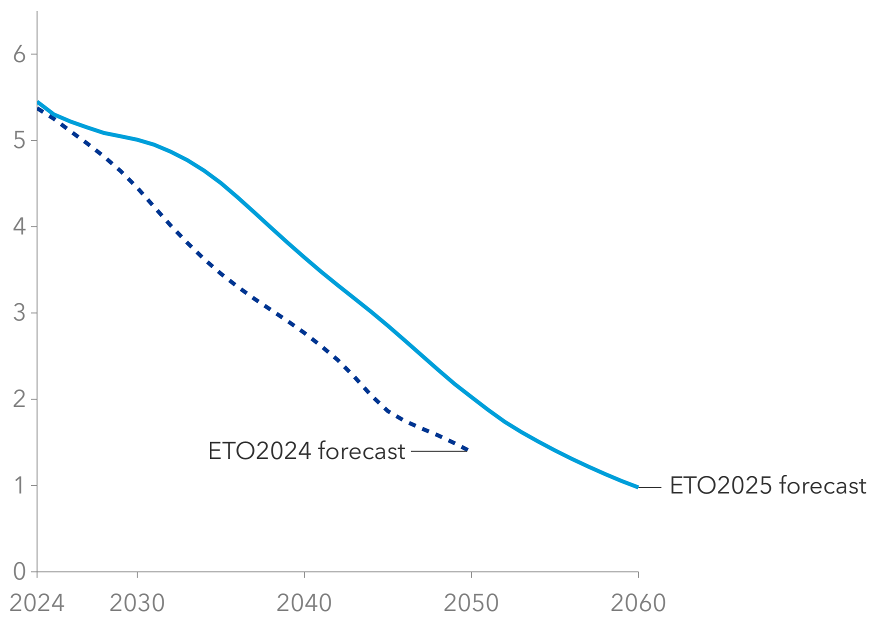


FIGURE 2.2 |

Overall, the 2025 policy shifts have significantly altered the emissions trajectory for North America from 2025 to 2050, reinforcing the reliance on fossil fuels and delaying progress toward long-term climate goals. The key drivers of this delayed decarbonization include:

- **Reduced policy support for renewables:** The withdrawal or early phaseout of incentives for wind and solar will slow project development and investment (Chapter 3, Chapter 6).

Transport and manufacturing are harder to decarbonize

Energy-related CO_2 emissions by sector ($GtCO_2$/yr)

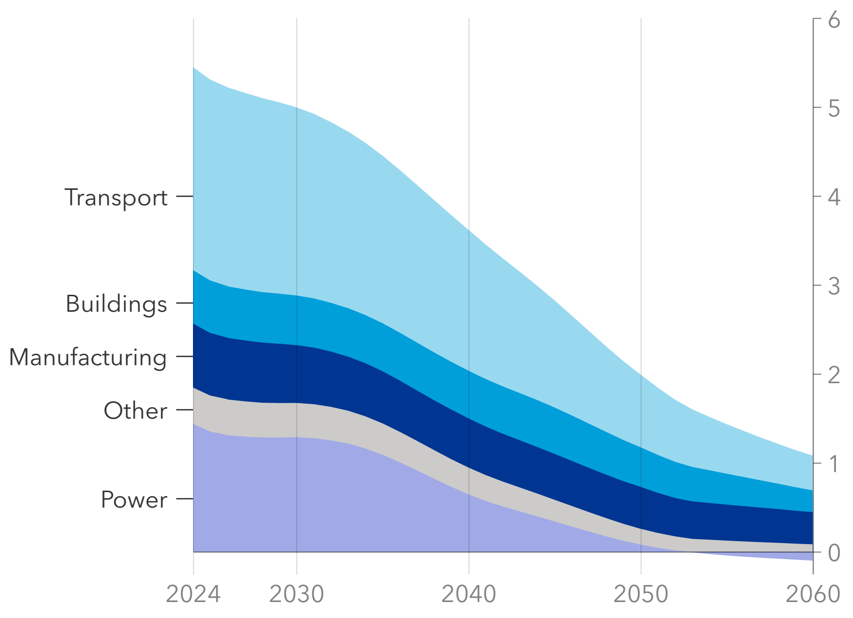


FIGURE 2.3 | Other includes H_2 production, energy sector own use, military, and agriculture energy demand. Manufacturing includes process emissions.

- **Higher technology costs:** Tariffs and FEOC provisions have increased the costs of solar, wind, and battery technologies, limiting deployment (Chapter 3).
- **Expanded fossil fuel incentives:** New fiscal support for oil and gas exploration will lead to greater production and availability of fossil fuels (Chapter 7).
- **Accelerating electricity demand:** Rapid load growth, combined with diminished support for renewables, will prolong the dominance of natural gas in the power sector (Chapter 4).
- **Weakened EV policies:** The rollback of EV incentives will sustain higher oil consumption in the transport sector (Chapter 4).
- **Grid infrastructure constraints:** Interconnection and transmission bottlenecks have delayed the integration of new solar and wind capacity, contributing to supply shortfalls and increased fossil generation (Chapter 4, Chapter 10).
- **Curtailment of green hydrogen support:** The early withdrawal of incentives for green hydrogen will slow decarbonization progress in hard-to-decarbonize sectors, such as high-temperature industrial processes (Chapter 9).

Cumulatively, between 2024 and 2050, this delay in decarbonization represents an additional 19 $GtCO_2$ of emissions – an increase with significant implications for the global carbon budget and temperature trajectory. Every gigaton of CO_2 avoided helps limit warming and deliver tangible benefits in reduced climate damages, improved health outcomes, and strengthened ecosystem and economic resilience.

The added emissions therefore not only delay progress toward global temperature stabilization, but also underscore how present-day policy reversals can have enduring effects on climate mitigation and long-term sustainability, not just for North America but globally.

We project that by 2040, North America's energy-related emissions will fall from 5.5 $GtCO_2$/yr to 3.6 $GtCO_2$/yr. By 2050, emissions will to drop to 2 $GtCO_2$/yr after accounting for carbon capture and storage (CCS), and by 2060 the remaining emissions drop to just under 1 $GtCO_2$/yr.

The power sector drives most of these reductions; rapid growth in solar and wind generation, complemented by bioenergy with carbon capture and storage (BECCS), means the sector can achieve net-negative emissions by 2060. In contrast, transport, manufacturing (including both energy and process emissions), and buildings remain more challenging to decarbonize.

By 2060, transport will account for roughly 40% of residual emissions, with aviation representing almost two thirds of transport emissions. Buildings contribute about 25%, largely due to slower electrification in the commercial segment. Manufacturing will still represent about 20%, reflecting the delayed adoption of hydrogen in high-temperature processes and the continued use of natural gas.

Photo by, Joe DelNero, NREL 90941

3 'INVISIBLE' HAND OF THE MARKET

3.1 INTERPLAY OF LEVELIZED COSTS AND DEMAND GROWTH

Lowest cost

Renewables have a significantly lower levelized cost of electricity (LCOE) than fossil fuels. Therefore, utilities and developers tend to choose renewables for new generation and buyers seek cheaper long-term contracts from those sources.

- Power capacity developers prioritize projects with the lowest LCOE because these can secure financing more easily and promise better returns (Roscoe, 2025).
- Utilities and large buyers look for long-term power purchase agreements (PPAs) with the lowest LCOE, making wind and solar preferred options for stable, affordable supply (Bruck et al., 2018).
- LCOE is used in negotiations to set contract prices; a project with a higher LCOE will struggle to win PPAs or forward contracts unless the buyer has no cheaper alternative (Rodriguez, 2022).
- Because renewables have lower operational costs (no fuel cost), their PPA prices are more predictable, further attracting buyers concerned about future fuel price spikes in natural gas or coal (Ramos et al., 2025).

'All of the above'

Electricity demand in North America is so high that no single type of generation can be deployed in enough volume to meet it; all deployable, grid-connectable power technologies are needed. As a result, North America is moving from a monolithic 'technology-dependent' approach to one that is 'all of the above'.

Availability is becoming as strong a capacity decision driver as cost and the other practical considerations described above and to the right. Wind and solar are the cheapest and most immediately available sources of electricity, but even without policy headwinds, they have not been able to keep up with the pace of demand on their own. As a result, data center developers are turning to more expensive sources of electricity. This includes gas turbines and solar+storage. However, turbine supply chains are already stretched, with backorders extending into the early 2030s (RMI, 2025). We expect solar+storage costs to remain elevated through to 2040 (Chapter 1), and gas turbine costs will likely rise – potentially matching or exceeding the LCOE spreads shown in Figure 3.1 (Shenk, 2025). In response, operators are extending the service lives of existing coal and nuclear plants. As these higher-cost sources are used to meet the surging electricity demand from data centers, overall electricity prices continue to climb.

Beyond LCOE

- System planners also consider grid reliability, intermittency, and integration costs. Sometimes a low-LCOE source like solar or onshore wind may require complementary investments (e.g. storage) that increase costs (Clean Air Task Force, 2025).
- While LCOE is the primary economic driver, non-price factors such as policy, reliability, and existing fleet characteristics also affect decisions, but these cannot offset large LCOE differences in the long run (Lazard, 2025).

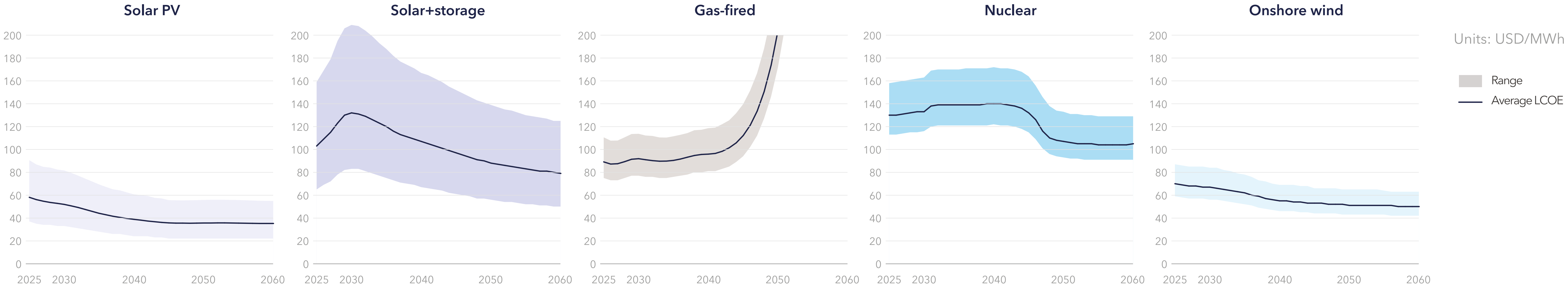


FIGURE 3.1 |

Solar costs **62%** and onshore wind costs **75%** as much as gas-fired electricity

One foot on the brake and one on the gas

The North American energy investing and financing landscape is experiencing a push-pull dynamic. A policy whirlwind and continued higher interest rates are applying the brakes to the energy transition and steering capital towards safer, more reliable assets. At the same time, the explosive, unrelenting electricity demand from AI and electrification is flooring the accelerator, demanding massive investment, and creating unprecedented opportunity for those capable of delivering power.

The foot on the brake: a flight to quality in a high-cost world

Expensive capital is the primary force compelling caution. The persistent higher cost of financing demands higher returns and risk protection, such as longer-term offtake contracts, to make deals feasible. This economic pressure has triggered a distinct 'flight to quality' within the investment community.

The US policy-driven uncertainty engulfing energy markets is adding to this pressure. Tariffs, executive actions, and tax credit repeals in the OBBBA have shortened timelines and added compliance burdens.

While short-term (2025–2030) build rates for utility-scale solar and onshore wind may take a hit as the market resets, the fundamentals are still compelling. On an unsubsidized basis, wind and solar remain among the lowest-cost options for new energy (Chapter 1). Tax credit phaseouts are a headwind, but the market will adjust. When credits fade, fewer tax equity compliance requirements could open up participation through simpler, globally accepted financing structures.

For now, the net effect is caution in energy investments (particularly renewables) and capital flowing towards the safer bets: projects that are de-risked through secured interconnection, credible offtake, and lower execution risk. In practice, US buyers are doubling down and concentrating capital into operating platforms and contracted projects, while global players are re-evaluating their commitment to the US market until policy clarity and cost visibility improve.

This dynamic has shifted bargaining power to sellers of de-risked projects and platforms, with near-ready contracted assets and diversified portfolios, including dispatchability (Chapter 6) commanding premium valuations. We have already seen the 2025 capital stack dominated by single 'megadeals'. Examples include Constellation's approximately USD 26.6bn acquisition of Calpine and Blackstone's purchase for around USD 11.5bn of TXNM Energy, underscoring buyer preference for scale and cash-flowing platforms (PwC, 2025; KPMG, 2025). Global giant EDF is meanwhile exploring a sale of 50% of its North American renewables unit (Nair et al., 2025), indicating that some global companies are redirecting capital back to 'safer' home markets.

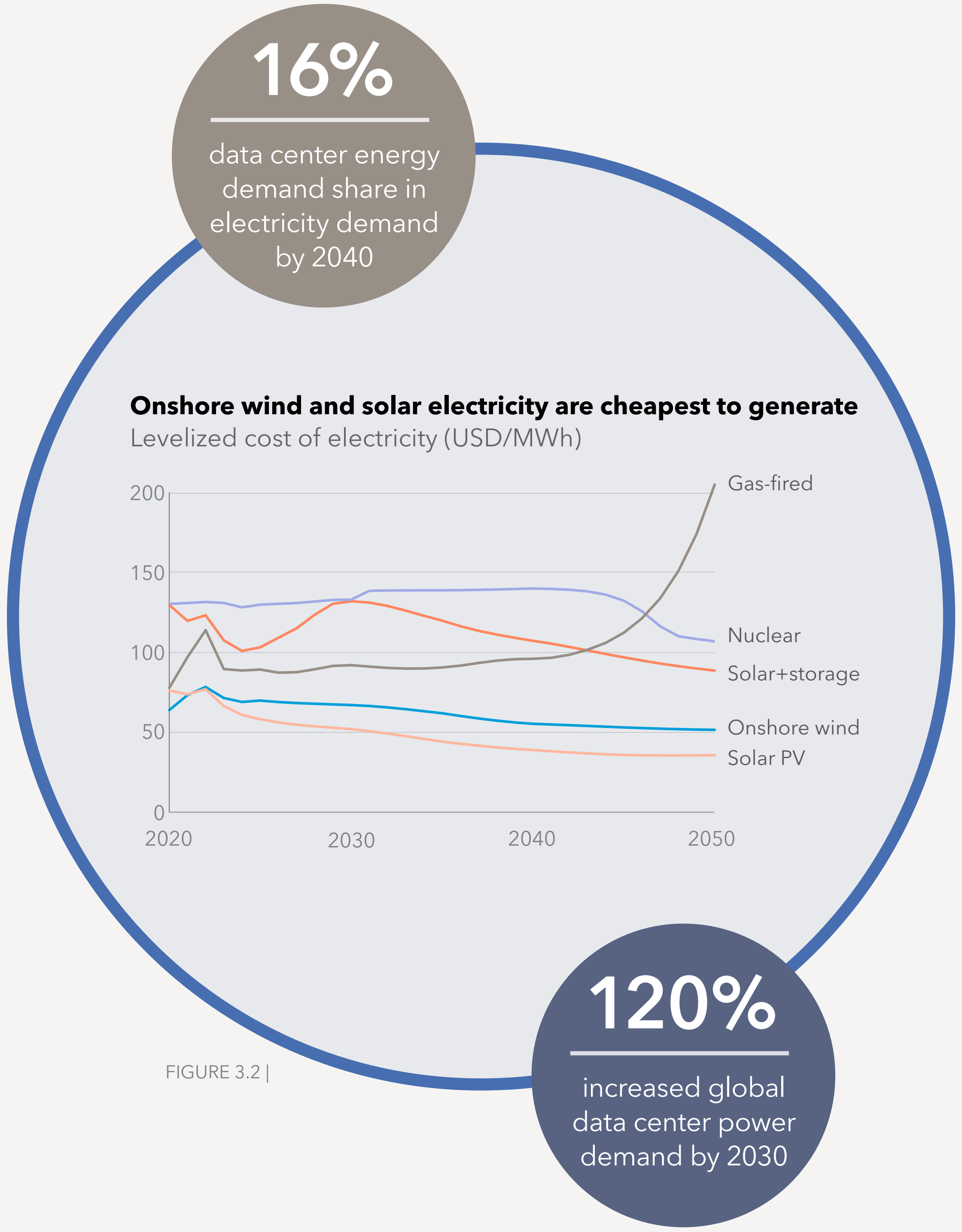


FIGURE 3.2 |

The foot on the gas: the unstoppable force of AI

Investors are encountering an era of unprecedented demand growth from AI that is reshaping energy investment. The scale is staggering: we forecast global data center power demand will soar 120% by 2030 (DNV, 2025). These computing loads could account for around 16% of all North American electricity use by 2040 (Chapter 4). With this surge comes massive capital requirements: nearly USD 7trn in global CAPEX for data centers needed by 2030 to meet the demand (McKinsey & Company, 2025).

This need is creating a powerful new investment magnet, pulling capital toward hybrid solutions that can provide the firm, dependable power that data centers prefer. The most attractive assets pair low-cost solar with battery storage and natural-gas generation, often co-located at the point of demand. In this way, the market's cautious flight to quality and the explosive demand for reliability are converging to create a clear path forward for integrated, dispatchable power platforms.

Power is the immediate constraint, driving a short-term urgency to seize the opportunity when it comes to AI development (Reuters, 2024). We have already seen developers actively exploring strategies to co-locate or convert renewables projects with firming resources to serve this burgeoning market. Utilities, meanwhile, are buying core generation and divesting non-core to fund record CAPEX for data-center load, part of a 2025 'dealmaking spree' tied to reliability and growth (Reuters, 2025).

In parallel, investors are gravitating to where the AI and cloud services market signals are strongest. They are balancing portfolios by selectively injecting more risk to command higher returns. These high-risk, high-reward positions often come through investing in the next wave of advanced technologies.

3.2 SUPPLY CHAIN CHALLENGES

North America's supply chain is undergoing rapid transformation, driven by clean energy investments, geopolitical pressures, and rising domestic demand. Both the US and Canada are pushing to secure their energy supply chains through reshoring, diversification, and federal support. However, supply chain challenges persist, and success hinges on stable policy, stream-lined permitting, and workforce development.

We forecast North American peak demand will rise by 80 GW between 2025 and 2030, while only 22 GW of new dispatchable generation is currently planned in the US (DOE, 2025). Ongoing supply chain constraints are likely to further delay these additions. With high demand and constrained supply, the price of electricity will increase.

Raw materials and basic components

Critical minerals and rare earth elements remain supply-constrained, with heavy reliance on imports (Nassar et al., 2025), and long lead times for acquiring power generation equipment and grid infrastructure like transformers and HVDC systems (Wood Mackenzie, 2025).

Despite producing around 60 minerals and critical materials and ranking among the world's top ten producers of cobalt, graphite, lithium, and nickel, Canada contributes less than 5% of global mine production for each of these key minerals. The country currently lacks sufficient processing capacity to meet its own critical material demand (Lemelin-Bellerose, 2025) and continues to face bottlenecks in expanding mine capacity and establishing new processing facilities. Similarly, despite having ample uranium processing capacity, Canada lacks fuel fabrication facilities for its SMRs (Chapter 8).

Manufacturing capacity

Under the *Inflation Reduction Act* (IRA), clean energy manufacturing had surged with investment in US-based production of solar panels, batteries, and EV components tripling between 2022 and 2025 (Clean Investment Monitor, 2025). More recently however, tariff escalations and policy uncertainty have led to project cancellations (Lavelle, 2025).

Labor and skills mismatch

The US faces severe workforce gaps. It is short more than 300,000 skilled clean energy workers, particularly in HVAC, electrical trades, hydrogen systems, and CCS (Redmond, 2025). Canada faces similar challenges, even in its well-established oil and gas industry (Williams, 2024). Staffing shortages, exacerbated by recent US federal agency job cuts, are increasing permitting delays (Bikales, 2025). Upskilling has been slow to scale and engineer shortages have affected the energy industry for decades. Recent immigration barriers erected by new federal administrations will likely make it more difficult to attract this expertise from the rest of the world (Hooper and Huang, 2024).

Intraregional trade tensions

Trade tensions between Canada and the US are beginning to affect the energy supply chain locally. In response to proposed tariffs on Canadian goods by the US, Canadian officials are considering retaliatory measures, including restricting electricity exports, and possibly critical minerals (Baskaran, 2025). As Canada's energy strategy takes shape, there is likely to be an acceleration of diversification efforts and a reduction of reliance on the US.

End-of-life management and circular economy

North America's recycling infrastructure still lags behind the growing demand to manage end-of-life renewable energy components, with limited capacity for solar panels, lithium-ion batteries, and wind turbine blades. As the first generation of renewables (those installed in the 2000s) nears retirement, we expect a surge in waste that will require urgent, scalable solutions. Emerging technologies, such as direct lithium extraction and repurposing wind blades, present a promising opportunity to build a circular economy while creating local jobs.

North America remains highly dependent on imports for critical minerals and basic components. Tariff escalations have made these imports more expensive while policy reversals and uncertainty have delayed investment in domestic production.

3.3 STATE OF THE BATTERIES MARKET

North American battery storage is here to stay. Despite short-term challenges from supply chains, tariffs, and costs, falling lithium-ion (Li-ion) prices and proven storage benefits ensure continued deployment across the power sector.

Global rise of batteries

The rapid rise of global battery manufacturing capacity is reshaping power-sector economics at a pace that surprises even optimistic observers. Li-ion cell production, initially driven by the EV segment, has expanded so rapidly that stationary energy-storage projects now benefit from a supply base measured in hundreds of gigawatt-hours per year. This scale-up has driven down prices more sharply than anticipated, triggering a positive feedback loop: lower costs enable more projects (and cheaper EVs), which in turn justify further manufacturing investment.

Battery costs drop below Greater China by the late 2030s

Li-ion battery capital costs (USD/MWh)

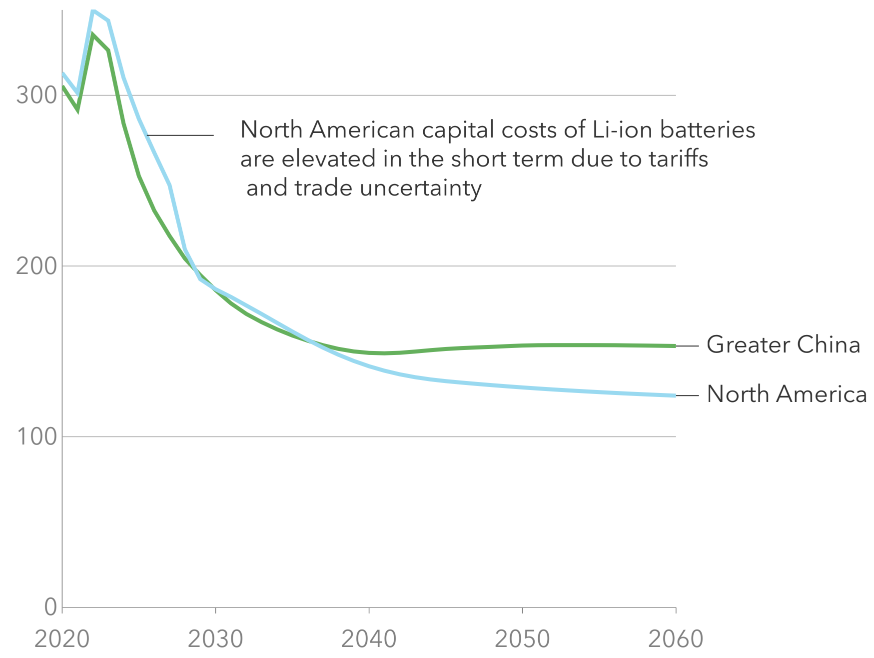


FIGURE 3.3 |

Turbulence in North America

In the short term, however, the North American market is experiencing turbulence. US tariffs on cell and module imports from Chinese and other foreign entities of concern create bottlenecks at almost every step of the supply chain (Troutman Pepper Locke, 2025), and uneven interconnection processes are driving up some project costs.

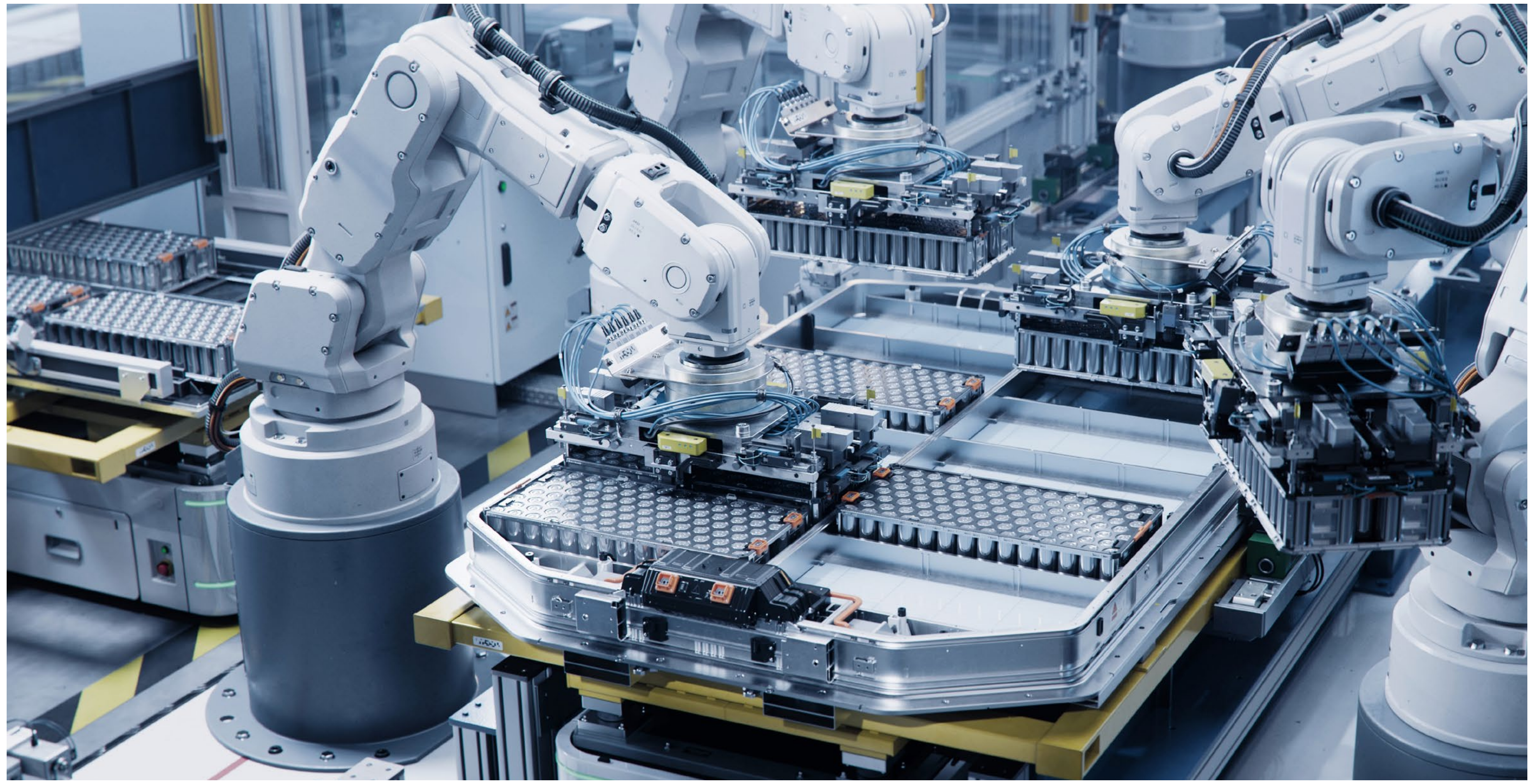
The future of battery manufacturing in the US is uncertain, with several projects cancelled or aban-doned by the cessation of clean energy technology manufacturing tax credits (Magill, 2025). The future of several such plants in Canada is similarly uncertain, with Honda postponing its plans for an EV battery plant for two years (CBC News, 2025).

In the near term, US onshoring policies may limit access to low-cost imports, constraining storage deployment that might otherwise occur. Over the longer term, the outlook is more favorable: by the early 2030s, local production could meet a substantial share of demand, capturing IRA incentives while reducing exposure to global supply shocks. North American developers face fluctuating module prices and uncertainty in delivery schedules. Policy incentives could help offset these pressures through tax credits and domestic content adders. However, with most gigafactories still under construction, developers remain reliant on imported cells.

At the same time, learning curves are improving for both Li-ion and emerging battery chemistries such as sodium-ion and iron-air. While these alternatives trail Li-ion batteries' scale advantage, targeted incentives could accelerate their commercialization.

Overall, storage is shifting from a niche grid tool to a mainstream investment class. Despite near-term volatility, the long-term trajectory for North America points to cheaper, more abundant storage supporting decarbonization.

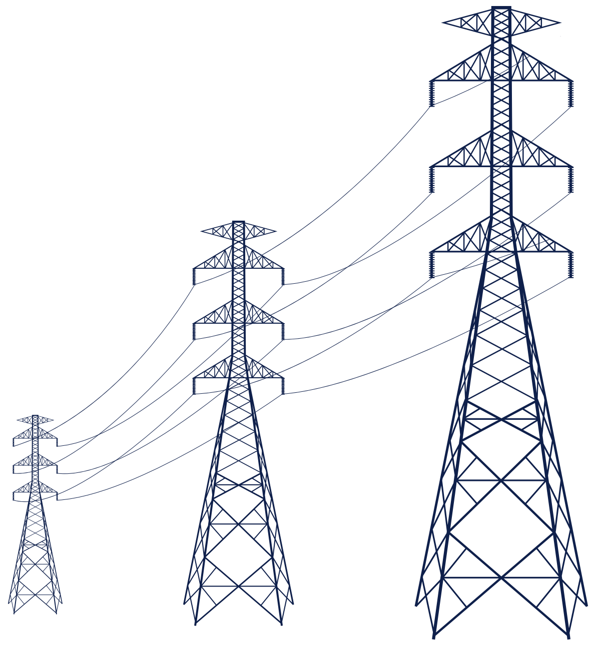
> As battery costs sharply decline, their use as a dispatchable resource will increase.



4 WATTS UP: ELECTRICITY DEMAND GROWTH

4.0 HIGHLIGHTS

After almost two decades of stasis, North American electricity demand is growing steeply. Data centers are largely responsible for this growth in the short term. EVs begin representing a substantial portion of electricity use starting in 2040, a delay of approximately 10 years from the previous ETO because of policy changes. At the same time, electricity supply growth is constrained until 2040. Therefore, we forecast electricity prices to increase through the 2030s.



We forecast that electricity demand for hyperscaler data centers will double in the next five years. Most of the electricity demand growth through 2060 will be from data centers. There are counteracting forces at play within our models. While improved algorithms show promise to reduce energy needs, modeling ever-growing data sets increases them. Data centers can become massive strains on nearby communities and ecosystems, and attention to more sustainable practices is growing.

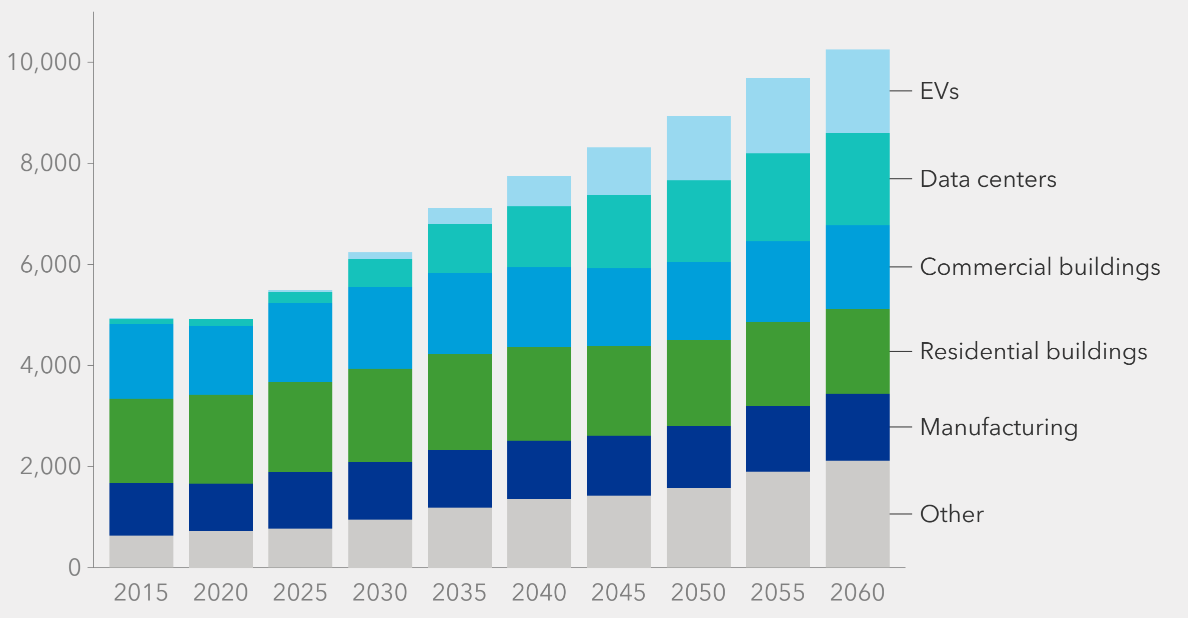
We also predict that transportation electrification will become a major source of electricity demand growth. However, policy changes in 2025 have delayed the transportation transition and EVs do not substantially affect demand until the late 2030s.

Industrial load growth and electricity demand from buildings do not change much through to 2060.

These demand increases occur during a period where supply expansion is highly constrained. Until these constraints (including grid de-bottlenecking, are alleviated), we expect the demand increases to contribute to increasing electricity prices.

Data centers and EVs represent most of the increase in electricity use

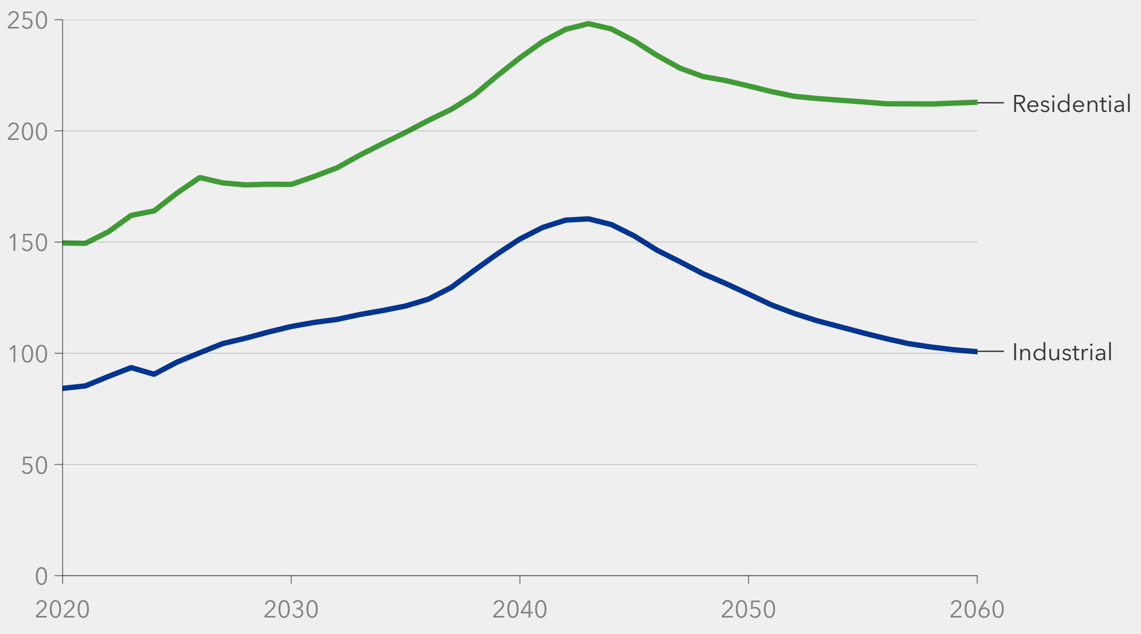
Electricity demand by segment (TWh/yr)



Historical data source: IEA WEB (2025)

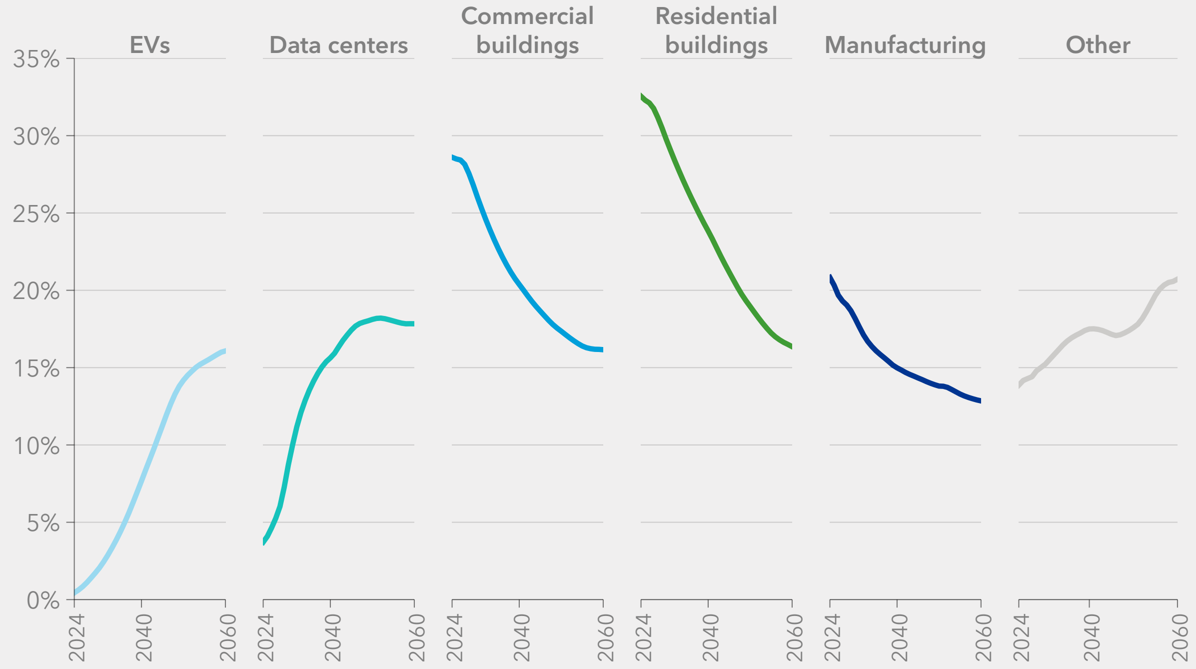
Electricity prices increase in the near-term

Average end-use electricity prices (USD/MWh)



Manufacturing load reduces its share in electricity demand

Share in electricity demand



4.1 HUNGRY HUNGRY HYPERSCALERS

We forecast that data centers will drive most of the electricity demand growth in the short term and up to 2060.

Data center electricity use accelerates through early 2030s

Data center electricity use (TWh/yr)

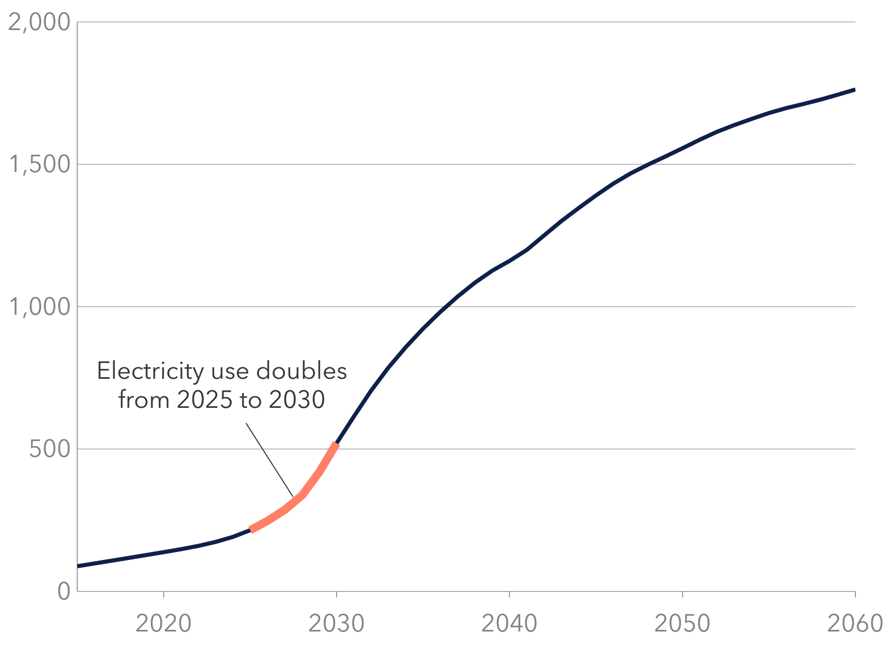


FIGURE 4.1 | Historical data source: IEA WEB (2025)

1 Strain on physical assets (generation and grid)

AI-driven demand is already colliding with a grid built for incremental growth. Unlike past periods of slow, steady expansion, today's electricity demand arrives in large, concentrated waves that strain physical infrastructure, business models, and the regulatory framework. In less than three years, data center electricity consumption has doubled from 103 TWh to over 200 TWh annually, with projections indicating another doubling by 2030. This trajectory requires an estimated 75 GW of new capacity by 2030 – equivalent to about 6% of current US grid capacity. By 2040, data centers will consume approximately 1,200 TWh of electricity annually, representing 16% of all electricity use in North America.

Data centers represent a new class of electricity demand that challenges traditional utility and market assumptions in several ways:

- **Scale of individual facilities:** Data centers now routinely reach 250 MW, 10 times historical averages of 25 MW, and often house hundreds of thousands of GPUs. This is equivalent to the peak demand of an entire city of approximately 200,000 people.
- **Short-term immutable load profiles:** Unlike conventional industrial loads, current data center operators prefer the ability to operate at near-full capacity 24/7 so they can quickly deliver queries to users during the inference phase (see Fact Box on page 28). They have deep pockets and consider latency a greater priority than electricity costs. This makes their demand largely non-price-responsive, treating power as a fixed operational cost rather than a variable input.
- **Emerging load flexibility:** There are early signs that data center operators are still capable of load flexibility. Examples of adaptability include Google's regional load-shifting to align with renewable availability and EPRI's DCFLEX initiative exploring demand response. Even small flexibility from this massive load could significantly benefit grid stability and clean energy integration.

In addition to load issues, there are key physical constraints, including:

- **Geographic concentration:** 80% of US data center demand is concentrated in just 15 states, with Virginia alone hosting approximately 35% of global hyperscale capacity (EPRI, 2024). This creates intense local stress on transmission and distribution systems.
- **Interconnection delays:** Grid interconnection queues now stretch for years, prompting some data center operators to bypass utilities entirely by using behind-the-meter (BTM) generation. In 2024, less than 1% of the electricity consumed by commercial and industrial buildings in North America was self-generated. By 2030, we forecast data center self-generated electricity to rise to almost 4%, driven by the adoption of BTM solar and battery systems.
- **Transmission bottlenecks:** The US Department of Energy (DOE) estimates interregional transfer capacity may need to grow by up to 412% by 2040, but new high-voltage lines take 10 to 20 years to permit and build.

Over the next several decades, rapid electricity demand growth from hyperscaler data centers will put enormous strain on physical assets, business models, and regulations.

2 Strain on business models

The growth of data center electricity demand has prompted a shift in utility planning and power systems operations.

- **Electricity costs are increasing rapidly:** In PJM, the US's largest wholesale market, data center demand has become a major driver of both infrastructure investment and rising resource clearing prices in the base residual auction (PJM, 2025):
  - 2024/25: USD 28.92/MW-day (USD 2.2bn total)
  - 2025/26: USD 269.92/MW-day (USD 14.7bn total)
  - 2026/27: USD 329.17/MW-day (USD 16.1bn total)

  New load is quickly reshaping the wholesale market dynamics; these increases translate into 10 to 20% higher bills for customers across the region.

- **Utilities are revising large load forecasts**, such as Georgia utilities from 400 MW in 2022 to 8,500 MW in 2025 (Walton, 2025), nearly 80% of the state's peak demand, mostly due to data centers. This forces utilities to rethink long-term resource planning and capital deployment.

- **Utilities are deferring coal plant retirements,** despite the fact they are losing money and harming decarbonization goals (Lavelle and Klein, 2025).

Current developments signal a shift toward parallel, self-managed energy systems that bypass traditional grid expansion timelines. With access to vast capital, hyperscalers are increasingly developing their own generation and interconnections, reducing reliance on utilities and altering the traditional utility-customer relationship.

- **Distributed generation growth:** More data center cogeneration projects were announced in 2024 than in the prior four years combined.

- **On-site generation investments:** One operator, Vantage Data Centers, is spending over USD 1bn annually on gas-fired generation to support a 1.4 GW facility in West Texas.

3 Strain on policy

These dynamics highlight a central tension: as hyperscaler operators increasingly develop their own dedicated power resources while continuing to rely on shared grid infrastructure, the question of who pays – and who benefits – emerges as one of the defining policy challenges of the data center era. Addressing this tension will require regulatory reforms that reconsider how costs are allocated, how new infrastructure is permitted, and how the benefits of growth are distributed across the grid. The pace of data center growth has triggered a wave of reactive and experimental policy measures:

- **Federal intervention:** In July 2025, an Executive Order designated 16 priority sites for AI data centers, accelerating permitting and infrastructure coordination for the stated reason of supporting national competitiveness.

- **Cost allocation conflicts:** Capacity prices have skyrocketed in PJM. These increases are passed on to all ratepayers, including those in states like Maryland and West Virginia, which see limited economic benefit from data center growth (PJM, 2025). This raises equity concerns about who pays for infrastructure serving concentrated, private-sector loads.

- **Some states have enacted policies to protect the grid from exploitation.** Ohio, Oregon, and Indiana have introduced 'minimum take' provisions that reduce cost-shifting risks by requiring large data centers to pay for most of their reserved capacity (Gibson Dunn, 2025).

- **Other states have enacted policies designed to attract data centers.** Mississippi, Kentucky, and Nevada have proposed tax changes designed to benefit and attract large data centers (Gibson Dunn, 2025).

> An increasing number of states are enacting regulations to reduce risks that large load additions such as those from data centers pose to the rest of the energy system.

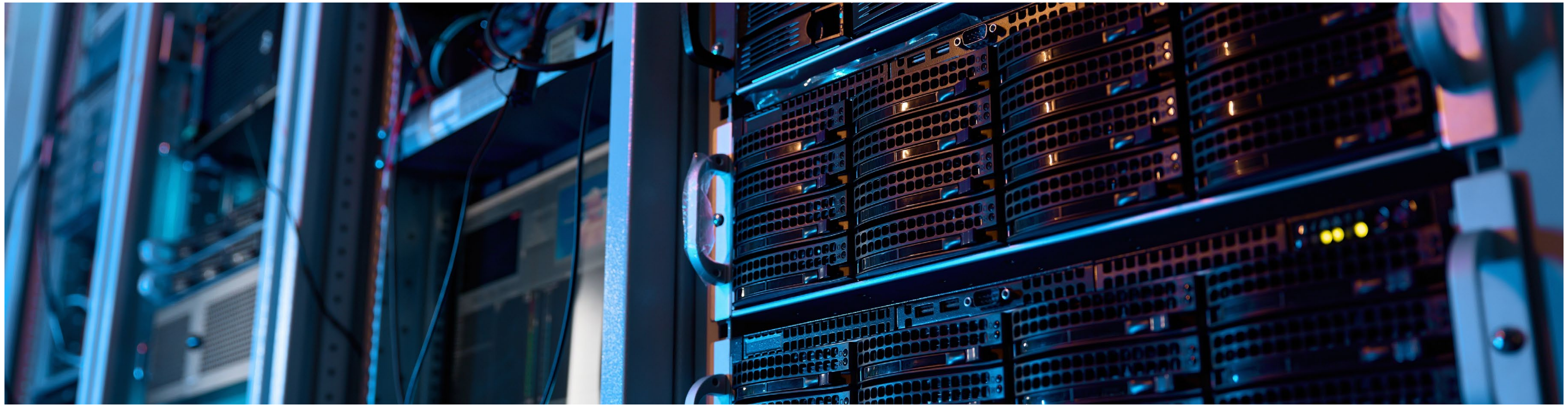
How data centers use electricity

AI's electricity demand is not a temporary spike but a permanent, concentrated load that challenges traditional grid planning. It unfolds in three phases:

1. **Training:** A one-time, electricity-intensive process (e.g. GPT-3 used approximately 1.3 GWh, GPT-4 used about 50 GWh (O'Donnell & Crownhart, 2025)) that unfolds over days or weeks, reinforces localized grid stress, and is concentrated in major data center hubs like northern Virginia.

2. **Fine-tuning:** Further training a pre-trained model on a smaller, task-specific dataset. While less intensive than training mode, it is ongoig and locks in inflexible demand as AI workloads resist interruption due to performance risks.

3. **Inference:** The dominant long-term load, running continuously to serve users. Each query uses a relatively small amount of electricity – around 0.002 kWh for modestly complex models (O'Donnell & Crownhart, 2025). However, these queries can number in the billions per day. As of mid-2025, ChatGPT was processing 2.6 billion queries daily (Chatterji et al., 2025), which amounts to approximately 5 GWh per day. Driven by strict latency requirements, it behaves like baseload power – largely non-responsive to price or grid conditions.



Despite this rigidity, flexibility pathways exist, including geographic load shifting, model optimization (e.g. pruning, dynamic batching), and tiered architectures that use smaller models for routine tasks.

Compounding the challenge, as models get more complex, all three phases use more electricity and rapid model iteration (e.g. GPT-3.5 to GPT-4 in 4 months; Grok 3 to 4 in 5 months) forces repeated training cycles.

As AI models become more complex, energy needs in all phases increase.

Training

Massively parallel GPU operations concentrated in a few hyperscale hubs, locking in local grid demand for days or weeks.

- GPT 4: about 50 GWh

Fine-tuning

Dense models are fine-tuned occasionally. Modular mixture-of-experts (MoE) designs invite repeated fine-tunings across many domains. Lower energy intensity than training.

Inference

The dominant mode. Supports billions of queries around the clock. Current service agreements treat this load more like baseline, but in practice, query volume follows human activity patterns.

- ChatGPT: about 5 GWh/day

Rapid iteration

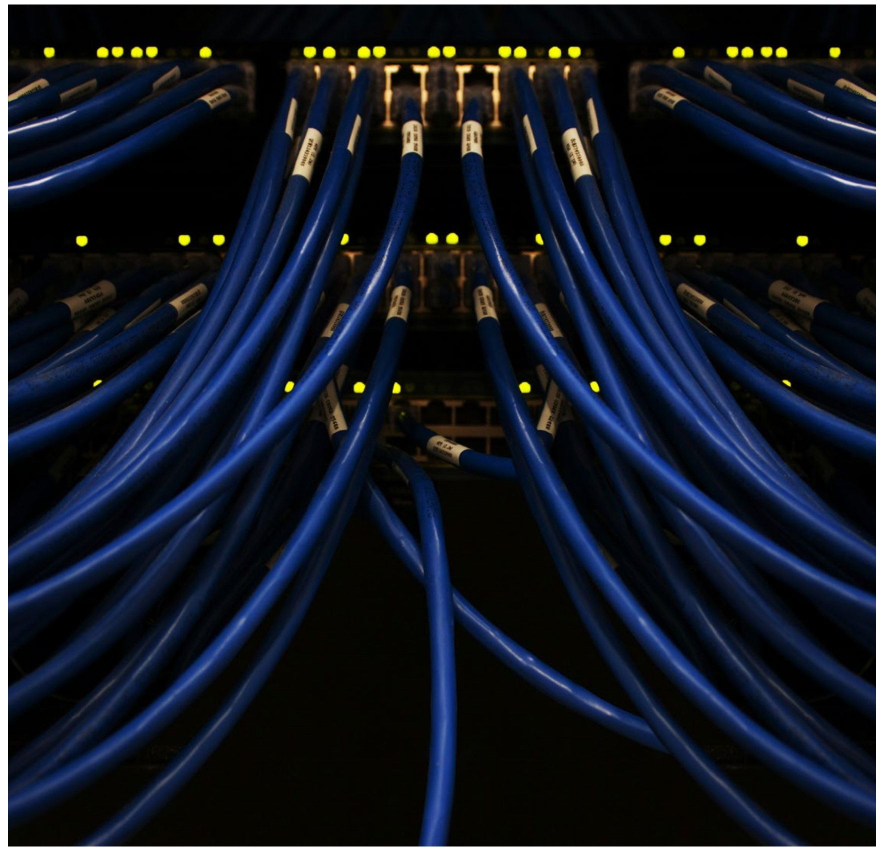
Each new model resets the cycle, driving ongoing training and accelerating grid buildout.

- GPT 3.5: Nov 2022
- GPT 4: Mar 2023
- Grok-3: Feb 2025
- Grok-4: Jul 2025

FIGURE 4.2 | How AI consumes energy

From load to leverage: Data centers as grid and community partners

The narrative thus far has highlighted data centers as a stress factor for the grid, utilities, and communities. However, a wave of emerging innovations in smarter algorithms, advanced energy efficiency, new resource strategies, technologies, business models, tariffs, and policies is partly reshaping that story. These advancements are moderating some of the resource challenges posed by data centers and opening up ways to operate them more sustainably.



Emerging solutions to common data center challenges

Challenge	Solution layer	Example
High energy consumption from AI model training and inference	Energy-efficient AI algorithms	**DeepSeek**'s V3 model requires about 2.78 million GPU-hours for training versus 30.8 million for comparable large models, translating to a significant reduction in total compute-related energy use if run on equivalent hardware and PUE conditions. The scale of efficiency improvement marks a notable inflection point in AI energy intensity, with major users like Saudi Aramco stating that the algorithm is making a "big difference" in operations, enhancing efficiency and reducing resources required (Moore, 2025; Wang, 2025).
High energy consumption for thermal management	Waste heat utilization for external heating applications	Waste heat from **Equinix**'s PA 10 data center was used to keep the water in the Aquatic Center at the optimal temperature at the 2024 Paris Summer Olympics. This data center will also provide heat for nearby homes free of charge for 15 years (Rella, 2024).
High water consumption for cooling systems	Use of treated waste-water and water-efficient cooling technologies	**Google**'s 1.3 million sq ft data center in Douglas County, GA switched to a custom system in 2012 that uses treated domestic wastewater for cooling, reducing reliance on potable water. Google also holds a discharge permit to treat its own wastewater onsite, a model replicated at other Google facilities (Ahmad, 2024). Microsoft's under-construction data centers in Phoenix, AZ and Mount Pleasant, WI that will come online in 2026 will pilot a closed-loop coolant system design that requires a one-time fill and thereafter uses zero additional water for cooling, eliminating over 33 million gallons of annual withdrawals per facility (Moss, 2024).
Grid stress from large, inflexible loads and peak demand spikes	Localized clean energy generation and storage to reduce grid dependency and enhance resilience	**Cipher Mining & Engie**'s (US) data center is co-located with a wind farm under a unique behind-the-meter power purchase agreement (BTM PPA). During periods of excess generation, Cipher uses the power directly, and potentially helps stabilize the grid by consuming excess supply (Reuters, 2025). **Project Salus** (Delta, CO): A planned edge micro-data center includes a microgrid with on-site solar panels, battery storage, backup generators, and EV charging to enhance resiliency and clean energy integration (Walton, 2022). **Microsoft**'s data center (San Jose, CA) leverages **Enchanted Rock** microgrid solutions featuring biogas generation to replace traditional diesel backup systems. The facility supports bridge-to-grid operations during outages and enables clean backup capabilities (Ampersand Partners, 2024; Cohn, 2023).

TABLE 4.1 | Continues on the next page

The opportunities ahead rely on cross-sector collaboration, with utilities, regulators, technology providers, and communities innovating together to advance efficiency, reliability, and equity in the energy transition. The examples to the right illustrate how targeted solutions can mitigate challenges posed by data centers to the grid, customers, and the environment, and sometimes enable them to serve as valuable assets to the grid and surrounding communities. In the absence of widely adopted, specialized building codes or standards for data centers, adoption of innovations and best practices remains largely voluntary and project-specific, making open knowledge sharing and collaborative learning across hyperscalers and solution providers essential to scale efficiency, resilience, and system-wide impact.

Building on this collaborative approach, a nonprofit focused on electrification called Rewiring America proposes that hyperscalers fund residential upgrades such as heat pumps, solar, and storage, meeting rising capacity needs while creating grid and community value, a model that signals the power of thinking holistically in a fast-evolving industry.

There is growing consensus that AI demand loads are flexible and that thoughtful management can mitigate some negative externalities.

Challenge	Solution layer	Example
Inflexible demand profiles and limited responsiveness to grid conditions	Intelligent load shifting and AI-driven energy management to align demand with grid capacity	**Google** has partnered with **Indiana Michigan Power** (I&M) and **Tennessee Valley Authority** (TVA), participating in formal demand response programs, reducing machine learning workload to ease grid strain during peak periods and protect customers (American Public Power Association, 2025; Kearney, 2025). **SynVista Energy**'s AI platform dynamically manages energy storage and discharge to smooth grid demand, reduce peak stress, and enhance battery safety for hyperscale data centers and industrial parks (SynVista, 2025). Independent research confirms that AI driven storage optimization and predictive dispatch are effective tools for demand smoothing and improving grid flexibility (Arevalo and Jurado, 2024). **DeepSeek** applies AI-optimized workload distribution, shifting compute to edge local nodes (e.g. inference and preprocessing) to reduce centralized grid demand and latency (Ithy, 2025).
Limited ability to support grid reliability or avoid renewable curtailment	Integration into grid services through demand response, VPPs, and prosumer models	Utilities such as **Entergy Arkansas** and **Montana-Dakota Utilities** require high-load customers to participate in interruptible or demand-response agreements, while new Texas legislation mandates remote disconnect and curtailment capabilities for large facilities to help prevent grid stress. Though still emerging, future data centers with renewables plus storage could export power during grid stress – acting as prosumers. **Amazon Web Services** (AWS) (Susquehanna, PA) is developing a data center campus adjacent to the Susquehanna nuclear power plant with a planned direct behind-the-meter connection, enabling the center to import and potentially export clean nuclear-generated power (Cohn, 2024). **Enel X** (International) collaborates with data centers in multiple countries to aggregate on-site generation and storage assets. Data centers can participate in **Virtual Power Plants** (VPPs) by adjusting consumption or delivering power back to the grid, monetizing flexibility while aiding grid stability (Enel, 2025).
Systemic externalities – rising electricity rates and cost-shifting to other customers	Regulatory mechanisms to ensure large loads pay fair share and avoid cross-subsidization	Large-load tariffs, such as those recently adopted or proposed by utilities including **Idaho Power**, **NV Energy**, **Dominion**, and **Duke**, ensure high-demand customers bear their incremental costs, preventing upward pressure on rates for all customers and supporting equitable grid planning (Satchwell et.al., 2025). Ohio, Oregon, and Indiana have introduced "minimum take" provisions, requiring large data centers to pay for most of their reserved capacity, reducing cost-shifting risks (Gibson Dunn, 2025).
Local externalities – community and environmental impacts	Local regulations and design standards to mitigate environmental and social impacts	Minnesota requires large data centers to conduct aquifer testing and assess public water-source viability (Nixon Peabody, 2025); York County in Virginia mandates sound studies, residential setbacks, and verified utility-capacity letters (Heckt, 2025); and Quebec's legislation protects users and businesses by requiring data centers operating in the province to manage personal and commercial information transparently and securely, similar in intent to GDPR protections in Europe (Bahr, 2025) These examples together illustrate how emerging regional frameworks can minimize local environmental and community externalities, and strengthen social licenses to operate.

TABLE 4.1 |

4.2 TRANSPORTATION ELECTRIFICATION

Oil currently dominates transportation energy. As the sector electrifies, it will put a noticeable demand on electricity production. We predict this demand will mostly materialize in the late 2030s and later.

Total energy use declines as transportation electrifies

Road energy demand by carrier (EJ/yr)

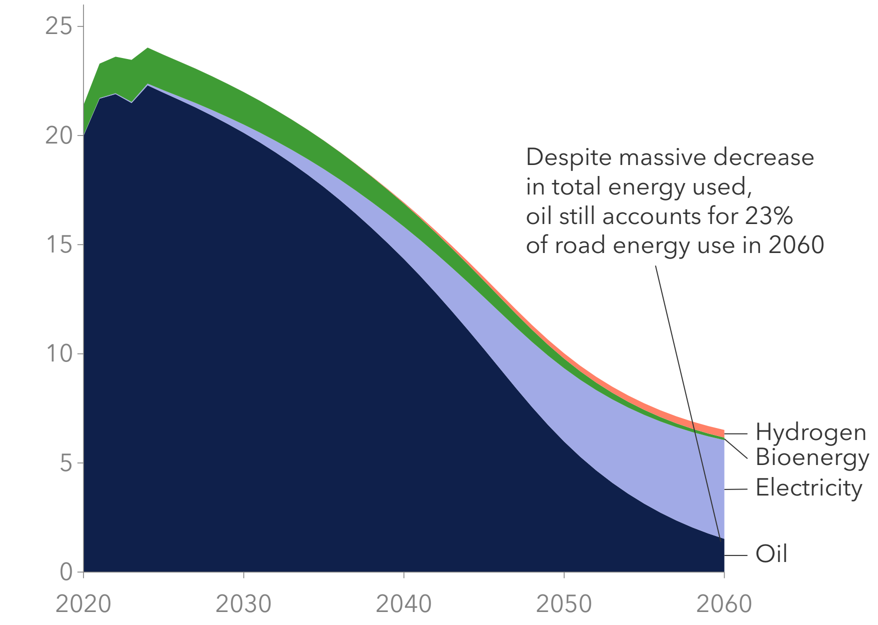


FIGURE 4.3 | Historical data source: IEA WEB (2025)

Slower EV adoption expected in ETO 2025 than ETO 2024

Share of EVs in vehicle sales

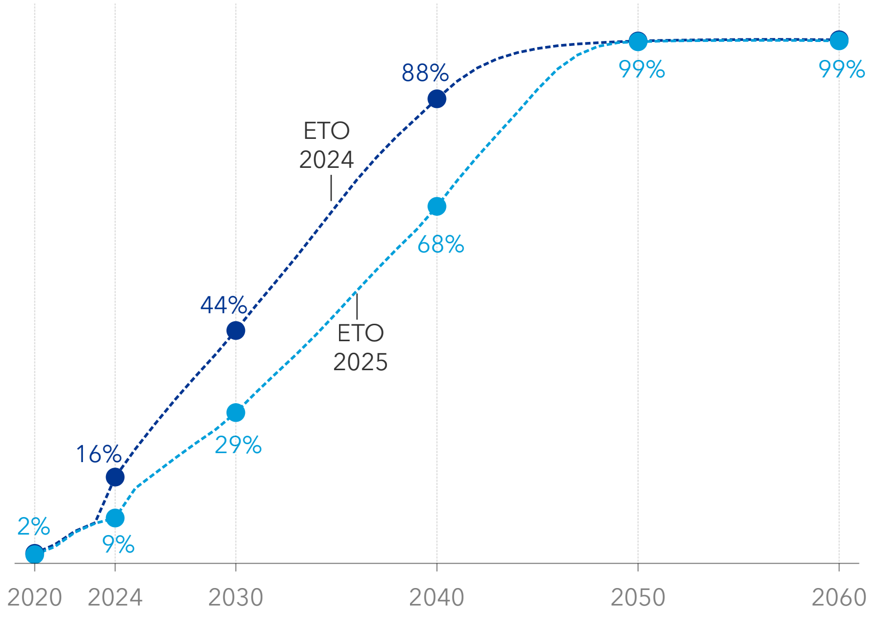


FIGURE 4.4 |

Total energy consumption from the transportation sector will decrease

- Electricity represents a growing share of transportation energy consumption while other sources of energy shrink.
- EVs are more efficient per vehicle-mile.
- The number of vehicles and total vehicle-miles will decrease because of the adoption of self-driving vehicles.

EV adoption will continue, but at a slower pace than before

- EV market saturation will be delayed by approximately six years compared to the ETO 2024 forecast.
- Sunsetting federal tax incentives and electricity prices that rise faster than oil prices cause this delay.
- A less beneficial total cost of ownership compared to internal combustion engines (ICEs), due to increasing electricity prices, also slows EV adoption in both the passenger and commercial segments.
- While not shown in Figure 4.4, the trend for commercial vehicles is similar to passenger vehicles.

Investment in charging infrastructure will remain flat until the early 2030s

- *The National Electric Vehicle Infrastructure* (NEVI) Formula Program, originally funded through the *Infrastructure Investment and Jobs Act*, has been paused and revised under the current administration. Other EV infrastructure incentives present in the *Inflation Reduction Act* were also eliminated in the recent *One Big Beautiful Bill Act*.
- In Canada, the government has paused its EV mandate (which set targets for the percentage of zero-emissions vehicle sales in new vehicle sales) and plans to review it.
- Combined with prevalent range anxiety, slow infrastructure build-out also slows EV adoption.
  - Range anxiety remains a major psychological barrier to EV adoption and discourages up to 58% of potential buyers (PwC, 2025).
  - Surveys suggest that participants place high importance on a reliable DC fast-charging (DCFC) network to support long-distance EV travel and address range anxiety concerns (Asensio et al., 2025).

Despite slower EV adoption, utilities and grid operators are engaging customers with novel rates and programs

- Time-of-use rates encourage vehicle charging in off-peak hours.
- These programs reduce transformer overloads, saving millions of dollars in replacement costs.

4.3 INDUSTRIAL LOAD GROWTH

While industrial uses currently represent a larger portion of the overall electricity demand than data centers, we do not forecast aggregate growth in industrial electricity demand.

Modest recent growth and aggressive goals for the future meet headwinds
Over the last few years, the US has seen modest growth in domestic manufacturing, particularly motor vehicles. At the same time, Canada's output has plateaued or declined. Both countries have goals to increase manufacturing output over the next five to ten years. Canada has aggressive goals. However, US trade policy and the growth of foreign economies puts pressure on these goals.

Overall manufacturing output and energy use decrease through 2060
Despite an increase in domestic iron and steel production, we expect a slight decrease in overall manufacturing output. Recent policy shifts are unlikely to arrest the long-term decline in North American manufacturing and, in the short term, policy uncertainty may be adding to manufacturers' difficulties (Deloitte, 2024). As a result, energy use from manufacturing in 2030 remains about the same as in the previous ETO.

Total energy used by manufacturing slowly decreases
Manufacturing energy use by carrier (EJ/yr)

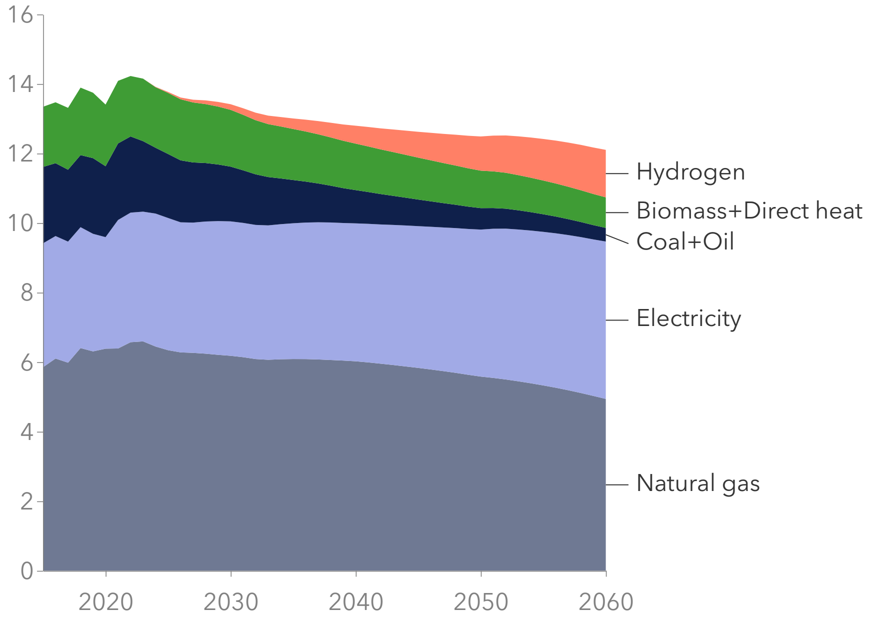


FIGURE 4.5 | Historical data source: IEA WEB (2025)

Iron and steel energy use slowly declines after 2030 peak
Iron and steel energy demand by carrier (PJ/yr)

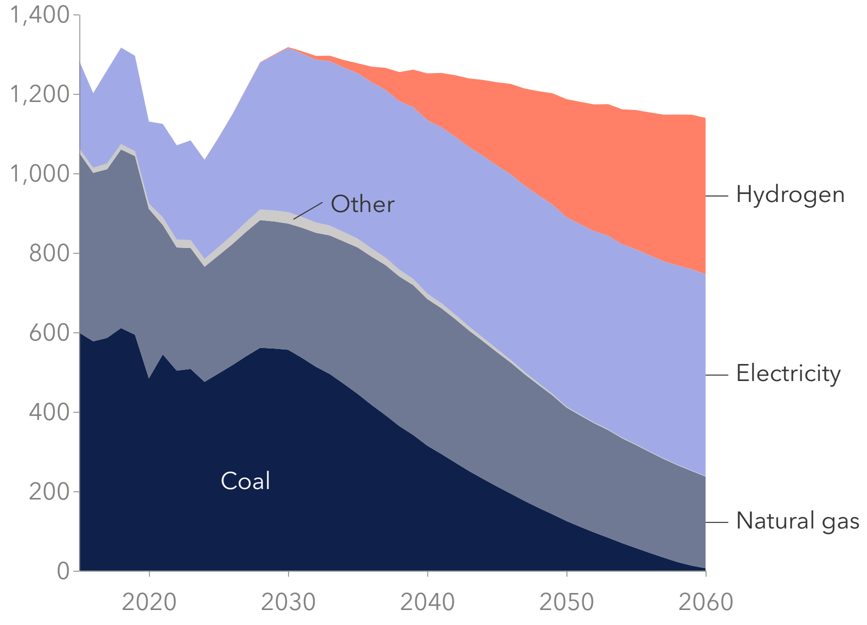


FIGURE 4.6 | Historical data source: IEA WEB (2025)

After 2030, there will be a slow decrease in energy use by manufacturing through to 2060. This is caused by a combination of efficiency gains and slightly decreased output. We forecast electricity's share in manufacturing energy demand will increase from 27% in 2024 to 29% in 2030, and reach 37% by 2060. As a result, fossil fuels make up a smaller proportion of the manufacturing energy mix in 2060 (44%), replaced by increases in hydrogen (11%) and electricity (37%). The majority of fossil fuel used in the manufacturing sector will remain natural gas, which is used in high-heat industries.

Iron and steel production will rise until 2030, then gradually decrease
We project North American iron and steel production will rise from 90 Mt/yr in 2024 to 118 Mt/yr by 2030. This additional energy load will be served by a mix of electricity, natural gas, and coal. After the peak in 2030, production will stabilize at about 105 Mt/yr through 2060. During this decrease, hydrogen will gradually replace energy provided by fossil fuels, especially coal.

We expect the newly-imposed tariffs on imported steel and related products will spur a short-term increase in US steel production, particularly among electric arc furnace (EAF) operators, which account for about 61% of domestic output in North America in 2024, about 55 Mt. Because EAFs primarily use scrap steel and electricity rather than iron ore and coke, they can scale output more flexibly in response to shifts in market conditions. As imports continue to slow in the coming months, we expect EAF capacity utilization to rise, strengthening domestic supply resilience. By 2030, we forecast EAF production of steel to increase to about 72 Mt, a 30% increase from 2024.

However, higher input costs (such as electricity prices) and tighter scrap markets could limit margin gains. At the same time, the policy may indirectly accelerate the North American steel industry's decarbonization trajectory as the shift toward EAF-based production reduces average sector emissions intensity.

Although steel demand from the automotive sector is weakening, we expect steady non-residential construction (such as data center campuses) and infrastructure investment to sustain domestic demand, potentially stabilizing prices despite the trade-induced supply adjustments.

Despite an increase in iron and steel production, overall manufacturing and energy use decline.

4.4 ELECTRICITY SUPPLY CONSTRAINTS

Electricity demand is growing quickly after decades of stasis. However, the ability of electricity supply to meet that demand is badly constrained in numerous ways.

Physical and supply chain constraints

- Critical equipment faces prolonged lead times:
  - Gas turbines require three to seven years to procure and are limited by the need for specialized components and the small number of global manufacturers (Cohen et al., 2025).
  - Basic distribution network equipment, such as service transformers, face lead times of 30 weeks to over two years. This is worsened by shortages of grain-oriented electrical steel (Intertek CEA, 2025).
- Labor shortages slow build-out: The energy industry has struggled with a shortage of electricians and electrical engineers for many years. There is no indication that this trend will ease in the foreseeable future (Association of Energy Engineers, 2025).
- Most critical minerals and related raw materials needed for the power system build-out are imported, and are thus vulnerable to international supply chain disruptions and to tariff uncertainty (see Fact Box 'Tariffs' in Chapter 2).

Permitting bottlenecks

- Transmission: New large-scale transmission projects take over 10 years to complete. Some current inter-regional transmission projects are approaching 25 years in development.
- Generation: Legacy interconnection processes – designed for slower, incremental growth – are over-whelmed. As of 2024, over 2,600 GW of projects await connection, with average delays of five years (Rand et al., 2024). However, the majority of these projects are likely to be withdrawn; between 2019 and 2024, only 14% of queued capacity reached completion due to speculative filings and long delays (Fung, 2025).

  Recent FERC reforms (2018, 2023) aim to streamline queues with cluster studies and firm timelines, but implementation is ongoing. Regional disparities persist (Fung, 2025).

Growth-limiting US policies

- Federal policies enacted in 2025 are limiting the growth of renewables, which will constrain supply growth further.
- Tariffs make it more difficult to import critical minerals.
- Extreme policy swings discourage investment by eroding trust and confidence. Investors in energy projects face the daunting possibility that fossil and non-fossil energy sources could oscillate between policy favor and disfavor with every election cycle.

Supply constraints are expected to lead to increased electricity prices through various causal factors:

- Utilities are stockpiling distribution equipment in reaction to equipment shortages, leading to increased prices for consumers.
- Major turbine manufacturers have recently announced plans to increase manufacturing capacity, but this is unlikely to substantially affect lead times (DiGanji, 2025). Despite the increases in manufacturing capacity, lead times are still increasing (Shenk, 2025). This puts upward pressure on CAPEX prices, which in turn puts upward pressure on electricity prices.
- In the long term, renewables are cheaper than natural gas, even after accounting for distribution costs. If North America were to continue investing in renewables at a similar pace to the past few years, we would expect retail electricity prices to decrease in the mid-to-late 2030s. Instead, with current levels of renewables investment, we estimate that retail electricity prices will continue to increase until the mid-2040s.

Waiting times have grown in the last 25 years

Transmission grid waiting times (Years)

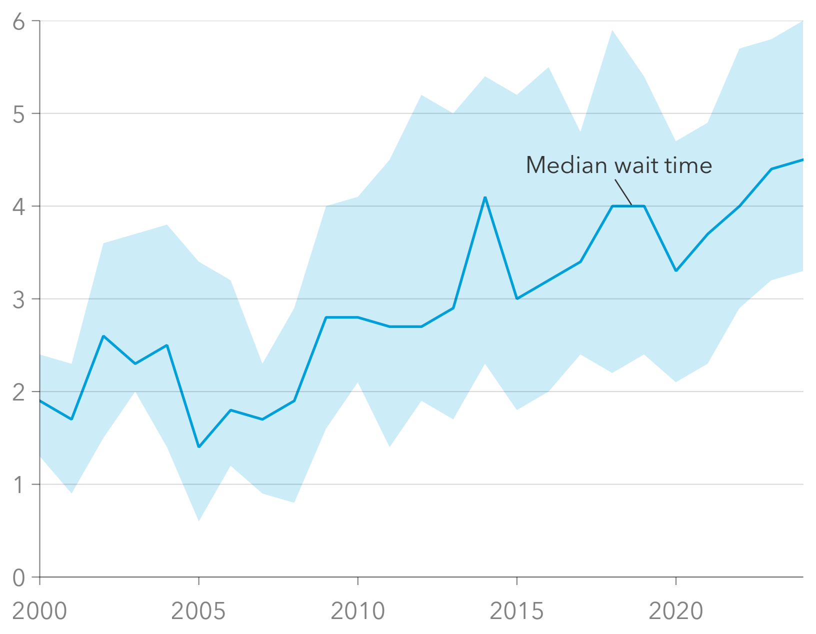


FIGURE 4.7 | Range shows p25/p75.
Data source: LBNC (2024)

Transformer lead times have ballooned since 2020

Transformer lead times (Weeks)

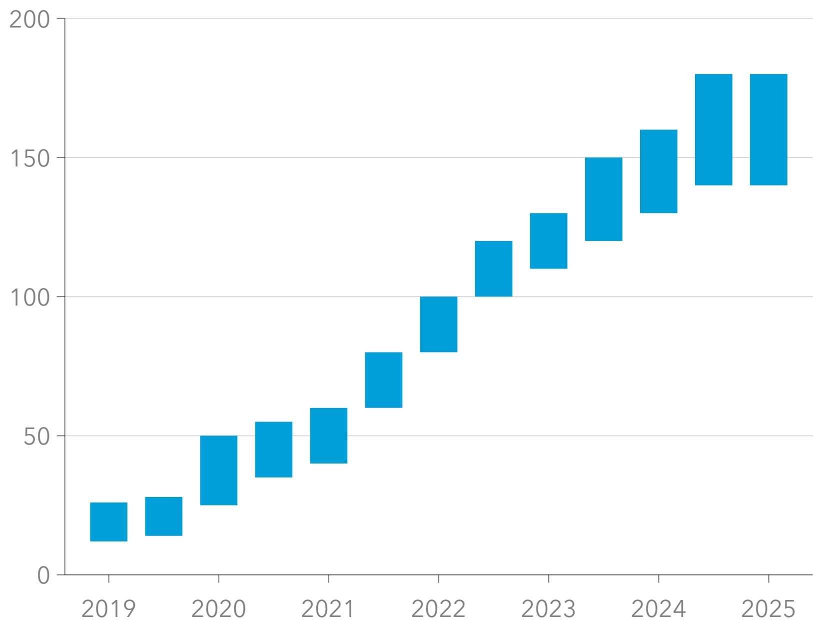
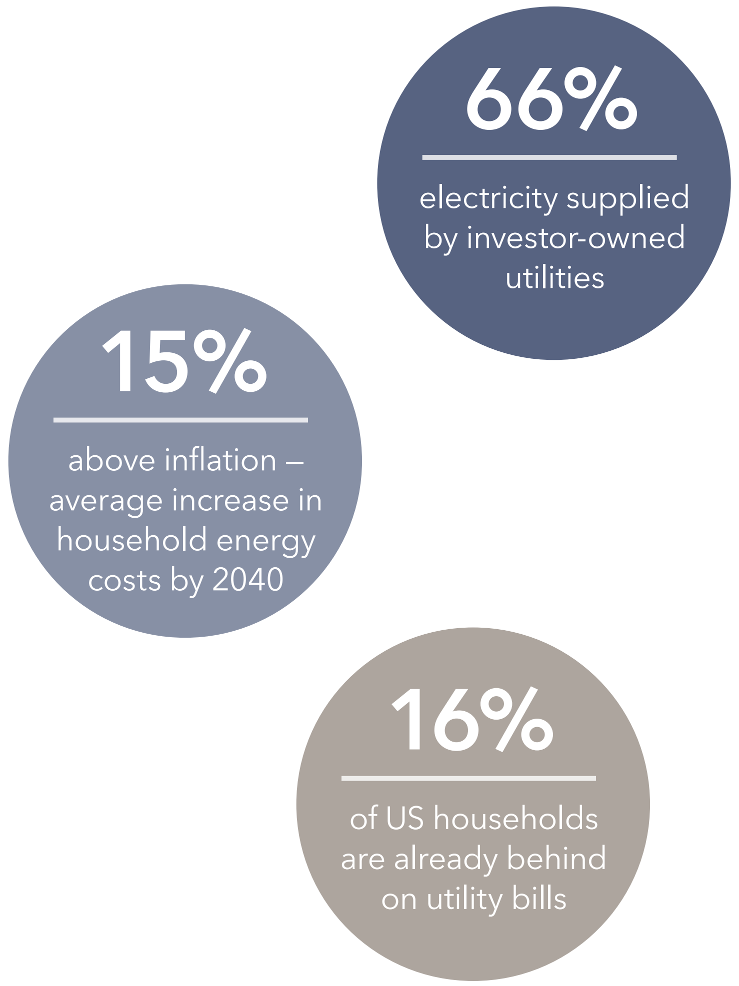


FIGURE 4.8 | Data source: DOE, Wood Mackenzie, NREL

5 EVERYDAY ENERGY IN ACTION

5.0 HIGHLIGHTS

In this chapter, we highlight how energy reaches the residential consumers in North America, starting from the local regulatory bodies to the utilities who get the energy to the consumer, and how procuring that energy impacts everyday people.



5.1 STATE-LEVEL POLICIES

Local regulatory bodies are responsible for providing electricity and other energy (most often natural gas or oil) for the services that residential customers require. For example, the states in the US have public utilities commissions (PUCs) that are led by elected or appointed officials. These PUCs are tasked with regulating the services of providing electricity and natural gas (among other things) and the rates levied by utilities. At the same time, PUCs implement state mandates and targets, for example on decarbonization or the integration of renewables.

While federal policies in both the US and Canada provide broad direction, state- and province-level activities (regulations, actions, and funding) also strongly influence the energy transition in North America. Each state and province makes independent policy decisions – often under conditions of fiscal duress – about how to balance the priorities of reliability, resilience, affordability, and decarbonization.

These priorities can be viewed as a feedback loop. Maintaining reliability in the face of aging infrastructure, the need for new resources (generation, transmission, and distribution), more frequent and extreme weather events, and historically high levels of demand growth, requires substantial capital and operational expenditures. This places pressure on affordability and contributes directly to increased rates for end-use customers. Electricity rate increases over the last five years are mainly due to reliability needs (Wiser et al., 2025). This has regulators focused on identifying least-cost alternatives, dispatchable resources, and benefit-cost analysis. In some cases, this causes policymakers to scale back decarbonization targets.

Some states like Florida and North Carolina (Ouzts, 2025), and provinces like Alberta (Government of Alberta, 2025), have scaled back or abandoned clean energy goals altogether. Even leading areas that remain committed to clean energy targets are struggling to hit milestones. In New York, Governor Kathy Hochul recently announced that the state would not meet 2030 goals due to lack of renewable energy projects coming online. Similarly, California is not currently on track to achieve 2030 goals until 2047 (Next 10, 2024). In addition, federal pressure and state-level needs for energy resources are ushering in a new wave of natural gas pipeline development after a period of lower development between 2022 and 2024 (EIA, 2024b).

Closing the loop, slower decarbonization will threaten reliability directly by disfavoring urgently-needed generation sources, and indirectly by contributing to even more frequent and extreme weather events and a need for more hardened infrastructure. It also threatens affordability through the slower retirement of high-cost fossil fuel generation, the use of utility rates to pay for climate-related public investments, and by exposing consumers to exogenous price shocks through the international trade of oil and gas.

The nexus of reliability, affordability, and decarbonization

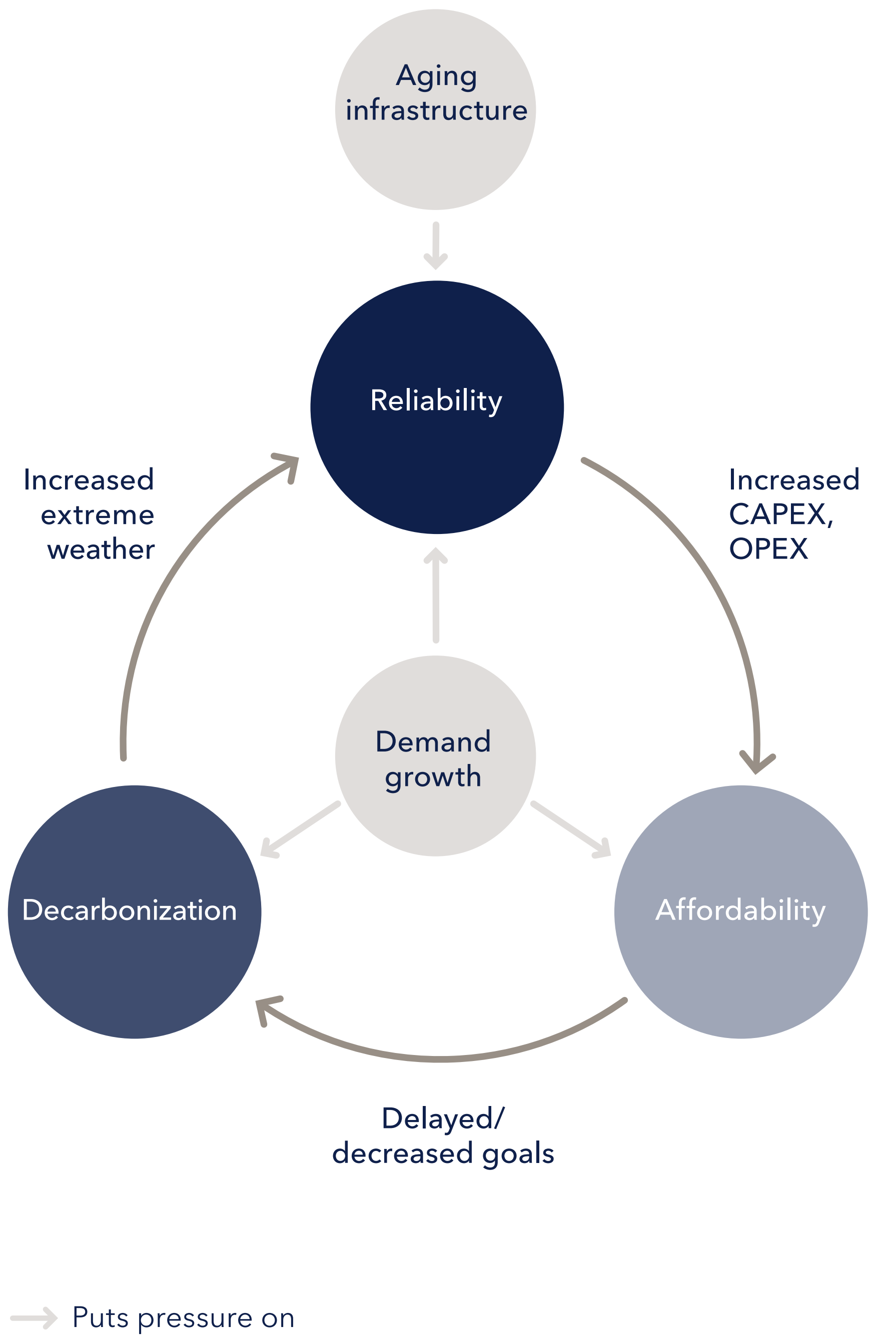


FIGURE 5.1

5.2 INVESTOR-OWNED UTILITIES

Investor-owned utilities (IOUs) are geographically dispersed across the US and Canada, and their ownership structure and business models vary significantly. IOUs serve approximately 66% of the electricity to US consumers (EIA, 2024a). Some operate as vertically integrated companies that own generation assets alongside transmission and distribution infrastructure. Others, particularly in deregulated markets, function primarily as 'wires-only' utilities, owning and operating transmission and distribution systems but relying on wholesale markets to procure generation.

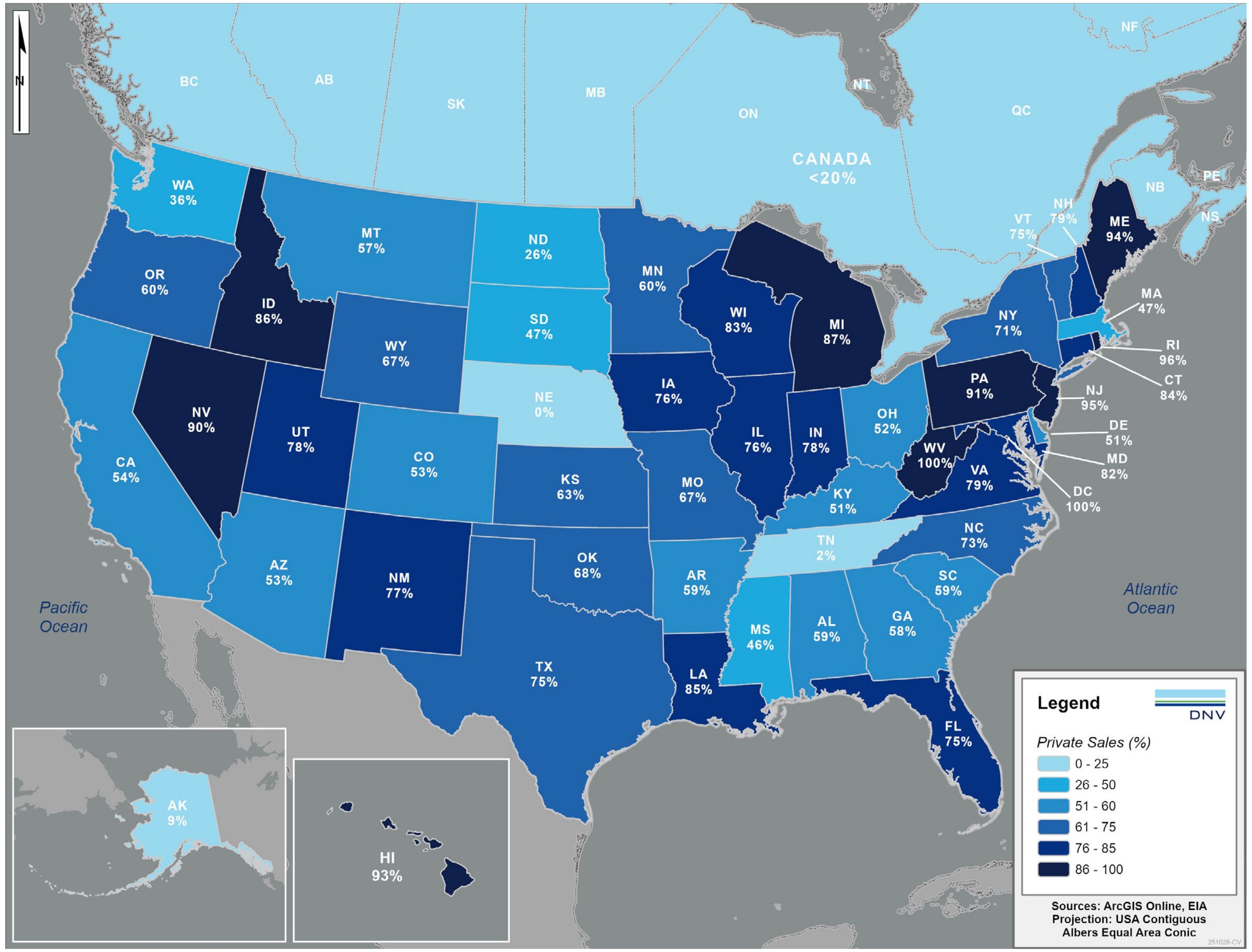
Despite these structural differences, IOUs share defining characteristics. They are profit-oriented enterprises regulated by PUCs or similar authorities under the supervision of state or local administration. Their mandate is to deliver reliable power and energy at the lowest possible cost while maintaining and upgrading transmission and distribution networks. They negotiate with regulators for the rates they charge customers to fulfill this mandate and make a monetary profit.

Thus, IOUs face the same challenges as PUCs around balancing the priorities of reliability, resilience, affordability, and decarbonization, along with an additional priority of making a profit. Looking ahead, this will be a very difficult, and unprecedented, balancing act for IOUs.

Over the next decade, IOUs will need to manage rising wholesale power costs, higher expenses associated with expanding and modernizing transmission and distribution systems to serve large new loads, and surging demand from data centers and the electrification of industry and households. At the same time, they must allocate significant capital to harden infrastructure against climate risks ranging from extreme weather events to wildfire threats. This combination of cost pressures, infrastructure needs, and resilience investments represents a fundamentally more complex operating environment than in the recent past.

IOUs are regulated monopolies with an obligation to provide affordable, reliable, and safe electricity. Over the next 20 years, meeting these obligations will be challenged by increased wholesale prices, increased demand from data centers and electrification, and infrastructure modernization and hardening needs.

Percentage of electricity provided by IOUs varies by state



5.3 AVERAGE NORTH AMERICAN RESIDENTIAL CONSUMER

The average North American household consumes about 25 MWh/yr. In 2025, 90% of this energy consumption is almost equally split into electricity and natural gas. In the recent past, both electricity and natural gas demand have been mostly stable.

However, in the next five years, we forecast that natural gas will start a steady, long-term decline in its share of household energy use. This is mostly due to electrification of household heating. We already see momentum in the adoption of energy-amplifying technologies such as heat pumps for space and water heating, which tend to displace natural gas furnaces and boilers. Even though some federally-funded programs have been stopped by cuts from the OBBBA, state funding for electrifying homes still exists.

What will happen to energy prices?

North Americans have been facing rapidly increasing energy costs over the past decade, especially since 2020. This has put pressure on household budgets. We expect electricity price increases to continue in the coming decade as well (see Chapters 3 and 4 for further discussion). Utility prices will continue to rise, further increasing the financial pressure most households feel. However, without raising prices, service reliability will suffer, also harming consumers.

Rising power prices will likely spur political pressure from consumers for action. There is a risk that politicians could respond with symbolic policies that sound good but fail to solve the underlying issues, igniting a further round of pressure politics, and so on. The repercussions for the energy transition are increased policy volatility and decreased investment predictability.

Rising electricity prices also raise the relative attractiveness of natural gas as an energy carrier and encourage its continued or indeed expanded use in sectors like manufacturing and heating commercial buildings. This may cause a modest and gradual increase in the retail price of natural gas as well.

Both increasing electricity rates and increasing natural gas prices will lead to higher household energy costs in real dollars (i.e. without considering the effects of inflation) until the 2040s. We expect energy costs of households to reduce only after the 2040s, when the higher uptake of cheap renewables starts to become evident in electricity rates and the energy efficiency benefits of electrification truly manifest.

Average household energy use declines through 2060

Average household energy use (MWh/yr)

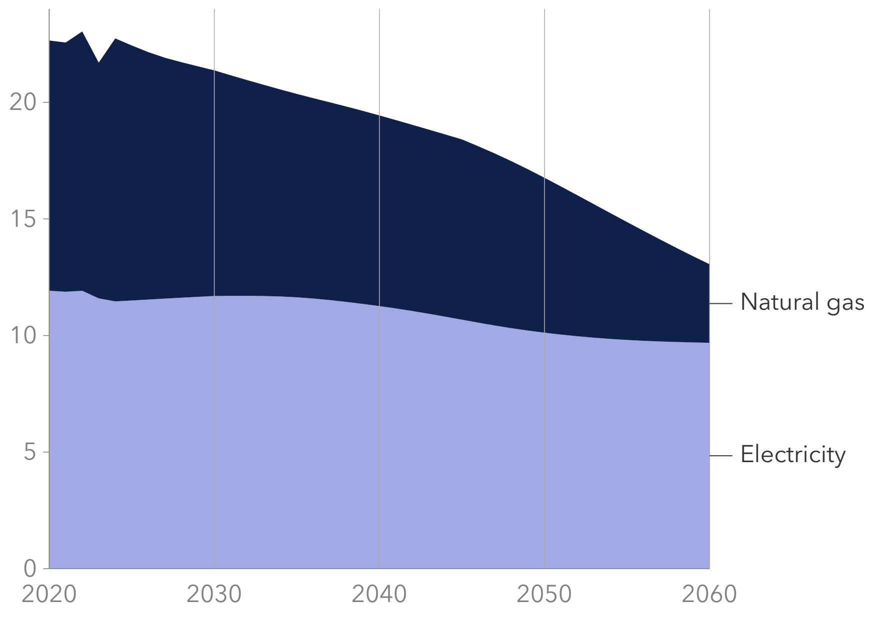


FIGURE 5.2 |

Rising electricity prices increase household energy costs

Average end-use electricity prices (USD/MWh)

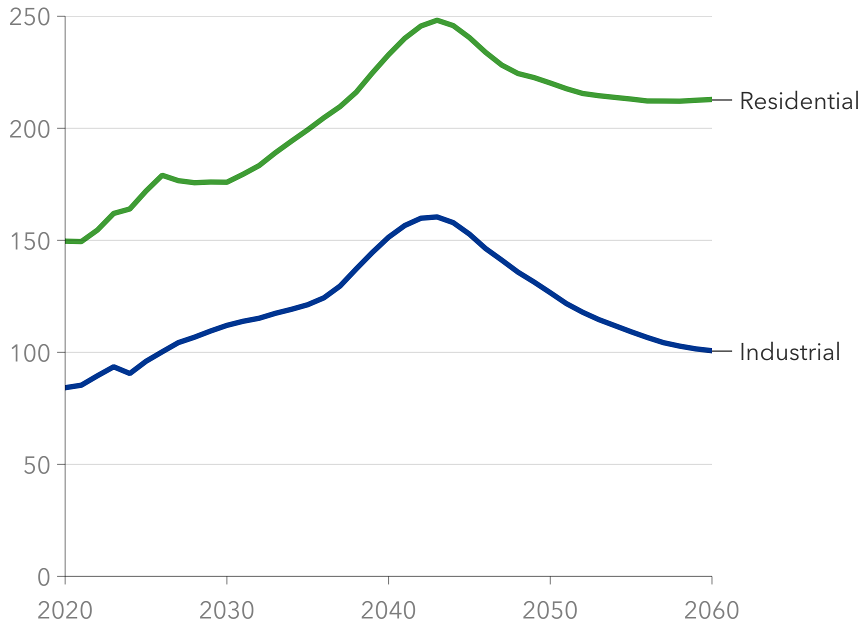


FIGURE 5.3 |

Rising natural gas prices increases household energy costs

Average end-use natural gas prices (USD/MMBtu)

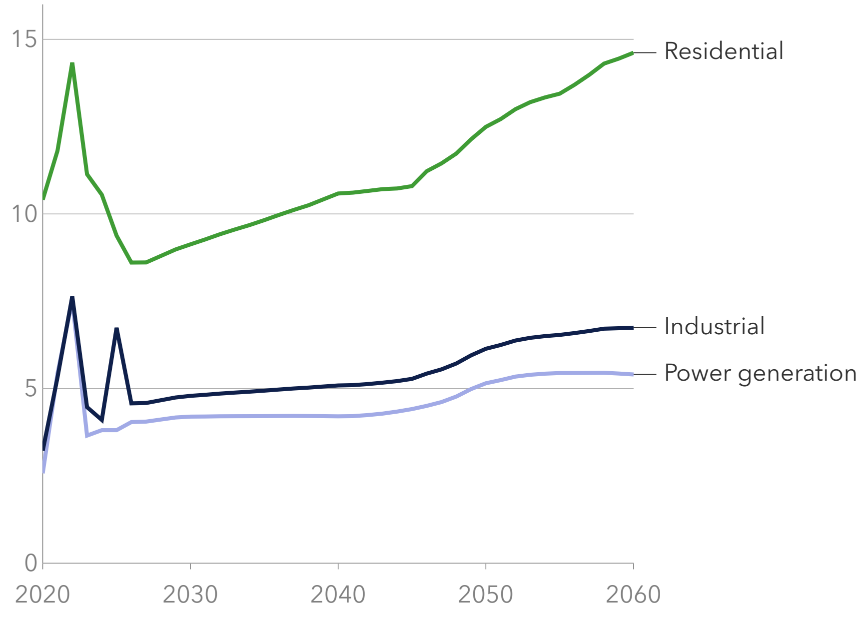


FIGURE 5.4 |

Uptake of renewables will decrease residential energy costs

Average residential energy cost (USD/household-yr)

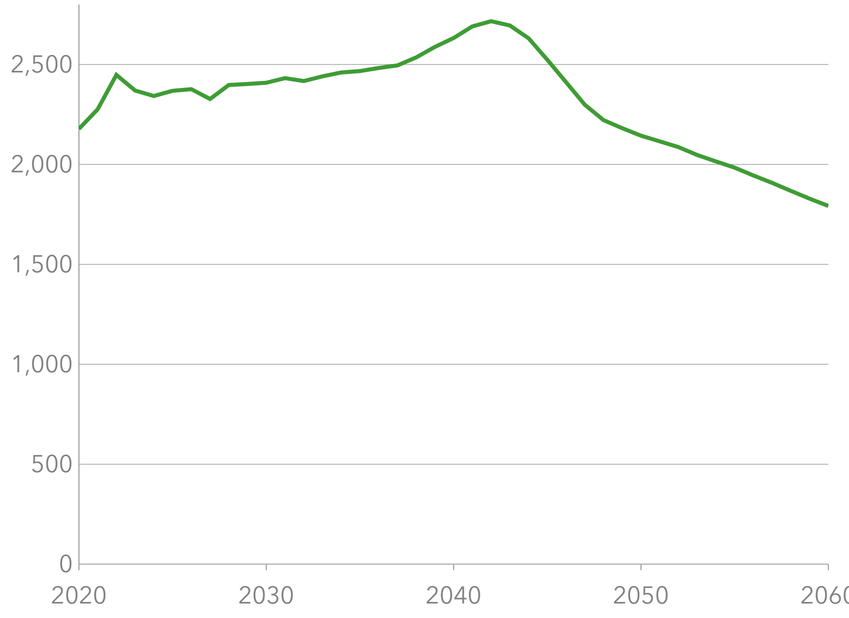


FIGURE 5.5 |

5.4 MOST VULNERABLE NORTH AMERICANS

Energy is a basic need, yet many North Americans face persistent structural barriers to accessibility and affordability. Increasing energy prices and decreased availability of social services will only intensify the financial strain on America's most vulnerable households.

- In 2024, about one in three US households reported facing the 'heat or eat dilemma' – forgoing necessary expenditures such as food or medicine to pay energy bills (Rosenbach et al., 2024)
- In 2023, 3% of Canadian households reported receiving a disconnection, shut off, or non-delivery notice with respect to their energy bill in the past 12 months. A larger share (1 in 10 households) reported that they had been late or unable to pay their energy bills in the past 12 months due to high energy prices (Statistics Canada, 2023).
- Energy insecurity remains higher among Black and Hispanic households even after accounting for factors like housing conditions and energy burden (Rosenbachet al., 2024).
- Disconnections are higher among households of color. Black households received 27% of disconnect or delivery stop notices in 2020, a disproportionate share relative to their population, and Latino households were 2.4 times more likely than white households to face disconnection between 2019 and 2020 (Rosenbach et al., 2024).
- Utilities are facing historic levels of arrears and debt from unpaid bills. Over 21 million households (approximately 16% of all US households) owe electric utilities USD 15.4bn and 15.1 million households owe natural gas companies USD 5.6bn as of September 2024. Electric arrears are increasing by 1.2% per year while gas arrears are increasing by 0.3% per year (Rosenbachet al., 2024).
- A national poll conducted by US non-profit PowerLines in partnership with Iposos in Q1 2025 found that 73% of Americans are concerned about electricity and gas utility bills rising in 2025, with an even higher percentage of respondents (80%) saying they feel powerless over how much utilities charge (Hua, 2025).

Many utilities have hitherto leveraged federal assistance programs such as LIHEAP and the Weatherization Assistance Program in the US, to help customers who are unable to pay their energy bills. The current administration has cancelled or drastically scaled back these programs.

Besides the obvious requirement that a full transition must address everyone's energy use, failing to resolve the plight of the most vulnerable Americans has repercussions for everyone. It creates a feedback loop of increased energy prices that will lead to more households falling behind. As more utilities are forced to carry arrears and unpaid bills, they will raise rates for remaining customers. Some of those customers may then be incentivized to install their own behind-the-meter generation, a form of 'grid defection' which in turn leads to a worsening profitability outlook for utilities.

Arrears feedback loop

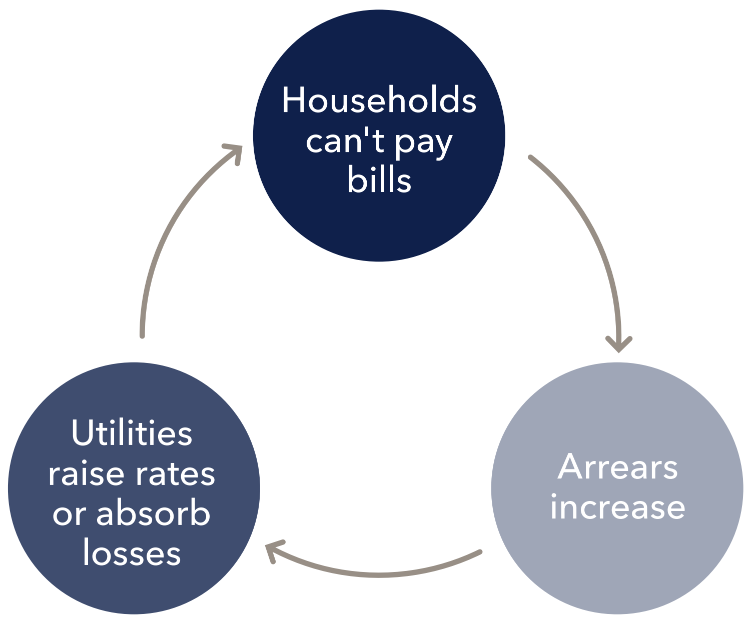


FIGURE 5.6

Arrears track utility rate increase requests in the US

Rate requests and arrears (Billion USD/yr)

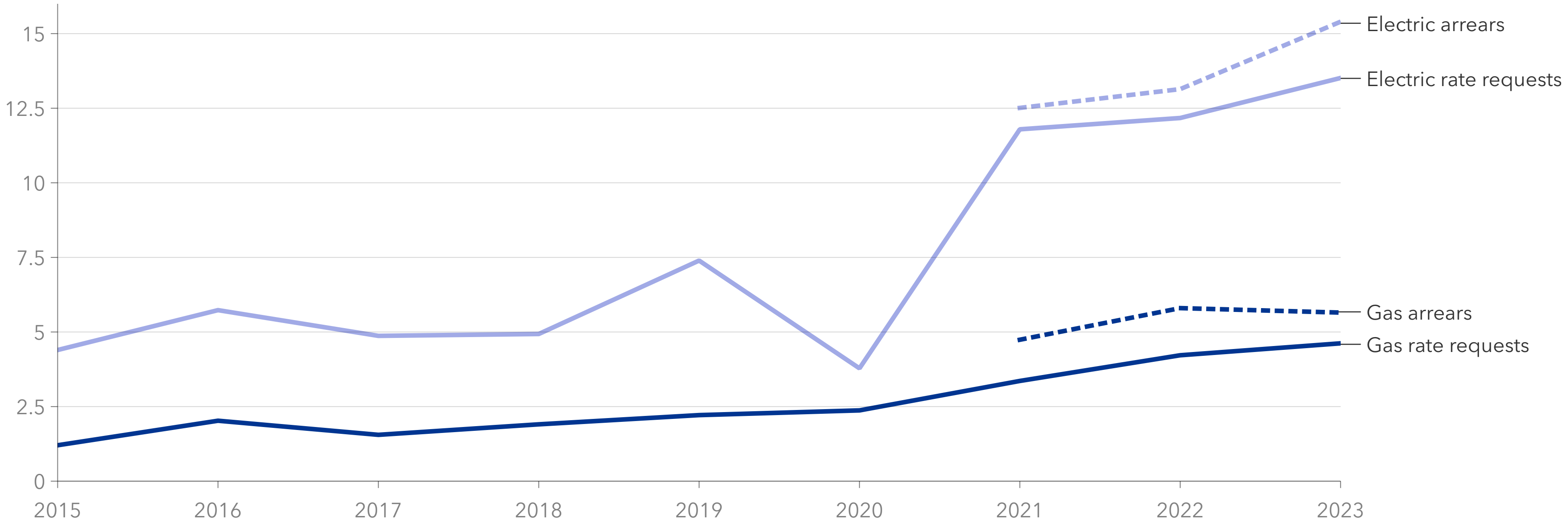


FIGURE 5.7 | Data source: Regulatory Research Associates, a group within S&P Global Commodity Insights (2024); RMI, (2025)

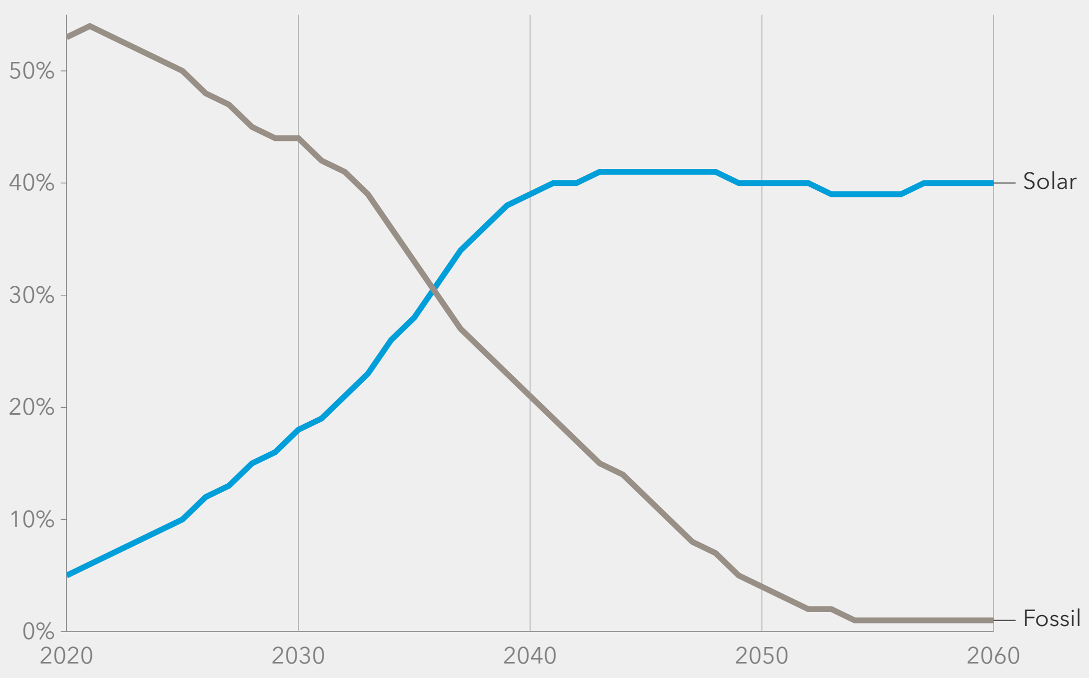
6 SOAK UP THE SUN AND WIND

6.0 HIGHLIGHTS

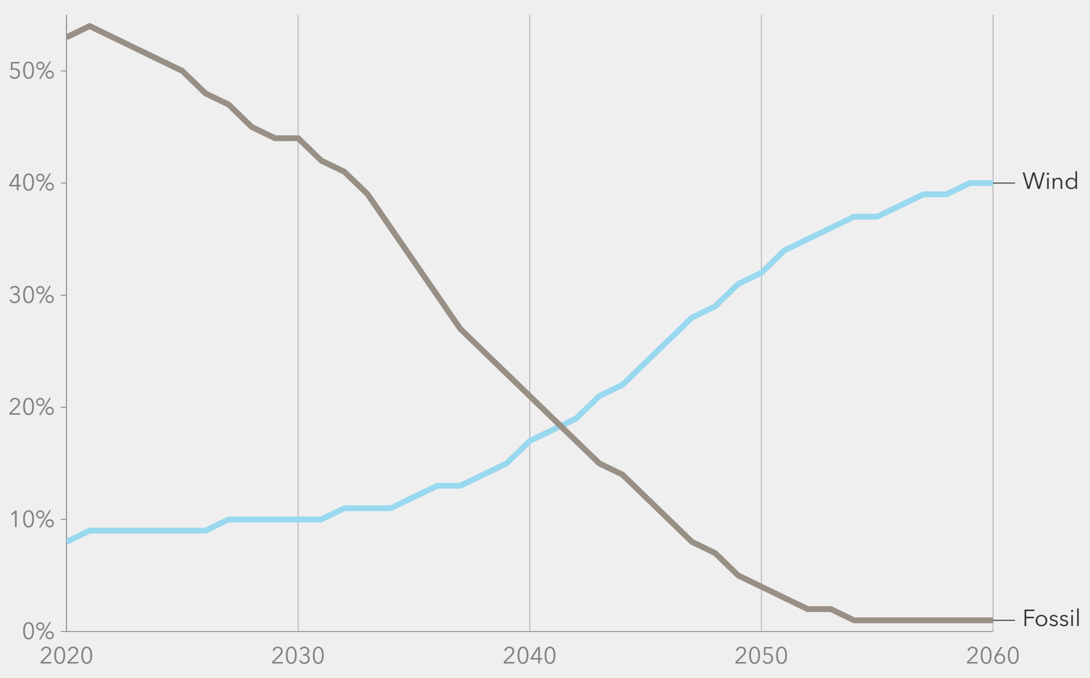
Renewables will make up the bulk of North America's power mix in the future, despite short-term headwinds.

Solar and onshore wind are positioned for sustained expansion in North America, despite natural gas-fired generation remaining a cornerstone of the power mix in the near to medium term. Even with the anticipated early phase-out of *Inflation Reduction Act* (IRA) investment and production tax credits (ITCs and PTCs) and ongoing uncertainty around Internal Revenue Service (IRS) guidance on capital safe-harboring, both technologies remain the lowest-cost sources of new electricity supply across much of the US and Canada. We forecast that solar, including distributed generation, will account for roughly 40% of total electricity generation by the 2040s and will maintain that share thereafter. Wind will expand more gradually, reaching 30% by the 2050s and achieving parity with solar at around 40% by 2060. By then, we expect wind and solar (supplemented by hydropower, biopower, and geothermal) will provide approximately 90% of North America's electricity, with nuclear generation supplying nearly all of the remainder.

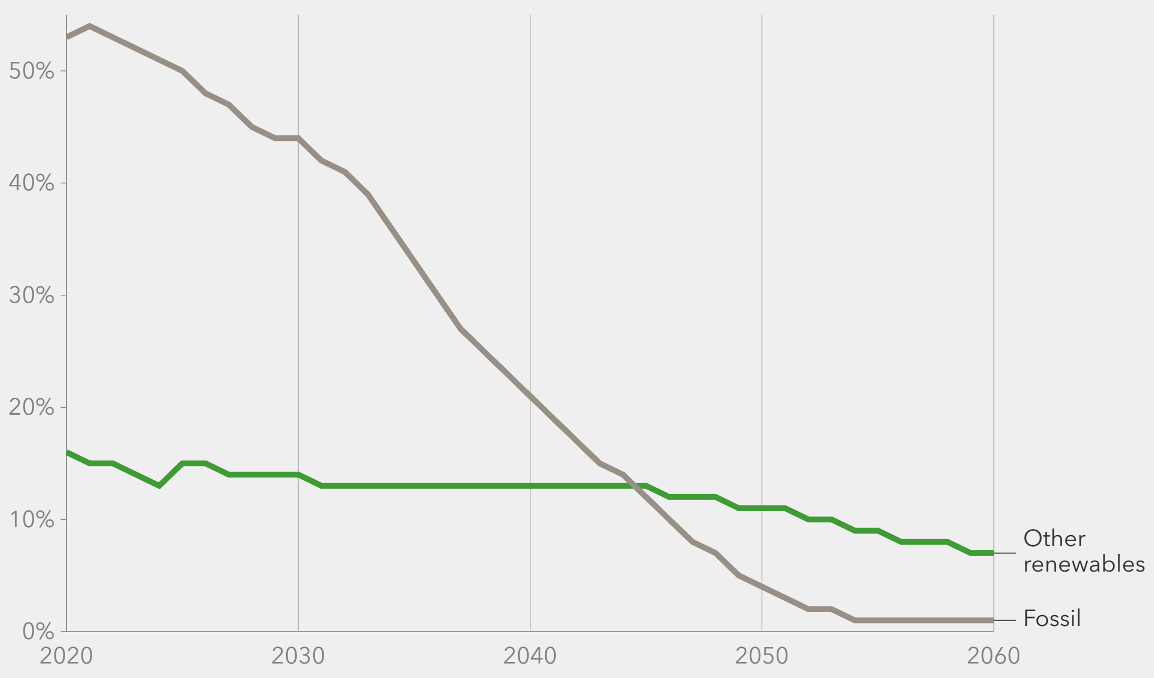
Share of solar versus fossil in electricity



Share of wind versus fossil in electricity



Share of other renewables versus fossil in electricity



6.1 UNSTOPPABLE SOLAR

Solar power has emerged as the lowest-cost source of new electricity generation in the US and Canada, with deployment occurring at an unprecedented scale. In 2024, solar (both standalone and paired with storage) represented approximately 75% (43 GW) of all new capacity additions in North America. This is equivalent to the average electricity needs of roughly 8 million US households, or the residential electricity demand of the state of Florida (Kearney, 2025).

Policy and financial conditions will shape the trajectory of future additions. The scheduled phase-out of investment and production tax credits in 2027, combined with uncertainty around safe-harbor provisions and a higher cost of capital in 2025, may constrain near-term investment (DiGangi, 2025). Nevertheless, underlying demand growth points to the continued expansion of solar capacity.

Between 2024 and 2030, we project electricity demand growth in North America will exceed the cumulative growth of the previous two decades, driven primarily by the increasing use of electricity in AI and data centers. Meeting this demand will require an 'all-of-the-above' supply strategy in which solar represents the largest incremental source of capacity thanks to cost, established project pipelines (EIA, 2025), and the shorter time it takes to break new ground on development compared with other new sources.

We project annual additions of 30 GW of solar and 10 GW of solar+storage through 2028. We expect a decline in annual installations following the phase out of federal tax credits. However, rising electricity demand will likely re-establish momentum by the early 2030s. By 2032, we project annual solar additions will recover to levels comparable with those observed in 2025.

By 2040, we project total installed solar capacity in North America will reach approximately 880 GW, with around 20% co-located with storage. However, several technical and economic constraints will likely drive a plateau in stand-alone solar deployment. As a non-dispatchable resource, solar will increasingly face value erosion in wholesale markets as penetration rises. In contrast, we expect solar paired with Li-ion batteries to expand, benefiting from its ability to shift generation into higher-value periods. Yet, because this dispatchability is limited to short durations, it will not fully offset the stagnation of standalone solar capacity growth.

2024 saw record capacity of solar PV coming online in North America; Share of solar in capacity additions remains robust

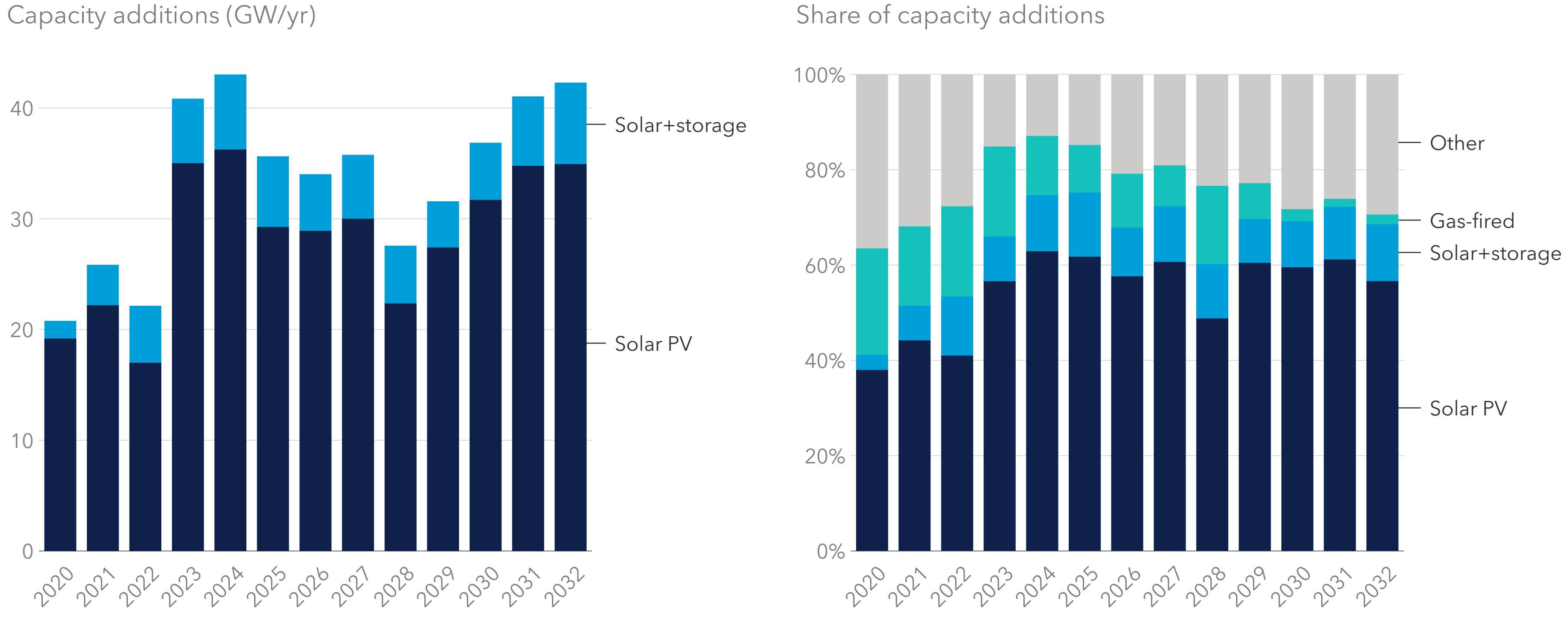


FIGURE 6.1 | Historical data source: GlobalData (2025)

Solar+storage growth outpaces solar from 2040s

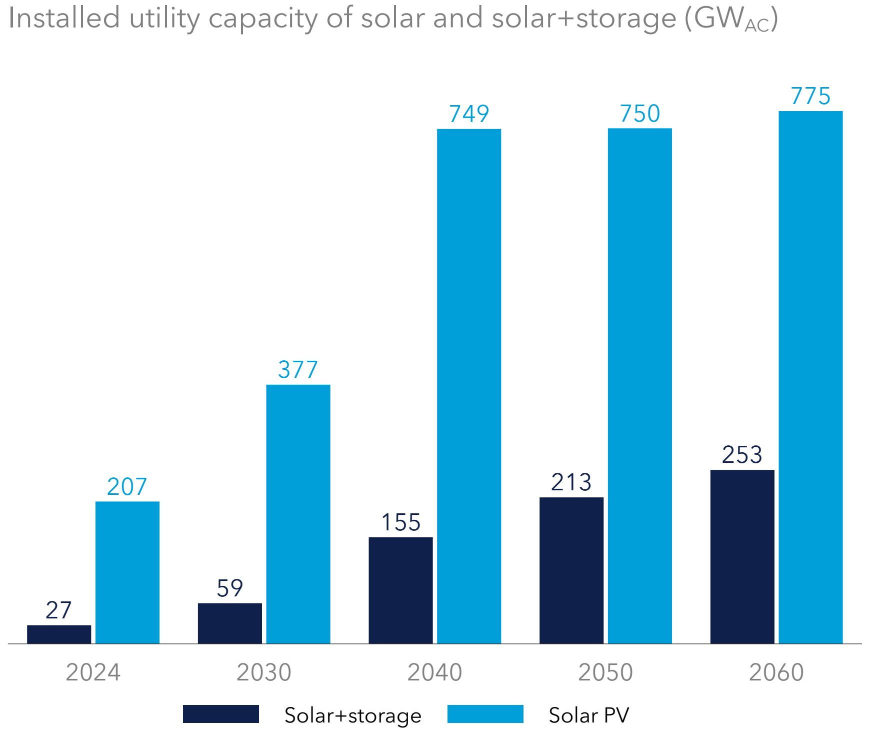


FIGURE 6.2 | Historical data source: GlobalData (2025)

The economics of solar overcome policy headwinds introduced by the current US administration.

Solar LCOE drives value

The trajectory of wholesale electricity prices and solar capture prices exemplifies the shifting economics of solar power in North America over the coming decades. We expect wholesale electricity prices to rise steadily through the 2030s, peaking at roughly USD 0.12/kWh in the early 2040s. This increase is the result of growing electricity demand, higher fuel and system costs, and capacity needs as legacy assets retire. Beyond this peak, wholesale prices decline gradually toward USD 0.05/kWh by 2060 as low-cost renewables and storage gain a larger share of the supply mix and exert downward pressure on market clearing prices.

At the same time, the capture price of standalone solar diverges significantly from wholesale trends. After 2030, solar capture prices fall consistently below both wholesale electricity and solar+storage, illustrating the challenge of 'value deflation'. This occurs because solar output is concentrated in midday hours when generation is abundant and marginal prices are depressed. By the 2040s and beyond, standalone solar projects earn much less per kilowatt-hour than the average wholesale price, with revenues declining to near USD 0.01/kWh by 2060. This steep decline is an economic vulnerability of projects that rely solely on solar generation without complementary storage or flexibility.

Adding storage increases solar value

Solar paired with Li-ion storage demonstrates a more resilient revenue trajectory. The capture price of solar+storage remains consistently higher than standalone solar after 2030, reflecting the ability of storage to shift output into higher-value periods such as evening peaks and overnight hours. While these capture prices also decline over time, they do so more gradually, remaining more closely aligned with wholesale market averages. Storage is thus a hedge against value erosion that allows projects to sustain more stable revenues even in high-renewable systems.

The widening gap between standalone solar and solar+storage economics carries important implications for the energy transition in North America: beyond a certain penetration level, additional standalone solar contributes less incremental value to the grid, while solar integrated with storage becomes increasingly critical to balancing supply and demand. Over time, storage is not only advantageous but essential for solar to remain competitive and profitable. As a result, we expect future solar deployment in the US and Canada will be increasingly coupled with storage, both to capture higher market revenues and to provide the dispatchability needed to integrate larger shares of variable renewable energy. In short, while standalone solar capacity growth is likely to stall under the weight of declining capture prices, solar+storage is positioned to expand as the economic and operationally viable pathway forward.

> Over time, storage is not only advantageous but essential for solar to remain competitive and profitable.

Wholesale electricity prices will exceed solar capture prices

Average capture price (USD/MWh)

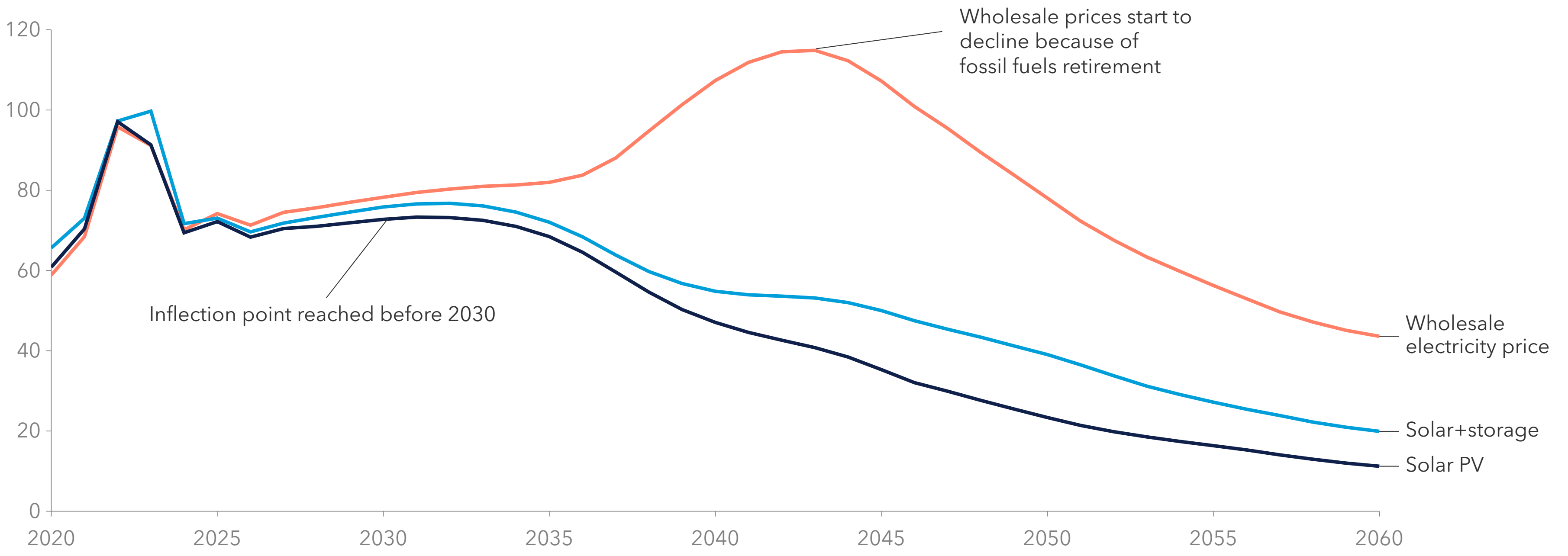


FIGURE 6.3 |

Let's spread the sunshine – the role of distributed generation

Distributed behind-the-meter (BTM) solar is already happening at scale in a number of states in the US (such as California and Texas) and in several provinces in Canada. With the cost of solar modules continuously reducing, many households and businesses are adopting distributed solar as a way to reduce their monthly electricity bills and decarbonize their energy footprint.

The early phaseout of IRA support for BTM residential systems will likely put pressure on the adoption of residential solar power in the US. Nevertheless, many states in the US – notably California, New York, and New Jersey – have local tax and other support incentives for residential solar systems (Brooks, 2025). While Canada may trail the US in utility-scale solar penetration, provinces such as Ontario and British Columbia currently provide rebates for both home solar and battery systems (EcoFlow, 2025).

More distributed systems will be co-located with storage

Capacity of distributed solar and solar+storage (GW_{AC})

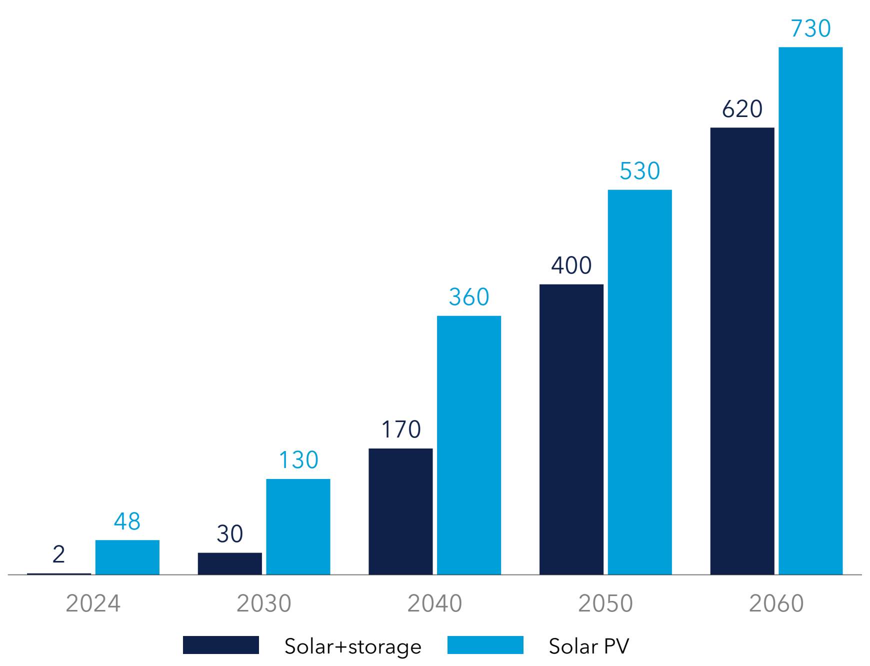


FIGURE 6.4 | Historical data source: IEA (2025)

Distributed solar+storage and time-of-use rates

As solar energy continues to integrate into the electricity grid, more solar self-generators will adopt Li-ion batteries with their solar systems. This will increase self-consumption and maximize savings. Batteries can be charged with excess electricity during generation, often when electricity prices are near-zero due to high solar generation.

Distributed solar systems get cheaper than grid electricity

Levelized cost of electricity (USD/MWh)

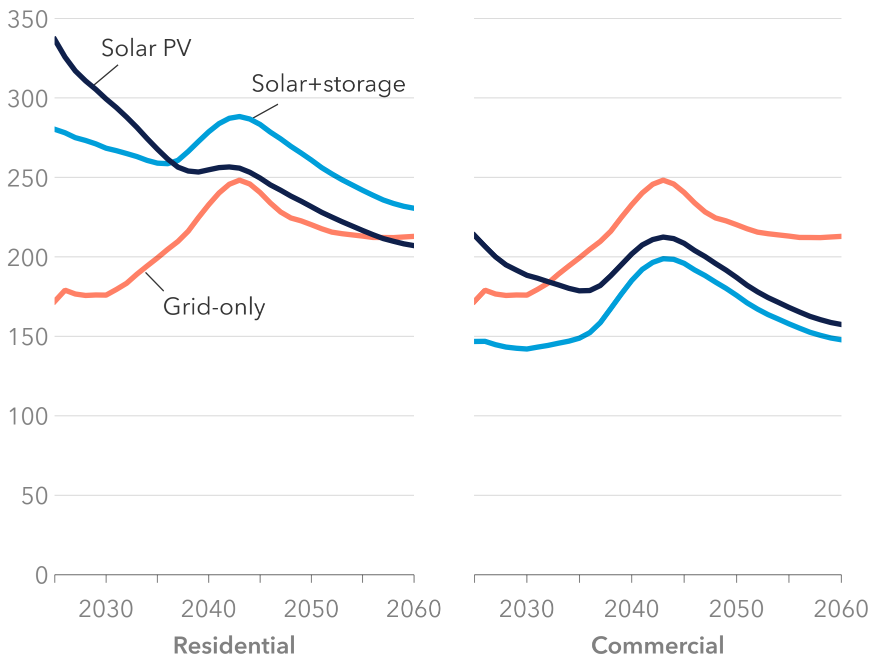


FIGURE 6.5 |

Instead of selling this excess electricity at low prices, self-generators can store it. When prices are higher, typically in the evenings, they can either use the stored electricity to reduce their grid consumption or sell it back to the grid. We forecast that by 2060, North America will have similar levels of distributed and utility-scale standalone solar, with distributed solar+storage being twice as prevalent as utility-scale solar+storage.

As more households and commercial establishments electrify, we expect this trend to continue along with more time-of-use (variable by time when electricity is consumed) rates. In fact, we already see signs of data centers and AI compute-related big loads being built with their own BTM solar and storage. Furthermore, we are seeing signs of such big loads getting faster interconnection when they come with their own BTM storage and generation sources. The market is ripe for the robust growth of commercial and industrial-scale solar+storage.

The favorable economics of self-generating options, compared to relying solely on the grid, have historically driven the adoption of distributed BTM solar systems – and will continue to do so – with residential and commercial electricity prices set to rise in the near future.

It's not all sunny for solar

Although the outlook for solar in North America remains strong – spanning utility-scale and distributed systems, with or without storage – there are emerging challenges on the horizon.

- **Price cannibalization:** Non-dispatchable ('unfirm') solar faces declining revenues due to price cannibalization (Figure 6.3). Co-located batteries can improve dispatchability, but typically only for a few hours. Profitability improves when projects secure dedicated off-take or power purchase agreements for at least part of their output, and when design and siting are optimized across the full value chain.
- **Policy and cost risks:** In the US, projects that achieve significant progress before 4 July 2026 remain eligible for PTCs and ITCs. However, tariffs and restrictions related to foreign entities of concern (FEOCs) could raise costs and undermine project profitability. Similarly, the Canadian province of Alberta has placed a moratorium on certain solar projects and enacted legislation that hinders solar development, further increasing investment risk.
- **Interconnection delays:** Lengthy interconnection queues remain a major obstacle to bringing new solar plants online. These delays drive up both capital costs and overall project expenditures.

As solar energy continues to integrate into the electricity grid, more solar self-generators will adopt batteries to maximize savings and manage excess generation.

6.2 ONSHORE WIND CAN WEATHER IT

Wind energy, specifically onshore wind energy, generated more utility-scale electricity than solar in North America in 2024. While we anticipate solar electricity to overtake wind electricity as early as 2026, it is undeniable that onshore wind energy has been instrumental in changing the electricity mix of many regional grids in the US (such as California and Texas) and Canada (such as Alberta).

One of the main reasons for onshore wind's favorability is that it complements solar electricity generation: when solar electricity generation ramps down, onshore wind picks up the slack. Furthermore, onshore wind is consistently the second-cheapest source of electricity in North America, after solar, and does not suffer from the diurnality of solar generation.

The period from 2020 to 2025 has been challenging for onshore wind in North America, especially in the US. Canada has managed to average about 1 GW of onshore wind installations every year in this period. However, after an installation peak in 2020, average installations have been declining in the US due to interconnection queues, local opposition to onshore wind, and competition from solar power installations.

However, we forecast this trend of reduced installation will reverse in the next five to ten years due to:

– **Growing demand:** Projected electricity load growth in both the US and Canada will require a diverse range of power generation sources.

– **A viable alternative:** Onshore wind is not only crucial, but often the only viable option to meet this demand, especially given the current supply chain backlogs and escalating costs for new gas turbines.

– **Favorable economics:** Onshore wind has a more stable and higher average market price than solar because it produces electricity more consistently throughout the day.

– **Less impacted by regulations:** We expect FEOC rules, which govern eligibility for key tax credits like the ITCs and PTCs, will affect onshore wind less than solar. While onshore wind's supply chain may still need some adjustments, the impact of these regulations is significantly less severe for onshore wind than for solar.

Average installations have been declining in the US, but we forecast this trend to reverse in the next five to ten years.

Trend reversal in onshore wind capacity coming online

Onshore wind capacity addition (GW/yr)

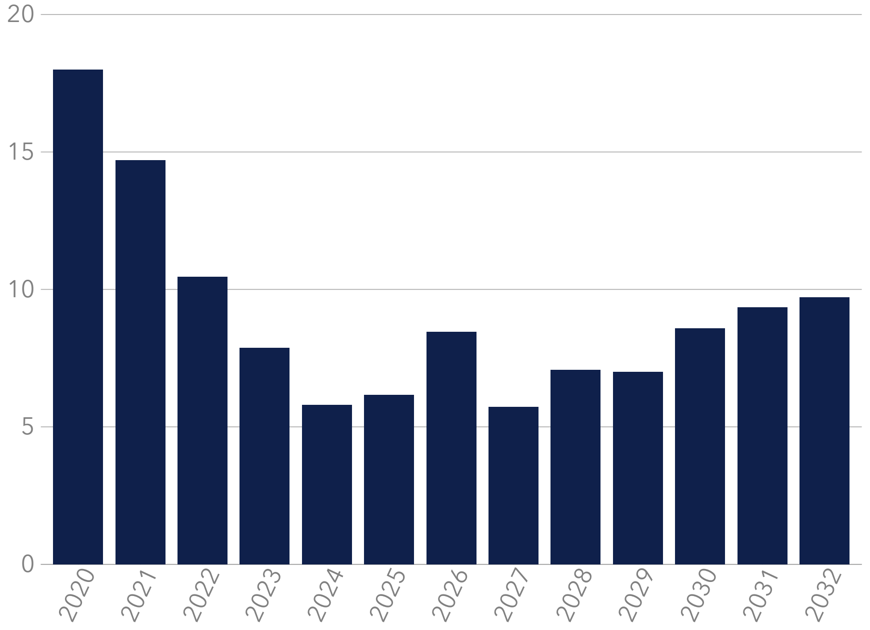


FIGURE 6.6 |

Average capture price of onshore wind tracks wholesale price

Capture and wholesale price of electricity (USD/MWh)

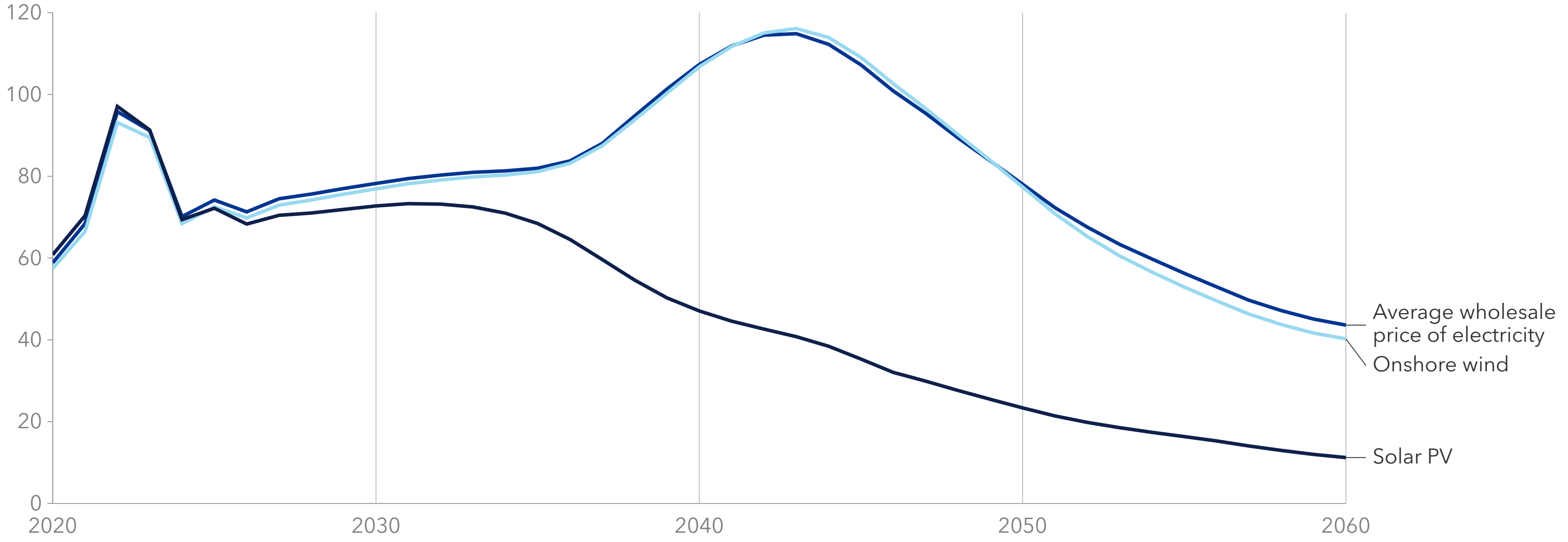


FIGURE 6.7 |

Onshore wind growth and volumes

We forecast onshore wind capacity in North America to grow from 180 GW in 2025 to more than 200 GW by 2030. By 2050, onshore wind capacity will grow to about 670 GW, representing about 25% of total installed power capacity. At that time, onshore wind will make up the majority (75%) of wind power capacity.

In North America, the economics clearly favor onshore wind over offshore wind. Despite good wind regimes off the Eastern Seaboard of both the US and Canada, the levelized cost of installing bottom-fixed wind turbines and connecting them to the onshore grid is higher. A typical onshore wind project with the final investment decision in 2025 has an estimated LCOE of about one third that of a typical bottom-fixed wind turbine project in the same year. Coupled with the policy headwinds and permitting times, developing an offshore wind project in the next five years will be difficult.

Onshore wind dominates

Wind capacity (GW)

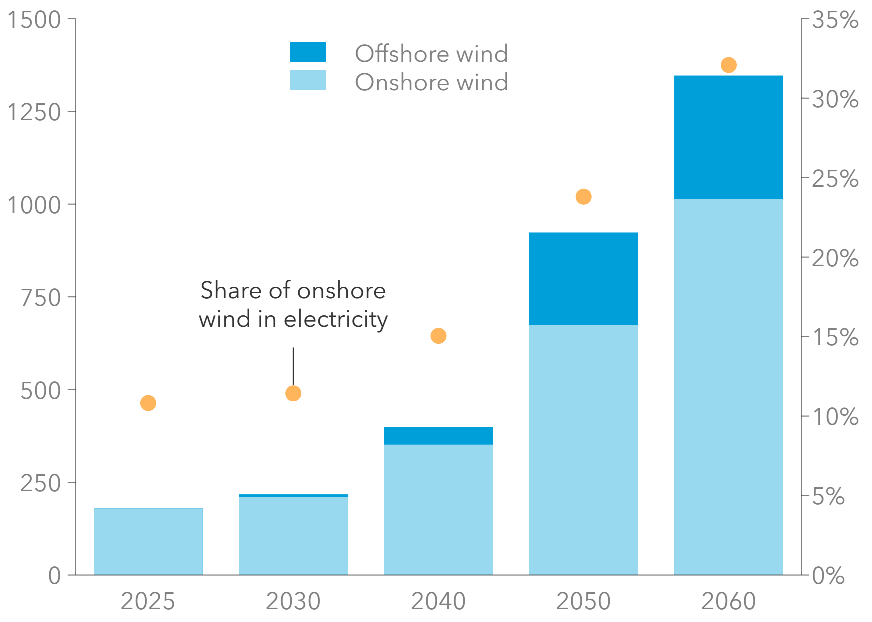


FIGURE 6.8 |

Onshore wind dominates because of lower LCOE

Levelized cost of electricity (USD/MWh)

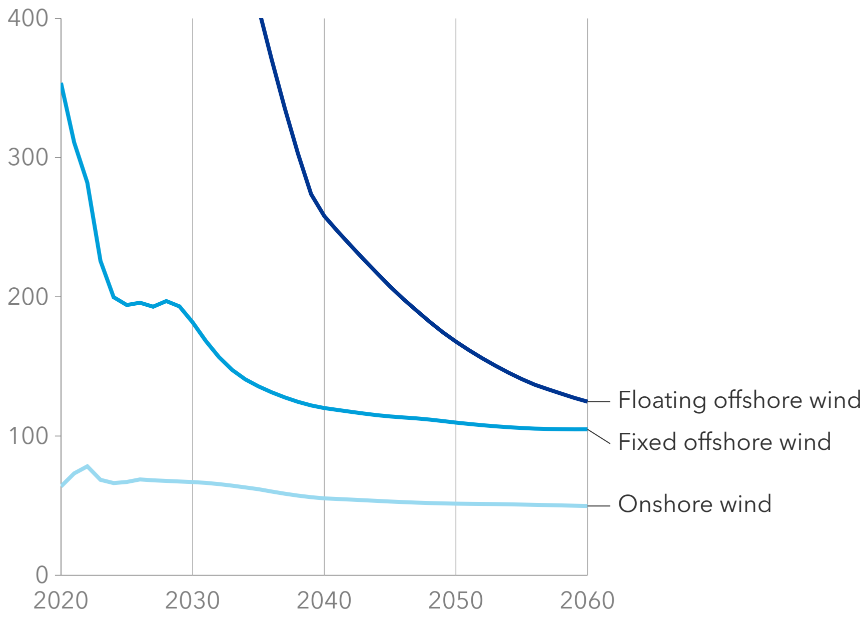


FIGURE 6.9 |

Repowering aging assets

Onshore wind has another advantage: the ability to repower aging assets, ensuring superior economics by prolonging their lifetime with a cost outlay much lower than a new project. An owner of a typical wind farm will consider either retiring the project or repowering it. In most cases, newer turbines are bigger and more efficient, requiring fewer turbines on the wind farm to maintain or even enhance the output.

In short, repowering aging wind assets is a financially attractive option because:

Aging fleet

– Over 70,000 onshore wind turbines in the US and Canada, many nearing or past design life, can be rejuvenated with repowering.

Policy and tax incentives

– The IRA allows older projects (10+ years) to requalify for PTCs through major upgrades; eligibility lasts until the end of 2027 despite credit phase-outs.

– Repowering has historically been used to extend credit eligibility and project life.

Economic and technical gains

– New components deliver higher efficiency, greater output, and lower maintenance needs.

– Repowering is cheaper than greenfield projects, since sites, foundations, and grid connections can be reused.

Repowering does come with its own set of challenges, however:

Regulatory and interconnection hurdles

– Upgrading might require re-permitting or revised environmental approvals, or new grid studies if the output increases materially. Interconnection queue delays remain problematic.

Physical and technical constraints

– Some older turbines may have exhausted their mechanical structural limits (fatigue, foundation issues, tower limitations). Upgrading parts might be constrained by compatibility. Moreover, removal and disposal is difficult, especially for large blades and composite materials.

Cost and supply chain costs

– New components, larger turbines, transport, crane costs, etc., can be expensive. Tariffs or import restrictions on key components increase costs. Renewed supply chain pressures (lead time, shipping, manufacturing capacity) are relevant.

Market and power price risks

– Even with more output, revenues depend on power purchase agreements (PPAs), power pricing, market conditions, curtailment risks (when supply exceeds the grid's ability to use or transmit it), and the value of incremental output during non-peak hours.

Policy uncertainty

– Incentives could change; tax credit eligibility rules may be updated; tariffs or trade rules might shift. For instance, changes in what qualifies for PTC or how 'repowering' is defined can impact the economic case.

6.3 OFFSHORE WIND IS SUNK (FOR NOW)

Offshore wind presents a significant opportunity for states and cities along the Eastern Seaboard of North America, such as New York and Massachusetts, and the eastern Canadian provinces. Although offshore wind technology carries higher costs and engineering challenges compared with onshore wind, many utilities and regions view it as essential to the future electricity mix. Unlike onshore wind and solar, which require extensive land, offshore wind reduces land-use conflicts – an important advantage in densely populated regions with limited space.

As a carbon-free resource, offshore wind also supports the ambitious climate and decarbonization commitments adopted at state levels. Its generation profile complements solar by producing more power in the late afternoon and evening, when solar output declines, thereby enhancing grid reliability.

Beyond its energy contributions, offshore wind has the potential to deliver substantial economic and industrial benefits. Domestic design, manufacturing, and construction can strengthen local supply chains, create employment opportunities, and revitalize port infrastructure. These attributes positioned offshore wind as a favored power technology along the Eastern Seaboard from 2020 to 2025.

However, the offshore wind industry in North America remains in its early stages. Under the current policy environment, meaningful growth is unlikely in the short to medium term (DiGangi, 2025b; DiGangi, 2025c). Cost pressures and industry headwinds – already evident in more mature markets such as Europe – further constrain prospects (DNV, 2025). As a result, significant new project development in the US and Canada is unlikely before 2028. While onshore wind and solar have reached a stage where deployment can continue even with reduced policy support, offshore wind has not yet achieved the same maturity. Any prolonged policy hiatus will therefore risk slowing momentum in the sector, with a recovery likely to take longer than more established renewable technologies.

As such, we have reduced our forecast for the market size of both fixed and floating offshore wind capacity of North America by almost half since the global *Energy Transition Outlook* in 2024 (DNV, 2024). Nevertheless, the long-term prospects of offshore wind are sizeable, given the need for clean power for cities and Canada's interest in offshore wind since 2025 (Natural Resources Canada, 2025).

Offshore wind is stalled until after 2030

Grid-connected offshore wind capacity (GW)

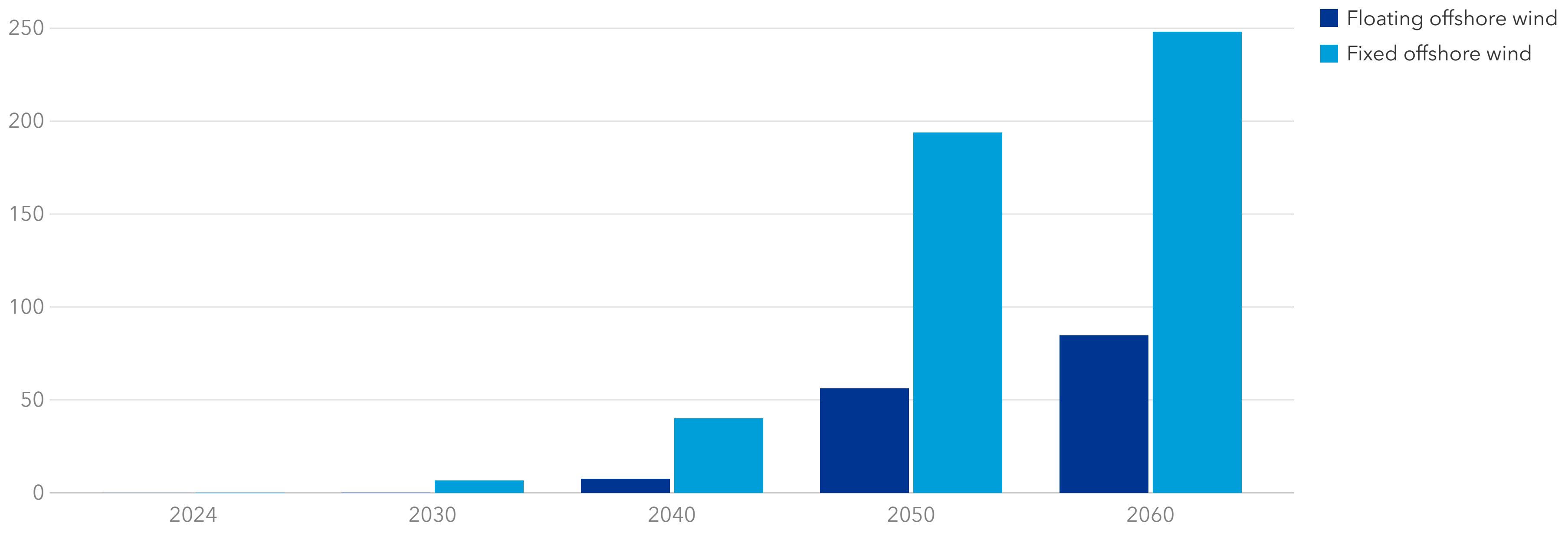


FIGURE 6.10 |

6.4 BATTERIES EVERYWHERE

Solar power has taken the lead role in new renewable generation in North America, and battery storage is increasingly its supporting actor. The logic is clear: as solar capacity expands, system operators must find flexible, dispatchable resources to absorb midday surpluses and shift that energy into the evening peak. Batteries, with their rapid response times and modular deployment, are uniquely suited to this role.

The near-term picture is complicated. In the US, developers face shifting market rules, especially regarding FEOC, interconnection delays, and uncertainty around qualification for IRA domestic content bonuses. These factors have delayed or repriced some projects in 2024 and 2025. Even in California and Texas – the two leading storage markets – developers are contending with congestion and price volatility that challenge project revenues.

The requirement for firm capacity during periods of low solar availability, together with persistent interconnection delays for large loads across many US and Canadian grid nodes, will be a key driver of Li-ion battery deployment. From a market perspective, we forecast annual additions of standalone battery capacity in North America to nearly triple within two years, rising from approximately 20 GWh in 2025 to 60 GWh in 2027.

We project that most new battery installations will be standalone systems, primarily participating through capacity payments and price arbitrage. In addition, large energy users – particularly data centers and AI computing facilities – will likely increasingly deploy grid-connected, BTM Li-ion batteries. These systems serve as both a hedge for operational flexibility and an accelerator for grid interconnection.

Despite higher costs and supply chain uncertainties for batteries and related components, the underlying drivers of Li-ion adoption remain strong. Solar is among the lowest-cost sources of new generation, and batteries can typically be deployed within months rather than the multi-year timelines for new gas capacity. This rapid deployment capability is especially valuable for states facing reliability challenges during extreme weather events, such as by recent heat waves in California and cold snaps in Texas.

Looking ahead, the long-term draw of storage is clear: abundant, low-cost solar makes storage not an optional add-on, but a fundamental enabler of a high-renewables and economical grid. As manufacturing scale reduces costs and domestic supply chains take hold, North America is likely to see storage deployment accelerate. While near-term turmoil may slow some projects, the trajectory is unmistakable – batteries are positioned as the technology that allows the region to truly soak up the sun.

Li-ion battery installations set to triple by 2027
Yearly battery capacity addition (GWh/yr)

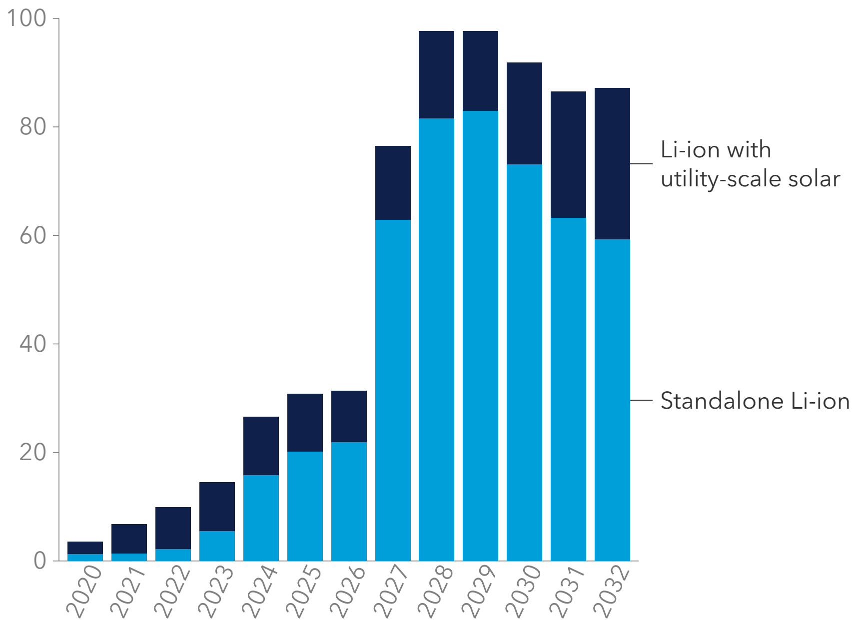


FIGURE 6.11 |

By 2030, storage capacity will be dominated by batteries
Energy storage capacity (GWh)

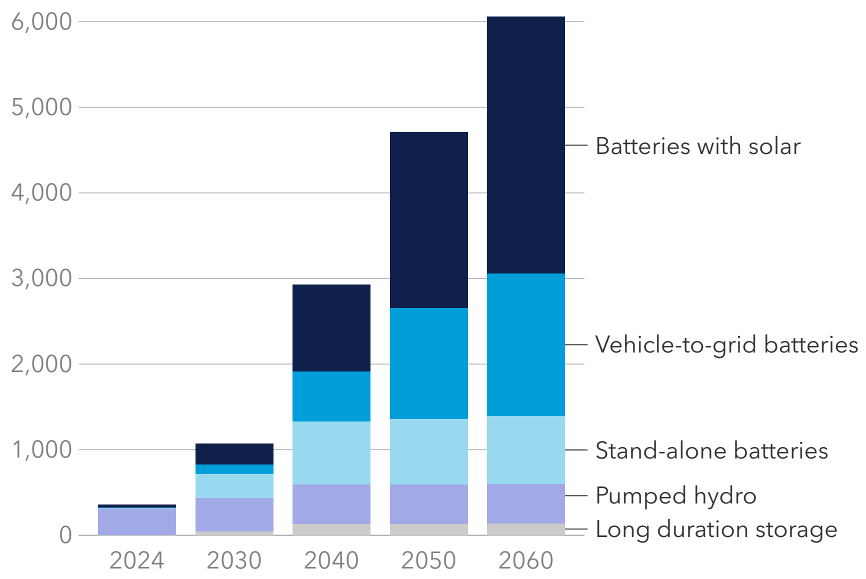


FIGURE 6.12 |

Longer-duration batteries
A notable development is underway toward longer-duration batteries. Whereas the first wave of US deployments centered on two- to four-hour systems, utilities and ISOs are increasingly exploring procurements for eight-hour projects (or more). This trend reflects developments in global markets, including those in the UK and Germany, where similar procurement strategies are being implemented.

In North America, eight-hour systems will allow renewables to play a more central role in meeting evening peaks, displacing some of the need for new natural gas peaker plants. Currently, we do not incorporate the significant use of long-duration lithium alternatives, such as flow batteries or compressed air systems, due to the absence of commercially viable, cost-effective options at present (i.e. these technologies are not mature enough to reliably project cost reductions). Canada is also beginning to see storage paired with solar in Alberta and Ontario, while provinces with hydro resources are exploring how batteries can provide localized resilience and grid services.

The long-term draw of storage is clear and North America is likely to see deployment accelerate.

Renewable developers

Renewable developers in the US and Canada currently face unprecedented opportunities and challenges.

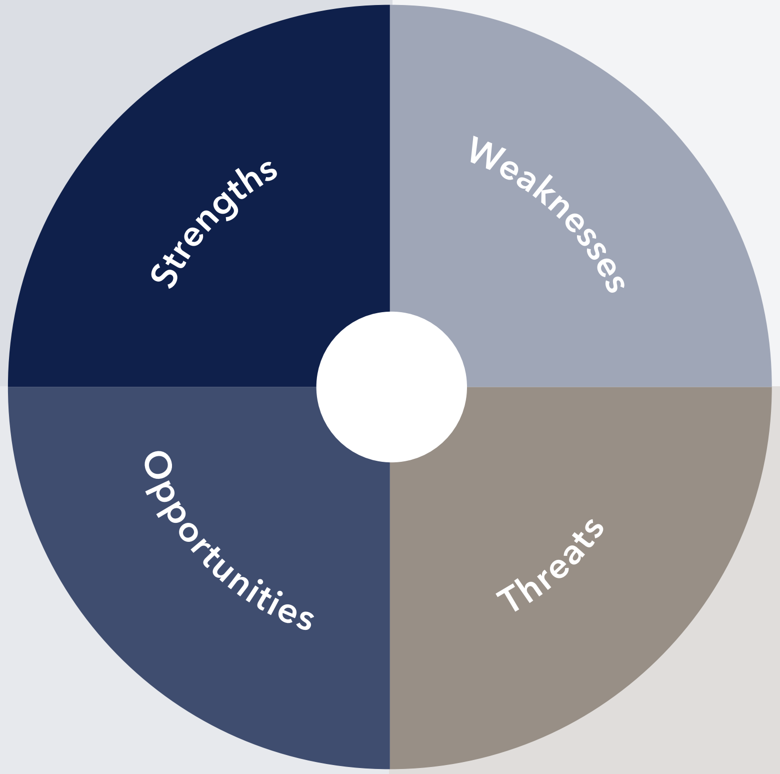
Unlike in the 2010s, North America is undergoing a period of remarkable load growth, creating a potentially captive market for renewable developers. On this page, we analyze the SWOT of a typical renewables developer in the US and Canada.

Strengths

- **Lowest LCOE** of all generation technologies
- Solar and onshore wind are **mature and proven technologies** in the region

Weaknesses

- **Dispatchability is weak** and needs to be paired with storage
- **Pairing with storage** may affect the profitability calculus
- May require components that are dependent on **imports subject to tariffs and elevated costs**
- Renewable developers depend on grid interconnection since generation is further away from demand centers; **no grid interconnection implies they have no way of transmitting the electricity** to demand centers



Opportunities

- **Electricity demand growth** in the region after almost two decades of stagnation, leading to a mostly captive customer base
- This electricity demand growth leads to easier **power purchase agreements and forward contracts**
- Despite the early sunsetting of the IRA ITCs and PTCs, clear rules regarding the early phase-out provide **better certainty**
- State and province **mandates regarding clean/low-carbon electricity generation** lead to higher demand for renewable electricity

Threats

- The **policy incoherence and friction** created at the different administrative levels of the two nations in North America can lead to projects not having off-takers
- The **tacit or explicit favor/support of natural gas or coal infrastructure;** specifically, building new gas-fired power plants or prolonging the life of a coal-fired power plant can harm the chances and profitability of renewables
- **Local opposition to renewables** can stop a project from proceeding; for example, the local opposition to onshore wind in many locations in the US
- **Trade tariffs on clean energy technologies or components**, such as solar modules or battery components, can increase the cost and threaten the survival of the project
- **Bans on imports of energy technologies or components** may threaten the survival of renewable projects

7 FOSSILS HOLD UP

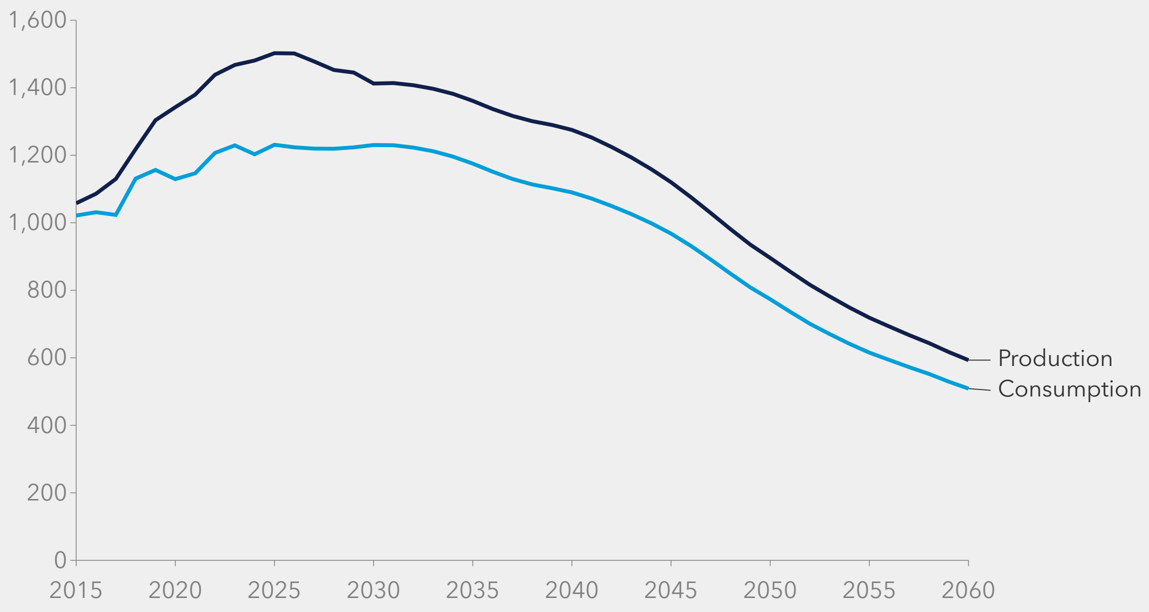
7.0 OVERALL TRENDS

Dismantling federal decarbonization policies has slowed the transition. Fossil fuels – particularly natural gas – will continue to play a central role in the energy mix through to at least 2060. However, continued investment in renewables, state-level policy commitments to decarbonization, public demand for climate action, and international demand for less carbon-intensive energy sources will continue. For utilities, project developers, and investors, understanding this dynamic is critical for balancing near- and long-term transition strategies.

Fossil fuels remain a significant source of energy delivery in North America throughout most of the forecast period covered in the ETO. We forecast natural gas production and consumption will peak in the late 2020s before beginning a gradual decline. By 2060, natural gas consumption will be approximately one-third of the peak levels seen in 2025. Oil and coal have already peaked. Coal will be rapidly phased out – though not as rapidly as forecast in ETO 2024 – and contributes a very small amount of overall energy in North America after 2040. The decrease in oil consumption and production is more gradual than coal, with oil consumption in 2060 still about one-quarter of the peak levels seen in the mid-2020s.

Natural gas peaks in the late 2020s then slowly reduces

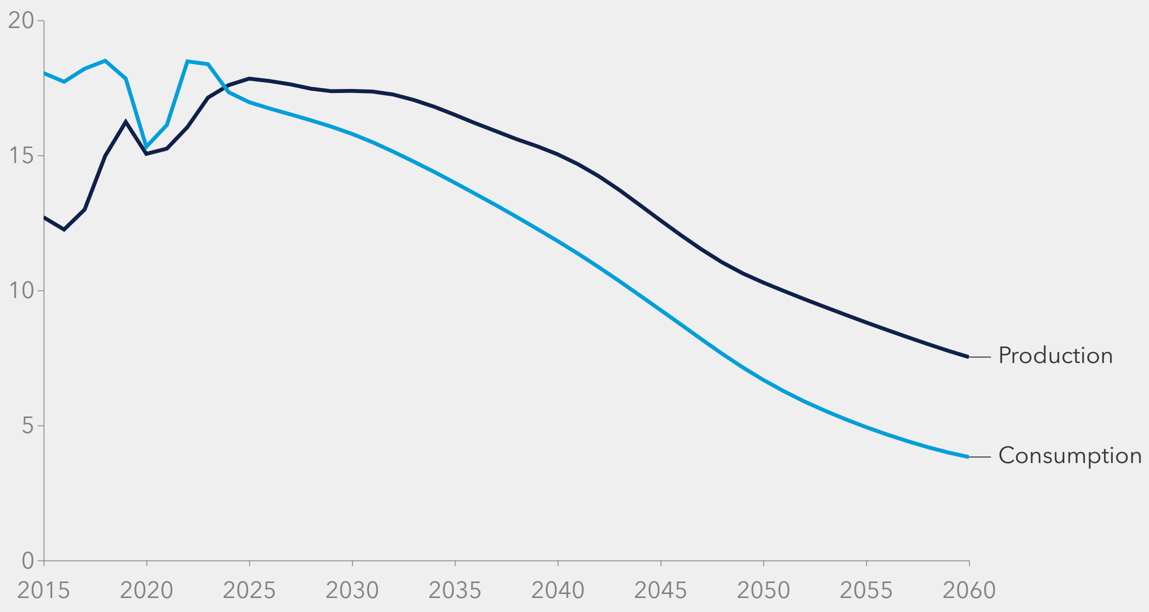
Natural gas production and consumption (Bcm/yr)



Historical data source: IEA WEB (2025)

Oil production and consumption gradually decreases

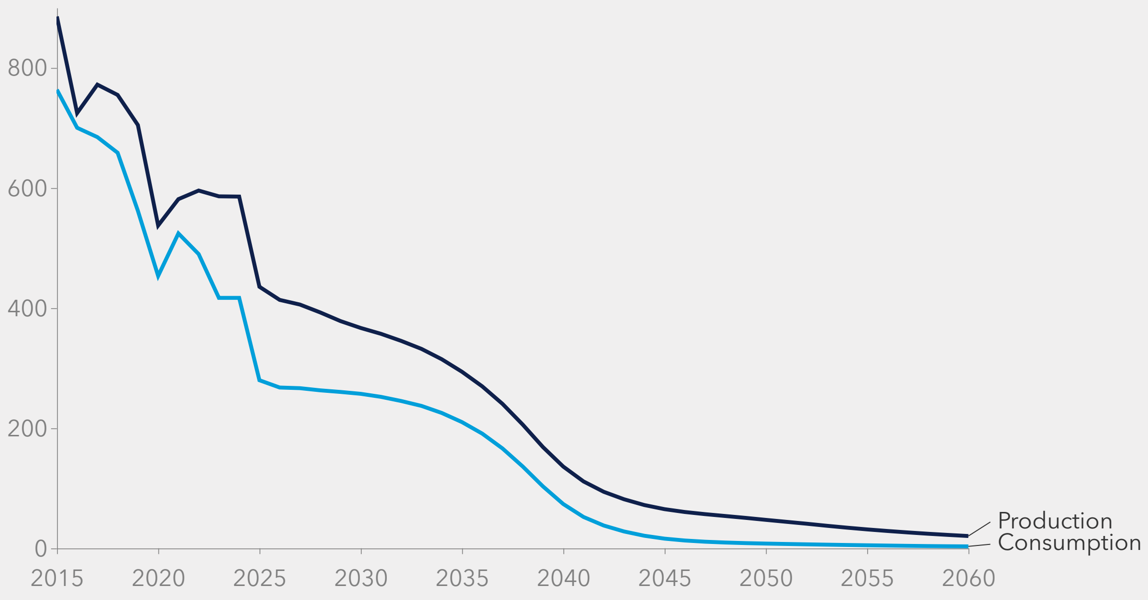
Crude oil production and consumption (Mbpd)



Historical data source: IEA WEB (2025)

Coal is well past peak production and consumption

Coal production and consumption (Mt/yr)



Historical data source: IEA WEB (2025)

7.1 NATURAL GAS

Natural gas will define North America's energy system through 2040. Yet its dominance will not last indefinitely. By mid-century, renewables, storage, and non-fossil technologies will reshape the landscape, with gas shifting from growth engine to balancing resource. For utilities, investors, developers, NGOs, and policymakers, the path forward requires both seizing the near-term gas expansion opportunities and preparing for the structural transition that will characterize the decades beyond 2045.

Growth phase: 2025-2035

From 2025 to 2030, natural gas production and consumption will rise modestly before gradually declining. Much of this growth will be concentrated in the US through expansion of shale gas basins such as the Permian, Marcellus, and Haynesville. Several factors drive this trajectory:

- **Data center expansion** – Many data centers are being built near existing gas-fired generation hubs to take advantage of the relatively cheap, dispatchable power.
- **Hard-to-decarbonize sectors** – High-heat industries such as aluminum and copper production and petrochemical production such as ethylene continue to use natural gas.
- **Infrastructure investment** – Significant capital is flowing into new pipelines, midstream infrastructure, and LNG export terminals, many of which are targeting export markets.
- **Cost competitiveness** – Through the early 2030s, natural gas remains inexpensive, balancing affordability and reliability.
- **Export expansion** – Exports from North America will likely rise sharply into the mid-2030s, driven by cost competitiveness and energy security concerns in Europe and OECD Asian countries.

Rising demand and infrastructure expansion means that natural gas will remain attractive to private equity, institutional investors, and utilities. Developers will find robust opportunities in pipeline projects, LNG facilities, and combined-cycle gas generation plants. Policymakers will face increasing pressure to manage emissions through methane regulations and carbon capture incentives.

Natural gas exports remain elevated through 2040

Natural gas export (Bcm/yr)

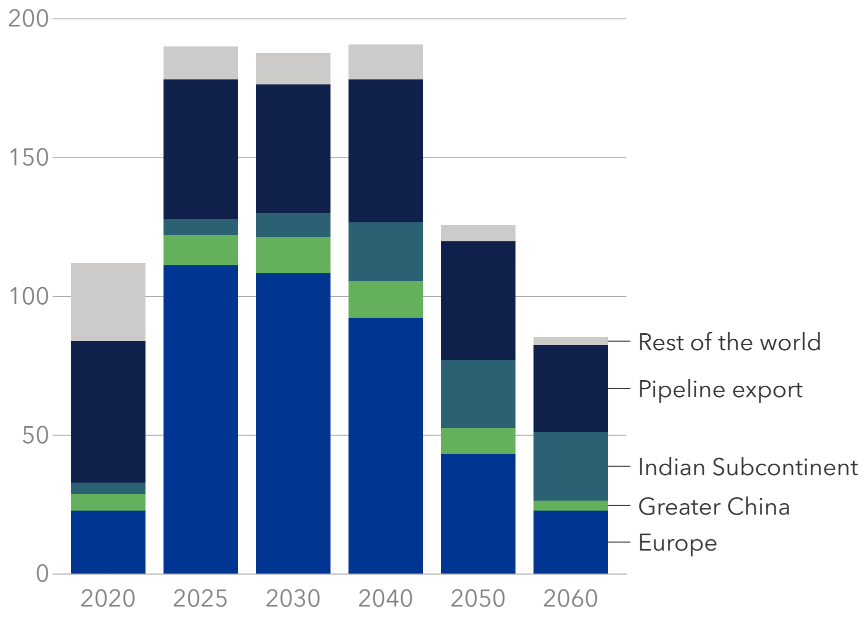


FIGURE 7.1 |

As North American production growth peaks in the early-2030s, the market begins to stabilize through the 2040s. Demand growth slows for three main reasons:

- **1) Global renewable buildout** - Europe and Asia accelerate deployment of solar, wind, and battery storage, gradually reducing their reliance on LNG imports.
- **2) Domestic renewable integration** – In North America, utilities expand renewable portfolios at scale, supported by transmission upgrades and falling costs for long-duration storage. Gas remains essential for system balancing, but its role as a primary growth driver diminishes.

Stabilization phase: 2035-2045

- **3) Policy pressure** – Climate commitments tighten, with carbon pricing, stricter methane standards, and emissions disclosure requirements making incremental gas projects more challenging.

During this stabilization phase, annual North American gas output plateaus. Exports stay strong, but face competition from lower-cost suppliers and renewable alternatives. Capital allocation becomes more selective and focuses on efficiency improvements, carbon capture integration, and incremental infrastructure rather than large greenfield developments.

For energy utilities and project developers, the 2040s represent a pivot point: natural gas remains indispensable, but growth shifts toward renewables and storage. Private equity and institutional investors will focus increasingly on hybrid strategies – pairing gas assets with carbon mitigation technologies and renewable expansion. Policymakers will play a critical role in defining this balance, ensuring both system reliability and alignment with climate objectives.

Demand for natural gas in the power sector will start declining in 2030. By the mid-2040s, renewable penetration accelerates to levels that begin to displace gas in a material way.

The decarbonization push around the world, especially in Europe and other OECD regions, decreases demand for North American natural gas. Regions such as the Indian Subcontinent that lack their own domestic resources maintain demand, but this will not fully compensate for European and OECD decreases.

Demand for natural gas as a raw material in the chemicals industry and as an energy carrier in the manufacturing sector will endure. By 2060, we forecast that almost half of natural gas demand in North America will be used in manufacturing and as a feedstock.

Decline phase: 2045-2060

For investors, stranded-asset risks will rise, especially for LNG and pipeline projects without carbon management. NGOs will press for faster retirements, while policymakers must manage workforce transitions and ensure reliability during the shift to renewables.

Gas use in power and building sectors declines after 2030

Natural gas demand by sector (EJ/yr)

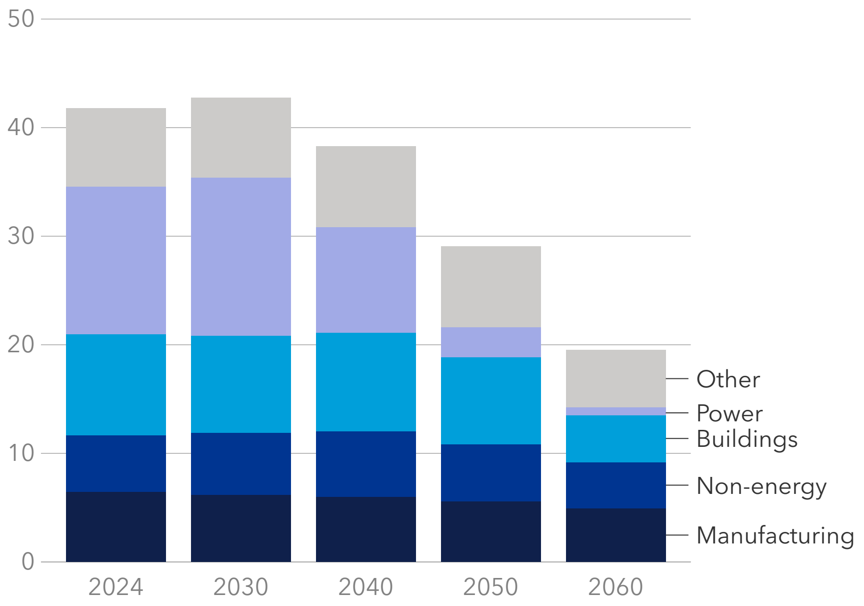


FIGURE 7.2 | Other includes hydrogen production, agriculture, and transport sector demand.

7.2 OIL

North American oil demand will reduce marginally from 2024 to 2030, an overall 9% reduction and an 8% reduction in oil demand for transportation. From 2030, the structural forces of electrification, renewables, and climate policy will drive a steady decline. By 2040, oil demand will be two-thirds of 2024 levels, with EVs leading to demand erosion in the transport sector. By 2060, oil demand in transport will be one-sixth of 2024 levels. For utilities, developers, investors, NGOs, and policymakers, the imperative is clear: leverage short-term oil-linked returns while preparing for a long-term future centered on electrification, sustainable fuels, and resilient energy systems. The North American market will reward those who balance immediate opportunity with forward-looking transition strategies.

Transportation declines, but continues to dominate oil use

Oil use by sector (Mb/yr)

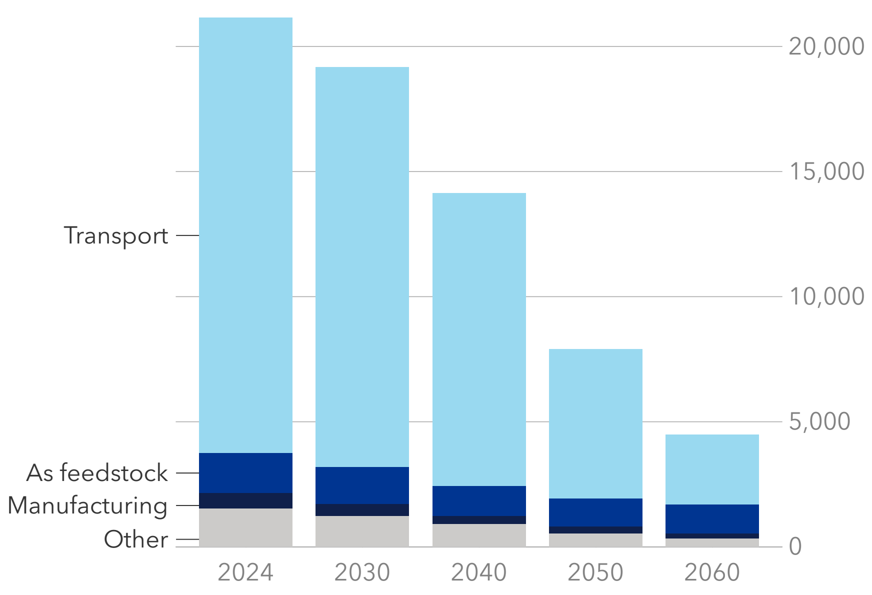


FIGURE 7.3 | Other includes power sector own use, buildings, agriculture, and military oil demand.

Outlook for oil production and consumption: 2025–2030

North America will remain among the world's most important oil producers and consumers through 2030. Globally, it is the second largest producer of crude oil, and the largest consumer of oil.

Production: US shale output (Permian, Bakken, Eagle Ford) will expand, keeping the region an important supplier of crude oil. Canada's oil sands maintain high volumes, though under mounting ESG scrutiny.

Consumption: Oil demand in transport will reduce by 8% by 2030 led by automation and lesser demand for travel. While EV sales accelerate after a temporary policy-related lull, the legacy fleet will continue to anchor gasoline and diesel consumption.

Transition phase: 2030–2045

After 2030, oil consumption in North America will begin a steady decline.

Passenger vehicles

- EVs achieve price parity with ICE vehicles by the early 2030s, driving adoption in urban and suburban markets. By 2045, EVs could account for **90% of new passenger vehicle sales.**
- Oil demand from light-duty vehicles (LDVs) falls **50% below 2030 levels** by 2045, though legacy ICE vehicles in rural regions slow the decline.

Freight and heavy-duty transport

- Trucking remains oil-intensive through the 2030s, but efficiency standards and new drivetrain technologies (electric, hydrogen, renewable natural gas) gradually erode demand.
- By 2045, oil consumption in freight would be **28% below 2030 levels.**

Aviation and shipping

- Aviation maintains liquid fuel reliance, though sustainable aviation fuels (SAFs) displace petroleum jet fuel at growing scale. By 2045, **28% of jet fuel demand** could be met by SAFs in North America.
- Shipping begins adopting LNG and ammonia fuels, with petroleum bunker fuel use down **75% from 2030 levels.**

Policy drivers

- Carbon pricing in Canada, zero-emission vehicle mandates in US states, and federal incentives for EVs and SAFs accelerate demand erosion.

Structural decline: 2045–2060

By the mid-century mark, electrification and alternative fuels dominate and petroleum's share of transportation collapses.

Passenger vehicles

- By 2060, EVs capture **99% of new vehicle sales**. Oil demand from passenger vehicles falls 95% below 2030 levels. ICE fleets persist in niche rural applications, but their role is marginal.

Freight and heavy duty

- Electric and hydrogen trucks reach full-scale deployment. Diesel use in freight declines **73% from 2030 levels** by 2060, though some long-haul and cross-border trucking retains fossil diesel.
- Renewable diesel and biofuels remain transitional but not dominant.

Aviation

- Petroleum-based jet fuel remains the most resilient sector but still erodes as SAFs and synthetic fuels scale up. By 2060, **52% of jet fuel demand** could be met by non-petroleum alternatives. Residual oil demand persists due to energy density needs.

Shipping

- Oil's role in North American shipping declines to **10% of energy demand** by 2060 as LNG, ammonia, and synthetic fuels become standard in new vessels. Petroleum bunker fuel remains only in older ships.

Overall

By 2060, we project North American transport oil demand will be **84% lower than 2024,** with aviation as the last major stronghold of petroleum demand. Other sectors (manufacturing, oil as feedstock, and other uses) show much smaller and more stable demand levels throughout the period. Oil use as feedstock remains steady around 1,100–1,500 Mboe/year, due to its persistent role in petrochemicals and plastics. Manufacturing and other uses are minor contributors and will gradually decline toward 2060.

7.3 COAL

Coal's outlook in North America is one of steady contraction. From a base of 400 Mt/yr today, production and consumption will decline to negligible levels by 2040 as renewables and natural gas dominate the energy landscape. For utilities, developers, investors, NGOs, and policymakers, the challenge lies not in reversing coal's decline but in managing it responsibly, capturing the opportunities of the clean energy transition, and mitigating the social and economic impacts on affected communities. The trajectory is clear: North America's energy future is post-coal and defined by flexibility, sustainability, and innovation.

Current position: 2025–2030

Coal consumption dwindles to nothing after 2040

Coal energy demand by sector (EJ/yr)

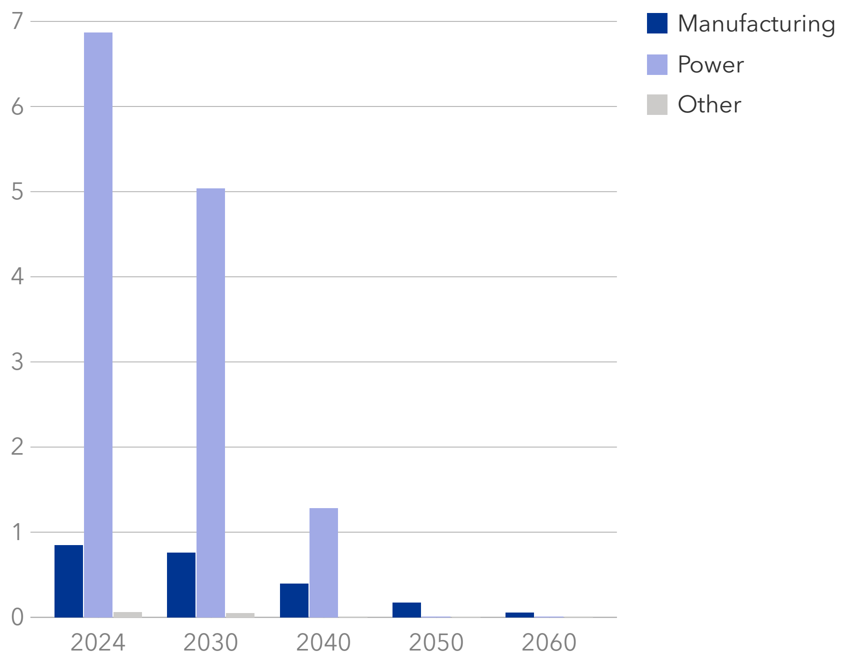


FIGURE 7.4 | Historical data source: IEA WEB (2025)

Coal still supplies a measurable portion of North America's power mix, particularly in the US where legacy plants remain operational in the Midwest and Appalachian regions. However, new coal plant construction is virtually nonexistent.

Regulatory pressure, aging infrastructure, and the comparative economics of gas and renewables are accelerating retirements. By 2030, we expect coal consumption to fall from 400 Mt/yr to roughly 350–375 Mt/yr, reflecting both supply-side contraction and demand-side substitution. Utilities are prioritizing natural gas combined-cycle plants and utility-scale renewables, both of which offer flexibility and lower emissions profiles. For investors, the near-term landscape still includes coal-related opportunities in infrastructure decommissioning, reclamation, and site repurposing.

Even with policy support, the demand fundamentals weaken substantially for coal (Brown, 2025), signaling the need for planning for a post-coal future.

Transition decades: 2030–2050

The period between 2030 and 2050 represents the decisive phase of coal's decline. Several dynamics will converge:

- **Environmental policy** – Decarbonization commitments across North America will tighten carbon regulations. Even without a uniform carbon price, state and provincial mandates are pushing utilities toward renewables and storage. By the 2040s, it will be nearly impossible for coal plants to compete without subsidies, which are unlikely given the political and social momentum toward clean energy.
- **Economics of alternatives** – The declining cost trajectory of wind, solar, and advanced storage will continue to undercut coal on price. Levelized costs of energy (LCOE) for solar and wind are already well below new-build coal. By the 2030s, even existing coal plants, especially those with low capacity-utilization, will struggle against the marginal cost of renewables paired with flexible natural gas backup.
- **Grid reliability solutions** – Stable baseload power – one of coal's traditional strengths – will be offset by advanced grid technologies, including distributed energy resources, digital management systems, and long-duration storage. This shift eliminates coal's strategic advantage and accelerates its displacement.

By 2050, we project annual coal consumption in North America will be well under 50 Mt/yr, largely limited to industrial uses or legacy plants in isolated regions. Power-sector demand, historically the backbone of coal consumption, will be virtually eliminated.

> By the 2030s, even existing coal plants will struggle against the marginal cost of renewables paired with flexible natural gas backup.

A negligible role for coal: post-2050 outlook

Beyond 2050, coal will have no meaningful role in North America's energy mix. Residual demand may persist for metallurgical coal in steelmaking or in certain export markets, but these niches will not reverse the structural decline. Carbon capture, utilization, and storage technologies could theoretically preserve a role for coal, but given the high costs, regulatory uncertainty, and faster progress in renewables and hydrogen, it is unlikely coal will regain competitiveness.

For investors and utilities, this period is best viewed as a post-coal economy where capital is fully reallocated toward clean energy, transmission, storage, and complementary gas assets.

Implications for stakeholders

Stakeholder	Natural gas	Oil	Coal
Energy utilities	Gas will remain central through the 2030s and 2040s, but utilities must prepare for long-term diversification by integrating renewables, hydrogen, and storage into their portfolios.	Accelerate investment in EV charging networks, renewable integration, and grid modernization in preparation for EVs overtaking ICE vehicles. Those with fuel distribution businesses must diversify or risk eroding margins.	Strategic planning should center on phased coal retirement schedules, workforce transition programs, and investment in gas and renewable assets. Utilities can also capture value in coal plant site redevelopment for solar, storage, or hydrogen hubs.
Project developers	Near-term opportunities abound in LNG terminals, pipelines, and gas-fired generation. Long-term, success will hinge on integrating carbon capture, repurposing infrastructure, and transitioning to hybrid renewable-gas projects.	Infrastructure tied to petroleum fuels carries heightened stranded-asset risk. Developers should prioritize flexible assets (SAF production plants, hydrogen hubs, and multi-fuel transport terminals) that adapt to shifting demand.	Opportunities in environmental remediation and brownfield redevelopment will open. Many coal-adjacent sites offer grid interconnection points, water access, and transportation links that can be repurposed for gas, renewable, and industrial projects.
Private equity & institutional investors	The investment window for pure-play gas expansion narrows by the 2040s. Capital must migrate toward transitional and clean technologies to avoid stranded asset risk.	Short-term oil-linked projects remain profitable, but investors must plan for a declining demand curve. ESG mandates will further limit long-lived oil assets. The most attractive opportunities will be in electrification, alternative fuels, and grid resilience.	Legacy coal investments face declining valuations, while adjacent industries (reclamation, recycling, and renewable deployment) offer high-return prospects. Long-term capital should shift toward enabling infrastructure, including transmission, storage, and LNG/gas capacity as transition bridges.
NGOs	Engagement will focus on methane leakage, flaring, and lifecycle emissions in the 2020s and 2030s, then shift to advocating for accelerated replacement of gas in the 2040s and 2050s.	NGOs will push for faster decarbonization.	Advocacy and oversight will remain critical in ensuring a 'just transition' for coal-dependent communities. NGOs can drive accountability in environmental restoration and workforce reskilling, ensuring that the benefits of the clean energy economy are broadly shared.
Policymakers	Balancing near-term energy security and global export leadership with long-term decarbonization commitments will remain a central challenge.	Policymakers must manage both emissions targets and economic disruption. Canada faces fiscal strain from oil sands decline. US states reliant on oil tax revenues will require transition planning.	The transition requires thoughtful design of regulatory frameworks. Carbon policies, labor market supports, and incentives for clean energy deployment will determine the pace and equity of the coal phase-out. Policymakers must also coordinate cross-border energy policy as the North American grid grows more integrated.

Oil and gas long term

Between 2025 and 2030, we expect North American oil and gas production to expand moderately, buoyed by favorable prices, export demand, and continued investment in LNG infrastructure. Yet the seeds of long-term decline are already visible, and three non-technical factors – regulatory policy, political stability, and labor availability – will shape the trajectory of the sector as the world accelerates toward renewables.

Regulatory policy

From 2025 to 2030, regulatory frameworks remain broadly supportive of upstream and midstream growth. Governments recognize oil and gas revenues as vital for energy security and geopolitical leverage. However, after 2030, global carbon-reduction commitments tighten. Stricter methane standards, carbon pricing mechanisms, and emissions reporting requirements increase the cost of operations. While some jurisdictions attempt to balance industry competitiveness with climate objectives, the overall trend is toward more restrictive regulation. By the 2040s, capital markets and policymakers increasingly favor renewable deployment, leaving oil and gas with a narrower, more expensive regulatory path.

Political stability

Political stability plays a dual role. Domestically, North American producers benefit from relatively stable governance compared with many resource competitors. This underpins their position as reliable exporters through 2030. However, the politics of climate policy and energy transition are intensifying. Electoral swings, trade disputes, and shifting alliances create uncertainty for investors and operators. Internationally, instability in other producing regions may briefly sustain demand for North American exports, but the broader global pivot to renewables ensures that these windows of opportunity are temporary. By 2050, political debate centers less on whether oil and gas should decline and more on how quickly the transition should proceed.

Labor availability

Skilled labor is already a constraint in the oil and gas sector, particularly in technical fields such as engineering, geology, and advanced operations. Between 2025 and 2035, rising wages and targeted recruitment allow the industry to manage, though at increasing cost. Beyond 2035, labor shortages deepen as societal priorities shift toward clean energy careers. Younger workers gravitate toward renewables and technology sectors, forcing oil and gas companies to automate more operations and reduce headcount. By the 2050s, a shrinking labor pool accelerates the industry's decline as workforce constraints compound regulatory and market pressures.

By 2050, political debate centers less on whether oil and gas should decline, and more on how quickly the transition should proceed.

Outlook summary

- **2025-2030:** Growth phase; supportive policy, stable politics, manageable labor shortages.
- **2030-2045:** Plateau and decline; tightening regulations and shifting demand reduce investment appeal.
- **2045-2060:** Structural contraction; minimal new development, legacy assets managed down, labor availability becomes a binding constraint.
- **After 2060:** Oil and gas remain present but diminished, serving niche industrial uses and strategic reserves rather than acting as the engine of economic growth. The interplay of regulatory tightening, political dynamics, and workforce evolution ensures that the industry's decline is not purely geological or technological, but deeply social and institutional.

8 GOING NUCLEAR

8.1 NUCLEAR POWER

Nuclear power is more popular now in the US and Canada than it has been in the last decade (Brennan, 2025). Despite this popularity, the prognosis for nuclear in the near term is indifferent, with a more positive outlook in the longer term.

Nuclear reactors – big and small
Nuclear energy has been part of the North American grid since the 1960s and continues to enjoy broad bipartisan support. Nuclear investment and production tax credits (ITC and PTC) were maintained in the OBBBA and the US Department of Energy (DOE) has increased support and R&D funding for nuclear material mining and fuel enrichment. Canada has had a small modular reactor (SMR) *Action Plan* and *Roadmap* in place since 2018 (Canadian Nuclear Association, 2018), and the Ontario-based Darlington SMR project has garnered funding from the Canada Infrastructure Bank.

Despite political support, we do not anticipate a significant increase in large-scale advanced nuclear (LSN) capacity in North America in the next 10 years. Beyond the reactivation of 2–3 GW of mothballed reactors in the US, we do not expect any major additions in the short term. However, nuclear is set to play a larger role over the longer horizon, with capacity rising from 115 GW today to 120 GW by 2040 and 232 GW by 2060. Most of the increased capacity after 2045 will be from SMRs.

Fuel acquisition is a major risk for nuclear energy in the US. In 2023, the US imported 99% of its uranium (EIA, 2025). About one-third of it comes from trade partners with mixed relationships with the US: Russia, Uzbekistan, and Kazakhstan. Furthermore, the current administration’s policies are creating tension in all of the US trade and foreign relationships. Russia is the only country that currently has capacity to produce the fuel used in SMRs; North American production capability still needs to be developed, essentially from scratch. The DOE is currently funding several research efforts (DOE, 2025). Canada is a major exporter of uranium, so fuel security is less of an issue there.

Go small or go home
Large-scale nuclear projects in the US have faced persistent challenges over the past decades, including cost overruns, delays, and ratepayer impacts (Day, 2023). Despite retained policy incentives under the OBBBA, these factors make new LSN an unsuitable choice for the next five years. LSNs also remain ill-suited to modern grid needs due to limited flexibility in ramping up and down. A grid that has a significant portion of solar and wind capacity requires flexibility in ramp-ups and ramp-downs from other generation technologies.

By contrast, we expect SMRs will play an increasingly important role for a few reasons:

- SMR's lower absolute CAPEX requirements reduce financial risk. They are significantly more expensive than LSNs on a per-kilowatt basis, but each SMR unit is on a scale of 100 MW, meaning that the total capital needed is lower than for an LSN.
- Smaller scale and modular designs help mitigate construction delays and complexity.
- Operational flexibility enables quicker ramp-up, making SMRs better suited to complement variable renewables.
- By 2045, we forecast SMRs will reach cost parity with LSN, making deployment of SMRs more cost effective.

While SMRs are not yet commercially viable and are unlikely to be so until the early 2030s, technological development is accelerating with strong government backing. The US DOE continues to support SMR R&D, fissionable material development (specifically High-Assay Low-Enriched Uranium (HALEU)), and supply-chain resilience.

Most new nuclear is from SMRs from the mid-2040s
Nuclear capacity addition (GW/yr)

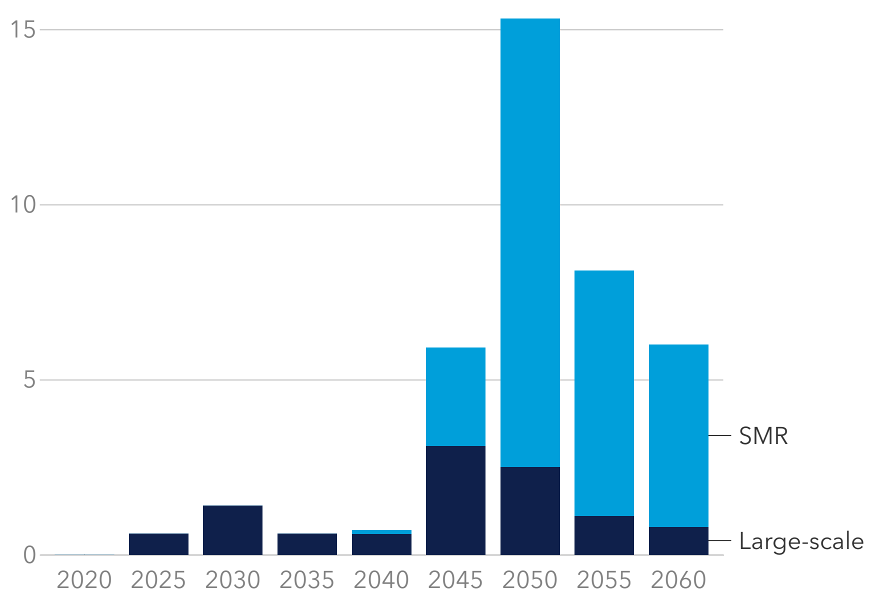


FIGURE 8.1 |

SMRs reach cost parity with large-scale by mid-2040s
LCOE of nuclear electricity (USD/MWh)

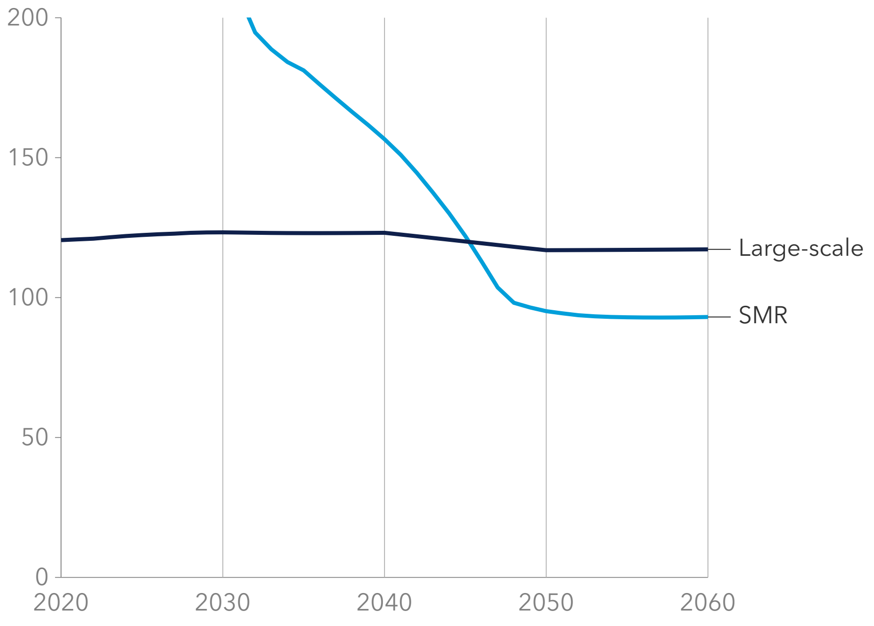


FIGURE 8.2 |

Importantly, Canada is in the advanced stages of bringing the first grid-scale SMR online by 2030 through Ontario Power Generation's Darlington project (Hunt, 2025). This will position it as a North American pioneer. It is very likely that the first working SMR in North America will be in Canada. However, to capitalize on its first-mover advantage in the region for SMRs, Canada may need to overcome some hurdles, such as establishing a working and feasible HALEU supply chain. At present, Canada fabricates its own fuel for its Canada deuterium uranium (CANDU) nuclear reactors, but does not possess the facilities to fabricate its own SMR fuel.

In the meantime, nuclear capacity growth will primarily come from extending the lifetime of existing reactors and reopening previously shuttered plants, such as Three Mile Island in Pennsylvania, US (Mandler, 2024).

Until SMRs become commercially viable, we do not expect a major expansion of nuclear capacity.

Nuclear for maritime

We forecast nuclear power will have a 3.5% share of North American maritime energy demand in 2050. By 2060, a little more than 10% of maritime and near-shore energy will come from nuclear power.

The International Maritime Organization has tabled Net Zero by 2050 goals that are pushing the maritime industry to accelerate adoption of alternative fuels and new technologies. With rising economic pressures and with no definitive answers from current fuel options, some eyes have begun to shift to an old energy source with a new twist: SMRs. Once viewed as an all-but-impossible dream for marine merchant shipping, advances in SMRs have key stake-holders reconsidering a maritime future with a significant contribution from nuclear energy.

Proponents highlight that nuclear is a zero-emission energy source that increases operational efficiency and negates demanding shore-power requirements imposed by ports. Some SMR manufacturers suggest that even worst-case failures would be contained within the midship of a large ocean-going vessel. Additionally, developers of shore-side infrastructure are also exploring SMR integration, in which floating nuclear can deliver clean power to fossil-fueled vessels and minimize local emissions, protect delicate ecosystems, and preserve the health of local communities.

Cost will be a major barrier to SMR deployment. Even once they become commercially viable, SMRs are likely to have much higher CAPEX, but lower OPEX (fuel) costs, than diesel engines. Financing options used to purchase ships will need to take these differences into account.

Another hurdle SMRs will likely face for maritime adoption are regulatory frameworks. Regulations around the construction of LSNs increase costs in North America relative to other countries with fewer regulations, such as China. With SMRs still in the development stage, an absence of careful planning and streamlined regulations could lead to similar costs.

Regulators and lawmakers are engaged in this planning. A recent bipartisan initiative in the US to rebuild the domestic maritime industry for national defense acknowledges China's significant lead in shipbuilding, a challenge that is difficult to overcome by traditional means. By specializing in SMR integration, US shipyards could carve out a competitive niche that could prompt the government to ease regulatory barriers and offer economic incentives. However, for the US to pull ahead in SMR propulsion, they would have to be competitive in both shipbuilding and cost-effective SMR, an unlikely combination.

Photo by Joe DelNero, NREL 77593

9 WHO MOVED MY MOLECULES?

9.0 HIGHLIGHTS

Clean fuels – either hydrogen or bio-based – are entering a recalibration phase in North America. Policy revisions under the OBBBA have reduced incentives for hydrogen and SAF while strengthening domestic bioenergy production. Canada's policy stability and new subsidies sustain biofuels as its primary growth driver in clean fuels. Blue ammonia continues to advance as an export-oriented fuel, while green variants progress more slowly under tighter credit and compliance regimes. Maritime and aviation decarbonization efforts face headwinds from a shift from policy-led acceleration toward market-driven adaptation in the region's low-carbon fuel transformation.

51%
share of aviation energy demand from SAF by 2060

45 Mt
annual hydrogen production by 2050

9.1 BIOENERGY

Bioenergy demand

Bioenergy currently supplies 4 EJ/yr of final energy demand (6% of final energy demand), mainly supporting transportation, manufacturing, and power generation. We forecast that by 2060, the contribution of bioenergy in power generation and transportation will increase by 400% and 56%, respectively. However, manufacturing's bioenergy consumption will drop by more than half (-53%) by then.

We expect biosolids, such as wood chips and pellets, to meet much of the demand from the manufacturing and power sectors. We also foresee the rise of biomethane production for injection into the gas grid. By 2050, the biomethane share in methane supply will likely reach 5%, driven by local decarbonization and non-wires incentives in agriculture-heavy states like California (CPUC, 2022). The transportation sector in North America consumes bioenergy predominantly as liquid biofuels.

Impact of the OBBBA on US bioenergy

The OBBBA, passed in July 2025 in the US, modifies key provisions in the 2022 IRA. Notably, it extended the IRA's Section 45Z, the Clean Fuel Production Credit, by two years from the end of 2027 to 2029. Additionally, non-North American bio-feedstock has been excluded from garnering the tax credits.

The foreign feedstock exclusion may be disruptive to sustainable aviation fuel (SAF) producers that rely on imported biomass which must now be purchased domestically (RSM US, 2025). Most critically, the 45Z tax credit ceiling for SAF decreased from USD 1.75/gallon to USD 1.00/gallon, which further widens the cost gap with fossil jet fuel.

Biodiesel may become the preferred low-carbon fuel for maritime because the OBBBA disrupted US green ammonia project pipelines; to be eligible for clean hydrogen credits, hydrogen facilities must now begin construction by January 2028 instead of 2033 (Gustafson, 2025). We forecast electrolytic hydrogen production will not overtake blue and gray hydrogen until the late 2050s, with green hydrogen being 18% of the hydrogen production mix in 2060.

Biogas producers may also benefit from the OBBBA, as transportation fuel derived from animal manure is exempt from the restriction on calculating carbon credits. The omission of indirect land use change (ILUC) in emission calculations is another boon to agriculture and bioenergy.

Current and future state of bioenergy in Canada

New incentives and regulatory certainty have positioned bioenergy as Canada's most immediate growth driver in the clean fuel transition. While removing the federal consumer carbon tax in March 2025 reduced direct costs on all fuels, it also redirected attention toward bioenergy production reform (Government of Canada, 2025). Hydrogen and SAF development have been slowed by subsidy delays while biofuels have advanced more rapidly (Reuters, 2024). Bioenergy is therefore likely to remain at the forefront of Canada's clean fuel expansion through the decade.

In September 2025, the federal government announced CAD 370m in subsidies and amended the *Clean Fuel Regulations* (CFR) for biofuels and SAF to stabilize domestic capacity and counter US competition. The package prioritizes canola farmers as feedstock suppliers. Opportunities are also emerging in biochar and manure-derived biogas, broadening agriculture's role in Canada's decarbonization (Bloomberg, 2025). The CFR drives biofuel demand by raising renewable blending requirements from 11% in 2025 to 15% by 2030, and mandates at least 50% GHG reductions by 2030 (Environment and Climate Change Canada, 2022). Profit volatility has slowed investment, particularly in British Columbia, amid US imports and weak LCFS credit prices.

Demand increases after 2040, especially for biomethane

Bioenergy energy demand (EJ/yr)

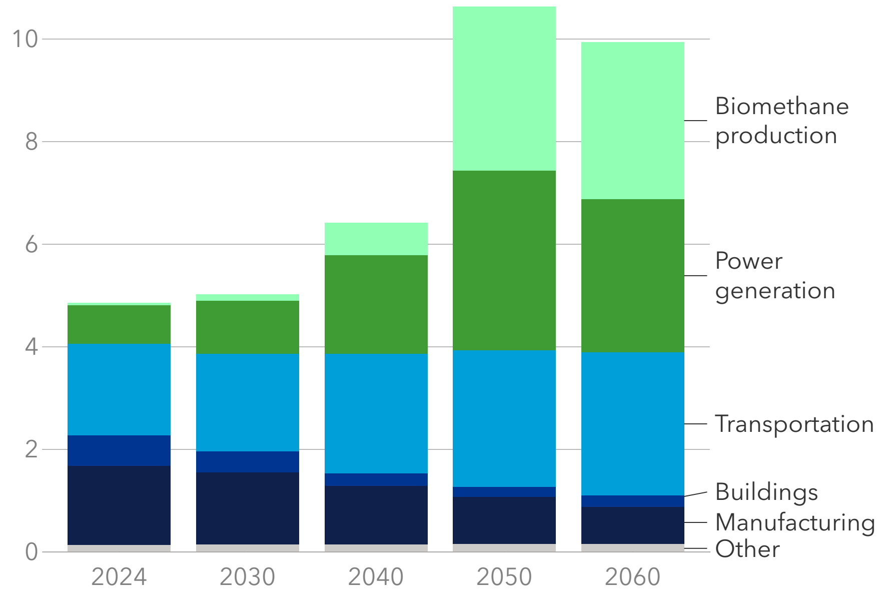


FIGURE 9.1 | Historical data source: IEA WEB (2025)

9.2 HYDROGEN

Hydrogen production and demand shows a decline in North America, with 2025 marking a pivotal year due to policy changes introduced by the OBBBA. We forecast hydrogen production in the region will decline about 6% from 17.5 MtH_2 in 2024 to 16.5 MtH_2 in 2025.

This trend of slower-than-expected growth extends from 2025 to 2060. In our ETO 2024 forecast, we estimated hydrogen production would reach 65 Mt by 2050 (DNV, 2024). We revised that forecast downward by 30% in the 2025 ETO to 45 Mt by 2050 (DNV, 2025). Furthermore, we now forecast that North American hydrogen production will be 56 Mt by 2060, 9 Mt less than the 2050 forecast in the 2024 ETO (DNV, 2024). To align with goals set by the *Paris Agreement*, hydrogen and its derivatives need to account for 15% of global energy demand by 2050. However, we forecast that North America will only reach 3% of its energy demand by 2050 (a decline from the 5% estimate in ETO 2024)

The loss of IRA tax credits makes it difficult for green hydrogen projects to find investors.

We expect the largest contraction will be in electrolytic hydrogen projects of greater capacity than 100 MW, which qualified for the highest production tax credits under the IRA. This green hydrogen was primarily intended for the production of green ammonia or e-methanol for export markets; with the loss of tax credits, these projects are now economically unattractive.

Blue hydrogen projects intended for ammonia production show signs of growth, with a few projects coming online as early as 2025 or 2026 using captured CO_2 for enhanced oil recovery. Other blue hydrogen projects have production start dates from 2029 to 2033. Furthermore, blue hydrogen projects are scaled to provide around 10% to 20% of production for domestic use in refining and chemicals, typically as self-offtake with the remainder used to make derivatives for export markets. The scaling improves project economics, reduces dependence on offtake, and enables partial fulfilment of GHG reduction goals locally.

In Canada, over 90% of offtakes are for low-carbon blue hydrogen. Wind-resourced renewable hydrogen production efforts are paused due to the lack of potential offtakes that were originally planned for export to Europe (Ryan, 2025). There are no significant policy changes to report for Canada, but priority seems to be shifting towards carbon capture, utilization of existing infrastructure, and finding new markets for export of products that can be scaled and produced in the near term.

Hydrogen is a critical vector for energy transition, both as a replacement for feedstock and as an energy carrier. Even with its slower than expected start than in ETO 2024, we expect North American production to rise to approximately to 45 MtH_2/yr by 2050. About 45% of this will be low-carbon blue hydrogen, 22% from grid-connected electrolysis, around 17% from dedicated renewables-based

Methane reforming dominates hydrogen production

Hydrogen production routes (MtH_2/yr)

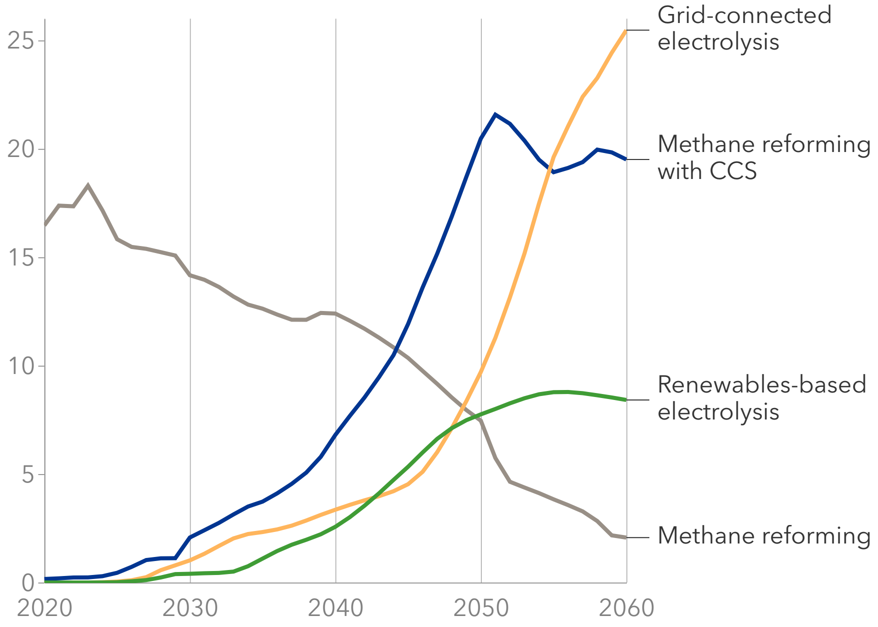


FIGURE 9.2 |

Hard-to-decarbonize sectors, ammonia production, and e-fuel production dominate hydrogen demand

Hydrogen demand (MtH_2/yr)

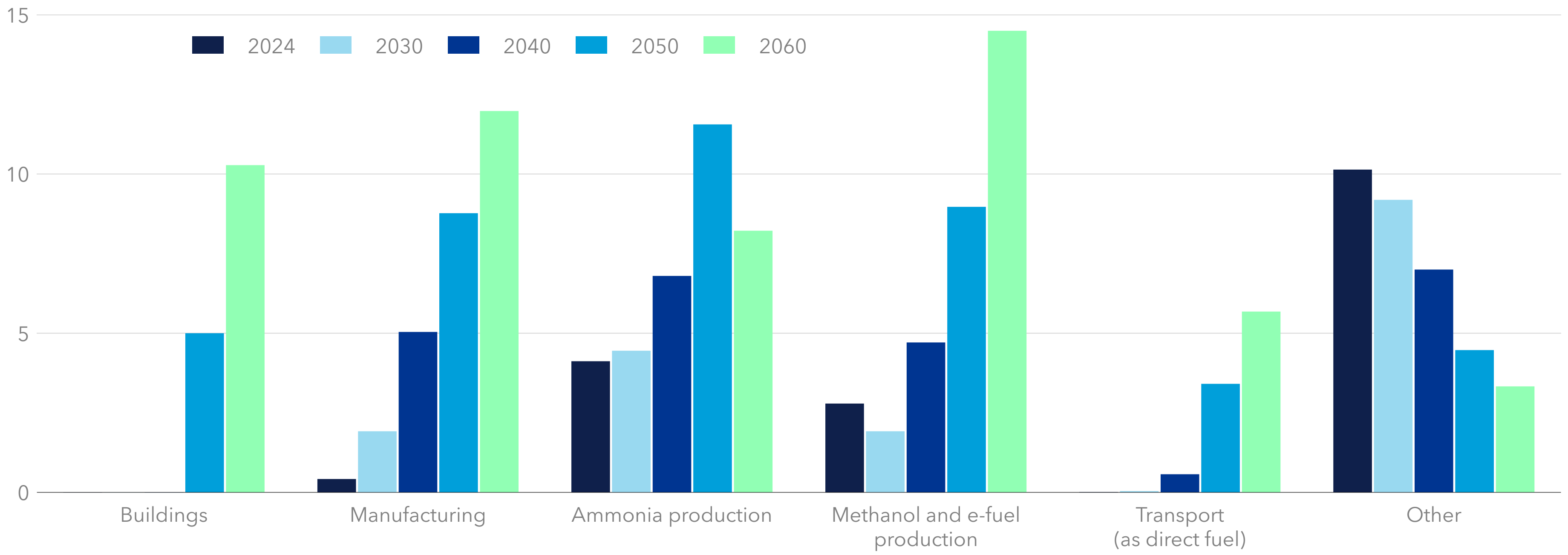


FIGURE 9.3 | Historical data source: IEA WEB (2025)

electrolysis, approximately 13% gray hydrogen, and the rest from other sources.

By 2060, we expect hydrogen production will rise further to 56 Mt, of which about half will be grid-connected electrolytic hydrogen and one-third blue hydrogen. More importantly, about half (around 30 MtH_2) of the total production in 2060 will be used as an energy carrier, compared with nearly none in 2024.

Hydrogen is mainly transported as derived ammonia

Hydrogen supply, demand, and trade (Mt/yr)

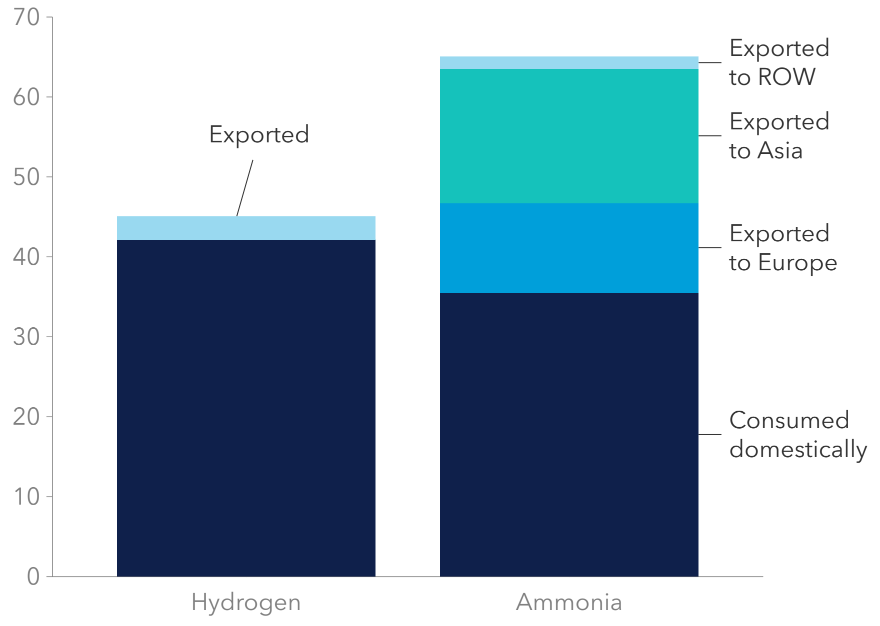


FIGURE 9.4 |

Policy signals and impact on projects

In 2025, the OBBBA scaled back financial incentives for hydrogen. The offered 45V PTC, which ranged from USD 0.6/kgH_2 to USD 3/kgH_2 based on carbon-intensity thresholds, is now available only for facilities that begin construction before 2028 rather than the originally proposed date of 1 January 2033 in the IRA. This has a negative impact on projects in the early stages of development, and which are unable to reach final investment decision (FID) prior to 2027. This timeline of reaching FID prior to the end of 2027 is further complicated by the need to receive required permits and begin construction by the new deadline.

Hydrogen uptake in sectors such as clean fuels (biodiesel, SAF, methanol) derived from bio-based feedstock is supported by 45Z clean fuel production credits. The date for this has been extended by two years (from the end of 2027 to 2029). Domestic crop-based oils (soy, canola, corn oil) gain a better competitive position due to indirect land use change (ILUC) removal, potentially boosting domestic demand and prices. With SAF credit reduced and merged with biodiesel / renewable diesel (RD) levels, investors may prefer RD because it commands similar or stronger margins at less risk. However, restrictions on foreign feedstock eligibility make low-cost imports (e.g. Brazilian ethanol or Chinese used cooking oil) ineligible, limiting feedstock availability and challenging profitability models. Further, producers are subject to strict rules on the involvement of 'foreign entities of concern (FEOC)'.

45Q (CO_2 sequestration credit) has been extended for CO_2 utilization and EOR to have parity with permanent storage (USD 85/tCO_2). This allows projects to collect CO_2 from various point-source emitters that meet CO_2 capture threshold requirements and clean hydrogen to produce derivatives such as e-SAF and green methanol, subject to early start date and foreign entity restrictions.

Project developers are navigating these changes in US policy, implementing deadlines, and shifting demand for the derivative products in domestic and international markets. Despite the uncertainty, a few projects have begun construction with local offtakes. including Infinium's e-SAF project in Texas that relies on green hydrogen (Infinium, 2025) and AvinaH_2 in California (Avina, 2025). Others are about to start production, such as CFI blue ammonia (Fuel Cells Works, 2025) and Woodside's blue ammonia project co-located with Linde blue hydrogen (Woodside Energy, 2025).

Foreign eligibility and FEOC restrictions make it more difficult for biofuels to source feedstock.

Photo by Gregory Cooper, NREL 94058

9.3 AMMONIA

We expect ammonia production in North America to rise steeply from 23 Mt in 2024 to 38 Mt by 2040, a 65% increase. This is due to the need for ammonia as an energy carrier, primarily in the maritime transport sector. The beneficial economics thanks to the recent OBBBA changes favor blue ammonia, which will dominate the production mix. Domestic production in the US and Canada will further increase to about 65 Mt by 2050, clearly aimed at the export markets in Europe and Asia, and then will reduce slightly to about 50 Mt by 2060 as Middle Eastern and Russian producers start competing on price.

Clean and low-carbon ammonia in North America

Production of low-carbon ammonia in North America has accelerated since 2024 from 10 kt to 30 kt, supported by US federal incentives under the IRA and Canada's *Clean Hydrogen Investment Tax Credit*. State and provincial measures such as California's *Low Carbon Fuel Standard* (LCFS) and Alberta's carbon pricing system (now stopped) further strengthen project economics.

Ammonia

Production of low-carbon ammonia is advancing rapidly, with distinct dynamics for blue and green pathways.

– Blue ammonia produced from natural gas with carbon capture and storage (CCS) dominates near-term development. The US Gulf Coast leads due to abundant gas, existing export infrastructure, and favorable CO_2 storage geology. Several large projects are advancing toward FID with Japan and South Korea as key buyers. The main challenges are sustaining high CO_2 capture rates and ensuring methane leakage control along the gas supply chain.

– Green ammonia produced from renewables-based electrolysis is emerging but faces significant headwinds. While developers in Texas, the Midwest, and Canada are pursuing projects, momentum has been dampened by changes to the 45V hydrogen production tax credit under the OBBBA. The revised credit design requires stricter hourly matching of renewable power and adds compliance complexity that reduces the near-term financial attractiveness of green hydrogen projects. Several projects have delayed FID or scaled down ambitions. The early tax credit phase out also starkly shortens the runway available for project developers, increasing the risk they take on. Nonetheless, falling electrolyzer costs and rising demand for certified green ammonia in Europe may support selective deployment later in the decade.

Blue ammonia dominates North American supply

Ammonia supply mix ($MtNH_3$/year)

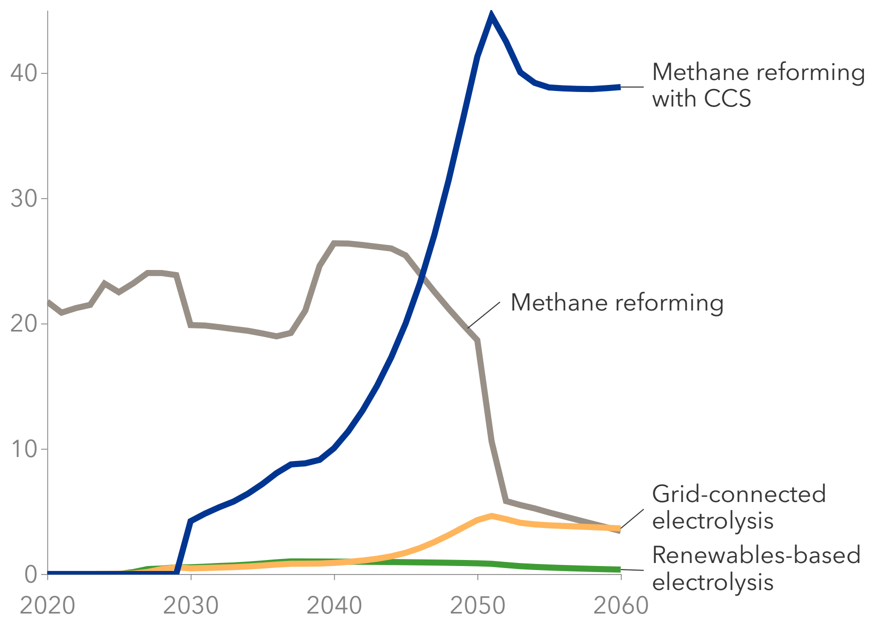


FIGURE 9.5 |

Demand growth is concentrated in three areas:

1. **Fertilizers and chemicals** – supply contracts increasingly prioritize low-carbon ammonia.
2. **Marine fuels** – the fastest-growing segment, with shipping lines contracting both blue and green ammonia for long-term supply.
3. **Power and energy storage** – still at pilot stage, with utilities testing ammonia as a hydrogen carrier and dispatchable fuel.

Outlook to 2060

- **2025-2040**: Blue ammonia dominates exports (5–10 Mt/yr), leveraging low-cost gas and CCS credits. Green ammonia remains limited to pilot and niche projects.
- **2040-2050**: Grid-based electrolysis-based ammonia begins scaling as electrolyzer costs fall and electricity prices start coming down. Blue ammonia maintains a strong role, but increasingly faces scrutiny over methane leakage and lifecycle carbon intensity.
- **2045-2060**: Blue ammonia increasingly replaces gray ammonia (methane-reforming with no carbon capture). Nevertheless, gray ammonia retains a role in fertilizer and regional markets where CO_2 emissions measures are not stringent.

Gray ammonia will dominate North American supply until the mid-2040s. At that point, blue ammonia will rapidly start replacing it.

9.4 MARITIME FUELS

The maritime industry plays an important economic role in the US and Canada due to their extensive coastlines and the volume of their international trade. Additionally, the intercoastal highways, inland waterways system, and the Great Lakes also move a significant tonnage of agricultural products and both dry and liquid bulk commodities to and from the international gateway ports. Miami is a global center of importance for the cruise industry which is under growing pressure from eco-conscious consumers and by authorities in environmentally sensitive destinations to reduce its environmental impact. As a consequence, most new vessels on order are capable of running on alternative fuels, mainly LNG but some are methanol-ready.

The current US administration's maritime strategy is centered on revitalizing US shipbuilding and maritime supremacy, with a heavy emphasis on national security and economic competitiveness. They are framing maritime revitalization as critical to countering China's dominance while rejecting international climate-driven regulations like those from the IMO.

However, there are ongoing efforts in both the US and Canada to accelerate the supply and production of low-carbon maritime fuels. LNG (bio-LNG and e-LNG) and renewable diesel are leading the near-term transition, while ammonia, methanol, and hydrogen are emerging as mid- to long-term solutions. Infrastructure development, regulatory alignment, and cost reduction remain critical for scaling adoption.

Low-carbon maritime fuels are any energy source used for propulsion or for the operation of any equipment on board a ship or offshore installation, and whose lifecycle emissions measured as well-to-wake (WtW) GHG intensity are demonstrably reduced in comparison to those of conventional fossil fuels. 'Lifecycle emissions' encompass both consumption and production of fuel, and includes feedstock extraction or recovery, processing, transportation, conversion, storage, distribution, and fuel utilization.

As concern about climate change among consumers worldwide rises (Bain & Company, 2024), the international shipping industry is responding as a key link in supply chains facing decarbonization pressure. One of its primary concerns revolves around the supply of carbon-neutral fuels and port infrastructure to deliver the fuels to ships; the industry is facing competition from other sectors for the limited supply of zero-carbon fuels that are expected to cost more than fossil fuels.

> Miami is a global center of importance for the cruise industry which is under growing pressure from eco-conscious consumers.

Outlook to 2060

- Overall, each low-carbon fuel is making significantly different progress across ship technologies, fuel supply, and infrastructure – the three pillars necessary for the uptake of these fuels. Notably, oil and natural gas have robust staying power in the mix, remaining dominant well beyond 2040. This must be seen in the context of the current administration's well-publicized opposition to the IMO's *Net-Zero Framework*. The US argues that the Framework would raise costs for US shipping and consumers by mandating expensive fuels (like green methanol, ammonia, and hydrogen) that are not yet widely available, and would preclude the use of LNG and biofuels, where US industry has a competitive edge.
- Instead of focusing on low-carbon fuels, the US administration is prioritizing revitalizing US shipbuilding, the expansion of LNG exports, the creation of Maritime Opportunity Zones, and financial incentives for domestic ship-building and infrastructure that are not tied to green fuel adoption.

The impact of this policy direction is that LNG gains favor as a proven technology and transitional fuel, aligning with the US administration's pro-fossil fuel stance. Biofuels are still mentioned as acceptable, but without strong federal incentives for scaling. The outlook for methanol, ammonia, and hydrogen weakens due to lack of policy support, infrastructure investment, and the US administration's resistance to international mandates that would accelerate their adoption.

Sustainable fuel increases, with a bioenergy majority

Maritime energy demand (PJ/yr)

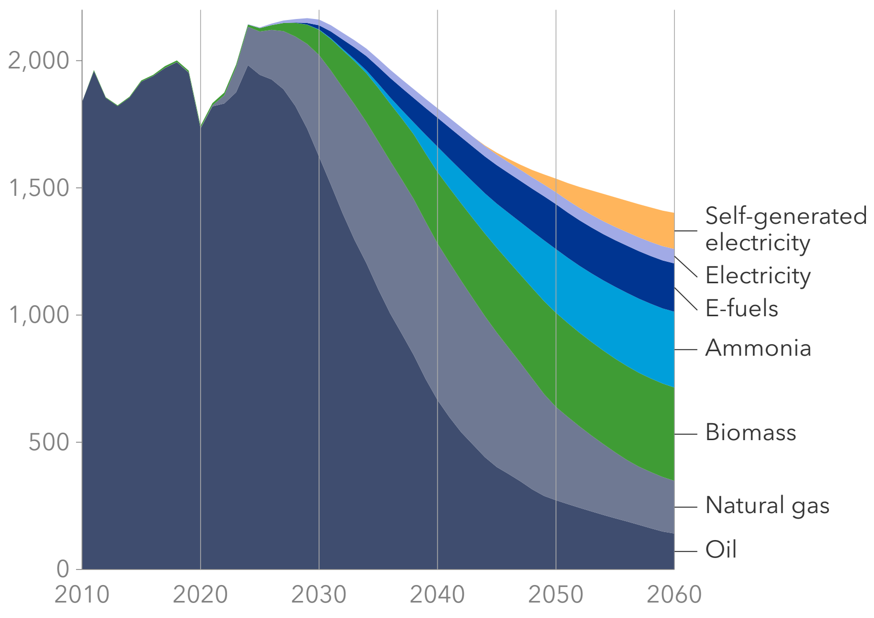


FIGURE 9.6 | Historical data source: IEA WEB (2025)

9.5 AVIATION FUELS

Sustainable aviation fuel (SAF) continues to gain traction in North America, with 2025 marking a pivotal year. We forecast SAF production in the region will grow from 38 PJ in 2024 to 58 PJ in 2025. This reflects ongoing investment in biomass-based supply chains, enhanced refinery integration, and rising demand across the aviation sector.

Outlook to 2060

- By 2060, we project over half of aviation's energy demand will come from sustainable aviation fuels (SAF): bio-SAF (34%), electrofuel-based SAF (e-SAF) (14%), and hydrogen used directly (3%). Bio-SAF will dominate, supplying just over one-third of aviation energy (about 2,100 PJ/yr or 15 billion gallons), reflecting its mature conversion pathways and established feedstock supply chains in the US and Canada.
- SAF remains the only scalable route to decarbonize long-haul aviation, but the required scale is immense. North American bio-SAF output must rise to over 10 billion gallons annually by 2050, supported by aligned policy, financing, innovation, and execution across the value chain. Given its technological maturity, bio-SAF will continue to lead, while e-SAF plays a smaller yet growing role – nearly 3 billion gallons (425 PJ/yr) by 2050 and more than doubling by 2060.

Policy signals and offtake commitments

In 2025, the OBBBA scaled back SAF incentives from the more generous IRA framework, reducing credit values, removing bonus provisions, and enforcing North America-only feedstock rules. The Section 45Z SAF tax credit was cut from USD 1.75/gallon to a maximum of USD 1.00/gallon for fuel produced after 2025. These reforms prioritize domestic feedstock and supply, creating additional challenges for producers using imported inputs and negatively affecting projects reliant on high-CI ethanol feedstocks through alcohol-to-jet (ATJ) pathways.

However, offtake agreements, which are critical for project bankability, have grown over the past year due to mounting climate-related pressure (Chiambaretto et al., 2024). Publicly disclosed volumes in North America total roughly 500 million gallons, with major commitments from United Airlines (United, 2025), Delta Air Lines (Flying Mag, 2025), and Air Canada (Neste, 2024). These agreements send strong demand signals, though production capacity still lags.

Challenges for e-SAF deployment

Electrofuels-based SAF (e-SAF) represents a key technological pathway for decarbonizing aviation, particularly in sectors with limited access to biomass or where lifecycle emissions must be minimized. In North America, e-SAF is emerging as a complementary solution to bio-based SAF. E-SAF is produced by combining green hydrogen (from electrolysis using renewable electricity) with captured CO_2 (from limited point-source, biogenic, or DAC sources).

Federal tax credits play a pivotal role in improving project economics:

- **Section 45V** provides up to USD 3/kg for clean hydrogen production, directly lowering e-SAF input costs but with a limited construction window.
- **Section 45Q** offers USD 60–130/ton for CO_2 used in fuel synthesis, depending on capture method and lifecycle impact.

However, under the OBBBA, eligibility for 45Q, 45V, and 45Z is evolving, and new sourcing rules add complexity. Beyond policy uncertainty, major barriers remain:

SAF becomes majority of aviation energy demand by 2060

Aviation energy demand (PJ/yr)

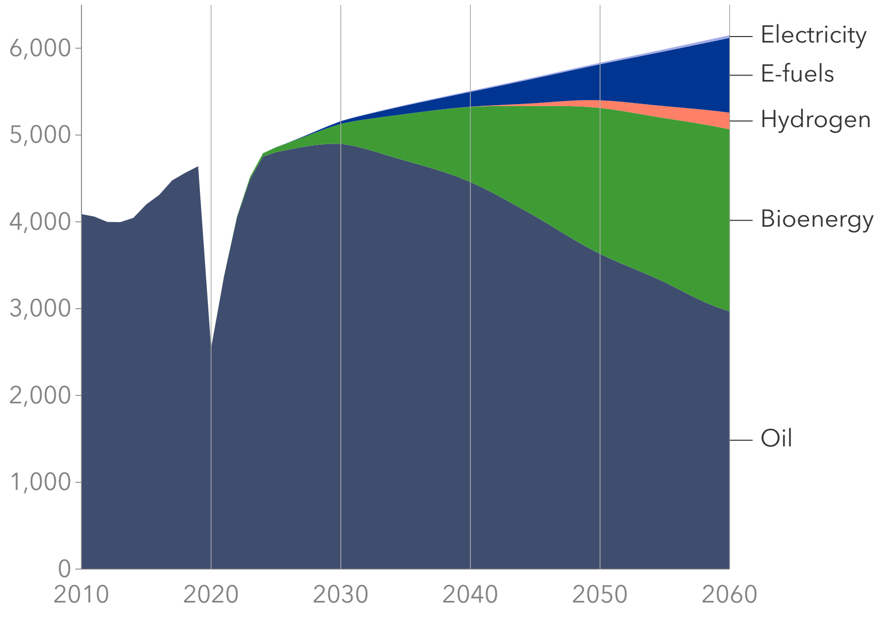


FIGURE 9.7 | Historical data source: IEA WEB (2025)

- High costs from hydrogen and CO_2 capture, especially DAC.
- Limited electrolyzer capacity and CO_2 infrastructure.
- Feedstock competition from other decarbonization sectors (e.g. e-methanol).
- Financing challenges, with few long-term offtake deals and limited commercial projects.
- Early 45V sunset (from 2032 to 2028), constraining FIDs for emerging projects.
- Strategic investment, stable regulation, and continued innovation will be critical to unlock e-SAF's role in aviation decarbonization across North America.

Investment challenges and risk factors

SAF production capacity is expanding globally, but many announced projects stall and remaining in feasibility or planning stages before reaching FID (IATA, 2024). While pipeline growth is encouraging, the typical three- to five-year lag and low FID conversion rates remain a major bottleneck (Surgenor, 2025). Moreover, project economics remain challenging with SAF costs currently two to seven times greater than for conventional jet fuel. Airlines and producers cite feedstock cost volatility, unclear pricing frameworks, and absence of long-term mandates as critical hurdles (IATA, 2024).

Energy conversion:

1 gallon SAF ≈ 131.88 MJ; thus 38 PJ ≈ 290 million gallons, and 58 PJ ≈ 435 million gallons (assuming energy equivalence with Jet A fuel).

10 INFRASTRUCTURE IN FLUX

10.0 HIGHLIGHTS

North America's energy system is entering a phase of profound structural transformation. Transmission constraints, aging infrastructure, and regulatory inertia are limiting the pace of electrification, even as new technologies and AI-enabled grid optimization begin to expand capacity. At the same time, investment in oil and gas infrastructure – particularly LNG export capacity – continues to grow in the near term, despite rising long-term risks of asset stranding. Emerging subsurface technologies, such as geothermal and carbon capture and storage, are leveraging existing expertise and assets to advance from demonstration to deployment.

20+ years
time it can take to complete a major transmission project

USD 200bn
savings that could be realized with massive grid expansion

10.1 JAMMED TRANSMISSION

Expanding regional and interregional transmission capacity would allow electricity supply to keep up with demand growth and pay huge dividends for an energy system that will include increasing amounts of renewable generation. Expanded transmission would save over USD 200bn by 2050 (US Department of Energy, Grid Deployment Office, 2024).

Several challenges affect how quickly the grid can expand:

The grid is a bottleneck for the next 15 years

Grid capacity accommodation of load (Indexed to 2022)

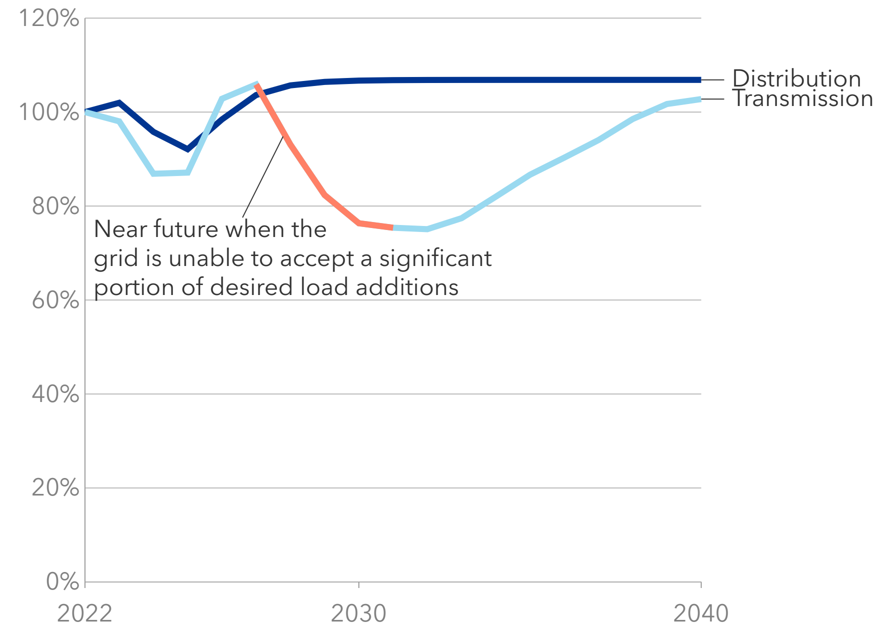


FIGURE 10.1 |

- **Size:** With 13 million circuit-km of power lines in North America receiving USD 79bn in investment in 2023 (ASCE, 2025), the grid is massive.
- **Increasing maintenance needs:** The increasing frequency and severity of climate hazards has increased the cost of merely maintaining existing functional capacity.
- **Technical complexity:** The need to maintain ancillary grid services – frequency regulation, voltage control, operating reserves, etc. – makes restructuring the grid more difficult.
- **Security:** Cyber-attacks on IT (data and supporting systems) and OT (operational technology for controlling physical processes) are a growing concern.
- **Regulations that prioritize reliability:** Regulations are highly conservative and risk-averse. Some regulators have responded to the flood of inter-connection applications for very large loads by setting even stricter requirements.
- **Policy changes:** Policy changes enacted by the current US administration have created uncertainty and headwinds in critical supply chains and the expansion of domestic manufacturing capabilities.

We foresee five years in which the grid is unable to accept a significant portion of desired load additions, and 15 to 20 years of constraints on additional supply capacity (Figure 10.1). Solar and onshore wind will face most of the delays. While there are exceptions, interconnecting thermal generation is generally easier because it is less variable and can be located closer to loads.

We expect the grid to grow three-fold by 2060. Investments in grid infrastructure and advanced technology have broad, albeit not comprehensive, support across the political spectrum. There are very clear opportunities to expedite the transition through better technologies and policies that are practical and possible, both economically and politically.

Grid capacity expected to grow three-fold by 2060

Transmission and distribution grid capacity (GW-km)

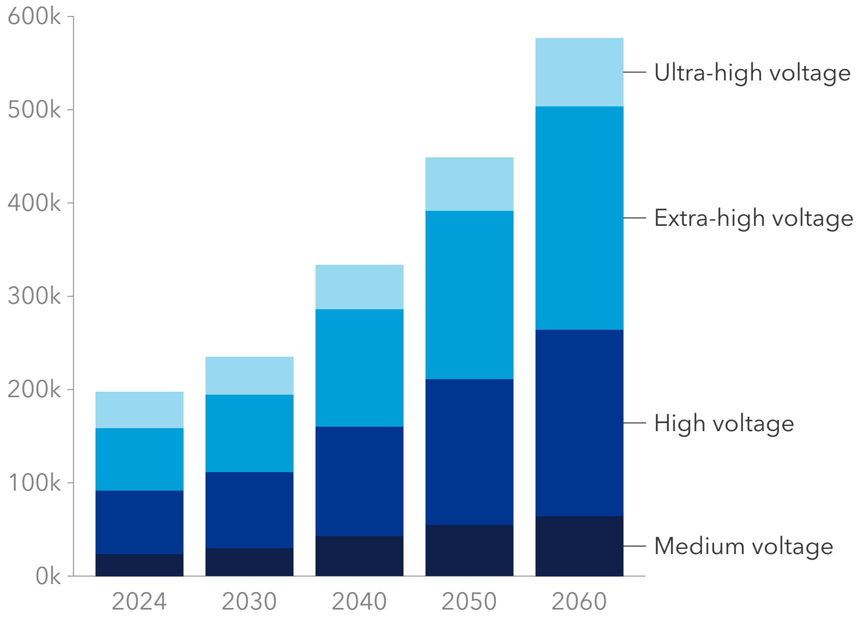


FIGURE 10.2 |

10.2 PIPELINES AND PORTS

The US and Canada each have extensive oil and natural gas infrastructure. These include intra- and inter-country oil pipelines and transport infrastructure, natural gas pipelines, storage infrastructure and, most importantly, LNG terminals and natural gas export infrastructure.

We forecast short-term growth in export-oriented LNG infrastructure in both countries in the next four years, bringing the total to about 240 Bcm/yr by 2028, from 114 Bcm/yr in 2024.

Significant LNG capacity will come online in the next 4 years

LNG capacity additions (Bcm/yr)

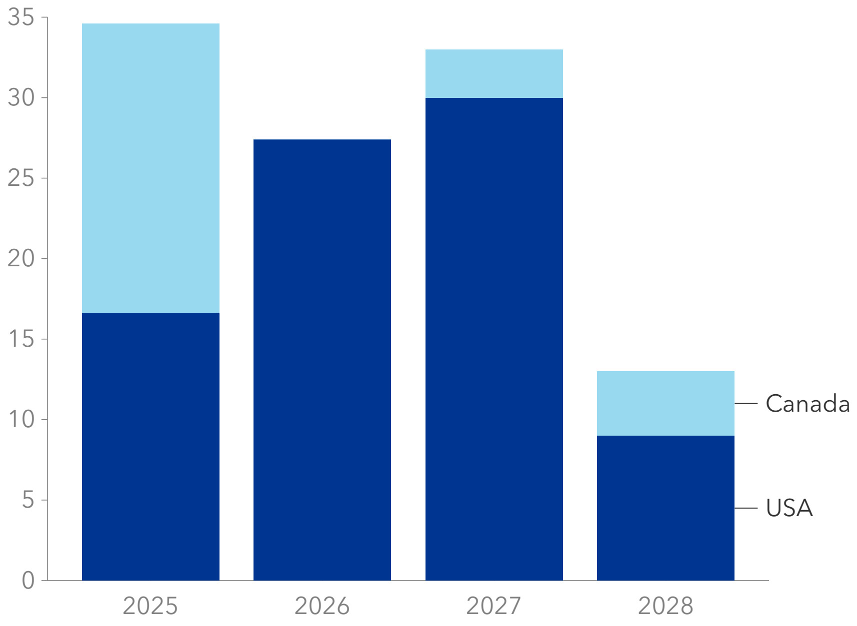


FIGURE 10.3 | Data source: US EIA (2025)

This remarkable growth is driven by a few key factors:

- Increased demand for North American natural gas from Europe due to the Russo-Ukrainian war, natural gas supply disruptions from Russia, and the EU's plan to phase out imports from 1 January 2028.
- Canada's long-term plan to open up LNG exports to Asian markets directly from its western ports (LNG Canada, 2025) and to reduce its dependence on US Eastern Seaboard exports and US LNG facilities.
- The Trump administration's fiscal support for the oil and gas sector.

We see a similar trend in crude oil pipelines in Canada where two structural changes stand out. One is the Canadian federal completion of the Trans Mountain Expansion Project (TMEP), which has almost tripled tidewater crude export capacity and materially changed market routing options for western Canadian crude oil. The other is Canada's need to diversify exports of crude oil beyond the continent.

In the US, oil and gas pipeline projects completed in 2024 materially increased takeaway capacity from producing basins (roughly a few Bcm per day), easing some regional bottlenecks while enabling more feedstock to reach Gulf Coast markets. These additions support higher flows out of the Appalachia, Permian, Haynesville, and Eagle Ford regions. What this entails is that both countries will continue to invest heavily in mid-stream oil and gas infrastructure in the near future.

These short-term growth expectations lead to three factors that will influence investment decisions:

- Regulatory friction, social unpopularity, and challenges regarding social license to operate – many projects face scrutiny and permitting challenges from affected communities and indigenous peoples. Delays or litigation can reroute flows and change expected returns. Investors should assume an elevated probability of multi-year slippages for large greenfield projects and build that risk into project timelines and discount rates.
- Increasing overlap with decarbonization infrastructure – stronger co-development of carbon transport and storage (in CCS chains) near large emitters and export hubs, and electrification/efficiency upgrades within midstream assets are to be expected. These add-on investments will reshape asset economics and extend useful lives for some facilities.
- The very likely risk of stranded assets – long-lived infrastructure like pipelines and LNG facilities may not recover full value if demand for hydrocarbons declines as quickly as we forecast. Rising global climate policies (especially in Europe and OECD Pacific) carbon pricing, and accelerated electrification could shorten asset lifespans and make cost recovery difficult.

10.3 BURIED POTENTIAL: GEOTHERMAL'S ROLE IN AN ELECTRIFIED FUTURE

Geothermal has long played a small and quiet role in the energy mix, delivering firm, zero-carbon baseload power. North America had about 4 GW of installed capacity in 2024, about 0.4% of electricity generation. Current installed capacity remains highly concentrated in California and Nevada (Gallucci, 2024).

As pressure builds to decarbonize heat, reduce land use, and diversify clean baseload supply, geothermal is attracting renewed attention from industry, government, and investors. We expect installed geothermal capacity to increase to about 7 GW by 2030, reaching 15 GW by 2040 and only increase marginally after that.

Trying to go from margin to momentum

Historically, geothermal development has been constrained by geography, permitting complexity, and drilling cost. Most operational capacity is concentrated in tectonically active regions: California, Nevada, and western Canada. Recent advances in enhanced geothermal systems (EGS) and closed-loop configurations are beginning to challenge those limitations.

These newer technologies promise to make geothermal location-flexible, scalable, and in some cases retrofittable by using existing oil and gas wells. US developers like Fervo Energy and Eavor are already demonstrating the technical viability of directional drilling, fiber-optic subsurface monitoring, and CO_2-based heat transfer loops. The US DOE has set an aggressive target of deploying about 90 GW of geothermal by 2050, up from 3.9 GW in 2023.

However, geothermal still faces the key barriers that have thwarted its development. (Bhatnagar et al., 2022):

Geothermal capacity expected to triple in 10 years
Geothermal power capacity (GW)

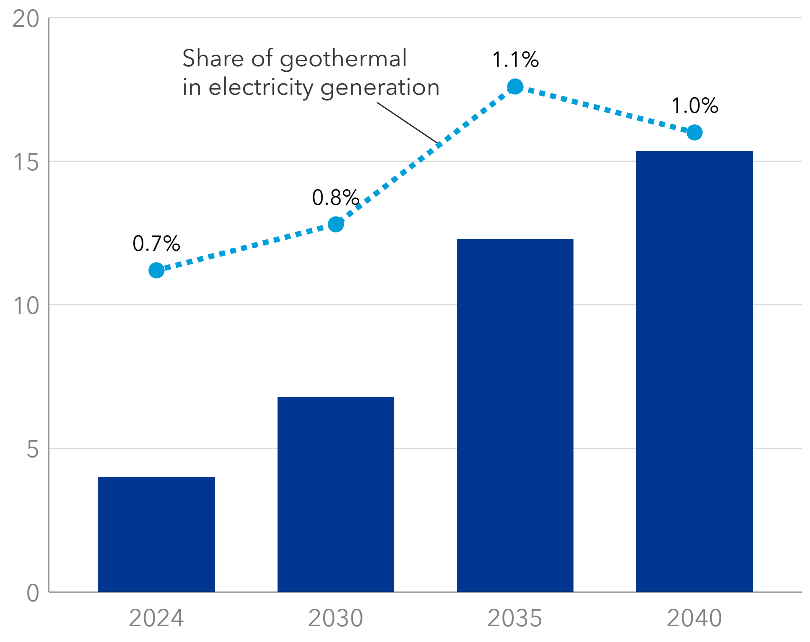


FIGURE 10.4 | Historical data source: GlobalData (2025)

- High upfront costs and financial risks, especially when compared to relatively cheap renewables such as solar and onshore wind, which are available and scalable now.
- Risk of underperformance and operational risk because geothermal plants have moving parts that erode, wells degrade with time, and scaling and corrosion can reduce output, increase operational costs, and reduce financial viability.
- Barriers with respect to siting and permitting, the same permitting risk and barriers that oil and gas infrastructure development faces.
- Remoteness and dependence on transmission availability are a limitation because most viable geothermal sites are in remote locations and need transmission grid availability to get them to the demand centers.

Due to these structural barriers, we expect North America will only reach a maximum of 15 GW by 2040, well below the US DOE target.

New development and subsurface advantage

North America may still hold a unique advantage in geothermal energy. With thousands of inactive oil and gas wells, skilled drilling contractors, and a maturing carbon management ecosystem, the region is well-positioned to repurpose existing infrastructure for geothermal development. The synergies extend beyond drilling, shared data and permitting pathways; even reservoir modeling techniques from CCS and hydrocarbon operations are directly applicable to geothermal.

When carbon becomes a conduit

Some of the most novel designs now being tested go one step further by using captured CO_2 as a working fluid in geothermal systems. In these configurations, supercritical CO_2 replaces water in closed-loop heat extraction. This offers improved thermal efficiency and eliminates water loss. Early pilot studies from US national laboratories and private developers suggest the concept is technically viable and may deliver higher energy output per well (NETL, 2023).

Beyond technical merit, this approach offers a symbolic reframing: waste from one sector becomes fuel for another. It also creates a natural bridge between CCS and geothermal, two subsurface solutions that are now converging through innovation.

> Despite bipartisan support, geothermal development faces the high CAPEX challenges common for renewables and the high OPEX challenges common for thermal generation.

10.4 CARBON CAPTURE

Carbon capture and storage (CCS) is no longer a niche emissions fix for oil and gas. It is becoming a cornerstone of decarbonization strategies across heavy industry, synthetic fuels, and increasingly, the power sector. Our forecast frames North America as a global CCS front-runner, moving from demonstration to deployment by 2030, and scaling to more than 400 $MtCO_2$/yr by mid-century. That baseline is important, but undersells what is really unfolding.

North America captured about 15 $MtCO_2$/yr in 2024. We project this will quadruple to 64 Mt by 2030 and reach roughly 420 Mt by 2060. Globally, CCS is still concentrated in industrial clusters, but North America has a unique head start: a mature ecosystem of pipelines, storage basins, and operating experience built on decades of CO_2 handling in natural gas processing and enhanced oil recovery (EOR). Whether that lead translates into climate impact depends on how quickly CCS moves from oil and gas to the harder-to-decarbonize sectors.

From demonstration to diversification

While oil and gas remains the most active early adopter, accounting for nearly half of captured volumes today, the growth curve is already shifting. By 2050, we expect manufacturing sectors like cement, steel, and chemicals to dominate North American CCS. These are industries that cannot fully electrify, making CCS essential rather than optional. Our modeling reflects this transition, but the story is broader: integration with hydrogen hubs, negative emissions via bioenergy with CCS (BECCS), and direct air capture (DAC) are already expanding the market's scope.

Utilities step in

The most underexplored CCS story may be in the power sector. North American utilities are beginning to act not only as off-takers but as project initiators. Calpine (ExxonMobil, 2025) and Vistra (Vistra Corp, 2025) have launched capture strategies tied directly to natural gas and coal-fired assets, in some cases as anchor tenants for CO_2 hubs. San Miguel Electric Cooperative represents another flavor of transition, leaning into renewables while still positioning within the CCS infrastructure wave (Cunningham, 2025).

Thirty-fold growth in CCS capacity from 2020 to 2060

Carbon capture and storage by sector ($MtCO_2$/yr)

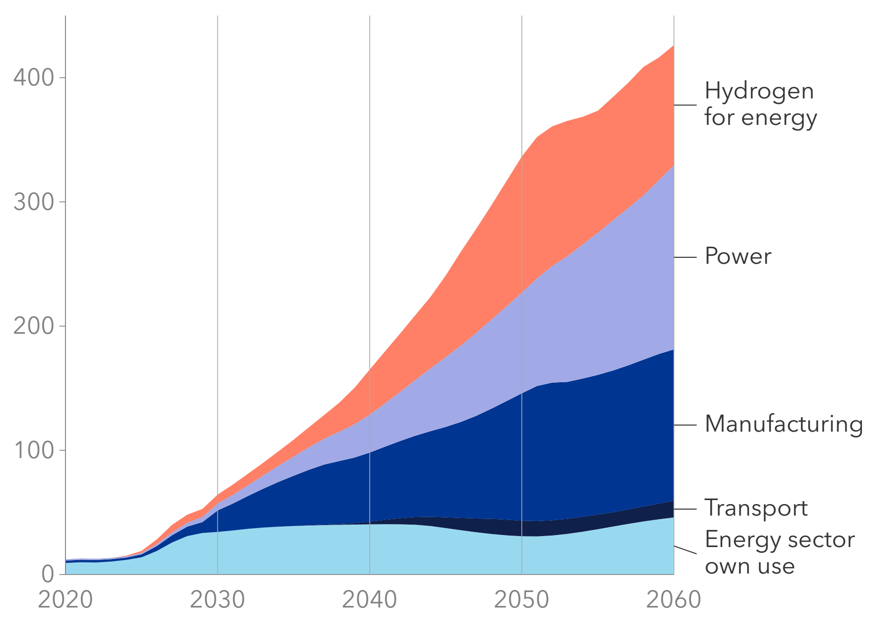


FIGURE 10.5 | Historical data source: GCCSI (2025)

These moves reflect two realities. First, as coal phases out and variable renewables dominate new builds, demand for dispatchable, low-carbon generation rises. This is a role CCS-equipped gas plants can fill. Second, utilities realize that joining CCS infrastructure today may be cheaper than reacting to carbon constraints tomorrow. The result: the CCS option is starting to appear in utility boardroom deliberations and data rooms, not just in oil and gas balance sheets.

A hub-centric future

The Gulf Coast, Midwest, and parts of Canada are emerging as hotbeds for CCS hubs, multi-tenant networks of emitters, pipelines, and shared storage. These hubs lower the cost of entry for smaller players and spread infrastructure investment across entire value chains. Some hubs are operator-led, but utilities are increasingly co-investing or signing on early. This suggests CCS infrastructure will eventually be viewed the same way we see transmission lines or gas pipelines: as part of the backbone of the energy system.

Policy and permitting remain the swing factors. The US Environmental Protection Agency's (EPA) progress on Class VI primacy – already granted in North Dakota and Wyoming with Texas, West Virginia, and Arizona in advanced stages – could

In a context where North America falls further behind on emissions reductions, carbon capture and storage will take on increased importance.

accelerate site approvals. At the same time, the DOE's cancellation of more than USD 500m in CCS grants in early 2025 shows how fragile policy momentum can be. Policy volatility is now a core risk factor.

Outlook
By 2060, we expect CCS will capture about 30% of North American energy-related CO_2 emissions, with more than 80% of that tied to permanent storage rather than utilization. This trajectory of 19 Mt today to 426 Mt by 2060 is strong, but falls well short of the scale needed for net-zero pathways. There is some risk of under-forecasting: if hubs mature, utilities accelerate, and policy alignment stabilizes, actual CCS build-out could exceed today's model. That possibility is rarely captured in baseline forecasts, but it may define the difference between incremental progress and systemic decarbonization.

We forecast a transition from demonstration projects to large-scale industrial deployment. Capacity will increase from about 32 $MtCO_2$/yr today to 88 $MtCO_2$/yr by 2030 and more than 480 $MtCO_2$/yr by 2050

Natural gas and oil EOR dominate early CCS deployment but cement, steel, chemicals, and removals (DAC/BECCS) take over by mid-century.

Where CCS changes occur from 2024 to 2050
Share of captured CO_2

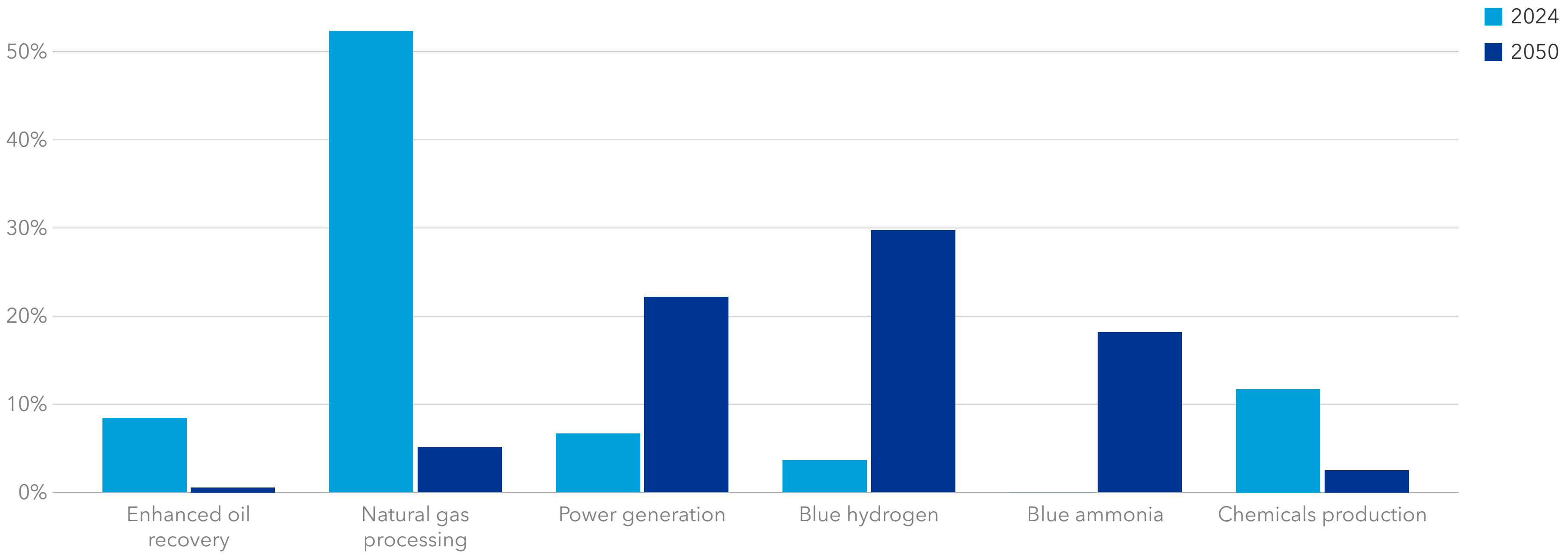


FIGURE 10.6 | Data compiled from DNV Energy Transition Outlook 2025, US DOE Carbon Management Program, and IEA CCS Tracking Report (2023).

10.5 DIRECT AIR CAPTURE

We forecast DAC capacity will grow from near zero in 2025 to approximately 50 $MtCO_2$/yr in 2060. Despite the rapid growth, this amount of DAC is insufficient to make a noticeable difference compared to the 980 $MtCO_2$/yr that North America will still be emitting after accounting for other CCS technologies.

In early October 2025, the US DOE cancelled 10 of 21 grants for DAC projects approved under the previous administration (Hiar, 2025), signaling that at the federal level, support for DAC will remain ad hoc and uncertain for the time being. Canada's industrial sector carbon pricing is the only policy currently in place in North America that supports DAC, and it does so indirectly. This, plus a voluntary carbon market in the US, is unlikely to be sufficient to drive research and commercialization of DAC or other negative emission technologies. Without some kind of additional policy support, such as widespread mandatory carbon markets, it seems unlikely a viable business case will emerge for scaling these technologies.

Not enough DAC to reach net-zero
Direct air capture ($MtCO_2$/yr)

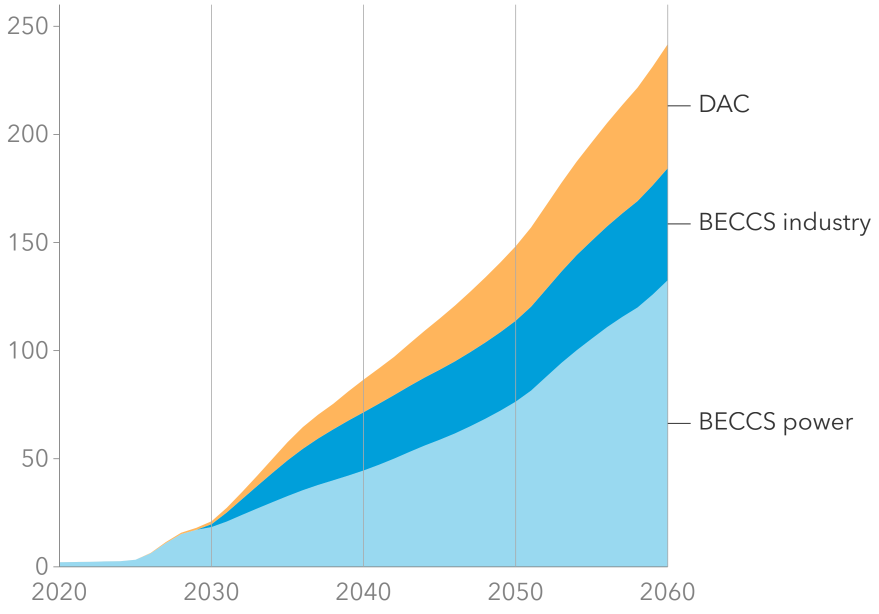


FIGURE 10.7 |

Direct air capture will be especially important to avoid the worst effects of climate change in the latter part of the 21st century. However, it needs policy support for commercial scalability.

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Historical data

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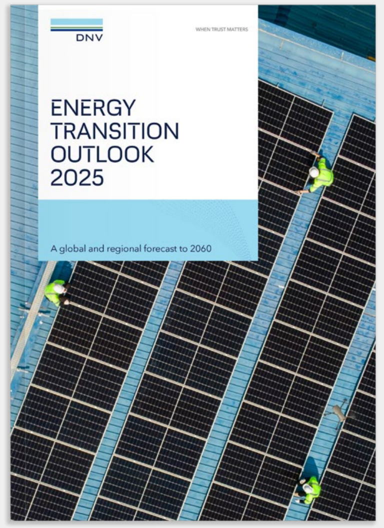

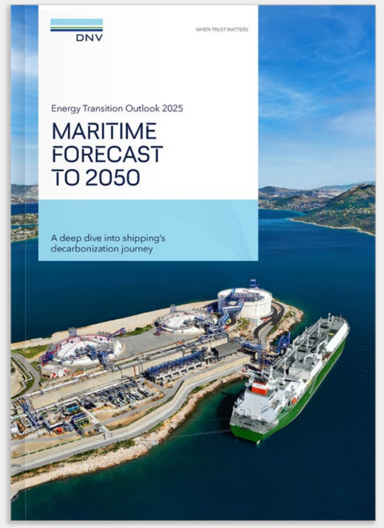

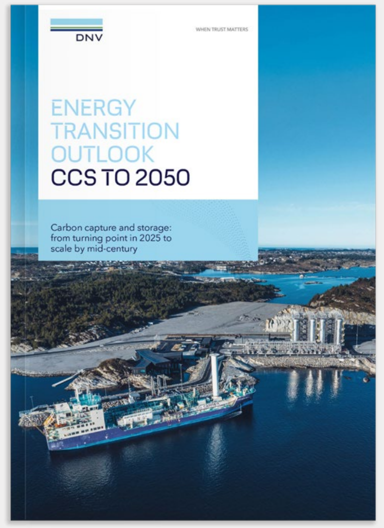

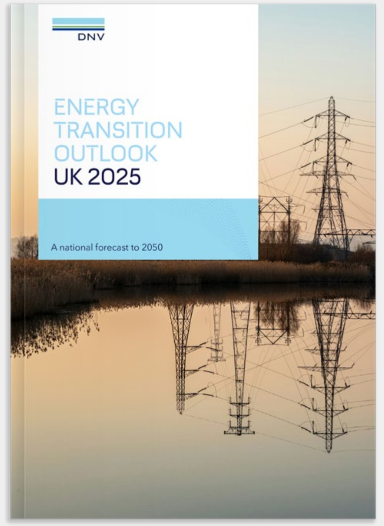

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