1 An overview of an energy market in transition

Australia's energy markets are in the midst of a major transition driven by decarbonisation, the decentralisation of energy services and new technologies.

This chapter describes recent developments across our evolving markets, providing an overview of the key issues and outcomes explored in further detail in chapters 2 to 6.

1.1 Context

Concerns about the impact of coal and gas generation on carbon emissions have led Australian governments to set renewable energy targets and offer incentives and support for low-emissions power generation. As the market for these technologies continues to grow, scale economies and technological improvements have strengthened their cost advantages over coal and gas plants. Generation businesses responded to these incentives by investing in wind and solar farms. Energy consumers also responded by installing rooftop solar panels and, to a lesser extent, batteries.

In contrast, Australia's coal plants are aging and increasingly costly to operate. Many require high levels of maintenance and refurbishment to keep them running. They are also prone to unplanned outages, sometimes prolonged outages, which make them increasingly unreliable. As these plants near the end of their economic lives, many are earmarked for closure over the next decade. Meanwhile, no energy business has invested in new coal-fired generation in Australia since 2013 and no coal plant proposals are currently being considered. There has also been relatively little recent investment in gas generation, except for Tallawarra B, a new gas peaking plant in New South Wales that added 320 megawatts (MW) of capacity in early 2024.

Almost all grid-scale generation investment since 2012 has been in renewable sources, initially mostly in wind farms but more recently in solar farms as well. The level of renewable energy injected into the grid regularly sets new records. On 6 November 2024, renewable sources supplied 75.6% of total generation during the half-hour interval ending at 1 pm, marking the highest share recorded to date.[1] In the future, the power system will at times be fully supplied by renewable energy.

Alongside this, while the wholesale market has been changing, energy customers have responded by consuming less electricity from the grid across the middle of the day, being more energy efficient and generating their own power through rooftop solar systems and installing batteries for storage.

While electricity consumption in the National Electricity Market (NEM) rose by 3.4% in 2024, about one-third of this increase was met by increased rooftop solar generation rather than being supplied through the grid.

The growth in solar generation has further deteriorated the economics of coal generation. When rooftop solar generation peaks in the middle of the day, the demand for grid-sourced electricity collapses (at times falling to zero in some regions). Coal plants are not engineered to run at low levels of output, so may offer negative prices to maximise the likelihood of being dispatched. Prolonged periods of negative spot prices, and potentially having to shut down during the day, makes it harder for coal plants to operate profitably.

The transition to a low emissions energy system can deliver significant benefits to consumers. Renewable energy has a very low marginal cost and relatively low investment cost compared with traditional generation and, if integrated efficiently into the power system, will deliver low-cost sustainable energy. For customers, resources such as rooftop solar and battery systems can help them save on power bills and manage energy use in ways to suit their needs, while also empowering them to take initiative on environmental concerns.

But the rapid transformation of Australia's energy system poses numerous challenges, which have become a central focus for governments, energy businesses, market bodies and regulators. These challenges include:

- ensuring enough generation and firming capacity, such as storage, is being built to offset the closure of coal-fired plants
- ensuring new generation capacity is located efficiently so it can be connected to the grid and delivered to customers at lowest cost
- ensuring new transmission network investment to support the transition is efficient and timely
- managing the safety and technical security of the grid as the generation mix changes
- efficiently integrating consumer energy resources into the system in the long-term interests of consumers
- ensuring all consumers benefit from the transition
- optimising the role of gas in the transition to firm the renewables.

Managing these challenges is complex. It requires reform to market design and regulatory frameworks, coordinated planning, the rollout of supporting technologies, changes in the way energy businesses operate and new protections for consumers.

Increased electrification is an inherent part of the transition; if we can decarbonise our electricity sector by moving to renewables, we can then decarbonise other parts of the economy. AEMO forecast that future energy consumption from the grid will grow by around 108% between now and 2050 as the economy moves towards more intensive electrification of industry and transport. Business and industry consumption is forecast to more than double from today's 145 terawatt hours (TWh) to almost 345 TWh in 2050.[2]

1 AEMO, Quarterly Energy Dynamics Q1 2025, Australian Energy Market Operator, 7 May 2025, accessed 6 June 2025. For this figure, renewable generation includes grid-scale wind and solar, hydro generation, biomass, battery generation and distributed PV, and excludes battery load and hydro pumping. Total generation is defined as NEM generation plus estimated PV generation.

2 AEMO, 2024 Integrated System Plan, Australian Energy Market Operator, June 2024.

Current projections indicate that while households will also consume more energy, they are unlikely to draw much more from the grid in 2050 than they do now. Higher energy needs will be mostly met from their own investments in rooftop solar and counteracted by improved energy efficiency. Consumers will also play a vital role in meeting future grid demand for industry. Integrating rooftop systems, home batteries and other consumer energy resources into the system will allow households to export rooftop solar and stored energy into the system when it is needed.

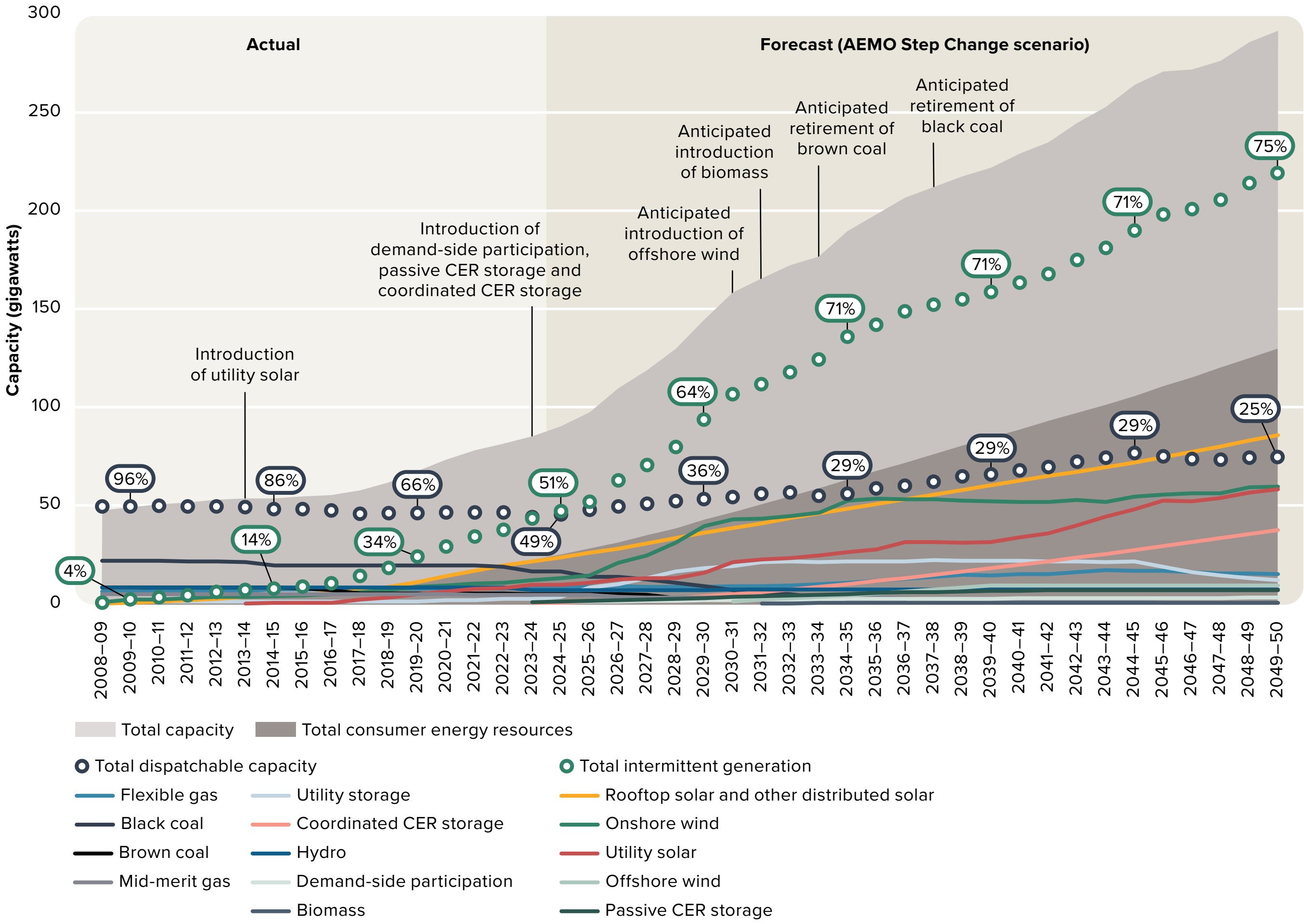
1.2 National Electricity Market (NEM)

Over the last decade, the profile of energy generation in Australia has changed significantly, and forecasts in AEMO's 2024 Integrated System Plan (ISP) highlight the significant amount of change that is still to come.

2024 was a notable year in many regards. New records were set for rooftop solar output, the highest number of negative-priced 30-minute periods, minimum daily electricity demand and entry of new registered generation capacity.

Increased price volatility is evidence that the wholesale electricity market is now increasingly driven by the complex relationship between weather conditions, shifting demand profiles and the diverse shifting mix of generation types in the NEM.

Figure 1.1 NEM capacity, by generation type



Note: CER: consumer energy resources. % reflects the proportion of total capacity.
Source: AEMO, 2024 Integrated System Plan, June 2024.

Between 2014 and 2024, more than 6.6 GW of coal-fired and gas-powered generation left the market. Over this same period, around 18.5 GW of large-scale wind and solar capacity and 18.2 GW of rooftop solar capacity came online.

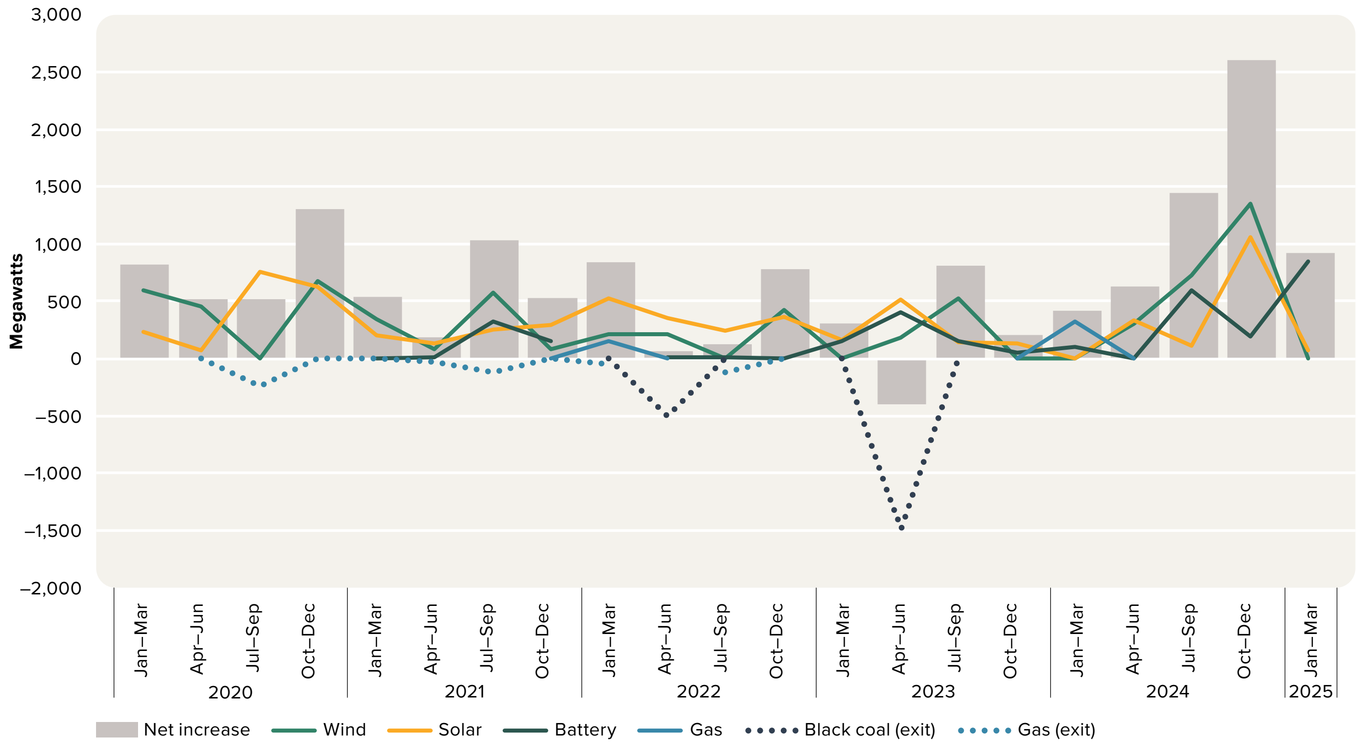
By the end of 2024, renewable technologies (rooftop solar, solar farms, wind, hydro and battery) made up 60% of the NEM's generation capacity, up from around 14% in 2014. The change is less pronounced for generation output because renewable energy is weather dependent and, unlike coal and gas plants, cannot run continuously. Therefore, it produces electricity at a lower rate relative to capacity. Renewable technologies (rooftop solar, solar farms, wind and hydro) met 39% of electricity demand in 2024, compared with 14% in 2015.

Around 90% of the NEM's coal generators are scheduled to retire by 2035 as plants reach the end of their economic lives.[3] Coal-fired generators expected to retire in the next decade include remaining units of Eraring (NSW – August 2027), Callide B (Queensland – 2031), Yallourn (Victoria – 2028) and Vales Point B (NSW – 2033).[4]

By 2030, the share of electricity requirements met by coal-fired generation is forecast to decline to 17% of the grid and 14% of total electricity. By 2050, there is forecast to be zero coal-fired generation in the NEM.[5]

Grid-scale wind and solar are forecast to meet 65% of grid electricity requirements by 2030 and 88% by 2050.[6] Gas-powered generation, hydro-generation, battery storage and consumer energy resources are forecast to meet the balance of demand.

Figure 1.2 Generator entry and exit



Note: This chart illustrates entry, exit and expected new entry. Solar and batteries are maximum capacity. Other plants are registered capacity. New entry date is the first day the station receives a dispatch target. Solar reflects large-scale solar and does not include rooftop solar.

Source: AER analysis using AEMO Generator Information.

Market conditions from July to September 2024 illustrate how the system is becoming more vulnerable to volatility caused by infrastructure outages and variable weather. Compared to the same quarter in 2023, wind generation was 21% higher, which drove a then record number of negative prices for the NEM. However, there were some periods of very low wind generation with output less than 7%

3 AEMO, 2024 Integrated System Plan, Australian Energy Market Operator, June 2024, p. 6.
4 AEMO, Generating Unit Expected Closure Year April 2025, Australian Energy Market Operator, 15 April 2025, accessed 6 June 2025.
5 AEMO, 2024 Integrated System Plan, Australian Energy Market Operator, June 2024, pp. 49–50.
6 AEMO, 2024 Integrated System Plan, Australian Energy Market Operator, June 2024, p. 30.

of installed capacity, which contributed to high price events throughout the period. Network outages also played a role, with the Heywood interconnector being constrained during the majority of events occurring in South Australia and Murraylink offline for both planned and unplanned outages for some of the quarter.

Since 2020, the frequency of both negative prices and prices above $300 per megawatt hour (MWh) has increased significantly. In 2024, across the NEM, negative prices accounted for 15% of all prices, up from 3.5% in 2020. Prices above $300 per MWh rose from 0.4% to 1.8% over the same period. Despite their greater frequency, negative prices have a relatively modest impact on average spot prices compared with high prices. This is partly because when high prices do occur, they are often much more extreme than negative prices (which are often only slightly below $0 per MWh) and they tend to occur when system demand is greater. This means high prices apply to a greater proportion of the electricity that is dispatched and therefore have a larger impact on volume weighted average electricity prices.

Orchestrating the timing and location of this investment with the timing and location of new generation is critical to a successful energy market transition.

1.3 Electricity networks

New solar and wind plants are being constructed in windy or sunny parts of the grid, where network capacity tends to be limited. Investment in new transmission capacity is needed to meet this challenge. Orchestrating the timing and location of this investment with the timing and location of new generation is critical to a successful energy market transition. Increases in the value of regulatory asset bases (RAB), that is, the total value of transmission network assets, are expected to continue as more major transmission network projects enter development and these networks grow.

AEMO in 2024 reported that the market needs around 5,000 km of new transmission lines by 2034 and 10,000 km by 2050.[7] In preparing the 2025 Integrated System Plan, AEMO assessed that these projects are critical to unlocking new sources of renewable energy to replace our aging and increasingly unreliable coal plant. It forecasts that these transmission projects will repay their investment costs, save consumers $18.5 billion in avoided costs and deliver emission reductions now valued at $3.3 billion.

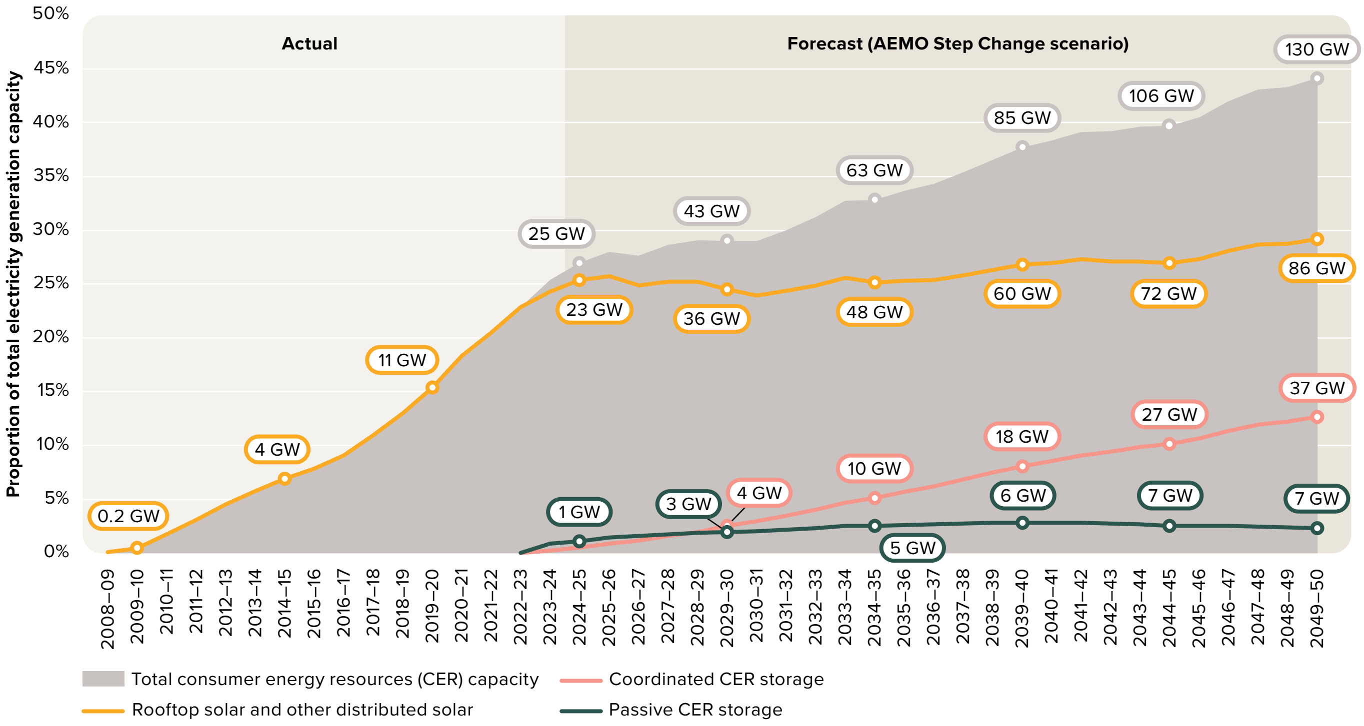
However, many key projects have faced delays and additional costs linked to social license and supply chain issues on equipment, materials and labour shortages which have resulted in challenges for transmission networks. Delays not only impede efficient delivery of transmission upgrades but may also impede timely delivery of generation that is reliant on them. In May 2025 AEMO estimated real costs for overhead transmission projects had increased 25% to 55% compared with equivalent cost estimates prepared for the 2024 ISP, and approximately 10% to 35% increase in real costs for transmission substation projects.

1.3.1 Consumer resources and distribution networks

Alongside major shifts in the energy market at the grid level, a raft of changes are occurring at the customer level. Energy customers are investing in consumer energy resources (CER) that can generate or store electricity to reduce their energy costs and support renewable energy. By far the most common form of CER in Australia is rooftop solar photovoltaic (PV) systems, but interest is also growing in batteries and electric vehicles.

7 AEMO, 2024 Integrated System Plan, Australian Energy Market Operator, June 2024.

Figure 1.3 Consumer energy resources share of total electricity generation (output)



Source: AEMO, 2024 Integrated System Plan, June 2024.

Australia has the largest per capita investment in rooftop solar in the world. As at December 2024, over 4 million households owned more than 22 GW in rooftop solar capacity connected to the grid, equivalent to 25% of all generation capacity in the market.

Total capacity of rooftop solar across Australia as at May 2024 was 7 times higher than capacity in May 2014. Output from rooftop solar systems has also more than tripled in the 7 years to 2023–24 and is now capable of meeting over half of underlying energy demand across the NEM in the middle of a sunny day.

Rooftop solar systems contributed 14.7% of the NEM's total generation in the first quarter of 2025, more than utility-scale solar (9.3%), wind power (13.7%), hydro (4.9%) and gas (3.5%).

As technologies mature and costs come down, more consumers will store surplus energy from solar systems in batteries to draw from when needed and, with the right incentives, export it into the grid when needed. In coming years, electric vehicle batteries are expected to play a similar role.

The rate of home battery installations in Australia is rising, albeit from a low base. Installations surged in 2024, with 74,582 home batteries installed, up from 46,127 in 2023 and marking a 62% year-on-year increase.[8] In July 2025, 19,592 home batteries were installed across Australia, with a total nominal capacity of 356.6 MWh.[9] Electric vehicle (EV) uptake in Australia has been slower than in other developed countries but new purchases continue to increase to and totalled more than 114,000 in 2024.[10]

8 Clean Energy Council, Rooftop solar and storage biannual report, 17 March 2025, accessed 6 June 2025.

9 Data is as at 4 August 2025 and is subject to change – it includes installations with applications that have claimed or had small-scale technology certificates approved. Data includes residential and small business installations. See Clean Energy Regulator, Strong solar battery uptake in first month, 4 August 2025.

10 Electric Vehicle Council, 2024 sets new record for EV sales in Australia, 6 January 2025, accessed 6 June 2025.

1.3.2 Orchestrating CER

Consumer energy resources are among the cheapest ways of meeting the projected growth in energy demand over time. If rooftop solar and batteries are orchestrated with the power system, they can deliver benefits to all consumers by mitigating price spikes and reducing the need for future grid-scale investment in generation, transmission and distribution.

However, when large amounts of CER are added to the power system it can lead to network congestion and make grid operation more difficult. For this reason, effective integration and coordination or orchestration of CER will be an important part of achieving a lowest-cost energy transition.

AEMO's market projections to 2050 factor in a substantial contribution from CER in meeting the NEM's energy requirements. It estimates coordinated CER storage will need to rise from today's 0.2 GW to 3.7 GW in 2029–30 and then 37 GW in 2049–50 to maintain system reliability. This coordinated storage would make up 66% of the NEM's storage capacity by 2050, or 36% of all coordinated capacity in the market (including generation). By 2050, this would make CER the largest energy source meeting grid demand. These coordinated resources could include virtual power plants, community batteries, vehicle-to-grid and other storage.[11]

Analysis published by the Energy and Climate Change Ministerial Council forecasts that successful integration of CER could offset up to $11 billion in network augmentation costs by 2040, along with $8 billion in saved generation and storage costs.[12]

These benefits are not guaranteed but require the right policy settings and market incentives, and consumer trust to make effective orchestration a success.

1.3.3 Role of distribution networks

Alongside the need for significant transmission investments to rewire the nation, the energy market transition is changing the role of distribution networks. In the past, distribution networks provided a one-way delivery service to energy customers. However, now they can host two-way flows of consumer energy resources (CER) as well as some larger-scale renewable and storage projects.

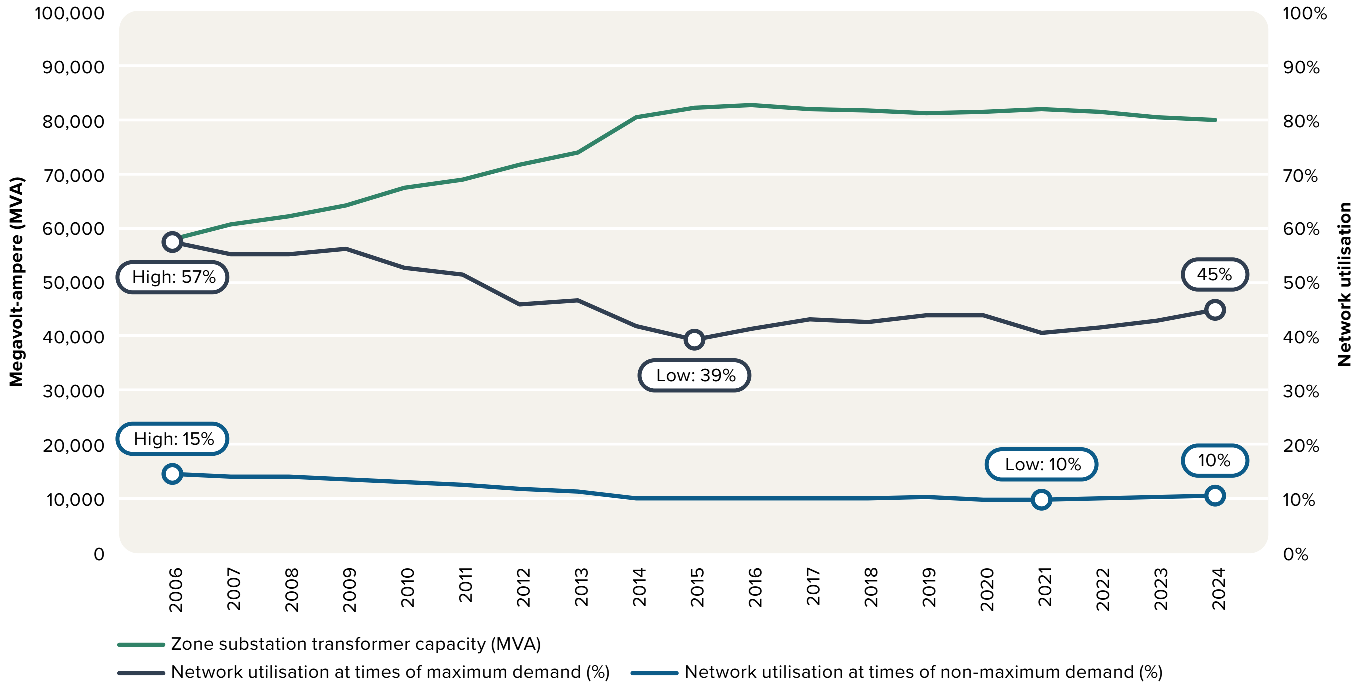
Utilisation rates on most networks in relation to maximum demand have been relatively stagnant in recent years, although has increased slightly (Figure 1.4). However, electrification of household heating and cooking appliances, use of electric vehicles and demand from data centres are expected to increase electricity consumption and peak demand on networks.

One method to deal with this expected demand is to use price signals and encourage certain consumption behaviour to shift this demand to periods of the day when there is lower network utilisation and greater availability of CER generation. This would also assist in flattening future peak demand and avoiding or minimising future capital investment into distribution networks.

11 AEMO, 2024 Integrated System Plan, Australian Energy Market Operator, June 2024.

12 Australian Government, National consumer energy resources roadmap – Powering decarbonised homes and communities, Department of Climate Change, Energy, the Environment and Water, 19 July 2024, accessed 28 July 2025.

Figure 1.4 Network utilisation



Note: Network utilisation at times of maximum demand is calculated using non-coincident, summated raw system annual maximum demand divided by total zone substation transformer capacity. Network utilisation at times of non-maximum demand is the average energy delivered over the year less the energy delivered during the 'peak' 30-minute interval divided by total zone substation transformer capacity. The changes identified in the labels refer to the relative change in utilisation in percentage points over previous years.

Source: Economic benchmarking RIN responses.

1.3.4 Role of incentives

Successful orchestration requires well-designed incentives to bring on CER when it is needed and ease it off when too much is entering the system. Using some form of flexible network tariff is one pathway. Flexible tariffs typically set network usage charges lower when the network has spare capacity (typically during the day when rooftop solar generation eases demand from the grid) and higher when the network is under strain (typically later in the day when solar generation falls and customer demand is high).

These price signals are intended to encourage customers to shape their energy demand for services like hot water heaters and pool pumps around available capacity on the network. Network determinations require networks to design tariffs that consider periods of the day when there is high peak demand and network constraints. These flexible tariffs aim to be reflective of the costs to provide network services, while also achieving equity among customers. Other flexible pricing models include two-way tariffs, which adjust charges based on energy export times, controlled load tariffs for managing specific high-consumption devices, and wholesale pricing that reflects real-time market conditions.

An alternative way of orchestrating consumer resources is through some form of direct control supported by financial reward, using technology to control appliances such as water heaters, pool pumps and air conditioning, so they can be operated when demand is low or curtailed when the grid is under stress.

The AEMC released a draft determination in July 2024 allowing CER to compete in the wholesale electricity market by pooling resources through mechanisms such as virtual power plants and community batteries.[13]

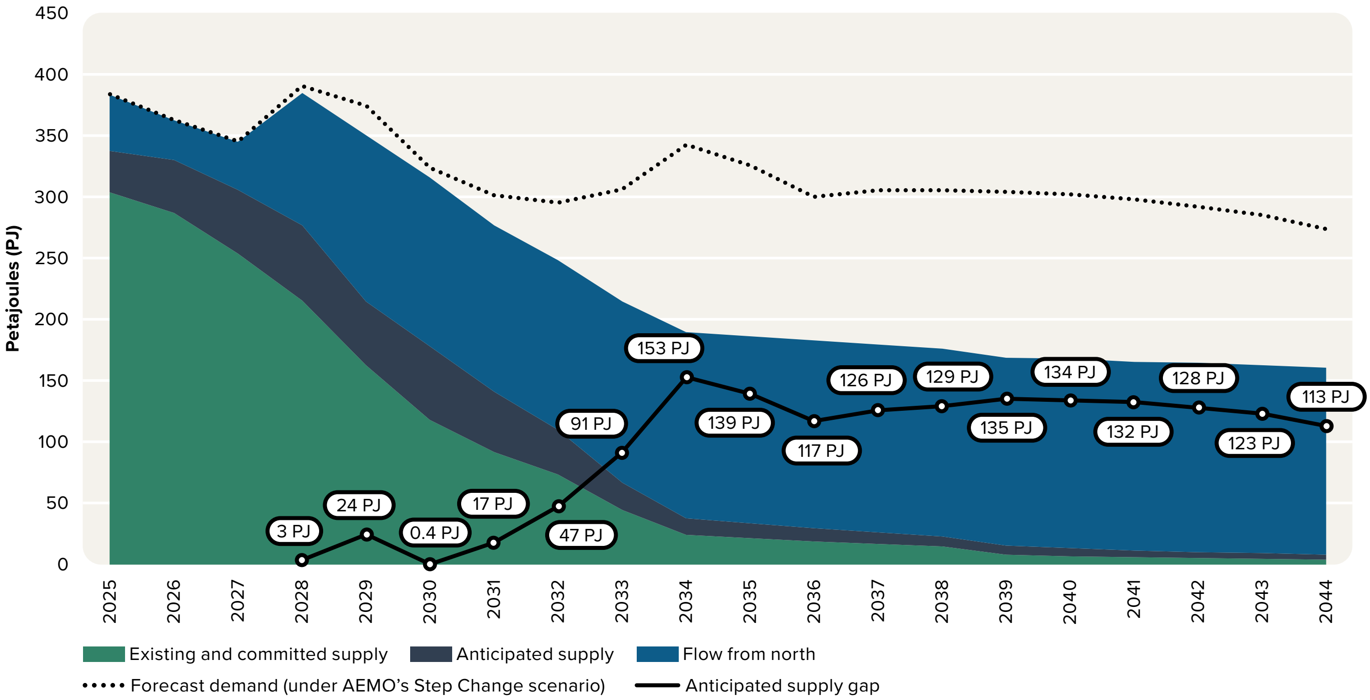
13 AEMC, Integrating price-responsiveness resources into the NEM, Australian Energy Market Commission, 25 July 2024.

The AER welcomes creative proposals by network businesses and other market participants to trial innovative services or technologies. In February 2025, the AER signalled a new approach to testing and trialling new ideas in the energy market with the introduction of policy-led sandboxing. Our regulatory sandbox enables us to grant waivers from regulatory requirements that may be standing in the way of a trial. Our policy-driven approach is focused on overcoming barriers to access, deployment and orchestration of new energy resources, such as community batteries, electric vehicles and rooftop solar, that will benefit consumers in the long term.

1.4 Gas markets in eastern Australia

Alongside events in electricity markets, the gas market is undergoing its own transition. In many ways the gas transition interlinks with events in electricity, but gas supply and demand also face their own unique challenges.

Figure 1.5 Projected gas supply adequacy in southern regions



Source: AEMO, Gas Statement of Opportunities, March 2025.

1.4.1 Demand conditions

Domestic gas customers in eastern Australia include industrial businesses, electricity generators, commercial businesses and households. Industrial customers consumed 46% of gas sold to the domestic market in 2024. Households and small commercial customers accounted for 36% of domestic demand, but this share is as high as 60% in Victoria, where gas is widely used for heating and cooking.

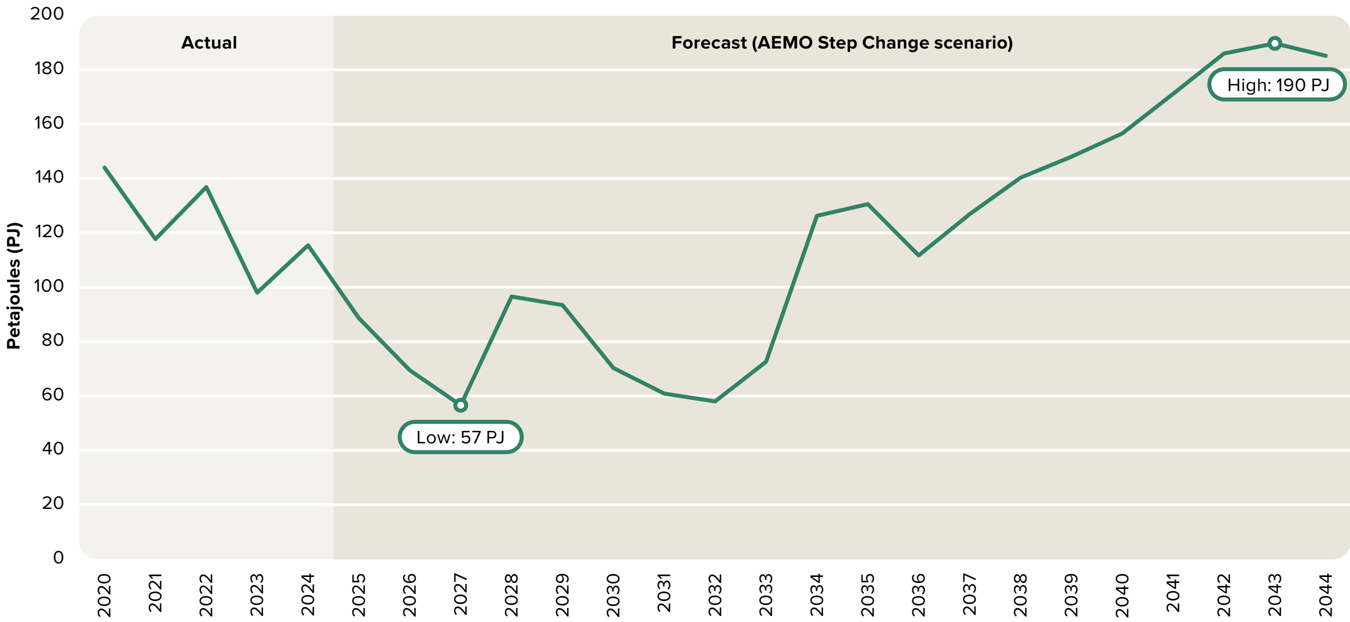
Gas consumption has been declining for many years, partly due to higher gas costs. This decline is forecast to continue as the economy continues its shift towards greater electrification to meet net zero targets. The Victorian and ACT governments are phasing out gas use in residential homes and are supporting research and investment in alternatives to achieve net zero targets. The impact of electrification on some parts of the industrial sector is likely to be less pronounced, due to the challenges in finding suitable substitutes for gas in processes such as for chemical feedstock production and heating at temperatures above 400°C.

1.4.2 Gas-powered generation

One source of demand that has fallen sharply in recent years is the use of gas for electricity generation. Around 19% of domestic gas demand in the NEM in 2024 was for power generation, down from 29% in 2017. Gas is more widely used for power generation in South Australia and Queensland (each supplied around 37% of gas-powered generation in the NEM in 2023).[14]

Higher gas fuel costs and relatively warmer winters contributed to the recent decline in gas-powered generation. Despite this, gas will remain a vital fuel for power generation during the energy market transition (section 1.2). Gas plants have the advantage of being able to start up and switch off quickly, providing fast dispatchability when cheaper plants are constrained by a lack of wind, sunshine or outages. This feature also makes gas plants an important provider of inertia and frequency stability as coal plants (the traditional supplier of these services) retire from the market. Reflecting these factors, AEMO projects that gas-powered generation demand will stabilise over the next decade and then rise from around 2033 (Figure 1.6). This growth is likely to be concentrated in winter, when solar generation is lower. The extent of this demand growth will depend on the timing of coal plant retirements and the capacity that replaces them.[15]

Figure 1.6 Gas demand for gas-powered generation



Note: Includes Northern Territory.
Source: AEMO, Gas Statement of Opportunities, March 2025.

14 AER, State of the energy market 2024, Australian Energy Regulator, 7 November 2024, section 5.4.
15 AEMO, 2025 Gas Statement of Opportunities, Australian Energy Market Operator, March 2024.

1.4.3 Adequacy of gas supply

While the use of gas in electricity generation is forecast to rise beyond 2032, overall gas consumption is forecast to keep declining in the future as electrification gathers pace. But while gas demand will fall, domestic supply may decline faster.

Supply conditions are particularly uncertain in southern Australia, where Victoria's Gippsland Basin output is declining due to the depletion of legacy fields. Southern gas markets have become especially vulnerable in winter, when households use gas for heating. This has increased reliance on drawing gas from Queensland gas fields as well as storage facilities in Victoria. Supply into the Victorian market is limited by pipeline capacity, although recent upgrades have improved this capability.

Recent evidence of gas supply pressures in southern Victoria emerged in winter 2024, when unusually low wind generation drove high levels of gas demand for power generation. Higher demand combined with weaker southern gas production caused gas storage levels at Dandenong LNG and Iona – Victoria's only facilities providing storage services to third parties – to run down rapidly despite increased gas flows from northern sources.

AEMO forecast that these risks will recur from 2028 under extreme peak demand conditions, with annual supply gaps growing from 2029 onwards.

In its June 2025 Gas inquiry report, the ACCC forecast that the gas supply outlook has deteriorated and gas shortfalls are expected in the southern states in the fourth quarter of 2025 and throughout 2026.[16] The ACCC also forecast the shortfalls will widen in future years without new supplies of gas coming online. In particular, the ACCC expects increased demand for gas-powered generation following the retirement of coal power generation, particularly post-2030, will coincide with substantial declines in forecast production in the Gippsland and Otway basins.

It noted new gas supplies and pipeline construction are facing delays due to long regulatory approval processes, technical factors (including uncertainties with geological and engineering) and making final investment decisions based on operational and market factors, some of which are beyond the control of producers.[17] In several jurisdictions, community concerns around environmental risks associated with fracking led to legislative moratoria and regulatory restrictions on onshore gas exploration and development. Given the uncertainty around gas proposals being considered for government approval, investors are finding it difficult to obtain project finance.[18]

More gas supply and associated infrastructure will be needed to fill projected supply gaps. But getting the optimum amount of new investment is a challenge. The longer-term outlook for gas remains uncertain, both due to supply uncertainty and policies to meet Australia's net zero carbon commitments by 2050. This uncertainty creates a dilemma for policy makers.

Currently, low-emission gases such as hydrogen and biomethane make a small contribution to Australia's energy mix. Once commercialised, the use of low-emission gases could grow to complement or potentially replace natural gas, especially in industry and power generation when their production costs match or outcompete the incumbent fuels.[19] Presently, there are significant challenges in supplying these gases economically at the scale required for their potential use; however, this may change as the methods of their production improve and become more efficient.

During Australia's transition to net zero, gas will continue to be used by households, businesses and industry, and to support reliability and security in the grid. But this role will decline over time. Therefore, the need for additional gas resources is temporary, which limits payback periods. In this context, identifying the least cost way of balancing gas supply and demand through to 2050 is challenging.

16 ACCC, Gas inquiry 2017–2030, June 2025, Australian Competition and Consumer Commission, 30 June 2025.

17 ACCC, Gas inquiry 2017–2025, interim report, June 2024, Australian Competition and Consumer Commission, July 2024, p. 36.

18 ACCC, Gas inquiry 2017–2030, interim report, January 2023, Australian Competition and Consumer Commission, January 2023, p. 125.

19 Department of Industry, Science and Resources, Finding new sources of gas to meet demand, accessed 14 July 2025.

1.5 Gas pipelines in eastern Australia

As the electrification of domestic gas applications continues, the number of gas customers will fall. In consequence, gas networks will face declining economies of scale. As network costs are spread over fewer and fewer customers, retail gas bills will escalate and threaten to drive more customers away from gas. This scenario could progress into a situation where some networks cannot maintain financial viability and become stranded assets. It also raises equity issues because consumers least able to afford the conversion costs of electrifying their energy supply are likely to be those most exposed to higher gas prices.

The AER is taking steps to manage the ongoing costs of maintaining gas networks over a declining customer base. Our aim is to ensure regulated businesses can invest where necessary to provide safe and reliable gas services while protecting consumers from unnecessary cost burdens now and in the future. For example, in Victoria, the AER allowed for some accelerated depreciation of assets, noting that bringing forward the recovery of assets while pipeline use remains relatively high spreads the increased costs among a larger pool of customers.[20]

The gas market transition also poses safety issues if disconnection results in leaving live unused assets in place. We are working with pipeline businesses to manage this risk by sharing costs between disconnecting users and all gas consumers in the network.

While the current regulatory framework allows us to take these steps to manage uncertainty over the next 5 years, the framework targets efficient growth of the service rather than an environment of declining demand.

In the longer term, the current regulatory framework based around gas access arrangement reviews may not be sufficient to deal with the scale and scope of equity and safety issues likely to arise in a scenario of sharply eroding domestic gas use.

1.6 Retail energy markets and energy consumers

The transition is also driving innovation and change in the retail energy markets. While Origin Energy, AGL and EnergyAustralia remain the largest energy retailers in Australia, Tier 2 retailers[21] have continued to grow their customer numbers and new retailers have entered the market with innovative business practices and product offerings. Some of these offers make renewable technologies accessible to a broader range of customers and include leases for batteries and solar, bundling batteries and solar with energy plans, virtual power plant plans, and peer-to-peer community trading.

The transition in Australia's energy market is being driven by consumers and affects them in a number of ways. Many consumers already benefit through self-production of rooftop solar energy, batteries to draw on when electricity is expensive, opportunities to earn income from exporting solar and battery discharge into the grid, savings from demand response and, where needed, access to cheap renewable power from the grid.

But not all consumers will benefit. Many people do not own a home, so cannot make their house more energy efficient or fit solar panels to the roof. Many cannot afford home batteries, an electric car or smart appliances they can use to respond to price signals. These customers will continue to draw electricity from the grid as they always have.

Ensuring that consumers don't get left behind and vulnerable customers are provided with the support they need now and in the future is important. It is also important that consumer protections give all customers confidence in the energy transition, as this will improve outcomes for everyone in the long term.

20 AER, State of the energy market 2024, Australian Energy Regulator, 7 November 2024, boxes 6.2 and 6.3.

21 Tier 2 retailers include any retailer that is not Origin Energy, AGL Energy, EnergyAustralia, nor one of the primary regional government-owned retailers – Ergon Energy (Queensland), ActewAGL (ACT) and Aurora Energy (Tasmania).

Over the past few years, initiatives outlined in the AER's *Towards energy equity strategy*[22] and Review of consumer protections for future energy services[23] have progressed. The Energy and Climate Change Ministerial Council's Better Energy Customer Experience reform program announced in March 2025 is progressing many of the AER's recommendations and intends to ensure the right consumer protections are in place through the energy transition and beyond. The Department of Climate Change, Energy, the Environment and Water (DCCEEW) is leading consultation that is considering whether the National Energy Customer Framework (NECF)[24] is appropriate for new energy products and services and customers in different market settings, such as embedded networks, off-grid and pre-payment services. Consideration is also being given to whether the current framework supports customers to easily navigate the complexity of the energy market.

The AEMC also announced rule changes to better protect energy customers experiencing vulnerability and ensure that households can access better energy deals.[25] The reforms will take effect on 1 July 2026 and are intended to restrict energy retailers from raising prices more than once per year, remove unfair fees for vulnerable customers, and ensure customers on hardship programs are receiving their retailer's best offer.

Recent developments are a step in the right direction, but there are more opportunities to improve consumer outcomes. In the 12-month period to 31 March 2025, the total number of residential customers (combined electricity and gas) and the proportion of customers with energy debt increased. The average debt among this cohort of customers was also higher. Alongside this, retailers reported that fewer customers were receiving assistance through hardship programs; however, both the average level of hardship program debt and the average level of debt on entry to hardship programs increased. These results highlight the need to address how customers experiencing vulnerability are supported and how those in hardship programs can be better supported.

The AER's Review of payment difficulty protections in the National Energy Customer Framework[26] identified more specific opportunities to ensure customers experiencing payment difficulty are identified early, engaged proactively and supported appropriately with assistance that is tailored to their individual circumstances. Recommended changes include:

- eliminating the distinction between 'hardship customers' and 'other' customers experiencing payment difficulty and introduce a single, inclusive definition
- introducing Tier 1 civil penalties for retailers that fail to uphold the principle that disconnection due to inability to pay energy bills should be a last resort option
- requiring retailers to proactively engage with customers in ways that meet their needs and provide information about assistance that is easy to access and understand
- banning retailers from requiring customers to provide proof of circumstances to access payment difficulty assistance and introducing minimum assistance for all customers
- strengthening protections to make payment plans more affordable and introducing minimum assistance (including assistance to lower energy costs) for customers experiencing payment difficulty
- banning reconnection fees, strengthening requirements for communication in the disconnection process and strengthening minimum disconnection protections.

As the energy sector continues to evolve, it is critical that the market maintains consumer agency and promotes consumer trust in the energy transition.

22 AER, Towards energy equity strategy, Australian Energy Regulator, 20 October 2022.

23 AER, Review of consumer protections for future energy services, Australian Energy Regulator, November 2023.

24 The National Energy Customer Framework is a suite of legal instruments. For further information see AEMC, National Energy Customer Framework, Australian Energy Market Commission, accessed 28 July 2025.

25 DCCEEW, New rules for energy retailers help more Australians access better deals, Department of Climate Change, Energy, the Environment and Water, 26 June 2025.

26 AER, Review of payment difficulty protections in the National Energy Customer Framework, Australian Energy Regulator, 15 May 2025.