State of the energy market

2024

AUSTRALIAN ENERGY REGULATOR

Australian Government

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Chair's preface

For more than 15 years the Australian Energy Regulator's (AER) flagship *State of the energy market* report has provided a comprehensive view of Australia's electricity and gas markets and the experiences of consumers. This year's edition continues this tradition with a detailed description of the year that was across all our energy markets and for energy consumers.

Alongside the *State of the energy market* we will continue to publish a range of in-depth reports into specific parts of the energy system. These reports will provide a deep dive into some of the critical issues facing the energy sector.

- Our November 2024 Annual retail markets report looks at how energy consumers are faring as prices increase and how retailers are addressing this challenge.
- In December 2024 we will release our biennial competition and efficiency review that examines the structure, conduct and performance of our wholesale electricity market as it goes through a profound transition.
- We will publish our second annual export services network performance report, looking at the increasingly important role of energy exports from rooftop solar systems and other technologies, as well as our analysis of regulated gas transmission pipeline performance and a focus report on the gas supply hubs.

The *State of the energy market* provides a rich background to these reports, documenting the end-to-end operation of our energy markets. It is a resource for both those new to the sector and those looking to understand the breadth of changes in the past 12 months.

Over the past year we have observed that wholesale prices have eased from the extreme levels of 2022–23, but that they are increasingly volatile. The market also saw record low minimum demand in New South Wales, Victoria, South Australia and Tasmania and record high maximum demand in Queensland. Weather and outages at both generator and network levels were key contributors to this. Rooftop solar photovoltaic (PV) is now the fuel source with the highest registered capacity across the National Electricity Market (NEM). Residential solar PV installed in the NEM now exceeds 20 gigawatts – equivalent to 25% of total registered generation capacity. Through their investment in rooftop solar, batteries and electric vehicles, consumers have become an integral part of the energy transition.

An important policy development over the past 12 months has been legislative reform to include emissions reduction in the national energy objectives. These objectives promote efficient investment in, and use and operation of, energy services in the long-term interests of consumers. In promoting these objectives, market bodies must now consider emissions reduction alongside factors such as price, reliability, quality, safety and security.

The change in relation to emissions will contribute to energy system planning and can now be factored into network investment proposals. It also reinforces that promoting efficiency is critical as we develop the energy system. This will help us ensure the energy system is least cost and that assets are well utilised.

The importance of efficiency has long been the clarion call of the AER. We are again urging industry to be disciplined about how existing assets are used before they build more. Now is the time to get creative about how to do this. With the sector changing so fast, it is unclear which mix of technology, economic and regulatory solutions will meet consumer and system needs most efficiently. The Energy Innovation Toolkit, which is a regulatory sandbox operated in partnership with the Australian Energy Market Commission, Australian Energy Market Operator, the Australian Renewable Energy Agency and the Essential Services Commission, allows innovative approaches to be trialled. Now is the time to experiment with an eye always to lowering future costs for consumers.

Significant shifts are not confined to our electricity markets. In gas markets we are seeing supply risks in the short to medium term. Gas will remain a critical fuel for electricity reliability and large industry for some time. However, we are also seeing moves towards electrification of domestic uses of gas, with accompanying uncertainty about the future of some of the infrastructure currently meeting those needs.

For energy consumers, the past 12 months has been a challenging time. Across the NEM, while the proportion of customers in debt has remained stable, the average amount of debt per customer increased in 2023–24. While price increases were offset by rebate assistance from governments, broader economic conditions meant that affordability and energy debt remained challenging.

Through our *Towards energy equity* strategy, released in 2022, we are continuing to highlight the importance of identifying consumers in need of support early and providing effective assistance. In November 2023, we submitted our 'game changer' reforms to Energy Ministers, setting out a suite of proposals to break the cycle of energy debt and fundamentally shift the way the energy sector supports consumers. We are pleased progress has been made on some of these reforms in the package of consumer-focused rule change requests endorsed by Energy Ministers in July 2024. We recognise that more must be done to drive systemic change for energy consumers who struggle to pay their energy bills. In addition to advocating for the remaining game changer reforms, we are reviewing the payment difficulty protections that currently exist and considering how these protections could be strengthened.

The energy transition means that consumers have access to an increasing array of new energy services such as electric vehicles, aggregation services (such as virtual power plants) and home energy management services. We expect these services to continue to grow as technology evolves and the sector innovates. However, we are concerned that protections for consumers using these new services are inadequate. Put simply, our current protections framework is designed for the one-way supply of electricity directly to a home or business and not a world in which a customer can use multiple energy services to consume, trade and produce energy. We have presented detailed analysis on this issue to Energy Ministers and look forward to seeing this progressed as part of the National Consumer Energy Resources Roadmap. The Roadmap will help address the risk of harm to consumers while creating the right environment for the continued development of services that can support the grid and reduce costs through the energy transition.

I recommend the *State of the energy market 2024* report to all stakeholders as a source of key data and clear insights on the industry, but also as a compelling reminder of our shared responsibility to help make energy consumers better off, now and in the future.

Clare Savage
AER Chair
November 2024

Contents

1 Market overview

This chapter describes recent developments across our energy markets, providing a brief summary of the key market outcomes explored in more detail in chapters 2 to 6.

1.1 National Electricity Market

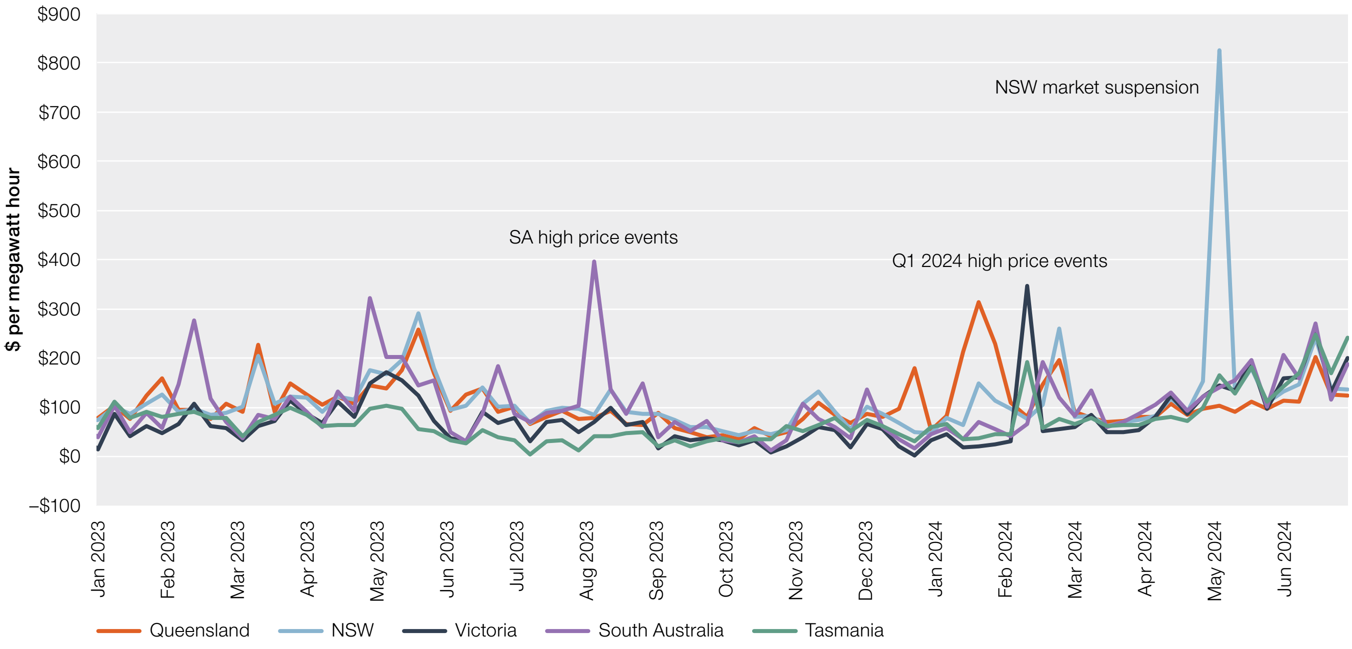
The National Electricity Market (NEM) continues to transition from a centralised system of large fossil fuel (coal and gas) generation towards an array of smaller scale, widely dispersed wind and solar generators, hydro-electric generation, grid-scale batteries and demand response. Entry of planned new capacity slowed in 2023–24 as projects have been delayed. 2.1 gigawatts of large-scale generation and storage were commissioned across the year. However, a substantial amount of the capacity commissioned to enter the market over 2023–24 is now forecast to enter the market in 2024–25, reaching 6.4 gigawatts at full output.

Wholesale electricity prices over 2023–24 were highly volatile, with fairly moderate conditions punctuated by high price periods across the NEM. Queensland recorded record peak demand levels during the hot and humid summer, which drove up prices. Meanwhile, storm damage affected supply in southern states in February 2024, driving up prices in Victoria. During the April to June 2024 quarter, periods of unusually cold weather, low wind output and lower water storage levels combined to increase demand and reduce supply, pushing up prices in all regions (Figure 1.1).

In New South Wales (NSW), network and generator outages, combined with generator rebidding, drove high price events in early May. As a result, the cumulative price threshold was breached for the first time since 2022. AEMO suspended the NSW market, a safety net mechanism that triggers administered prices in order to stabilise wholesale spot prices and reduce financial stress for market participants.

Despite these high price events and overall volatility, wholesale prices were lower across all regions of the NEM in 2023–24 than in the previous year, influenced by record high prices during winter 2022.

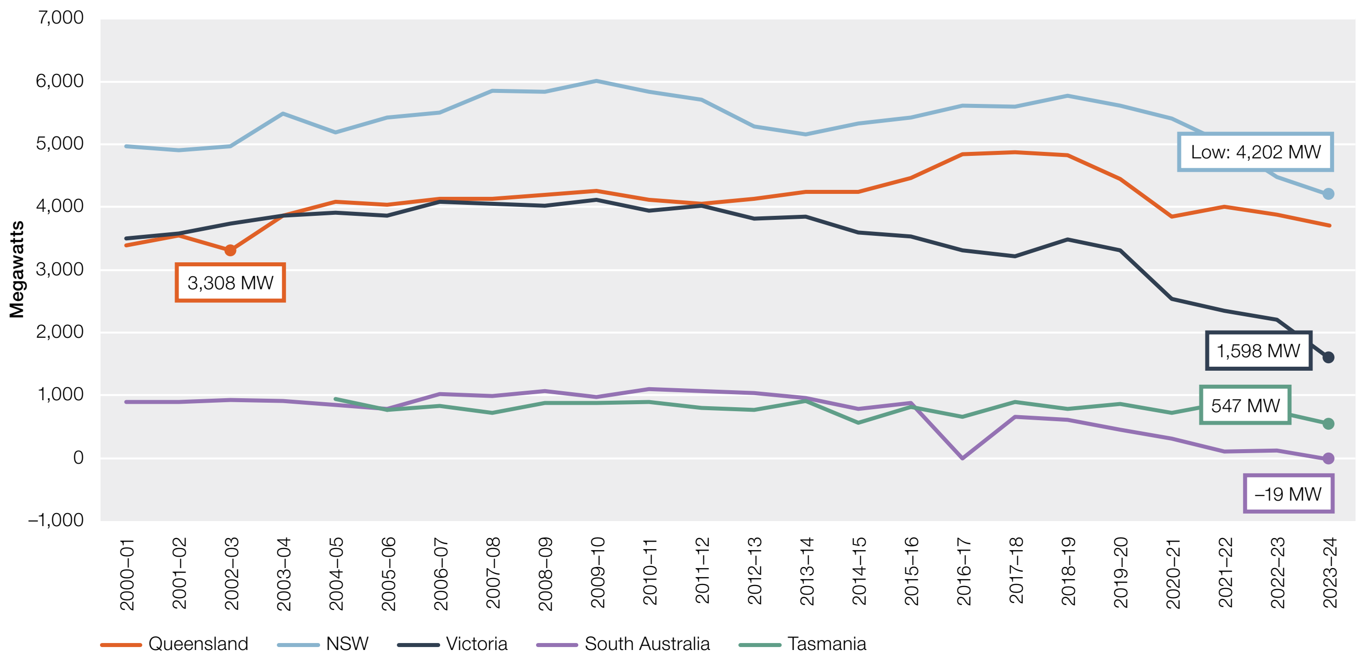
Figure 1.1 Weekly wholesale electricity prices



Note: Volume weighted weekly average prices.
Source: AER; AEMO (data).

In 2023–24, record lows in minimum demand were set across all regions except Queensland. Output from rooftop solar continues to increase in line with ongoing installations by households, further reducing grid demand during the middle of the day across the NEM (Figure 1.2).

Figure 1.2 Minimum grid demand

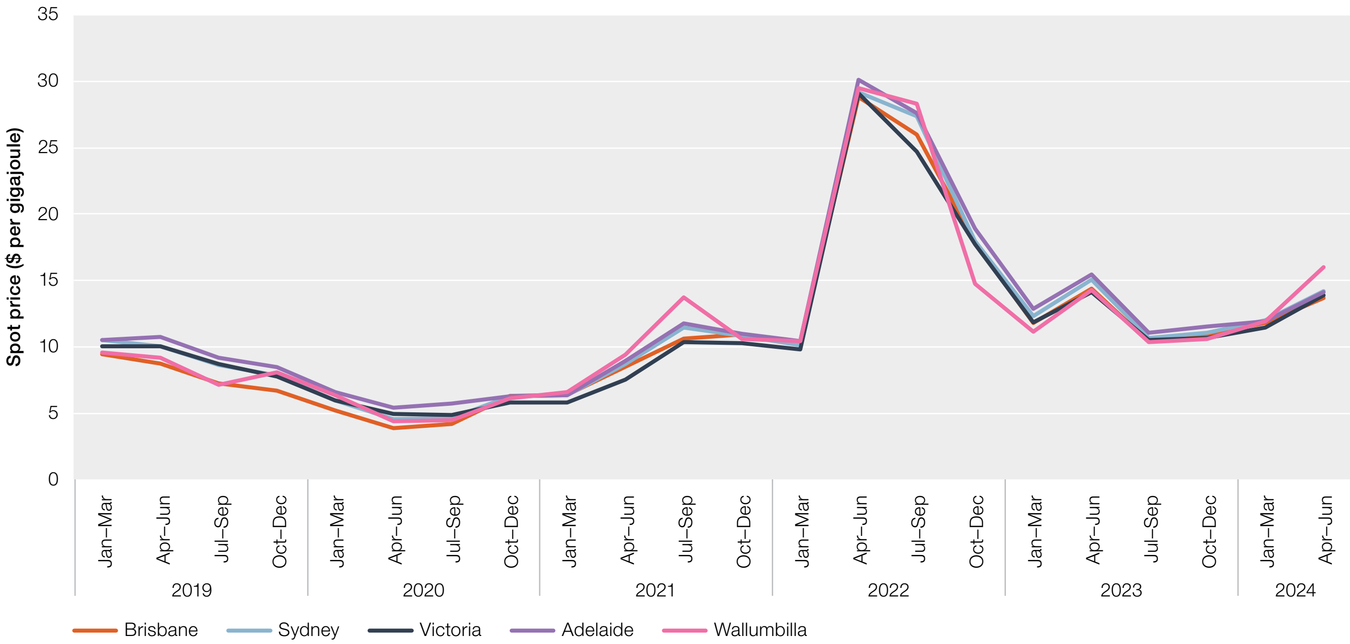


Note: Minimum 30-minute grid demand (including scheduled and semi-scheduled generation, and intermittent wind and large-scale solar generation) is for any time during the year. Data excludes consumption from rooftop solar systems. The low value for South Australia in 2016–17 is due to the Black System event in October 2016.
Source: AER; AEMO (data).

1.2 Gas markets in eastern Australia

Gas prices stabilised from mid-2023, with milder winter conditions lowering demand and influencing a significant reduction from the unprecedented high prices of mid-2022. Prices remained stable until a stretch of cold weather and constrained southern production in late May 2024 put upwards pressure on the market (Figure 1.3).

Figure 1.3 Eastern Australian gas market prices

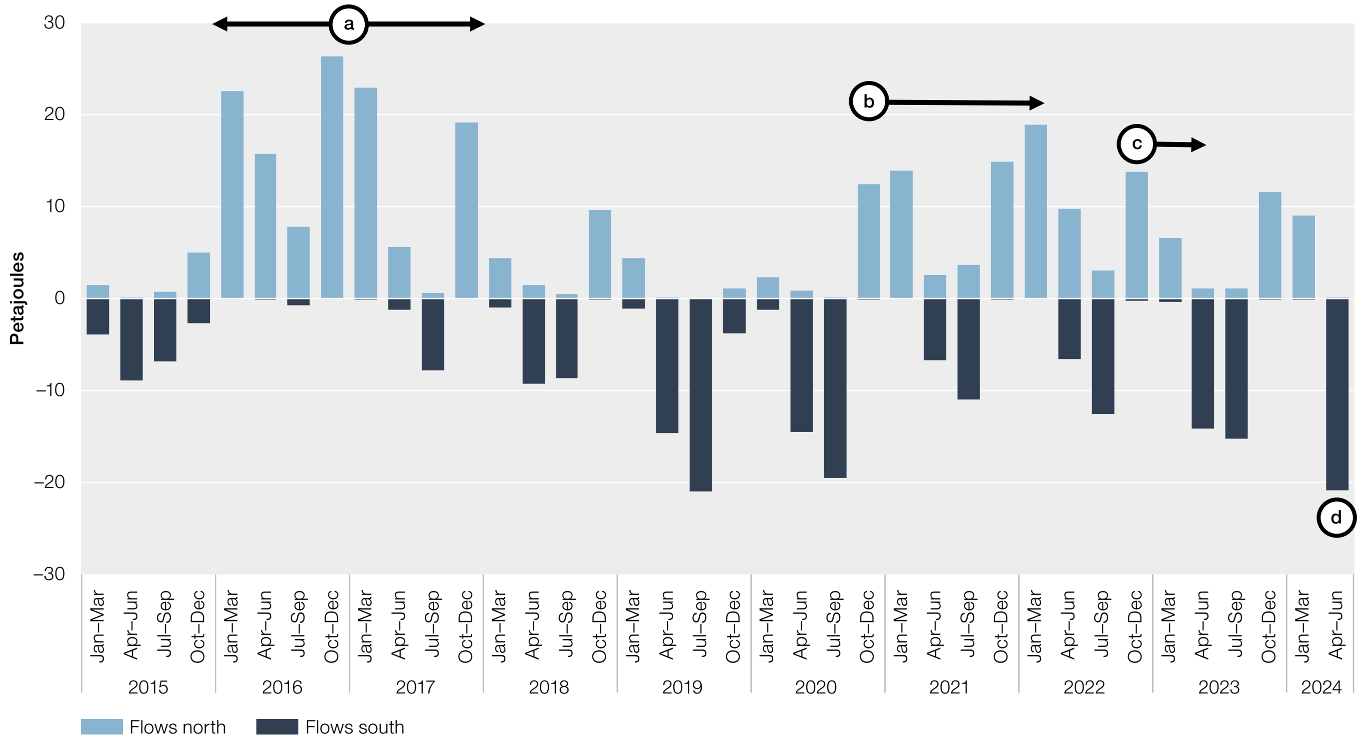


Note: The Wallumbilla price is the volume weighted average price for day-ahead, on-screen trades at the Wallumbilla gas supply hub. Brisbane, Sydney and Adelaide prices are ex-ante. The Victorian price is the average daily weighted imbalance price.

Source: AER analysis of gas supply hub, Short Term Trading Market and Victorian Declared Wholesale Gas Market data.

In 2023–24, the seasonal pattern in gas markets continued, with gas flowing north to export markets during summer and south in winter to meet demand for heating. This remained the case in early 2024, despite reduced production from the Longford facility in Victoria, with exports for the quarter at the highest level observed for the start of the year.

Figure 1.4 North–south gas flows in eastern Australia



Note: Flows on the QSN (Queensland / South Australia / New South Wales) Link segment of the South West Queensland Pipeline (flowing through the Moomba location).

a 2016 to 2017: Increased southern production to meet LNG demand.

b Late 2020 onwards: record LNG exports continue to rise.

c Late 2022 onwards: LNG exports reduce closer to 2019 levels.

d Winter 2024: additional compressors commissioned on the Moomba to Sydney Pipeline and South West Queensland Pipeline in May and June. Expanded capacity facilitates record monthly gas flows south in June (close to 11 PJ).

Source: AER analysis of Gas Bulletin Board data.

In late 2023, demand for gas reached a record low, alongside lower levels of gas-powered generation. While this continued over the summer, the second quarter of 2024 saw spikes in gas-powered generation output to offset low wind and solar generation. This demonstrates the interdependencies between our electricity and gas markets.

In mid-2024, transportation capacity upgrades were completed on the north–south pipeline corridor to increase the ability to flow more gas south and reduce existing gas supply constraints. This delivered more supply from Queensland to southern markets. As a result, and due to elevated southern market demand over winter, record gas flows south from Queensland were evident in June 2024 (Figure 1.4).

Concerns about potential gas shortfalls have prompted a range of potential market responses. These include further gas development, LNG imports, transmission pipeline solutions and demand response. AEMO's *Gas Statement of Opportunities* reports have repeatedly highlighted the risk of both short-term and long-term shortfalls in the east coast gas markets, particularly due to the depletion of legacy gas fields in Victoria's offshore Gippsland Basin. However, several projects that could help fill the supply gap have either stalled, been postponed or abandoned.

In response to concerns around the adequacy of gas supplies to meet domestic demand and prolonged price volatility seen in 2022, the Australian Government and some state and territory governments have intervened in the market. These interventions have included measures to increase supply stability, reduce demand, limit price volatility and provide additional monitoring powers to market bodies.

In addition, the Australian Domestic Gas Security Mechanism (ADGSM) empowers the Australian Government Minister for Resources to require LNG projects to limit exports, or find offsetting sources of new gas, if a supply shortfall is likely. Since 2017, the Minister has been able to determine if a shortfall is likely in the following year and may revoke export licences if necessary to preserve domestic supply.

Following the introduction of this mechanism, Queensland's LNG producers entered agreements with the government, committing to offer uncontracted gas on reasonable terms to meet expected supply shortfalls. They also committed to offer gas to the Australian market on competitive market terms before offering any uncontracted gas to the international market. In 2023, following a review by the Australian Government, the scheme was extended until 2030. The changes made to the ADGSM introduced more flexibility to activate the mechanism to secure domestic supply on a quarterly basis, rather than the yearly timeframe in the previous regulations.

The new reforms came into place on 30 March 2023 with a newly negotiated Heads of Agreement with east coast LNG exporters in place until 1 January 2026. To prevent a gas supply shortfall, an additional 157 petajoules of gas was committed to the east coast market in 2023.

1.3 Electricity networks and regulated gas pipelines

Over the 12-month period to 30 June 2023, electricity network service providers collected $12.5 billion in revenue for delivering core regulated services,[1] 2.9% less than in the previous year. Over the same period, $1.6 billion in revenue was collected for providing access (selling capacity) to parties needing to transport gas, 9% less than in the previous year.[2]

As at 30 June 2023, the total combined value of the regulatory asset base (RAB) for electricity network service providers was around $116 billion, an increase of $1.7 billion (1.5%) from the previous year. The total combined value of the capital base for gas pipeline service providers was around $13.3 billion, an increase of $31 million (0.2%) from the previous year.

As part of the revenue determination process, network service providers submit expenditure proposals. The AER assesses the proposals and determines efficient investment requirements over the forthcoming regulatory period. Efficient investment approved by the AER is added to the RAB (or 'capital base' for regulated gas pipelines) at the end of each regulatory period on which the service provider earns returns. Over time, depreciation on existing assets is deducted from the asset base and returned to shareholders. As such, the value of a service provider's asset base[3] will grow over time if approved new investment exceeds depreciation.

Over the 12-month period to 30 June 2023, electricity network service providers invested $6.8 billion on capital projects, $1.1 billion (20%) more than in the previous year. The recent increase in growth-related expenditure in the electricity transmission network has been driven by Transgrid's (NSW) substantial investment in Project EnergyConnect – a major new interconnector between NSW and South Australia – stage 1 of which is expected to be completed in December 2024.[4]

Significant investment in the electricity transmission network is expected to continue over the next few years, with early works commencing on the VNI West project between Victoria and NSW and the AER approving a $4.0 billion cost application for the Humelink project in NSW. Subject to a financial investment decision by the proponent, Humelink is likely to be completed by 2026–27 (Figure 1.5).

Despite the increased spend on capital projects, network service providers spent $372 million (2.9%) less on electricity network costs and $165 million (9%) less on gas pipeline costs than in the previous year. As the RAB/capital base is only adjusted at the end of the regulatory period and not on an annual basis, the year-on-year relationship between revenue and capital expenditure incurred is not linear.

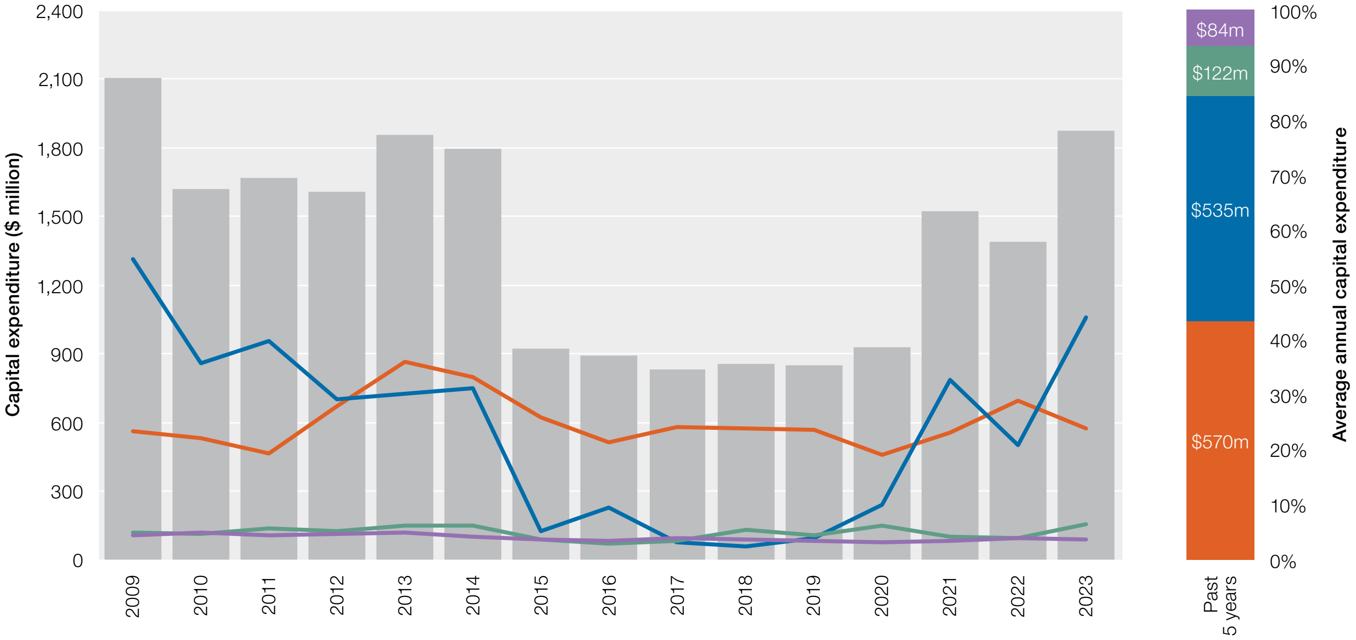
1 Prescribed transmission services for transmission network service providers and standard control services for distribution network service providers.

2 Excludes revenue earned by Amadeus Gas Pipeline (Northern Territory). Amadeus Gas Pipeline's actual revenue is confidential because it contains commercially sensitive information.

3 Asset bases and capital bases are indexed using actual inflation.

4 AEMO, 2024 Integrated System Plan, Australian Energy Market Operator, June 2024, p. 14.

Figure 1.5 Drivers of capital expenditure – electricity transmission networks (aggregate)



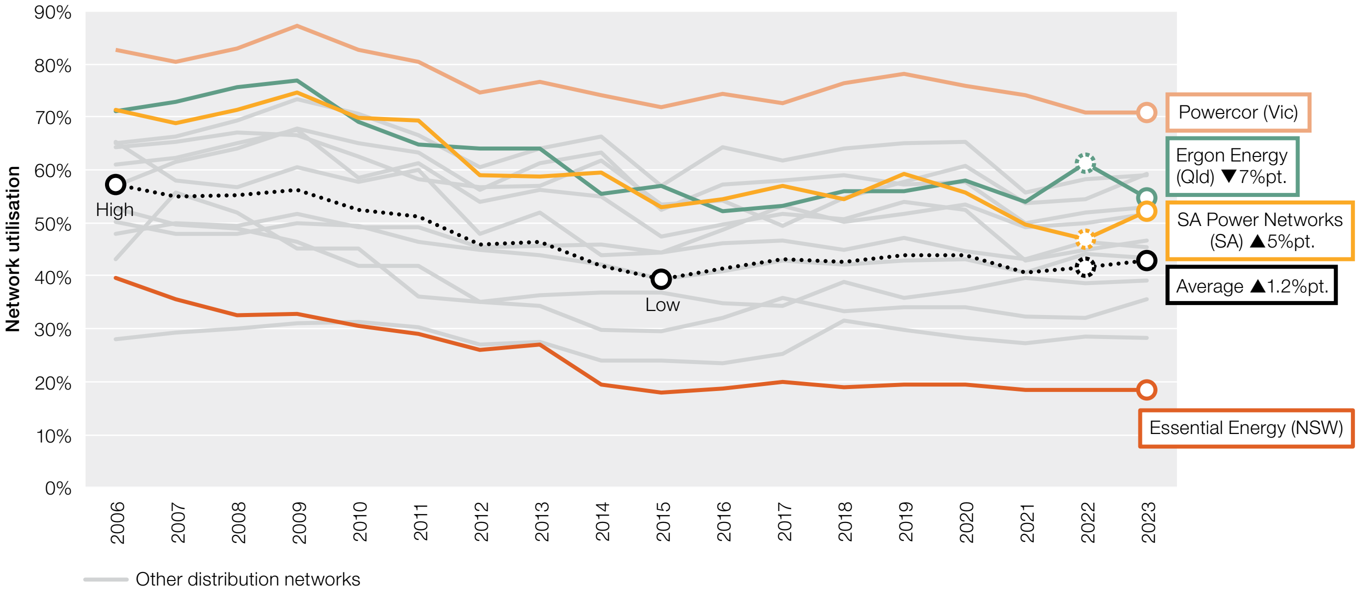
Note: All data are adjusted to June 2023 dollars. The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018). Augmentation of the Victorian transmission network is carried out by AEMO; hence, AusNet Services reports $0 expenditure for augmentation carried out on the transmission network.

Source: Category analysis RIN responses.

In 2023, a 2% increase in maximum demand, coupled with a slight decrease in electricity distribution network capacity, saw the overall distribution network utilisation rate increase to 43%, the highest since 2020 (Figure 1.6). The AER is encouraging network service providers to, where possible, increase the rates of network utilisation by utilising existing capacity before investing in new assets. Opportunities to increase electricity network utilisation may also be found through electrification, load shifting and generation management.

For the gas distribution pipelines, under-utilised assets raise the risk of asset stranding – whereby assets are no longer useful – unless network service providers respond to changing conditions.

Figure 1.6 Network utilisation – electricity distribution networks



Note: Network utilisation is the non-coincident, summated raw system annual peak demand divided by total zone substation transformer capacity. The changes identified in the labels refer to the relative change in utilisation in percentage points over the previous year.

Source: Economic benchmarking RIN responses.

Despite spending less on network services, reliability outcomes continued to improve when compared with historical levels. Electricity consumers experienced the fewest unplanned interruptions to supply on record, as well as a reasonably low number of unplanned minutes off supply (both measures exclude the impacts of major events). The relatively low number of minutes off supply experienced by the average NEM customer in 2022–23 was in part driven by the lack of catastrophic weather events throughout the year. While some network customers were impacted by isolated severe weather events – such as flooding in NSW and severe thunderstorms in South Australia – the weather in 2022–23 was generally mild compared with the previous 3 years.

Investment in gas pipelines increased slightly from the previous year, driven by APA Victorian Transmission System's expansion of the South West Pipeline and its construction of the Western Outer Ring Main project. Investment in gas pipelines continues to be driven by expenditure on new gas connections and by several major programs to replace old steel or cast-iron distribution pipes with plastic pipes.

State and territory governments are already taking measures to reduce residential and small commercial consumers' reliance on gas.

In November 2020, the NSW Government released its Electricity Infrastructure Roadmap – a 20-year plan to transform the state's electricity system into one that is affordable, clean and reliable for everyone. Gas will continue to play an important role in the energy transition and the NSW Government aims to maximise investments through its Electricity Infrastructure Roadmap and renewable energy zones (REZ).

In October 2022 the Victorian Government released its Gas Substitution Roadmap – a plan to help Victoria reduce the cost of energy bills and cut carbon emissions.[5] Victoria is taking steps to speed up the transition to renewable energy with the goal of achieving a 45–50% reduction in emissions by 2030, 75–80% reduction by 2035 and net zero by 2045.[6] To achieve its targets, Victoria must cut emissions across the entire economy, including the gas sector, which contributes around 17% of the state's net greenhouse gas emissions.

5 Victorian Government, Victoria's Gas Substitution Roadmap, Department of Energy, Environment and Climate Action, accessed 18 July 2024.
6 Victorian Government, Victoria's Gas Substitution Roadmap, Department of Energy, Environment and Climate Action, accessed 18 July 2024.

The pace of change in Victoria has continued to accelerate, with the introduction of rule changes to reduce new and existing gas connections. Since 1 January 2024, all new homes in Victoria requiring a planning permit are required to be all-electric. This means new homes and residential subdivisions that require a planning permit can no longer connect to the gas network.

The ACT Government's Climate Change and Greenhouse Gas Reduction (Natural Gas Transition) Amendment Bill 2022 established the legal framework to end new fossil fuel gas connections in the ACT.[7] In June 2024, the ACT Government announced its intention to invest in an all-electric, zero emissions future for Canberra with the release of a new Integrated Energy Plan (IEP). The IEP sets out the next stage of work for the ACT's transition over the next 20 years, including a range of government commitments to support consumers through the transition.[8] Falling gas demand also has implications for how gas network costs are allocated to customers and the AER's approach to approving access arrangements for regulated gas pipelines.

1.4 Retail energy markets

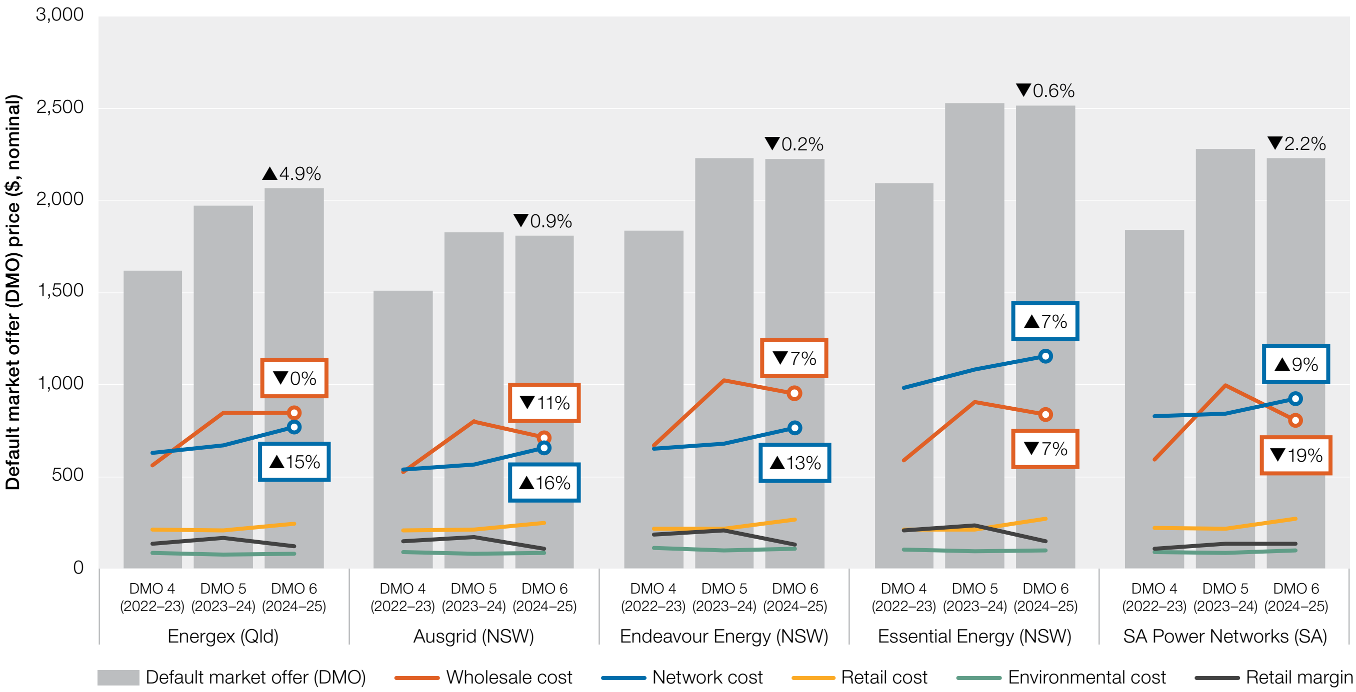
Consumers continue to invest in consumer energy resources such as rooftop solar and home batteries. Residential rooftop solar capacity now exceeds 20 gigawatts (GW), equivalent to 25% of registered generation capacity across the NEM, reflecting an increase of 2.9 GW from the previous year.

In 2023–24, electricity bills increased for customers on both standing and market offers in all NEM regions. Gas bills increased for customers on standing offers in all NEM regions and for customers on market offers in all NEM regions except for Queensland.

Wholesale electricity costs eased in the second half of 2023 following the record highs of 2022. For networks, the external economic effects of higher interest rates and higher inflation contributed to increased regulated revenues compared with previous regulatory periods. This, in combination with higher expenditure requirements for a number of networks, is likely to place upward pressure on networks' costs. The AER's calculation of the 2024–25 electricity default market offer (DMO 6) reference price decreased for customers in NSW and South Australia and increased for customers in South East Queensland (Figure 1.7). This also reflects that increased retail costs were mostly offset in many regions by the lower allowances (including margins) that the AER allowed retailers.

7 ACT Government, ACT reaches milestone preventing new fossil fuel gas connections, media release, 8 June 2023.
8 ACT Government, Electrifying Canberra, media release, 19 June 2024.

Figure 1.7 Components of the default market offer



Note: Comparison of cost components calculated for the 2022–23 (DMO 4), 2023–24 (DMO 5) prices and 2024–25 (DMO 6) prices, for residential customers without controlled load. Prices include GST. Values are nominal. In previous years this data was measured in cents per kilowatt hour and included totals for all NEM regions, enabling like-for-like comparison to Figure 6.3. As at September 2024, this data was unavailable for 2024.

Source: AER, Default market offer prices 2023–24, July 2024.

The Australian and state and territory governments provided significant assistance with electricity bills during 2023–24. However, energy debt and hardship measures suggest that broader cost-of-living pressures, combined with energy price rises, continue to put pressure on consumers' ability to pay. Average debt levels per customer have increased in most regions. More customers are accessing hardship programs, which is an important form of assistance. However, we also saw customers in these programs struggling to meet ongoing energy costs.

2 National Electricity Market

Electricity generated in eastern and southern Australia is traded through the National Electricity Market (NEM). Generators make offers to sell electricity into the market and the Australian Energy Market Operator (AEMO) schedules the lowest priced generation available to meet demand. The amount of electricity generated needs to match demand in real time. The market covers 5 regions – Queensland, New South Wales (NSW) including the ACT, Victoria, South Australia and Tasmania. The NEM is one of the world's longest interconnected power systems, stretching from Port Douglas in Queensland to Port Lincoln in South Australia and across the Bass Strait to Tasmania.

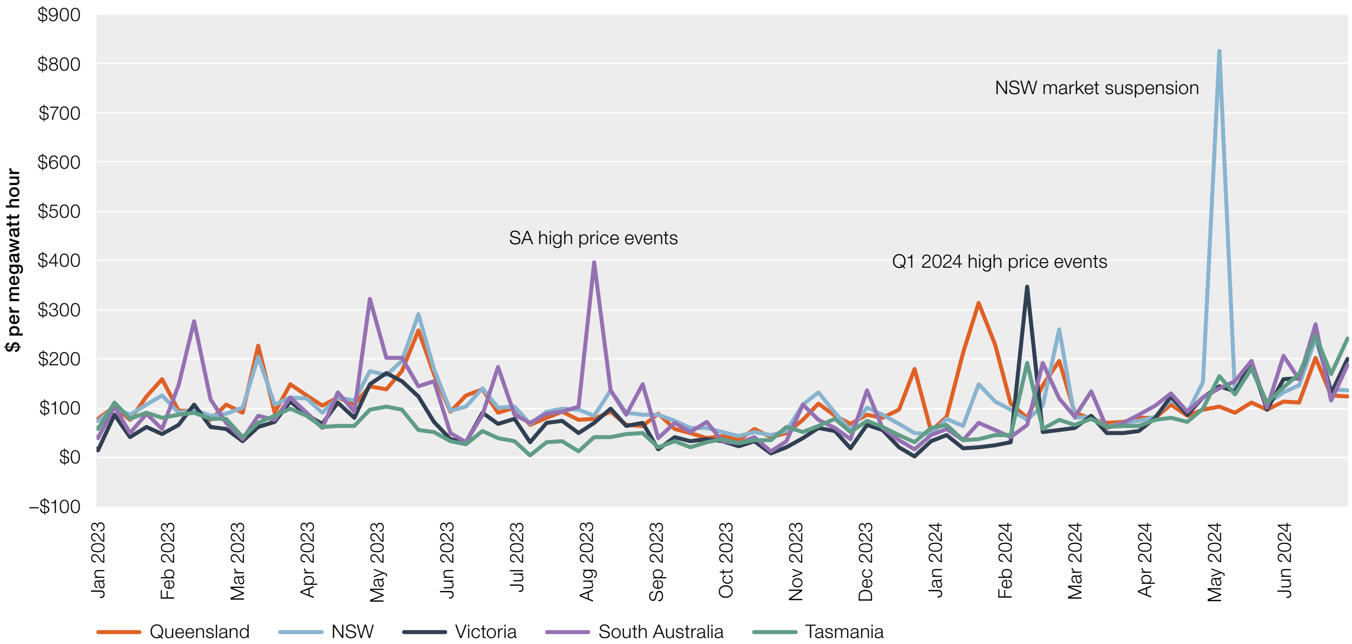
2.1 Snapshot

Since the last *State of the energy market* report:

- Wholesale prices declined across all regions of the NEM for the 2023–24 financial year compared to the previous financial year, which was influenced by the record high prices during winter 2022. Prices were lowest in the second half of 2023, before increasing over 2024 when there was an increase in the number of high price events across the different regions. Contract market activity increased trade volumes and liquidity in all regions, although activity in the South Australian market remains low.
- The more extreme weather conditions in 2023–24 drove significant price variation. Queensland recorded record peak demand levels during the hot and humid summer and storm damage affected supply in southern states in February 2024. Increased demand for more expensive gas-powered generation in the April to June quarter was driven by unusually cold weather in May, unusually low wind output and drought conditions in Tasmania.

- Following the Liddell coal power stations retirement in 2023, network and generator outages in NSW drove high price events in Q2 and demonstrate the current tightness in the demand-supply balance as we transition to becoming more reliant on renewable energy. In May 2024 the cumulative price threshold was breached in NSW for the first time since 2022, triggering administered prices.[9]
- Entry of planned new capacity in 2023–24 slowed as projects have been delayed, with a substantial amount of capacity now forecast to enter over the next financial year. The next coal-fired generator to close has a planned closure date of 2027, with Eraring (2,880 MW capacity) to withdraw from the NEM in August 2027.
- Record lows in minimum demand were set across all regions except Queensland in 2023–24. This demonstrates the urgent need to increase storage and integrate consumer energy resources (CER) into the NEM so that consumers that are willing and able are better supported to shift some of their demand to times of excess supply.
- Major reforms to system security frameworks have supported forward-planning for the replacement of inertia and system strength services. RIT-T application processes for system security investments, new FCAS markets and greater transparency over AEMO's procurement system security services will support the market to respond with innovative solutions.

Figure 2.1 Weekly wholesale electricity prices



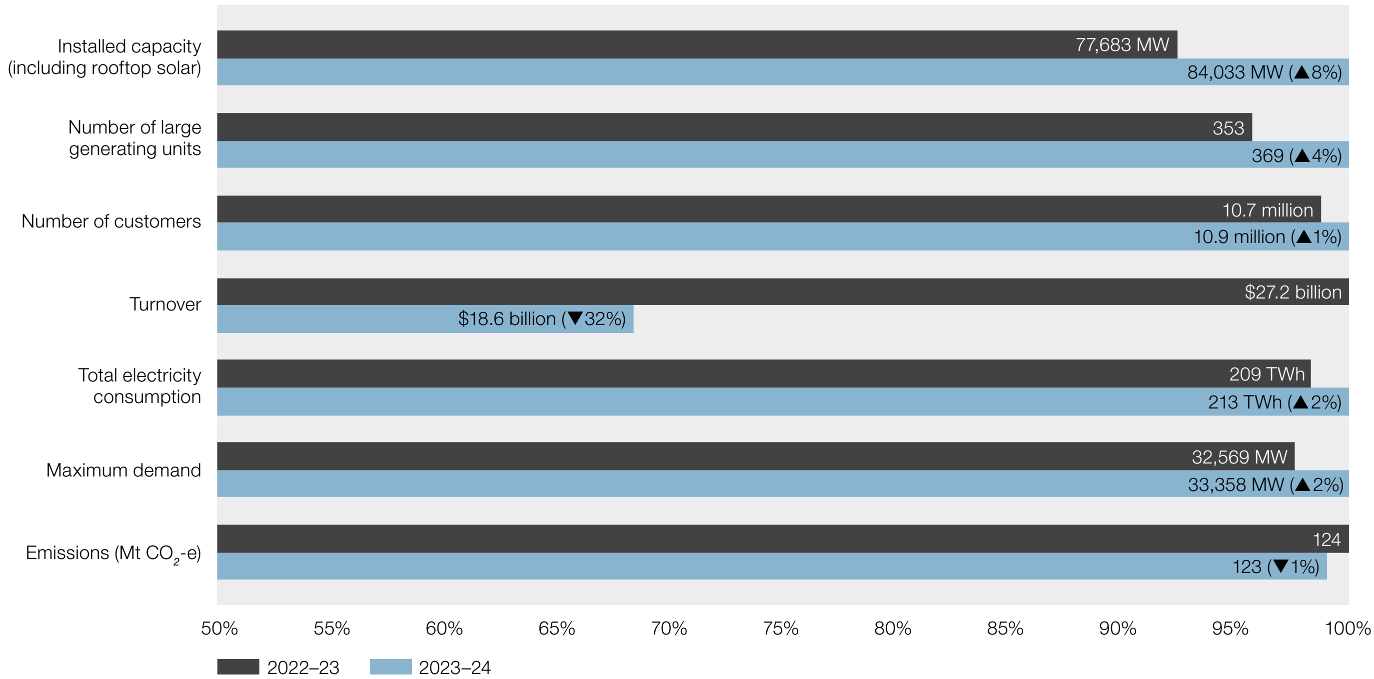
Note: Volume weighted weekly average prices.
Source: AER; AEMO (data).

9 The administered price is a component of the market safety net which operates to protect and sustain electricity trading in the National Electricity Market (NEM) during periods of sustained high prices. If market prices in a region rise to levels that are likely to cause substantial financial stress, then those prices are capped until they return to lower levels.

2.2 NEM overview

369 generating units produce electricity for sale into the NEM (Figure 2.2). A transmission grid carries this electricity along high voltage power lines to industrial energy users and local distribution networks (chapter 2). Energy retailers complete the supply chain by purchasing electricity from the NEM and packaging it with transmission and distribution network services for sale to residential, commercial and industrial energy users.

Figure 2.2 NEM key statistics



Note: MW: megawatts; TWh: terawatt hours. All data as at 1 July 2024, except customers, which are as at 30 June 2023. Includes energy met by the grid and rooftop solar generation.

Source: AER; AEMO (data); Clean Energy Regulator (data).

Box 2.1 How the NEM works

The NEM consists of a wholesale spot market for selling electricity and a transmission grid for transporting it to energy customers.

Power stations make offers to supply quantities of electricity in different price bands for each 5-minute dispatch interval. Scheduled loads, or consumers of electricity such as pumped hydro and batteries, also offer into the market. From 2021, consumers (either directly or through aggregators) are also able to bid demand response directly into the wholesale market as a substitute for generation.[10] Electricity generated by rooftop solar systems and used by the consumer is not traded through the NEM, but it does lower the demand that market generators need to meet.

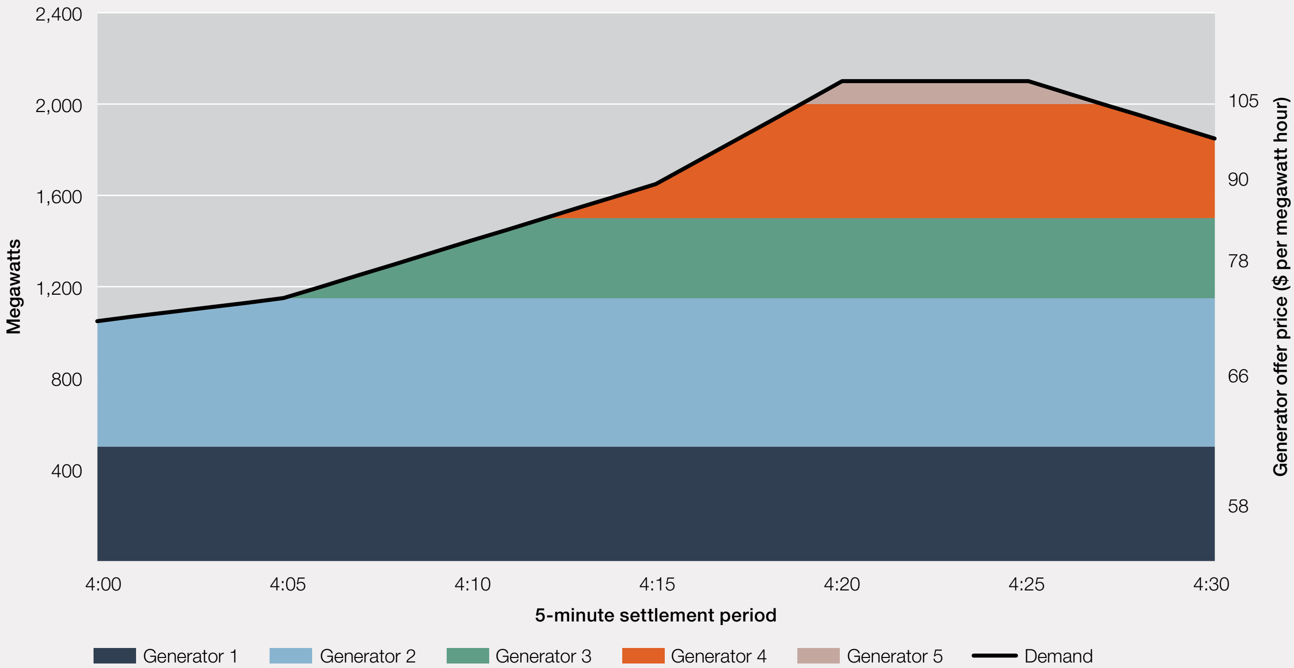
10 Large customers can participate through the wholesale demand response mechanism and small customers can participate through their retailers in virtual power plants (VPPs).

A separate price is determined for each of the 5 NEM regions. Prices are capped at a maximum of $16,600 per megawatt hour (MWh) in 2023–24. A price floor of –$1,000 per MWh also applies. The market cap has previously increased in line with the consumer price index (CPI) each year, but is due to increase to $18,600 on 1 July 2025, $20,700 on 1 July 2026, then $22,800 on 1 July 2027 in order to better support new entrant investment and reliability over the long term. The market floor price remains unchanged for now but will be considered as part of the next Reliability Standard and Settings Review.[11]

As the power system operator, AEMO uses forecasting and monitoring tools to track electricity demand, generator bidding and network capability to determine which generators should be dispatched to produce electricity. It repeats this exercise every 5 minutes for every region. It dispatches the cheapest generator bids first then progressively more expensive offers until enough electricity can be produced to meet demand. The highest priced offer needed to cover demand sets the 5-minute price in each region.

The Box Figure 2.1 illustrates how prices are set. In this example, 5 generators offer capacity in different price bands between 4:00 pm and 4:30 pm. At 4:15 pm the demand for electricity is 1,650 MW. To meet this demand, generators 1, 2 and 3 must be fully dispatched and generator 4 is partly dispatched. The dispatch price is $90 per MWh. By 4:20 pm demand has risen to the point where a fifth generator is needed. This generator has a higher offer price of $105 per MWh, which becomes the dispatch price for that 5-minute interval. That price is paid to all dispatched generators, regardless of their offers. This process is repeated for all 5-minute intervals.

Box Figure 2.1 Setting the price



While the market is designed to meet electricity demand in a cost-efficient way, other factors can intervene. At times, dispatching the lowest cost generator may overload the network or risk system security, so AEMO dispatches more expensive (out of merit order) generators instead.

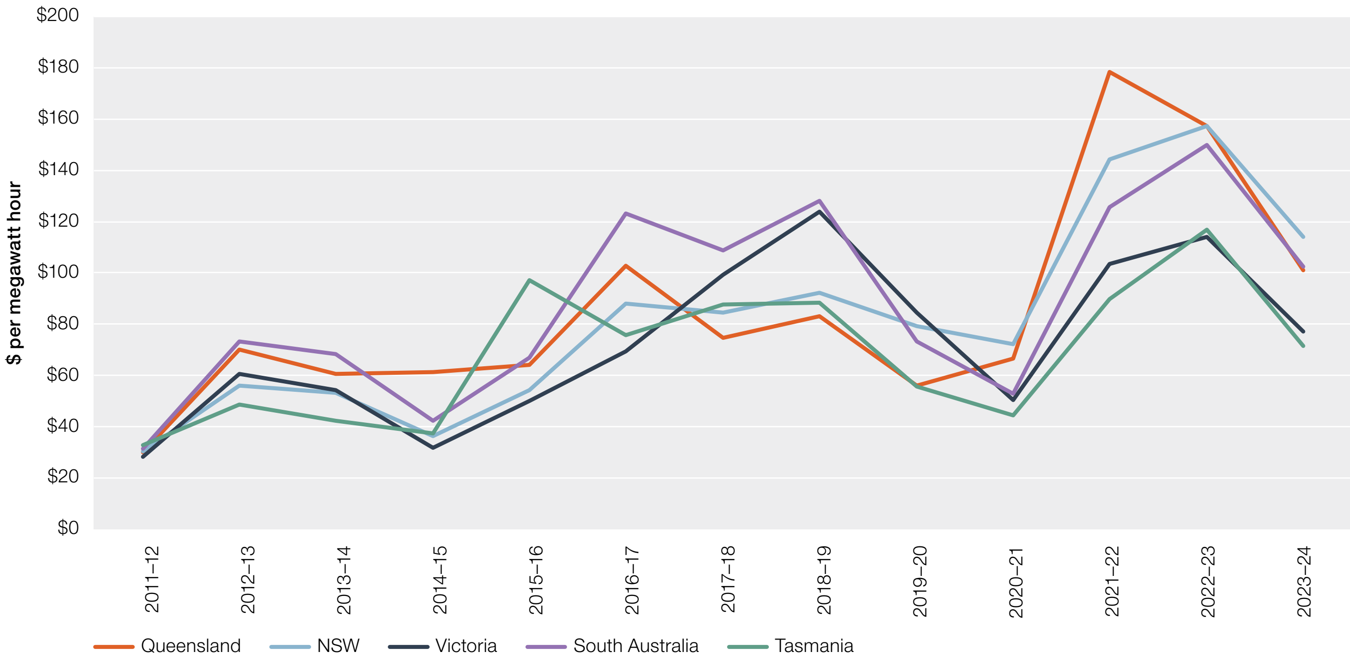
Retailers buy power from the wholesale market and package it with network services to sell as a retail product to their customers. They manage the risk of volatile prices in the wholesale market by taking out hedge contracts (derivatives) that lock in a firm price for electricity supplies in the future, by controlling generation plant or taking out demand response contracts with their retail customers.

11 AEMC, Amendment of the Market Price Cap, Cumulative Price Threshold and Administered Price Cap, Rule determination, Australian Energy Market Commission, 7 December 2023.

2.3 Wholesale prices and activity

Wholesale electricity prices have fallen significantly from the previous year, which can be attributed largely to the high prices in winter 2022 continuing to subside. Average prices remain high compared with historical levels in several regions (Figure 2.3).

Figure 2.3 Annual wholesale prices, financial year



Note: Volume weighted average financial year prices.
Source: AER; AEMO (data).

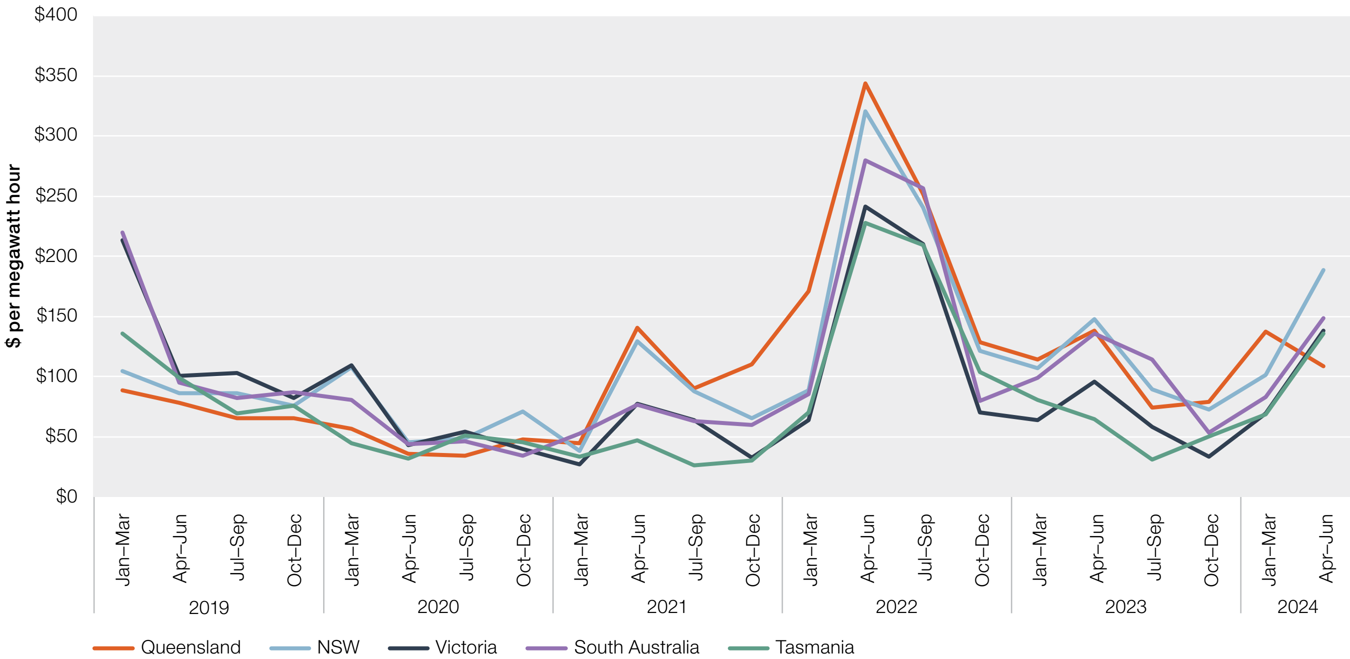
Average annual volume weighted prices fell across all regions in the 2023–24 financial year, following a decline from the high prices that occurred over the 2022–23 financial year (Figure 2.4). Comparing average quarterly prices across the NEM:

- Queensland ($101 per MWh) prices fell 36% in 2024 compared with 2023 and were higher than the other regions in the warmer months – October to December 2023 and January to March 2024 due to high demand days and warm and humid weather. However, low demand put downward pressure on average prices in other quarters, particularly April to June 2024, when Queensland was the only region to experience reduced demand.
- NSW ($114 per MWh) prices fell 27% compared with 2023 but replaced Queensland as the highest priced region over the year. NSW experienced the highest or second highest average prices across the NEM in all quarters. Prices were particularly impacted in the April to June 2024 quarter, when generator and network outages, combined with rebidding from some market participants, increased prices significantly. Higher prices caused the cumulative price to exceed the threshold for the first time since 2022, which triggered administered prices between 8 May and 15 May to stabilise wholesale spot prices and reduce financial stress for market participants. Administered prices cap wholesale prices at $600 per MWh.
- South Australia ($103 per MWh) prices fell 32% in 2024 and were marginally above Queensland prices. South Australia was the highest priced region in July to September 2023, experiencing several high price events in August due to low renewable output, interconnector network outages and generator rebidding.

- Victoria ($77 per MWh) remained one of the lower priced regions in the NEM and averaged only $6 per MWh more than Tasmania in 2024. Victoria experienced the lowest regional price between October and December 2023, averaging $34. Lower regional demand, driven by rooftop solar output alongside strong wind and solar generation, pushed down prices and contributed to negative daytime prices over the March to June quarter. Severe storms on 13 February led to the collapse of multiple transmission towers in Victoria, resulting in high priced events that increased prices over the January to March 2024 quarter.
- Prices in Tasmania ($72 per MWh) fell 39% in 2024. Tasmania was the lowest priced region in the NEM, a place it has held 4 out of the last 5 years. As with other regions, Tasmania's decrease was largely underpinned by the low prices experienced in the July to September 2023 quarter. Despite lower prices in 2024, Tasmania experienced high prices between April and June 2024, with average prices more than 100% higher than the same period in 2023, influenced by high hydro generation prices following significantly lower rainfall in the region.

As is typical, prices across the year varied from quarter to quarter with changing seasonal dynamics. Prices were lowest in the second half of 2023, increasing over 2024 due to strong seasonal impacts and the influence of high price events (Figure 2.4).

Figure 2.4 Quarterly wholesale electricity prices



Note: Volume weighted average quarterly prices.
Source: AER; AEMO (data).

July to September 2023

From July to September 2023, average prices fell across all regions. Prices were significantly below July to September 2022 prices, and closer to long-term averages. Mild weather and high rooftop solar generation contributed to record low demand for the July to September period. Although demand was low, several high price events (prices exceeding $5,000 per MWh) impacted average prices, particularly in South Australia. This illustrates that, even in favourable conditions, market outcomes are vulnerable to short-term changes in conditions.

October to December 2023

From October to December 2023, prices fell in NSW, Victoria and South Australia, but rose in Queensland and Tasmania. Prices were lower across all regions compared with the same period in 2022. Rooftop solar output increased due to longer days and strong growth in installations, and all regions set rooftop solar output records. Wind and large-scale solar also saw a record high share of generation output, accounting for 26% of output over the period.

There were large differences between daytime and evening prices – Victoria and South Australia averaged negative daytime prices, while evening peak prices in Queensland, NSW and South Australia exceeded $100 per MWh.

January to March 2024

From January to March 2024, prices increased across all regions. The 2023–24 summer was Australia's third warmest on record, which led to higher demand and prices.[12] Hot and humid weather in Queensland drove a material increase in demand from the last week of December 2023 to February 2024. This contributed to record maximum demand being recorded in Queensland as maximum demand exceeded the previous record 3 times over the period. Severe storms in Victoria led to the collapse of multiple transmission towers, which contributed to higher prices in Victoria, Tasmania and South Australia.

Summer periods can increase demand levels, but longer daylight hours can also lead to higher generation by rooftop solar, reducing demand from the grid. High rooftop solar output from January to March resulted in record minimum daily demand in Victoria and South Australia compared with equivalent quarters in previous years.

April to June 2024

From April to June 2024, prices increased in all regions except Queensland. With the exception of Queensland, prices were higher than the same period in 2023, but remained well below 2022 prices. Low wind and shorter days reduced wind and solar generation, resulting in increased generation from higher priced gas and hydro generators.

In NSW, generator and network outages, combined with rebidding from some market participants, increased prices significantly. This caused the cumulative price to exceed the cumulative price threshold, which triggered a period of administered prices and prices were capped from 8 May to 15 May to protect consumers.

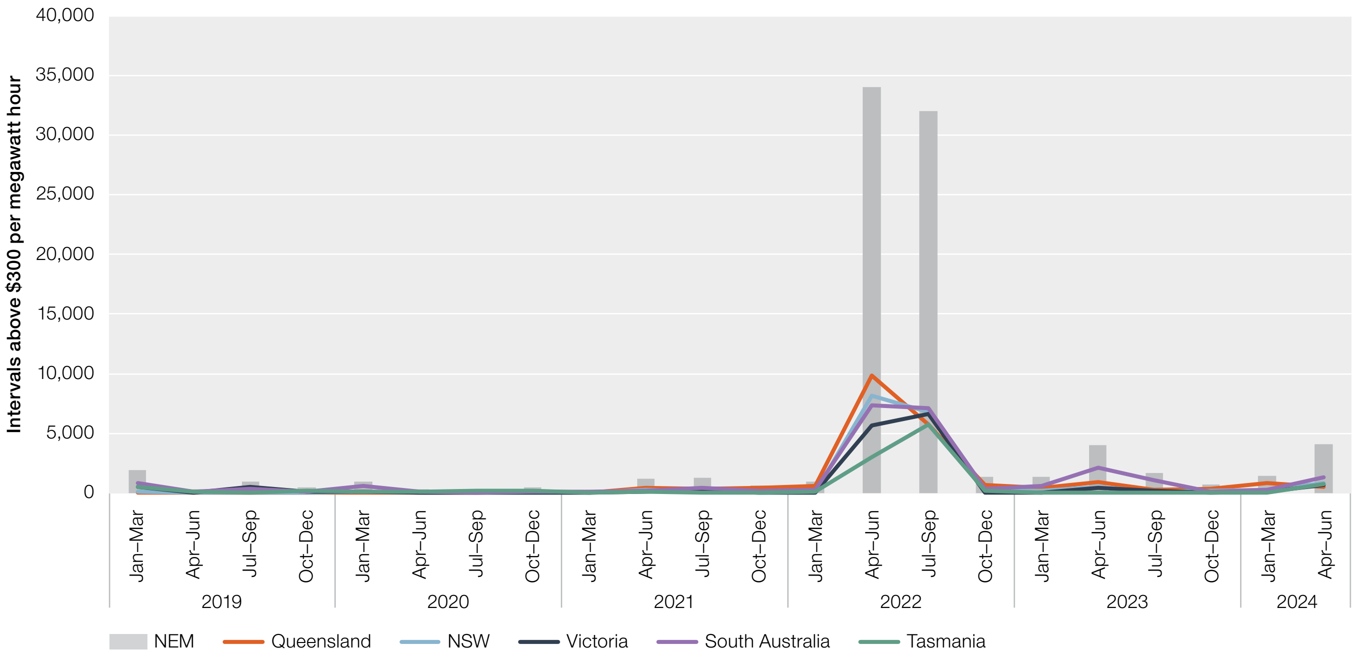
12 AER, Wholesale markets quarterly – Q1 2024, Australian Energy Regulator, 18 April 2024.

2.3.1 Price volatility

Price volatility is a natural feature of energy markets that can signal to the market that investment in new generation is needed. This signal is present in wholesale electricity markets today, with price volatility having increased dramatically in the last few years.

Once rare, spot prices above $300 per MWh have become more common. In the 2023–24 financial year, the frequency of 5-minute prices above $300 per MWh fell significantly compared with the previous 2 years. However, the rate of prices above $300 per MWh remains higher than any previous year before the winter 2022 market events (Figure 2.5).

Figure 2.5 Count of prices above $300 per MWh



Note: Count of 5-minute prices above $300 per megawatt hour. Prices were not settled in 5-minute intervals until October 2021, although prior to this dispatch was determined on a 5-minute basis using 5-minute prices.

Source: AER; AEMO (data).

Over the year, prices above $5,000 per MWh in a 30-minute period occurred 60 times, an increase on the previous year but not as often as in the 2021–22 financial year. Most significant price events occurred in NSW and were concentrated in May, when generator and network outages, combined with rebidding from some market participants, increased prices significantly.

2.3.2 Negative prices

In recent years the NEM has also seen more incidences of negative prices. Generators in the NEM may offer capacity as low as the market floor price of –$1,000 per MWh.

Historically, generators have offered negatively priced capacity into the market for a range of reasons. Generators whose capacity is dispatched by AEMO will receive the market price for that capacity, rather than the price for which they offered it. Because AEMO usually dispatches the lowest priced capacity first, a generator that bids negatively priced capacity is far less likely to have their bid rejected. Coal generators typically have high startup costs, so paying to generate for a period of time is usually more cost-effective than being switched off and incurring a startup cost. Additionally, if a generator has a contract ahead of time that ensures a fixed price for electricity sold into the market, its exposure to negative prices may be lower.

Negative prices have been more frequent since renewables entered the market.

The output of wind and solar generators varies with prevailing weather conditions. These generators do not incur high startup or shutdown costs and have marginal costs close to zero. If wind and solar generating conditions are optimal, they may need to bid capacity at negative prices to guarantee dispatch. The geographic grouping of renewable generators can intensify the effect because when conditions are favourable for one generator in the area, conditions tend to be favourable for others too.

Some wind and solar generators also source revenue from power purchase agreements[13] (PPA) and the sale of renewable energy certificates.[14] As such, they may operate profitably even when wholesale prices are negative. Instances of negative spot prices are highest when these technologies, alongside rooftop solar, are generating.

If electricity demand is low, the market has surplus capacity and the chances of the market settling at a negative price are higher. With multiple low-cost generators all competing for dispatch, the likelihood of negative prices increases.

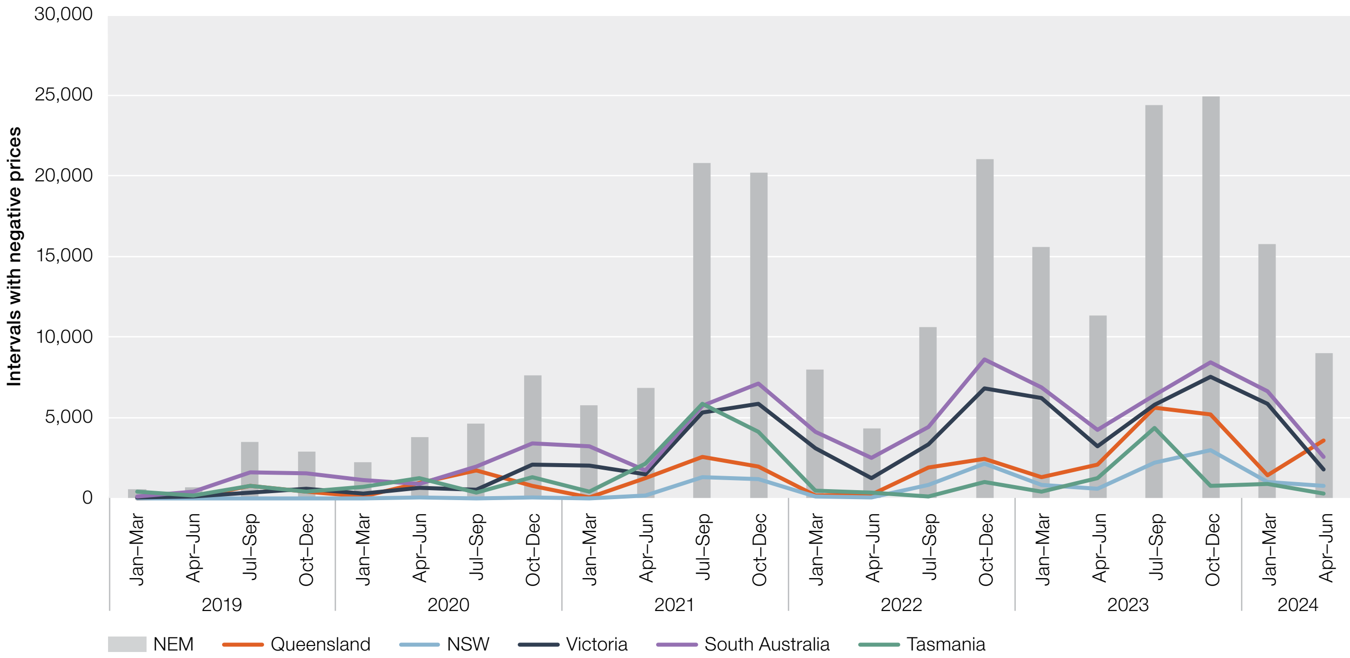
Negative prices usually occurred when electricity demand was low and weather conditions were optimal for renewable generation. While historically occurring overnight, they are now more common during the middle of the day when solar resources are producing maximum output and the generation of rooftop solar is being subtracted from demand.

In 2023–24 negative price events increased compared with the previous year and represented the fifth consecutive year in which a record number of negative prices were set (Figure 2.6). The number of negative price events in South Australia and Victoria remained relatively stable and continued to account for most negative price events, representing a combined 60% across the NEM. All other regions experienced a material increase in the number of negative price events. Queensland more than doubled and had the third highest number of negative price events, while events in Tasmania and NSW increased by 130% and 61%, respectively.

13 A power purchase agreement is a contract between an electricity generator and a purchaser (retailer or consumer) for the sale and supply of energy.

14 Clean Energy Regulator, Renewable Energy Target, July 2024.

Figure 2.6   Count of negative prices



Note: Count of 5-minute prices below $0 per MWh. Prices were not settled in 5-minute intervals until October 2021, although prior to this dispatch was determined on a 5-minute basis using 5-minute prices.

Source: AER; AEMO (data).

Between July and September 2023, unseasonably mild weather and high rooftop solar output reduced demand to a record low for a July to September quarter. This, alongside record high Queensland solar output, contributed to a record number of negative price events. This record was subsequently broken in the following quarter as more renewables entered the NEM. Instances of negative price events are likely to continue to increase.

2.4 Generator fuel costs and market interventions

After reaching record highs in previous years, generator fuel costs had decreased by the start of 2023–24 and remained stable across the year. The international export price for coal averaged just over $200 per tonne, significantly lower than prices experienced in 2022–23, but still above historical averages. Domestic spot gas market prices fell to an average of $12 per GJ for 2023–24.

Coal generators offered more coal at lower prices into the NEM in 2023–24. This was the result of easing domestic and international prices for coal, improved domestic availability and fewer coal generation outages. Falling costs also appear to have been assisted by a temporary cap on the price of black coal supplied to domestic coal-fired power stations. However, the impact of the $12 per GJ gas price cap on NEM gas-powered generation is less clear. The gas price cap has since been replaced with a mandatory gas code of conduct (chapter 4, section 4.3.1).

2.4.1 Market interventions

Coal price cap

In the months preceding the NEM market suspension of June 2022, several coal-fired generators reported severe under-delivery of coal. This was attributed to unseasonable rains that caused flooding, resulting in the closure of some mines and interruption of rail freight. Compounding these sourcing difficulties, above average volumes were diverted for export due to high international coal prices, with domestically available volumes falling as a result.

In response, the NSW Premier declared a coal market price emergency on 22 December 2022. The NSW Minister for Energy was granted the power to give directions to respond to the emergency while the declaration was in place, with these issued the following day. The Queensland Government moved simultaneously to direct its coal-fired generators to respond to the emergency.

As a result of directions given, the price of black coal sold to black coal-fired generators was capped at $125 per tonne in NSW. Although the directions to Queensland coal-fired generators are not public, the AER understands Queensland has a mechanism in place to achieve a similar effect. Additionally, black coal-fired generators in NSW were required to plan to maintain a minimum coal stockpile sufficient to meet at least 30 days of projected demand. Certain coal mines in NSW were required to reserve a proportion of future coal production to supply NSW coal-fired generators, as well as prioritise delivery to generators with low stockpiles.

The NSW directions ended on 30 June 2024.

Fuel cost is an integral determinant of a generator's marginal cost of producing electricity. If a generator has a lower marginal cost, it may be more likely to offer electricity into the market at lower prices, depending on other market and generator-specific factors. With more supply available at lower offer prices, higher priced capacity is less likely to be required and this should put downward pressure on prices. The price cap is particularly impactful when attached to black coal because black coal-fired generation is typically the most frequent price setter in Queensland and NSW. Other regions that don't use black coal as a generation fuel can still benefit through cheaper imports of electricity available via interconnection.

Following the implementation of these interventions, the AER observed some material change to the offer structure of some NSW black coal-fired generators. In January 2023, the first month of the cap's implementation, several generators began to offer more capacity into the market, with most of the additional capacity offered in lower price bands. This trend largely continued throughout the period of the directions. In the 2023–24 financial year, coal-fired generation output was higher than in the previous year and was offered into the market at relatively lower prices.

Other market dynamics, such as international coal prices, have also improved since the coal price cap was implemented. However, it appears likely that the coal price cap has played a role in lower wholesale prices.

Gas price cap and mandatory code of conduct

In winter 2022 the abnormally high number of unplanned coal generator outages, among other exacerbating factors, saw the NEM become significantly more reliant on gas-powered generators (GPGs) to meet demand. As a result, contracted deliveries of gas to GPGs were insufficient, resulting in an unprecedented volume of gas being purchased through spot markets. This in turn drove spot prices to record levels. Expensive gas purchased at short notice saw GPG marginal costs rise significantly, with severe effects on wholesale electricity prices.

On 9 December 2022, the Australian Government announced an emergency, temporary cap on the price of gas at $12 per GJ, which came into effect on 23 December 2022, for a 12-month period. The cap applied to gas sold by gas producers under contracts negotiated directly between parties and trades scheduled more than 3 days ahead of delivery agreed through the Gas Supply Hub.

The Australian Government further introduced a mandatory Gas Market Code, which commenced on 11 July 2023, with a 2-month transition period before the obligations came into effect. The purpose of the code is to ensure the domestic wholesale gas market supplies adequate gas at reasonable prices and on reasonable terms for both suppliers and buyers. The code includes a reasonable price provision, currently set at $12 per GJ, and an exemptions framework to incentivise short-term supply commitments and investment to meet ongoing domestic medium-term demand.

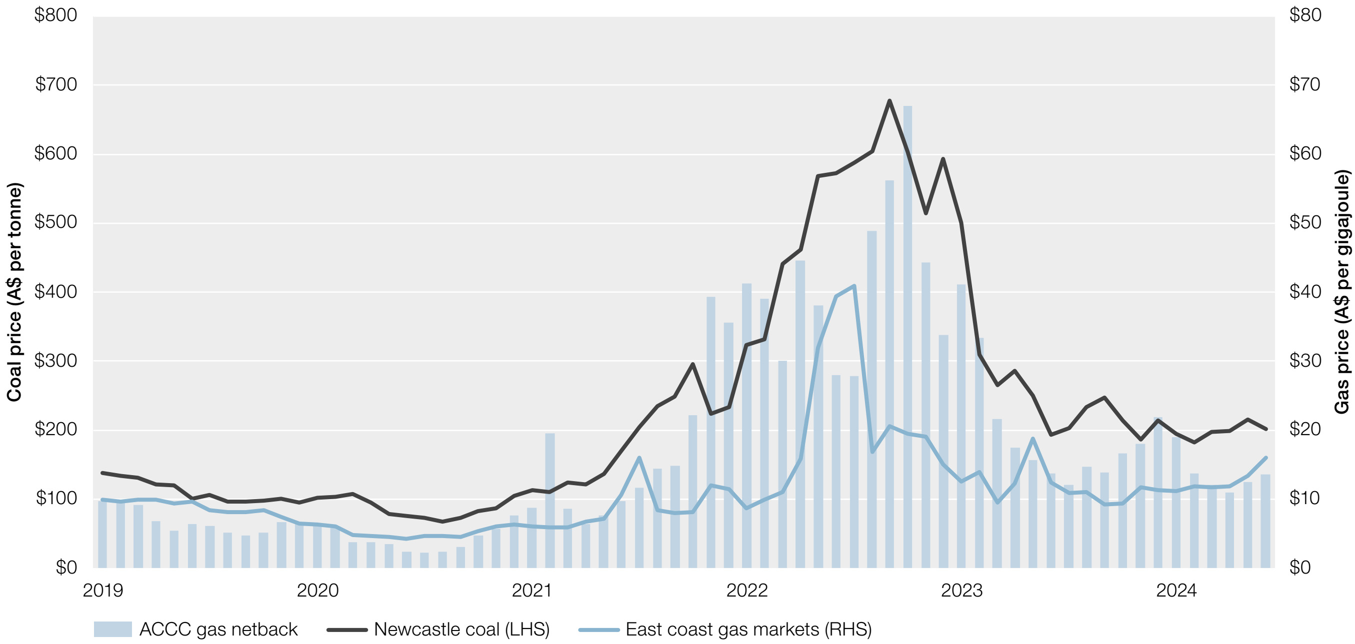
The effect of the gas price cap and mandatory code of conduct on wholesale electricity prices is less clear, with domestic trade through the spot markets exempt from the price cap. Chapter 3 includes more detailed analysis on wholesale gas prices, and the introduction of the gas price cap and Gas Market Code.

2.4.2 International fuel prices

Upstream black coal and gas market conditions can affect fuel costs for generators. Although black coal generators do not generally pay international spot prices for their coal supply, a high international price can put upward pressure on the domestic price. In NSW, it can shape prices for short-term supply contracts and determine when long-term contracts are renegotiated. In 2023–24 the international export price for coal averaged just over $200 per tonne, which equates to around $80 per MWh (Figure 2.7). These prices are significantly below the high prices that occurred in 2022, but higher than historical averages.

Over the same period, domestic spot gas market prices averaged around $12 while international LNG prices fell to the lowest level since early 2022. More detail on this is set out in chapter 3.

Figure 2.7 Coal and gas prices



Note: The black coal price is derived from the Newcastle coal index (US$ per tonne), converted to Australian dollars with the Reserve Bank of Australia exchange rate. The east coast gas market (ECGM) average gas price is the average of gas prices in Queensland, NSW, Victoria and South Australia downstream spot markets. The ACCC gas netback is the Asian gas price benchmark plus additional costs associated with export.

Source: AER analysis using globalCOAL data; ACCC data.

2.5 Electricity derivative contract markets

Derivative contract markets are critical for retailers to manage price risk on behalf of customers. They are also critical in driving generator behaviour. A liquid, accessible and adaptable contract market is integral to competitive and sustainable wholesale market outcomes.

Derivative (exchange-traded or over-the-counter) markets operate parallel to the wholesale electricity market. Prices in the wholesale market can be volatile, posing risks for market participants. Generators face the risk of low settlement prices reducing their earnings, while retailers risk paying high wholesale prices that they cannot pass on to their customers. A retailer may expand its operation and sign up a significant number of new customers at a particular price, only to incur unexpectedly high prices in the wholesale market, ultimately leaving the retailer substantially out of pocket.

Generators and retailers can manage their market exposure by locking in prices for which they will trade electricity in the future. An alternative strategy adopted by some participants is to internally manage risk through vertical integration – that is, operating as both a generator and a retailer (gentailer) to offset the risks in each market.

Typically, vertically integrated gentailers are imperfectly hedged – their position in generation may be ‘short’ (small relative to their retail load) or ‘long’ (large relative to their retail load). For this reason, gentailers participate in contract markets to manage outstanding exposures, although usually to a lesser extent than standalone generators and retailers.

Alongside generators and retailers, participants in electricity contract markets include financial intermediaries and speculators, such as investment banks. Brokers often facilitate contracts between parties in these markets.

In Australia, 2 distinct financial markets support the wholesale electricity market:

- In exchange-traded markets, electricity futures products are traded on the Australian Securities Exchange (ASX) or through FEX Global (FEX). Electricity futures products are available for Queensland, NSW, Victoria and South Australia.
- In over-the-counter (OTC) markets, 2 parties contract with each other directly (often assisted by a broker). The terms of OTC trades are usually set out in International Swaps and Derivatives Association (ISDA) agreements.

Various products are traded in electricity contract markets. Exchange-traded products are standardised to encourage liquidity. These products are also traded in the OTC market – the OTC offers additional products that can be tailored to suit the requirements of the counterparties. The standardised products available on exchanges and OTC include:

- Futures contracts allow a party to lock in a fixed price (strike price) to buy or sell a given quantity of electricity at a specified time in the future. Available products include quarterly base contracts (covering all trading intervals) and peak contracts (covering specified times of generally high energy demand). Futures can also be traded as calendar or financial year strips covering all 4 quarters of a year. Futures contracts are settled against the spot market price in the relevant region – that is, when the spot price exceeds the strike price, the seller of the contract pays the purchaser the difference; when the spot price is lower than the strike price, the purchaser pays the seller the difference. In OTC markets, futures are known as swaps or contracts for difference.
- Caps are contracts setting an upper limit on the price that a holder will pay for electricity. Cap contracts on the ASX have a strike price of $300 per MWh and the FEX caps have a strike price of $300 or $500 per MWh. When the spot price exceeds the strike price, the seller of the cap (typically a generator) must pay the buyer (typically a retailer) the difference between the strike price and the spot price. Alternative (higher or lower) strike prices are available in the OTC market.
- Options are contracts that give the holder the right – without obligation – to enter a contract at an agreed price, volume and term in the future. The buyer pays a premium for this added flexibility. An option can be either a call option (giving the holder the right to buy the underlying financial product) or a put option (giving the holder the right to sell the underlying financial product). Options are available on base load futures contracts, often referred to as swaptions.

Prices are publicly reported for exchange trades, but activity in OTC markets is confidential and not disclosed publicly. The Australian Financial Markets Association (AFMA) reported data on OTC markets through voluntary surveys of market participants, providing some information on the trade of standard OTC products such as swaps, caps and options. This report was discontinued after 2020–21 – as such, no data on OTC trading activity is available since then.

Exchange-traded contracts are settled through a centralised clearing house, which acts as a counterparty to all transactions and requires daily cash margining to manage credit default risk. In OTC trading, parties manage credit risk by determining the creditworthiness of their counterparties.

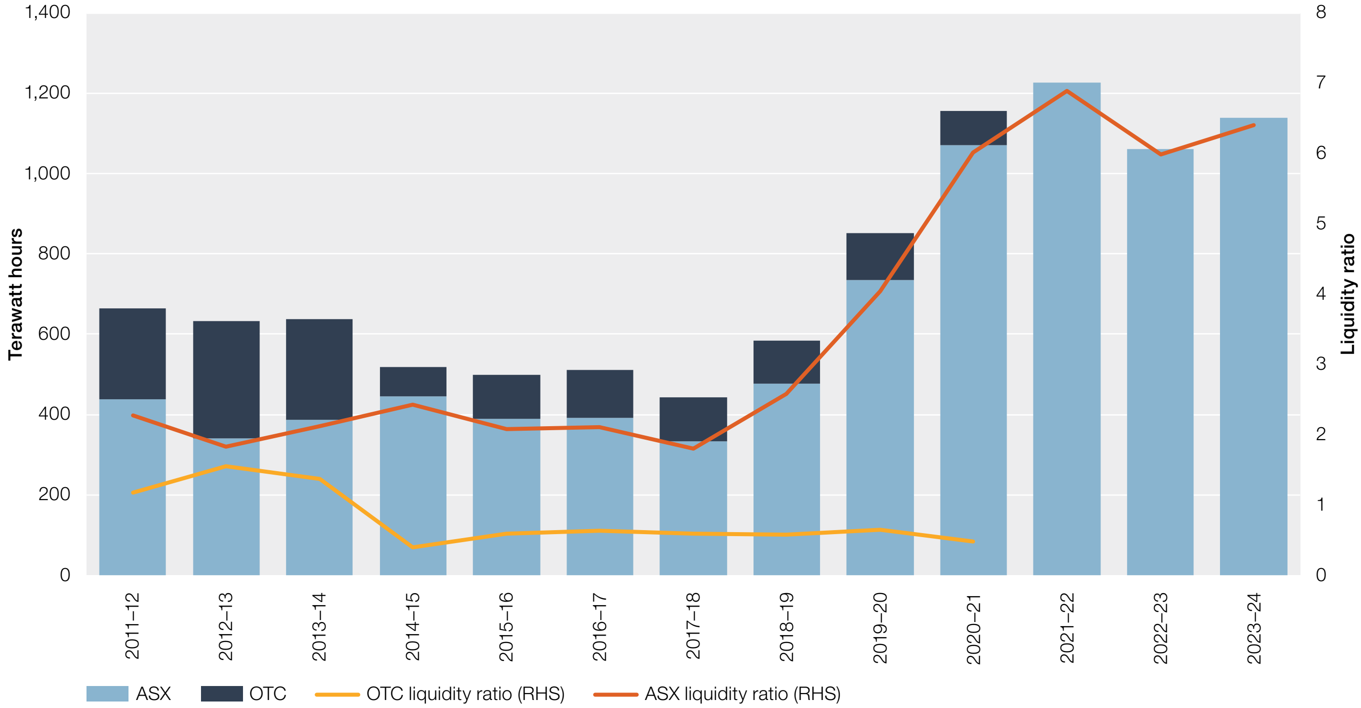
2.5.1 Contract market activity

Until recently, the ASX was the sole futures exchange operating in the NEM. FEX Global launched a separate futures exchange in March 2021 offering a similar range of products, but the volume of trade on the exchange has been minimal.

Regular ASX trades occur for the Queensland, NSW and Victorian regions of the NEM, but liquidity has been poor in South Australia for several years and continues to worsen.

ASX trade has increased materially since the 2017–18 financial year, more than tripling in volume by 2020–21 and trade peaking in the following year. In 2023–24, ASX-traded volumes increased 7% from the previous year but remain lower than peak volumes traded in 2021–22 (Figure 2.8).

Figure 2.8 Traded volumes in electricity futures contracts



Note: This liquidity ratio measures how liquid the contract market is by comparing its traded volumes to the total volume of electricity demand. Exchange trades are publicly reported, while activity in over-the-counter (OTC) markets is confidential and disclosed publicly only via voluntary participant surveys in aggregated form. The OTC data are published on a financial year basis. To allow some comparability across OTC and exchange-traded data, this graph refers to financial years for both markets. OTC contracts data has not been available since 2020–21. The OTC liquidity ratio forecast is the liquidity ratio comparing the total traded volumes to demand across the 4 combined regions.

Source: AER; AFMA; ASX Energy (data).

Increases in the volume of trade on the ASX from 2018 to 2022 was primarily driven by an increase in the volume of swaptions contracts being traded and, to a lesser extent, an increase in the volume of base futures contracts being traded. The increased level of trade on swaptions contracts has driven the increase in trade of base futures contacts. This is because if a swaption contract is exercised, it results in the trade of the underlying base futures contract.

Base futures contracts are typically traded seasonally, with large volumes traded between April and June, and September and December. This in part reflects market participants exercising their options contracts leading into the start of the calendar and financial years.

The trade of both swaptions and base futures contracts peaked in 2022 and represented 51% (624 TWh) and 39% (474 TWh) of trade, respectively. Since 2022, trade in base futures contracts have fallen year on year, by 1% in 2023 and 7% in 2024. The volume of options contracts similarly fell 19% in 2023 but rebounded in 2024, increasing by 12%.

2.5.2 Contract market liquidity

The liquidity ratio measures how liquid the contract market is by comparing its traded volumes to the total volume of electricity demand. Higher market liquidity allows market participants to trade contracts more readily and can provide greater price certainty.

Contract liquidity increased in 2023–24 after falling the previous year, driven by the increase in trade of swaptions. The liquidity ratio (contract trading relative to underlying demand) across the NEM increased from around 600% to 640% (Figure 2.8), with all regions except Queensland recording an increase.

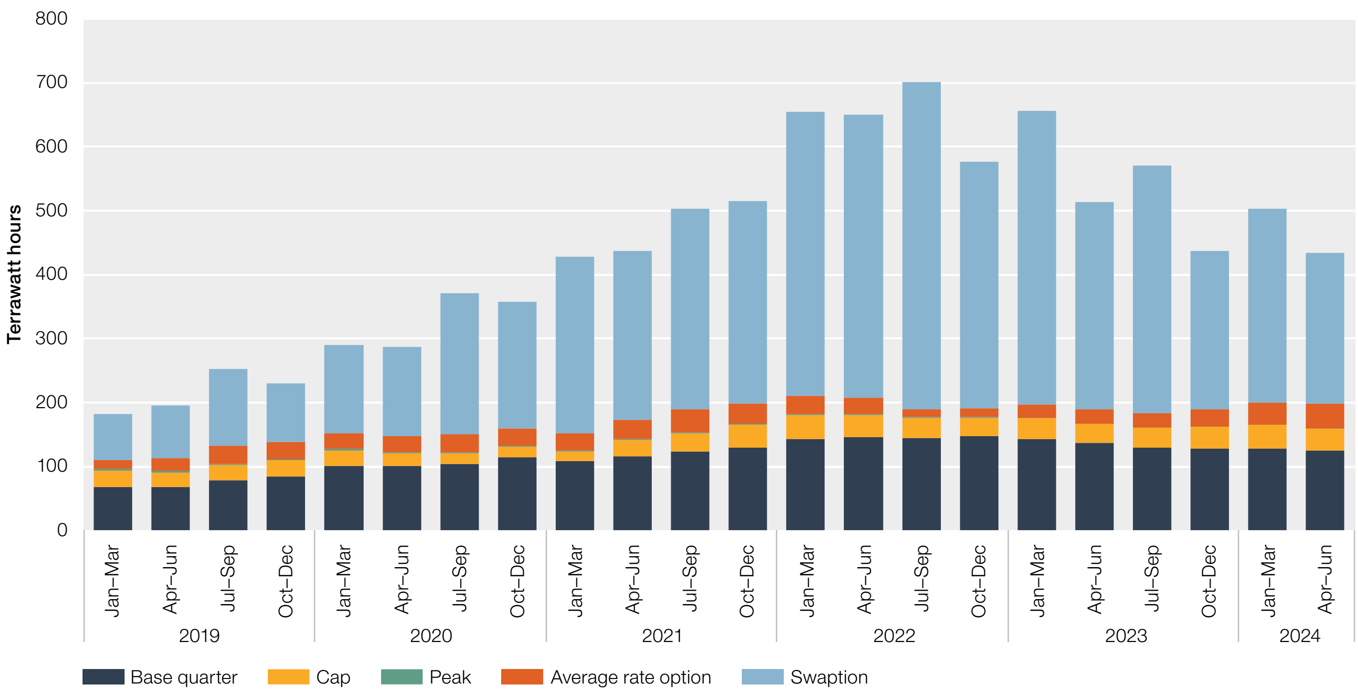
Total contract volumes across the ASX exceed the underlying demand for electricity by a significant margin in Queensland, Victoria and NSW. Given the extent of vertical integration in Victoria and NSW, this indicates that substantial trading (and re-trading) occurs in capacity made available for contracting.

Contract liquidity increased in South Australia but continues to remain poor, where traded volumes are less than underlying electricity demand. The volume of ASX contracts traded represented only 33% of underlying demand in 2023–24. The region's high proportion of renewable generation and relatively concentrated ownership of dispatchable generation has likely contributed to this weaker liquidity, with renewable energy less suited to underwriting the standard contracts listed on the ASX.

2.5.3 Open interest

Open interest reflects the total number of contracts that are not closed or delivered at the end of the day and is used as a measure of market activity. Open interest volumes continued to fall in the 2023–24 financial year, having peaked in the July to September quarter 2022 (Figure 2.9). Open interest volumes, primarily for swaptions, had more than tripled from 2019 to 2022, coinciding with increased volumes of trade in derivative contracts. Since mid-2022, open interest volumes in swaptions have been falling, but they remain above historical levels.

Figure 2.9 ASX open interest volumes



Source: AER; ASX Energy (data).

2.5.4 Composition of trade

Traded volumes increased in all regions except for Queensland in 2023–24 compared with the previous year. Traded volumes in Queensland, NSW and Victoria accounted for 36%, 33% and 31% of ASX volume, respectively. Trading in South Australia accounted for less than 0.3% of contract volumes despite the region accounting for around 7% of mainland NEM demand.

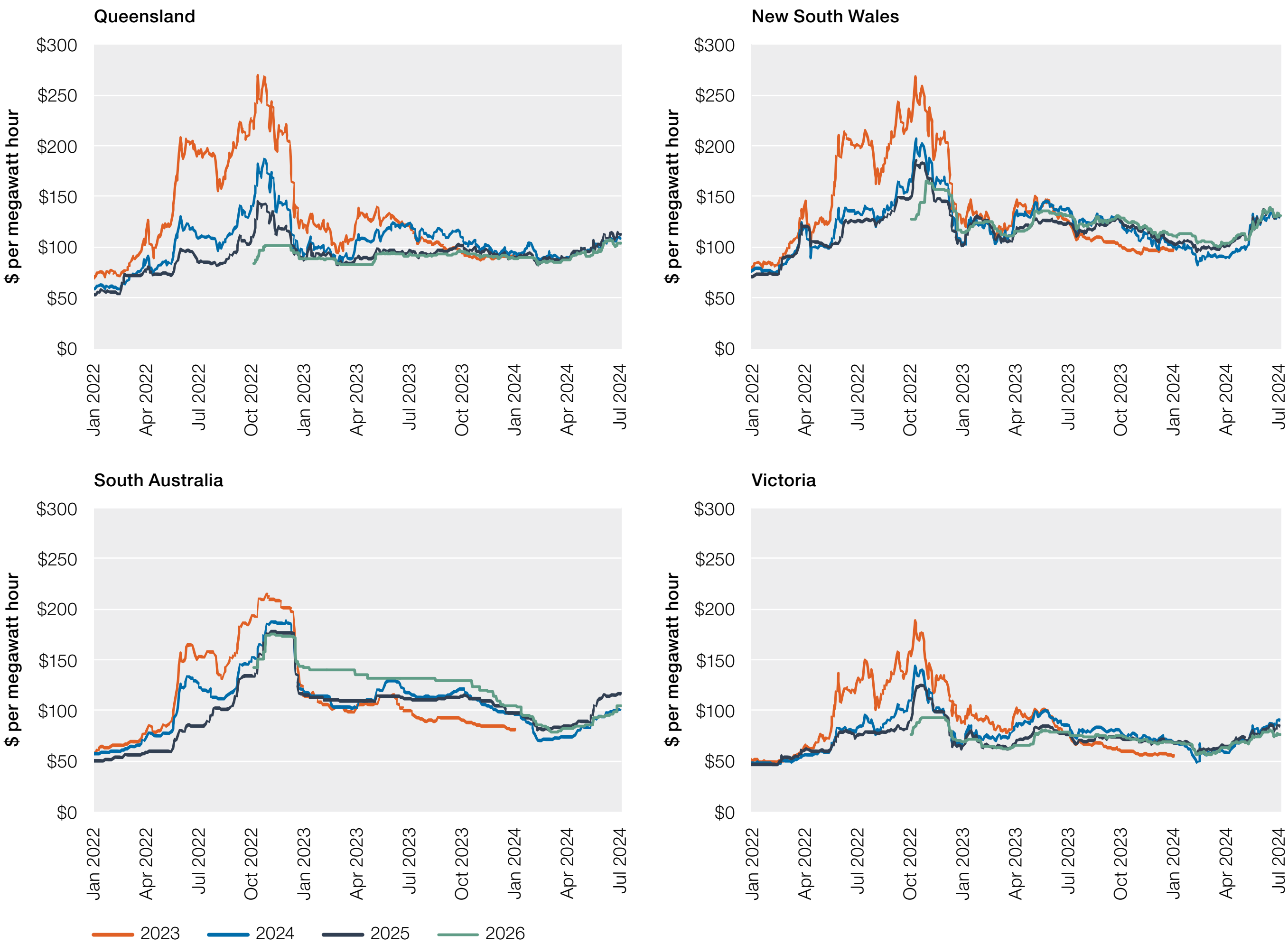
For 2023–24, swaptions (50%) were the most traded products on the ASX. The next most traded products were quarterly base futures, accounting for 39% of the traded volume. Average rate options (6%) and caps (6%) are traded at lower rates, with month base futures and peak contracts rarely traded (0.1%).

2.5.5 Contract prices

From mid-2023 to early 2024, calendar year base futures prices remained flat or fell in all mainland regions. Prices were lowest from February to March 2024 across all regions before increasing over the remainder of the financial year. Increases in base futures prices occurred in response to increased price volatility over April to June 2024, including several high price events, particularly in NSW.

At 30 June 2024, prices for 2024 contracts ranged between $91 per MWh in Victoria to $130 per MWh in NSW. Futures prices traded below the high prices that occurred in mid-2022 but remain higher than historical prices.

Figure 2.10 Prices for calendar year base futures

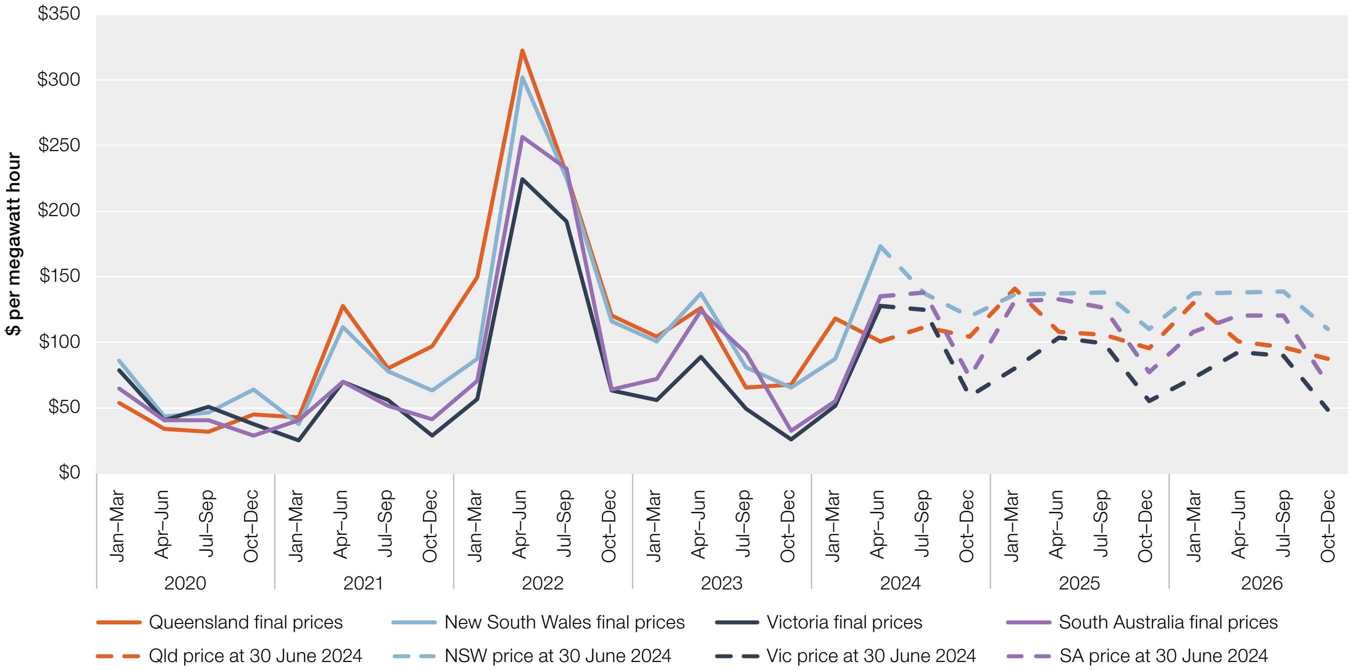


Source: AER; ASX Energy (data).

Prices for futures contracts in 2025 and 2026 mostly traded in line with prices for 2024 – prices as of 30 June 2024 ranged between $130 per MWh in NSW and $84 per MWh in Victoria for 2025 and $131 per MWh in NSW and $76 per MWh in Victoria for 2026. The outlook indicates that, while prices in future years are expected to be lower than in 2022, they are also expected to remain elevated compared with historical levels.

Quarterly base futures are stable for the remainder of 2024 but exhibit a seasonal profile, with prices lower in the October to December quarter when demand is usually at its lowest (Figure 2.11).

Figure 2.11 Prices for quarterly base futures



Note: Prices for quarterly base futures up to and including the April to June quarter are finalised (as they are no longer traded). Prices for quarterly base futures for the July to September quarter 2024 and beyond (which are still being traded) are as of 30 June 2024.

Source: AER; ASX Energy.

2.5.6 Access to contract markets

Access to contract markets, either via an exchange (ASX or FEX) or in OTC electricity markets, can present a significant barrier to retailers and generators looking to enter or expand their presence in the market. This poses a significant risk because contracts offer a degree of control over costs (for retailers) and revenue (for generators).

In the ASX market, the cash requirements for clearers through initial and daily margining of contract positions imposes significant costs on retailers. The use of standardised products with a minimum trade size of 1 MW is too high for smaller retailers, which may be better served with the kind of 'load following' hedges accessible through the OTC market. These OTC hedge contracts remove volume risk and are particularly sought by smaller or new retailers without extensive wholesale market capacity. However, credit risk can act as a barrier to smaller retailers in the OTC market, with counterparties likely to impose stringent credit support requirements on them. Before entering an OTC contract, the parties must generally establish an ISDA agreement, which is costly to set up. Further, the retailer must establish a separate agreement with each party with whom it contracts, resulting in further costs.

Access to clearing services has been a key issue raised by participants in the past 2 years following the withdrawal of Bell Potter as an ASX clearing participant. To transact on either the ASX or FEX Global, a market participant requires a clearer to clear and settle the transaction. The Exchange Clearing House manages their risk by imposing margin requirements on their contracting counterparties, the clearing participants. The clearing participants then pass on these margin requirements to retailers and generators.

In 2023–24 the number of clearing service providers for electricity contracts on the ASX returned to 6, having fallen to 5 in the previous year. Marex has entered the market and onboarded new clients. The ASX has also confirmed that a new seventh clearing member will soon be ready to offer clearing services.

2.5.7 Developments in contract markets

Intermittent renewables generation is not as well suited to the sale of standard contracts as coal generation. This is because its output is uncertain and weather dependent. 'Firming' this generation with energy storage or gas-powered plant could help support contract market participation. Several market participants with flexible generation capacity offer firming products targeted at renewable generation.

ARENA provided funding support to Renewable Energy Hub, a specialist advisory and technology solutions provider, to establish a firming market platform that offers new hedge products designed for clean energy technologies.[15] The platform aims to fill a gap in risk management products and overcome a market barrier for clean energy technologies. New hedging products introduced by Renewable Energy Hub include:

- 'solar shape' and 'inverse solar shape' contracts to provide a level of flexibility to manage the intermittency of renewable generation; they are tailored to specific periods of the day and provide an alternative to flat contracts – trades in the contract have thus far been subdued
- a 'super peak' electricity contract for electricity supply during the high demand hours of the morning, afternoon and evening periods
- a 'virtual storage' electricity swap for buying and selling stored energy – the price of the product is set at the spread of the agreed charge and discharge prices. The first ever trade deal for stored energy was brokered for the 2021–22 financial year.

15 ARENA, Renewable Energy Hub Contract Performance, Australian Renewable Energy Agency, accessed 15 August 2023.

2.6 Electricity demand and consumption

Electricity 'grid demand' is demand for electricity produced by generators and sold through the NEM. Electricity consumption refers to the total amount of electricity consumed and includes electricity produced by consumer energy resources, such as rooftop solar and home storage batteries. Consumer energy resources reduce grid demand because they replace electricity that would otherwise be supplied by large generators.

Electricity grid demand is a key driver of wholesale electricity prices and varies by time of day and season. During a 24-hour period, grid demand typically peaks in the early evening when residential use increases and rooftop solar generation falls. Seasonal peaks occur in winter (driven by heating loads) and summer (for air conditioning), often reaching maximum levels on days of extreme heat.

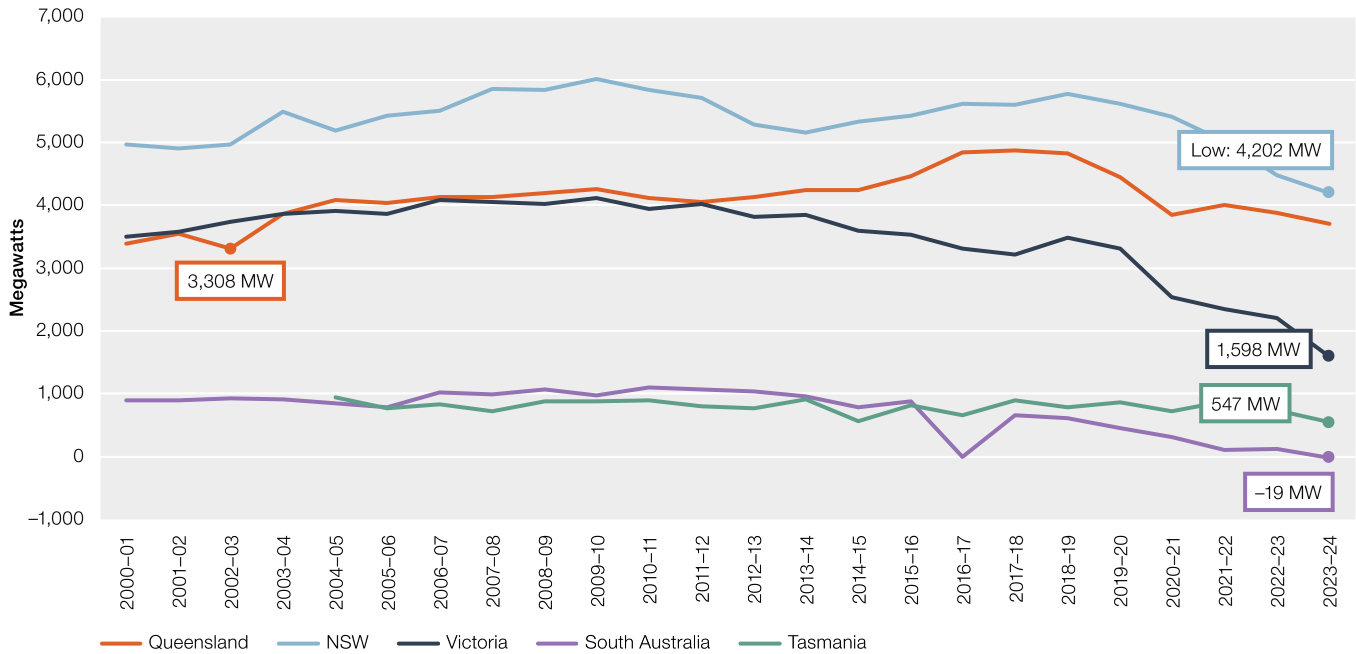
Electricity consumption has increased over the past decade. Increased consumption has been met by increasing rooftop solar generation, offsetting total grid demand. In 2023–24, 213 TWh of electricity was consumed by energy users in the NEM, a 2% increase from the previous year and the highest level recorded (Figure 2.15). Grid demand has remained relatively steady over the past few years but has fallen by nearly 15 TWh since 2011–12.

2.6.1 Minimum grid demand

Output from rooftop solar continued to increase in line with ongoing installations by households, further reducing grid demand during the middle of the day across the NEM. Consecutive rooftop solar output records were set in 2023–24. Record rooftop solar output for a 30-minute period occurred on 2 February 2024, totalling 13,311 MWh.

In 2023–24, minimum demand fell in all regions (Figure 2.12). Minimum demand set record lows in all regions except Queensland, which, while not a record, has fallen 24% from its peak in 2017–18. In South Australia, minimum grid demand was –19 MWh, the first time a region has experienced negative minimum demand. South Australia has the highest percentage of installed rooftop solar capacity, 40% of its total installed capacity, and the highest percentage of renewable capacity, 74% of its total installed capacity (Figure 2.14).

Figure 2.12 Minimum grid demand



Note: Minimum 30-minute grid demand (including scheduled and semi-scheduled generation, and intermittent wind and large-scale solar generation) is for any time during the year. Data excludes consumption from rooftop solar systems. The low value for South Australia in 2016–17 is due to the Black System Event in October 2016.

Source: AER; AEMO (data).

AEMO has noted that minimum grid demand is forecast to fall low enough to pose a risk to system security in coming years.[16] As rooftop solar output rises, demand at certain periods of the day is forecast to continue falling, with grid generators responding by withdrawing supply. Coal and gas-fired generators offer multiple essential system services alongside electricity supply, including voltage management, frequency control and inertia. Without these generators operating, the grid may be unable to operate safely unless essential system services come from elsewhere.

Several mechanisms have been developed to respond to grid demand low enough to threaten system security. Where gaps in system security occur, AEMO can intervene in the market to maintain system security.[17] The South Australian and Queensland governments have also implemented rooftop solar management programs, whereby AEMO may prevent some rooftop systems from generating during a 'minimum system load event' to minimise risk of blackouts. More information on system security is set out in section 2.13.

Consumer energy resources have the potential to offset some system security needs by shifting demand from peak periods into times of minimum demand or increasing demand during those times by charging batteries or EVs.

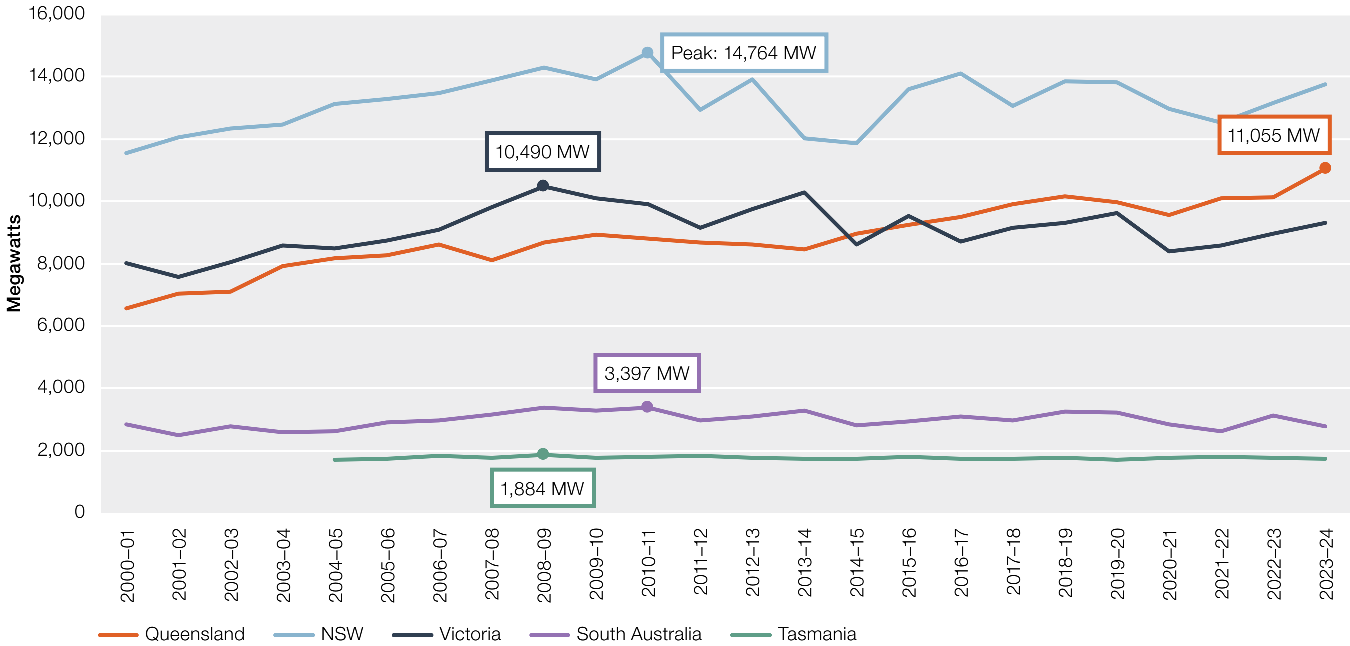
2.6.2 Maximum grid demand

In 2023–24, maximum grid demand rose compared with the previous year in Victoria, NSW and Queensland, with Queensland setting a record high. In most regions, high grid demand usually occurs when temperatures are hot enough to prompt widespread use of air conditioning, particularly after the sun has set and rooftop solar no longer offsets demand. For all mainland regions, the interval with the highest grid demand for the financial year occurred during the January to March quarter, between 4:00 pm and 7:00 pm. For Tasmania, high demand typically occurs in winter when heating demand is at its greatest.

Looking forward, AEMO's 2023 Electricity Statement of Opportunities central planning scenario sees maximum grid demand increasing over the next 10 years.[18] High demand events pose significant likelihood of high wholesale prices should available generation be insufficient to respond. High maximum demand also increases the need to invest in increased network capacity to manage peak flows, unless demand can be shifted to times of surplus generation or energy efficiency can be improved to reduce demand overall.

16 AEMO, Factsheet: Minimum operational demand, Australian Energy Market Operator, November 2022.
17 AEMO, Factsheet: Minimum operational demand, Australian Energy Market Operator, November 2022.
18 AEMO, National Electricity and Gas Forecasting, Australian Energy Market Operator, accessed 27 July 2023.

Figure 2.13 Maximum grid demand



Note: Maximum 30-minute grid demand (including scheduled and semi-scheduled generation, and intermittent wind and large-scale solar generation) is for any time during the year. Data excludes consumption from rooftop solar systems.

Source: AER; AEMO (data).

2.7 Sources of generation in the NEM

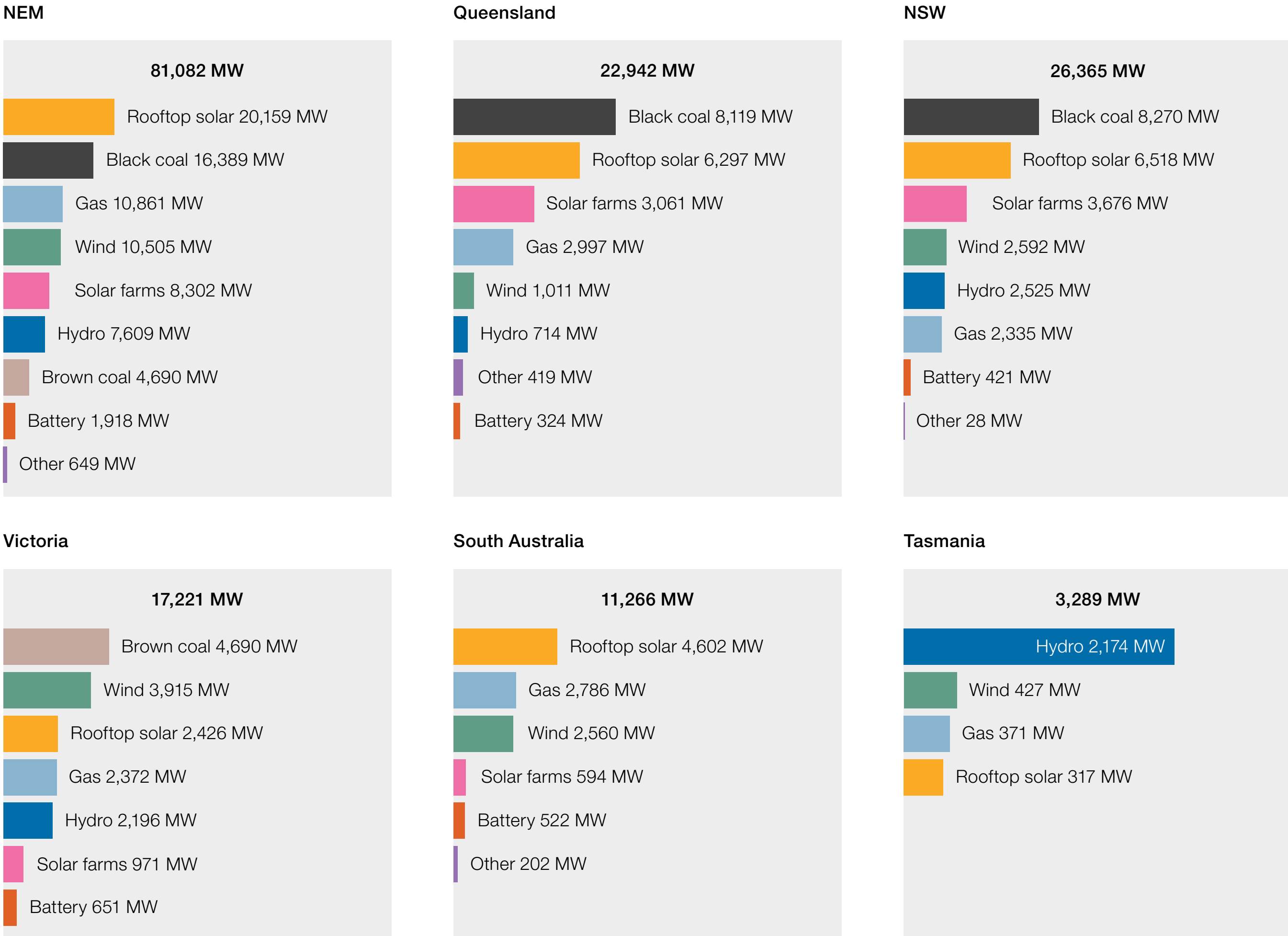
The NEM's generation fleet uses a mix of technologies to produce electricity (Figure 2.14). There are 2 ways to measure the NEM's generation mix – based on the registered capacity of each generating unit or based on their total output.

Registered capacity refers to the highest amount of electricity a generator has been registered to produce per hour. A typical generator will produce electricity at a rate lower than its registered capacity most of the time, with different generation technologies able to produce electricity at different rates of their capacity. Thermal generators typically produce at a high rate relative to capacity because they can generate continuously throughout the day. Renewable generation is intermittent and produces electricity at a lower rate relative to capacity.

A fuel type's relative share of total generation capacity depends on whether rooftop solar is considered part of the generation mix. While the energy produced by household rooftop solar systems reduces grid demand, this reduction is the result of localised electricity generation. To reflect this, the analysis below includes rooftop solar as generation.

By the end of 2023–24, total generation capacity measured 81,082 MW. Rooftop solar was the highest capacity totalling 25% of registered capacity, followed by black coal at 20%. Renewable technologies (rooftop solar, solar farms, wind, hydro and battery) made up 60% of capacity. Capacity for renewable technologies increased from the previous year, while the capacity of fossil fuel generators (black and brown coal and gas) largely remained the same.

Figure 2.14 Generation capacity, by fuel source

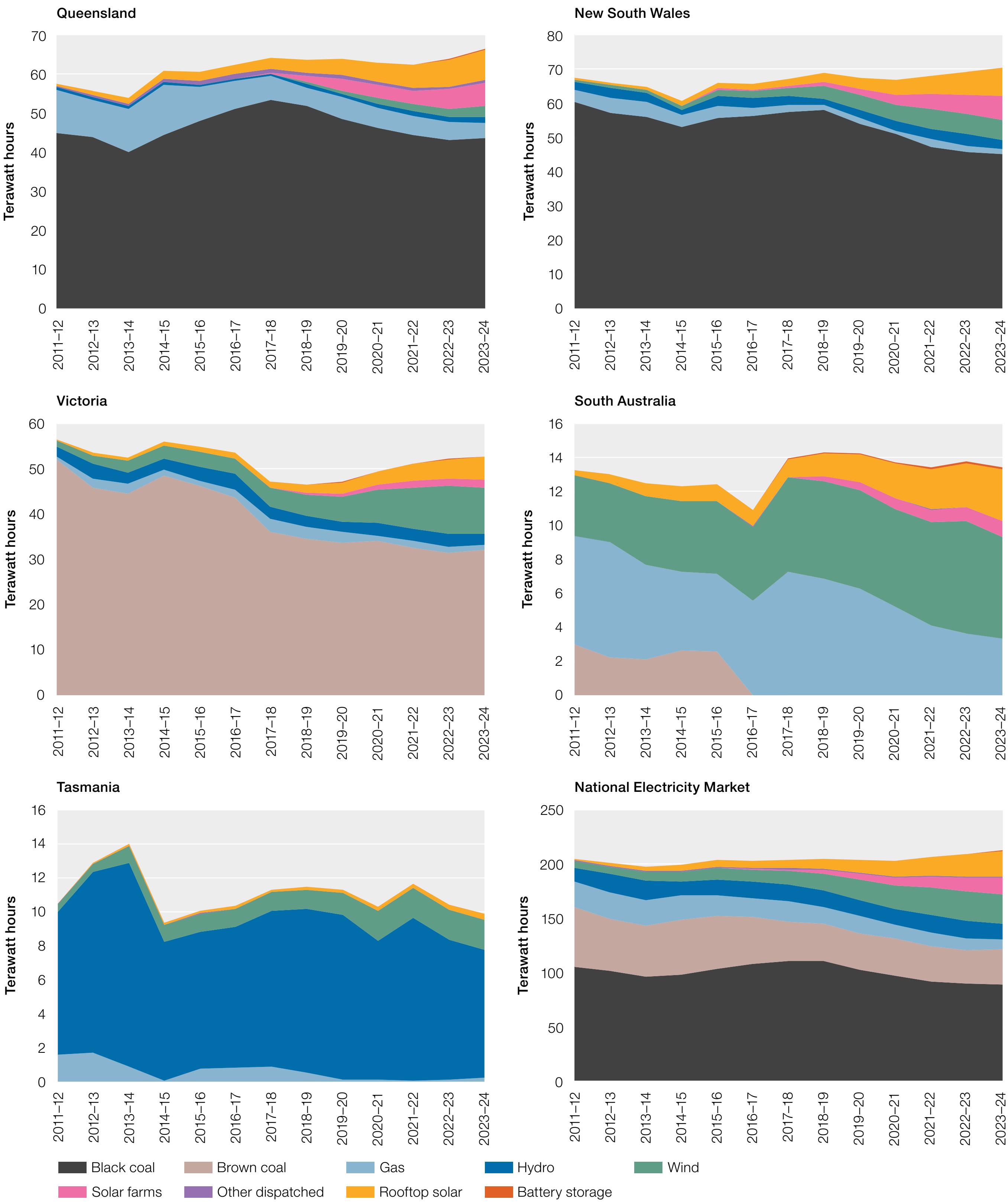


Note: Generation capacity at 30 June 2024. Other dispatch includes biomass, waste gas, diesel and liquid fuels. Loads and non-scheduled generation have been excluded. Solar capacity is maximum capacity, rather than registered capacity.

Source: Grid demand: AER; AEMO (data). Rooftop solar: AER; Clean Energy Regulator (data).

Generation output (Figure 2.15) refers to the total amount of electricity produced over a given period. In 2023–24, 213 TWh of electricity was generated. Fossil fuel generators produced 61% of electricity, a decrease of 1.5% from the previous year. Solar (solar farms and rooftop solar) and wind output increased to 31% of total generation.

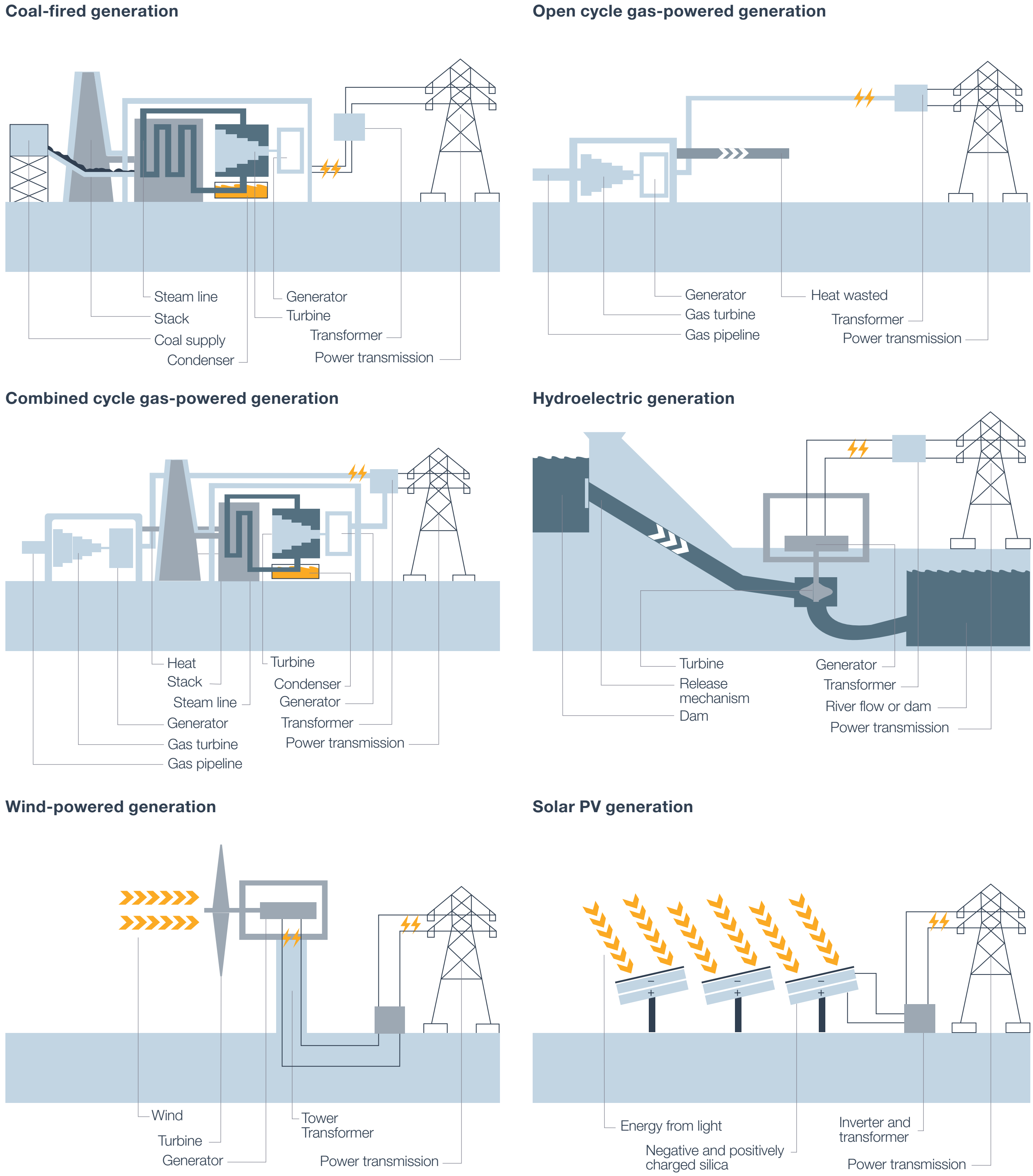
Figure 2.15 Generation output, by fuel source



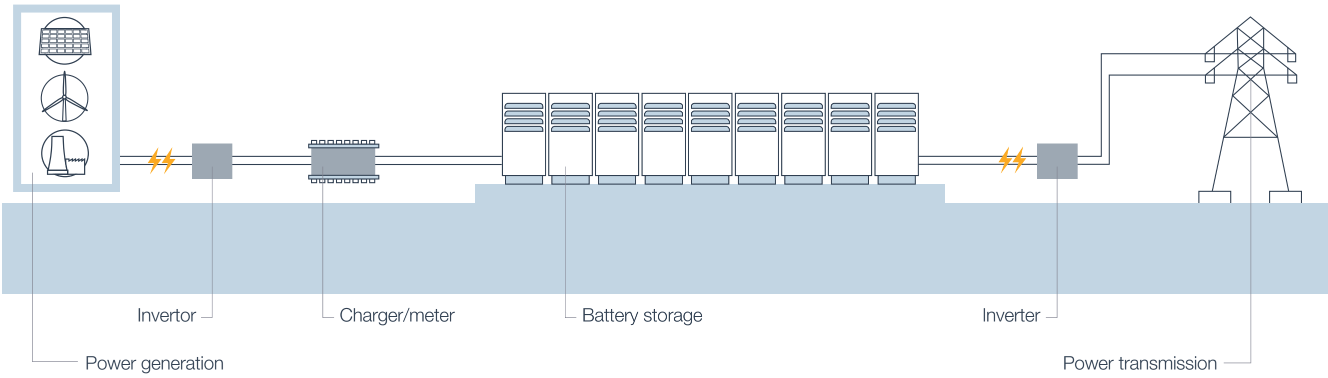
Note: Other dispatch includes biomass, waste gas, diesel and liquid fuels.
Source: AER; AEMO (data).

The various generation technologies have differing characteristics (Figure 2.16). Differences in startup, shutdown and operating costs influence each fuel type’s bidding and generation strategies. Technology types also have different implications for power system security, including system strength and frequency.

Figure 2.16 NEM generation technologies



Battery energy storage system



2.7.1 Coal-fired generation

Coal-fired generators burn coal to create pressurised steam, which is then forced through a turbine at high pressure to drive a generator. Coal is the only fuel type in the NEM that tends to generate at all hours of the day. Coal-fired generation remains the dominant supply technology in the NEM, producing just under 57% of all electricity traded through the market in the 2023–24 financial year (Figure 2.17). In absolute terms, coal-fired generation increased marginally compared with 2022–23.

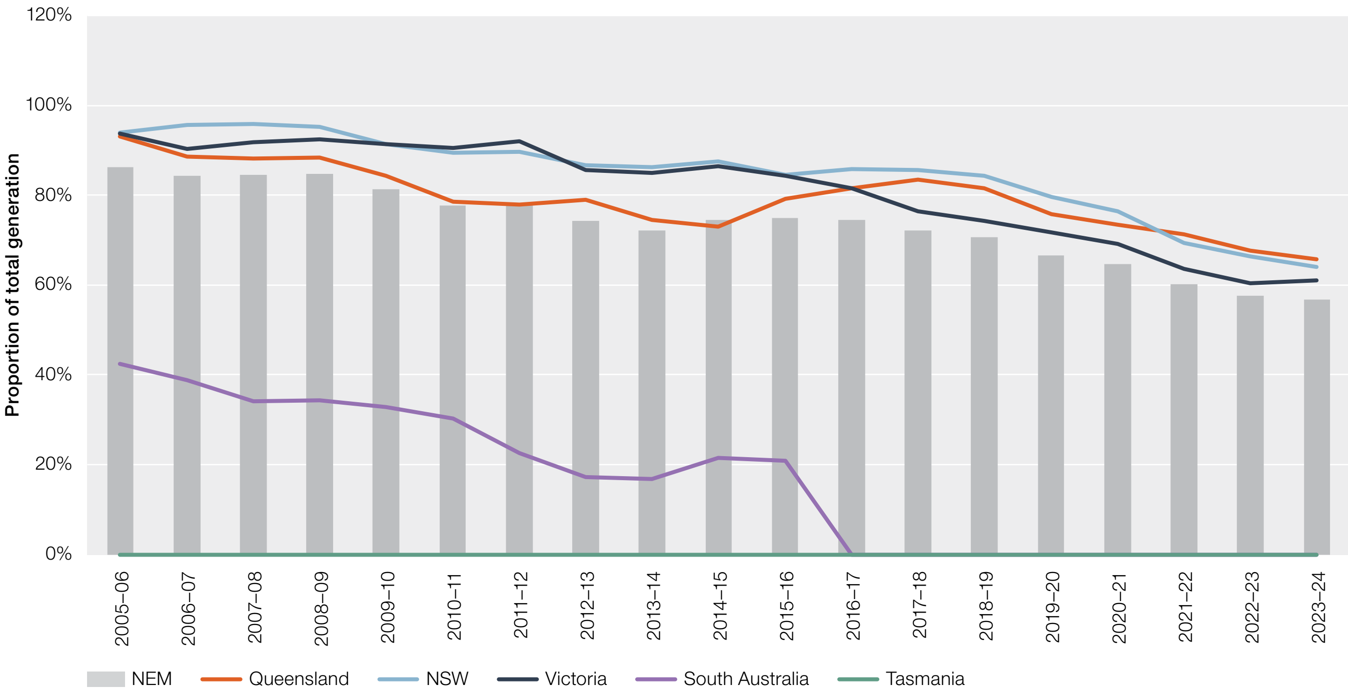
Coal plants operate in Queensland, NSW and Victoria. Generators in Queensland and NSW burn black coal and generators in Victoria depend on brown coal. Black coal produces more energy than brown coal because it has lower water content and 30–40% lower greenhouse gas emissions when used to generate electricity. Victorian brown coal is among the lowest cost coal in the world, because the Gippsland region has abundant reserves in thick seams close to the earth's surface.

Coal-fired generators can require a day or more to activate, but their operating costs are low. Once switched on, coal plants tend to operate continuously. For this reason, coal-fired generators usually bid a portion of their capacity into the NEM at low prices to guarantee dispatch and keep their plant running. Aside from providing relatively low-cost electricity to the market, coal-fired generators also help maintain power system stability.

Impact of solar on coal-fired generation

The rapid influx of grid and rooftop solar over the past 5 years has changed the shape of wholesale electricity prices and demand for baseload (coal) generation during the day. As a result, coal-fired generation makes up a declining but still large proportion of total NEM generation (Figure 2.17).

Figure 2.17 Proportion of total generation by region, coal



Note: The share of regional output produced by coal generators. South Australia and Victoria output is from brown coal generators while all other regions are from black coal generators.

Source: AER; AEMO (data).

These changing conditions, backed by global investors and a local push to decarbonise, are compromising the economic viability of the NEM's remaining coal-fired power stations. NSW's Liddell power station closed in April 2023, and retirements have been announced for all but one of the remaining coal-fired power stations, with half announcing they will close by 2035. AEMO's most recent Integrated System Plan[19] suggests that, to meet government policy objectives, the remaining coal fleet will close 2 to 3 times faster than that, with all coal generators retired by 2037–38.

Current announcements for upcoming coal closures include:

- Eraring (2,880 MW) – Australia's largest power station. It was initially due to close in 2032 but its owner, Origin Energy, brought the closure date forward to 2024. In 2024 the NSW Government came to an agreement with Origin to delay closure until August 2027.[20]
- Yallourn (1,480 MW) – In 2021 EnergyAustralia announced that it would retire Victoria's Yallourn power station in 2028, 4 years earlier than planned.
- Callide B (840 MW) – CS Energy's Callide B power station is also expected to close in 2028.
- Vales Point B (1,320 MW) – Delta Energy's Vales Point B power station was expected to close in 2029 but has been pushed back to 2033.
- Bayswater and Loy Yang A (4,850 MW) – In early 2022, AGL announced the accelerated closure of its remaining coal-fired power stations of Bayswater (2030–2033) and Loy Yang A (2035).

While the exit of coal-fired generation is necessary to meet emissions reduction targets and inevitable due to its declining financial viability, disorderly exit poses risks to both reliability and wholesale prices. AEMO has forecast reliability gaps over the next 10 years should the rate of investment in firm capacity (that which is dispatchable on command) fail to increase significantly[21] Further information on system reliability is set out in section 2.12.

19 AEMO, Integrated System Plan, Australian Energy Market Operator, June 2024.
20 NSW Government, NSW Government secures 2-year extension to Eraring Power Station, NSW Government, 23 May 2024.
21 AEMO, Update to the 2023 Electricity Statement of Opportunities, Australian Energy Market Operator, May 2024.

Coal outages fell in 2023–24 but remain a risk

Coal-fired generators break down more frequently as they age – the NEM's aging fleet of coal generators is particularly prone to outage as stations near the end of their lives. Winter quarters are emerging as the periods during which coal outages pose the greatest risk to wholesale prices and reliability, due to seasonally lower renewables output. The April to June quarter usually sees planned maintenance of coal plant as operators prepare stations for peak winter demand.

While coal-fired generator outages have been increasing over time, outages in the 2023–24 financial year decreased compared with the previous year, averaging 2.7 GW per quarter.

2.7.2 Gas-powered generation

Two dominant types of gas-powered generation technologies operate in the NEM (Figure 2.16). Open cycle gas turbine (OCGT) plants burn gas to heat compressed air that is then released into a turbine to drive a generator. In combined cycle gas turbine (CCGT) plants, waste heat from the exhaust of the first turbine is used to boil water and create steam to drive a second turbine. The capture of waste heat improves the plant's thermal efficiency, making it more suitable for longer operation than an open cycle plant. Reciprocating engine gas plants use gas to drive a piston that spins a turbine. These plants operate similarly to OCGTs but are more flexible. Some legacy 'steam turbines' – which operate similarly to coal plants – also remain in the market.

Gas plants can operate more flexibly than coal – open cycle plants (and newer CCGT plants and reciprocating engines) need as little as 5 minutes to ramp up to full operating capacity. This has made gas-powered generation more responsive than coal to prices since the start of 5minute settlement in October 2021.

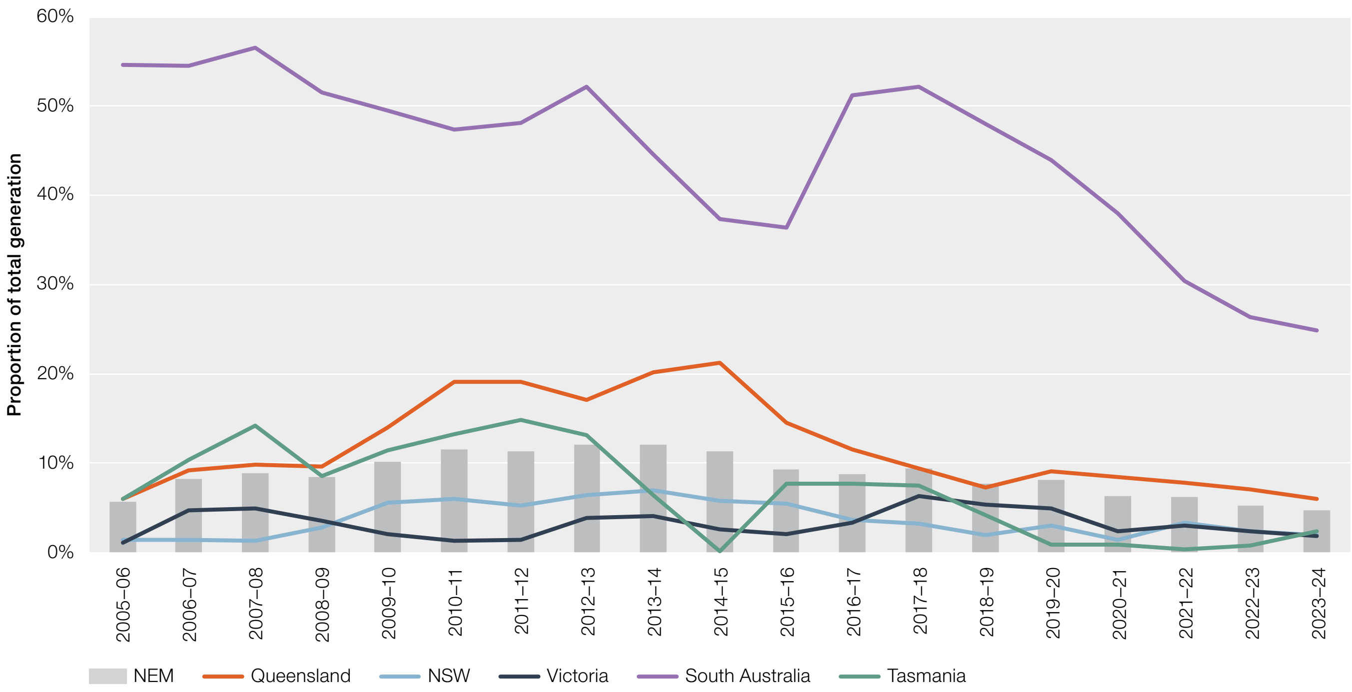
The ability of gas plants to respond quickly to sudden changes in the market makes them a useful complement to wind and solar generation, which can be affected by sudden changes in weather conditions. The most efficient gas-powered generation is less than half as emissions intensive as the most efficient coal-fired plant.

Gas is generally the most expensive fuel for electricity generation, so gas generators typically operate as 'flexible' or 'peaking' plants, preferring to be dispatched only when wholesale prices are high. Gas will increasingly be used as a flexible generation technology. It will be used to support renewables by supplying energy during periods of renewable drought and extreme peak demand periods. Gas generation also provides system security services to maintain grid stability, as is the case currently in South Australia, until cheaper solutions are implemented. AEMO's latest Integrated System Plan[22] calls for 15 GW of gas-powered generation by 2050 to help firm renewable energy in the absence of suitable renewable options.

Across the NEM, gas-powered plants supplied only 5% of electricity generated in 2023–24. South Australia relies more heavily on gas-powered generation than other regions, primarily because it has no coal-fired generation. In 2023–24, the state produced 25% of its local generation from gas-powered generation. Gas usage in South Australia has decreased over recent years as renewable generation increased and gas-powered generation moved to a firming role (Figure 2.18).

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

Figure 2.18 Proportion of total generation by region, gas



Note: The share of total regional output produced by gas-powered generators.
Source: AER; AEMO (data).

In response to the closure of the Liddell power station, the previous Australian Government supported the entry of 2 new gas generators. In early 2024, the construction of EnergyAustralia's Tallawarra B gas power station (320 MW) was completed, and it is now generating electricity in the NEM. It is based in NSW's Illawarra region and can use a blend of hydrogen and natural gas.

Additionally, Snowy Hydro plans to construct a 660 MW open-cycle gas-powered power station at Kurri Kurri in NSW's Hunter Valley. Kurri Kurri is expected to be completed in December 2024 and, as a gas peaking plant, is only expected to operate around 2% of the time.

2.7.3 Hydro-electric generation

Hydropower uses the force of moving water to generate power. The technology involves channelling falling water through turbines. The pressure of flowing water on the blades rotates a shaft and drives an electrical generator, converting the motion into electrical energy (Figure 2.16). Like coal and gas plants, hydro-electric generators are synchronous, meaning they provide inertia and other services that support power system security. Because their fuel source is usually available (except in drought conditions), they are 'dispatchable' plants that can switch on as required.

Most of Australia's hydro-electric plants are large-scale projects that are over 40 years old. A number of 'mini-hydro' schemes also operate. These schemes can be 'run of river' (with no dam or water storage) or use dams that are also used for local water supply, river and lake water level control, or irrigation.

Hydro-electric plants have low fuel costs (that is, they do not explicitly pay for the water they use), but they are constrained by storage capacity and rainfall levels to replenish storage, unless pumping is used to recycle the water. For this reason, the opportunity cost of fuel is comparatively high. Therefore, hydro-electric generators typically operate as 'flexible' or 'peaking' plant, similar to gas-powered generation. As the NEM transitions to increased renewable generation, hydro-electric generation will play an important role firming renewables, uniquely placed to provide longer-term storage and balance energy availability across seasons.

Conditions in the electricity market affect incentives for hydro-electric generation. Subject to environmental water release obligations, hydro-electric generators tend to reduce their output when electricity prices are low and run more heavily when prices are high. Incentives under the Renewable Energy Target (RET)[23] scheme also affect incentives to produce.

Hydro-electric generation can also be constrained by environmental factors. In NSW in 2022, despite pressure to run harder to compensate for the high level of coal outages, generation at Snowy Hydro's biggest power station, Tumut 3, was constrained due to concerns resulting from heavy rains. These included high water levels in the release reservoir, Blowering Dam, and the limited release capacity of the Tumut River.[24] In 2024, hydro-electric generation has been constrained in Tasmania due to low storage levels following below average rainfall in the region.

In the 2023–24 financial year, hydro-electric generators accounted for 9% of capacity in the NEM and supplied 7% of electricity generated. Tasmania is the region most reliant on hydro-electric generation, with 76% of its 2023–24 generation from this source. NSW and Victoria also have significant hydro-electric generation plants located in the Snowy Mountains region.

2.7.4 Wind generation

Wind turbines convert the kinetic energy of wind into electricity. Wind turns blades that spin a shaft connected (directly or indirectly via a gearbox) to a generator that creates electricity (Figure 2.16).

Renewable generation, including wind, has filled much of the supply gap left by thermal plant closures. Government incentives, including the RET scheme, provided impetus for the growth of wind generation in the NEM. While providing low-cost energy, the weather-dependent nature of wind generators makes their output variable and sometimes unpredictable.

Wind-powered generation continues to grow in the NEM, with 822 MW of capacity added in the 2023–24 financial year. In 2023–24 wind-powered generation accounted for 13% of total generation in the NEM. While capacity was added, total output was slightly lower than the previous year due to differences in wind conditions. Generation was down across the year, and particularly low in the April to June quarter 2024, which had the lowest amount of quarterly wind-powered generation since the same period in 2021.

Wind-powered generation penetration is especially strong in South Australia, where it provided 45% of the state's electricity output in 2023–24.

23 Clean Energy Regulator, About the Renewable Energy Target, June 2022.

24 Snowy Hydro, Snowy Hydro water releases from Tumut 3 Power Station, June 2022.

2.7.5 Grid-scale solar farms

Australia has the highest solar radiation per square metre of any continent, receiving an average 58 million petajoules of solar radiation per year. All solar investment to date has been in photovoltaic systems, which use layers of semi-conducting material to convert sunlight into electricity (Figure 2.16).

Investment in large-scale solar farms in Australia did not occur at a significant scale until 2018, supported by government incentives under the RET scheme and funding support from the Australian Renewable Energy Agency (ARENA) and Clean Energy Finance Corporation (CEFC). In 2017, commercial solar farms accounted for only 0.5% of total NEM generation capacity and met only 0.3% of the NEM's electricity requirements. In 2023–24, solar farms made up 10% of registered capacity and 7% of generation output.

Generation from solar farms continued to break output records in 2023–24 as new capacity entered the market. Solar generation was higher in all quarters relative to comparative quarters in the previous year, and the absolute quarterly output record was broken in the October to December quarter 2023 and then again in the January to March quarter 2024.

Relatedly, 2023–24 saw record quarterly negative price intervals in the July to September 2023 quarter and subsequently in the October to December 2023 quarter. High solar output is strongly correlated with negative prices for 2 reasons:

- it floods the NEM with cheap electricity – sunshine is free and often widespread
- if grid-scale solar is producing strong output, rooftop solar is usually doing the same, reducing demand in the process.

To fully optimise the low-priced capacity solar brings to the NEM, the market needs sufficient infrastructure to store it so it can be dispatched during evening demand peaks when and where it is needed. As consumer energy resources grow, the role of storage in avoiding curtailment of rooftop solar and the resulting loss of income for consumers becomes even more significant.

2.7.6 Grid-scale storage

Stored energy can be used to support system reliability by being injected into the grid at times of high demand and can provide stability services to the grid by balancing variability in renewable generation. Storage technologies in the NEM include batteries and pumped hydro-electricity. As the capacity of coal generators exits the market and is replaced by intermittent wind and solar generation, increased storage will be essential to manage daily and seasonal variations in output.

Battery storage

Lower costs and expanding opportunities for battery technology has seen a significant increase in battery investment.

Batteries provide multiple benefits to the market. They have fast response times, which enable them to help maintain the power system in a secure state faster than other technologies (although they cannot provide sustained generation). They can be co-located with renewable resources to firm output or with gas plants to provide instant energy while the gas plant starts up.

Batteries take advantage of variations in the spot price. They typically charge when prices are low, which is often in the middle of the day, and discharge when prices are high during morning and evening demand peaks. The difference between the charge price and the dispatch price determines the battery's profit ratio per megawatt. With increasing instances of negative spot prices during the day being followed by high evening prices, batteries can often profit from both charging and dispatching.

Batteries in the NEM can also earn significant revenue from operating in frequency control markets, although this comes at the expense of their availability in the energy-only market. Analysis from 2022's *Wholesale electricity market performance report* indicated that batteries prefer to operate in electricity spot markets when prices are high, but favour frequency control markets at other times.

Batteries made up just under 2 GW of capacity in the NEM in 2023–24. Total output from batteries increased compared with the previous year but accounted for less than 0.5% of total generation output.

AEMO's latest ISP[25] forecasts grid-scale battery storage to grow rapidly, peaking at 21,912 MW in 2037–38 before stabilising and eventually falling to 12,007 MW in 2050. Over the next year, around 2 GW of battery capacity is expected to enter the NEM, nearly doubling existing capacity. This includes the Waratah Super Battery, which at 700 MW will be the largest battery in the NEM.

Pumped hydro-electricity

Large-scale storage can be provided through pumped hydro-electric projects, which allow hydro-electric plants to reuse their limited water reserves. The technology involves pumping water into a raised reservoir while electricity is cheap and releasing it to generate electricity when prices are high. Like batteries, a greater difference in the pump price against the dispatch price results in a higher profit margin per megawatt.

Pumped hydro-electric technology has been available in the NEM for some time, with generation in Queensland (570 MW at Wivenhoe) and NSW (240 MW at Shoalhaven and 1,500 MW at Tumut 3). Use of this technology is limited by the availability of appropriate geography. However, advances in technology and the rise of intermittent generation are providing new opportunities for deploying this form of storage at a larger scale. In particular, pumped hydro-electricity is the basis of the Snowy 2.0 (2,000 MW) and Battery of the Nation (2,500 MW) projects in NSW and Tasmania. In its April 2024 project update, Snowy Hydro's target date for commercial operation of all units is December 2028, a year earlier than reported in our last report.[26]

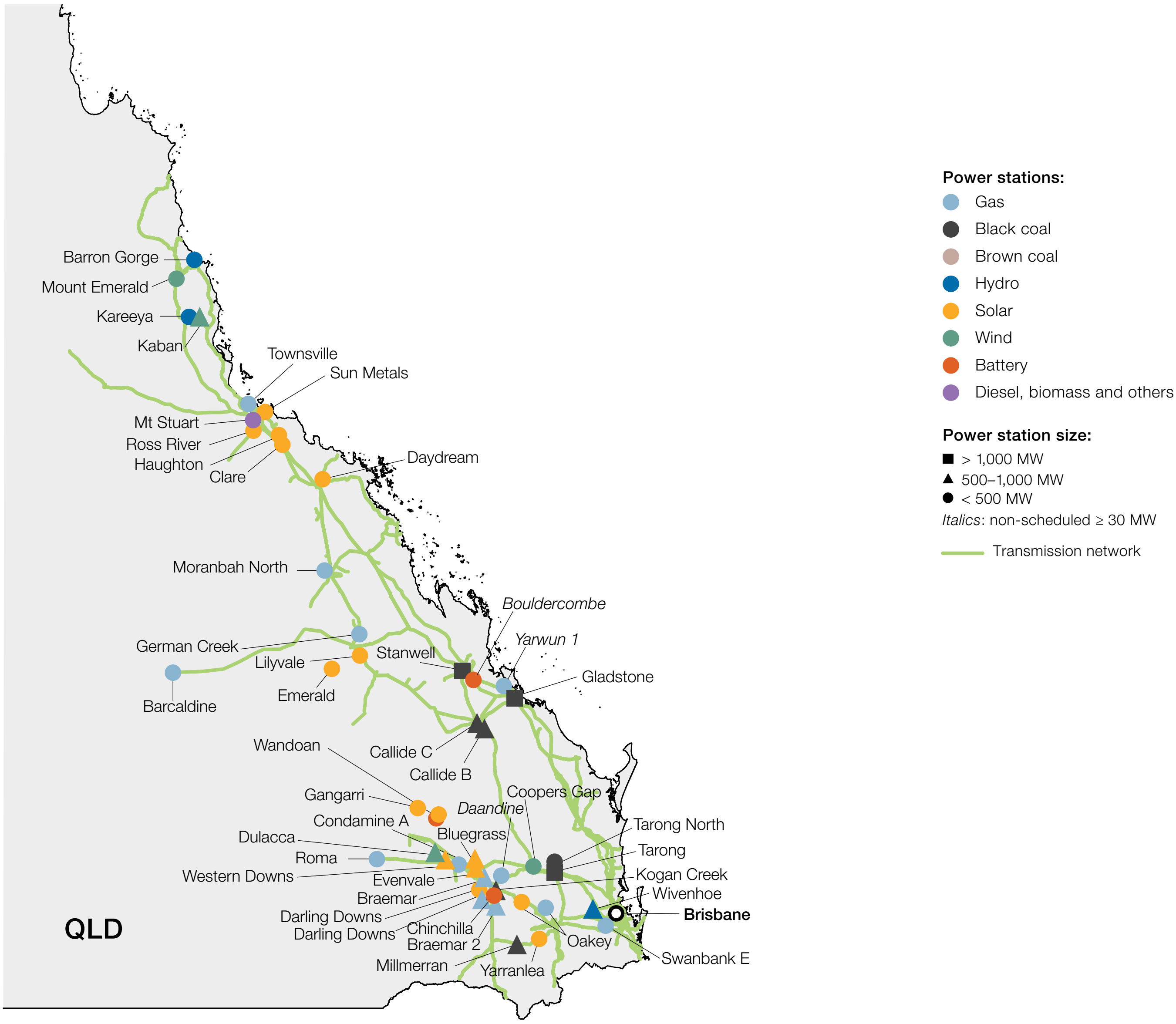
25 AEMO, 2024 Integrated System Plan, Australian Energy Market Operator, June 2024.

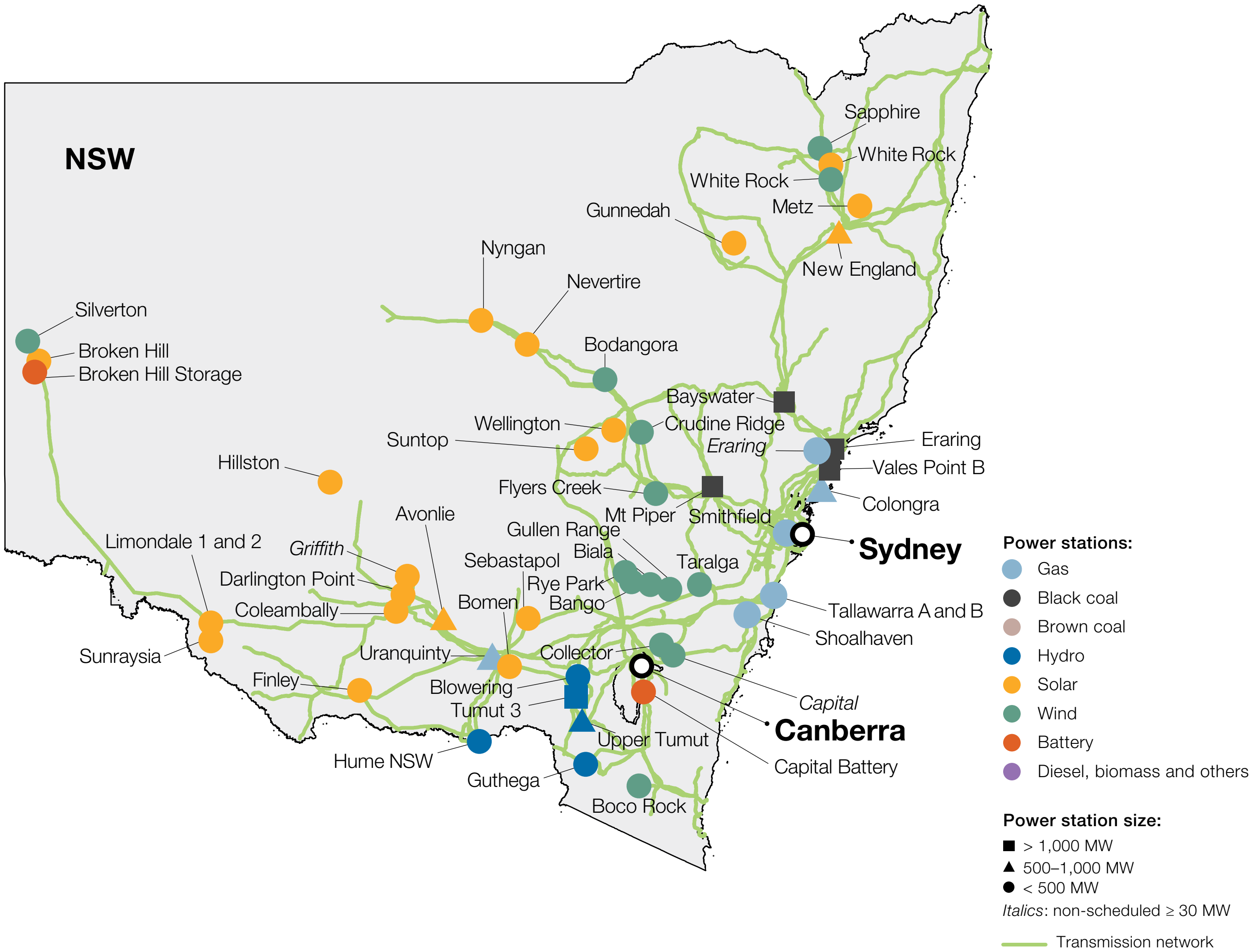
26 Snowy Hydro, Snowy 2.0 Project Update – April 2024, April 2024.

2.7.7 Generator information

Figure 2.19 maps the locations of generation plants and the types of technology in use.

Figure 2.19 Generators in the NEM




NSW
Sapphire
White Rock
White Rock
Metz
Gunnedah
New England
Nyngan
Nevertire
Silverton
Broken Hill
Broken Hill Storage
Bodangora
Bayswater
Wellington
Crudine Ridge
Suntop
Eraring
Eraring
Vales Point B
Hillston
Flyers Creek
Colongra
Avonlie
Mt Piper
Smithfield
Limondale 1 and 2
Griffith
Gullen Range
Sydney
Biala
Sebastapol
Taralga
Darlington Point
Rye Park
Bomen
Bango
Coleambally
Tallawarra A and B
Shoalhaven
Sunraysia
Uranquinty
Collector
Finley
Blowering
Capital
Tumut 3
Canberra
Upper Tumut
Hume NSW
Capital Battery
Guthega
Boco Rock
Power stations:
Gas
Black coal
Brown coal
Hydro
Solar
Wind
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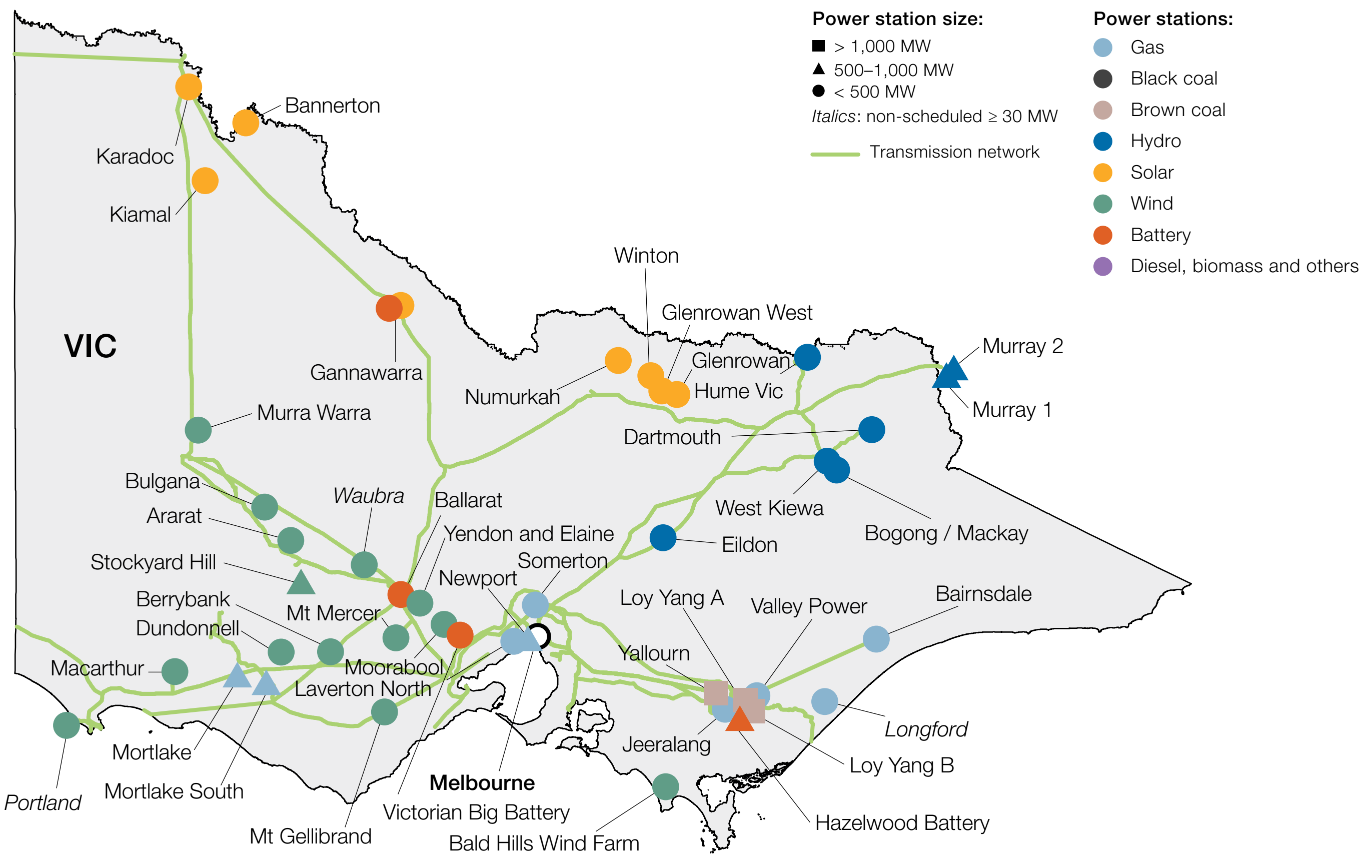
Diesel, biomass and others
Power station size:
> 1,000 MW
500–1,000 MW
< 500 MW
Italics: non-scheduled ≥ 30 MW
Transmission network


Power station size:
> 1,000 MW
500–1,000 MW
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Italics: non-scheduled ≥ 30 MW
Transmission network
Power stations:
Gas
Black coal
Brown coal
Hydro
Solar
Wind
Battery
Diesel, biomass and others
Bannerton
Karadoc
Kiamal
Winton
Glenrowan West
VIC
Gannawarra
Glenrowan
Murray 2
Numurkah
Hume Vic
Murray 1
Murra Warra
Dartmouth
Bulgana
Waubra
Ballarat
West Kiewa
Ararat
Yendon and Elaine
Bogong / Mackay
Eildon
Stockyard Hill
Somerton
Newport
Berrybank
Mt Mercer
Loy Yang A
Valley Power
Bairnsdale
Dundonnell
Yallourn
Macarthur
Moorabool
Laverton North
Longford
Jeeralang
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Loy Yang B
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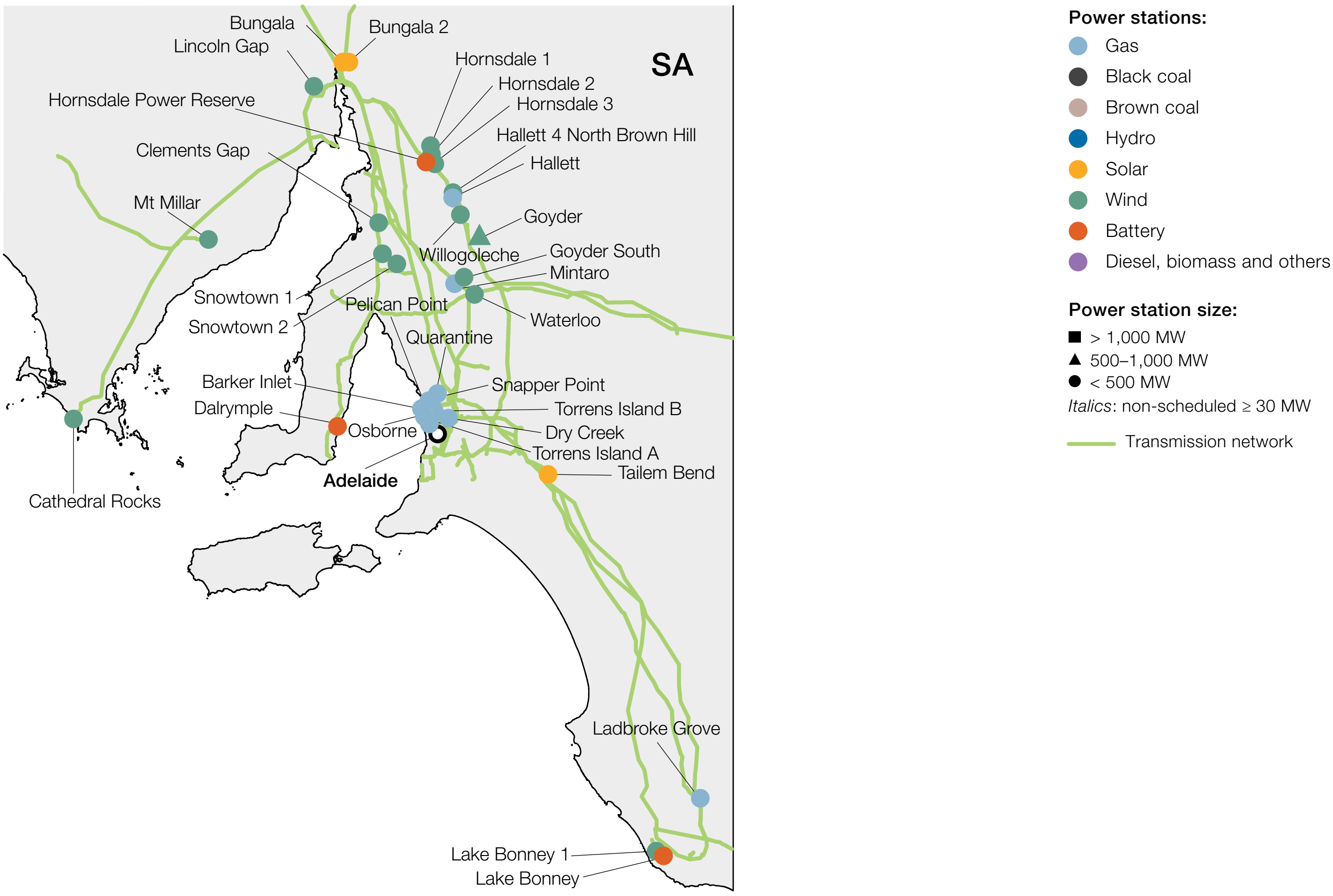
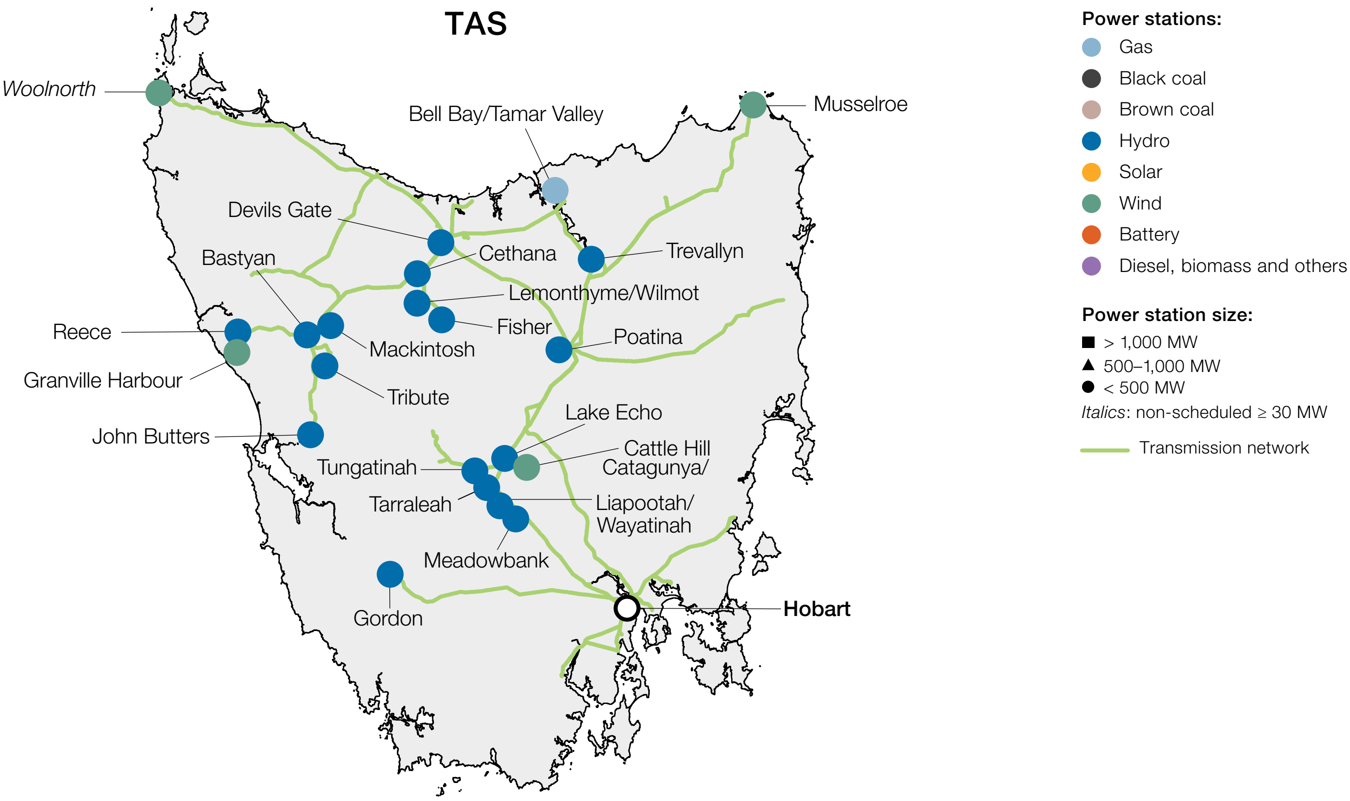
Portland
Mortlake South
Victorian Big Battery
Hazelwood Battery
Mt Gellibrand
Bald Hills Wind Farm





Note: Excludes solar, wind and diesel/biomass smaller than 100 MW registered capacity.
Source: AER.

2.8 Consumer energy resources

Alongside major shifts occurring in the technology mix at the grid level, significant changes are occurring in small-scale electricity supply with the uptake of consumer energy resources (CER). These resources allow individual consumers and groups to generate or store their own electricity, as well as enabling them to actively manage their consumption. They include:

- rooftop solar
- storage, including batteries and electric vehicles
- demand response, which uses load control technologies to regulate the use of household appliances such as hot water systems, pool pumps and air conditioners.

By far the fastest development has been in rooftop solar installations, but interest is also growing in battery systems, electric vehicles and demand response.

2.8.1 Rooftop solar generation

Capacity generated by rooftop solar is not traded in the NEM but is instead subtracted from demand. By installing solar panels, consumers may save on their electricity bills in 2 ways. The most efficient is to consume the electricity generated directly, rather than paying for supply from the grid. The second is to export the electricity back into the grid for other households to consume; however, this is subject to a feed-in tariff, which partially offsets savings for exporting consumers. Importantly, the electricity generated by solar panels is unable to be stored for later consumption, unless connected to a battery.

Australia is the largest per capita user of rooftop solar in the world. Backed by Australian and state government incentives, households and businesses have continued to install large volumes of rooftop solar capacity every year since 2015. In the 2023–24 financial year, rooftop solar capacity totalled over 20 GW (Figure 2.14). Queensland and NSW have the most installed capacity, but South Australia has the highest relative rooftop solar capacity, making up 40% of its total capacity.

In 2023–24, output from rooftop solar increased by 16% compared with the previous year, and total output has more than tripled since 2017–18. In 2023–24 it accounted for over 11% of total generation, up from 10% the previous year.

The rapid uptake of rooftop solar has dramatically changed the shape of daily spot price and grid demand in the NEM. Prior to mass adoption of the technology, the middle of the day typically saw the peak of both prices and demand in summer months; the opposite is now true.

2.8.2 CER storage

Customers are increasingly storing surplus energy from rooftop solar systems in batteries to draw from when needed, thus reducing their demand for electricity from the grid during peak times. Home battery systems may play an important role in meeting demand peaks in the grid, depending on the extent to which technology improvements can reduce installation costs. Community batteries or other distribution-connected batteries can also provide storage close to sources of rooftop solar generation, lowering transport costs and curtailment due to congestion.

The pace of uptake of electric vehicles will potentially have a significant impact on electricity demand and supply. Charging the batteries of electric vehicles will likely generate significant demand for electricity from the grid. As charging technologies mature, electric vehicle batteries may also supply electricity back to the grid at times of high demand. Coordinated CER storage is projected to exceed the growth in large-scale utility storage in the NEM in the coming years.[27]

Small-scale battery installations in the NEM saw storage capacity increase by 64% from 2022 to 2023, with 2023 having the largest volume of storage capacity additions in the NEM to date. In the first half of 2024, a further 12% of storage capacity has been added compared with 2023, with total installed storage capacity totalling 1,755 MVAh.[28]

27 CER storage means consumer energy resources such as batteries and electric vehicles. AEMO, 2024 Integrated System Plan, Australian Energy Market Operator, June 2024.

28 AEMO, DER Data Dashboard, Australian Energy Market Operator, accessed 26 August 2024.

2.8.3 Bespoke tariffs

The use of bespoke tariffs for commercial and industrial consumers is a longstanding method of incentivising customers to shape their energy demand around the available capacity on the network by offering them cheaper prices at times of abundant electricity supply.

For small customers, this has historically been known as controlled load. It has previously involved the installation of a separate meter for consumption-heavy appliances such as hot water heaters, and typically incurs a lower usage tariff. Electricity distribution network service providers are happy to charge a lower usage tariff for appliances included in a controlled load package in exchange for a guarantee that those appliances will only be switched on at certain times of day. Controlled load tariff times vary by distribution network. Controlled load allows electricity retailers and distribution networks to predict demand more accurately and can grant savings to consumers with predictable usage patterns.

As technology advances, including home energy systems, and smart meters are rolled out, the potential for new, innovative controlled load products has increased beyond the traditional application to hot water heaters and pool pumps to include a wider range of loads including EV charging.[29] There are trials of two-way charging taking place, where an EV can either discharge electricity to power a home or export energy to the grid when it is needed.[30]

2.8.4 Orchestrated CER

A rooftop solar system coupled with a small-scale battery installation can make a meaningful difference to a single household's energy bill, but aggregated across thousands of households these technologies can enhance system reliability and security. By connecting home batteries and those in electric vehicles to an energy sharing network, the electricity stored within them can be used to supplement supply during shortfalls. During a demand peak, when grid supply is strained, the electricity stored in consumer-owned batteries can dispatch in a coordinated response, servicing excess demand and taking pressure off grid supply. By picking up the slack during a supply shortfall, orchestrated CER can mitigate high spot prices and prevent potential blackouts and receive credits on their electricity bills for what they contribute.

AEMO forecasts within its optimal development path that coordinated consumer energy resources, including virtual power plants (VPPs), vehicle to grid and other coordinated CER storage, will need to provide 31 GW of dispatchable storage capacity by 2050. Orchestration is also important for system security. As the volume of unscheduled price-responsive resources such as VPPs grows, this could create problems for the grid through deviations from forecast demand. AEMC released a draft determination in July 2024 setting out the potential issues and options for better integrating CER into AEMO's scheduling and dispatch functions, with a final determination due by the end of 2024.[31]

29 ARENA, Flexible Demand, accessed 6 September 2024.

30 Endeavour Energy, EV charging trial, accessed 24 September 2024.

31 AEMC, Integrating price-responsiveness resources into the NEM, 25 July 2024, Australian Energy Market Commission, accessed 16 September 2024.

2.9 Trade across regions

Transmission interconnectors enable energy transfers between the NEM's 5 regions (mapped and listed in chapter 3). Interconnectors generally deliver energy from lower priced regions to higher priced regions. They also increase the reliability and security of the power system by enabling demand in one region to be met by generation from an adjacent region.

The ability of generators to supply energy to other regions is limited by the capacity of the transmission network. This capacity can change depending on the direction of flow, outages on the network or other physical constraints and limits AEMO imposes to manage system security.

An interconnector is constrained when the flow across it reaches its technical limit. When an interconnector is constrained, cheaper sources of generation in one region cannot replace more expensive generation in another, effectively separating those regions into separate markets (price separation). Interconnector constraints are often a factor in high price events.

To support the transition to renewable generation, new transmission infrastructure will be needed. AEMO's 2024 Integrated System Plan provides a coordinated whole-of-system plan for efficient development of the power system in the NEM to ensure needs are met in the long-term interests of consumers. As part of this transition, several major interconnector transmission projects are planned or underway. More information on transmission projects is set out in chapter 3.

Queensland and Victoria tend to be net exporters of energy, providing surplus baseload energy to NSW and South Australia. This was the case in the 2023–24 financial year, with Queensland and Victoria net exporters of energy and NSW and South Australia net importers. Tasmania's trade position varies with environmental and market conditions; in 2023–24 it was a net importer of electricity.

Figure 2.20 Inter-regional trade

Source: AER; AEMO (data).

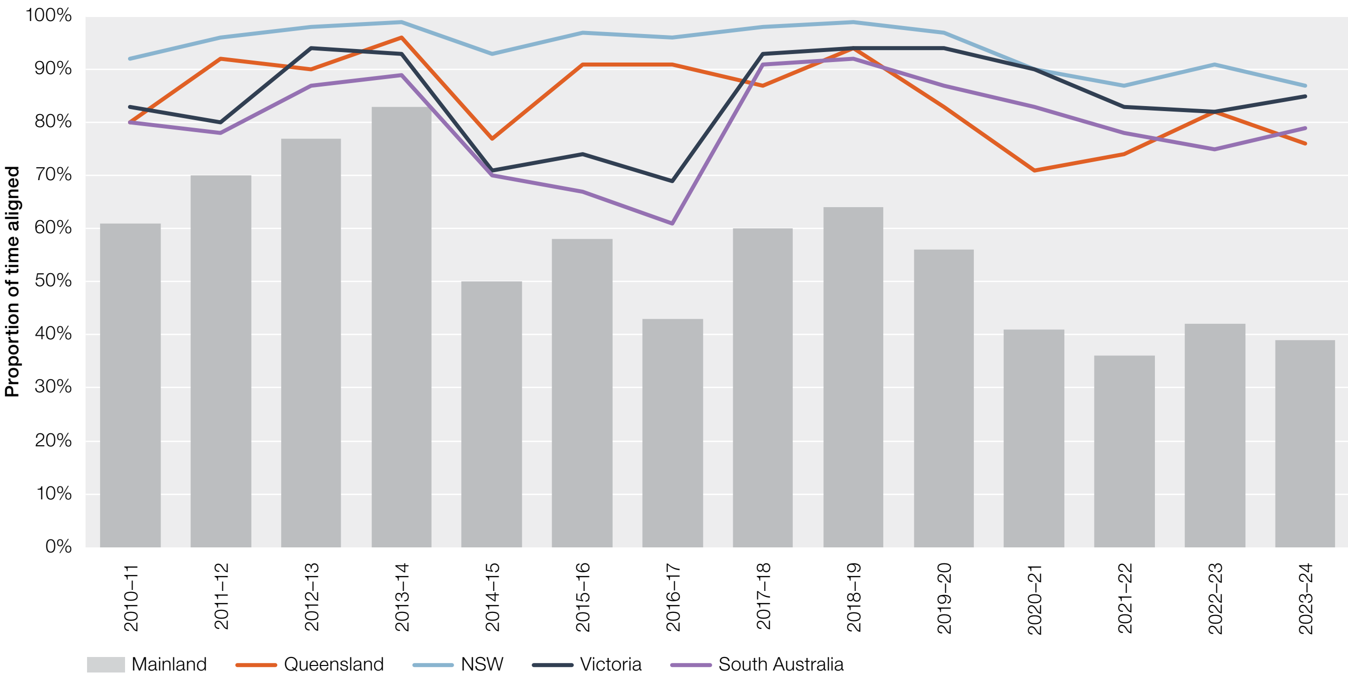
2.9.1 Market alignment and network constraints

The market sets a separate spot price for each NEM region. When interconnectors are unconstrained, competitive pricing pressure from neighbouring regions brings prices into alignment across the NEM (with slight variations caused by physical losses that occur when transporting electricity). At these times, the NEM functions more like a single market than a collection of regional markets, because generators are exposed to competition from generators in other regions.

As coal-fired generators retire and new generation sources appear in new locations, new constrained locations are appearing, potentially due to line capacity or system security reasons. This can have price impacts if they prevent cheaper electricity making it to market and could influence inter-regional trade outcomes in the future.

Over recent years price alignment across regions has been falling. Price alignment in the NEM fell in 2023–24 but remains higher than the low set in 2021–22 (Figure 2.21).

Figure 2.21 Price alignment in mainland NEM regions



Note: Inter-regional price alignment shows the proportion of the time that prices in one NEM region are the same as those in at least one neighbouring region, accounting for transmission losses.

Source: AER; AEMO (data).

Being the geographical middle of the NEM, NSW prices are typically the most aligned, this remained consistent in 2023–24. However, in 2023–24 NSW alignment decreased compared with the previous year, as did alignment in Queensland, which is only connected to NSW. Victoria and South Australia recorded increases in price alignment compared with the previous year.

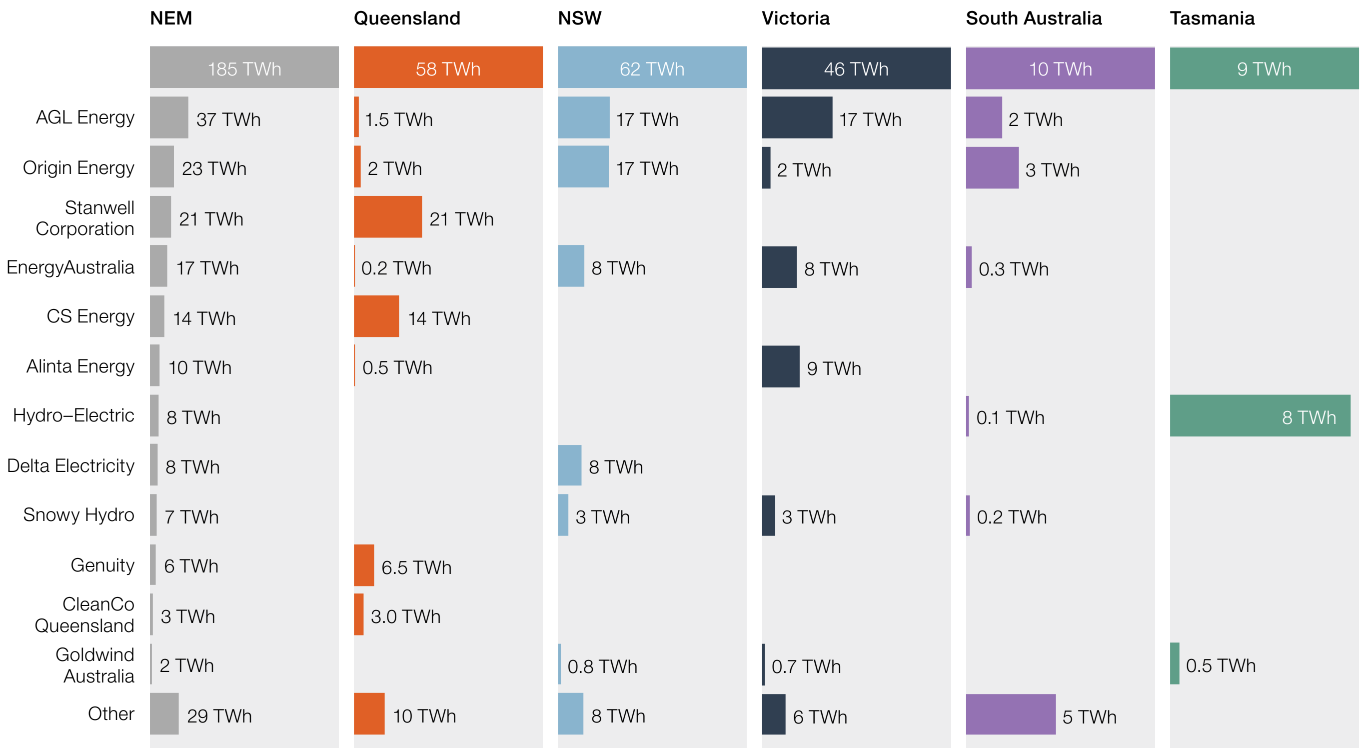
2.10 Market structure

Over 350 electricity generators sell electricity into the NEM. Despite significant new entry in recent years, a few large participants control a significant proportion of generation in each NEM region. As intermittent renewables (wind and solar) continue to increase their share of total capacity, flexible generation will play an increasingly important role in the market. Detailed analysis of market structure and competition, including concentration and competition in the supply of flexible capacity, in addition to broader market outcomes, are addressed in the AER's *Wholesale electricity market performance report* released every two years, most recently in December 2022.[32] The AER will publish the next edition of the report in December 2024.

2.10.1 Market concentration

Generation in the NEM is concentrated among a relatively small number of owners. In each NEM region except South Australia, the largest 2 owners account for over half of the region's output capacity. In South Australia, the largest 2 owners account for 47% of capacity (Figure 2.22).

Figure 2.22 Market shares in generation output



Note: Output in 2023–24. Market shares are determined based on ownership of each unit's output. Where we have been unable to determine ownership of output, we have allocated market shares according to ownership of the asset. Output is split on a pro rata basis if ownership changed in 2023–24. Where multiple owners are invested in a generating unit, the output of that unit has been split proportionally between owners according to their percentage of total ownership. Output from rooftop solar systems, interconnectors, loads and non-scheduled generation are excluded from the data.

Source: AER; AEMO; company announcements.

32 AER, Wholesale electricity market performance report 2022, Australian Energy Regulator, December 2022.

Private entities control most generation output in NSW, Victoria and South Australia, whereas government-owned entities control most generation output in Queensland and Tasmania.

Ownership of flexible generation, or generation that can respond quickly to changing market conditions, is particularly concentrated. A few participants control significant flexible generation capacity in NSW, Victoria and Tasmania.

Snowy Hydro controls more than 5,000 MW of registered flexible generation capacity. Most of these assets are located in NSW and Victoria and, as a result, Snowy Hydro controls more than 60% of flexible generation in NSW and almost 50% in Victoria. In addition, Snowy Hydro is developing Snowy 2.0, which would add a further 2,000 MW of flexible capacity to its portfolio. It also plans to construct a 660 MW gas-fired power station near Kurri Kurri. Origin Energy is the second largest provider of flexible generation, with significant capacity across the mainland. Collectively, Snowy Hydro and Origin Energy control over 80% of all flexible capacity in NSW and nearly 60% in Victoria. Ownership of flexible capacity is less concentrated in the other regions.

2.10.2 Vertical integration

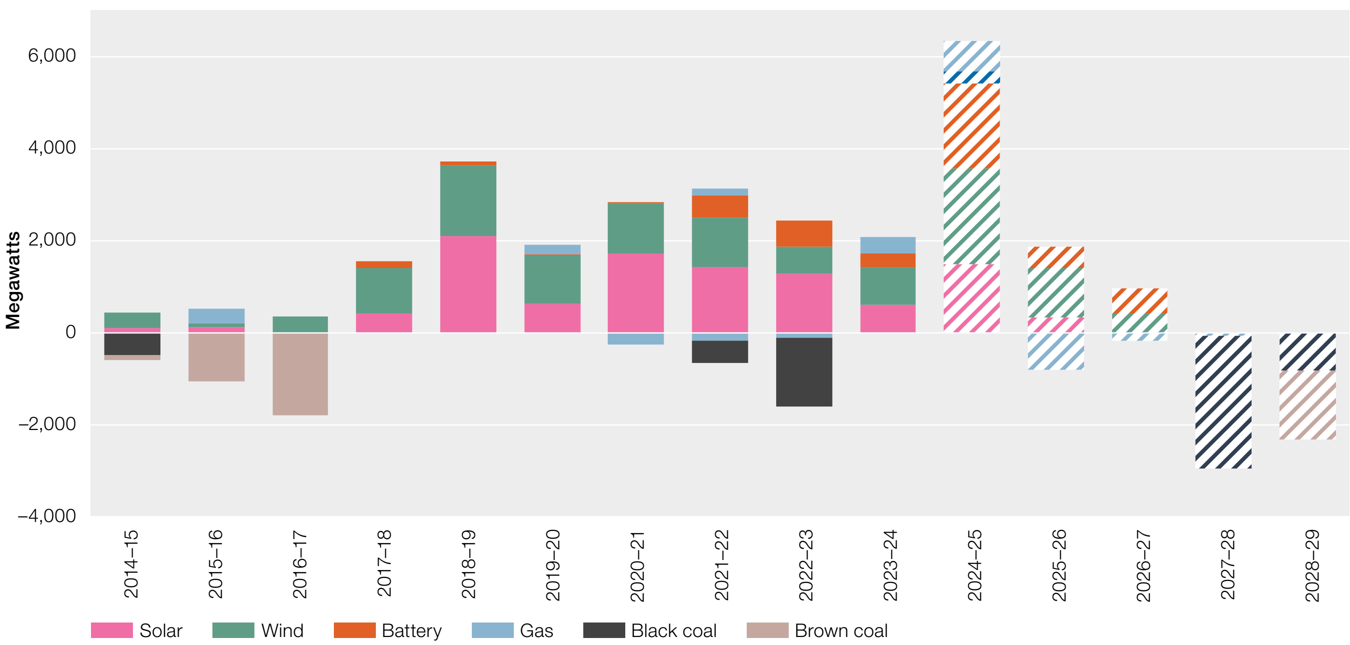
Most large generators in the NEM are vertically integrated, with portfolios in both generation and retail. Because generators sell into the spot market while retailers buy from it, vertical integration allows 'gentailers' to hedge against price risk in the wholesale market without entering into external contract agreements.

The 4 largest vertically integrated participants in each region account for most of the generation output and supply more than half of retail load. Second tier retailers also own major generation assets. More information on retailers in the NEM is set out in section 6.7.4 in chapter 6.

2.11 Generation investment and plant closures

Over 15 GW of new grid-scale solar, wind and battery investment has been added to the NEM since the beginning of the 2017–18 financial year. Over the same period, just over 2.5 GW of coal and gas capacity was withdrawn (Figure 2.23).

Figure 2.23 New generation investment and plant withdrawal



Note: Capacity includes scheduled and semi-scheduled generation, but not rooftop solar capacity. New entry and exit are by registered capacity, except for solar which uses maximum capacity. Committed investment and closures from 30 June 2024 are shown as shaded components.

Source: AER; AEMO (data).

In 2023–24, nearly 2.1 GW of capacity entered the market, including:

- 600 MW of solar capacity, located in NSW, Victoria and South Australia
- 820 MW of wind capacity, located mostly in NSW and South Australia
- 300 MW of battery capacity (2 batteries in NSW, 2 in Queensland and 1 in South Australia)
- 350 MW of gas capacity, including 320 MW at Tallawarra B, a gas peaking plant in NSW.

While no generator exits are expected in the next financial year, large volumes of historical fossil fuel generators are scheduled to close in the next 5 years. This includes 1,050 MW of gas, 3,720 MW of black coal and 1,480 MW of brown coal. Large volumes of renewable and dispatchable generation will be required to meet the supply gap.

AEMO's most recent Integrated System Plan noted that, in 2023–24 alone, 13.5 GW of generation and storage connection applications were approved. However, it also noted that in recent years, projects have been taking longer to reach commissioning stage. This is due to a range of factors, including changes in financial markets, supply chain constraints, construction contracting challenges, and environmental and planning approvals.[33] Imminent investment is required to ensure the ongoing reliability of the NEM.

2.12 Power system reliability

Reliability is about the power system being able to consistently supply enough electricity to meet consumers' demand.

The transition in the energy market has increased the risk of reliability gaps. Coal plant closures remove a source of firm capacity that could historically be relied on to operate when needed. As contribution from weather-dependent generation increases, the power system must respond to increasingly large and sudden changes in output caused by changes in weather conditions and dispatch decisions by plant operators.

Reliability risks are typically highest over summer, particularly at times of peak demand. But they may also emerge at other times in the year, when solar or wind output is low, or there are transmission or plant outages.

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

Box 2.2 How reliability is measured

Reliability outcomes are measured in terms of unserved energy – that is, the amount of energy required by consumers that cannot be supplied due to a shortage of capacity. The reliability standard requires any shortfall in power supply to not exceed 0.002% of total electricity demand. It has rarely been breached, but AEMO has increasingly intervened in the market to manage forecast supply shortfalls in recent years.

While the 0.002% target is used to assess market performance and the appropriateness of reliability settings such as the market price cap, a stricter interim reliability measure of 0.0006% was introduced in 2020 and recently extended to run until 30 June 2028.[34] The interim reliability measure is used as a trigger for 2 mechanisms to prevent forecast supply shortages from occurring. If it forecasts unserved energy will exceed the 0.0006% threshold, AEMO can:

- request the AER to trigger the Retailer Reliability Obligation and organise for liable entities to enter sufficient qualifying contracts to cover their share of a 1-in-2-year demand event; this can occur up to 3 years before a forecast reliability gap
- if a forecast reliability gap persists, contract out of market capacity under the reliability and reserve trader mechanism to reduce the risk of a supply gap.

The reliability standard excludes outages caused by 'non-credible' threats, such as bushfires and cyclones, because the power system is not engineered to cope with these issues and the cost of doing so would be prohibitive. It also excludes supply interruptions originating in local distribution networks. Around 95% of a typical customer's power outages originate in distribution networks and are caused by local power line and substation issues.

In effect, the standard sets a level of unserved energy that balances the cost of providing reliability against the value that customers place on avoiding an unexpected outage.

2.12.1 Reliability outlook

In its May 2024 update to the 2023 Electricity Statement of Opportunities, AEMO forecast reliability gaps in all mainland regions across varying time periods over the next 10 years.

Against the interim reliability measure, AEMO has forecast that NSW and Victoria will face reliability gaps from 2024–25 until 2027–28, while South Australia will face a reliability gap in 2026–27. AEMO has indicated it will tender for interim reliability reserves to cover the reliability gaps in 2024–25. Against the normal reliability standard, NSW and Victoria will continue to face reliability gaps from 2028–29 onwards, while South Australia and Queensland are forecast to experience reliability gaps in 2031–32.

The main reason for forecast reliability gaps is the exit of over 8 GW of firm capacity in the next decade, as coal-fired and other thermal generators retire. Liddell's (NSW) closure in April 2023 marked the first of 4 coal station exits for the decade, with Eraring (NSW, 2027), Yallourn (Victoria, 2028) and Callide B (Queensland, 2028) all set to retire before 2030. Vales Point (NSW) is expected to retire in 2033. There are increased risks of reliability gaps if there are delays in planned transmission network infrastructure or delays in dispatchable generation such as batteries.

In releasing its updated 2023 Electricity Statement of Opportunities, AEMO noted that urgent investments in capacity in the NEM were needed to manage reliability risks and that 'once federal and state government programs, actionable transmission developments, and orchestration of forecast consumer energy resources (CER) are also considered, beyond the short term, reliability risks have the potential to be managed within relevant standards over most of the next 10-year horizon'.[35]

34 AEMC, Final rule to extend Interim Reliability Measure, Australian Energy Market Commission, September 2023.
35 AEMO, Update to the 2023 Electricity Statement of Opportunities, Australian Energy Market Operator, May 2024.

2.12.2 Managing reliability

The wholesale market is the primary mechanism for delivering reliability. Price signals in electricity spot and contract markets provide incentives for market participants to supply generation and, over a longer time horizon, investment in additional generation where required. Forward planning documents such as AEMO's Electricity Statement of Opportunities provide important transparency to the market, as well as mechanisms such as the Capacity Investment Scheme (section 2.14), should also support longterm investment. Where supply shortfalls are forecast and market options have been exhausted, the Retailer Reliability Obligation and the Reliability and Emergency Reserve Trader mechanisms can be used to mitigate the shortfall risk. AEMO also has the ability to issue directions to individual participants to manage reliability.[36]

AEMO's 2023 Electricity Statement of Opportunities forecast that reliability gaps are likely to be more common, and increased volumes of interim reliability reserves or long notice reserves may be required to meet reliability shortfalls. This cost will ultimately be borne by customers.

Reliability and Emergency Reserve Trader

The Reliability and Emergency Reserve Trader (RERT) is a mechanism through which AEMO may use reserve contracts to prevent load shedding (deliberate disconnection of customers to prevent potentially significant damage to the power system) or other threats to reliability. When forecast reliability is outside the relevant standard, AEMO can pay large industrial customers to standby to reduce their consumption should this be required to prevent load shedding. AEMO may also pay generators from outside the market to standby in case additional supply is required.

Reserves procured under the RERT must be 'out of market'. Any generator or load that participated in the wholesale market in the previous 12 months may not provide emergency reserves through the RERT. AEMO maintains a panel of RERT providers that can provide short notice and medium notice reserve if required. Panel members for short notice RERT agree on prices when appointed to the panel, whereas panel members for medium notice RERT negotiate the price when reserves are required. AEMO may procure long notice reserve through invitations to tender, where it has 10 weeks or more notice of a projected shortfall, as well as interim reliability reserves if the stricter reliability target is forecast to be exceeded.

Market participants that provide short notice reserves are compensated if the reserves are activated, or preactivated, but are not compensated based on availability. In contrast, participants that provide long-run or interim reliability reserves are compensated for making generation available. The RERT should only be activated if necessary to avert load shedding or other risks to reliability and system security. The capacity activated under the RERT scheme is typically more expensive than that acquired through the market; this is a cost that is ultimately borne by customers.

The cost incurred by AEMO for these standby services should be less expensive than the projected cost of load shedding for customers. The value of customer reliability (VCR) is a threshold set by the AER.[37] The VCR represents the per kilowatt cost to the economy of a load shedding event. A guiding principle of RERT payments is that they should not exceed the VCR, but doing so is not prohibited.[38]

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36 AEMO, Procedures for issue of directions and clause 4.8.9 instructions, Australian Energy Market Operator, effective 4 July 2024, accessed 16 September 2024.

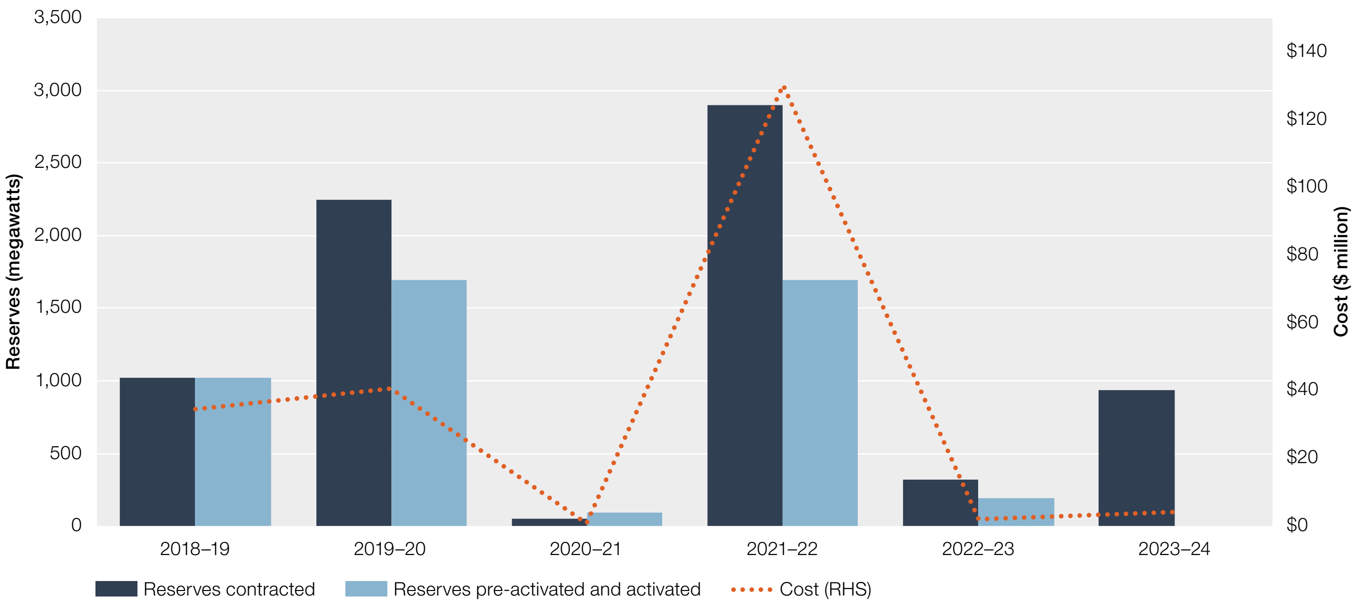
37 AER, Values of customer reliability, Australian Energy Regulator, accessed 20 August 2024.

38 AEMC, National Electricity Amendment (Enhancement to the Reliability Emergency Reserve Trader) rule 2019, Australian Energy Market Commission, May 2019.

In 2023–24 AEMO entered into interim reliability reserve (IRR) contracts for the first time, in response to reliability shortfalls identified in its 2023 Electrical Statement of Opportunities. AEMO contracted a total of 100 MW of IRR in Victoria and 10 MW in South Australia for the period between 1 December 2023 and 31 March 2024. It subsequently contracted an additional 19 MW in Victoria for the period between 1 January 2024 and 31 March 2024.[39] The contracted interim reliability reserves were not activated or preactivated but incurred an availability cost of $98 per day per MW in South Australia and $645 per day per MW in Victoria on average, totalling $4,252,685.

AEMO entered into several short notice contracts in response to forecast lack of reserve 2 conditions on 14 December 2023, 27 January 2024 and 13 February 2024, totalling 807 MW. AEMO did not preactivate or activate any of the contract capacity, so no costs were incurred.

Figure 2.24 RERT reserves and costs



Note: Reliability and Emergency Reserve Trader (RERT) costs include costs for availability, preactivation, activation and other costs (including compensation costs).

Source: AER analysis of AEMO's RERT reporting.

The RERT has averted multiple instances of load shedding since the initiative began, but doing so comes at significant cost to the consumer. Typically, RERT costs have been calculated in reference to the MWh usage of activated contracted capacity. The average cost of the RERT in the previous 5 financial years has been just over $36,000 per MWh, more than double the current market price cap of $16,600 per MWh. The average cost of RERT in 2022–23 was more than $50,000 per MWh and more than the VCR.

In the 2023–24 financial year no RERT contracted volumes were activated. However, because interim reliability reserves were contracted, the total cost was higher than the previous year. AEMO's 2023 Electricity Statement of Opportunities forecast that reliability gaps are likely to be more common, and increased volumes of interim reliability reserves or long notice reserves may be required to meet reliability shortfalls. This cost will ultimately be borne by customers.

39 AEMO, Reliability and Emergency Reserve Trader (RERT) Quarterly Report Q4 2023, Australian Energy Market Operator, February 2023.

Retailer Reliability Obligation

The Retailer Reliability Obligation (RRO) is designed to be a long-term solution to ensure reliability at the lowest cost by preparing for and eliminating forecast reliability gaps before they occur.

If AEMO identifies a material reliability gap 3 years and 3 months out, it will apply to the AER to trigger the RRO by making a T-3 reliability instrument. Each Minister for Energy in a NEM region can also trigger the RRO by making an instrument directly. Where a reliability instrument is made, liable entities (retailers and other parties that purchase electricity directly from the wholesale energy market) are on notice to enter into sufficient qualifying contracts with generators to cover their share of a 1-in-2-year peak demand. If AEMO continues to identify a reliability gap 1 year and 3 months out, it will apply to the AER to make a T-1 reliability instrument, which requires liable entities to report their net contract position (NCP) to the AER. Liable entities can face civil penalties if they do not submit an NCP report and if a reliability gap eventuates and their NCP is insufficient. Liable entities with insufficient contracts may be liable to pay Procurer of Last Resort costs of up to $100 million each under the RERT scheme.

The RRO also includes a market liquidity obligation on specified generators to post bids and offers in contract markets in the period leading up to a forecast reliability gap to help smaller retailers meet their requirements.

The AER has made several reliability instruments in response to forecast reliability gaps between 2024 and 2027. The first T-1 reliability instrument was made for South Australia between 8 January 2024 and 29 February 2024.[40] On 12 March 2024, AEMO reported that actual demand did not exceed the 1-in-2-year peak demand forecast and the reliability instrument was closed.

In February 2024 the AEMC published a final report on recommendations to improve the operation of the RRO.[41]

2.13 Power system security

Power system security refers to the power system's technical stability in terms of frequency, voltage, inertia and similar characteristics. System strength refers to the power system's ability to ensure correct operation of network protection equipment and maintain stable voltage waveforms. To ensure a secure power system, system security and system strength must be maintained within defined limits.

The NEM's coal, gas and hydro-electric generators help maintain a stable and secure system as a by-product of producing energy. Generally, these services are provided from the heavy spinning turbines used to generate electricity, which are physically coupled (synchronised) to the grid. This means that these turbines spin at a rate that lines up with the electrical frequency of the power grid and their physical momentum provide inertia to help resist unwanted changes to system frequency. As coal and gas generators retire, or reduce operations in response to falling demand, the supply of system security and strength are reduced with them.

Generation technologies replacing retiring coal and gas generators, such as wind and solar, are less able to provide system security and system strength services. Energy rule reforms have widened the pool of providers (such as batteries and demand response) of certain security services and made changes to how it is procured to support more efficient planning by network service providers. More recent reforms have put responsibilities on network service providers to maintain minimum security standards set by AEMO, for example, through their inertia and system strength reports as well as those encoded in the National Electricity Rules. In terms of managing system strength, nominated network service providers are required to meet a new system strength standard by 2 December 2025. Market policy and regulatory bodies are developing further reforms of the energy market's architecture to manage security risks in the context of an evolving energy market.

Where gaps in security or strength emerge, AEMO has powers to intervene in the market to protect system security and strength.

40 AER, T-1 and T-3 reliability instruments decision - FINAL, Australian Energy Regulator, October 2022.
41 AEMC, Review of the Retailer Reliability Obligation, Australian Energy Market Commission, February 2024.

2.13.1 Security performance in the NEM

As part of AEMO's market operations, it is required to maintain system frequency within a secure range (between 49.85 and 50.15 hertz). Any deviations from this range should not exceed more than 1% of the time over any 30-day period. Maintaining system security during the energy transition has been a key focus of the NEM market bodies.

Security performance can be impacted by changing system conditions (including extreme weather) and uncertain supply demand balance. AEMO reports annually on system security needs across the NEM for the coming 5-year period. Its December 2023 report confirmed previously identified voltage shortfalls in NSW, Queensland and Tasmania and noted that remediation for the shortfalls is currently in place or being progressed by the relevant network businesses.[42]

AEMO expects the need for additional system security services will only increase over the coming yearsas power stations that previously supplied these services withdraw from the system. AEMO needs to consider what technologies will be incentivised to provide these services in future and whether the new market arrangements currently being developed will provide sufficient incentives to do so.

2.13.2 Frequency control markets

AEMO procures some of the services needed to maintain power system stability through markets. In particular, it operates markets to procure various types of frequency control services.

Frequency control ancillary services (FCAS) are used to maintain the frequency of the power system close to 50 hertz. Following the introduction of very fast raise and lower FCAS markets in October 2023, the NEM has 10 FCAS markets, which are either regulation services or contingency services. Regulation services operate continuously to balance minor variations in frequency caused by small changes in demand or supply during normal operation of the power system. Contingency services manage large frequency changes from sudden and unexpected shifts in supply or demand, and they are used less often.

Costs for regulation services are recovered from participants that contribute to frequency deviations (causer pays), costs for raise contingency services are recovered from generators and costs for lower services are recovered from market customers (usually retailers). AEMO acquires FCAS through a co-optimised market that coordinates offers from generators and other participants in both energy and FCAS markets to minimise overall costs.

Local FCAS services are provided from market participants in a region when that region is electrically islanded from the NEM. Global FCAS services occur when services are provided in a region that is connected to other regions, through available interconnectors.

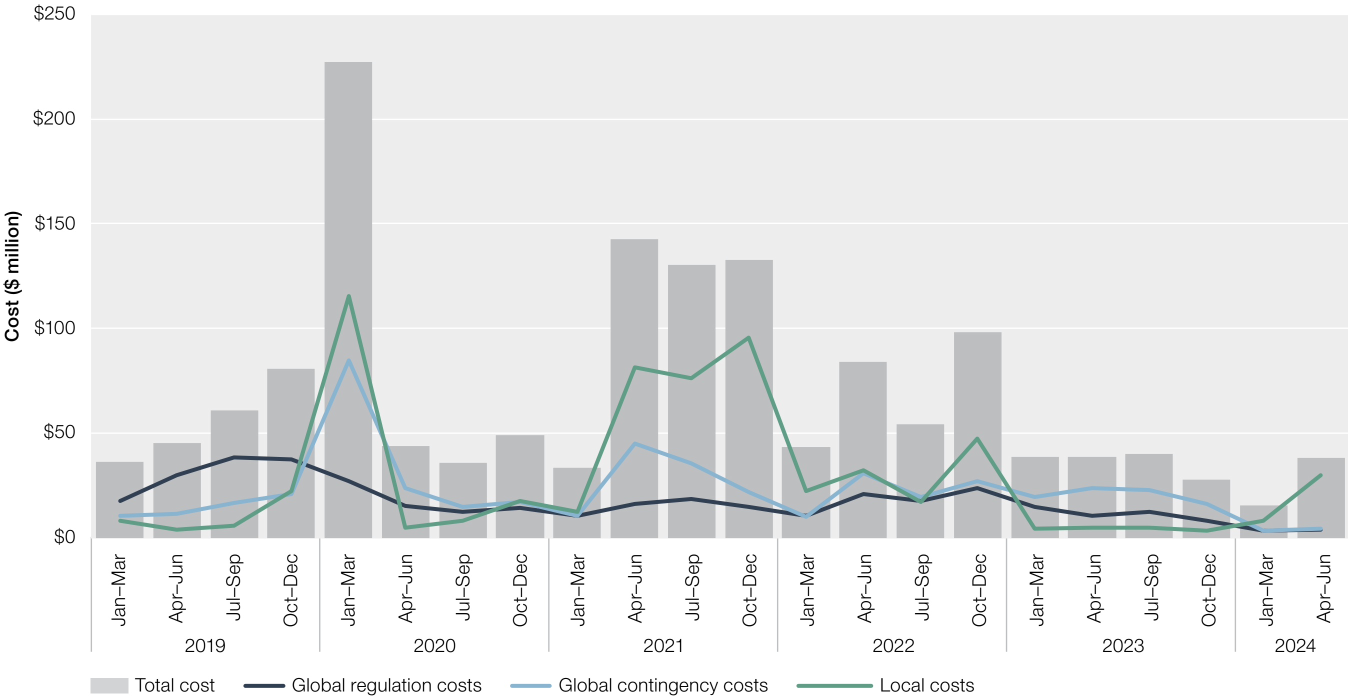
Fewer participants operate in FCAS markets than in the wholesale electricity market, but participation is growing – just over 60 participants are currently registered to provide services.[43] On 30 June 2024, 15 participants were providing FCAS in Queensland, 18 in NSW, 17 in Victoria, 16 in South Australia and 3 in Tasmania. New generation technologies, such as batteries, demand response and virtual power plants, offer FCAS services. Some of these new entrants account for only a small proportion of FCAS trades and others such as batteries have displaced incumbent providers.

FCAS costs fell by 47% in 2023–24 compared with 2022–23 (Figure 2.25). The fall in costs was observed in both global and local costs. Global costs in 2024 for both regulation and contingency were materially lower than in previous years. Local costs were also lower compared with previous years, except in the April to June 2024 quarter. This was driven by local costs in Queensland – FCAS prices increased in May to support Queensland generation flowing into NSW following extreme high price events.

42 AEMO, 2023 System Strength Report, Australian Energy Market Operator, December 2023.

43 AEMO, Registered Participants, Australian Energy Market Operator, accessed 22 August 2024.

Figure 2.25 Frequency control ancillary service costs



Note: Record FCAS costs in the January to March quarter 2020 were due to high local costs in South Australia when it was islanded for several weeks following the loss of the Heywood interconnector. In January 2020 bushfires also drove high prices across the NEM.

Source: AER; AEMO (data).

Very fast raise and lower FCAS markets were introduced on 9 October 2023. Since then, 1-second FCAS costs have made up a large portion of contingency raise costs; 6-second and 60-second costs have declined materially. One-second contingency raise costs accounted for $13.5 million (84%) of raise costs between January and March 2024 and $6.7 million (60%) between April and June 2024. One-second FCAS costs in contingency lower markets have not seen similar growth, accounting for less than 1% of contingency lower costs.

2.13.3 Other system security market features

System security services previously provided by synchronous generators can be replicated by other technologies and the design of the NEM.

For example, synchronous condensers are machines specially built to supply only reactive power and can replicate system security services. They can also include a flywheel with a large amount of stored momentum to provide inertia. In South Australia, 4 synchronous condensers, installed by ElectraNet, started operating in October 2021 to provide system strength and inertia. In the event of a disturbance on the network, the synchronous condensers provide some electrical inertia to ride through the fault. Under the new system strength framework, network service providers are required to identify most efficient solution for meeting minimum system strength requirements in a proactive manner by addressing the need before a shortfall arises.[44]

Large-scale grid batteries with advanced inverter technology are also a potential source of system security.[45] Batteries can also improve the utilisation of new and existing transmission lines. AEMO has directly contracted several large-scale grid batteries to provide system strength services.[46]

Strategic construction of transmission interconnectors will also support system security in the NEM, reducing the risk of a region being islanded and increasing inter-regional transfer capabilities.

44 AEMC, Efficient management of system strength on the power system, Australian Energy Market Commission, 21 October 2021, accessed 16 September 2024.

45 AEMO, Voluntary Specification for Grid-forming Inverters, Australian Energy Market Operator, May 2023.

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

2.13.4 AEMO use of directions

AEMO has powers to direct market participants to take relevant actions to maintain or restore power system security or system strength. Directions are intended as a last resort intervention when the market has not delivered the necessary requirements.

The energy transition is necessitating more frequent directions from AEMO to maintain power system security. In South Australia, directions to market participants to take action to maintain or restore power system security have been in place for a substantial amount of time for the past several years.[47] In March 2024, new rules improving the transparency of AEMO's power to issue directions were published, alongside a new requirement for AEMO to report annually on the steps it will take to manage security through the transition.

2.14 Market reforms and policy developments

In 2021, significant market reforms were introduced to support the NEM's transition to a low carbon future. In the past year, market reform and policy development has continued to support the transition, following the inclusion of a new emissions reduction objective in the National energy objectives in June 2023.

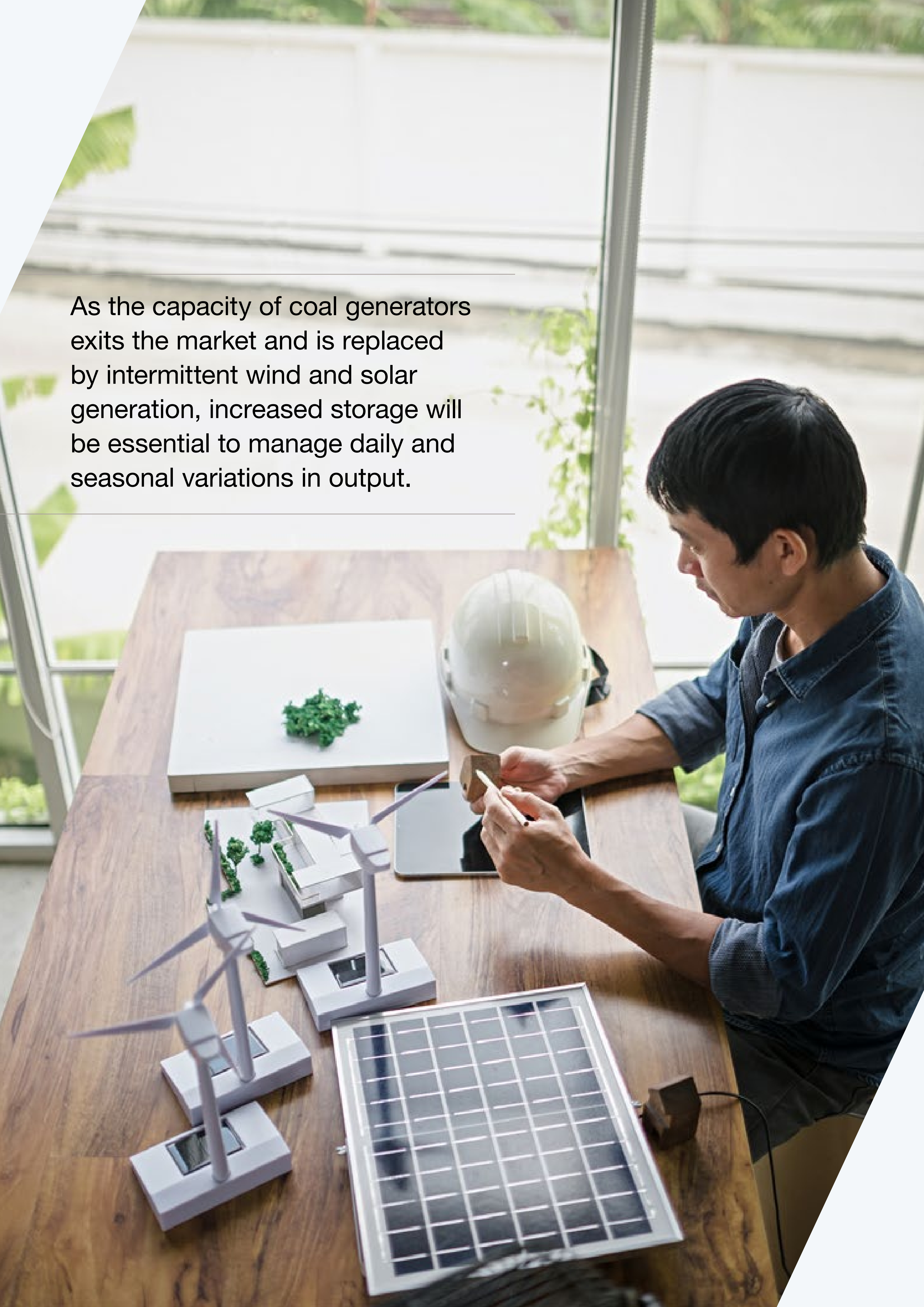
Following consultation throughout 2023, the Australian Government began launching its Net Zero Plan in 2024. This is now a legislated, economy-wide plan to achieve net zero emissions in Australia by 2050.[48] The Net Zero Plan builds on the Australian Government's Capacity Investment Scheme, a revenue-underwriting mechanism to unlock investment in clean, dispatchable power.[49] In November 2023, the Australian Government announced expansion of the scheme to deliver 9 GW of dispatchable capacity and 23 GW of variable capacity nationally, representing a total $67 billion in investment.[50]

Throughout 2023 and 2024, the Australian Government consulted with industry and state and territory jurisdictions to design the Capacity Investment Scheme. The first competitive tender was launched in May 2024. Since then, 1.1 GW of dispatchable capacity has been made available.[51] The remaining 30.9 GW of total capacity will be rolled out in stages via competitive tenders approximately every 6 months, to 2027. The additional capacity is anticipated to help fill reliability gaps as aging coal-fired generation exits the market and aims to deliver the Australian Government's target of 82% renewable electricity by 2030.

Unlocking investment in clean, dispatchable energy will support Australia's greenhouse gas emissions reductions target to achieve net zero (or lower) by 2050.[52] In June 2024, the AEMC released indicative targets to reduce greenhouse gas emissions at Australian, state and territory levels across electricity and gas sectors.[53] These include interim targets for Australian jurisdictions to reach by 2030 and 2035 to 2045, with net zero (or lower) to be achieved by 2050.

The AEMC guide includes, by jurisdiction, several supply-side and demand-side strategies and targets likely to contribute to reducing emissions. Key target areas include renewable energy uptake, energy storage or firming of renewables, electrification of transport and of domestic and industrial gas consumption and demand response.[54] The greenhouse gas emission reduction targets have been officially incorporated into the National Electricity Rules and national energy objectives; this is a significant development enabling formal consideration of emissions reduction within the energy sector.[55]

47 AEMO, Quarterly Energy Dynamics Q2 2024, Australian Energy Market Operator, July 2024.
48 Australian Government, Net Zero, accessed 22 August 2024.
49 DCCEEW, Capacity Investment Scheme to power Australian energy market transformation, Department of Climate Change, Energy, the Environment and Water, December 2022
50 Australian Government, Energy and Climate Change Ministerial Council Meeting Communique – 24 November 2023.
51 Australian Government, Capacity Investment Scheme, accessed 22 August 2024.
52 Australian Government, Net Zero, accessed 22 August 2024.
53 AEMC, Targets statement for greenhouse gas emissions, Australian Energy Market Commission, accessed 25 September 2024.
54 AEMC, Emissions targets statement under the national energy laws, June 2024, Australian Energy Market Commission, accessed 25 September 2024.
55 AEMC, Transformative changes as emissions reduction included in national energy rules, Australian Energy Market Commission, 1 February 2024.



As the capacity of coal generators exits the market and is replaced by intermittent wind and solar generation, increased storage will be essential to manage daily and seasonal variations in output.

2.15 Compliance and enforcement activities

The AER's compliance and enforcement work ensures that important protections are delivered, and rights are respected. It gives consumers and energy market participants confidence that energy markets are working effectively and in their long-term interests. This ensures consumers can participate in market opportunities as fully as possible and are protected when they cannot do so.

Compliance work helps to proactively encourage market participants to meet their responsibilities and enforcement action is an important tool when breaches occur.

Each year, the AER identifies and publishes a set of compliance and enforcement priorities, some of which relate to participants in the NEM.

The AER's key 2022–23 priority for wholesale electricity markets was to support power system security and an efficient wholesale electricity market by focusing on generators' compliance with offers, dispatch instructions, bidding behaviour obligation and providing accurate and timely capability information to AEMO.

It is critical that generators provide accurate and timely information about capacity and availability to AEMO, including for system services such as frequency control ancillary services (FCAS) and for AEMO's project assessments of system adequacy (PASA), which assesses the adequacy of electricity supply to meet demand.

Since July 2023 the AER has undertaken a range of actions to support system operation. These include:

- reviewing self-forecasting data and its potential impact on wholesale market bidding behaviour
- commencing a review of various compliance guidance to identify updates required due to recent market reforms
- issuing compliance messaging to industry to support AEMO's management of risks identified in its *Summer operations 2023–24 work program*
- obtaining 2 important court judgements – the Pelican Point judgement and AGL FCAS judgement.

Pelican Point judgment

On 20 September 2023, the Federal Court found that Pelican Point Power Limited (Pelican Point) breached the Electricity Rules by failing to disclose to AEMO the full capacity of its Pelican Point Power Station that was available during heatwave conditions in South Australia on 8 February 2017. Specifically, it found that Pelican Point failed to comply with its legal obligation to disclose short-term availability information to AEMO.

Pelican Point was ordered to pay a pecuniary penalty of $900,000 for not disclosing its short-term availability and not updating AEMO of changes to its medium-term availability. The AER and Pelican Point agreed that Pelican Point pay $950,000 in costs. The AER sent a letter to industry reiterating the importance of complying with PASA obligations and calling on relevant scheduled generators and market participants to assess and plan for the medium-term and short-term operation of the energy system and submit details of physical plant capability available.

AGL FCAS judgment

On 30 October 2023, the Federal Court ordered that operators of AGL's Bayswater and Loy Yang power stations pay penalties totalling $6 million for failing to comply with dispatch instructions given to them by AEMO in relation to FCAS they had offered, and were paid to provide, in periods between September 2018 and August 2020. The finding reinforced the importance of market participants ensuring effective internal lines of communication about the status of any plant settings affecting plant ability to deliver FCAS, proactively monitoring plant performance in response to frequency deviations and having comprehensive processes and procedures in place to support compliance.

The AER has also supported AEMO's work in improving overall compliance with supervisory control and data acquisition (SCADA) infrastructure. In March 2024, AEMO published a detailed incident report covering 18 incidents that occurred throughout the NEM between January 2021 and November 2023. SCADA infrastructure is a system of software and hardware elements that enables plant operators, owners and other stakeholders an inside, real-time look at what's happening in a plant, facility or process. It provides AEMO and transmission network service providers with data on the status of transmission, load and generator equipment and facilitates delivery of dispatch instructions. The AER has written to the Energy Networks Association to encourage ongoing commitment from network service providers to work with AEMO to enhance overall SCADA system resilience and reliability and will continue to assess potential individual breaches with a focus on identifying systemic issues.

Other wholesale electricity compliance and enforcement activities

During 2023–24 the AER also:

- reviewed generator compliance programs, engaging certain stakeholders to review their compliance frameworks and make any necessary improvements
- initiated proceedings in the Federal Court against Callide Power Trading Pty Ltd for failing to comply with its performance standards for the Callide C power station
- issued letters to system strength service providers setting out compliance approaches for maintaining a stable power system
- received payment from CS Energy totalling $67,800 for an infringement notice issued for an alleged breach of the National Electricity Law for operating a generating system without the required regulatory approval.

More detail on the AER's compliance and enforcement work is outlined in the *Annual compliance and enforcement report 2023–24.*[56]

56 AER, AER Annual compliance and enforcement report 2023–24, Australian Energy Regulator, July 2024.

3 Electricity networks

Australia's electricity infrastructure consists of transmission and distribution networks, as well as smaller standalone regional systems. Together, these networks have traditionally transported electricity from generators to residential, commercial and industrial customers. However, Australia's energy system is rapidly changing and affecting how electricity networks are used. Technological developments and consumer preferences are leading us away from a supply-side orientated system to one that needs to support two-way flows of electricity, and away from centralised generation to distributed generation. This chapter covers the 21 electricity network service providers regulated by the Australian Energy Regulator (AER), which are located in all Australian states and territories except Western Australia.

3.1 Snapshot

In 2024, the AER finalised revenue determinations for transmission network service provider TasNetworks (Tasmania) and distribution network service providers Ausgrid (NSW), Endeavour Energy (NSW), Essential Energy (NSW), TasNetworks (Tasmania), Evoenergy (ACT) and Power and Water Corporation (Northern Territory). These determinations set target revenue controls through to 30 June 2029.

Across all transmission and distribution network service providers, over the 12-month period to 30 June 2023:

- $12.5 billion in revenue was collected for delivering core regulated services,[57] 2.9% less than in the previous year (section 3.9).
- $6.8 billion was invested in capital projects, 20% more than in the previous year and the most since 2014 (section 3.13).

57 Prescribed transmission services for transmission network service providers and standard control services for distribution network service providers.

- Regulated asset bases grew by $1.7 billion (1.5%), driven by investment on Transgrid's (NSW) and ElectraNet's (South Australia) transmission networks. Asset bases are forecast to grow at an accelerated rate as several major transmission projects progress (sections 3.11 and 3.13.6).
- $4.1 billion was spent on operating costs, 4.1% more than in the previous year and the most since 2019 (section 3.14.1).
- The average customer experienced 8% fewer unplanned interruptions to supply than in the previous year (section 3.16.4).[58]
- The average customer experienced 25% fewer unplanned minutes off supply than in the previous year (section 3.16.4).[59]
- Improvements in network reliability were driven by the decrease in the frequency and severity of major weather events (section 3.16.4).

3.2 Electricity network characteristics

Transmission networks transport high-voltage electricity from large-scale generators located away from population centres to consumers situated in major load centres. Electricity is injected from points along the transmission grid into the distribution networks, where the voltage is stepped down to safely deliver electricity to residential homes and commercial and industrial premises. Distribution networks consist of poles and wires, substations, transformers, switching equipment, and monitoring and signalling equipment. Electricity from small-scale local generation is increasingly being injected into the distribution grid to supply consumers.

Network service providers transport and deliver electricity to consumers, but they do not sell it. Instead, retailers purchase electricity from the wholesale market and package it with network services to sell to customers (chapter 6).

Electricity networks traditionally provided a one-way transportation service to consumers. However, the role of electricity networks has evolved and technology continues to change how electricity is generated and used. Consumers are adopting innovative ways to reduce and manage demand from the grid, investing in what the industry collectively refers to as 'consumer energy resources'. Many small-scale generators such as rooftop solar systems are now embedded within distribution networks, resulting in two-way electricity flows along the networks. Consumers with rooftop solar systems are able to source electricity from the distribution network when they need it and sell the surplus electricity they generate at other times. Electricity generated using rooftop solar systems is also increasingly being stored using battery storage systems. Due to the versatility and falling cost of battery technology, and the need to better store excess solar generation for use later in the day, the use of batteries is expected to continue growing over the coming years.

3.3 Geography

Electricity networks in Queensland, New South Wales (NSW), Victoria, South Australia, Tasmania and the Australian Capital Territory (ACT) create an interconnected grid forming the National Electricity Market (NEM). The NEM transmission grid has a long, thin, low-density structure, reflecting the dispersed locations of electricity generators and demand centres. The 5 state-based transmission networks[60] are linked by cross-border interconnectors. Three interconnectors (Queensland–NSW, Heywood (Victoria–South Australia) and Victoria to NSW) are owned by the state governments and 3 interconnectors (Directlink, Murraylink and Basslink) are privately owned (Figure 3.2).
The transmission network also directly supplies electricity to large industrial customers, such as rail companies, mines and mineral processing facilities.

58 After removing the impact of interruptions to supply deemed to be beyond the control of the network service providers.
59 After removing the impact of interruptions to supply deemed to be beyond the control of the network service providers.
60 Transgrid operates the high voltage transmission network in both NSW and the ACT.

The transmission grid connects with 13 distribution networks.[61] Consumers in Queensland, NSW and Victoria are served by multiple distribution network service providers, each of which owns and operates its network within a defined geographic region. Consumers in South Australia, Tasmania and the ACT are served by single distribution network service providers operating within each jurisdiction (Figure 3.1 and Figure 3.2).

The Northern Territory has 3 separate distribution networks – the Darwin–Katherine, Alice Springs and Tennant Creek systems – all owned by Power and Water Corporation (Power and Water). The 3 networks are classified as a single distribution network for regulatory purposes but do not connect to each other or the NEM.[62] The AER regulates all major network service providers in the NEM, other than the Basslink interconnector linking Victoria and Tasmania.[63] It also regulates the Northern Territory's distribution network.

In September 2024, distribution network service provider Powercor was granted a licence by the Essential Services Commission (Victoria) for a licence to plan, design and build transmission infrastructure within its current distribution footprint across western, central and northern parts of Victoria. Powercor can now deliver transmission infrastructure, including new terminal stations and 220 kilovolt powerlines, to connect customer-related projects to the grid.[64]

Several additional interconnectors have regulatory approval and are either currently under development or highly likely to proceed. These include:

- Project EnergyConnect – a new 330 kilovolt double-circuit interconnector between South Australia and NSW, with a new 220 kilovolt double-circuit line to Victoria
- incremental upgrades to the transfer capacities of the existing Victoria to NSW (VNI Minor) and Queensland–NSW (QNI Minor) interconnectors (section 3.13.6).

The combined value of the regulatory asset bases (RABs) for the electricity networks regulated by the AER is around $116 billion.[65] This comprises 7 transmission networks valued at $26.1 billion and 14 distribution networks valued at $89.9 billion. In total, the networks consist of more than 800,000 kilometres of line and deliver electricity to more than 10.9 million customers.

The AER does not regulate electricity networks in Western Australia, where the Economic Regulation Authority (ERA) administers state-based arrangements. Western Power (owned by the WA Government) is the state's principal network, covering the populated south-west region, including Perth. Another state-owned corporation – Horizon Power – services Western Australia's regional and remote areas.[66]

61 Some jurisdictions also have small networks that serve regional areas.

62 For this reason, any text or charts within this chapter that refer to 'whole of NEM' do not include Power and Water (NT).

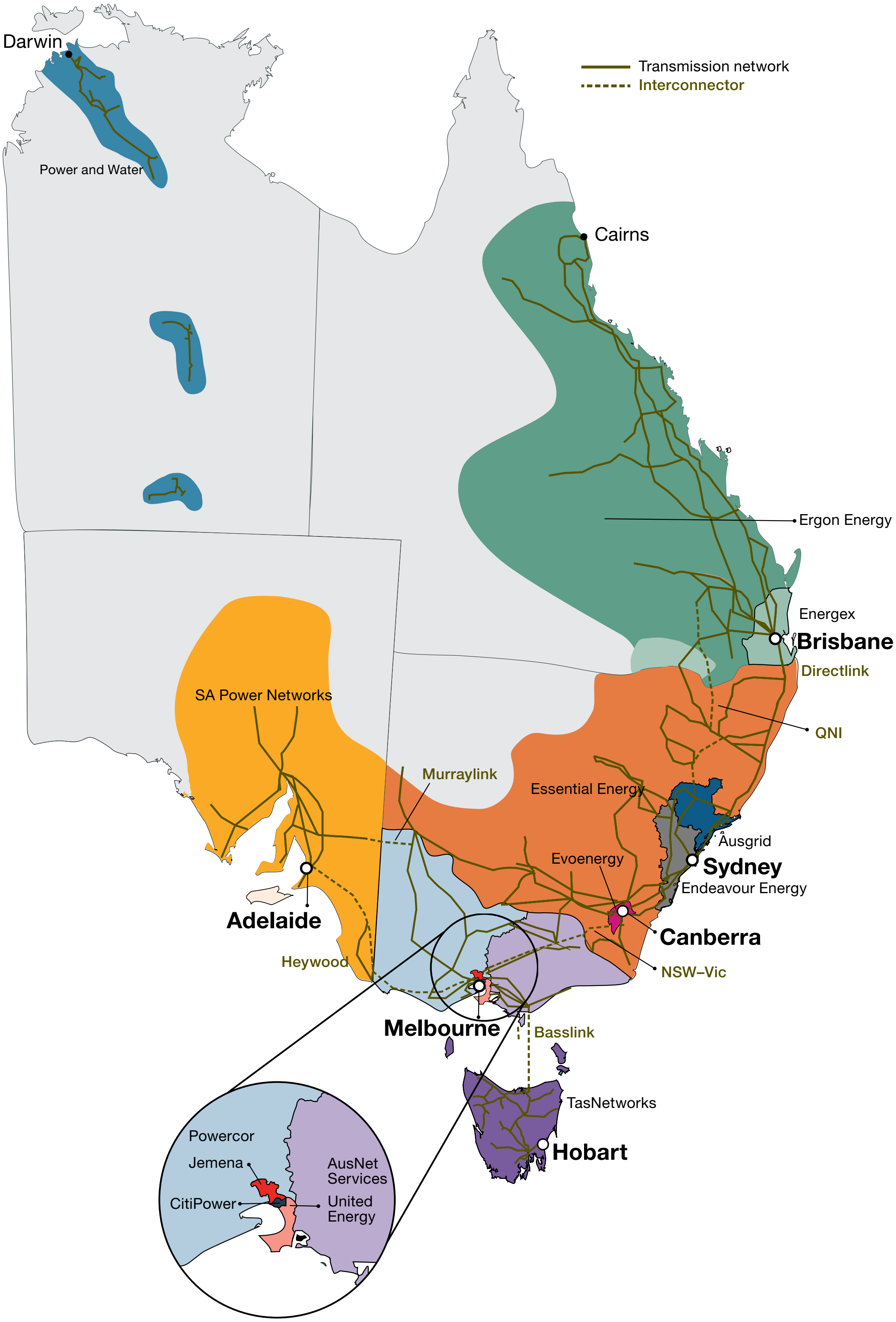
63 On 19 May 2023, APA Group lodged an application to the AER seeking to convert Basslink's network services from market network services to prescribed transmission services. The AER will assess APA Group's request to convert Basslink concurrently with undertaking the 1 July 2025 to 30 June 2030 revenue determination process (Basslink - Determination 2025–30).

64 Powercor, New transmission provider to deliver more choice and better service to Victoria, media release, Powercor, 25 September 2024, accessed 20 October 2024.

65 RABs capture the total economic value of assets that are providing network services to customers. These assets have been accumulated over time and are at various stages of their economic lives.

66 For further information, see the WA Department of Treasury and ERA websites.

Figure 3.1 Electricity networks regulated by the AER



Note: QNI is the Queensland–NSW Interconnector. The AER does not currently regulate the Basslink Interconnector.
Source: AER.

Figure 3.2 Electricity networks regulated by the AER – transmission

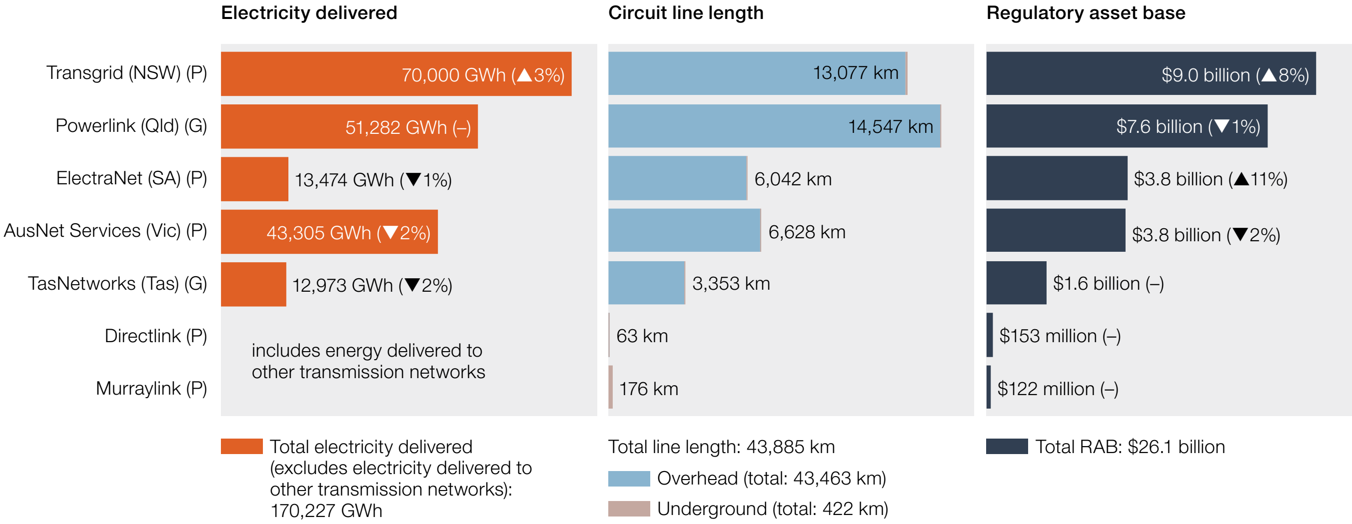
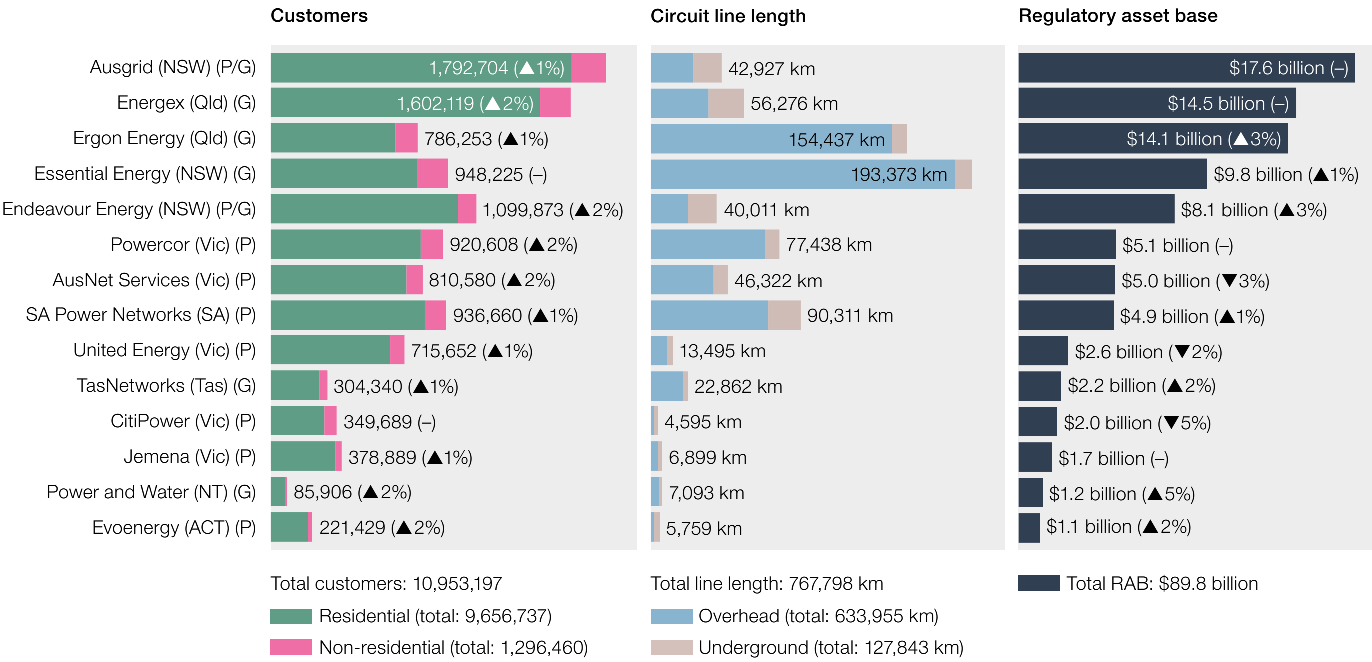


Figure 3.3 Electricity networks regulated by the AER – distribution



Note: (G): state government owned. (P): privately owned. GWh: gigawatt hours. km: kilometres. % values represent change from previous year. Regulatory asset base is adjusted to June 2023 dollars. Line length and regulatory asset base are as at 30 June 2023 (31 March 2023 for AusNet Services transmission). Electricity delivered is for the 12-month period to 30 June 2023 (year to 31 March 2023 for AusNet Services). Electricity delivered is a measure of total energy transported through the transmission networks. The information reported includes electricity transmitted to distribution networks, pumping stations and directly connected end users. Electricity delivered to other transmission networks is included in the data for individual transmission network but has been excluded from the total. Customer numbers, line length and asset base are as at 30 June 2023 for the distribution networks. For regulatory purposes, Northern Territory transmission assets are treated as part of the distribution system.

Source: AER revenue determinations and economic benchmarking regulatory information notices (RINs).

3.4 Network ownership

Australia's electricity networks were originally government owned, but 3 jurisdictions have now either partly or fully privatised the assets. Ownership of the partly or fully privatised networks in NSW, Victoria and South Australia is concentrated among relatively few entities. These entities include Hong Kong's Cheung Kong Infrastructure Holdings (CKI Group) and Power Assets Holdings, Singapore Power International and State Grid Corporation of China.

Electricity networks in Queensland, Tasmania, the Northern Territory and Western Australia remain wholly government owned, as does Essential Energy (NSW). In 2016, the Queensland Government merged the state-owned distribution service providers Energex and Ergon Energy under a parent company, Energy Queensland.

In some jurisdictions, ownership of electricity networks overlaps with other electricity industry segments. For example, Queensland's state-owned Ergon Energy provides both distribution and retail services in regions outside south-east Queensland. In such cases, ring-fencing arrangements are in place to ensure the network service providers do not use revenue from regulated services to cross-subsidise their unregulated products (section 3.8.3).

3.5 How network prices are set

Electricity networks are capital intensive and require significant investment in order to build and operate the necessary infrastructure. This gives rise to a natural monopoly industry structure, where having a single network service provider is more efficient than having multiple providers offering the same service.

Because monopolies face no competitive pressure, they have opportunities and incentives to charge higher prices than they could charge in a competitive market. This monopolistic environment poses risks to consumers, given network charges currently make up as much as 46% of a residential electricity bill (Figure 6.2 in chapter 6). To counter these risks, the role of the AER as the economic regulator is to replicate the incentives that network service providers would face in a competitive market (that is, to control costs, invest prudently and efficiently and not overcharge consumers).

On 1 February 2024, the National Electricity Rules were amended to include 'changes in Australia's greenhouse gas emissions' as a class of market benefit.

3.5.1 Regulatory objective and approach

One of the AER's key objectives is to deliver efficient regulation of monopoly electricity and gas infrastructure while incentivising networks to become platforms for energy services (section 3.13.4).[67] This objective relates to the transformation of traditional power grids into open systems that facilitate a variety of energy services beyond just delivering electricity to retail customers. The transformation enables interactions between multiple energy producers, consumers and third parties. Examples of open systems include the management of consumer energy sources (integrating rooftop solar and battery storage), demand response programs, peer-to-peer energy trading and electric vehicle charging solutions, allowing for more flexible, decentralised energy systems. The National Electricity Law and the National Electricity Rules set out the framework that the AER administers when regulating electricity networks.

67 ACCC and AER, ACCC and AER Corporate plan 2024–25, 30 August 2024, accessed 11 September 2024.

In May 2023, Energy Ministers agreed to amend the national energy laws to incorporate an emissions reduction into the National Electricity Objective.[68] The amended National Electricity Objective seeks to promote efficient investment in, and efficient operation and use of, electricity services for the long-term interests of consumers of electricity with respect to:

- price, quality, safety and reliability and security of electricity supply
- the reliability, safety and security of the national electricity system
- the achievement of targets set by a participating jurisdiction
  - for reducing Australia's greenhouse gas emissions, or
  - that are likely to contribute to reducing Australia's greenhouse gas emissions.

On 1 February 2024, the National Electricity Rules were amended to include 'changes in Australia's greenhouse gas emissions' as a class of market benefit to be considered as part of the Integrated System Plan (ISP) (section 3.13.6) and the regulatory investment tests for transmission (RIT-T) and distribution (RIT-D) (section 3.13.5).[69]

The amended National Electricity Rules also enable electricity network service providers to include expenditure that contributes to achieving emissions reduction targets in their revenue proposals.

Together, these amendments to the National Electricity Law and National Electricity Rules provide greater clarity to Australia's energy market bodies[70] with regards to transitioning Australia's energy system to net zero by 2050.

The regulatory framework and toolkit used by the AER to meet its objectives is wide ranging (Box 3.1), but one of its fundamental roles is to set the maximum revenue that a network service provider can collect from customers for delivering a safe, reliable and secure electricity service. The AER fulfils this role via a periodic revenue determination process, in which it assesses the amount of revenue a prudent network service provider would need to cover its efficient costs and address important emerging issues such as network cybersecurity, climate resilience, integration of consumer energy resources, and digitalisation. Network revenues are capped at the determined level for the duration of the regulatory period, which is typically 5 years.[71]

Network service providers operate within a dynamic and continually evolving landscape. For example, the current cost-of-living crisis has put greater pressure on network service providers to further manage the costs, timing and need for new investments.

As part of the determination process, a network service provider submits a proposal to the AER setting out the amount of revenue it considers necessary to cover the costs of providing a safe and reliable supply of electricity. The AER assesses the proposal and makes a judgment on the reasonableness of the service provider's forecasts and the prudency and efficiency of its proposed expenditure.

If the AER is not satisfied the network service provider's proposal is in the long-term interests of consumers, it will request further information or a clearer business case. Subsequently, the AER may amend the amount of revenue proposed to ensure the approved cost forecasts are efficient. Proposals that are developed through genuine engagement with consumers and meet the AER's expectations for forecast expenditure, depreciation and tariff structure statements are more likely to be largely or wholly accepted at the draft decision stage.

In conducting its assessment of a network service provider's proposal, the AER draws from a range of inputs, including expenditure forecasts, benchmarking and revealed costs from past expenditure. It engages closely with network service providers and stakeholders from early in the process, including before the network service provider lodges a formal proposal (section 3.7).

68 The National Electricity Objective (NEO), National Energy Retail Objective (NERO) and the National Gas Objective (NGO) govern and guide the Australian Energy Market Commission (AEMC) in all of its activities under the relevant national energy legislation.

69 AEMC, Harmonising the national energy rules with the updated national energy objectives (electricity), Australian Energy Market Commission, 1 February 2024, accessed 3 April 2024.

70 The Australian Energy Market Commission (AEMC), the Australian Energy Market Operator (AEMO) and the Australian Energy Regulator (AER) and Western Australia's Economic Regulation Authority (ERA).

71 While a 5-year regulatory period helps to create a stable investment environment, it poses risks of locking in inaccurate forecasts. The National Electricity Rules include mechanisms for dealing with uncertainties – such as cost pass-through triggers and a process for approving contingent investment projects – when costs were not clear at the time of the revenue determination.

Capital expenditure – the money required to build, maintain or improve the physical assets needed to provide core regulated services – generally accounts for the most significant component of a network service provider's revenue requirement. To form a view on the reasonableness and efficiency of a network service provider's capital expenditure forecast, the AER assesses the drivers of the proposed expenditure. Although the AER is responsible for determining the total capital expenditure forecast, it does not determine forecasts for individual capital expenditure drivers, programs or projects. Once the total capital expenditure forecast has been determined, the network service provider must prioritise their program and deliver services at the lowest possible cost.

Unlike capital expenditure, a network service provider's operating costs are largely recurrent and predictable. As such, the AER begins its assessment by reviewing the actual operating expenditure incurred in the (then) current regulatory period. The AER uses several assessment techniques to determine whether this 'base' expenditure is efficient before applying a rate of change to account for forecast changes in prices, productivity and the outputs the service provider is required to deliver. The AER may also add (or subtract) step changes for any other efficient costs not captured in the base expenditure or the rate of change.

The AER publishes guidelines on its approach to assessing capital and operating expenditure and applying incentives.[72]

Box 3.1 The AER's role in electricity network regulation

All electricity network service providers are regulated under revenue caps. Every 5 years we determine the total allowed revenue a network service provider can collect from its customers. Each year network service providers set their prices to target earning the maximum revenue allowed under the revenue cap. Alongside this central role, we undertake broader regulatory functions, including:

- assessing distribution network charges each year to ensure they reflect underlying costs and do not breach the determined revenue cap
- providing incentives for network service providers to improve their performance in ways that customers value
- assessing whether any additional costs not anticipated at the time of our final determination should be passed on to customers (section 3.9.3)
- publishing information on the performance of network service providers, including benchmarking and profitability analysis
- assessing whether network service providers properly evaluate the merits of new investment proposals
- promoting and enforcing compliance with regulations, including connections policies and ring-fencing (section 3.8.3).

We also help implement reforms to improve the quality of network regulation and achieve better outcomes for energy customers, such as:

- adopting a more consumer-centric approach to setting network revenues (section 3.7)
- reviewing and refining our guidelines and incentive schemes to ensure they remain relevant and fit for purpose
- reviewing how rates of return and taxation allowances are set for energy networks (section 3.12).

We also carry out state-level regulatory functions in both Queensland and NSW. State-based arrangements aim to coordinate the timing of building network infrastructure with renewable generation while simultaneously managing issues associated with social licence, employment and supporting First Nations people. The newly conferred functions allow the AER to use its expertise to support this aim and promote the long-term interests of consumers in those states. Under the *Electricity Infrastructure Investment Act 2020* (NSW), we make revenue determinations for network projects procured through contestable and non-contestable processes.

Under the *Energy (Renewable Transformation and Jobs) Act 2024* (Qld), the responsible ministers may ask for our advice about priority transmission investments. This can include assessing whether Queensland transmission network Powerlink's proposed expenditure for a network project is prudent and efficient.

72 AER, Networks guidelines, schemes, models and reviews, Australian Energy Regulator, accessed 21 February 2024.

3.5.2 Building blocks of network revenue

The AER uses a 'building block' approach to assess a network service provider's revenue needs. Specifically, it forecasts how much revenue the service provider will need to cover:

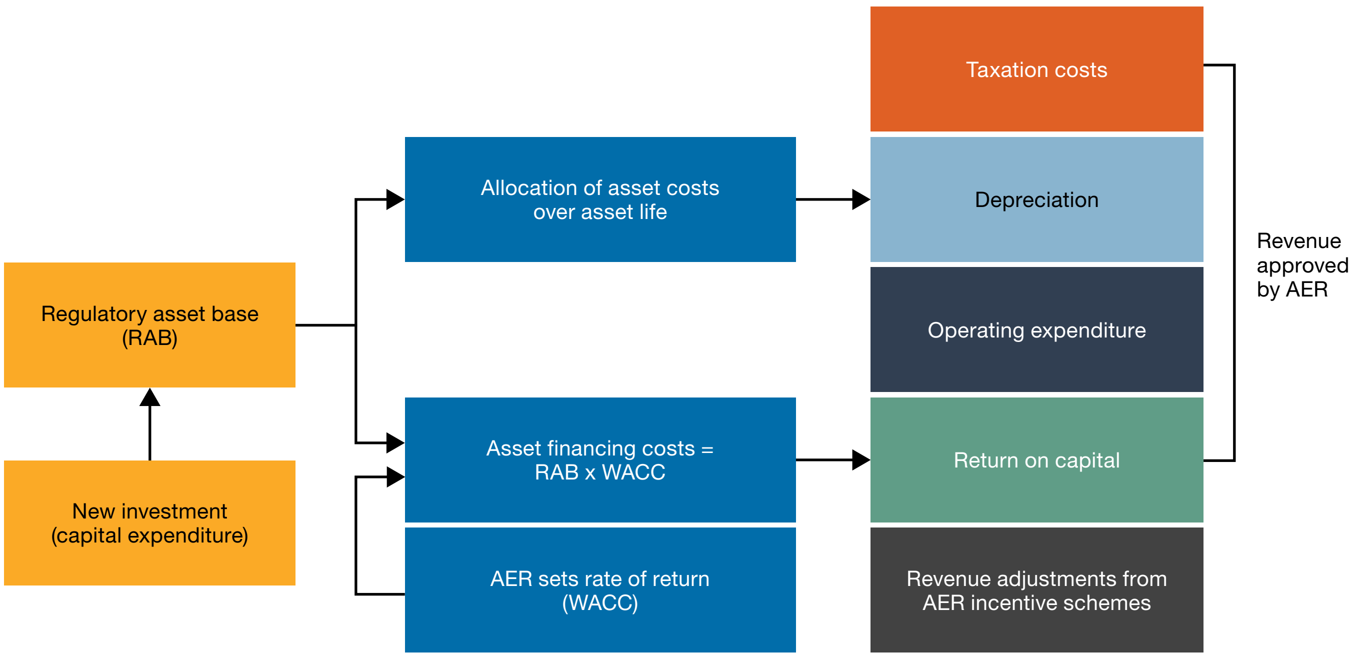
- a return to the investors that fund its assets and operations
- efficient operating and maintenance costs
- asset depreciation costs
- taxation costs.

The AER also makes revenue adjustments for over- or under-recovery of revenue made in the past and for rewards or penalties earned through any applicable incentive schemes.

Network service providers are entitled to collect revenue to cover their efficient costs each year, but this revenue does not include the full cost of investment in new assets installed throughout the year. Network assets have a long life and investment costs are recovered over the economic life of the assets, which may run to several decades. The amount recovered each year is called 'depreciation', and it reflects the lost value of network assets each year through wear and tear and technical obsolescence (Figure 3.4).

The regulatory asset base (RAB) represents the total remaining economic value of the assets that are used to provide network services to customers, to be recovered through depreciation over time. Depreciation is the amount provided so capital investors recover their investment over the economic life of the asset (return of capital). All things being equal, a higher RAB would increase both the return on capital and depreciation (return of capital) components of the maximum allowed revenue calculation.

Figure 3.4 Forecasting electricity network revenues



Note: AER: Australian Energy Regulator. RAB: regulatory asset base. WACC: weighted average cost of capital.
Revenue adjustments from incentive schemes encourage network service providers to efficiently manage their operating and capital expenditure, improve services provision to customers and adopt demand management schemes that avoid or delay unnecessary investment.

Source: AER.

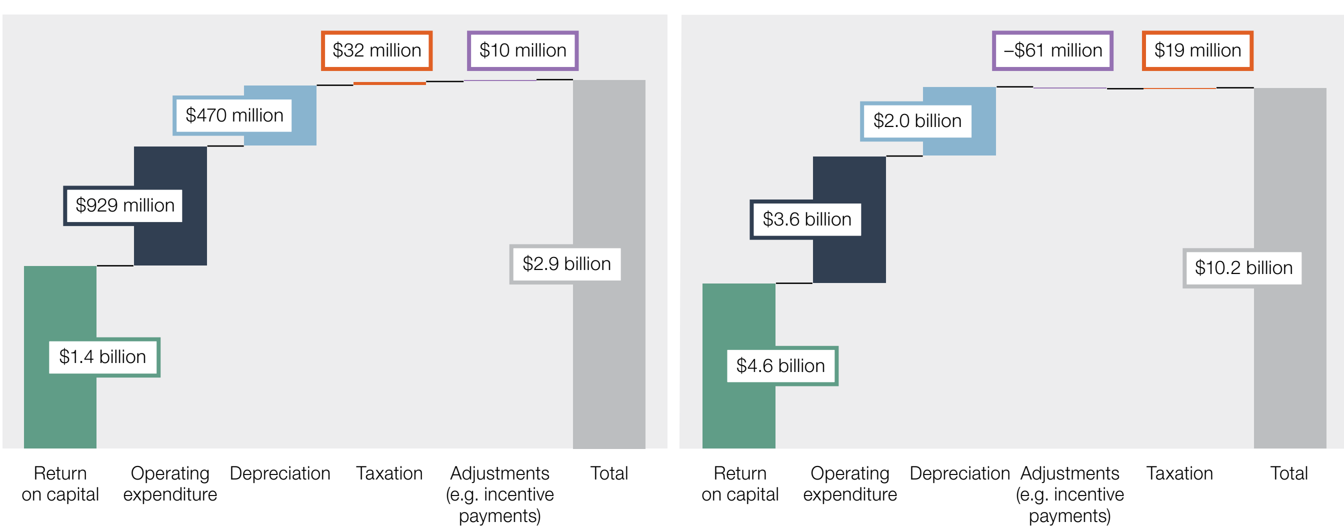
Additionally, the shareholders and lenders that fund these assets require a return on their investment. The AER sets the allowed rate of return (also called the weighted average cost of capital (WACC)) (section 3.12). The size of this return depends on:

- the value of the network's RAB
- the allowed rate of return that the AER allows based on the forecast cost that a benchmark efficient entity would incur in funding those assets through equity and debt.[73]

Overall, the return on capital takes up the largest share of network revenue, accounting for 45% of total revenue across all networks (Figure 3.5).

Sections 3.11 to 3.14 examine major cost components in more detail.

Figure 3.5 Composition of average annual electricity network revenue



Note: Composition of average annual electricity network revenue – current periods as at 1 July 2024. All data are adjusted to June 2023 dollars.
Source: Post-tax revenue modelling used in AER determination process.

3.6 Recent AER revenue determinations

In April 2024, the AER finalised revenue determinations for transmission network service provider TasNetworks (Tasmania) and distribution network service providers Ausgrid (NSW), Endeavour Energy (NSW), Essential Energy (NSW), TasNetworks (Tasmania), Evoenergy (ACT) and Power and Water (Northern Territory).

The determinations set target revenue controls for the 5-year period ending 30 June 2029 and seek to balance affordability with providing the necessary expenditure that will support the changing nature of the electricity system. In making the determinations the AER addressed emerging issues such as network cybersecurity, climate resilience, integration of consumer energy resources and digitalisation, as well as the introduction of the new emissions reduction objective (Table 3.1).

73 The return on equity is the return that shareholders of the business will require for them to continue to invest. The return on debt is the interest rate that the network business pays when it borrows money to invest.

Table 3.1 Recent AER electricity network revenue determinations

Network service provider	Revenue (forecast)	Capital expenditure (forecast)	Operating expenditure (forecast)
TasNetworks (Tasmania) (transmission)	$818m (▲5%)	$278m (▲53%)	$201m (▲16%)
Ausgrid (NSW)	$7.9b (▲1.7%)	$3.2b (▲4.3%)	$2.3b (▼15%)
Endeavour Energy (NSW)	$5.0b (▲1.7%)	$1.8b (▼10%)	$1.4b (▼13%)
Essential Energy (NSW)	$5.6b (▲1.4%)	$2.6b (▼3.2%)	$2.2b (▲11%)
TasNetworks (Tasmania) (distribution)	$1.8b (▲29%)	$701m (▼6%)	$520m (▲1.5%)
Evoenergy (ACT)	$819m (▲6%)	$501m (▲39%)	$351m (▲3.4%)
Power and Water (Northern Territory)	$1.0b (▲26%)	$546m (▲41%)	$372m (▼2.4%)

Note: All revenue and expenditure data are adjusted to June 2023 dollars. Changes in revenue and expenditure are in relation to forecasts from the previous regulatory periods.

Source: AER estimates.

The primary driver of the increase in forecast revenues is the forecast rate of return, which is higher than the rate applied in the previous period and is reflective of the increase in inflation and the current economic environment.[74] This effectively means that the cost for network service providers to obtain the capital needed to make the required investments and operate their businesses has increased.

The relative increases in forecast revenues for both Ausgrid and Endeavour Energy were also impacted by the inclusion of significant one-off negative revenue adjustments for the 2019–24 regulatory period. These negative adjustments represented decisions made by the AER following the 2014–19 remittal decision.[75]

The drivers of higher forecast revenues were partially offset by the collective reduction in forecast operating expenditure, driven by lower actual operating expenditure in recent years due to improving efficiencies.

74 The rate of return is a nominal rate of return unless stated otherwise.

75 In 2015, the AER published final decisions on the 2014–19 revenue determinations for Ausgrid, Endeavour Energy, Essential Energy and Evoenergy (then ActewAGL). All 4 network service providers sought merits review of the AER's final decisions. The Australian Competition Tribunal remitted the decisions to the AER to be remade.

3.7 Refining the regulatory approach

The regulatory framework is not static, with the regulatory process increasingly focusing on how network service providers engage with their customers in shaping regulatory proposals.

In December 2021, the AER published the *Better Resets Handbook – Towards consumer-centric network proposals* (the Handbook). The Handbook aims to encourage network service providers to develop high-quality proposals through genuine engagement with consumers and that meet the AER's expectations. This will lead to a number of benefits, including regulatory outcomes that better reflect the long-term interests of consumers. In May 2024, the AER published an updated version of the Handbook to include minor changes to reflect the addition of the emissions reduction objective to the existing National Energy Objectives.[76]

The Handbook outlines what the AER expects should be included in a high-quality, consumer-centric regulatory proposal. Regulatory proposals that are developed through genuine engagement with consumers and meet the AER's expectations for forecast expenditure, depreciation and tariff structure statements are more likely to be largely or wholly accepted at the draft determination stage, creating a more efficient regulatory process for all stakeholders.

The Handbook is also expected to provide many other benefits, including improved relationships and understanding between network service providers and the consumers they serve, greater trust between all parties in regulatory processes, and the creation of new ideas and regulatory approaches that benefit both consumers and service providers.

Another key resource in promoting the interests of consumers is the AER's Consumer Challenge Panel. The Panel – comprising experienced and highly qualified individuals with consumer, regulatory and/or energy expertise – provides independent input on issues of importance to consumers.
It advises the AER on:

- whether the revenue proposals submitted by network service providers are in the long-term interests of consumers
- the effectiveness of network service providers' engagement with their customers
- how consumer views are reflected in the development of network service providers' proposals.[77]

The AER was satisfied that all network service providers that were part of the 2024–29 revenue determination process demonstrated a strong commitment to engaging with customers, considering their preferences and generally meeting the expectations outlined in the Handbook.[78] Endeavour Energy (NSW) and Essential Energy (NSW) concurrently became the first network service providers to use the Handbook's 'early signal pathway', which provides an alternative process for network service providers to engage with the AER, allowing them to get earlier formal feedback on aspects of their regulatory proposal.

The AER accepted much of Endeavour Energy's and Essential Energy's proposals at the draft decision stage, including their total capital expenditure and operating expenditure forecasts.

The AER felt that the breadth and depth of engagement undertaken by Energex (Queensland) and Ergon Energy (Queensland) in preparing their 2025–30 proposals fell short of what is expected under the Handbook and was not to the standard of other recent electricity distribution resets. Both network service providers' engagement started late and was narrow in its scope as a result. The absence of meaningful and comprehensive consultation on future investment decisions also meant that the issue of affordability was unable to be addressed with consumers.[79]

76 AER, Better Resets Handbook – Towards consumer centric network proposals, Australian Energy Regulator, 30 July 2024.
77 AER, Consumer Challenge Panel, Australian Energy Regulator, accessed 21 February 2024.
78 AER, Final decision – Ausgrid electricity distribution determination 2024–29 – Overview, Australian Energy Regulator, 30 April 2024.
79 AER, Energex – Draft decision – Overview – Energex - 2025–30 distribution revenue proposal, Australian Energy Regulator, 23 September 2024. AER, Ergon Energy – Draft decision – Overview – Energex - 2025–30 distribution revenue proposal, Australian Energy Regulator, 23 September 2024.

The AER's Consumer Challenge Panel and the SA Power Networks' Consumer Advisory Board both found that SA Power Networks' (South Australia) consumer engagement largely met the expectations in the Handbook. However, both advisory groups noted that the framing of the focused discussions guided consumer preferences toward higher service levels.[80]

3.7.1 Aligning business and consumer interests

The regulatory process is complex and the process of developing regulatory proposals is led by the network service providers. In this environment, consumers and other stakeholders are often not well resourced and may find it challenging to have their perspectives heard and to assess whether a network service provider's proposal reflects their preferences. The AER and network service providers continue to trial new approaches to help consumers and other stakeholders engage in the regulatory process, for example:

- The AER publishes informative documents – including fact sheets that simplify technical language – and holds public forums.
- The AER's Consumer Challenge Panel provides an additional mechanism for consumer perspectives to be voiced and considered.
- The *Better Resets Handbook* includes a requirement for network service providers on the 'early signal pathway' to submit an independent consumer report on the development of the regulatory proposal.

Several network service providers have experimented with early engagement models to better reflect consumer preferences and perspectives in framing their regulatory proposals – such as running 'deep dive' workshops. Early engagement offers the potential to expedite the regulatory process, reducing costs for both network service providers and consumers. Effective consumer engagement can contribute to the AER accepting significant components of a network service providers' revenue proposal.

In its 2024 final decisions, the AER recognised that all network service providers undertaking the 5-year revenue determination process had demonstrated a significant step-up in consultation with customers and stakeholders. In particular, Endeavour Energy's (NSW) extensive consumer engagement was a material factor in the AER's decision to accept most of its initial proposal. The AER commended Endeavour Energy, in its final determination, for the scope of its engagement and its commitment to identifying and exploring topics for which consumers could have the most impact.[81]

Service providers are increasingly looking to maintain open and ongoing dialogue with a wide range of stakeholders and consumers throughout the regulatory period, rather than engaging intensively once every 5 years when a proposal is being developed. Consumer engagement also plays a valuable role outside of the 5-year revenue proposal process. For example, in January 2024 transmission network Transgrid (NSW) sought feedback from residents, landowners, community organisations, First Nations people, local councils and other key stakeholders about the preferred route for a proposed transmission line to be built between substations in Mount Piper and Wallerawang.[82]

The AER is not the only organisation focusing on consumer engagement. Each year, Energy Networks Australia[83] and Energy Consumers Australia[84] recognise an Australian energy network service provider that has demonstrated best practice consumer engagement. In September 2024, Endeavour Energy (NSW) was awarded the Consumer Engagement Award for 2024 for co-designing a microgrid at Bawley Point, NSW. Endeavour Energy partnered with local residents, community groups, and various government bodies in Bawley Point and Kioloa to design and deliver NSW's first community microgrid.[85]

80 AER, SA Power Networks – Draft decision – Overview – Energex - 2025–30 distribution revenue proposal, Australian Energy Regulator, 27 September 2024.

81 AER, Final decision – Endeavour Energy electricity distribution determination 2024–29 – Overview, Australian Energy Regulator, 30 April 2024.

82 Transgrid, Community has a say on preferred route for Mount Piper to Wallerawang Transmission Line Upgrade Project, 15 January 2024, accessed 17 April 2024.

83 The national industry body representing Australia's electricity transmission and distribution and gas distribution networks.

84 The independent, national voice for residential and small business energy consumers.

85 ENA, Endeavour Energy wins Energy Networks Consumer Engagement Award, Energy Networks Australia, media release, 2024.

3.7.2 Changes to revenue setting approaches

The AER frequently reviews and updates key aspects of its revenue setting approaches to ensure they remain fit for purpose.

In February 2023, the AER released its latest rate of return instrument (the 2022 Instrument).[86] The rate of return is a key component used to determine the amount of revenue network service providers can recover from customers. The AER sets the rate of return to cover the cost of capital of an efficient service provider. In August 2023, the 2022 Instrument was amended due to the unavailability of the Reserve Bank of Australia F16 data series. In March 2024, the 2022 Instrument was superseded by 'version 1.2' as the February 2023 version could not be applied to Victorian electricity and gas distribution service providers.

The instrument sets out the approach by which the AER will estimate the rate of return and comprises the return on debt and the return on equity, as well as the value of imputation credits. The 2022 Instrument binds all regulatory determinations from 25 February 2023 (section 3.12).

The AER also continues to review and incrementally refine elements of its benchmarking methodology and data. The aim of this work is to continually improve the reliability of the benchmarking results it publishes and uses in its network revenue determinations.

Review of incentive schemes

In April 2023, the AER published its final decision on its review of incentive schemes for network service providers.[87] The review forms part of the AER's strategic objectives for 2020–25 to improve its approach to regulation by being more efficient and focusing on outcomes that matter most to consumers.

Incentive regulation rewards network service providers for improving consumer outcomes by realising efficiency gains, reducing costs and improving service outcomes. Insights gained through applying the AER's incentive schemes are used as inputs into determining future revenue forecasts.

A key reason for the AER conducting its review of incentive schemes was in response to consumer concerns about the lack of transparency of the benefits to consumers compared with the observed costs. Consumers had questioned the extent to which network service providers are being rewarded for over forecasting expenditure rather than efficient spending, particularly in the context of capital expenditure. In aggregate, the efficiency benefit sharing scheme (EBSS), capital expenditure sharing scheme (CESS) and the service target performance incentive scheme (STPIS) payments added up to $1.2 billion (2%) of revenues over the 5 years to 2021–22.

The AER concluded that the incentive schemes have driven significant improvements in performance through efficiency gains, which reduces prices and interruptions to supply over time. While network service providers have been rewarded for achieving the efficiency gains, the majority of benefits have gone to consumers. As such, the AER has continued to apply the incentive schemes, although several modifications have been made to the CESS via the *Capital Expenditure Incentive Guideline* to limit rewards, improve transparency and limit the application of the scheme for large transmission investments.[88]

Sections 3.10, 3.14 and 3.16 examine the incentive schemes in more detail. Further information can be found in the AER's annual electricity network performance reports, which provide analyses of the impact incentive schemes have had on network service providers' revenue and performance.[89]

86 AER, Rate of Return Instrument 2022, Australian Energy Regulator, accessed 18 April 2024.
87 AER, Review of incentive schemes for regulated networks, Australian Energy Regulator, accessed 18 April 2024.
88 AER, AER capital expenditure incentive guideline – November 2013 (updated April 2023), Australian Energy Regulator, April 2023.
89 AER, Networks performance reporting, Australian Energy Regulator, accessed 31 August 2024.

3.8 Electricity pricing for a renewable future

Electricity generated from consumer energy resources within distribution networks continues to grow (chapter 2, section 2.8). This continual growth presents opportunities and challenges as technologies such as electric vehicles and storage shift the way electricity is supplied, stored and used. Electrification of gas appliances will further contribute to the growth in demand for electricity.

As we transition to a renewable future, it is important that individual consumers can make informed choices about their electricity usage to avoid increasing costs for all consumers. One way to incentivise consumers to use electricity in ways that minimise the need for future network investment is through sending price signals. Network assets are long lived and are paid for by consumers. Distribution network service providers manage their assets and are best placed to develop network tariffs that signal the impact demand will have on network costs.

The AER's role is to approve or not approve network tariffs proposed by the distribution network service providers based on whether they comply with the pricing principles of the National Electricity Rules and contribute to the achievement of the National Electricity Objectives. The AER aims to approve network tariffs that enable electricity retailers to reflect the distribution network service providers' price signals in their retail offers. With each subsequent tariff structure statement, distribution network service providers are required under the National Electricity Rules to progressively move towards more cost-reflective tariffs.[90]

3.8.1 Smart meters, new technologies and network pricing

Smart meters play an essential role in supporting the energy transition and enable more flexible demand to balance the variability of renewable electricity supply. They are a vital tool in implementing demand management strategies such as facilitating time-varying retail pricing and supporting the orchestration of consumer energy resources, which can reward customers for using electricity when supply is abundant.

Smart meters provide detailed data about consumers' electricity use and enables distribution network service providers to pass cost-reflective network tariffs on to retailers. This enables retailers to allow those consumers who are willing and able to respond to time-variable retail tariffs and make informed decisions in managing both their electricity usage and exports.

The penetration of smart meters has increased over the past decade. However, the proportion of network customers outside of Victoria with access to smart meters remains relatively low. Outside of Victoria, most households still have accumulation meters that need to be manually read, have only been assigned to flat network tariffs and only had access to flat retail offers. Unlike cost-reflective tariffs, flat tariffs do not signal when electricity is scarce or abundant, and do not reward retailers or customers for using electricity during periods of abundance or exporting during periods of scarcity. Cost-reflective tariffs incentivise retailers to facilitate alternative ways of aligning consumers' energy use with efficient use of network infrastructure. Accelerating the deployment of smart meters means that customers and the broader energy system can get faster access to the benefits offered by smart meters.

In August 2023, the Australian Energy Market Commission (AEMC) released its final report supporting the roll-out of smart meters.[91] The report set out several recommendations and options to accelerate the deployment of smart meters with the goal of achieving universal penetration across the NEM by 2030. Following this, the AEMC published a draft determination and draft rule seeking to efficiently accelerate the deployment of smart meters to all customers.[92] The AER demonstrated its support of the AEMC's proposed acceleration of the roll-out by approving the cost-recovery of old network-delivered meters in the quickest, lowest cost way to all customers.[93]

90 Distribution network service providers are now moving into the third round of submitting tariff structure statements.
91 AEMC, Final report – Review of the regulatory framework for metering services, Australian Energy Market Commission, 30 August 2023.
92 AEMC, Draft rule determination – Accelerating smart meter deployment, Australian Energy Market Commission, 4 April 2024.
93 AEMC, Final report – Review of the regulatory framework for metering services, Australian Energy Market Commission, 30 August 2023.

The regulatory framework must also continue to support appropriate pricing structures, protections and guidance for consumers who are unable to respond to time-varying price signals or do not have access to consumer energy resources. In July 2024, the AEMC announced it would be extending the final determination date of the smart meter deployment rule change to allow for further consultation on enhancing consumer protections (section 5.9).[94]

Electric vehicle-related demand is growing

Network tariff structures are increasingly designed to consider the growing demand for electricity related to electric vehicle (EV) charging. EVs provide many benefits, such as reducing costs for consumers and increasing network utilisation (section 3.15.2). However, distribution network service providers need to manage this increase in electricity demand to minimise the potential for EVs to contribute to electricity scarcity. The timing of electricity demand associated with EV charging must be managed now to mitigate the need for future capital expenditure to support this growth.

Managing the forecast growth in demand due to EV charging has become a significant consideration in the AER's recent decisions on distribution network service providers' tariff structure statements. In making these decisions, the AER must adhere to the National Electricity Objectives, which include the achievement of jurisdictional emissions reduction targets. The AER must approve network tariff structures that incorporate low-price windows that encourage EV charging during the day and overnight during periods of electricity abundance. Examples of how retail offers can influence EV owners to charge their vehicles at times that do not contribute to network demand peaks include:

- AGL's Electric Vehicle Orchestration Trial, which found that EV customers on time-of-use retail offers (that reflect cost-reflective network tariffs) respond strongly to price signals and move EV charging to off-peak periods[95]
- Origin Energy's trial, which demonstrated that providing incentives to participants through time-varying offers reduced charging consumption at peak times by 20%.[96]

The AER has also encouraged distribution network service providers to offer a choice of network tariffs to support a growing EV charge point operator industry.

Large and small-scale storage

In recent years the AER has seen the emergence of network tariffs and trials aimed at facilitating storage. Storage, such as batteries, provides a valuable resource to the network by facilitating more hosting capacity for residential solar, as well as reducing the need to draw from the grid at times of peak demand. This can reduce or avoid the cost of investing in network assets. AEMO's Integrated System Plan (section 3.13.6) forecasts that storage will need to increase tenfold by 2050 to achieve the optimal capacity of coordinated consumer energy resources, with at-home batteries being a significant component of the total storage required.[97]

The AER continues to consider how to balance incentives for storage that contribute to the National Electricity Objective holistically. The AER considers that network price signals should indicate when battery operation drives costs or benefits to the network. Without such price signals, battery owners may not factor network costs into their decisions on battery operation and may operate batteries in ways that trigger network augmentation, increasing future network costs. These same price signals contribute to the achievement of jurisdictional emissions reduction targets. Higher charges that signal network investment costs (in the late afternoon and early evening) also disincentivise consumption when generation is dominated by fossil fuels, and low charges in the middle of the day promote consumption of rooftop solar, including by storage devices.

94 AEMC, AEMC extends smart meter rollout decision to consult further on consumer safeguards, media release, Australian Energy Market Commission, 4 July 2024.

95 AGL, AGL Electric Vehicle Orchestration Trial Final Lessons Learnt Report, May 2023.

96 Origin Energy, Origin EV Smart Charging Trial Lessons Learnt Report, May 2022.

97 AEMO, 2024 Integrated System Plan, Australian Energy Market Operator, June 2024, p. 66.

3.8.2 Regulatory reforms that support changing energy flows

Network tariffs continue to evolve as the pace of the energy transition accelerates. Network tariffs are designed to signal to electricity retailers the varying costs of the network, over time of day, time of year and potentially by location.

In the past, network tariffs were either static or flat. That is, retailers were charged the same price per unit of electricity for using the distribution network regardless of what time of day the electricity was used. Flat network tariffs are independent of when electricity is used, so they do not reflect the relatively higher costs of a network built to supply electricity during peak periods.

The AER encourages collaboration between network service providers, retailers and industry to trial alternative tariff structures and to develop other ways to shift both demand and solar exports to more cost-efficient times of the day.

Tariff structure statement process

Under the Power of Choice reforms the AER has administered a network tariff reform program that requires distribution network service providers to introduce more cost-reflective or dynamic tariff structures.[98]

Distribution network service providers are required to submit tariff structure statements to the AER every 5 years as part of the wider revenue determination process. Tariff structure statements set out proposed network tariff structures for the forthcoming 5-year period, policies on how network tariffs are assigned and information on how network tariffs are set. The 5-year tariff structure cycle was imposed to place weight on certainty for electricity retailers and consumers, because distribution network service providers cannot modify approved network tariffs within a 5-year period unless exceptional circumstances have been met. Given the pace of the energy transition, a 5-year cycle may no longer be fit for purpose. The AER will look to explore more flexibility in the tariff structure statement process as part of the AEMC's *Electricity pricing for a consumer-driven future* review (section 6.9.1).

There are some examples of network tariffs being a low-cost mechanism to reduce distribution network service providers' forecast expenditure. For example, the AER's draft decision on Evoenergy's (ACT) 2024–29 revenue proposal rejected $76.1 million of EV-related augmentation expenditure because Evoenergy had not adequately taken into account how network tariffs could mitigate the need for network augmentation. Additionally, approved tariff structure statements have included modelling showing that many customers could benefit from lower network charges (as charged to their retailer) if they were assigned to a 'cost-reflective' network tariff rather than a flat tariff.[99]

The energy transition is already set to impose significant costs on consumers through the substantial upgrades in transmission and new generation sources. To give effect to the benefits consumers are forecast to receive, avoided network augmentation costs must actually be carried through to expenditure and revenue proposals (chapter 6, section 6.9).

98 AER, Network tariff reform, Australian Energy Regulator, accessed 13 September 2024
99 For example, Endeavour Energy, Tariff structure explanatory statement, 30 November 2023, p. 81.

Shift away from static network tariff structures

Distribution network service providers have already taken steps to incentivise and reward behaviours that increase the efficient utilisation of the network and potentially reduce future network investment, including by:

- simplifying tariffs and modifying peak windows to provide clear, consistent signals
- designing tariffs that more closely reflect network costs, including introducing 'solar soak' periods – tariffs that have low charges during the day to encourage consumers to use electricity in this time (most distribution network service providers have or will soon include these tariffs)
- introducing export reward tariffs.

In April 2024, the AER approved the future use of export reward tariffs, which offer rewards to consumers for exporting electricity during times of the day when it is most needed (in addition to solar feed-in tariff payments) and apply charges for exporting large amounts of solar into the grid at times when electricity is not needed.[100] Export reward tariffs are intended to help consumers who generate solar decide when to consume the solar electricity themselves and when to export it.

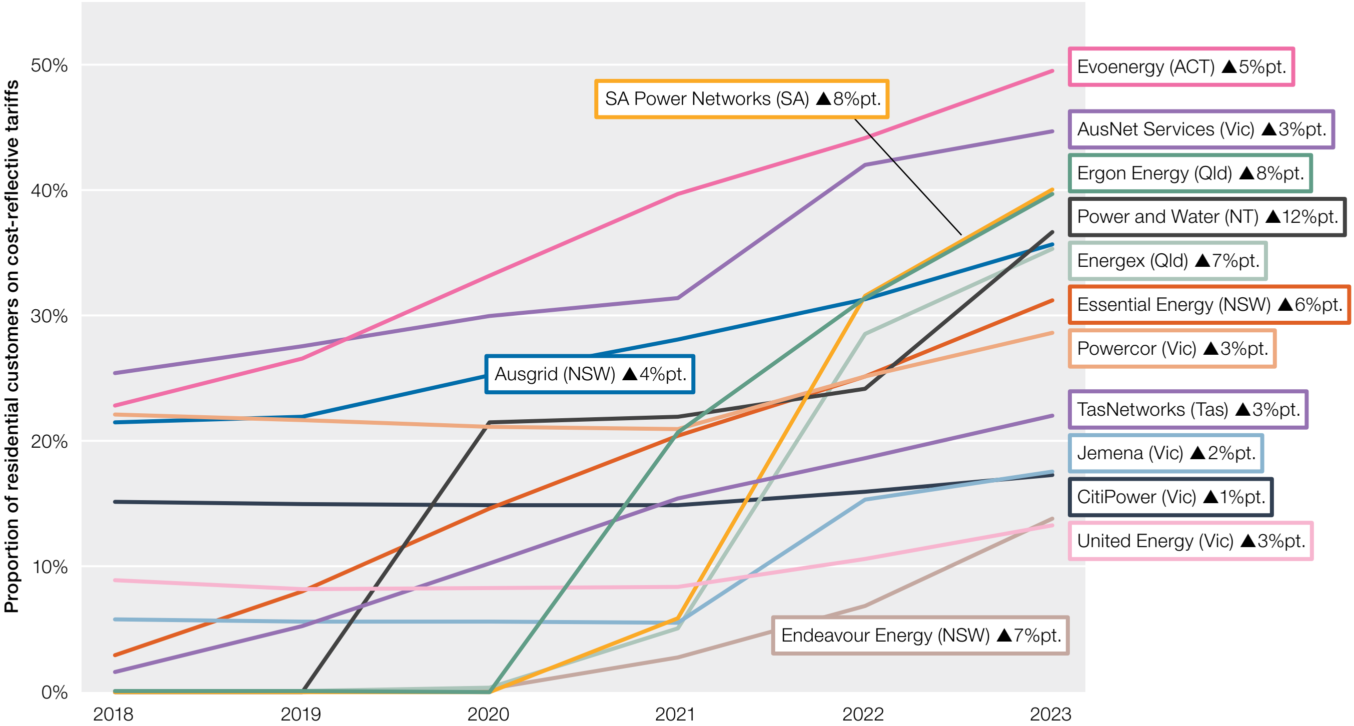
Export reward tariffs were introduced on 1 July 2024 by distribution network service providers in NSW. Network service providers are not required to introduce export reward tariffs and any proposed export reward tariff is subject to the AER's approval as part of the tariff structure statement process. The direct impact on a customer's bill will still depend on how their retailer structures its retail market offers and to what extent it decides to pass through the price signals or absorb them within its existing retail tariff structures.

The AER's approval of export reward tariffs provides one example of tariff reform and follows the rule change made by the AEMC in August 2021 to integrate consumer energy resources, such as small-scale solar and batteries, more efficiently into the electricity grid. Export reward tariffs better reflect the costs and benefits to the network from solar-exporting consumers and also incentivise behaviours and technologies such as batteries for the benefit of all customers.

As at 30 June 2023, approximately 36% of residential consumers were served by a retailer that faces cost-reflective network tariffs (Figure 3.6). This number will likely increase in response to the accelerated roll-out of smart meters, which will enable more retailers and customers to respond to cost-reflective tariffs and dynamic pricing.

100 AER, Export reward tariffs and you, Australian Energy Regulator, April 2024.

Figure 3.6 Residential customers on cost-reflective tariffs



Source: Annual RIN responses.

Tariff trials to incentivise innovative network tariffs

The AER encourages collaboration between network service providers, retailers and industry to trial alternative tariff structures (sub-threshold tariffs) during a regulatory period to support the introduction of innovative tariff structures, and to develop other ways to shift both demand and solar exports to more cost-efficient times of the day. Examples of trials include:

- Energex and Ergon Energy (Queensland) – storage tariff trials (dynamic flex and dynamic pricing) to trial dynamic pricing and dynamic connections for storage consumers. Energex and Ergon Energy aim to use the outcomes of the trials to inform storage tariffs for introduction from 2025.
- Endeavour Energy (NSW) – a flexible controlled load tariff trial with specific focus on hot water and electric vehicle solar soaking.
- SA Power Networks (South Australia) – a residential 'electrify' tariff trial with a targeted peak window and solar sponge, designed to encourage consumers with flexible load to shift electricity use to during the day or overnight. SA Power Networks aims to introduce this tariff to all residential consumers from 2025.

Unlike tariff structures introduced through the 5-year regulatory proposals, tariff trials do not need to be approved by the AER but are subject to other safeguards:

- distribution network service providers are required to notify the AER of proposed tariff trials
- tariff trials are also not allowed to recover more than 5% of a distribution service provider's revenue.

With the need for innovative solutions to support changes in consumers' energy use more urgent than ever, the AER may look for rule amendments around sub-threshold tariffs to be less restrictive as part of the AEMC's *Electricity pricing for a consumer-driven future* review.

3.8.3 Ring-fencing

Ring-fencing refers to the separation of the regulated and competitive business activities of an electricity network service provider.

The objective of ring-fencing is to provide a regulatory framework that promotes the development of competitive markets. It does so by providing a level playing field for natural monopoly and third-party service providers in new and existing markets for contestable services.[101] Effective ring-fencing arrangements are an important mechanism for promoting increased choice of service providers for consumers and more competitive outcomes in markets for electricity services without losing the cost efficiencies of natural monopolies.

Ring-fencing should not be regarded as a barrier to innovation or a barrier to the emerging role of electricity networks as platforms for new energy services. The aim of ring-fencing is to prevent network service providers from using revenue from regulated services to cross-subsidise their unregulated products or services, and/or discriminate in favour of affiliated businesses. Before a network service provider offers services in a competitive market, robust ring-fencing arrangements must be in place to ensure it competes fairly with other service providers.

The AER publishes separate ring-fencing guidelines for transmission and for distribution networks. Under the guidelines, network service providers must identify and separate the costs and business activities attributed to the provision of regulated network services from those attributed to the delivery of services in competitive markets.

All network service providers are required to report to the AER any breaches of the guidelines within 15 business days of becoming aware of the breach. In addition, network service providers must annually report to the AER on their compliance with the guidelines. When breaches have occurred, network service providers have generally communicated promptly with the AER, acted quickly to remediate any potential harms and put plans in place to prevent breaches from recurring. The introduction of civil penalties for ring-fencing breaches has further encouraged improved compliance.

101 The 2015 Power of Choice reforms required the AER to develop the distribution ring-fencing guideline.

In the 12-month period to 30 December 2023, 2 transmission and 8 distribution network service providers reported breaches related to the protection of ring-fenced information. The AER did not consider these breaches to have had a material impact on competition within contestable markets.

The guidelines allow the AER to grant waivers for network service providers from some ring-fencing obligations. The AER encourages network service providers to submit waiver proposals that demonstrate consumer benefit through increased choice or reduced future capital spending.

Table 3.2 provides a summary of the waivers granted by the AER in the 12-month period to 30 June 2024. In addition, the AER has previously granted waivers – some of which specifically target new and innovative services – for distribution network service providers to install and operate community-scale batteries to further test and trial how locally based storage can benefit consumers.

Table 3.2 Recent AER waiver approvals

NSP	Waiver description	Waiver end date
Transgrid (NSW)	Provide telecommunications services to 6 customers for a period of 12 months.[102]	12 April 2025
Transgrid (NSW)	Backup generation.[103]	13 February 2029
Endeavour Energy (NSW)	Undertake a trial of 7 batteries.[104]	31 December 2027
Essential Energy (NSW)	Provide relevant training services.[105]	30 June 2029
Ergon Energy (Queensland)	Provide services from a microgrid and isolated systems test (MIST) facility.[106]	30 June 2030
Ergon Energy (Queensland)	Provide battery storage services under its Local Battery Plan.[107]	30 June 2035
SA Power Networks (South Australia)	Provide services for testing data communications under the Market Active Solar Trial.[108]	31 December 2025
Evoenergy (ACT)	Provide ‘other services’ to a single site for a large customer for a defined transition period.[109]	22 May 2026
Power and Water (Northern Territory)	Lifts the obligation to publish registers.[110]	30 June 2034

102 AER, Transgrid – Ring-fencing waiver, Australian Energy Regulator, 28 March 2024.
103 AER, Transgrid – Ring-fencing waiver, Australian Energy Regulator, 13 February 2024.
104 AER, Endeavour Energy – Ring-fencing waiver, Australian Energy Regulator, 25 March 2024.
105 AER, Essential Energy – Ring-fencing waiver, Australian Energy Regulator, 13 February 2024.
106 AER, Ergon Energy – Ring-fencing waiver, Australian Energy Regulator, 28 March 2024.
107 AER, Ergon Energy – Ring-fencing waiver, Australian Energy Regulator, 27 March 2024.
108 AER, SA Power Networks – Ring-fencing waiver, Australian Energy Regulator, 12 April 2024.
109 AER, Evoenergy – Ring-fencing waiver, Australian Energy Regulator, 22 May 2024.
110 AER, PWC – Ring-fencing waiver, Australian Energy Regulator, 1 July 2024.

3.9 Revenue

Electricity network businesses collect revenue for providing services to customers. Some services are regulated, but others are provided through competitive markets. Regulated services include electricity transportation, connections and metering services and represent the majority of a network service provider's revenue. This report focuses exclusively on revenues collected for providing core regulated services.

For transmission network service providers, 'regulated services' include revenues associated with delivering prescribed transmission services. For distribution network service providers, it includes revenues associated with providing standard control services.[111]

All electricity network service providers are regulated under revenue caps. Under this form of control, the AER determines each network service provider's total allowed revenue. Each year, network service providers set their prices to target earning the maximum revenue allowed under the revenue cap.

The AER updates the revenue targets each year to account for actual inflation, changes in network service providers' allowed returns on debt, cost pass-throughs (section 3.9.3) and other factors. Interest rates and inflation are factors outside both network service providers' and the AER's control. These uncontrollable factors are expected to place upwards pressure on network service providers' allowed revenue in future years.[112]

3.9.1 Revenue in 2023

Over the 12-month period to 30 June 2023, network service providers earned $12.5 billion for delivering core regulated services,[113] $372 million (2.9%) less than in the previous year.

Table 3.3 and Figure 3.7 to Figure 3.10 provide a summary of the revenue that network service providers collected for providing services to customers in 2023 and how it compared with previous years' targets and actuals.

Table 3.3 Revenue in 2023 – key outcomes

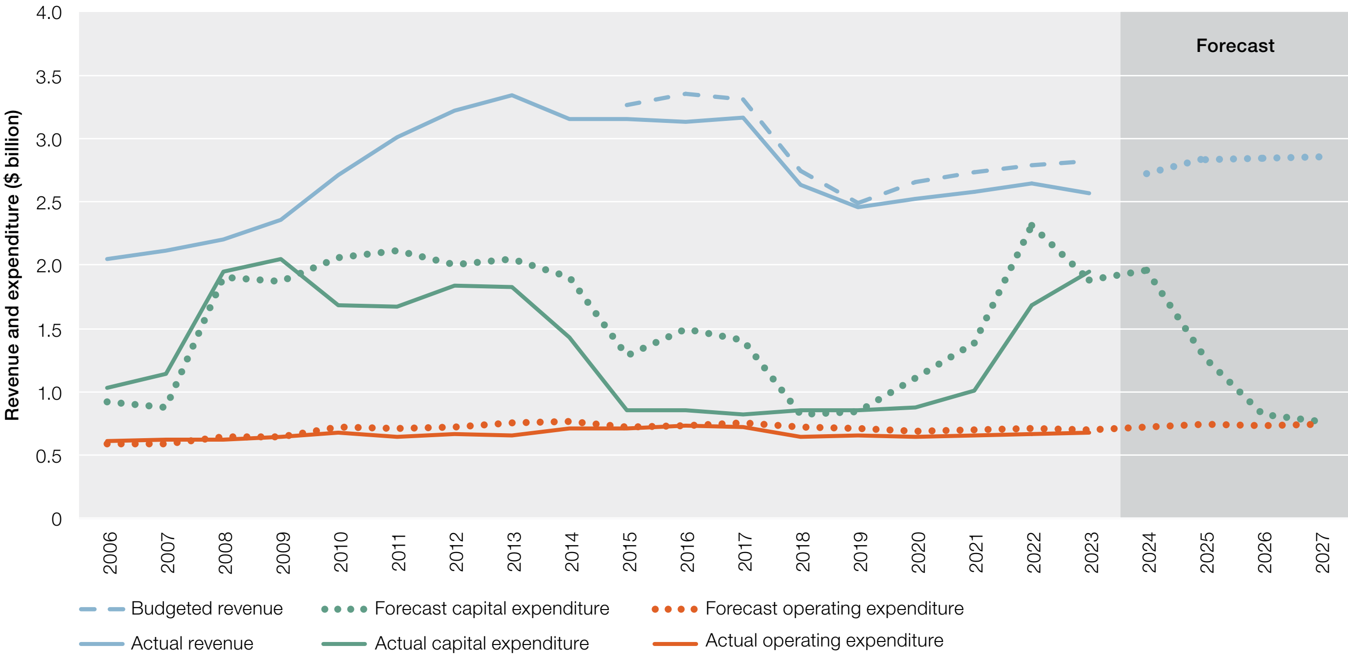
Service type	Revenue (actual) (2023)	Revenue (actual) (compared with 2022)	Revenue (actual) (compared with peak)
Transmission	$2.6b	▼$82m (▼3.1%)	▼$778m (▼23%) (2013)
Distribution	$9.9b	▼$290m (▼2.8%)	▼$4.7b (▼28%) (2015)
Total	$12.5b	▼$372m (▼2.9%)	▼$5.2b (▼27%) (2015)

111 Regulated services include electricity transportation, connections and metering services and represent the majority of an network service provider's revenue. For transmission network service providers, 'regulated services' include revenues associated with delivering prescribed transmission services. For distribution network service providers, it includes revenues associated with providing standard control services.

112 AER, Rate of return – overview for consumers, Australian Energy Regulator, February 2023.

113 Prescribed transmission services for transmission network service providers and standard control services for distribution network service providers.

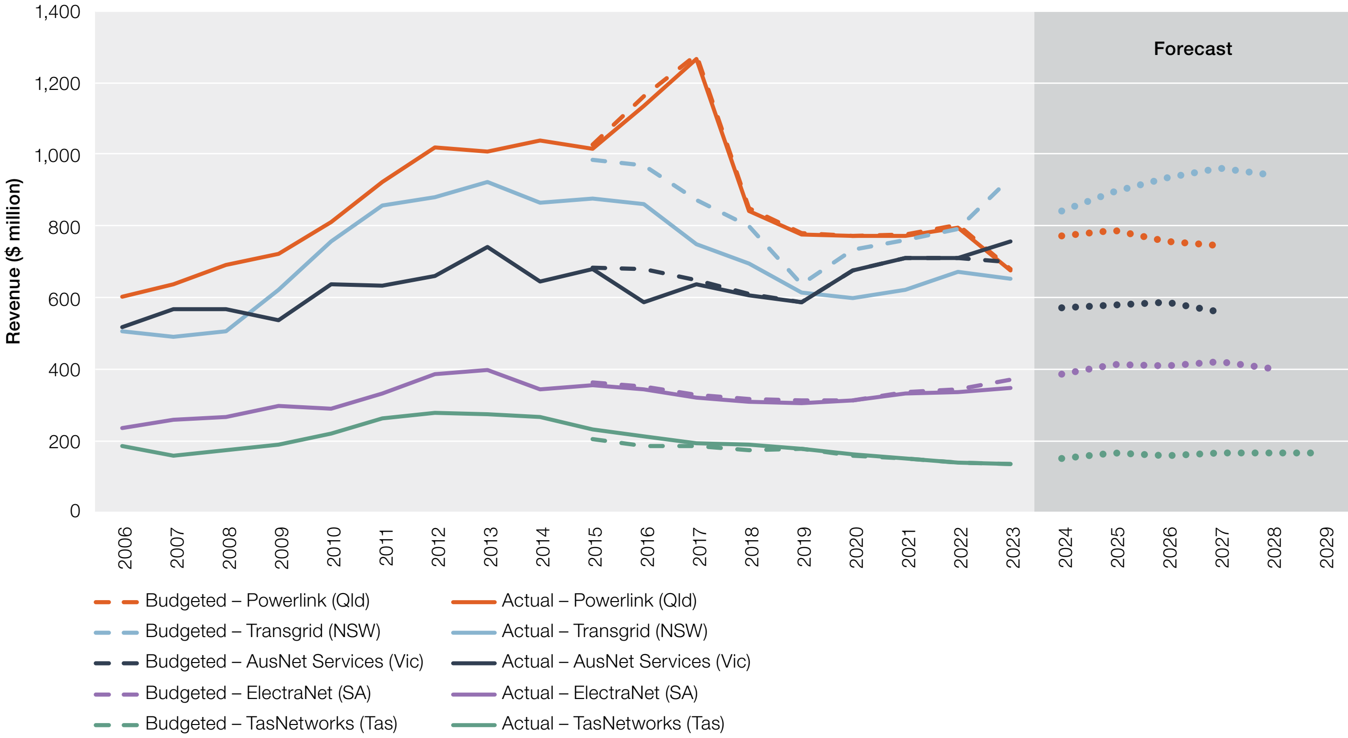
Figure 3.7 Revenue and key drivers – electricity transmission networks (aggregate)



Note: All data are adjusted to June 2023 dollars. Most network service providers report on a 1 July to 30 June basis. The exception is AusNet Services (Victoria), which reports on a 1 April to 31 March basis. The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018). Transmission network service providers earn revenues for delivering prescribed transmission services, some of which comes directly from customers and other from sources such as inter-regional and intra-regional settlements residues or inter-regional settlements auction proceeds. The budgeted revenue shown in Figure 3.7 reflects the revenues network service providers budgeted to be collected from customers.

Source: Revenue: economic benchmarking RIN responses; capital expenditure: AER modelling, category analysis RIN responses; operating expenditure: AER modelling, economic benchmarking RIN responses.

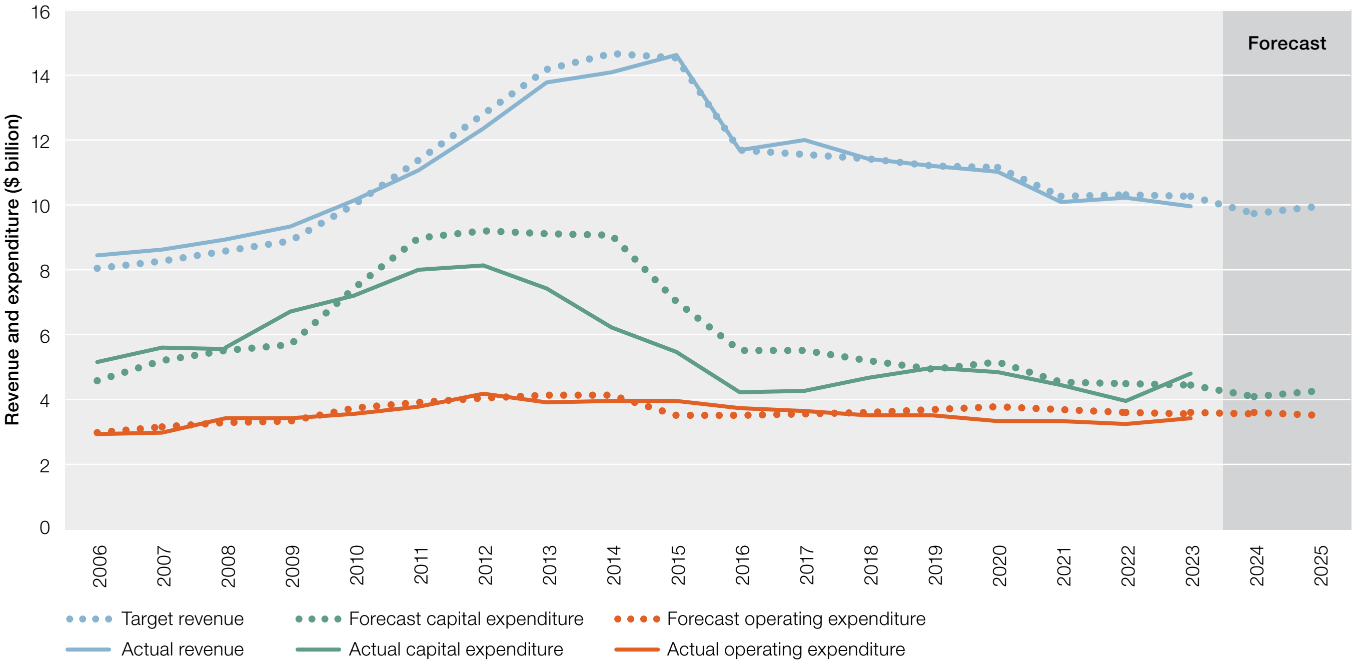
Figure 3.8 Revenue – electricity transmission networks



Note: All data are adjusted to June 2023 dollars. The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018). Transmission network service providers earn revenues for delivering prescribed transmission services, some of which comes directly from customers and other from sources such as inter-regional and intra-regional settlements residues or inter-regional settlements auction proceeds. The budgeted revenue shown in Figure 3.8 reflects the revenues budgeted to be collected from customers. Forecast revenue is derived from regulatory determinations but adjusted to present it on a comparable basis to actual revenues. The adjustments include rewards and penalties from incentive schemes, cost pass-throughs and other factors that are considered in determining the target revenues used to set prices each year.

Source: AER modelling; annual reporting RIN responses.

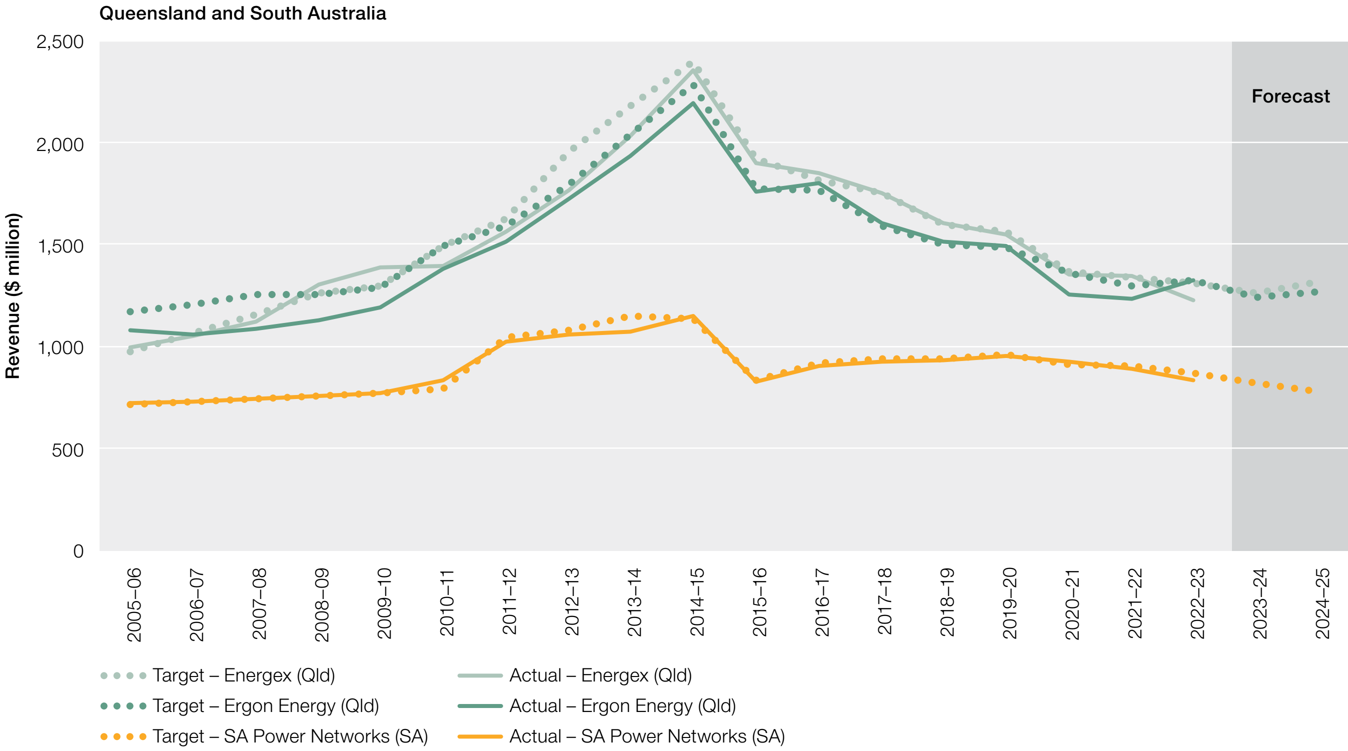
Figure 3.9 Revenue and key drivers – electricity distribution networks (aggregate)

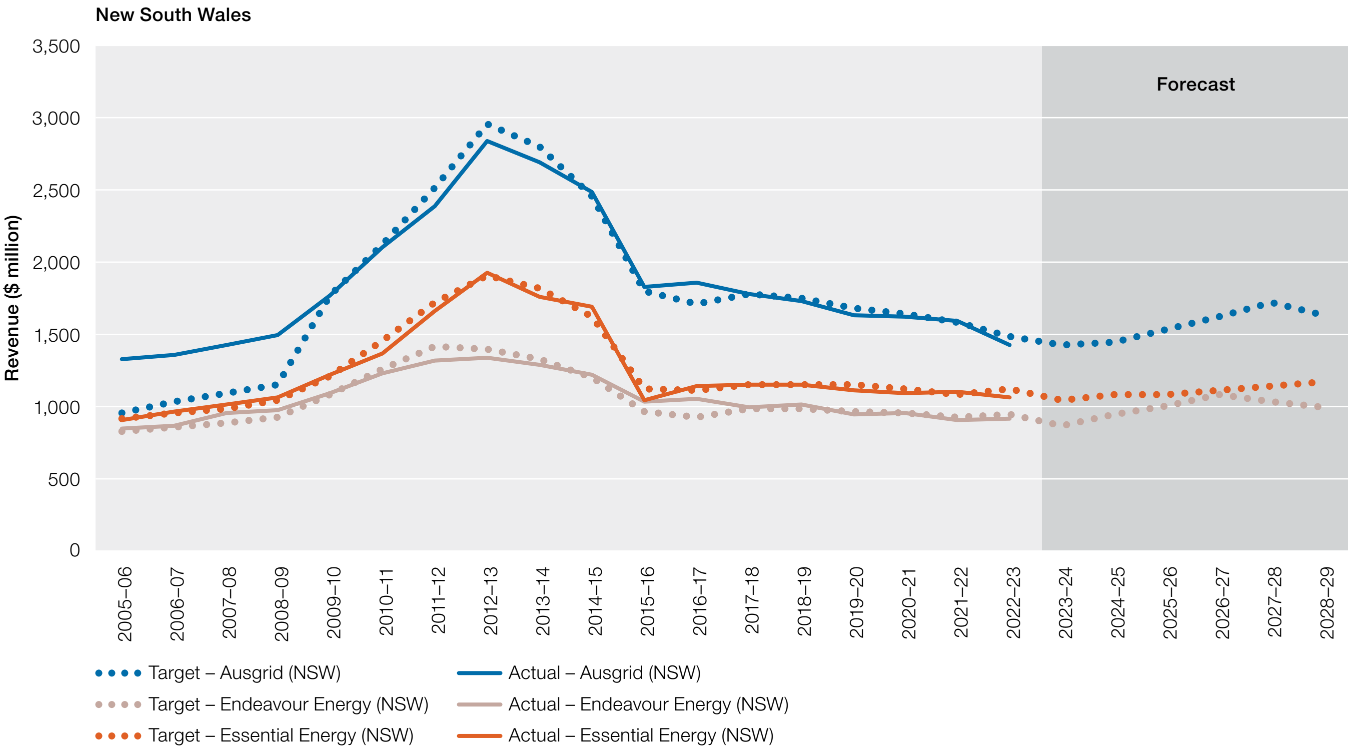


Note: All data are adjusted to June 2023 dollars. The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018). The exception is the Victorian networks, which until year end 2020 reported on a 1 January to 31 December basis. Target revenue for the Victorian distribution networks for the 2021 year has been derived from the transitional year (1 January to 30 June 2021). To enable reporting on equivalent terms, these values have been doubled. Target revenue is derived from regulatory determinations but adjusted to present it on a comparable basis to actual revenues. The adjustments include rewards and penalties from incentive schemes, cost pass-throughs and other factors that are considered in determining the target revenues used to set prices each year. The exception is the Victorian networks, which until year end 2020 reported on a 1 January to 31 December basis.

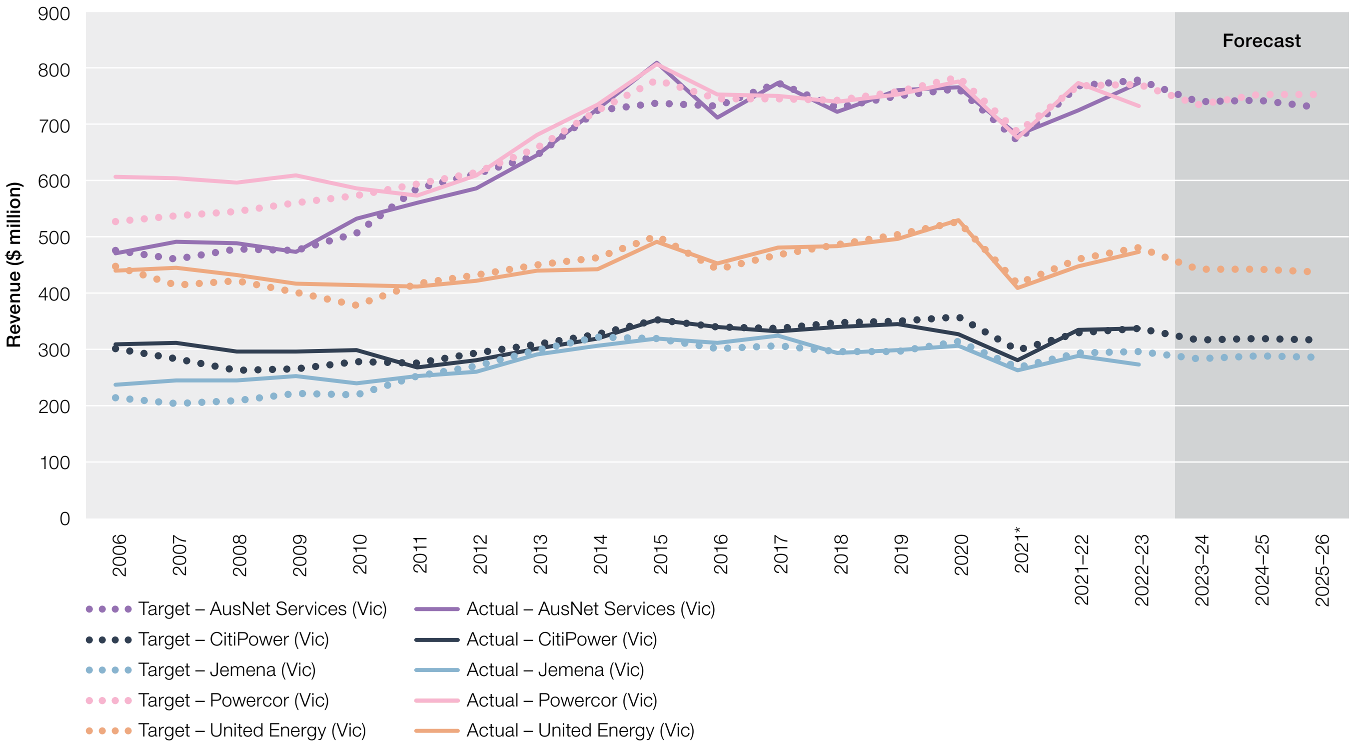
Source: Revenue: economic benchmarking RIN responses; capital expenditure: AER modelling, category analysis RIN responses; operating expenditure: AER modelling, economic benchmarking RIN responses.

Figure 3.10 Revenue – electricity distribution networks





Victoria



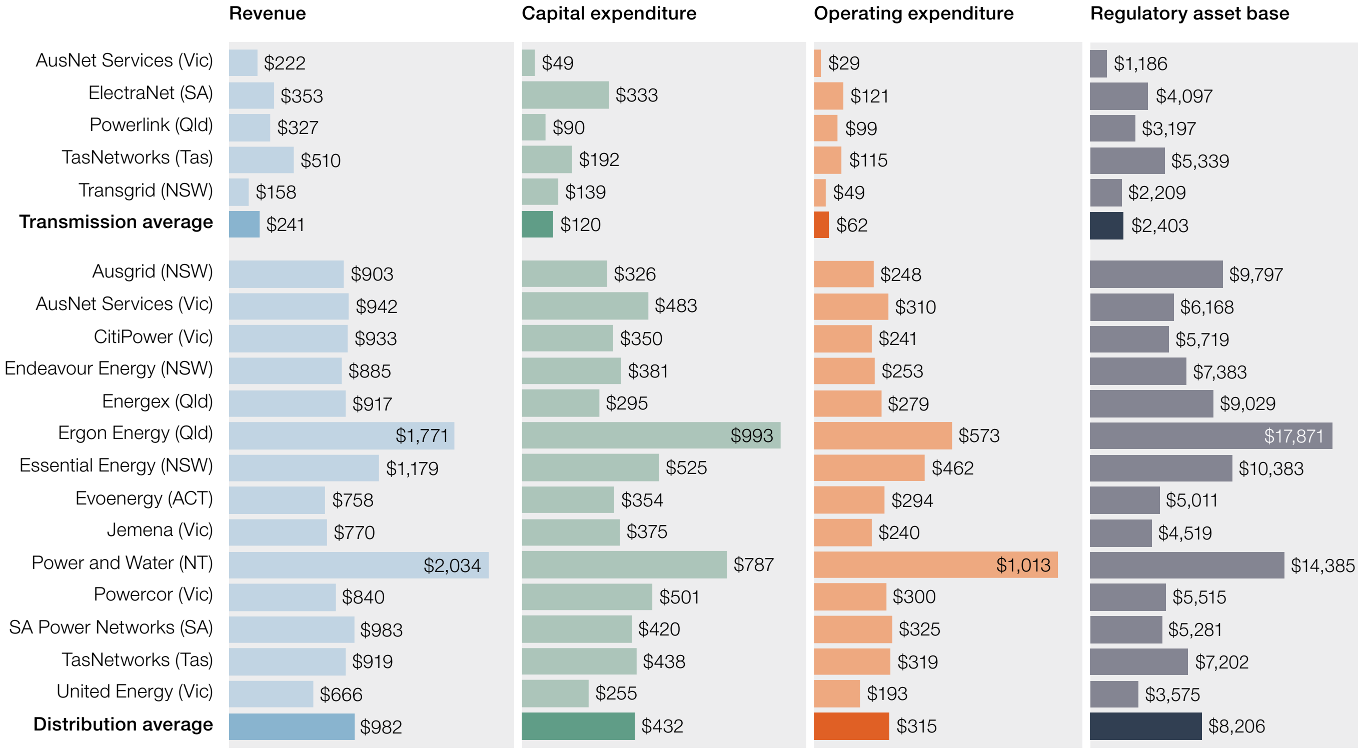
Tasmania, ACT and Northern Territory

Note: All data are adjusted to June 2023 dollars. Most network service providers report on a 1 July to 30 June basis. The exception is the Victorian networks, which until year end 2020 reported on a 1 January to 31 December basis. Target revenue for the Victorian distribution networks for the 2021 year has been derived from the transitional year (1 January to 30 June 2021). To enable reporting on equivalent terms, these values have been doubled.

Source: AER modelling; annual reporting RIN responses.

Figure 3.11 summarises key financial indicators for electricity network service providers on a per customer basis, which allows for greater comparability across networks.[114] [115]

Figure 3.11 Average per customer metrics – 2019 to 2023 (5 years)



Note: All data are adjusted to June 2023 dollars. In 2023, residential customers (a customer who purchases electricity principally for personal, household or domestic use) accounted for 88% of total customers on the distribution network. While the proportion differed across network service providers – for example, 91% residential for Endeavour Energy (NSW) and 83% for CitiPower (Victoria) – the differences do not materially affect the 'per customer' metric. Revenue, capital expenditure and operating expenditure are the annual averages over the 5 years to 30 June 2023. RAB is the actual closing RAB at 30 June 2023. For regulatory purposes, Northern Territory transmission assets are treated as part of the distribution system.

Source: AER revenue determinations and economic benchmarking RINs.

We note the 'revenue per customer' output for Ergon Energy (Queensland) shown in Figure 3.11 does not reflect what Ergon Energy's network customers actually pay. The Queensland Government supports customers in regional Queensland (served by Ergon Energy) by ensuring they pay similar prices for their electricity to customers in South East Queensland (served by Energex). This is done by subsidising – through the Community Service Obligation payment – additional costs involved in supplying electricity to regional Queenslanders through payments to Ergon Energy Retail.[116]

Forecast revenue is translated into a path of 'X-factors', which are locked in at the beginning of the regulatory period and updated annually to take into account changes in cost of debt. These X-factors – alongside changes in inflation, incentive schemes and other factors – control the change in the maximum revenue network service providers can recover each year. Under this model, network service providers are incentivised to provide services at the lowest possible cost because their returns are determined by the actual costs of providing services. If network service providers reduce their costs to below the estimate of efficient costs, the cost savings are shared with consumers in future regulatory periods.

114 Per customer metrics allow for easier comparison of network service providers of different sizes. But multiple factors other than customer numbers – such as line length and terrain – have an impact on these indicators.

115 Transmission network service providers do not report customer numbers. Per customer metrics for the transmission networks were calculated using the total number of distribution customers in the relevant jurisdictions.

116 Queensland Government, Electricity prices, Business Queensland, accessed 31 July 2024.

Table 3.4 provides a summary of the AER's revenue determinations for all electricity network service providers for their respective current regulatory periods.

Table 3.4 AER electricity network revenue determinations – current regulatory period

NSP	Revenue (forecast)	Capital expenditure (forecast)	Operating expenditure (forecast)
Transmission	$14.1b (–%)	$5.6b (▼25%)	$3.7b (▲6%)
Distribution	$52.4b (▼5%)	$21.9b (▼14%)	$17.8b (▼2.5%)
Total	$66.5b (▼4.4%)	$27.6b (▼17%)	$21.5b (▼1.2%)

Note: The current regulatory period is the period in place at 1 July 2024. All revenue and expenditure data are adjusted to June 2023 dollars. Changes in revenue and expenditure are in relation to forecasts from the previous regulatory periods.

Source: AER estimates.

The key drivers behind lower revenues for most of the network service providers have been the changes in the net tax allowance and the allowed return on capital.

In 2019, the AER reviewed how it calculates the cost of corporate tax and made changes to its approach to align with the rulings of the Australian Taxation Office. The impact of the changes have generally resulted in the cost of corporate tax in the current regulatory period being lower that it was in the past.

In the most recent round of regulatory determinations,[117] the allowed rate of return increased from the rate applied in the previous period due to the increase in interest rates. This created significant upward pressure on network revenue. However, most of the regulatory determinations currently in place were made before 2024, when lower interest rates saw the allowed rate of return decrease from the previous regulatory period, leading to downward pressure on network revenue.

3.9.2 Trends in network revenue

Revenues for network service providers increased by around 6% per year from 2006 to 2015, when network charges included:

- rapid growth in regulatory asset bases (RABs) caused in part by stricter reliability standards imposed by state governments, which required new investment and increased operating expenditure
- higher costs of capital during the global financial crisis.

These increases were more pronounced in Queensland and NSW than in other jurisdictions.

Cost pressures began to ease when demand for electricity from the grid plateaued, causing new investment to be scaled back from 2013. The changing demand outlook coincided with government moves to allow network service providers greater flexibility in meeting reliability requirements.
The financial environment also improved after 2012, easing borrowing and equity costs. After peaking at over 10% between 2009 and 2013, allowed rates of return for some network service providers fell to around 4.5% in 2023 (section 3.12).

Reforms phased in from 2015 also helped offset the increasing network revenues. The reforms, which explicitly linked network costs to efficiency factors, encouraged network service providers to better control their operating costs.

117 In 2024, the AER finalised revenue determinations for transmission network service provider TasNetworks (Tasmania) and distribution network service providers Ausgrid (NSW), Endeavour Energy (NSW), Essential Energy (NSW), TasNetworks (Tasmania), Evoenergy (ACT) and Power and Water (Northern Territory). These determinations set target revenue controls through to 30 June 2029.

A combination of these factors reduced the revenue needs of network service providers. Decreasing investment and rates of return lowered revenue requirements as the service providers entered a new 5-year regulatory cycle. However, consumers will continue to pay for the relatively high investment in network assets from 2006 to 2013 for the remainder of the economic lives of those assets, which in some cases may extend to 50 years. In 2018, independent public policy think tank Grattan Institute called for the asset bases of some networks to be written down, so consumers would not continue to pay for the overinvestment.[118] The Australian Competition and Consumer Commission (ACCC) supported this position, particularly for government-owned networks in Queensland, NSW and Tasmania.[119]

Since 2017 network revenues have decreased, driven by a significant reduction in target revenue for the NSW-based networks in the 2015–19 regulatory period, followed by a significant reduction for the Queensland based networks in the 2016–20 regulatory period.

Consumer groups and some industry observers remain concerned that the regulatory framework enables network service providers to earn excessive profits. In response to calls for greater transparency around the actual returns earned by network service providers, the AER now publishes information on network profitability in an annual network performance report. The AER's network performance report provides detailed analyses of key operational and financial trends as well as key profitability measures.[120] The network performance report provides key insights to enable stakeholders to make more informed assessments of the returns earned by each network service provider.

Operating, maintenance and other costs are relatively stable in comparison to the investment in capital projects. While operating expenditure has always been lower than capital expenditure, the contrast between the 2 has fluctuated over time. From 2009 to 2013 expenditure on capital projects was more than twice that of operating costs. However, by 2016 capital (53%) and operating (47%) expenditure had almost reached parity due to weakening investment (section 3.14).

3.9.3 Pass-through events

The AER is responsible for assessing cost pass-through applications, where a network service provider may apply to recover additional costs incurred during a regulatory period. The application is assessed against a list of predefined events that are specified in either the National Electricity Rules or in the network service provider's revenue determination.

Table 3.5 summarises the cost pass-through applications approved by the AER in the 12-month period to 30 June 2024.

Table 3.5 Cost pass-throughs

Network service provider	Pass-through event	AER approved ($ nominal)	Recovery period
Powerlink (Queensland)	Network support	$0.9 million	2024–25
ElectraNet (South Australia)	Inertia shortfall	–$6.2 million	2024–25
ElectraNet (South Australia)	Network support	$10.1 million	2024–25
Murraylink (interconnector)	Connection charges	–$1.0 million	2024–25
AusNet Services (Victoria)	Easement land tax	$55.8 million	2024–25
SA Power Networks (South Australia)	Natural disaster (flood)	$11.2 million	2024–25
TasNetworks (Tasmania)	Network support	$0.4 million	2024–25

Note: Approved under clauses 6.6.1, 6A.7.2, 6A.7.3 or 11.6.21 of the National Electricity Rules.
Source: AER, Cost pass throughs.

118 T Wood, D Blowers, K Griffiths, Down to the wire – a sustainable electricity network for Australia, Grattan Institute, March 2018.
119 ACCC, Retail Electricity Pricing Inquiry – final report, Australian Competition and Consumer Commission, June 2018.
120 AER, Networks performance reporting, Australian Energy Regulator, accessed 31 August 2024.

3.10 Network charges and retail bills

Electricity network charges made up as much as 46% of a residential customer's electricity bill in 2023 (Figure 6.2 in chapter 6). Distribution network services accounted for most of the costs (63% to 92%), with transmission network service costs (up to 27%), jurisdictional scheme costs[121] (up to 15%) and metering costs (up to 8%) making up the balance.

A customer's electricity bill reflects the combined costs of all the electricity supply chain components – wholesale electricity generation, transmission, distribution, metering, jurisdictional scheme and retail costs. The estimated impact of the AER's current revenue determinations on residential customer bills represents the impact of the prescribed transmission services and standard (distribution) control services components of the bill.

The AER's revenue determinations for the current regulatory periods are estimated to increase residential electricity bills by an average of 0.2% per year across all states and territories (Figure 3.12). The estimated bill impact is based on average annual electricity usage for a residential customer. As such, customers with different usage will experience different changes in their bills. In the past, the most significant changes to network charges generally arose in the first year of a regulatory period. However, in the most recent revenue determinations, the most significant changes (increases) often occur later in the period. For example, residential customers on Power and Water's (Northern Territory) distribution network will see an estimated 6% increase in the second year of the current regulatory period, compared with an estimated average 4.1% increase per year over the whole period.[122]

To minimise price shocks, network revenues are smoothed across the regulatory period. Revenue smoothing involves reallocating some of the forecast costs to adjacent years within the regulatory period to minimise the potential of large revenue variances at the start of the following regulatory period.

Distribution network service providers submit annual pricing proposals to the AER, outlining proposed prices to take effect in the following year. These proposed prices must be consistent with the service provider's approved revenues but can account for additional costs associated with transmission and jurisdictional schemes.

The difference between network service providers' initial revenue proposal and the AER's final decision, which happens over a 15-month period, is illustrated in Figure 3.12. In the most recent round of revenue determinations, the AER predominately approved higher revenues than were proposed by the network service providers in their revised proposals. This was mainly driven by fluctuating external economic factors, which involved adjusting the expected inflation rate and incorporating the impact of higher interest rates.

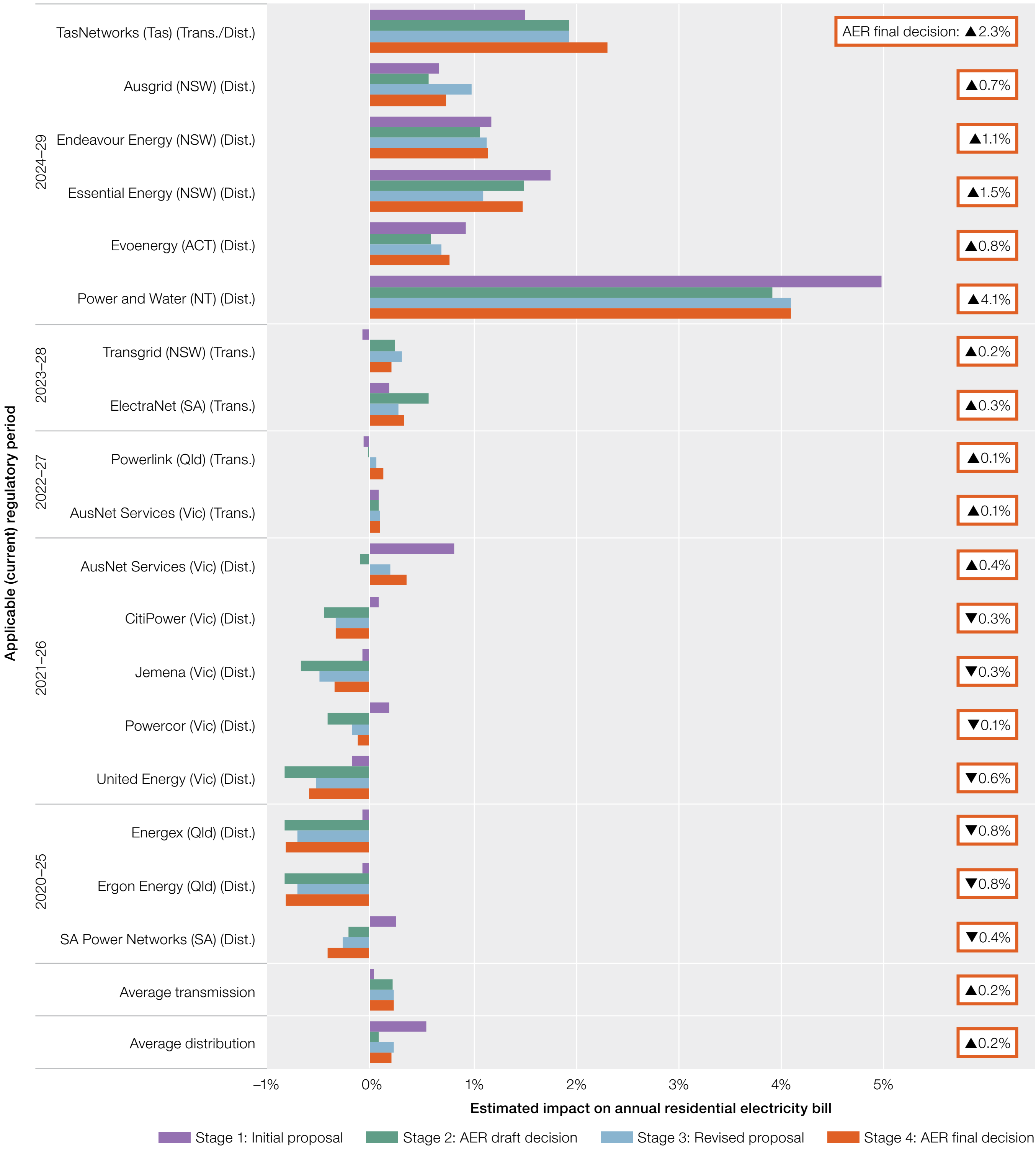
Among other factors, the annual processes update prices for changes in the consumer price index (CPI). Since June 2021, CPI has increased significantly. Over the 12 months to December 2023, applying to network prices over 2024–25, CPI increased by 4.1%. CPI growth has eased but remains relatively high due to the stronger labour market and higher petrol prices. The Reserve Bank of Australia expects inflation to return to the target range (2–3%) in the second half of 2025 and to reach the midpoint in 2026.[123] As these inflation results feed into annual pricing over coming years, they will continue to put upward pressure on prices.

121 Jurisdictional scheme costs are costs related to jurisdictional regulatory obligations that are passed through to customers by distribution network service providers. These schemes generally relate to historical premium feed-in tariff schemes, as well as emerging renewable energy zones, such as the NSW Electricity Infrastructure Roadmap.

122 Most customers in the Northern Territory are subject to the government's Electricity Pricing Order. This caps retail prices for customers using less than 750 MWh of electricity per annum. It is important to recognise that the impact of any changes to Power and Water's revenue as a result of the AER's decision is constrained by the Pricing Order. Therefore, the outcomes flowing from the AER's final decision may not affect the retail electricity bill under the Pricing Order for customers in the Northern Territory.

123 RBA, Statement of Monetary Policy, Reserve Bank of Australia, May 2024.

Figure 3.12 Impact of AER revenue determinations on residential customer electricity bills



Note: Estimated impact of latest AER determination on the network component of a residential electricity bill based on AER estimates of retail electricity prices and typical residential consumption in each network. Revenue impacts are nominal and averaged over the life of the current determination. Annual change amounts and percentages are indicative. They are derived by varying the network component of the estimated bill amount in the final year of the previous regulatory period in proportion to yearly expected revenue divided by AEMO's forecast electricity delivered on the transmission network and forecast electricity for distribution as submitted by the relevant distribution network service provider. Actual bill impacts will vary depending on electricity consumption and tariff class. The data account only for changes in network charges, not changes in other bill components. Outcomes will vary among customers, depending on electricity use and network tariff structures.

Source: AER revenue determinations; additional AER modelling.

AEMO's 2024 Integrated System Plan appeals for urgent investment in generation, storage and transmission to deliver secure, reliable and affordable electricity through the energy transition.

3.11 Regulatory asset base

The regulatory asset base (RAB) represents the total economic value of assets that provide network services to customers.[124] The value of the RAB substantially impacts a network service provider's revenue requirement and the total cost a customer ultimately pays. Given some network assets have a life of up to 50 years, network investment will impact retail electricity bills long after the investment is made.

Network service providers receive a guaranteed return on their RAB. For this reason, they have an incentive to overinvest if their allowed rate of return exceeds their actual financing costs. Previous versions of the National Electricity Rules enabled significant overinvestment in network assets, which partly drove the sharp rise in network revenue from 2006 to 2015 (section 3.9). Under reforms introduced in 2015, the AER may remove inefficient investment from a network service provider's RAB if the service provider overspent its capital allowance, to ensure customers do not pay for it.

As part of the revenue determination process, the AER forecasts a network service provider's efficient investment requirements over the forthcoming regulatory period. Efficient investment approved by the AER is added to the RAB on which the business earns returns, while depreciation on existing assets is deducted. As such, the value of a service provider's asset base will grow over time if approved new investment exceeds depreciation. The RAB is adjusted at the end of the regulatory period to reflect actual investment.

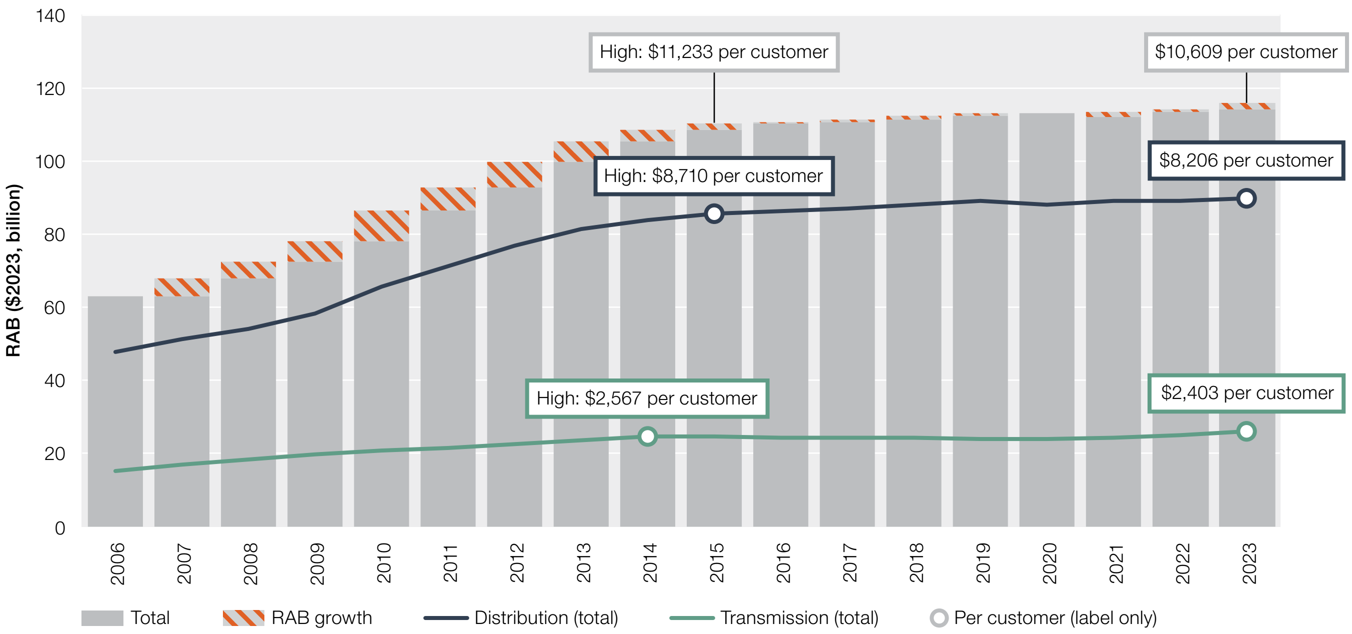
Escalating investment inflated the value of the total electricity network RAB from $63.2 billion in 2006 to $105.3 billion in 2013 – an increase of around 8% per year. Since then, network investment has steadied, as has the growth in the value of the total network RAB. From 2014 to 2023 the value of the total network RAB has continued to grow but at a considerably slower rate of around 1% per year.

124 To the extent that they are used to provide such services.

3.11.1 Regulatory asset base in 2023

As at 30 June 2023, the total combined value of the RAB for electricity network service providers was around $116 billion, an increase of $1.7 billion (1.5%) from the previous year (Figure 3.13).

Figure 3.13 Value of electricity network assets (regulatory asset base)



Note: All data are adjusted to June 2023 dollars. The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018).

Source: AER modelling; economic benchmarking RIN responses.

Recent RAB growth has been most pronounced for the Transgrid (NSW) and ElectraNet (South Australia) transmission service providers. Several major capital project investments in the previous period (2018–23) – Project EnergyConnect, HumeLink, Queensland–NSW Interconnector and Victoria–NSW Interconnector Minor – have driven the increase in Transgrid's RAB. Current period investment in these projects has already been scrutinised through contingent project assessments.[125]

Transgrid's RAB growth over the current regulatory period (2023–28) is expected to slow. However, possible 2023–28 investment projects, such as those relating to AEMO's Integrated System Plan (ISP) (section 3.13.6) and triggered contingent projects, could significantly increase Transgrid's RAB over the period.[126]

For ElectraNet (South Australia), large ISP-driven projects – including Project EnergyConnect and the Main Grid System Strength project – were added to regulated revenue during the previous regulatory period (2018–23). As these new assets are added to ElectraNet's RAB, the return on that capital investment will continue to be a significant contributor to the increase in ElectraNet's revenue and tariffs for 2023–28.

Increases in the values of the RAB are expected to continue as more major transmission network projects, which are required to enable the reliable supply of low carbon energy, enter development (section 3.13.6).

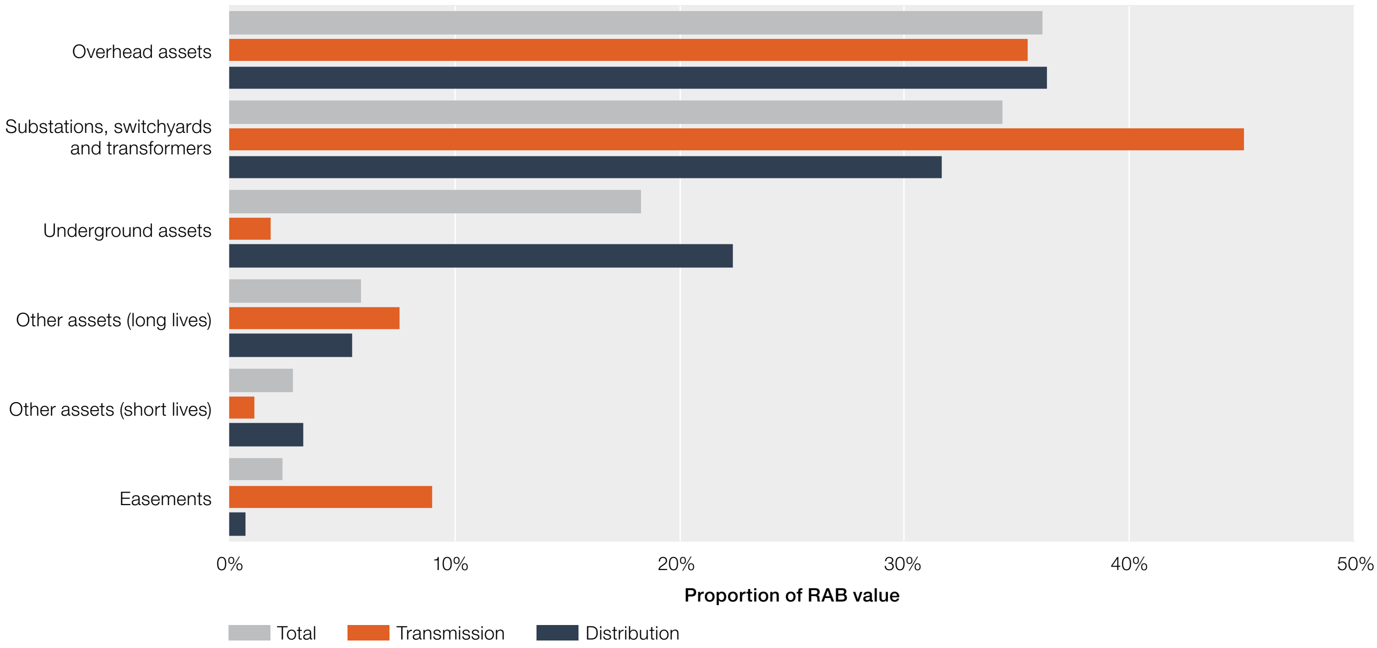
125 The AER is required by the National Electricity Rules (NER) to assess applications by network service providers to amend their regulatory revenue determination to include the revenue required for a contingent project. Contingent projects are major network infrastructure assets that have been flagged in long-term investment plans. When a network service provider has met the requirements to request cost recovery from consumers for one of these projects, it submits a contingent project application to the AER for approval. The AER then undertakes a rigorous assessment process to ensure that consumers pay no more than is needed to build the new infrastructure.

126 For example, the AER has approved 5 contingent projects with a combined value of $365 million.

3.11.2 Overhead support structures

A network service provider's RAB is made up of many assets, which can be broken down into several categories. Overhead network assets represent the most observable component of electricity network infrastructure and account for the greatest proportion (around 36%) of the total network RAB. This is not surprising given the combined transmission and distribution networks include more than 800,000 kilometres of line, 84% of which is above ground (Figure 3.14).

Figure 3.14 Disaggregated value of electricity network assets (regulatory asset base)



Source: Economic benchmarking RIN responses.

Network service providers install transmission towers and distribution poles to support overhead powerlines. Transmission towers are predominately made of steel, whereas distribution poles are made of wood, concrete, steel or composites like fibreglass. The differing environmental conditions faced by each network service provider can influence their choice of material. For example, in some parts of Australia, wooden poles are more quickly destroyed by termites, so metal poles are used instead. In its 2024–29 draft determination, the AER acknowledged Essential Energy's (NSW) proposed use of composite poles (made from resin and fibreglass) to replace wooden poles as part of its 'at-risk' poles program.[127]

Stobie poles – which are unique to South Australia – consist of 2 perpendicular lengths of steel-channel section held apart by bolts and the intervening space is filled with concrete, which protects the steel from corrosion. The poles – which were patented a century ago in 1924 – came about as an engineering solution to South Australia's lack of tall, termite-resistant hardwood for poles to carry powerlines and telephone wires.[128] SA Power Networks manufactures about 4,500 Stobie poles every year, which are used to replace poles when they have reached the end of their working life or when new overhead powerlines are being installed.[129]

SA Power Networks' distribution network consists of more than 70,000 kilometres of overhead powerlines.[130] However, overhead network assets only make up around 19% of the value of SA Power Networks' RAB. This relatively low proportion of overhead assets in SA Power Networks' RAB is uncommon among network service providers, especially given the extensive size of the network service area.

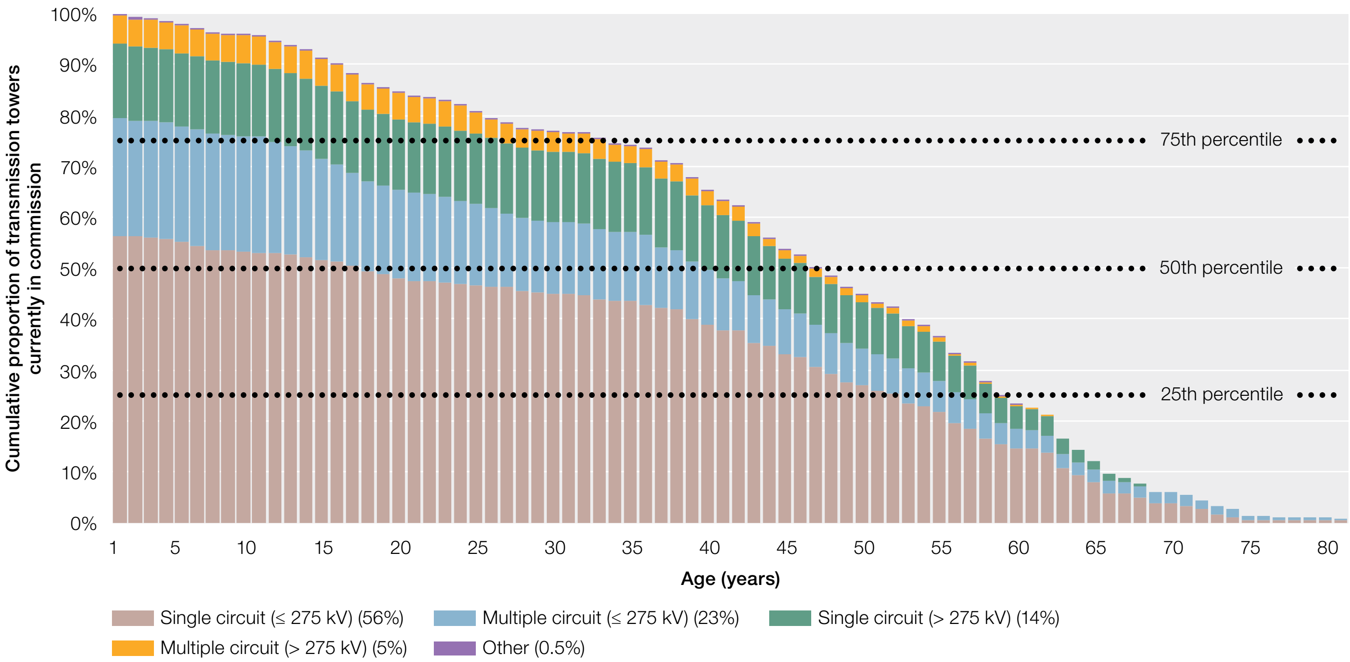
127 AER, Draft decision – Attachment 5 – Capital expenditure – Essential Energy 2024 to 2029, Australian Energy Regulator, September 2023.
128 P Sumerling and W Prest, Stobie Poles, SA History Hub, History Trust of South Australia, accessed 14 December 2020.
129 ABC News, Stobie poles are a South Australian icon, but how did they come about?, 31 March 2023, accessed 5 March 2024.
130 Third only to Essential Energy (NSW) with 182,936 km and Ergon Energy (Queensland) with 144,817 km.

Because of the hard-wearing and near-indestructible nature of the poles used in South Australia, the average pole in SA Power Networks' distribution network is considerably older than those found in any other network. Due to the relative age of the poles, a significant proportion of SA Power Networks' overhead assets are no longer included in the RAB. This unique feature makes SA Power Networks somewhat of an anomaly in the NEM and has the impact of providing cost savings for its current customers.

Some service providers, such as Essential Energy (NSW) and Ergon Energy (Queensland), operate larger, rural distribution networks that are almost entirely above ground. Conversely, CitiPower (Victoria) and Evoenergy (ACT) operate smaller, urban distribution networks that are predominately underground. It is not surprising that predominately rural networks are more reliant on overhead poles than the networks operating in more urban environments.

The asset age profiles shown in Figure 3.15 and Figure 3.16 provide an overview of the age of the towers and poles currently in commission across the collective transmission and distribution networks. However, we note the asset age and the types of towers and poles vary considerably between each network.

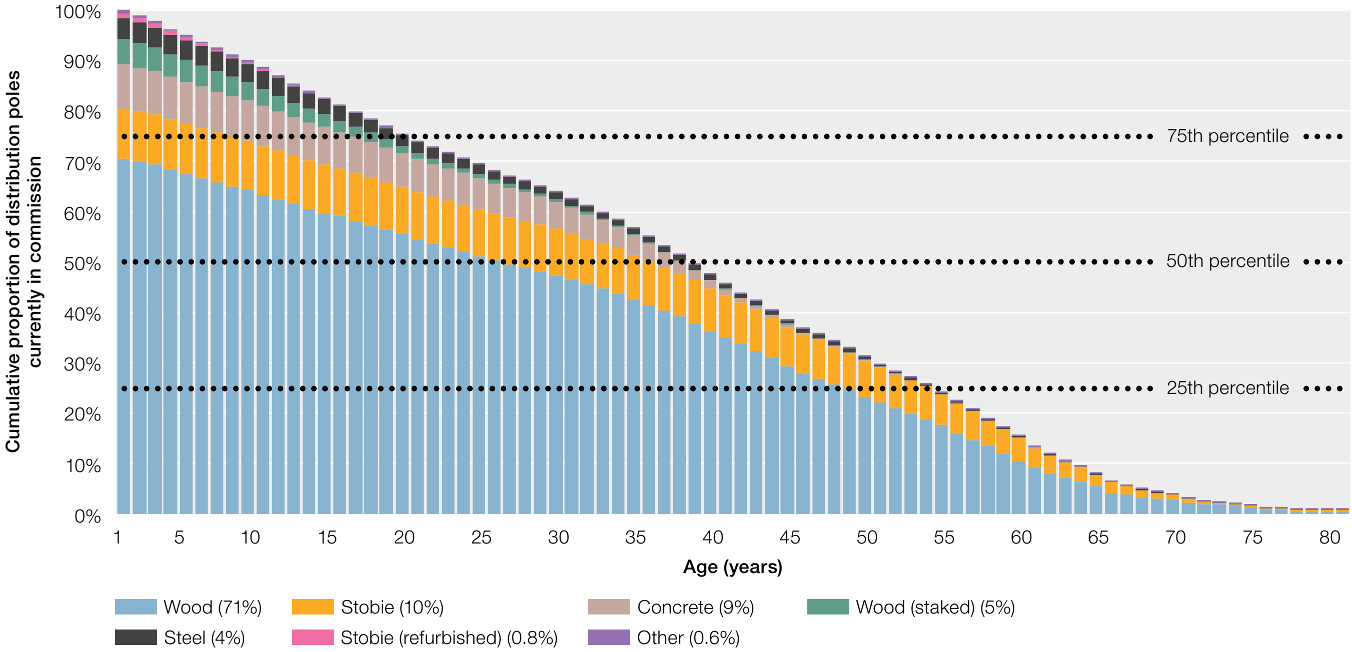
Figure 3.15 Overhead support structures – electricity transmission network towers



Note: kV: kilovolt.

Source: Category analysis RIN responses.

Figure 3.16 Overhead support structures – electricity distribution network poles



Note: Stobie poles, used almost exclusively in South Australia, are made up of 2 vertical steel posts with a slab of concrete between them.
Source: Category analysis RIN responses.

In May 2024, transmission network Transgrid (NSW) expressed that it aims to use as many Australian-made products as possible when constructing new transmission lines. However, due to considerable restrains on the availability of locally produced products, Transgrid has been forced to purchase equipment from overseas after it used up most of the existing capacity in Australia.

The increase in demand for the materials needed to construct energy infrastructure has been driven by the rollout of thousands of kilometres of new transmission lines to cater for the transition away from coal-fired energy.[131]

3.12 Rates of return

The shareholders and lenders that finance a network service provider expect a return on their investment. The rate of return estimates the financial returns that a network service provider's financiers require to justify investing in the business. It is a weighted average of the expected returns needed to attract equity and debt funding. Equity funding is provided by shareholders in exchange for part ownership of a network service provider, while debt funding is provided by an external lender such as a bank. Given this weighting approach, the rate of return is sometimes called the weighted average cost of capital (WACC).

The AER sets an allowed rate of return based on a benchmark efficient entity, but a network service provider's actual returns can vary from the allowed rate. The difference can be due to several factors, such as the impact of incentive schemes, efficiency improvements, forecasting errors or the network service provider adopting a different debt or tax structure to the benchmark efficient entity. Some differences may be temporary if caused by revenue over- or under-recovery under a revenue cap or the revenue smoothing process. The AER calculates allowed returns each year by multiplying the RAB (section 3.11) by the allowed rate of return.[132]

131 The Australian, Limits to buying local: Transgrid, 8 May 2024.

132 For example, if the rate of return is 5% and the RAB is $50 billion, then the return to investors is $2.5 billion. This return forms part of a network's revenue needs and must be paid for by energy customers.

If the AER sets the allowed rate of return too low, network service providers may not be able to attract sufficient funds to invest in the assets needed for a reliable power supply. Conversely, if the rate is set too high, service providers have a greater incentive to overinvest.

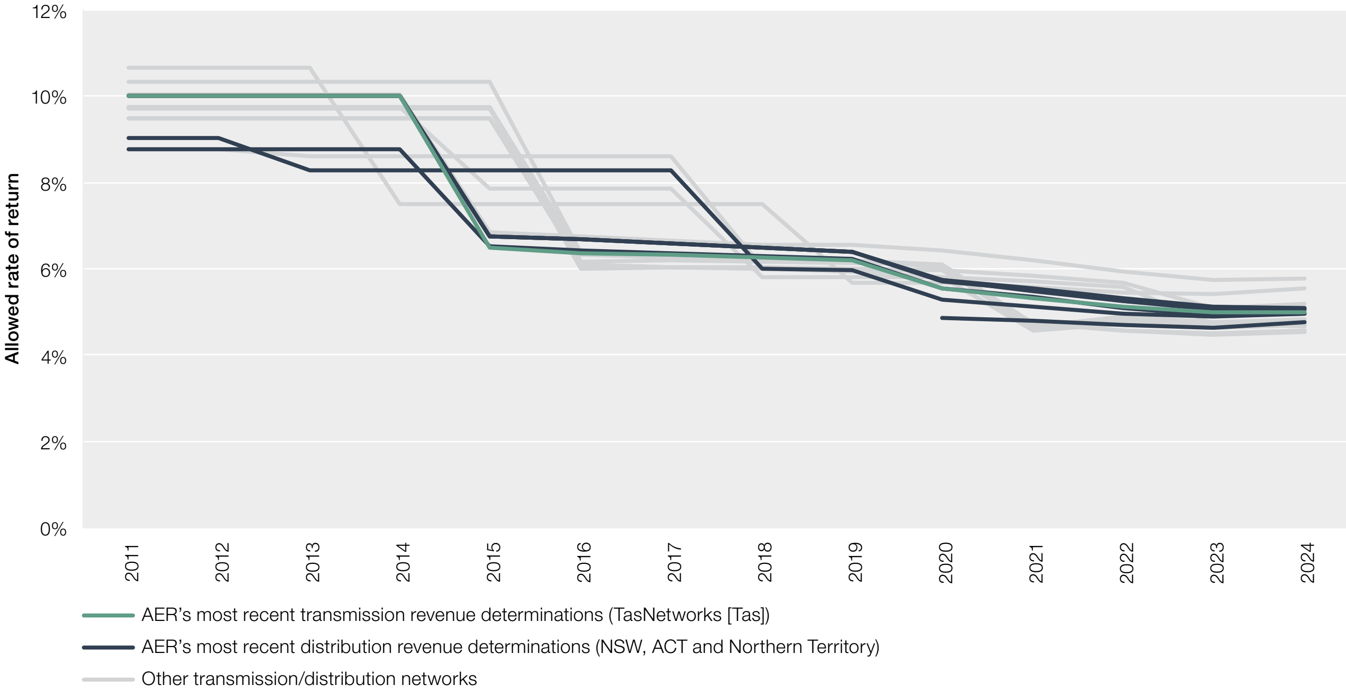
Because electricity networks are capital intensive, returns to investors typically make up around 45% (50% for transmission, 44% for distribution) of a network service provider's total revenue allowance. As such, a small change in the allowed rate of return can have a significant impact on both a network service provider's revenue and customers' electricity bills.

As an estimate, a one percentage point increase in the allowed WACC will increase revenues by around 8%, which would increase average household bills by around 4%.[133] For this reason, before limited merits review was abolished and the binding rate of return instrument was introduced, the allowed rate of return was often the most contentious part of the AER's individual revenue determinations.

Conditions in financial markets are a key determinant of the allowed rate of return. The AER's revenue determinations from 2009 to 2012 took place against a backdrop of the global financial crisis, an uncertain period associated with reduced liquidity in debt markets and high-risk perceptions. In revenue determinations made during this period the allowed rate of return was greater than 10%, reflecting the conditions in financial markets (Figure 3.17). The Australian Competition Tribunal increased some allowed rates of return following appeals by network service providers.

Since 2015 the AER has updated the allowed rate of return annually to reflect changes in debt costs. More stable financial market conditions resulted in allowed rates of return averaging around 6% from 2016. These lower allowed rates became a key driver of lower network revenues and charges over the past few years (Figure 3.17).

Figure 3.17 Allowed rate of return



Note: Allowed rate of return is the nominal vanilla weighted average cost of capital (WACC).

Source: AER determinations on electricity network revenue proposals; AER determinations following remittals by the Australian Competition Tribunal or Full Federal Court.

133 Average household bill calculation assumes $2,000 average household bill, 50% network component (transmission + distribution) and ignores demand impacts.

Recently, a key input into rates of return has increased. The risk-free rate is an important driver of allowed returns on equity and is estimated using required returns on Commonwealth Government Securities (CGSs), also known as Australian Government bonds. Since January 2020, annual yields on 10-year CGSs have ranged from 0.61% (March 2020) to 4.94% (November 2023). Over the 12-month period to July 2024, annual yields on 10-year CGSs averaged around 4.24%.[134]

If the risk-free rates continues to increase it will put upward pressure on network revenue over coming years.

In recent years the AER has estimated network service providers' actual returns to provide a comparison against their allowed returns. The outcomes suggest that actual returns often exceed the AER's allowed returns. This is not unexpected given that the premise of a revealed efficient cost framework is to encourage network service providers to become more efficient, allowing for short-term profits to be earned above the allowed rate.[135]

In March 2024 the 2022 Rate of Return Instrument was superseded by 'version 1.2' because the February 2023 version could not be applied to the Victorian electricity and gas distribution service providers. This updated version binds all regulatory determinations from 25 February 2023 until the next revision of the Instrument.[136]

3.13 Capital expenditure

Network service providers invest in capital equipment such as towers, poles, wires and other infrastructure needed to transport electricity to consumers. Investment drivers vary among networks and depend on each network's age and technology, load characteristics, the demand for new connections, and reliability and safety requirements. Substantial investment is needed to replace aging equipment as it wears out or becomes technically obsolete. Other investments may be made to augment (expand) a network's capability in response to changes in electricity demand.

3.13.1 Capital expenditure in 2023

Over the 12-month period to 30 June 2023, network service providers invested $6.8 billion in capital projects, $1.1 billion (20%) more than in the previous year and $437 million (7%) more than was forecast.

Table 3.6, Figure 3.18 and Figure 3.19 provide a summary of the capital expenditure outlaid in 2023 and how this compared with previous years' expenditure and forecasts.

Table 3.6 Capital expenditure in 2023 – key outcomes

Service type	Capital expenditure (2023)	Capital expenditure (compared with 2022)	Capital expenditure (compared with peak)
Transmission	$1.9b (▲3.6% than forecast)	▲$259m (▲15%)	▼$98m (▼4.8%) (2009)
Distribution	$4.8b (▲8% than forecast	▲$851m (▲21%)	▼$3.3b (▼41%) (2012)
Total	$6.8b (▲7% than forecast)	▲$1.1b (▲20%)	▼$3.2b (▼32%) (2012)

Note: Excludes AER determinations on transmission interconnectors.

134 RBA, Capital Market Yields – Government Bonds – Daily – F2, Reserve Bank of Australia, accessed 10 July 2024.

135 The AER's Electricity network performance reports investigate network profitability and provide a more thorough analysis of actual returns than allowed/forecast returns.

136 AER, Rate of Return Instrument 2022, Australian Energy Regulator, accessed 18 April 2024.

ElectraNet's (South Australia) overspend is 2023 was driven by both the Eyre Peninsula Transmission Supply project[137] and its contribution to the delayed Project EnergyConnect.[138]

Forecast capital expenditure increased for Transgrid (NSW) in 2023 primarily due to the forecast costs associated with Project EnergyConnect. Transgrid's actual capital expenditure in 2022 was significantly lower than forecast due in large part to its reprofiling of expenditure on Project EnergyConnect.

Significant investment in the transmission network is forecast to continue over the next few years (Figure 3.18). Although the estimated cost of actionable ISP projects under the 2024 ISP is around $27.8 billion[139] (Figure 3.24), most of this estimated cost does not yet fall within the AER's approved forecast expenditure window.

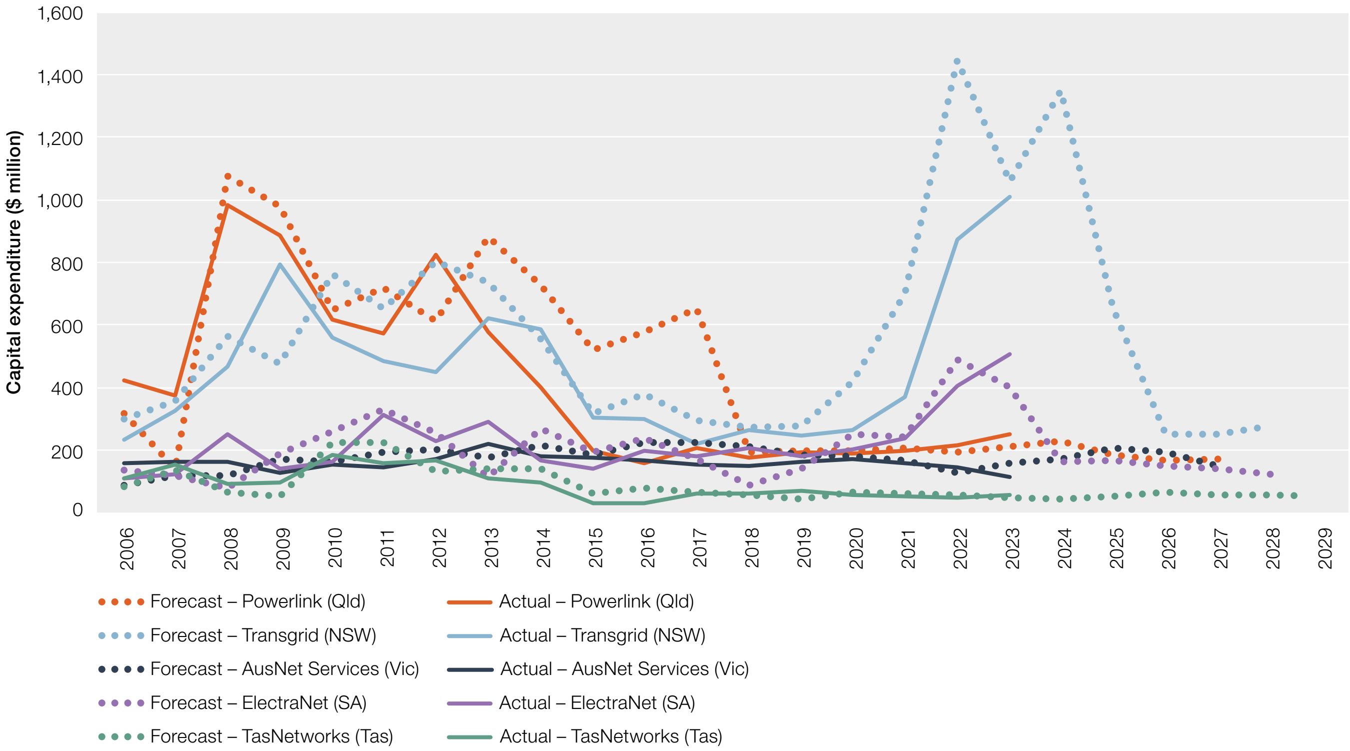
HumeLink, a proposed 500 kilovolt transmission line that will connect Wagga Wagga, Bannaby and Maragle and expand Transgrid's transmission network in NSW was identified as a staged actionable ISP project in AEMO's 2020[140] and 2022[141] ISPs and was confirmed to be actionable in AEMO's 2024 ISP.[142]

In 2022 and 2023, the AER made decisions on Transgrid's HumeLink stage 1 contingent project application, which related to early works or preconstruction activities. These activities included project design, stakeholder engagement, land-use planning and approvals and acquisition, project management and procurement of long lead equipment. These activities also allowed Transgrid to lock in prices, secure supply-chain availability for necessary equipment and refine its construction cost estimate for stage 2 of the project.

In August 2024, the AER approved $4.0 billion in forecast capital expenditure for stage 2 of Transgrid's HumeLink project. The AER's role in the process was to assess Transgrid's contingent project application to determine the incremental revenues that are to be added to its revenue allowance. The AER did not accept Transgrid's proposed expenditure of $4.3 billion because it did not consider the proposed amount reflected prudent and efficient capital expenditure required to deliver the project. Subject to a financial investment decision by the proponent, Humelink is likely to be completed by 2026–27.

137 ElectraNet, Eyre Peninsula Link, accessed 31 July 2024.
138 AER, Electricity network performance report 2023, Australian Energy Regulator, July 2023, p. 16.
139 AEMO, 2024 Integrated System Plan, Australian Energy Market Operator, June 2024, pp. 61–63.
140 AEMO, 2020 Integrated System Plan, Australian Energy Market Operator, July 2020.
141 AEMO, 2022 Integrated System Plan, Australian Energy Market Operator, June 2022.
142 AER, Transgrid HumeLink contingent project stage 2, Australian Energy Regulator, 2 August 2024.

Figure 3.18 Capital expenditure – electricity transmission networks



Note: All data are adjusted to June 2023 dollars. The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018). Assumptions are set out in the Figure 3.7 notes.

Source: AER modelling; annual reporting RIN responses.

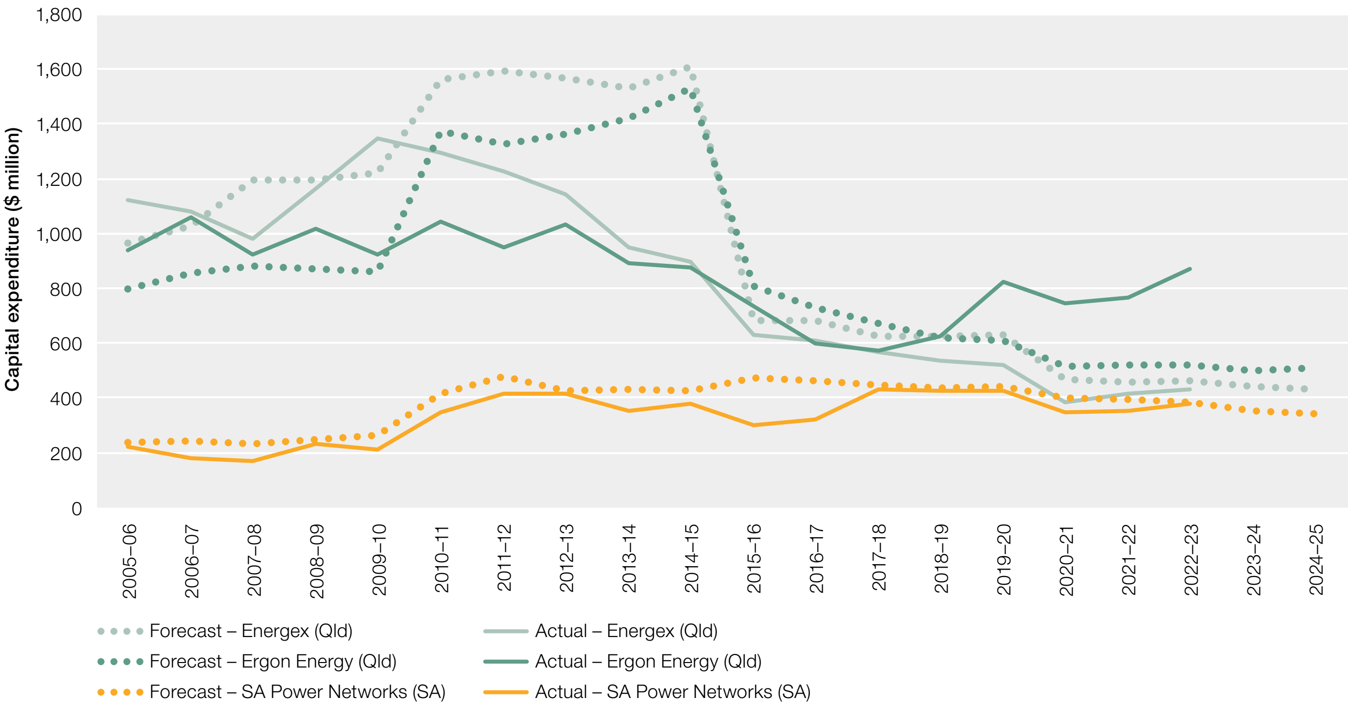
In 2023, Ergon Energy (Queensland) materially overspent against forecast capital expenditure for the fourth consecutive year. Ergon Energy submitted that overspends were driven by the need to address priority network safety programs, including defect rectifications and remediation works.[143]

If the AER considers that over expenditure against the approved capital allowance is efficient, the excess spending, or a proportion thereof, may be added to the RAB (section 3.11). Conversely, if the AER considers over expenditure to be inefficient, the excess spending may not be added to the RAB. Instead, the service provider bears the cost by taking a cut in profits. This condition protects consumers from funding inefficient expenditure.

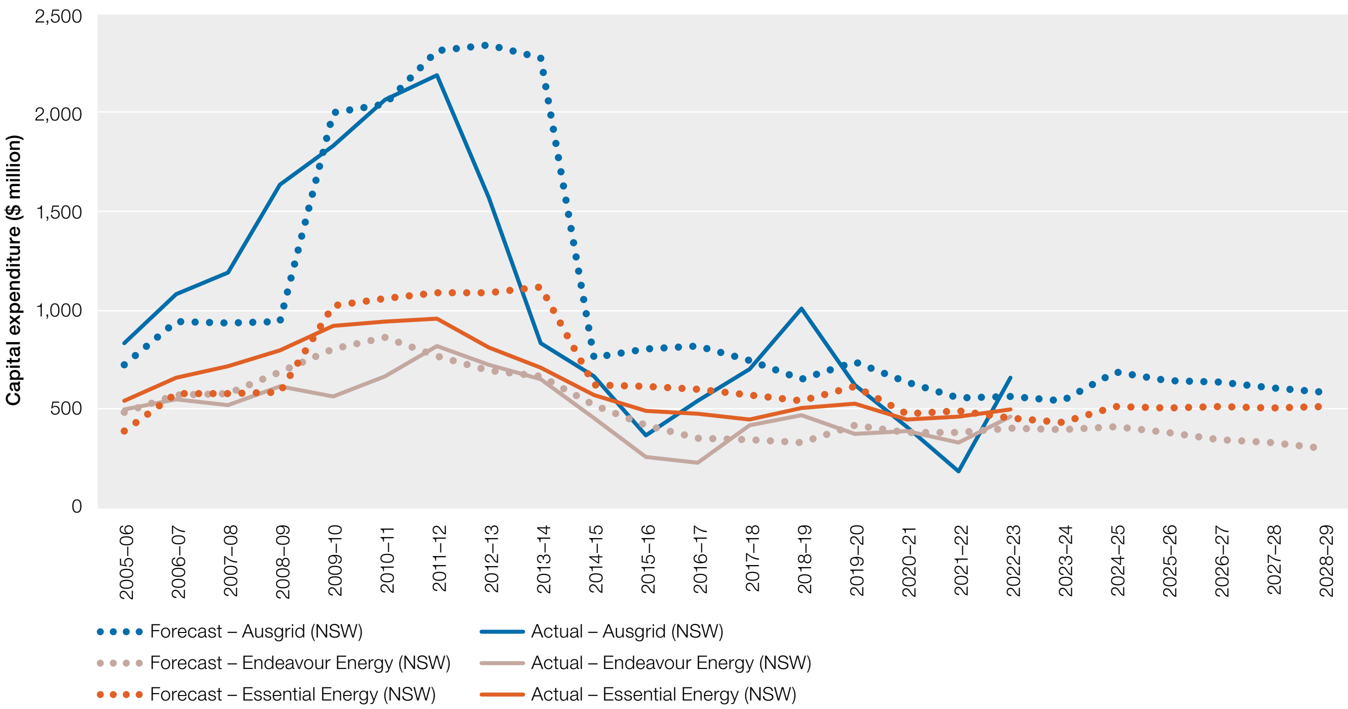
143 Ergon Energy, 2021-22 and 2022-23 Annual reporting RINs, 31 October 2022 and 2023.

Figure 3.19 Capital expenditure – electricity distribution networks

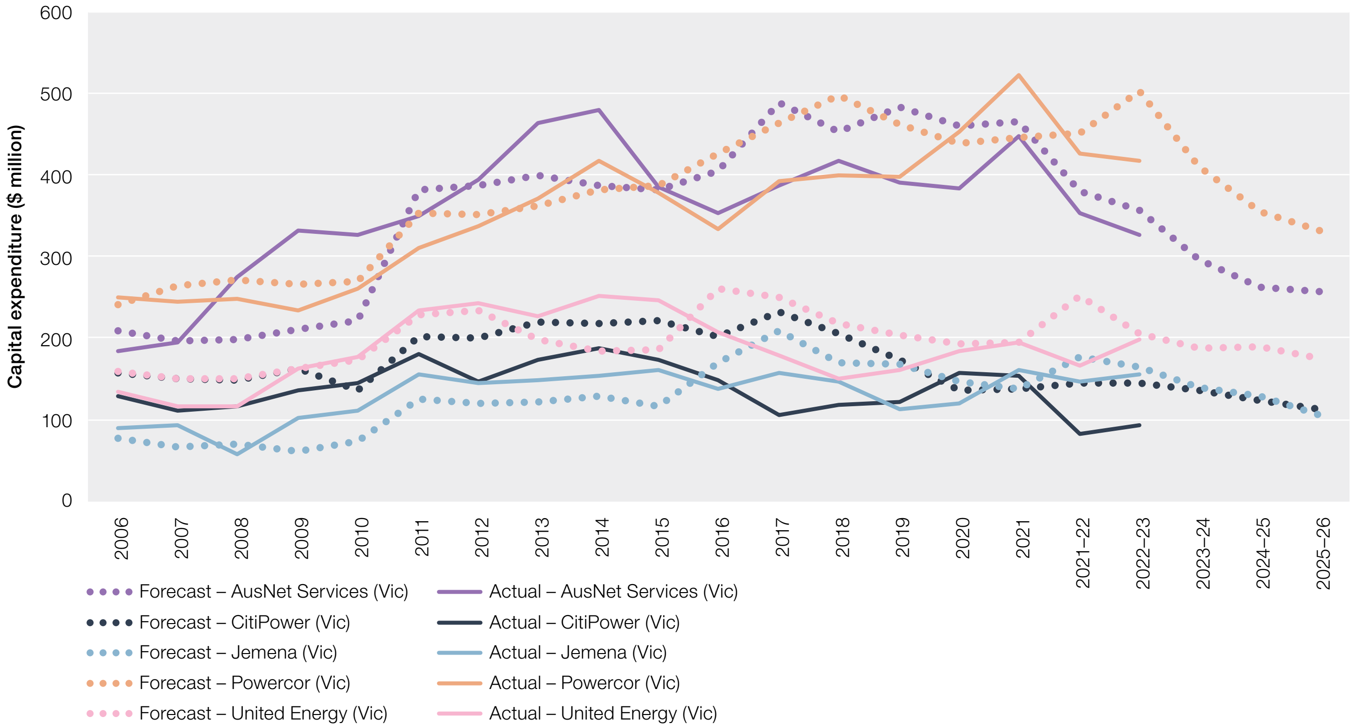
Queensland and South Australia



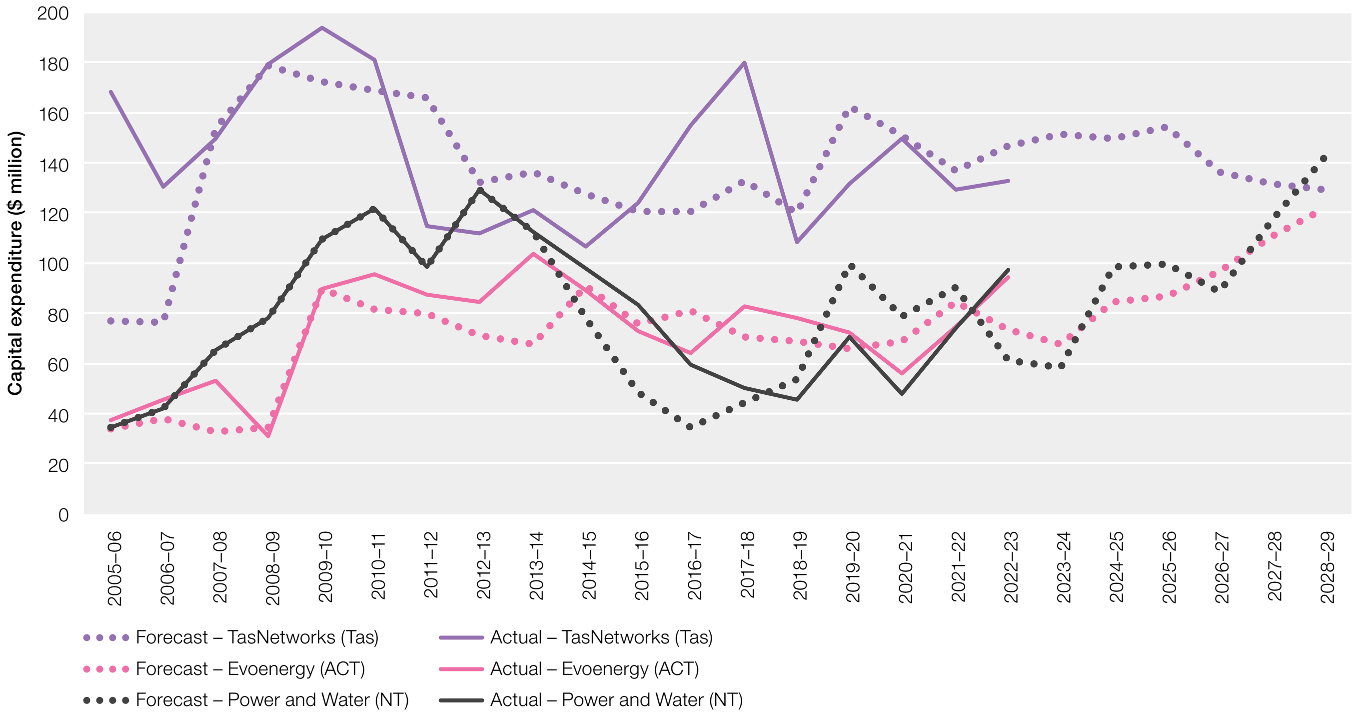
New South Wales



Victoria



Tasmania, ACT and Northern Territory



Note: All data are adjusted to June 2023 dollars. Most network service providers have always reported on a 1 July to 30 June basis. The exception is the Victorian networks, which until year end 2020 reported on a 1 January to 31 December basis. Capital expenditure for the Victorian distribution networks for the 2021 year has been derived from the transitional year (1 January to 30 June 2021). To enable reporting on equivalent terms, these values have been doubled.

Source: AER modelling; annual reporting RIN responses.

3.13.2 Trends in capital expenditure

Investment in electricity transmission and distribution networks increased by an average of 8% per year in the 6-year period from 2006 before peaking at around $10 billion in 2012 (Figure 3.7 and Figure 3.9).

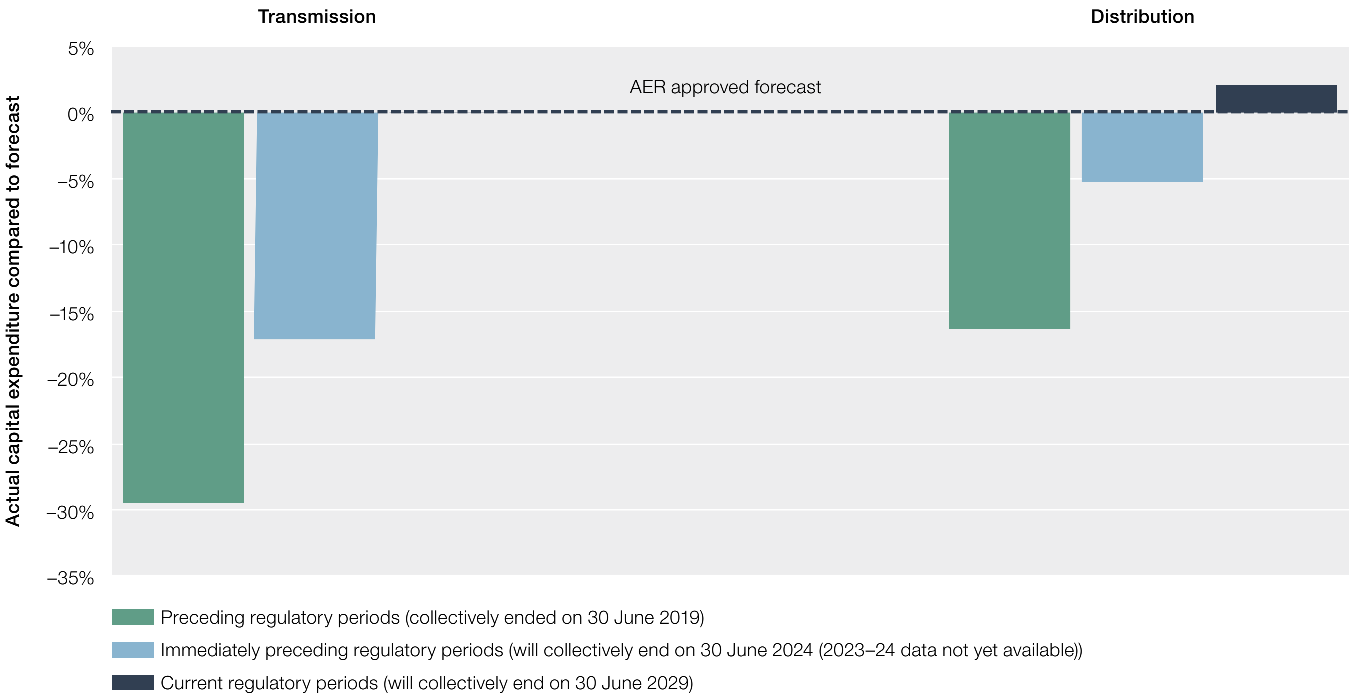
In the 4-year period from 2006 to 2009, network service providers invested $2.7 billion (10%) more on capital projects than was forecast. In 2006, governments and the AEMC changed the rules to incentivise greater investment to address concerns that network investment was not keeping pace with projected growth in electricity demand. More stringent reliability standards imposed by state governments in NSW and Queensland also contributed to this growth by requiring new investment to meet the stricter targets.

However, the trend of overspending was soon to be reversed, with service providers underspending by $14.8 billion (18%) against forecast over the following 9 years (from 2010 to 2018). Over this time, many investment projects were either postponed or abandoned when it became clear earlier projections of sustained demand growth would not eventuate. Further, a shift in government policy towards less stringent reliability obligations made some projects redundant, leading to several proposals being scaled back or deferred.

The disparity between forecast and actual investment has eased in recent years. This timing aligns with the AER's reforms to protect consumers from funding inefficient network projects (Figure 3.20).

Over the 5-year period from 2014 to 2018, network service providers invested $9.6 billion (24%) less on capital projects than was forecast. Over the past 5 years (from 2019 to 2023), network service providers have continued to underspend against forecast, but the level of under expenditure has declined ($1.7 billion (5%) less than was forecast). The service providers reporting the most significant (relative) underspends over the past 5 years were Transgrid (NSW) and CitiPower (Victoria), which collectively underspent by 27%.[144]

Figure 3.20 Capital expenditure against forecast



Source: AER modelling; annual reporting RIN responses.

144 Transgrid's actual capital expenditure in 2022 was significantly lower than forecast due in large part to its reprofiling of expenditure on Project EnergyConnect.

The AER assesses capital expenditure drivers when forming its view on the prudency of a network service provider's capital expenditure forecast. The AER does not determine which capital programs or projects a network service provider should or should not undertake. Once the AER sets a capital expenditure forecast, it is up to the network service provider to prioritise its investment program. However, all network service providers are required to undertake a cost-benefit analysis for new investment projects that meet specific cost thresholds.

In the AER's most recent revenue determinations, the most significant driver of forecast investment expenditure was the replacement of assets that are reaching the end of their life, along with infrastructure that supports the delivery of electricity transmission services.

In 2015 the AER introduced the capital expenditure sharing scheme (CESS), which offers financial incentives for network service providers to avoid undertaking investment above forecast levels (Box 3.2).

Box 3.2 Capital expenditure sharing scheme

The AER's capital expenditure sharing scheme (CESS) incentivises network service providers to keep new investment within the forecast levels approved in their regulatory determination. The CESS rewards efficiency savings (spending below forecast) and penalises efficiency losses (spending above forecast).

In its current form, the CESS allows a network service provider to retain underspending against forecast for the duration of the applicable regulatory period (which may be up to 5 years, depending on when the spending occurs). In the subsequent regulatory period, the network service provider must pass on 70% of underspends to its customers as lower network charges. The service provider retains the remaining 30% of the efficiency savings.

After the regulatory period, the AER conducts an ex-post review of the network service provider's spending. Approved capital expenditure is added to the regulatory asset base (RAB) (section 3.11). However, if a service provider overspends its capital allowance, and the AER finds the overspending was inefficient, the excess spending may not be added to the RAB. Instead, the service provider bears the cost by taking a cut in profits. This condition protects consumers from funding inefficient expenditure.

Following its 2023 review of incentive schemes[a] the AER elected to amend the CESS and implement the Bright-Line Tiered Test. This will apply:

- a 30% sharing ratio for any underspend up to 10% of the forecast capital expenditure allowance in the previous regulatory period
- a 20% sharing ratio for any underspend that exceeds 10% of the forecast capital expenditure allowance in the previous regulatory period
- a 30% sharing ratio for any overspend of the forecast capital expenditure allowance in the previous regulatory period.

The Bright-Line Tiered Test approach has been designed to be asymmetric. Despite improvements in the AER's capital expenditure assessment toolkit and stakeholder engagement, a level of information asymmetry between the regulator, consumers and the network service providers remain. The scheme poses risks that network service providers may inflate their original investment forecasts. To manage this risk, the AER assesses whether proposed investments are efficient at the time of each revenue determination. Another risk is that the scheme may incentivise a network service provider to earn bonuses by deferring critical investment needed to maintain network safety and reliability.

To manage this risk, the CESS is balanced by separate incentives that focus on efficient operating expenditure (Box 3.3) and service quality (Box 3.4). This balancing of schemes encourages network service providers to make efficient decisions on their mix of expenditure to provide reliable services in ways that customers value (section 3.16.1).

For large transmission investments, the AER will consider whether the CESS is fit for purpose on a case-by-case basis.

The changes to the CESS are supplemented by transparency measures that will require network service providers to better explain the reasons for variations between operating and capital expenditure outcomes and forecasts. This will in turn assist stakeholders to better understand the extent to which genuine efficiency gains have driven expenditure outcomes, and the value of incentive payments.

a AER, Review of incentive schemes for regulated networks, Australian Energy Regulator, accessed 3 May 2023.

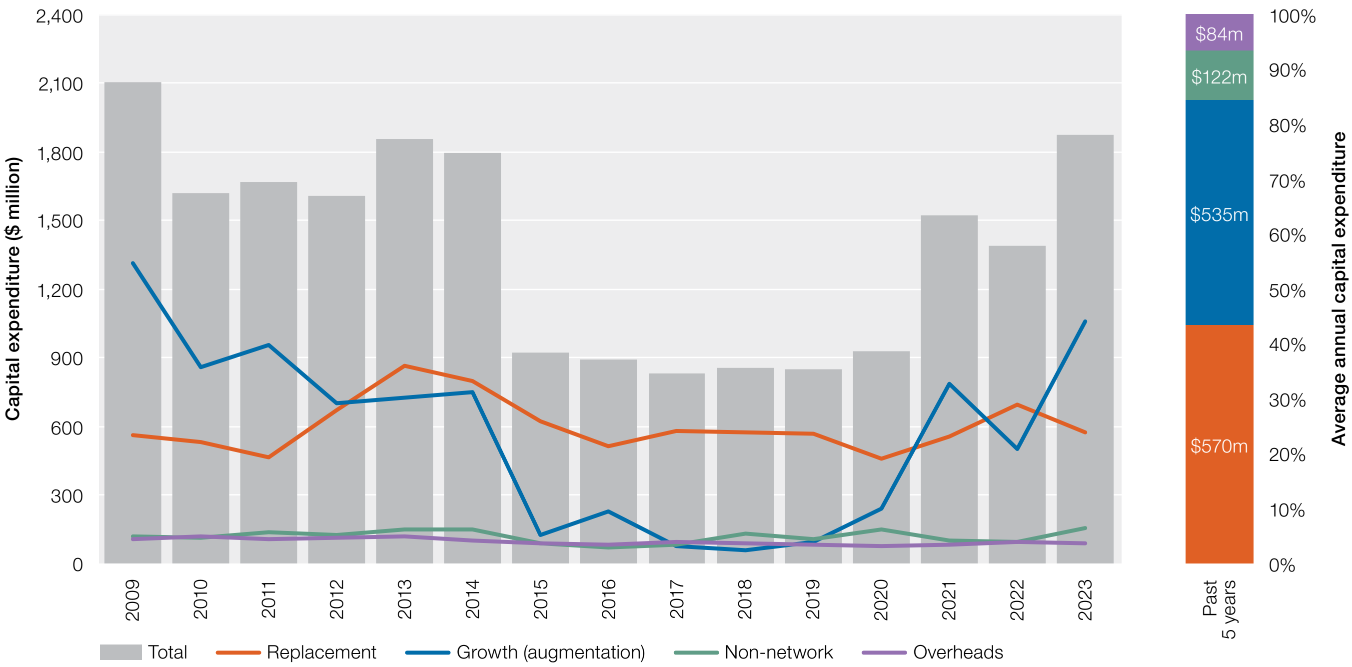
3.13.3 Changing composition of investment

Over the 12-month period to 30 June 2023, service providers invested $2.5 billion on replacing existing infrastructure on their respective networks. Over the last decade, replacement expenditure has been the primary component of network investment (Figure 3.21 and Figure 3.22).

However, in 2023 network service providers also spent $2.1 billion on growth-related projects, $578 million (38%) more than in the previous year and the most since 2014. The recent increase in growth-related expenditure has been driven by Transgrid's (NSW) substantial investment in Project EnergyConnect, stage 1 of which is expected to be completed in December 2024.[145]

Transgrid has also forecast substantial investment in developing HumeLink (section 3.13.1), which, among other roles, aims to connect Snowy 2.0 to the grid by 2026. In May 2024, Snowy Hydro stated that despite 'challenging' conditions the project is on schedule and is expected to be operational by December 2028.[146]

Figure 3.21 Drivers of capital expenditure – electricity transmission networks (aggregate)



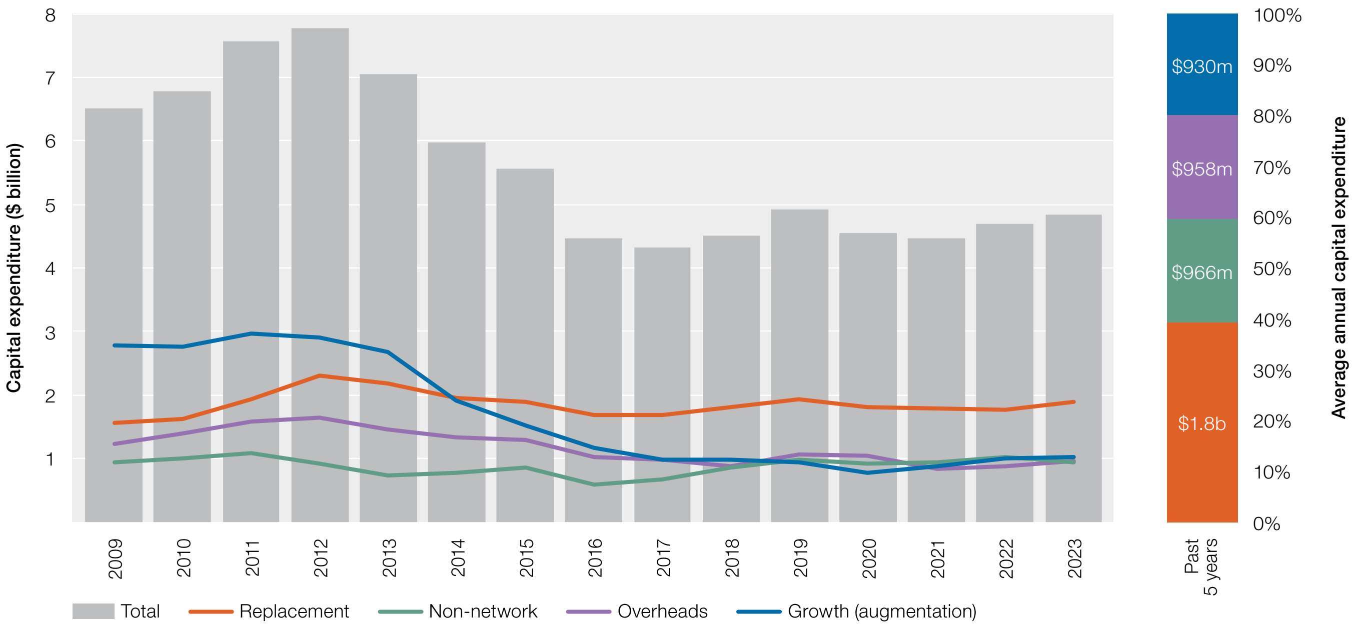
Note: All data are adjusted to June 2023 dollars. The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018). Augmentation of the Victorian transmission network is carried out by AEMO; hence, AusNet Services reports $0 expenditure for augmentation carried out on the transmission network.

Source: Category analysis RIN responses.

145 AEMO, 2024 Integrated System Plan, Australian Energy Market Operator, June 2024, p. 14.

146 ABC News, Snowy Hydro boss doubles down on project timeline despite slow progress and budget blow-out, 9 May 2024, accessed 8 August 2024.

Figure 3.22 Drivers of capital expenditure – electricity distribution networks (aggregate)



Note: All data are adjusted to June 2023 dollars. The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018).

Source: Category analysis RIN responses.

AEMO's 2024 ISP notes that effective integration of consumer energy resources has the potential to significantly reduce future grid-scale investment needed to support increases in electricity consumption. For example, recent analysis by the Institute for Energy Economics and Financial Analysis indicates that consumer energy resources (across the full range of possible sources) has the potential to deliver $11 billion in avoided network costs if well integrated.[147]

3.13.4 Valuing consumer energy resources

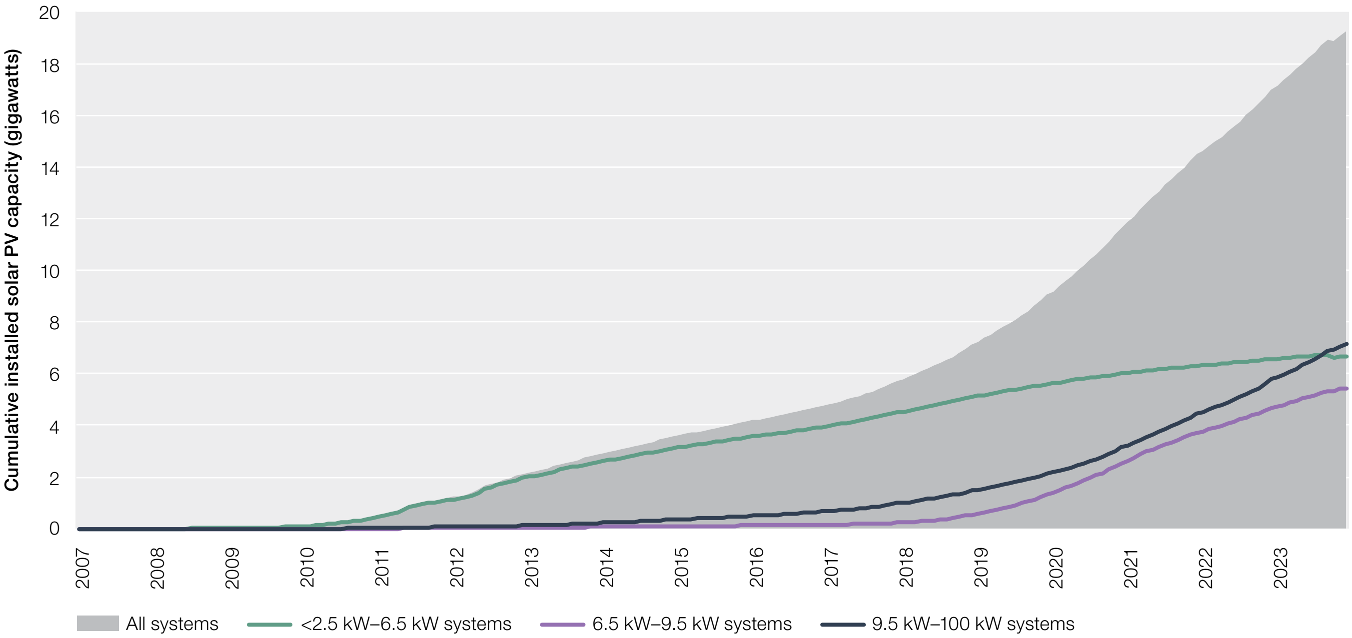
The uptake of rooftop solar photovoltaic (PV) systems has grown exponentially over the past decade. As a result of this rapid growth, integration of consumer energy resources such as solar PV, batteries and electric vehicles now presents a significant, emerging area of network expenditure.

Solar PV costs have decreased over time, which means it is now more affordable for consumers to install a larger system to cover a higher proportion of their energy consumption. Over the 3 years to December 2023, the total installed capacity of smaller solar PV systems with a capacity of up to 6.5 kilowatts increased by 11%, while the total installed capacity of systems with a larger capacity of 6.5 to 100 kilowatts increased by 122% (Figure 3.23).[148]

147 Australian Government, National consumer energy resources roadmap – Powering decarbonised homes and communities, 19 July 2024, accessed 8 August 2024, p. 9.

148 Excludes Western Australia.

Figure 3.23 Cumulative installation of small-scale solar, by system size



Note: kW: kilowatts. PV: photovoltaic.
Includes installations of PV systems up to 100 kW in size. Data covers all jurisdictions in Australia except Western Australia.

Source: AER analysis of postcode data from the Australian PV Institute, collected on 14 May 2024.

In November 2019, the AER began developing guidance around assessing proposed expenditure for integrating consumer energy resources. As part of this process, the AER sought stakeholder views on the current and predicted effects consumer energy resources are having on electricity networks and whether its current set of expenditure assessment tools are fit for purpose.

In 2020, the AER released a report (by the CSIRO and CutlerMerz) on potential methodologies for determining the value of consumer energy resources.[149] The preferred methodology compares the total electricity system costs from increasing hosting capacity with the total electricity system costs of not doing so. Electricity system costs include the investment costs, operational costs and costs on the system from environmental outcomes of large-scale generation, essential system services, network assets and consumer energy resources installed by customers.

The findings and recommendations of the report were reviewed and considered as part of the AER's draft consumer energy resources integration expenditure guidance note published in July 2021.[150]

The AEMC, in its *Electricity network economic regulatory framework 2020 review*, noted that the central roles of networks in a future with high levels of consumer energy resources are likely to remain the same as today. Network service providers will continue to be responsible for transporting electricity and providing a safe, secure and reliable supply of electricity as a monopoly service provider. However, how they undertake this role could differ. In particular, how the electricity distribution network is operated and the services provided by distribution network service providers could change.

An environment with high levels of consumer energy resources could mean that distribution network service providers need to alter aspects of their operation – from transporting electricity one-way to being platforms for multiple services, facilitating electricity flows in multiple directions and enabling efficient access to markets for consumer energy resources so that they can provide the greatest benefits to the system as a whole. This change is likely to have implications for some features of the current regulatory framework.[151]

149 CSIRO and CutlerMerz, Value of distributed energy resources: methodology study – final report, October 2020. The labels 'consumer energy resources' and 'distributed energy resources' are used interchangeably.

150 AER, Draft DER integration expenditure guidance note, Australian Energy Regulator, 6 July 2021.

151 AEMC, Electricity network economic regulatory framework 2020 review, Australian Energy Market Commission, 1 October 2020.

In April 2023, the AER released its consumer energy resources strategy, which communicates its goal to enable consumers to own and use energy resources to consume, store and trade energy as they choose in support of the broader long-term interest of all energy consumers. The strategy also provides an overview of how the various AER workstreams fit together holistically to achieve the goal.[152]

In December 2023, the AER published its first export services network performance report.[153] The report provides an overview of the increasing role consumer export resources have within the NEM. The AER will publish updates to the export services network performance report annually.

In July 2024, the Australian Government published its National Consumer Energy Resources Roadmap, setting national reform priorities to build consistency across Australia and support a harmonised approach to unleashing the full potential of consumer energy resources. The reforms intend to enable uptake of consumer energy resources to be as efficient and effective as possible, with benefits spread more fairly, including where jurisdictions choose to provide subsidies to accelerate investment.[154]

3.13.5 Regulatory tests for efficient investment

The AER assesses network service providers' efficient investment requirements every 5 years as part of the regulatory process, but it does not approve individual projects. Instead, it administers a cost-benefit test called the regulatory investment test (RIT). The National Electricity Rules require a network service provider to apply the RIT for transmission projects that have an estimated capital cost of greater than $7 million and for distribution projects that have an estimated capital cost of greater than $6 million.

There are separate tests for transmission networks (RIT-T) and distribution networks (RIT-D). The AER publishes guidelines on how to apply the tests and monitors network service providers' compliance with the tests. The AER also resolves disputes over whether a network service provider has properly applied a test. Civil penalties including fines apply to service providers that do not comply with some of the RIT requirements (including the required consultation procedures).

A service provider must evaluate credible alternatives to network investment (such as generation investment or demand side response) that may address the identified need at lower cost. The network service provider must select the option that delivers the highest net economic benefit, considering any relevant legislative obligations. This assessment requires public consultation.

In 2020, the AER published guidelines that prescribe the cost benefit analysis framework, consultation processes and forecasting practices that the Australian Energy Market Operator (AEMO) must apply when developing its Integrated System Plan (ISP). AEMO's 2022 ISP brought into effect the AER's guidelines to make the ISP actionable.[155] The guidelines include a cost benefit analysis guideline,[156] a forecasting best practice guideline and updates to the regulatory investment test for transmission (RIT-T) instrument[157] and application guidelines.[158] The guidelines are part of broader reforms that were led by the Energy Security Board, with changes made to the National Electricity Rules to streamline the transmission planning process while retaining rigorous cost-benefit analyses.

152 AER, Consumer energy resources strategy, Australian Energy Regulator, 3 April 2023.

153 AER, Export services network performance report 2023, Australian Energy Regulator, 20 December 2023.

154 Australian Government, National consumer energy resources roadmap – Powering decarbonised homes and communities, 19 July 2024, accessed 8 August 2024, p. 5.

155 AER, Final decision – guidelines to make the Integrated System Plan actionable, Australian Energy Regulator, August 2020.

156 AER, Cost benefit analysis guidelines, Australian Energy Regulator, August 2020.

157 AER, Application guidelines – regulatory investment test for transmission, Australian Energy Regulator, August 2020.

158 AER, Guidelines to make the integrated system plan actionable, Australian Energy Regulator, August 2020, accessed 29 March 2022.

In April 2024, the AER commenced a review of the cost benefit analysis guidelines, the RIT instruments and accompanying application guidelines. This review is considering changes to these guidelines and instruments to account for recent changes to the NER and changes raised in the AER's *Directions paper – Social licence for electricity transmission projects*. The review is considering the changes in the NER by including additional guidance on:

- valuing changes in Australia's greenhouse gas emissions as a class of market benefit
- enhanced community engagement by RIT-T proponents
- treatment of concessional finance benefits
- treatment of costs associated with early works that are undertaken concurrently with a RIT-T for an actionable ISP project
- the timing and bases for ISP feedback loop assessments by AEMO in relation to final RIT-Ts for actionable ISP projects.

In January 2024, the AER published a report detailing the outcomes of its transparency review of AEMO's Draft 2024 ISP.[159] The AER assessed the adequacy of AEMO's explanation of how key inputs and assumptions had been derived and how those inputs and assumptions contributed to the outcomes in the Draft 2024 ISP. The review is not intended to assess the merits of AEMO decisions; rather, it is to form an opinion on the adequacy of AEMO's explanations.

The AER identified some issues that required AEMO to provide further explanation in an addendum to their Draft 2024 ISP and to consult on these issues in the Final 2024 ISP. Transparency in understanding AEMO's approach is important because it promotes stakeholder understanding of key inputs and assumptions that impact the ISP, which in turn promotes confidence in the ISP itself.

159 AER, Transparency review of AEMO draft 2024 Integrated Systems Plan, Australian Energy Regulator, accessed 9 August 2024.

3.13.6 AEMO's Integrated System Plan

AEMO's ISP provides a coordinated whole-of-system plan for efficient development of the power system in the NEM to ensure needs are met in the long-term interests of consumers. Through its ISP, AEMO identifies the transmission network options (or equivalent non-network solutions) that are most likely to optimise net market benefits through the electricity system's transition to a lower carbon future.

The 2024 ISP appeals for urgent investment in generation, storage and transmission to deliver secure, reliable and affordable electricity through the energy transition. The ISP's optimal development path sets out the needed generation, firming and transmission to transition to net zero by 2050 through current policy settings. The optimal development path includes 'actionable projects', which should be delivered urgently, and 'future ISP projects', which may require transmission network service providers to undertake preparatory activities. It also states that distribution will play a major role in the transition by hosting consumer energy resources and some utility-scale renewable and storage projects – facilitating coordinated two-way flow of electricity between grids.[160]

Significant investment in the transmission network is forecast over the next decade. The modelled cost of actionable ISP projects under the 2024 ISP is around $27.8 billion (Figure 3.24).

The 2024 ISP reflects that many consumers – both residential and business – are already taking steps to shape their future energy systems. Consumers continue to adopt innovative ways to reduce and manage their demand, investing in consumer energy resources – such as solar systems, batteries and electric vehicles – and contributing to virtual power plants to bring them together. These innovations and resources – supported by distribution, system operators and third parties – play a key role in the energy transition and will be a valuable resource in the future energy system. The ISP forecasts more than 30% of generation will be provided by rooftop/other distributed solar and consumer-based storage by 2049–50 compared with only 12% in 2023–24.

AEMO recognises the impact that new transmission infrastructure has on landholders and their communities, which is why there is a clear need for earlier engagement to allow for more coordinated and effective consultation.

The AER provides oversight of the ISP by ensuring that AEMO's processes are robust, credible and transparent. The requirements and considerations that are expected of AEMO's forecasting processes are specified in the AER's forecasting best practice guidelines[161] and cost benefit analysis guidelines.[162] The guidelines seek to provide AEMO with flexibility in how it identifies the optimal pathway for the NEM when developing the ISP based on a quantitative assessment of the costs and benefits of various options across a range of scenarios. The guidelines also apply to RIT-Ts for actionable ISP projects.[163]

A distinction between ISP and non-ISP projects was introduced to avoid duplication of project assessments where analysis has already occurred in developing the ISP. The current transmission planning framework will remain largely unchanged for non-ISP projects, such as asset replacements.

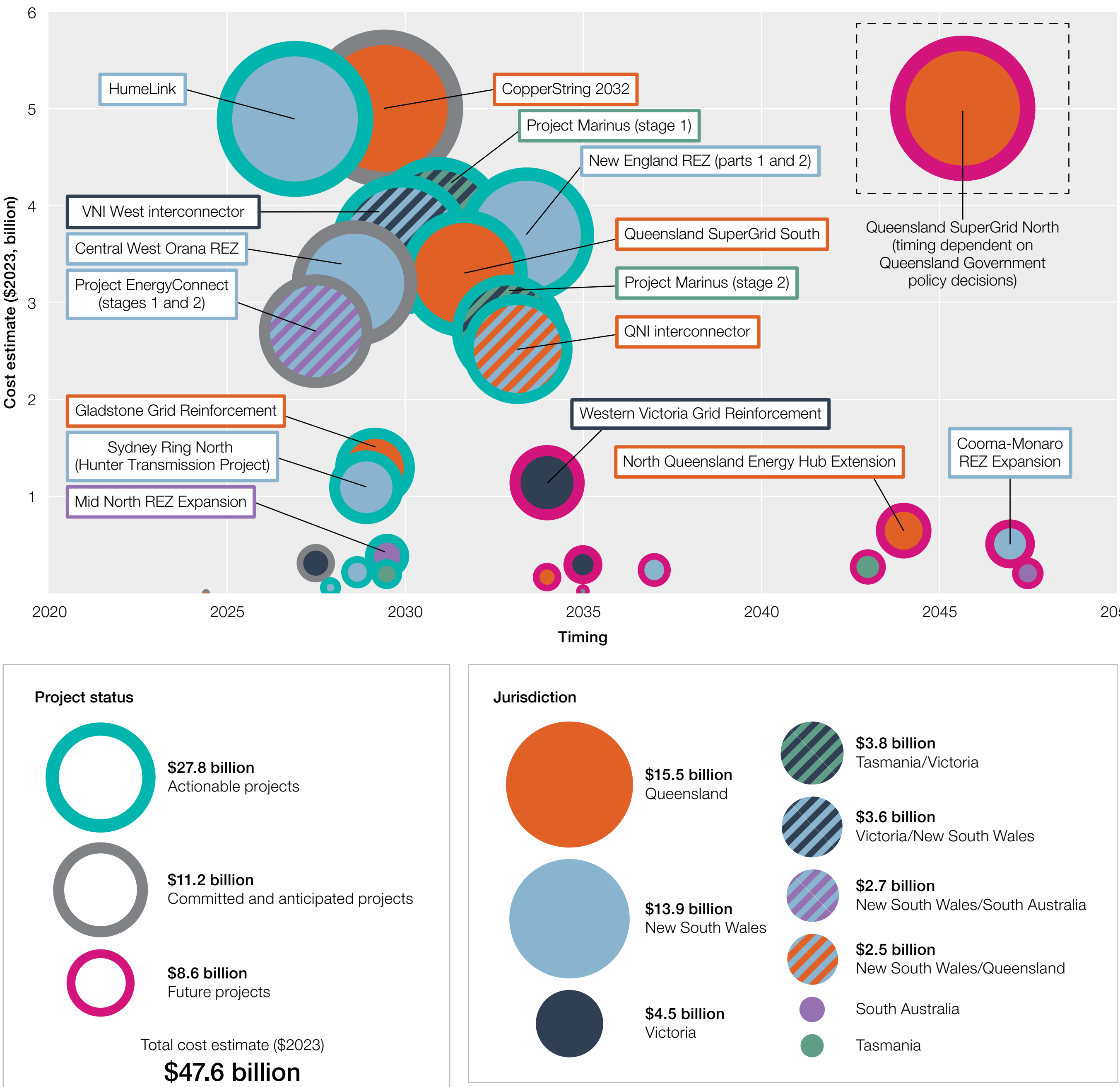
160 AEMO, 2024 Integrated System Plan, Australian Energy Market Operator, June 2024.

161 AER, Forecasting best practice guidelines, Australian Energy Regulator, August 2020.

162 AER, Cost benefit analysis guidelines, Australian Energy Regulator, August 2020.

163 Actionable ISP projects are identified in an ISP and trigger RIT-T applications for these projects. Under the RIT-T Instrument, RIT-T proponents must identify the credible option that maximises the present value of net economic benefit to all those who produce, consume and transport electricity in the market.

Figure 3.24 AEMO's 2024 Integrated System Plan



Note: The size of the bubble reflects the estimated costs, **not** the estimated construction time for each project.

Source: AER analysis; AEMO integrated system plan, June 2024.

3.13.7 Regulatory tests – recent activity

As at August 2024, several RIT-T processes were ongoing across the transmission networks. This section highlights major developments among actionable ISP projects.

Victoria to NSW Interconnector West (VNI West)

VNI West is a proposed high-capacity 500 kilovolt double-circuit overhead transmission line between Victoria and NSW. The VNI West RIT-T has been jointly undertaken by AEMO Victoria Planning (AVP) and Transgrid (NSW) for the respective Victorian and NSW parts of the project.

In February 2023, the Victorian Minister for Energy published a Ministerial Order under the *National Electricity (Victoria) Act 2005* to confer functions on AVP, which included assessing alternative additional options to the preferred options (as identified through the RIT-T) that would expedite the development and delivery of VNI West or otherwise better meet a crucial national electricity system need in Victoria.[164]

In May 2023, AVP and Transgrid published the project assessment conclusions report (PACR) for VNI West. The PACR is a major milestone in the RIT-T process, representing the final stage in the RIT-T consultation process.[165]

In May 2024, the AER published its decision to approve Transgrid's contingent project application for capital expenditure to undertake early works related to the NSW portion of the project.[166] Early works will enable Transgrid to refine the project scope, identify and manage project risks, and progress pre-construction activities and community engagement.

Marinus Link

TasNetworks (Tasmania) completed a RIT-T for Marinus Link, a proposed project connecting Victoria and Tasmania through 2 new high voltage direct current cables, each with 750 megawatts of transfer capacity and associated alternating current transmission. Marinus Link will connect to the existing transmission networks in both states.

In October 2022, the Tasmanian, Victorian and Australian governments agreed on a funding arrangement to build Marinus Link. A loan scheme will make up the majority of financing for the estimated $3.5 billion power cable, with the 3 governments jointly contributing 20% equity.

In June 2023, the AER published its decision to commence a revenue determination process for Marinus Link. This decision allowed Marinus Link to progress the project and submit a regulatory proposal for costs associated with stage 1 early works. The AER approved these proposed costs in December 2023.[167] These costs will not be recovered from consumers until the Marinus Link Interconnector is commissioned.[168]

New 2024 ISP identified actionable projects proceeding under RIT-T framework

Four newly actionable projects – Sydney Ring South, Waddamana to Palmerston transfer capability upgrade, Mid North South Australia REZ Expansion and QNI Connect – were identified in the 2024 ISP. AEMO has stated that these projects will proceed under the RIT-T framework.[169]

The RIT-T proponent responsible for each of these actionable projects will be required to initiate its RIT-T process by publishing a project assessment draft report (PADR) by the relevant date specified in the 2024 ISP.

164 Victorian Government, VNI West and Western Renewables Link Ministerial Order, Victorian Government Gazette, 20 February 2023.
165 AER, AEMO Victoria Planning and Transgrid: VNI West PACR, Australian Energy Regulator, 21 June 2023.
166 AER, Transgrid VNI West stage 1 early works contingent project, Australian Energy Regulator, 6 May 2024.
167 AER, AER Determination – Marinus Link Stage 1 Part A (Early works), Australian Energy Regulator, 19 December 2023.
168 AER, Marinus Link – Intending transmission network application, Australian Energy Regulator, 1 June 2023.
169 AEMO, 2024 Integrated System Plan, Australian Energy Market Operator, June 2024, p. 14.

Actionable ISP projects not proceeding under RIT-T framework

The 2024 ISP identified 5 actionable projects that AEMO states will progress under NSW or Queensland frameworks.[170] These projects will not complete a RIT-T but will instead be subject to the requirements of their respective frameworks.

Two of these projects were previously identified as actionable in the 2022 ISP – Sydney Ring North (previously Sydney Ring) and New England REZ Network Infrastructure Project (previously New England REZ Transmission Link).

The 3 newly identified actionable projects that are outside of the RIT-T framework are Gladstone Grid Reinforcement, Queensland SuperGrid South and Hunter-Central Coast REZ Network Infrastructure Project.

Table 3.7 shows the 11 network projects classified as actionable in AEMO's 2024 ISP.

Table 3.7 Network projects in the 2024 ISP optimal development path

Actionable project	Actionable framework
HumeLink	ISP
Sydney Ring North (Hunter Transmission Project)	NSW[a]
New England REZ Network Infrastructure Project	NSW
Victoria – New South Wales Interconnector West (VNI West)	ISP
Project Marinus[b]	ISP
Hunter-Central Coast REZ Network Infrastructure project	NSW[a]
Sydney Ring South	ISP
Gladstone Grid Reinforcement	Queensland[c]
Mid North South Australia REZ Expansion	ISP
Waddamana to Palmerston transfer capability upgrade	ISP
Queensland SuperGrid South	Queensland[c]
Queensland – New South Wales Interconnector (QNI Connect)	ISP

Note: a These projects will progress under the *Electricity Infrastructure Investment Act 2020* (NSW) rather than the ISP framework.
b Project Marinus is a single actionable ISP project without decision rules.
c These projects will progress under the *Energy (Renewable Transformation and Jobs) Act 2024* (Qld) rather than the ISP framework.
Source: AEMO integrated system plan, June 2024, p. 14.

3.13.8 Annual planning reports

Network service providers must publish annual planning reports identifying new investments that they consider necessary to efficiently deliver network services. The reports identify emerging network pressure points and options to alleviate those constraints. In making this information publicly available, the reports enable non-network providers to identify and propose solutions to address network needs.

The AER publishes guidelines and templates to ensure the annual planning reports provide practical and consistent information to stakeholders.[171] This results in service providers providing data on network constraints to assist third parties in offering non-network solutions and to inform connection decisions at the transmission level.[172]

170 *Electricity Infrastructure ACT 2020* (NSW) or *Energy (Renewable Transformation and Jobs) Act 2024* (Queensland).
171 AER, Final decision: Distribution annual planning report template v1.0, Australian Energy Regulator, June 2017; AER, Final decision: Transmission annual planning report guidelines, Australian Energy Regulator, December 2018.
172 An example of the available constraint data can be found in the datasheets under Ausgrid's Distribution and transmission annual planning report, accessed 11 July 2024.

3.13.9 Demand management

Network service providers manage demand on their networks to reduce, delay or avoid the need to install or upgrade network assets. Managing demand can minimise network charges, improve the reliability of supply and reduce wholesale electricity costs.

The AER offers incentives for distribution network service providers to find lower cost alternatives to new investment to help cope with changing demands on the network and to manage system constraints. The demand management incentive scheme (DMIS) incentivises distribution network service providers to undertake efficient expenditure on alternatives, such as small-scale generation and demand response contracts with large network customers (or third-party electricity aggregators) to time their electricity use to reduce network constraints. The scheme gives the service providers an incentive of up to 50% of their expected demand management costs for projects that bring a net benefit across the electricity market.

To receive an incentive payment, a network service provider must first submit a claim for its eligible projects[173] to the AER and provide information on how it is using demand management to deliver value to its customers. The AER uses the information provided to determine if the network service provider is eligible to receive an incentive payment.

Complementing this scheme, the AER operates a demand management innovation allowance mechanism (DMIAM).[174] [175] The DMIAM provides funding for network service providers to undertake research and development works to help them develop innovative ways to deliver ongoing reductions in demand or peak demand for network services. An objective of the innovation allowance is to enhance industry knowledge of practical approaches to demand management. Network service providers publish annual activity reports setting out the details of projects they have undertaken.

The AER assesses expenditure claims to ensure distribution service providers appropriately use their funding. Any underspent or unapproved spending is returned to customers through revenue adjustments.

To date, the DMIS has delivered an estimated $51 million in benefits to consumers (at a cost of $3.5 million) by encouraging distribution service providers to defer replacement or augmentation capital expenditure in favour of pursuing demand management activities (Figure 3.25).[176]

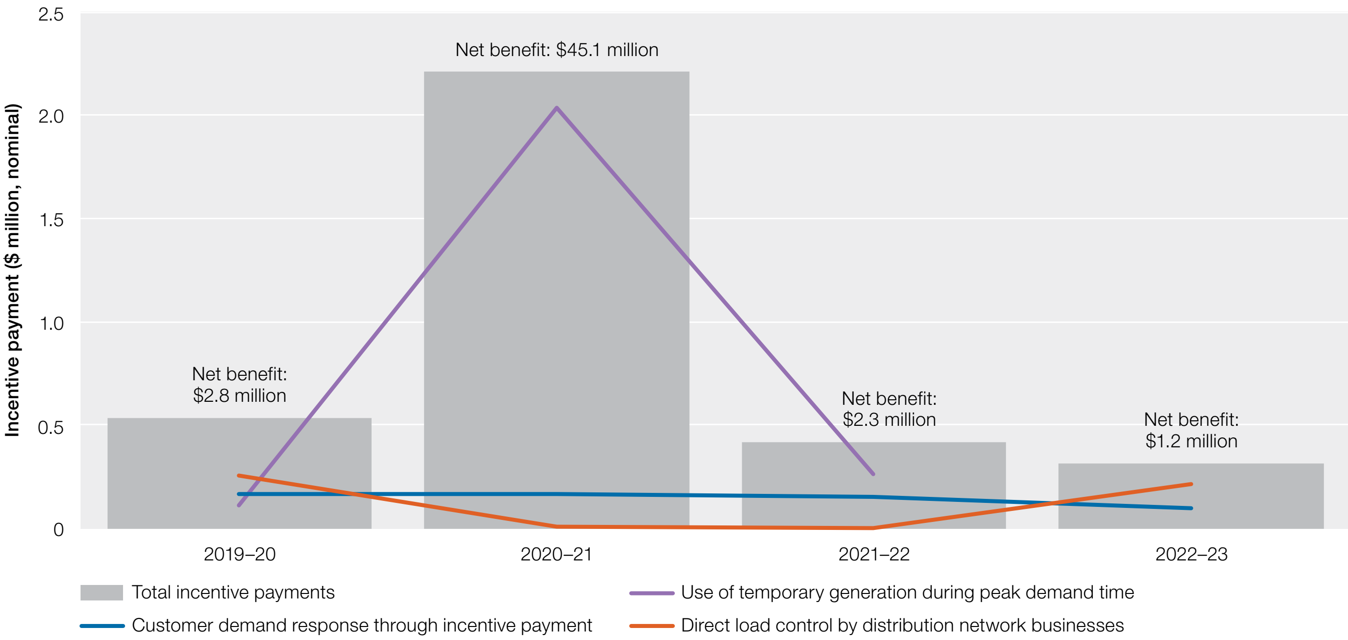
173 Eligible projects are set out in the AER's revenue determinations for each network service provider.

174 AER, Demand management incentive scheme and innovation allowance mechanism, Australian Energy Regulator, 14 December 2017.

175 AER, Demand management innovation allowance mechanism (transmission), Australian Energy Regulator, 27 May 2021.

176 For further information on the demand management incentive scheme see the reports published by the AER on Demand management incentive scheme (DMIS).

Figure 3.25 Funding of demand management innovations – electricity distribution networks



Source: AER, Demand management incentive scheme (DMIS) assessments.

In May 2024, Victorian distribution network service providers CitiPower, Powercor[177] and United Energy[178] gave non-network providers the opportunity to propose alternative ways, beyond a 'traditional' upgrade,[179] to increase the network's capacities to meet maximum demand. The key questions asked by the network service providers were: 'can we deliver similar results using different technology at a lower cost?' and 'does this create value for network customers?'.

A platform has been developed by Piclo Flex (the 'Piclo Flex platform')[180] to provide a marketplace for alternatives to undertaking traditional poles and wires work. The Piclo Flex platform provides an interactive map of local network constraints and allows non-network providers the opportunity to match their solutions – such as batteries, virtual power plants or demand management programs – with network opportunities.

3.14 Operating expenditure

Network service providers incur operating and maintenance costs that account for around 34% of their annual revenue (Figure 3.5). As part of its 5-year revenue determination processes, the AER sets an allowance for each network service provider to recover the efficient costs of supplying electricity to customers. The allowance accounts for forecasts of electricity demand, productivity improvements, changes in input prices and changes in the regulatory environment. The AER reviews the operating expenditure forecasts in each network service provider's regulatory proposal. If the AER is not satisfied the network service provider's proposal is in the long-term interests of consumers, it will request further information or a clearer business case. Subsequently, the AER may amend the proposed operating expenditure to ensure the approved cost forecasts are prudent and efficient.

Alongside this assessment, the AER's efficiency benefit sharing scheme (EBSS) encourages network service providers to explore opportunities to lower their operating costs (Box 3.3).

177 CitiPower/Powercor, Victorian electricity networks seek third-party innovation for upgrades, media release, CitiPower/Powercor, 17 May 2024.
178 United Energy, Non-network opportunities, media release, United Energy, viewed 21 May 2024.
179 Such as transformer upgrades or an uprated powerline to ensure a reliable supply of energy to customers.
180 Piclo, Piclo Flex, Open Utility Ltd., 2024.

Box 3.3 Efficiency benefit sharing scheme

The AER's efficiency benefit sharing scheme (EBSS), introduced in 2007, is designed to share the benefits of efficiency gains in operating expenditure between network service providers and their customers.

The regulatory framework allows a network service provider to keep the benefit (or incur the cost) of reducing (or increasing) its ongoing level of actual operating expenditure until the end of the regulatory period. The EBSS allows a network service provider to keep the benefits (or incur the costs) for an additional period. In effect, this allows the network service provider to keep the benefit (or incur the cost) for a total of 6 years regardless of when in the regulatory period it reduces its costs (or its costs increase).

The EBSS provides network service providers with the same reward for underspending (or penalty for overspending) in each year of the regulatory period. Its incentives are designed to align with those in the capital expenditure sharing scheme (CESS) (Box 3.2). The EBSS incentives also balance against those of the service target performance incentive scheme (STPIS) (Box 3.4) to encourage network service providers to make efficient holistic choices between capital and operating expenditure in meeting reliability (Box 3.4) and other targets.

When the AER released the capital expenditure incentive guideline and EBSS in 2013[a] it estimated around 70% of the benefits from the EBSS would go to customers. Since then, changes in rate of return parameters have increased the share of benefits going to customers. We estimate the customers are now receiving around 80% of the benefits.

Following its 2023 review of incentive schemes[b] the AER decided to retain the EBSS in its current format. AER analysis shows that the EBSS has contributed to improved efficiency and lower prices, and that the scheme is working as intended. The benefits to consumers are up to 4 times the benefits to network service providers.

a AER, Expenditure incentives guideline, Australian Energy Regulator, accessed 30 May 2024.
b AER, Review of incentive schemes for regulated networks, Australian Energy Regulator, accessed 5 May 2024.

3.14.1 Operating expenditure in 2023

Over the 12-month period to 30 June 2023, network service providers spent $4.1 billion on operating costs, $160 million (4.1%) more than in the previous year, but $222 million (5%) less than was forecast.

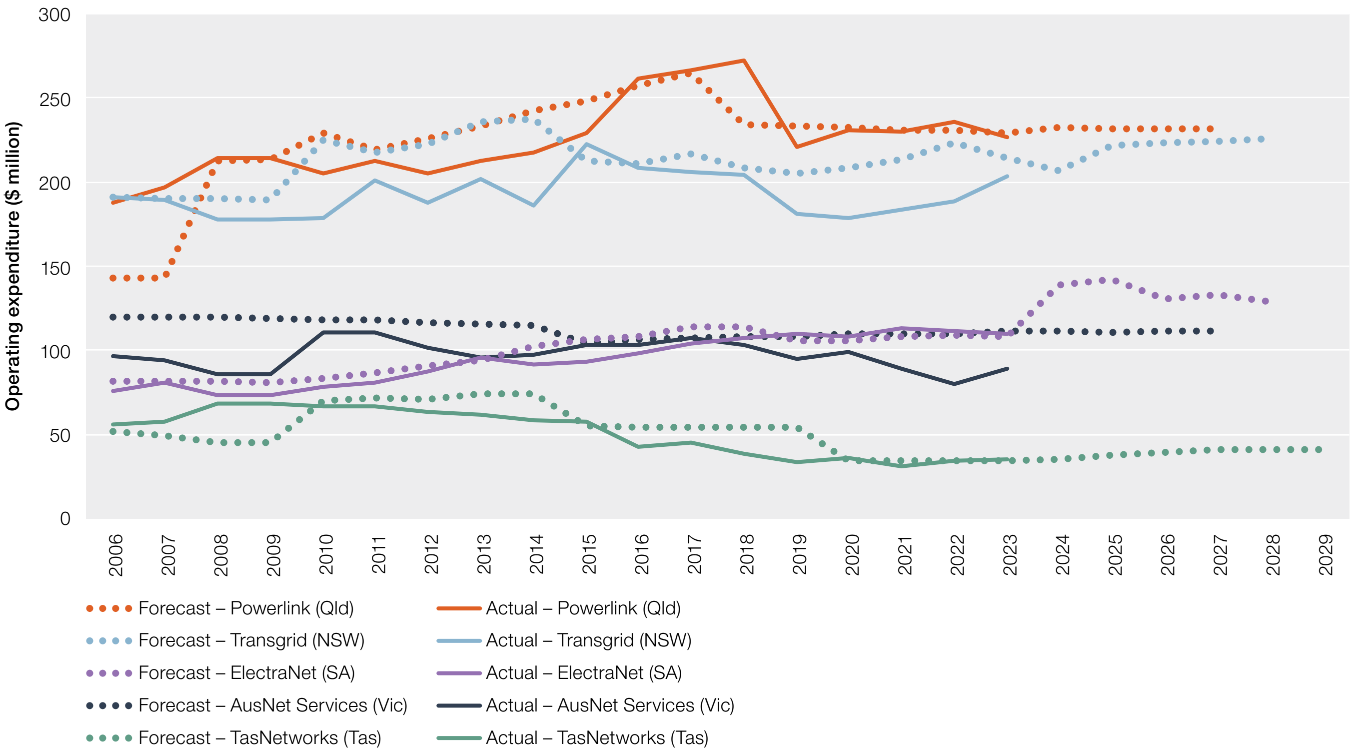
Table 3.8, Figure 3.26 and Figure 3.27 provide a summary of the operating expenditure outlaid in 2023 and how this compared with previous years' expenditure and forecasts.

Table 3.8 Operating expenditure in 2023 – key outcomes

Service type	Operating expenditure (2023)	Operating expenditure (compared with 2022)	Operating expenditure (compared with peak)
Transmission	$677m (▼3.2% than forecast)	▲$12m (▲1.8%)	▼$53m (▼7%) (2016)
Distribution	$3.4b (▼6% than forecast)	▲$148m (▲4.5%)	▼$763m (▼18%) (2012)
Total	$4.1b (▼5% than forecast)	▲$160m (▲4.1%)	▼$755m (▼16%) (2012)

Note: Excludes AER determinations on transmission interconnectors.

Figure 3.26 Operating expenditure – electricity transmission networks

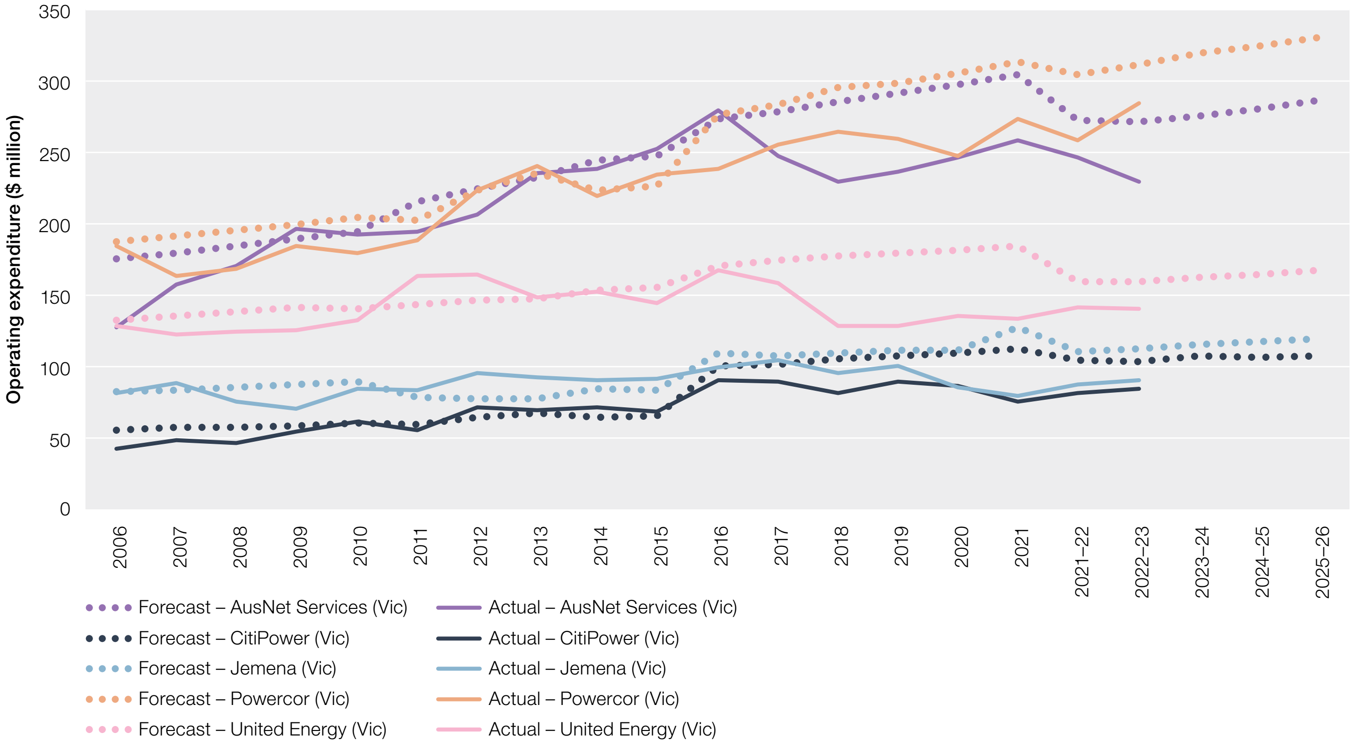


Note: All data are adjusted to June 2023 dollars. The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018). Assumptions are set out in the Figure 3.7 notes.

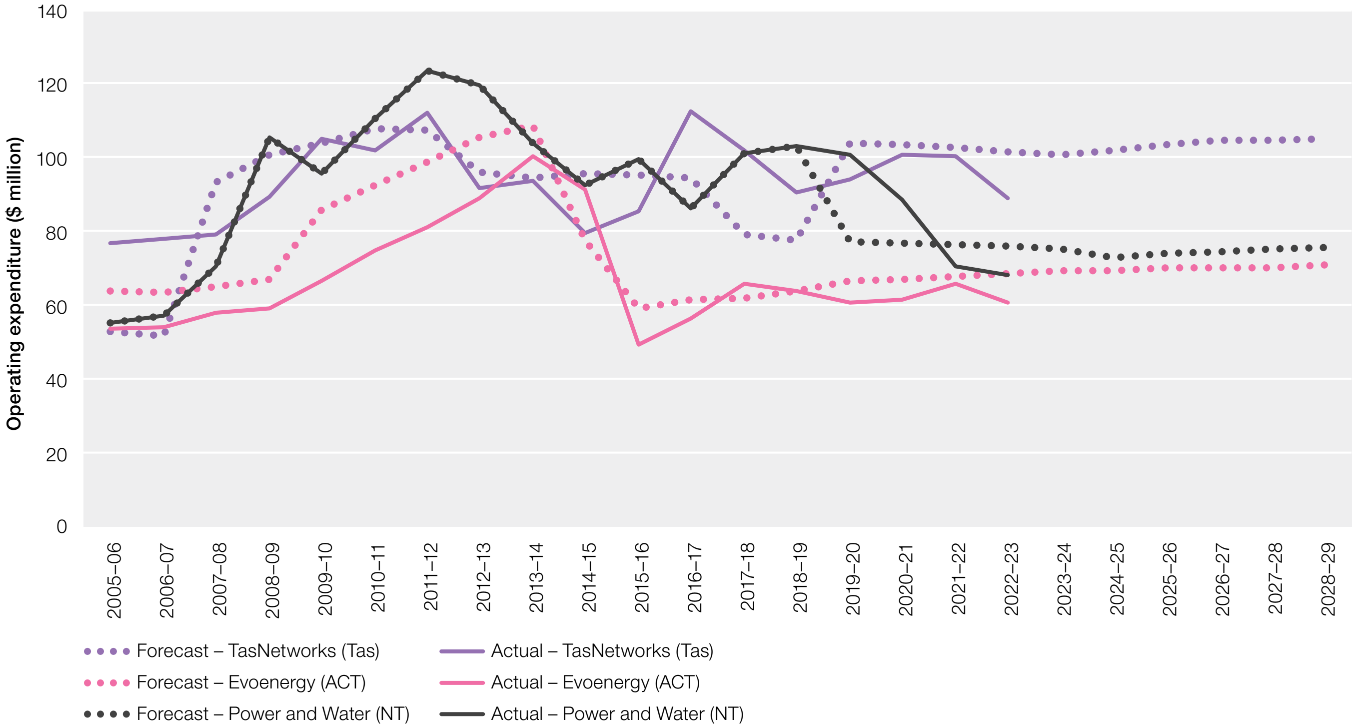
Source: AER modelling; annual reporting RIN responses.

Figure 3.27 Operating expenditure – electricity distribution networks

Victoria



Tasmania, ACT and Northern Territory



Note: All data are adjusted to June 2023 dollars. Most network service providers have always reported on a 1 July to 30 June basis. The exception is the Victorian networks, which until year end 2020 reported on a 1 January to 31 December basis. Operating expenditure for the Victorian distribution networks for the 2021 year has been derived from the transitional year (1 January to 30 June 2021). To enable reporting on equivalent terms, these values have been doubled.

Source: AER modelling; annual reporting RIN responses.

3.14.2 Trends in operating expenditure

Total combined operating expenditure for transmission and distribution network service providers increased by an average of 6% per year in the 8-year period from 2006, before peaking at $4.9 billion in 2014 (Figure 3.7 and Figure 3.9).

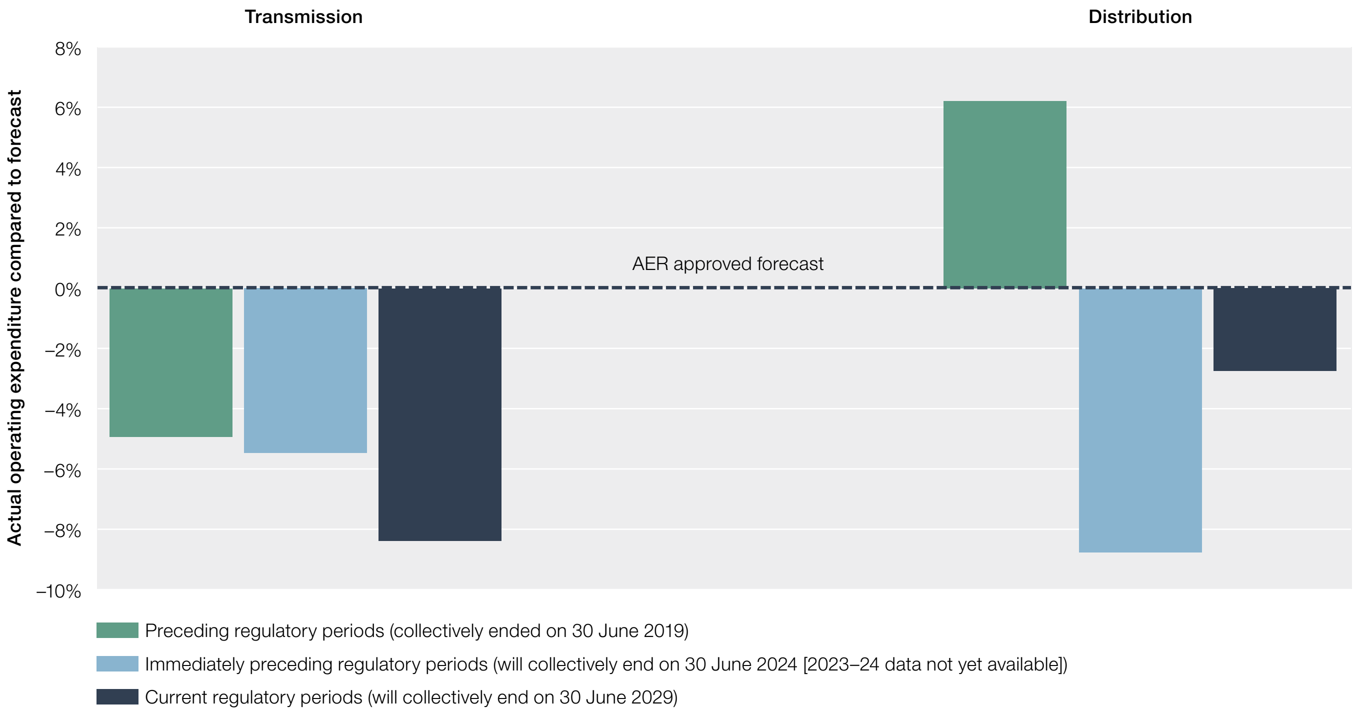
A number of network service providers implemented efficiencies in managing their operating expenditure from 2015, when the AER widened its use of benchmarking to identify operating inefficiencies in some networks.

Unlike capital expenditure, a network service provider's operating expenditure – such as inspection and maintenance, vegetation management, emergency response, payroll, insurance and any funds allocated for research and development – are largely recurrent and predictable. As such, actual operating expenditure against forecast has consistently been more stable than it has been for capital expenditure (Figure 3.28).

Since 2020, operating expenditure has decreased, largely due to network service providers implementing more efficient operating practices. However, the decrease in operating expenditure has been less marked than it has been for capital expenditure.

However, other factors such as reporting obligations, pricing reforms and greater use of non-network options (section 3.8) can also impact costs.

Figure 3.28 Operating expenditure against forecast



Source: AER modelling; annual reporting RIN responses.

A combination of AER incentives and network-driven efficiencies has contributed to significant cost reductions, especially among the government-owned (or recently privatised) distribution network service providers in Queensland and NSW. Those savings – for example, from the uptake of technology solutions and from changes to management practices – are used to set lower operating expenditure forecasts, which has the effect of lowering network prices for customers.

3.15 Productivity

The AER benchmarks the relative efficiency of electricity network service providers to enable comparisons over time. This form of benchmarking assesses how effectively each network service provider uses its inputs (assets and operating expenditure) to produce outputs (such as meeting maximum electricity demand, electricity delivered, reliability of supply, customer numbers and circuit line length). Productivity will increase if the service provider's outputs rise faster than the inputs used to maintain, replace and augment its energy network.

Although benchmarking provides a useful tool for comparing network performance, some productivity drivers – for example, adhering to reliability standards set by government bodies – are beyond the control of network service providers. More generally, benchmarking may not fully account for differences in operating environment, such as legislative or regulatory obligations, climate and geography.[181]

The AER uses a forecast productivity growth rate when reviewing the operating expenditure forecasts of transmission and distribution network service providers. This growth rate reflects the productivity improvements that an efficient distribution service provider should be able to make in providing services. It is informed by the productivity growth the AER observes in its economic benchmarking results.

3.15.1 Productivity trends

Productivity for most network service providers declined from 2006 to 2015. The decline was most evident for distribution service providers and was largely driven by:

- rising capital investment and therefore capital assets (inputs) at a time when electricity demand (output) had plateaued or was declining in Australia
- rising operating costs and declining reliability (for most network service providers)
- rising expenditure on the distribution networks to meet stricter reliability standards in Queensland and NSW, and regulatory changes following bushfires in Victoria.

Over this period, the privately operated service providers in Victoria and South Australia consistently recorded higher productivity than those of government-owned or recently privatised service providers in other regions.

Transmission network productivity

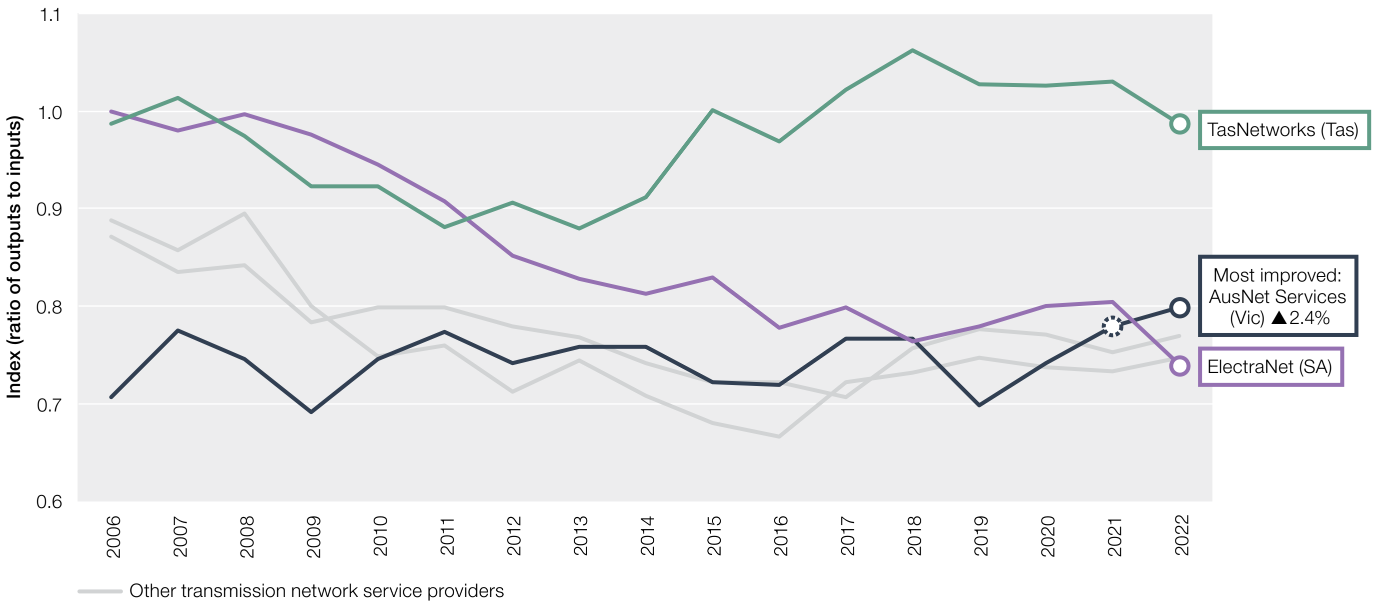
Productivity for transmission network service providers[182] decreased by 0.4% in 2022, primarily due to reductions in reliability[183] on the Powerlink (Queensland), ElectraNet (South Australia) and TasNetworks (Tasmania) networks.[184]

Viewed over a longer time frame, the productivity of transmission network service providers has declined at an average rate of 0.8% per year in the 16 years since 2006. Capital partial factor productivity – output per unit of capital stock – has declined at an average rate of 1.4% per year compared with average operating expenditure partial factor productivity – output per unit of operating expenditure – of 0.5% per year over the same period.

In 2022, 3 of the 5 electricity transmission network service providers in the NEM improved their productivity (Figure 3.29).[185]

181 AER, Annual benchmarking report, electricity distribution network service providers, Australian Energy Regulator, November 2023, pp. 66–74.
182 As measured by total factor productivity (TFP).
183 As evidenced by increase in the amount of unsupplied energy due to storm events.
184 AER, Annual benchmarking report – Electricity transmission network service providers, Australian Energy Regulator, 28 November 2023.
185 As measured by multilateral total factor productivity (MTFP).

Figure 3.29 Productivity – electricity transmission networks



Note: Index of multilateral total factor productivity relative to the 2006 performance of ElectraNet (South Australia). The 'most improved' label refers to the relative change in multilateral total factor productivity over the previous year. The transmission index shown in Figure 3.29 cannot be directly compared with the distribution index shown in Figure 3.30. The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018).

Source: AER annual benchmarking report for electricity transmission networks, 2023.

Distribution network productivity

Productivity for distribution network service providers[186] decreased by 0.2% over 2022, primarily due to decreases in reliability caused by storm events impacting all but one network service provider. The decrease in productivity in 2022 marked only the second year since 2015 – the other year being 2019 – where the overall productivity of distribution network service providers did not increase from the previous year.[187]

In 2022, 5 of the 13 distribution network service providers in the NEM improved their productivity. The time series shown in Figure 3.30 highlights the variability in annual productivity for individual distribution network service providers. This variability emphasises the importance of considering single year changes in productivity, be they negative or positive, in the context of longer-term trends. Since 2006 there has been some convergence in the productivity levels of distribution network service providers.

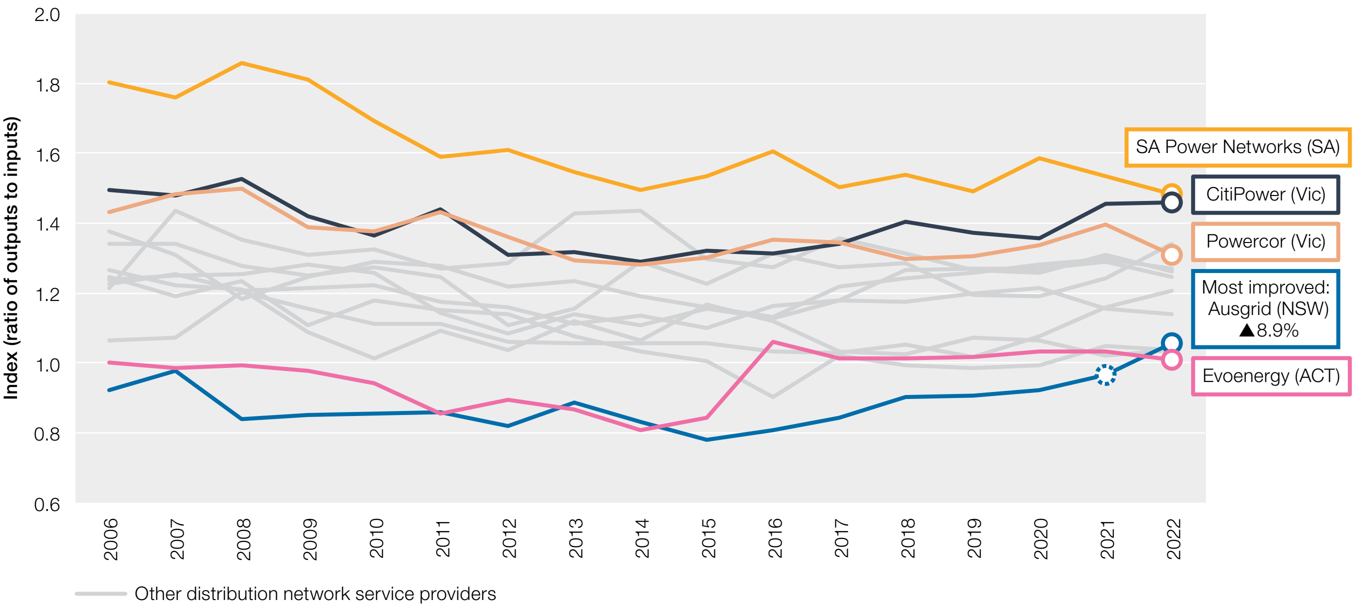
SA Power Networks (South Australia), CitiPower (Victoria) and Powercor (Victoria) have consistently been the most productive distribution network service providers in the NEM since at least 2006 (Figure 3.30).[188]

186 As measured by multilateral total factor productivity (MTFP).

187 AER, Annual benchmarking report – Electricity distribution network service providers, Australian Energy Regulator, 28 November 2023.

188 As measured by multilateral total factor productivity (MTFP).

Figure 3.30 Productivity – electricity distribution networks



Note: Index of multilateral total factor productivity relative to the 2006 performance of Evoenergy (ACT). The 'most improved' label refers to the relative change in multilateral total factor productivity over the previous year. The distribution index shown in Figure 3.30 cannot be directly compared with the transmission index shown in Figure 3.29. The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018).

Source: AER annual benchmarking reports for electricity distribution networks, 2023.

3.15.2 Network utilisation

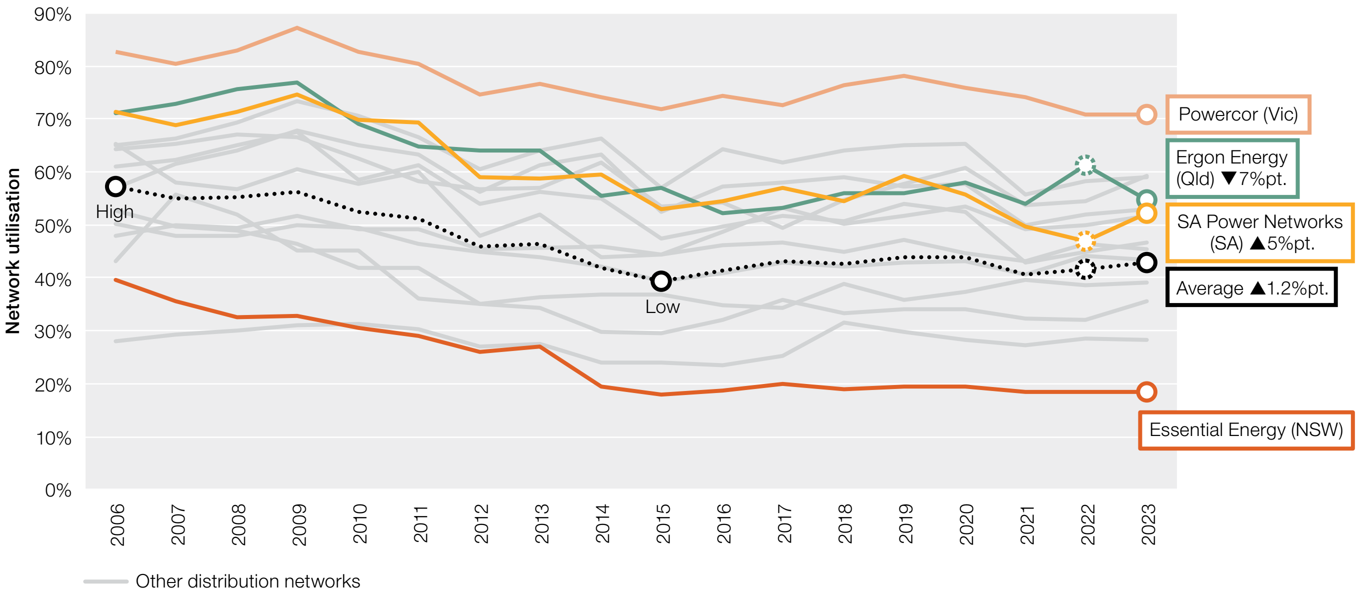
The network utilisation rate indicates the extent to which a network service provider's assets are being used to meet the needs of consumers at times of maximum demand. The utilisation rate can be improved through efficiencies such as using demand response (instead of new investment in assets) to meet rising maximum demand.

In 2023:

- a 2% increase in maximum demand, coupled with a slight decrease in network capacity, saw the overall network utilisation increase to 43%, the highest since 2020 (44%)
- privately owned distribution network service providers utilised 56% of network capacity
- fully or partly government-owned networks utilised only 38% of network capacity[189]
- 5 of the 6 most highly utilised distribution networks were privately owned (Figure 3.31).

189 Section 3.4 provides information on network ownership.

Figure 3.31 Network utilisation – electricity distribution networks



Note: Network utilisation is the non-coincident, summated raw system annual peak demand divided by total zone substation transformer capacity. The changes identified in the labels refer to the relative change in utilisation in percentage points over the previous year.

Source: Economic benchmarking RIN responses.

The average level of network utilisation among all distribution network service providers decreased from a high of 57% in 2006 to a low of 39% in 2015.[190] This followed significant investment by many network service providers at a time of weakening electricity maximum demand. The AER is encouraging network service providers to, where possible, increase the rates of network utilisation by utilising existing capacity before investing in new assets. Opportunities to increase electricity network utilisation may also be found through electrification, load shifting and generation management.

Network utilisation is an informative, but incomplete, measure of a network's ability to respond to increases in maximum demand on the network. While a lower utilisation rate (that is, higher spare capacity) indicates a network can service large increases in maximum demand, it may also mean customers are paying for network assets they rarely use.

The method of measuring network utilisation shown in Figure 3.31 does not account for two-way network flows and may not show localised constraints from exports from solar photovoltaic (PV) systems. These constraints are becoming more prevalent as more consumers install solar PV systems, requiring distribution network service providers to possibly limit consumer energy resources being exported into the grid to protect network assets.

Measuring network utilisation is further complicated by the different de-rating factors that networks may apply to their reported substation transformer capacities.

In August 2023, Energy Consumers Australia (ECA) wrote that numerous factors indicate that electricity demand is likely to increase over the coming years. In February 2024, the University of Technology Sydney's Institute for Sustainable Futures secured a grant from ECA to undertake a research project aimed at revolutionising network utilisation metrics. The core focus of the project is to enhance network productivity to reduce the overall cost of energy, especially as customers increasingly adopt solar and move towards electrifying their homes and vehicles.[191]

Given the current utilisation rates, distribution networks may be well placed to accommodate increases in demand without the need for major investment. Responding to increasing demand through actions like demand response, as opposed to additional network investment, will see distribution charges to customers decrease.[192]

190 Data before 2006 is not available.

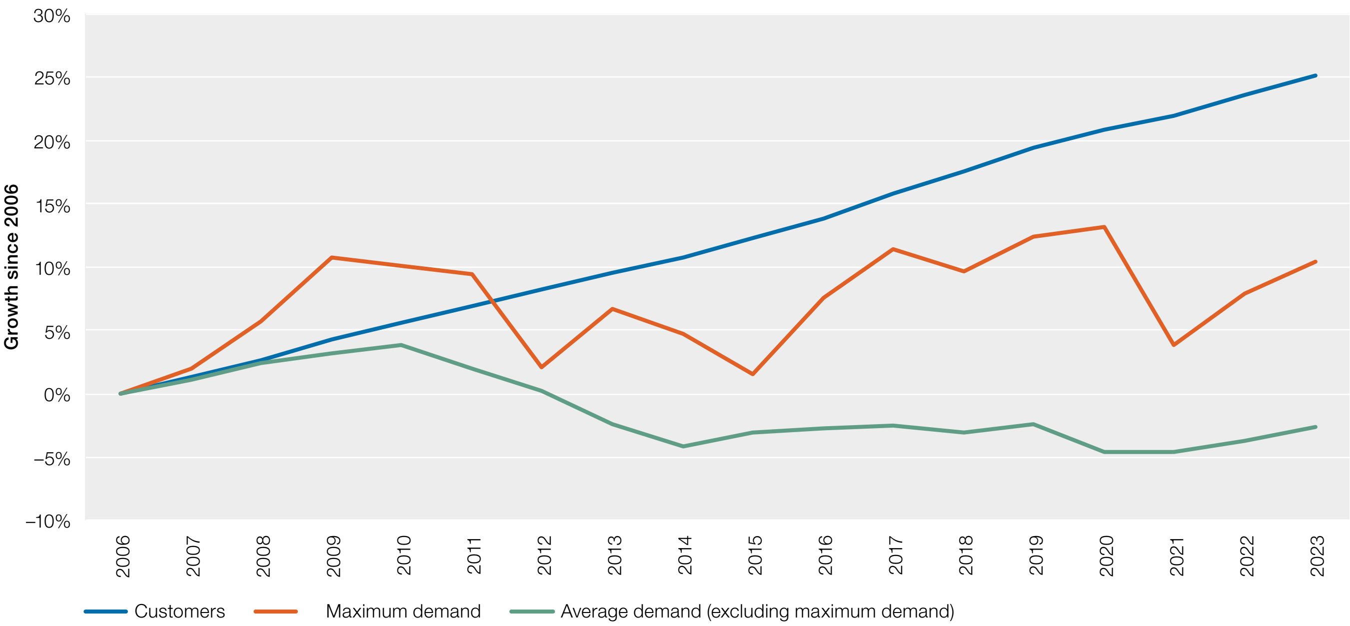
191 University of Technology Sydney, Empowering tomorrow's energy by redefining network utilisation, 8 February 2024, accessed 12 March 2024.

192 Energy Consumers Australia, The bECAuse Blog, 2 August 2023, accessed 6 August 2023.

Capital expenditure is largely driven by the need to meet the maximum level of demand on the network. Average demand has declined since 2006 (driven in part by improved energy efficiency and increased self-consumption of solar PV), whereas maximum demand has become more variable. While maximum demand has always varied with the weather, the increased use of air conditioners and solar PV has exacerbated this effect.

As network demand becomes 'peakier', assets installed to meet demand at peak times – which occur for approximately 0.01% of the year – may sit idle (or be underused) for longer periods. This outcome is reflected in poor asset usage rates, which weakens utilisation. The number of customers connected to the distribution network has steadily increased by around 1.5% per year since 2006 and has outpaced growth in both maximum and average 'non-maximum' demand (Figure 3.32).

Figure 3.32 Growth in customers and demand – electricity distribution networks



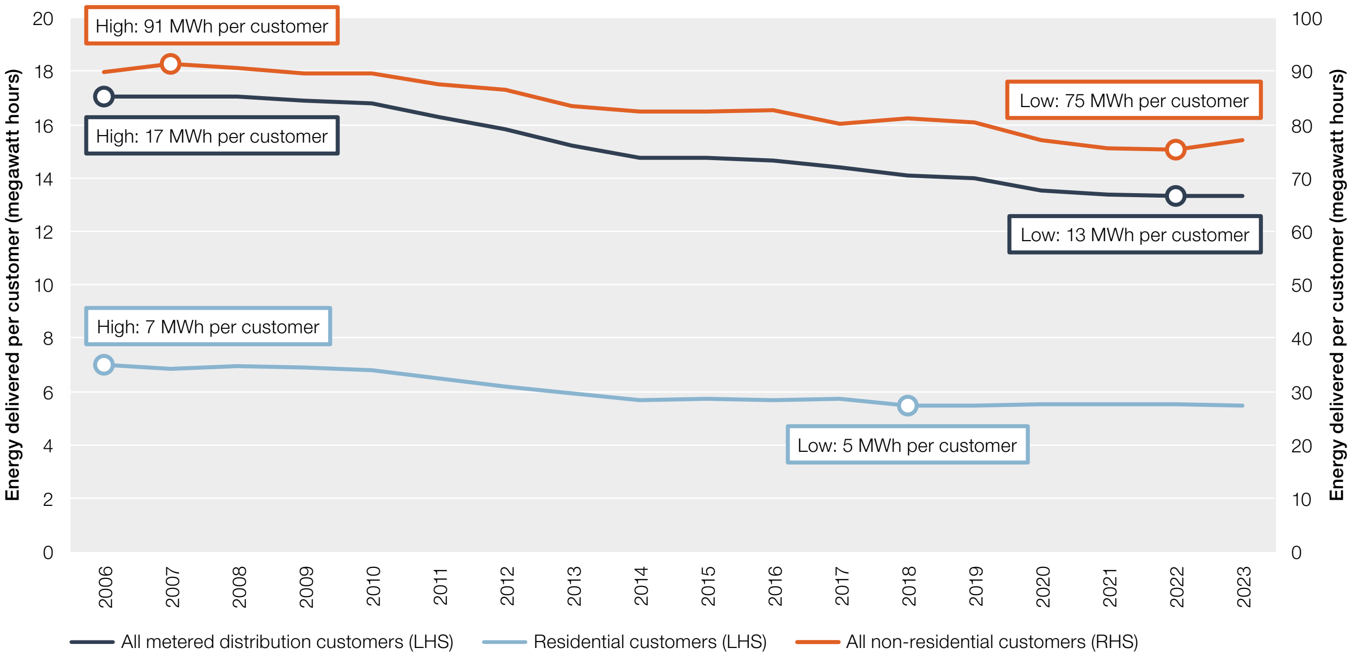
Note: Maximum demand is the network sum of non-coincident, summated raw system maximum demand (megawatts). Non-maximum demand is the total energy delivered (gigawatt hours) for the year, excluding the energy delivered at the time of maximum demand divided by hours in the year minus one. The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018).

Source: Economic benchmarking RIN responses.

In 2023, the average residential customer[193] consumed around 5 megawatt hours of electricity from the distribution network, 22% less than in 2006. Over the same period the average non-residential customer – which includes low voltage, high voltage and 'other' customers – decreased their annual usage by around 14%. The uncharacteristic uptick in 2023 was largely driven by a 22% decrease in the number of 'other' customers being offset by a 4% increase in the amount of energy they consumed (Figure 3.33).

193 A customer who purchases energy principally for personal, household or domestic use at premises.

Figure 3.33 Average grid usage per customer – electricity distribution networks



Note: The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018).
Source: Economic benchmarking RIN responses.

The overall decline in energy consumption from the grid can be attributed to several factors, including:

- rooftop solar replacing electricity previously sourced from the grid
- housing and appliances becoming more efficient
- consumers reducing their energy use in response to higher prices
- reductions in demand from large industrial customers
- in 2021 the impact of COVID-19 on consumer behaviour.

However, the trend in declining energy consumption from the grid is not expected to continue. As the upfront cost of electric vehicles falls, more households are expected to make the switch from petrol or diesel cars to electric vehicles. Research conducted by the CSIRO suggests that electric cars tend to be charged at times when the grid is not stressed and more aligned with solar production. While this does have the impact of increasing demand, it does not significantly increase the network cost to meet this demand.[194]

3.16 Reliability and service performance

In this section, the term 'reliability' refers to the continuity of electricity supply to customers.[195] Many factors can interrupt the flow of electricity on a network. Supply interruptions may be planned (for example, due to the scheduled maintenance of equipment) or unplanned (for example, due to equipment failure, bushfires, extreme weather events or the impact of high demand stretching the network's engineering capability).

194 ECA, Stepping up: A smoother pathway to decarbonising homes, Energy Consumers Australia, 10 August 2023, accessed 12 September 2024.

195 The continuity of electricity supply from customers is also an element of service performance for networks with customers that export energy into the grid (for example, energy generated from rooftop solar PV). Reforms are underway to treat export services more clearly as distribution services. See AEMC, Rule determination: Access, pricing and incentive arrangements for distributed energy resources, Australian Energy Market Commission, August 2021.

A significant network failure might require the power system operator to disconnect some customers (known as load shedding). Load shedding is the managed reduction of electricity to selected areas during extreme events to protect the electricity network from damage and widespread consumer outages. Used as a last resort, load shedding assists in balancing supply and demand to maintain power system security.[196]

AEMO identifies the amount and duration of electricity shortfalls, but it does not decide which areas have their power turned off. The transmission and distribution network service providers determine how manual load shedding is done at a local level to meet the shortfall.

Most interruptions to supply originate in distribution networks. They typically relate to powerline damage caused by lightning, car accidents, debris such as falling branches, and animals (including possums and birds). Peak demand during extreme weather can also overload parts of a distribution network. Transmission network issues rarely cause consumers to lose power, but the impact when they do occur is often widespread. For example:

- in September 2016, South Australia's catastrophic network failures caused a state-wide blackout[197]
- in February 2024, a significant thunderstorm crossed Victoria causing 6 high voltage transmission towers to collapse, resulting in 2,210 megawatts of generation to be disconnected and 90,000 customers having their supply switched off (load shedding).[198]

Electricity outages impose costs on consumers, including the cost of lost productivity, and business revenues and other costs such as reduced convenience, comfort, safety and amenity.

Residential and business consumers desire a reliable electricity supply that minimises these costs. But maintaining or improving reliability may require expensive investment in network assets, which is a cost passed on to electricity customers. Therefore, there is a trade-off between electricity reliability and affordability. Reliability standards and incentive schemes need to strike the right balance by targeting levels of reliability that customers are willing to pay for.

State and territory governments set reliability standards for electricity networks that seek to efficiently balance the costs and benefits of a reliable power supply. Although approaches to setting standards have varied across jurisdictions, governments have now moved to a more consistent national approach to reliability standards. This approach factors in the value that consumers place on having a reliable power supply.

3.16.1 Valuing network reliability

Understanding the value that consumers place on reliability is important when setting reliability standards or network performance targets. This value tends to vary among customer types and across different parts of the network. Considerations include a customer's access to alternative energy sources; experience of interruptions to supply; and the duration, frequency and timing of interruptions.

The AER develops new estimates of customers' reliability valuations (VCR) every 5 years and updates these values annually. The values have a wide application, including as an input for:

- cost-benefit assessments, such as those applied in regulatory tests (section 3.13.5) that assess network investment proposals
- assessing bonuses and penalties in the service target performance incentive schemes (Box 3.4)
- setting transmission and distribution reliability standards and targets
- informing market settings, such as wholesale price caps.

In December 2023, the AER updated the VCR based on a consumer price index (CPI) of 5.37%. The AER encourages network service providers, market operators and regulators that are required to apply the VCR to adopt the adjusted values from 18 December each year.[199]

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196 AEMO, Load shedding factsheet, Australian Energy Market Operator, December 22, accessed 22 March 2024.

197 AER, Investigation report into South Australia's 2016 state-wide blackout, Australian Energy Regulator, accessed 17 July 2023.

198 Engage Victoria, Interim report – Network outage review 2024, Department of Energy, Environment and Climate Action, 5 July 2024, accessed 15 July 2024.

199 AER, Value of customer reliability update, December 2023, Australian Energy Regulator, accessed 20 August 2024.

The AER is currently reviewing the VCR and will publish the outcome of its review by December 2024.[200]

In September 2024, the AER published its final decision on its review of the value of network resilience (VNR) for outages lasting longer than 12 hours (i.e. ‘prolonged’ outages). The VNR will help inform network service providers and stakeholders about making appropriate investments to enhance network resilience against extreme weather events, considering both the ability to withstand and recover from such events. The AER’s VNR review was conducted tangentially to the VCR review and provides an estimate of the value customers place on network resilience during prolonged outages.[201]

3.16.2 Transmission network reliability

Transmission networks are engineered and operated to be extremely reliable, because a single interruption can lead to high impact or widespread power outages. To minimise the risk of outages occurring, the transmission networks are engineered with capacity to act as a buffer against credible unplanned interruptions.

In addition to system reliability, congestion management is another indicator of transmission network performance. All networks are constrained by capability limits, and congestion arises when electricity flows on a network threaten to overload the system. As an example, a surge in electricity demand to meet air conditioning loads on a hot day may push a network service provider to the brink of its secure operating limits.

Network congestion may require AEMO to change the generator dispatch order. A low-cost generator may be constrained from running to avoid overloading an affected transmission line and a higher cost generator may be dispatched instead, raising electricity prices. At times, congestion can cause perverse trade flows, such as a lower priced NEM region importing electricity from a region with much higher prices.

Congestion on the transmission network caused significant market disruption in 2006, when rising electricity demand placed strain on the networks. But increased network investment from 2006 to 2014 – including upgrades to congested lines – eliminated much of the problem. Weakening energy demand reinforced the trend and for several years network congestion affected less than 10% of NEM spot prices. But ultimately, consumers have paid for the substantial costs of network investment.

Not all congestion is inefficient. Reducing congestion through investment to augment transmission networks is an expensive solution. Eliminating congestion is efficient only to the extent that the market benefits outweigh the costs of new investment.

Network service providers can help minimise congestion costs by scheduling planned outages and maintenance to avoid peak periods. The AER offers incentives for service providers to reduce the market impact of congestion.

3.16.3 Distribution network reliability

For distribution networks, the reliability of supply – that is, how effectively the network delivers power to its customers – is the main focus of network performance. Around 95% of the interruptions to supply experienced by electricity customers are due to issues in the local distribution network.[202] The capital-intensive nature of the networks makes it prohibitively expensive to invest in sufficient capacity to avoid all interruptions.

Planned interruptions – when a network service provider needs to disconnect supply to undertake maintenance or construction works – can be scheduled for minimal impact, and the service provider must provide timely notice to customers of its intention to interrupt supply. Unplanned interruptions to supply – such as those resulting from asset overload or damage caused by extreme weather – provide no warning to customers, so they cannot prepare for the impact of an interruption.

200 AER, Values of customer reliability 2024, Australian Energy Regulator, accessed 16 July 2024.
201 AER, Value of network resilience 2024, Australian Energy Regulator, accessed 3 September 2024.
202 AEMC, Final report – 2019 annual market performance review, Australian Energy Market Commission, 12 March 2020, p. 51.

Jurisdictional reliability standards were historically set at more stringent levels to protect customers from the cost and inconvenience of supply interruptions. Following power outages in 2004, the Queensland and NSW governments in 2005 tightened jurisdictional reliability standards for distribution networks. This required significant investment, driving network costs for several years. In contrast, Victoria placed more emphasis on reliability outcomes and the value that customers place on reliability.

Concerns that reliability-driven investment was putting upwards pressure on power bills led to governments adopting an alternative approach to setting distribution reliability targets.[203] The alternative approach considers both the likelihood of an interruption occurring and the value that customers place on removing or reducing the impact of an interruption (section 3.16.1). While the Queensland and NSW governments began to relax reliability standards from 2014, the assets built to meet the previously high standards remain in the RAB and customers continue to pay for them.[204]

Two widely applied measures of distribution network reliability are the system average interruption frequency index (SAIFI) and the system average interruption duration index (SAIDI). SAIFI measures the frequency – or number – of interruptions to supply the average customer experienced each year, while SAIDI measures the total time the average customer was without power each year.[205]

The SAIFI and SAIDI metrics have generally been used to focus on the impact of unplanned interruptions to supply. However, the impact of planned interruptions must also be considered when assessing the overall customer experience. The AER has acknowledged this and has incorporated the impact of planned outages into some of its regulatory determinations through the customer service incentive scheme (CSIS) (Box 3.5).

Both the frequency and duration of planned and unplanned interruptions to supply varies considerably among the distribution networks. The specific features of each distribution network can have a significant impact on the service provider's reliability performance. Customer densities, geographical characteristics and environmental conditions differ across networks, which can materially impact the number of customers affected by an outage as well as a network service provider's response time. Levels of historical investment also affect reliability outcomes.

Maintaining or improving reliability may require expensive investment in network assets, which is a cost passed on to electricity customers. Therefore, there is a trade-off between network reliability and affordability.

Central business district (CBD) and urban network areas have higher load and customer connection densities. Distribution lines supplying urban areas are generally significantly shorter than those supplying rural areas. CBD and urban areas also tend to have a higher proportion of underground cables (which are protected from pollution, storms, trees, bird life, vandalism, equipment failure and vehicle collisions) and more interconnections with other urban lines. Restoration times following interruptions to supply are usually quicker for network service providers operating in urban areas than in rural areas.

Conversely, rural areas generally have lower load and lower customer connection densities and often include customers living in smaller population centres remote from supply points. Distribution lines supplying customers in rural areas tend to cover wider geographic areas. This increases exposure to external influences, such as storm damage, trees and branches and lightning. Further, rural lines are generally radial in nature, with limited ability to interconnect with nearby lines. These characteristics tend to result in more frequent and longer duration interruptions.

203 Ministerial Forum of Energy Ministers (formerly CoAG Energy Council), *Response to the Australian Energy Market Commission's review of the national framework for distribution reliability and review of the national framework for transmission reliability,* December 2014.

204 ACCC, Retail Electricity Pricing Inquiry final report, Australian Competition and Consumer Commission, 11 July 2018, p. 109.

205 Unplanned SAIDI excludes momentary interruptions (3 minutes or less).

For these reasons, care must be taken when comparing network reliability outcomes between different distribution network service providers.

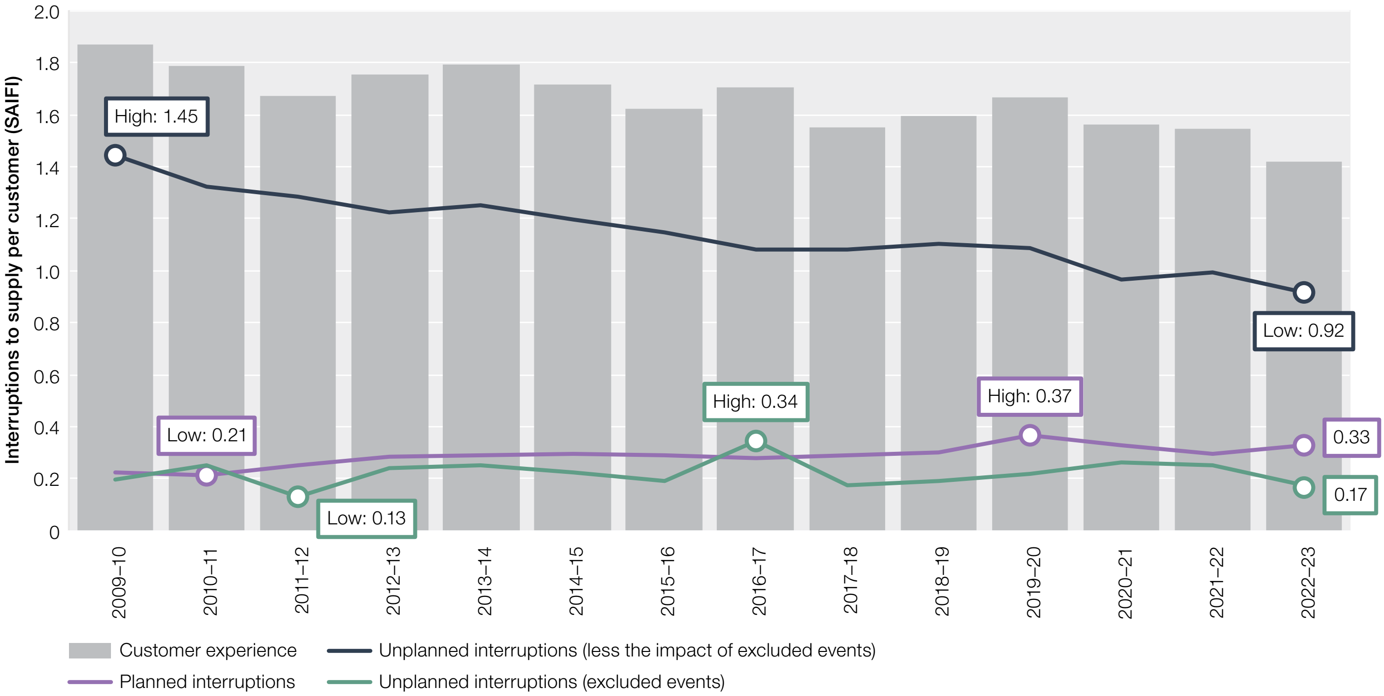
3.16.4 Distribution network reliability in 2022–23

Over the 12-month period to 30 June 2023, the average customer in the NEM experienced 1.42 interruptions to supply, a new record low and 8% fewer interruptions than the previous record low in 2021–22 (Figure 3.34).

The 1.42 interruptions to supply comprised of:

- 0.92 unplanned interruptions to supply (normalised for STPIS) – 8% less than in the previous year
- 0.17 unplanned interruptions to supply (STPIS excluded events) – 31% less than in the previous year and the least since 2011–12
- 0.33 planned interruptions to supply – 11% more than in the previous year.

Figure 3.34 Interruptions to supply (SAIFI) – electricity distribution networks



Note: SAIFI: system average interruption frequency index.
Data in Figure 3.34 shows interruptions to supply that lasted longer than 3 minutes. This is consistent with the definition of a sustained interruption in the AER's current service target performance incentive scheme (STPIS) (version 2.0, November 2018). The previous version of the STPIS (May 2009) defined sustained interruptions as those that lasted longer than one minute. Reporting historical SAIFI using a consistent definition allows for greater comparability over time. As such, the values shown above may not reflect outcomes reported in the past. Years reflect 1 July to 30 June. The unplanned (STPIS excluded events) as shown in Figure 3.34 cannot be directly calculated at a whole of NEM level because the major event day calculation must be made at a network level. For example, 22 November 2022 was classed as a major event (STPIS excluded event) for AusNet Services (Victoria) but did not qualify as a major event day for any of the other 12 distribution network service providers in the NEM. As such, the unplanned (STPIS excluded events) and unplanned (normalised measures) in Figure 3.34 are calculated based on each individual network service provider's outputs and subsequently weighted to show a 'whole of NEM' measure.

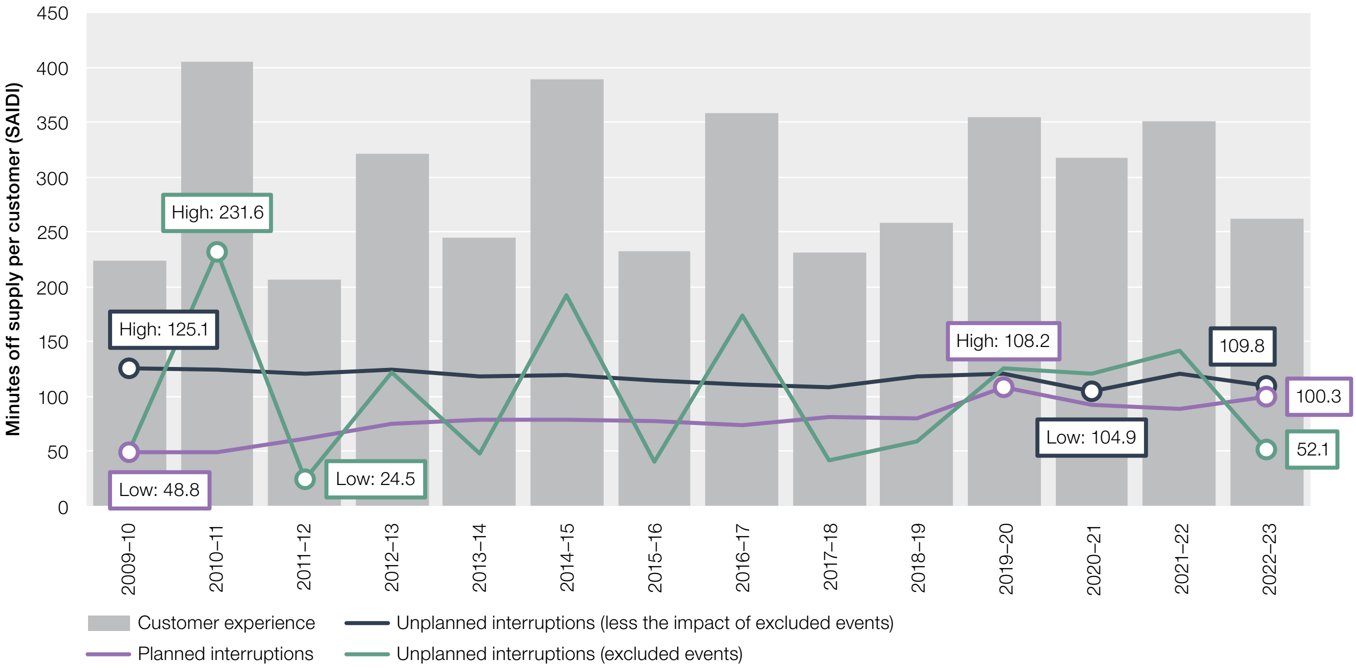
Source: AER modelling; category analysis regulatory information (RIN) responses.

Over the 12-month period to 30 June 2023, the average customer in the NEM experienced 262.2 minutes off supply – 25% less than in the previous year (Figure 3.35).

The 262.2 minutes off supply comprised of:

- 109.8 unplanned minutes off supply (normalised for STPIS) – 9% less than in the previous year
- 52.1 unplanned minutes off supply (STPIS excluded events) – 63% less than in the previous year and the least since 2017–18
- 100.3 planned minutes off supply – 13% more than in the previous year.

Figure 3.35 Minutes off supply (SAIDI) – electricity distribution networks



Note: SAIDI: system average interruption duration index.
Data in Figure 3.35 shows interruptions to supply that lasted longer than 3 minutes. This is consistent with the definition of a sustained interruption in the AER's current service target performance incentive scheme (STPIS) (version 2.0, November 2018). The previous version of the STPIS (May 2009) defined sustained interruptions as those that lasted longer than one minute. Reporting historical SAIDI using a consistent definition allows for greater comparability over time. As such, the values shown above may not reflect outcomes reported in the past. Years reflect 1 July to 30 June. The unplanned (STPIS excluded events) as shown in Figure 3.35 cannot be directly calculated at a whole of NEM level because the major event day calculation must be made at a network level. For example, 22 November 2022 was classed as a major event (STPIS excluded event) for AusNet Services (Victoria) but did not qualify as a major event day for any of the other 12 distribution network service providers in the NEM. As such, the unplanned (STPIS excluded events) and unplanned (normalised measures) in Figure 3.35 are calculated based on each individual network service provider's outputs and subsequently weighted to show a 'whole of NEM' measure.

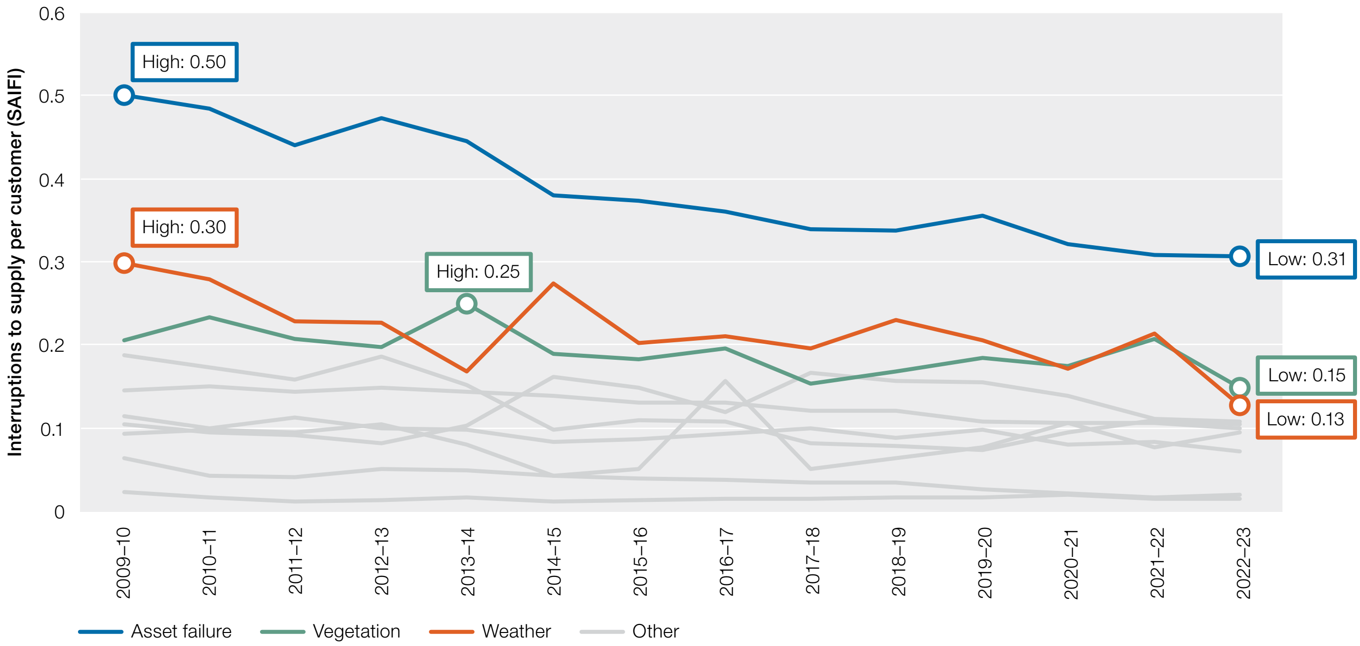
Source: AER modelling; category analysis regulatory information (RIN) responses.

Unplanned interruptions occur for many reasons, including:

- weather events
- vegetation interfering with powerlines
- bushfires
- asset failure and technical faults
- third-party accidents
- animals
- load shedding (reducing or disconnecting load from the power system) to help balance supply and demand during the peak period.

Since 2009–10, asset failure[206] has consistently been the primary cause of interruptions to supply in the NEM (around 28% each year) (Figure 3.36). However, asset failure is rarely the most disruptive in terms of time off supply (around 23%) (Figure 3.37). Over the same 14-year period, weather events such as lightning, floods, heatwaves or high winds have generally been the secondary cause of interruptions to supply (around 15% each year) but are more often than not the most disruptive in terms of duration (16–60%). This clearly demonstrates the destructive nature of weather events on the electricity network.

Figure 3.36 Reasons for unplanned interruptions to supply (SAIFI) – electricity distribution networks

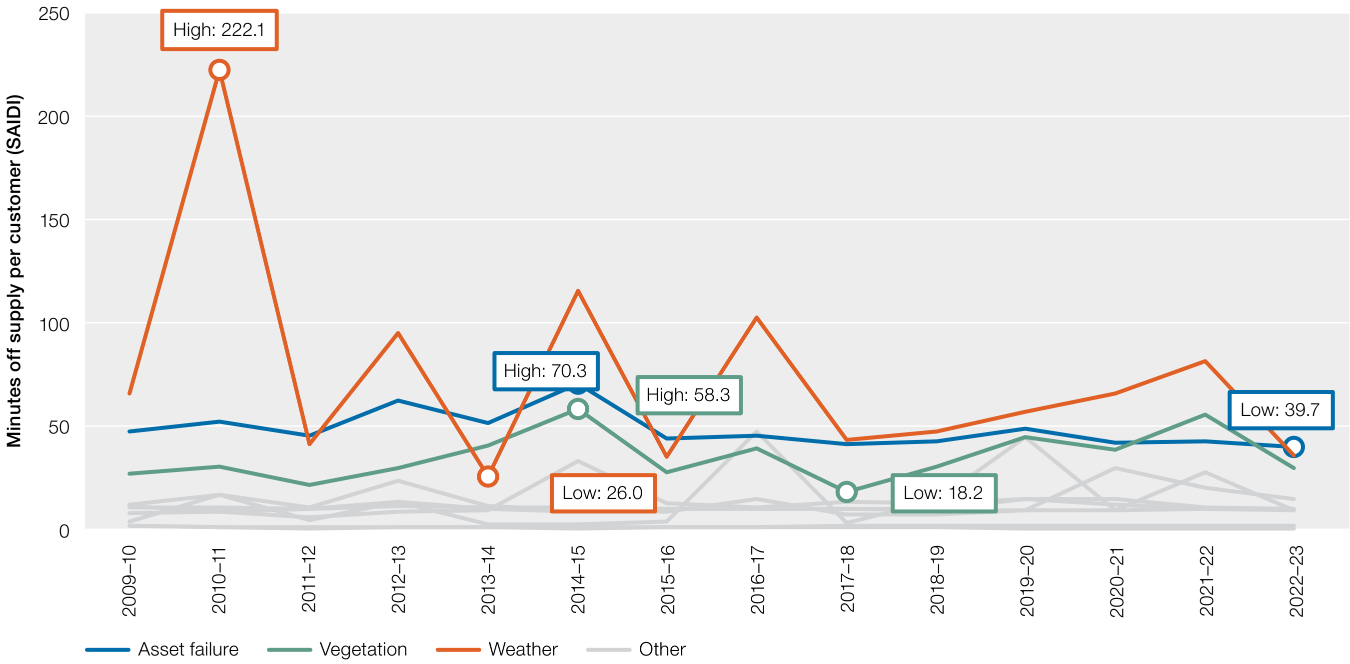


Note: SAIFI: system average interruption frequency index.
Data in Figure 3.36 shows interruptions to supply that lasted longer than 3 minutes. This is consistent with the definition of a sustained interruption in the AER's current service target performance incentive scheme (STPIS) (version 2.0, November 2018). The previous version of the STPIS (May 2009) defined sustained interruptions as those that lasted longer than one minute. Reporting historical SAIFI using a consistent definition allows for greater comparability over time. As such, the values shown above may not reflect outcomes reported in the past. Years reflect 1 July to 30 June.

Source: AER modelling; category analysis regulatory information (RIN) responses.

206 The failure of an asset to perform its intended function safely and in compliance with jurisdictional regulations, not as a result of external impacts such as extreme or atypical weather events, third-party interference, wildlife interference or vegetation interference.

Figure 3.37 Reasons for unplanned minutes off supply (SAIDI) – electricity distribution networks



Note: SAIDI: system average interruption duration index.
Data in Figure 3.37 shows interruptions to supply that lasted longer than 3 minutes. This is consistent with the definition of a sustained interruption in the AER's current service target performance incentive scheme (STPIS) (version 2.0, November 2018). The previous version of the STPIS (May 2009) defined sustained interruptions as those that lasted longer than one minute. Reporting historical SAIDI using a consistent definition allows for greater comparability over time. As such, the values shown above may not reflect outcomes reported in the past. Years reflect 1 July to 30 June.

Source: AER modelling; category analysis regulatory information (RIN) responses.

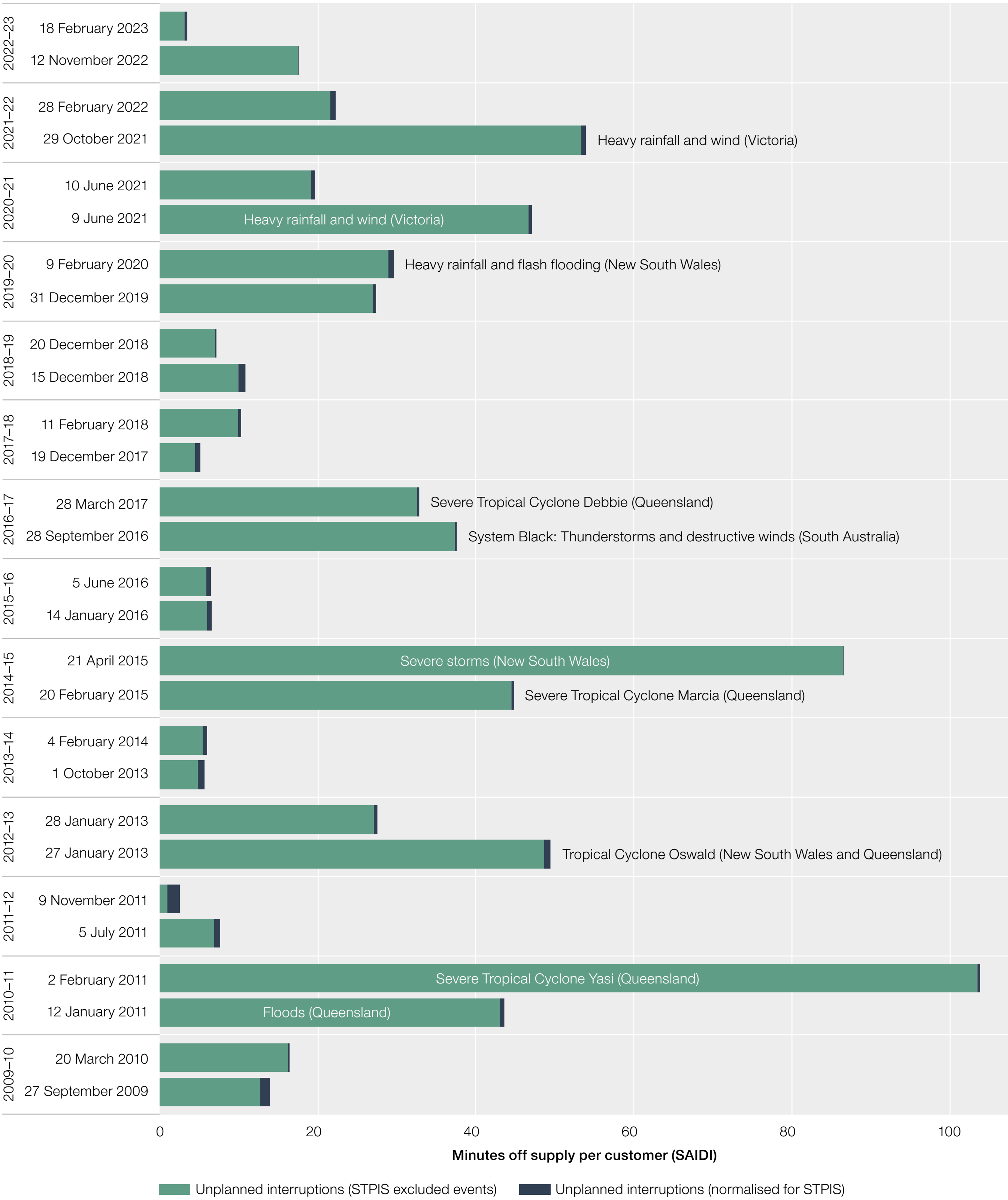
Due to the sheer size of the NEM, which operates on one of the world's longest interconnected power systems, the impact of a severe weather event in one region, or on a specific network within a region, can have little or no impact on neighbouring regions or networks.

This is best illustrated by the impact of Severe Tropical Cyclone Yasi on Ergon Energy's distribution network. On 2 February 2011, the average customer on the Ergon Energy network – which operates in regional Queensland – experienced an extraordinary 1,391 minutes off supply. On that same date, the average customer on the neighbouring Energex network – which services Brisbane and other major urban areas – experienced only 0.2 minutes off supply.

The relatively low number of minutes off supply experienced by the average NEM customer in 2022–23 was in part driven by the lack of catastrophic weather events throughout the year. While some network customers were impacted by isolated severe weather events – such as flooding in New South Wales[207] and severe thunderstorms in South Australia[208] – the weather in 2022–23 was generally mild compared with the previous 3 years (Figure 3.38).

207 Bureau of Meteorology, New South Wales in November 2022: very cool and wet, accessed 18 March 2024.
208 Bureau of Meteorology, Greater Adelaide in November 2022: very wet with cool days, accessed 18 March 2024.

Figure 3.38 Unplanned minutes off supply – most disruptive days of each year



Note: SAIDI: system average interruption duration index.
Data in Figure 3.38 show interruptions to supply that lasted longer than 3 minutes. This is consistent with the definition of a sustained interruption in the AER's current STPIS (version 2.0, November 2018). The previous version of the STPIS (May 2009) defined sustained interruptions as those that lasted longer than one minute. Reporting historical SAIDI using a consistent definition allows for greater comparability over time. As such, the values shown above may not reflect outcomes reported in the past. Years reflect 1 July to 30 June.

Source: AER modelling; category analysis regulatory information (RIN) responses.

Reliability and weather events

A significant storm event hit Victoria on 13 February 2024, causing heavy rainfall and damaging winds. The event caused significant damage to Victoria's electricity distribution network, affecting around 12,000 kilometres of distribution lines and more than one million customers.[209] Following this event, the Victorian Government commissioned an independent review into the operational response of electricity network service providers to the February 2024 storms. In September 2024, the Network Outage Review Expert Panel (the Panel) published its final report consisting of 19 recommendations and 12 observations focused on delivering a clear pathway of improvements, necessitating a step change in the operational response by transmission and distribution network service providers during prolonged power outage events.

The Panel's recommendations provide a strong focus on achieving change quickly, with certainty and using mechanisms that are within Victoria's control.

The final report detailed the importance of better preparedness, coordination and collaboration; actions to improve the reliability of the electricity system and support the community by placing people, their needs and safety at the forefront.

We note the SAIFI and SAIDI data on the impact of the 13 February 2024 storm event will not be available until late 2024. The impact of the storms will be captured in the 2025 State of the energy market.

In April 2024, independent advisory body Infrastructure Victoria published a report stating that most of Victoria's infrastructure – such as roads, electricity networks and buildings – are not built to perform in an environment with more severe weather and intense rainfall events, and more hot days and bushfires.[210]

Since 1 July 2022, Energy Safe Victoria (ESV) has had the power to issue fines to Victorian network service providers that do not keep trees safely clear of powerlines. Before this, ESV's powers to take enforcement action for line clearance breaches were limited to issuing warnings or notices to take corrective action or prosecution through the court system.

In May 2024, Powercor (Victoria) was fined $2.1 million for breaching the Electricity Safety Act and contravening electric line clearance regulations. ESV prosecuted Powercor for 105 offences, including failing to inspect almost 5,000 powerlines and failing to clear vegetation from more than 100 other lines, including one span at Glenmore where a destructive fire broke out.[211]

3.16.5 Incentivising good performance

Inconsistencies in the measurement of reliability across NEM jurisdictions led the AEMC to develop a more consistent approach. In November 2018, the AER adopted the AEMC's recommended definitions for distribution reliability measures for purposes such as setting reliability targets in the STPIS.[212]

More generally, the AER reviewed the STPIS to align with the AEMC's recommendations – for example, it amended the scheme to encourage network service providers to reduce the impact of long interruptions to supply experienced by customers at the end of rural feeders.

209 Engage Victoria, Final report – February 2024 storm and power outage event – Independent review of transmission and distribution businesses operational response, Department of Energy, Environment and Climate Action, September 2024, accessed 15 October 2024.

210 Infrastructure Victoria, Weathering the storm – Adapting Victoria's infrastructure to climate change, April 2024, accessed 16 July 2024.

211 ESV, Powercor convicted on record number of charges, fined $2.1 million, media release, Energy Safe Victoria, 8 May 2024, accessed 15 July 2024.

212 AER, Amendment to the service target performance incentive scheme (STPIS) / Establishing a new Distribution Reliability Measures Guideline (DRMG), Australian Energy Regulator, November 2018.

Box 3.4 Service target performance incentive scheme

The AER applies a service target performance incentive scheme (STPIS) to regulated network service providers. The STPIS offers incentives for network service providers to improve their service performance to levels valued by their customers. It provides a counterbalance to the capital expenditure sharing scheme (CESS) (Box 3.2) and efficiency benefit sharing scheme (EBSS) (Box 3.3) by ensuring network service providers do not reduce expenditure at the expense of service quality. A separate STPIS applies to distribution and transmission networks.

Transmission

The transmission STPIS covers 3 service components:

- the frequency of supply interruptions, duration of interruptions to supply and the number of unplanned faults on the network
- rewards for operating practices that reduce network congestion
- funding for one-off projects that improve a network's capability, availability or reliability at times when users most value reliability or when wholesale electricity prices are likely to be affected.

Financial bonuses of up to +4% of revenue, or penalties of up to –1% of revenue, are available for exceeding/failing to meet performance targets under the scheme.

In December 2023, the AER released an issues paper on its review of aspects of the STPIS for transmission network service providers. In particular, the review will cover the market impact component (MIC) and network capability component (NCC) of the transmission STPIS. The timing of the review will allow any revisions to the STPIS to be picked up in time for the 2029–34 Queensland and South Australian transmission reset processes. Because the network capability incentive parameter action plan (NCIPAP) is closely linked to the MIC, the AER is reviewing the NCIPAP scheme alongside the MIC review.[a]

Distribution

A distribution network service provider's allowed revenue is increased (or decreased) based on its relative service performance. The bonus for exceeding (or penalty for failing to meet) performance targets can range to ±5% of a distribution service provider's allowed revenue.

Currently, the AER applies the distribution STPIS to 2 service elements:

- reliability of supply – unplanned (normalised) system average interruption duration index (SAIDI), unplanned (normalised) system average interruption frequency index (SAIFI) and momentary interruptions to supply (MAIFI)
- customer service – response times for phone calls, streetlight repair, new connections and written enquiries.[b]

The reliability component sets targets based on a network service provider's average performance over the previous 5 years. Performance measures are 'normalised' to remove the impact of supply interruptions deemed to be beyond the network service provider's reasonable control. While the reliability performance of each network fluctuates from year to year, network service providers have generally performed better than their STPIS targets.

a AER, Issues paper - Transmission STPIS review - MIC and NCC, Australian Energy Regulator, 8 December 2023, accessed 19 August 2024.
b Since April 2021, the AER has applied the CSIS instead of the STPIS telephone answering parameter to distribution network service providers whose customers support the change in customer service measurement.

3.16.6 Incentives to avoid fire starts

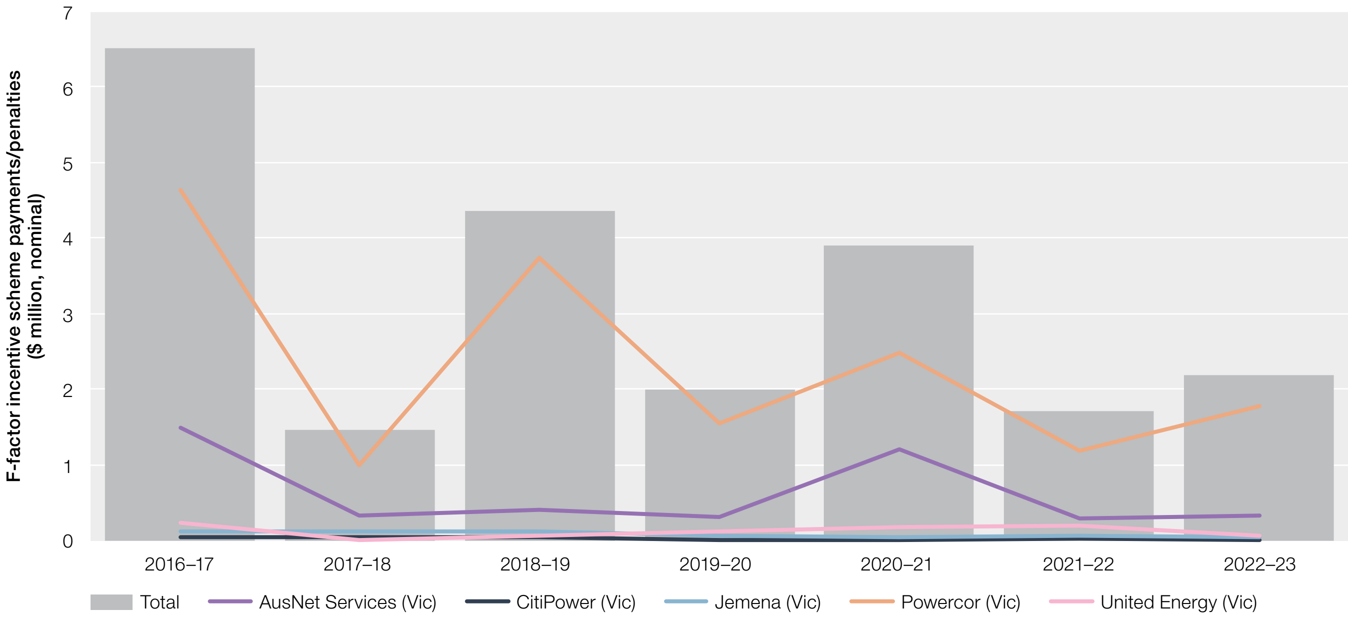
The AER administers the Victorian Government's f-factor scheme, an initiative that provides financial incentives to Victorian distribution service providers to minimise the number of fire starts within their networks in high fire danger zones and times.

If the number of fire starts increases, the distribution network service provider is required to pay a penalty. Likewise, if the number of fire starts decreases, the service provider may receive an incentive payment. Payments and penalties are incorporated into network service providers' allowable revenue each year.

The penalty or reward rates under this scheme range from around $1.48 million per fire start in high-risk areas on code-red days to $300 in low-risk areas on a low fire danger day.

For the 2022–23 reporting period, incentive payments varied from a $9,798 reward for CitiPower with a totally CBD/urban network to $1.8 million for Powercor with a predominately rural network. The impact of the incentive payments from 2022–23 will take the form of adjustments to the network service providers' regulated revenues in 2024–25.

Figure 3.39 F-factor incentive payments – Victorian distribution networks



Source: AER, Victorian electricity distributors' fire start reports for the July 2022–June 2023 reporting period.

3.16.7 Customer service

While reliability is the key service consideration for most energy customers, a distribution network service provider's performance also relates to the network business:

- providing timely notice of planned interruptions
- ensuring the quality of supply, including voltage variations
- avoiding wrongful disconnection (including for life support customers) and ensuring quick time frames for reconnection
- being on time for appointments
- having a fast response to fault calls
- providing transparent information on network faults.

Each jurisdiction sets its own standards for these performance indicators. Some jurisdictions apply a guaranteed service level (GSL) scheme that requires network service providers to compensate customers for inadequate performance. Because reporting criteria vary by jurisdiction, performance outcomes are not directly comparable. The AER provides an annual summary of outcomes against some of these measures for networks in Queensland, NSW, South Australia, Tasmania and the ACT.[213] Victoria reports separately on network performance.[214]

In July 2020 the AER released its customer service incentive scheme (CSIS), which provides incentives for distribution network service providers to provide measurable levels of customer service that align with their customers' preferences (Box 3.5).[215]

Box 3.5 Customer service incentive scheme

The AER's customer service incentive scheme (CSIS) is designed to encourage distribution network service providers to engage with their customers and provide a level of service that reflects their customers' preferences. The AER sets customer service performance targets as part of the 5-year revenue determination process. Under the CSIS, distribution network service providers may be financially rewarded or penalised depending on how well they perform against the designated customer service targets. The revenue at risk under the scheme is capped at ±0.5%.

The CSIS is a flexible 'principles based' scheme that can be tailored to the specific preferences and priorities of a service provider's customers. This flexibility allows for the evolution of customer engagement and the introduction of new technologies.

The CSIS provides safeguards to ensure the financial rewards/penalties under the scheme are commensurate with actual improvements/detriments to customer service. The incentives target areas of service that customers want to see improved.

The AER generally sets performance targets under the CSIS at the level of current performance. However, it may adjust the performance targets if the level of current performance is not considered to provide a good outcome for consumers.[a]

The incentive rates are tested with customers to confirm that they align with the value that customers place on the level of performance improvement/decline. This means that, even if a network service provider performs exceptionally well against its targets, customers will still benefit. In subsequent regulatory periods, the targets under the scheme will be adjusted and set in accordance with any improved level of customer service.

To date the CSIS has only been applied to Victorian distribution network service providers AusNet Services, CitiPower, Powercor and United Energy for their current period (1 July 2021 to 30 June 2026). In 2022–23 the outcomes of the CSIS were rewards of:

- $296,225 for AusNet Services
- $1.7 million for CitiPower
- $1.6 million for Powercor
- $2.4 million for United Energy.

a AusNet Services' historical performance for the complaints parameter was not considered acceptable. In this case, using targets based on historical performance would not have the desired effect. As such, the performance target was calculated using industry-leading performance. Therefore, AusNet Services will only be rewarded for material improvements to customer service.

213 AER, Annual retail markets report 2022–23, Australian Energy Regulator, 30 November 2023.
214 ESC, Victorian energy market report, Essential Services Commission, 27 June 2024.
215 AER, Final – Customer Service Incentive Scheme, Australian Energy Regulator, 21 July 2020.

4 Gas markets in eastern Australia

This chapter covers upstream gas markets in eastern Australia, encompassing gas production, wholesale markets for gas and the transport of gas along transmission pipelines for export or domestic use.[216] Much of the chapter is focused on markets facilitated by the Australian Energy Market Operator (AEMO), but also includes information on bilateral commodity gas trades up to a year in duration.[217]

The main production basin in eastern Australia is the Surat–Bowen Basin in Queensland. There are smaller basins in South Australia, New South Wales (NSW), off coastal Victoria and in the Northern Territory. Combined, these basins account for around 43% of Australia's total gas production.[218]

The eastern gas market is interconnected by transmission pipelines, which source gas from these basins and deliver it to liquefied natural gas (LNG) facilities for export and to large industrial customers and major population centres for domestic use (Figure 4.1).

Due to the rapid expansion of the Australian LNG industry on both the east and west coasts, Australia has become one of the world's largest LNG exporters.

Since the launch of the LNG export industry in 2015, gas producers have had the choice to export or sell gas domestically. Consequently, prices in the domestic market are influenced by international gas prices.

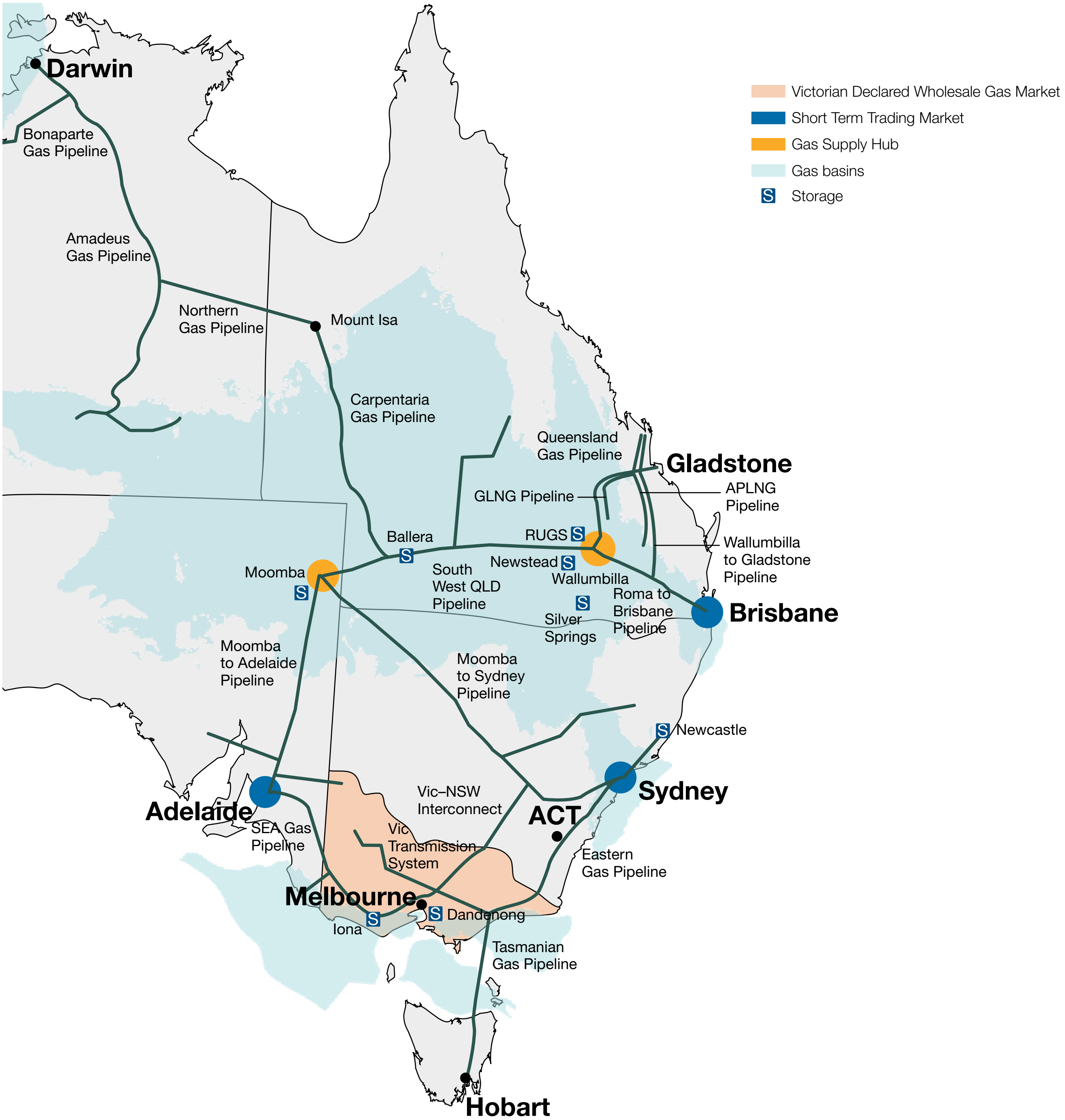
216 The Australian Energy Regulator (AER) has regulatory responsibilities in the eastern Australian gas market in Queensland, NSW, Victoria, South Australia, Tasmania and the ACT.

217 AEMO-facilitated markets includes the Short Term Trading Market hubs and the Gas Supply Hub. Bilateral commodity reporting under the Gas Rules commenced in 2023, adding to secondary bilateral transaction reporting since 2019.

218 71% of Australia's total gas reserves are conventional gas resources and 29% are unconventional (coal seam gas) resources. Surat–Bowen accounts for most of Australia's coal seam gas production. Most of Australia's conventional gas resources are located off the north-west coast of Western Australia and at the end of 2023 they accounted for around 56% of total gas production.

Australian exports accounted for 20% of global exports in 2023, alongside Qatar (20%) and the United States (21%).[219] On the east coast, exports account for the majority of gas demand, significantly exceeding domestic consumption levels.[220]

Figure 4.1 Eastern gas basins, markets, major pipelines and storage



Source: AER; Gas Bulletin Board.

219 Department of Industry, Science, Energy and Resources, Resources and energy quarterly, March 2024, p. 71.

220 Compared with residential and commercial, industrial and gas generation demand, LNG demand accounted for around 70% of gas consumption on the east coast in 2023. AEMO, *2024 gas statement of opportunities*, March 2024, p. 12.

Box 4.1 The AER's role in wholesale gas markets

The Australian Energy Regulator (AER) has regulatory responsibilities across the entire gas supply chain in eastern Australia. At the wholesale level, we monitor and report on spot gas markets in Sydney, Brisbane, Adelaide and Victoria; gas supply hubs at Wallumbilla (Queensland) and Moomba (South Australia); short-term secondary capacity markets for gas transportation; and activity on the Gas Bulletin Board, which is an open access information platform covering the eastern gas market.

We monitor the markets and bulletin board to ensure participants comply with the National Gas Law and National Gas Rules, and we take enforcement action when necessary. Our compliance and enforcement work aims to promote confidence in the gas market to encourage participation. We also monitor the markets for particular irregularities and wider inefficiencies. For example, our monitoring role at the Wallumbilla and Moomba hubs explicitly looks to detect price manipulation. We are also the compliance and enforcement body for AEMO-facilitated auctions for secondary capacity in transmission pipelines.

We publish various reports, including gas industry statistics and our Wholesale markets quarterly reports, which cover gas spot market activity, prices and liquidity. The quarterly reports also include analysis of eastern Australia's liquefied natural gas (LNG) export sector and its impact on the domestic market. From July 2023, the AER began reporting a wider set of information on the export, reserve, storage, and domestic sale and swaps of gas. In May 2024, new wholesale market monitoring powers were legislated to facilitate a review of gas contract markets. Additional reporting from 2025 will consider this new information alongside associated spot market impacts and implications on final costs faced by consumers.

The AER also has regulatory responsibilities for transmission and distribution pipelines (chapter 5) and retail markets (chapter 6).

We continue to engage with the Energy Ministers' gas reform agenda and, when appropriate, we propose or participate in reforms to improve the market's operation. We also draw on our regulatory and monitoring work to advise policy bodies and other stakeholders on market trends, policy issues and irregularities.

Outside the eastern gas market, the AER is the gas pipeline regulator for the Northern Territory but plays no role in the territory's wholesale market. Facility operators in the Northern Territory must report gas flow activity to the Gas Bulletin Board.

We have no regulatory function in Western Australia, where separate laws apply. The Economic Regulation Authority is the economic regulator for gas markets and pipelines in Western Australia and AEMO operates a spot gas market there.

4.1 Gas market snapshot

Since the last *State of the energy market* report:

- Prices in facilitated gas markets stabilised from mid-2023, with milder winter conditions lowering demand and influencing a significant reduction from the unprecedented high prices of mid-2022 (section 4.3).
- In 2024, prices remained stable at around $9 to $13 per GJ until late May when a stretch of cold weather and constrained southern production put upwards pressure on market prices (section 4.3). Daily prices peaked at around $28 per GJ in June and influenced a period of high ancillary payments in Victoria in July (sections 4.3 and 4.5).
- Transportation capacity upgrades on the north–south pipeline corridor to increase the ability to flow more gas south were completed in May and June, delivering more supply from Queensland to southern markets (sections 4.6 and 4.8.3).
- Historically low demand was observed at the end of 2023 alongside lower levels of gas-powered generation (GPG). While lower GPG continued into the first quarter of 2024, the second quarter saw spikes in GPG output to offset low wind and solar generation. This demonstrates the interdependencies between electricity and gas markets in the National Electricity Market (NEM).
- Gas markets remains vulnerable to weather-driven peak demand days when existing supplies to southern states must be supplemented with drawdowns from storage. Southern gas storage inventory at Iona depleted rapidly over June and July 2024 before easing market conditions resulted in storage levels being replenished in August, averting the potential threat of a supply shortfall (section 4.5.4).
- Depleting offshore legacy gas fields in Victoria continue to limit southern production and increase supply shortfall risks, with reduced peak day capabilities declining further from the lower levels of 2023. Projected reductions in coming years are expected to drive a 58% decline in peak day production capacity from the Gippsland region by 2028, with one of Longford's 3 production trains scheduled for retirement after winter 2024 (section 4.5.3).

4.2 Structure of the east coast gas market

The east coast gas market is made up of several separate underlying markets and supply hubs, as well as a supporting bulletin board. Around 10% to 30% of gas is traded in these spot markets. All other gas trade is struck under confidential bilateral contracts separate to these markets.

4.2.1 Contract markets

The majority of gas in Australia is traded through bilateral contracts, which secure future supply and transportation capacity and limit participants' exposure to price fluctuations in downstream markets. Contract prices generally reflect expectations of future market conditions, but shorter-term transactions in spot markets can reflect short-term shifts in market conditions due to factors such as gas supply and gas storage levels, the timing of LNG shipments and conditions in the electricity market. As a result, the price levels are not always aligned, but they often move in similar directions.

For many domestic users, contract prices are likely to be more indicative of the costs they face.

The 2 main levels of gas contracts (also known as gas supply agreements) are:

- offers by gas producers to very large customers, such as major energy retailers and gas-powered generators
- offers by retailers and aggregators that buy gas from producers and on-sell it to commercial and industrial (C&I) customers.[221]

221 Public information about contract prices was unclear. Much of the pricing was private and negotiated contract outcomes are often bespoke. There was also a disparity between the type of information available to large participants that are frequently active in the market and that available to smaller players. This imbalance favoured large incumbents in price negotiations. In response, in 2018 the ACCC began publishing gas price data as part of its 2017–2030 gas inquiry. Further reforms following the gas market transparency review require participants to report information to AEMO from 15 March 2023 for publication on the Bulletin Board, including reserves resources reporting, facility developments, LNG spot transactions and bilateral short-term supply and swap transactions.

Long-term gas contracts historically locked in prices and other terms and conditions for several years. More recent analysis indicates the industry shifted towards shorter-term contracts (one to 2 years) with review provisions.[222] Although there has been a recent increase in the number of longer-term contracts executed at higher volumes, the overall volumes contracted for 2024 were lower than for 2023.[223]

4.2.2 Spot markets

Spot markets allow wholesale customers to trade gas without entering long-term contracts. Spot market trading can be a useful mechanism for participants to manage imbalances in their contract positions.

Several separate spot markets operate in eastern Australia – Victoria's Declared Wholesale Gas Market, the Short Term Trading Market, the Gas Supply Hub and a separate east coast wide market for transportation and compression services.

Victoria's Declared Wholesale Gas Market (DWGM)

Victoria's DWGM manages gas flows across the Victorian Transmission System. Participants submit daily bids ranging from $0 per gigajoule (GJ) (the floor price) to $800 per GJ (the price cap). Prices in the Victorian market cover gas as well as transmission pipeline delivery. AEMO selects the least cost bids needed to match demand to establish a clearing price.

AEMO operates the financial market and manages physical balancing, including by scheduling gas injections at above market price to alleviate short-term transmission constraints if any arise.

Short Term Trading Market (STTM)

The STTM is a short-term trading market for gas with hubs in Sydney, Brisbane and Adelaide that allows gas trading on a day-ahead basis. AEMO sets a clearing price at each hub based on scheduled withdrawals and offers by shippers to deliver gas, with a price floor of $0 per GJ and a cap of $400 per GJ. Pipeline operators schedule flows to supply the necessary quantities of gas to each hub.

AEMO operates a balancing service – called market operator services (MOS) – to meet any variations in gas deliveries or withdrawals from the schedule. These services are mainly paid for by the parties causing the imbalance.

Gas Supply Hub (GSH)

Gas supply hubs at Wallumbilla in Queensland and Moomba in South Australia are a voluntary platform for gas trading. There are 5 standard product lengths that participants can use when trading at the gas supply hubs – balance of day, daily, day-ahead, weekly and monthly. Participants can trade gas up to a year in advance of physical supply.

Wallumbilla is a major pipeline junction linking gas basins and markets in eastern Australia, making it a natural point of trade. A single trading location makes it easier for participants to organise their gas trade across multiple pipelines, thus pooling potential buyers and sellers into a single market.

Like Wallumbilla, the Moomba hub is located at a major junction in the gas supply chain serving eastern Australia. Three critical pipelines – the South West Queensland, Moomba to Sydney and Moomba to Adelaide pipelines – connect to the hub. On 28 January 2021, trade points at Culcairn and Wilton were also introduced to facilitate trades at the Victorian and Sydney gas market locations, respectively. AEMO is also planning to introduce the Eastern Gas Pipeline and Iona underground storage trade points alongside swap products for the notional transfer of gas between different locations, which can be traded to achieve similar physical outcomes to trading currently existing spread products.[224]

222 ACCC, Gas inquiry 2017–2020, interim report, Australian Competition and Consumer Commission, July 2018, August 2018, pp. 24, 49.
223 ACCC, Gas inquiry 2017–2030, interim report, Australian Competition and Consumer Commission, December 2023, p. 34.
224 The introduction of the Eastern Gas Pipeline and Iona underground storage trade points on 11 July 2024 encountered technical issues. Changes are now expected to be incorporated into the Gas Supply Hub Exchange Agreement effective from 14 November 2024.

A significant proportion of trade occurs 'off-screen', which allows participants to use brokers to match trades on their behalf or leverage their existing bilateral arrangements to facilitate spot trades.[225]

Day Ahead Auction (transportation related services)

Gas produced in one region can help address a supply shortfall elsewhere, provided transmission pipeline capacity is available to transport the gas. However, several key pipelines experience contractual congestion, which arises when most or all of a pipeline's capacity is contracted, making the pipeline unavailable to third parties. Contractual congestion may occur even if a pipeline has spare physical capacity. Reforms introduced in March 2019 enabled participants to access this unutilised pipeline capacity across the east coast.

Unutilised (contracted but not nominated) pipeline transport and gas compression capacity for the next day is sold the day before through an auction. Since its inception, the auction has been widely used to move gas between the east coast gas markets. From late 2022, participation in the auction has increased significantly and set consecutive records for capacity won, with amounts procured more than double the highest levels observed across previous years (section 4.6.2).

4.2.3 Gas Bulletin Board

The Gas Bulletin Board is an open access website providing current information on gas production, storage and transmission pipelines in eastern Australia. It plays an important role in making the gas market more transparent, especially for smaller players that may not otherwise be able to access day-to-day information on demand and supply conditions. It supplies information such as:

- pipeline capabilities (maximum daily flow quantities, including bidirectional flows), pipeline and storage capacity outlooks, and nominated and actual gas flow quantities
- daily production capabilities and capacity outlooks for production facilities
- gas stored, gas storage capacity (maximum daily withdrawal and holding capacities) and actual injections/withdrawals
- gas field information – reserves and resources, movement, development status, commercial recovery, including information on the basis of estimate preparation, and prices underpinning reserve and resource estimates
- LNG export and import information – shipment dates and volumes as well as detailed reporting of spot LNG transactions
- short-term gas supply and swap transactions with a contract length up to a year
- 36-month outlooks for uncontracted primary firm capacity (compression, storage, production and LNG import facilities) and short/medium-term outlooks for smaller users.

The bulletin board includes an interactive map showing gas plant capacity and production data, and gas pipeline capacity and flow at any point in a network.

Reforms were implemented in March 2023 that expanded the scope of information reported with some participants required for the first time to report to the Gas Bulletin Board (section 4.11.1).

225 Most gas trading occurs 'off-screen' (not traded through the gas markets), but some of these trades are reported to the market operator and settled through the Gas Supply Hub trading platform.

4.3 Gas prices

Gas market prices are typically elevated during winter periods, when colder weather in southern markets increases demand for residential gas heating. This is particularly significant in the larger Victorian market, where daily demand can exceed 1 petajoule (PJ) on cold days. Gas prices can also increase during summer periods, influenced by higher demand for gas-powered generation in the electricity market, which coincides with warmer temperatures and increased demand for air conditioning.

Unlike previous years, winter 2023 temperatures were particularly mild. Prices did increase in the April to June quarter, but this was primarily driven by supply constraints during May rather than the typical price increases observed in June and July when demand is higher.[226] Over the winter months, there was generally lower demand for electricity generation and international prices were low. Alongside significant supply quantities coming south from Queensland, these factors, combined with the lower winter demand, contributed to putting downward pressure on gas market prices.

Prices across the downstream markets remained relatively stable at around $9 to $13 per GJ until late May 2024, when elevated market and gas generation demand occurred at the same time that planned maintenance work at Longford constrained southern supply. Similar factors in June, colder weather and a delayed ramp-up of production at Longford, drove an increased reliance on Iona's underground storage stocks.

4.3.1 Gas contract prices

Gas contracts can take many different forms, with variations in the time between traded and delivery dates, and the timespan in which the gas is delivered over. For example, gas can be contracted to be delivered in daily quantities for weeks or months at a time and can range from 1 to 10 years in length domestically. LNG export contracts are set over longer periods of around 20 years.[227]

Market participants are required to report their gas contract information to the ACCC. The ACCC then reports on these prices through its gas inquiry responsibilities. The inquiry's interim updates consider numerous factors influencing contract prices, including the impact of domestic market supply and market price trends, LNG export activity and links to international prices (section 4.3.4).

Domestic contract prices increased significantly during 2021 and 2022, influenced by international price volatility and global gas supply uncertainties. From mid-2023, domestic gas contract prices rose to be on par with international price levels but remained relatively stable as international prices gradually increased out to the end of the year.[228]

226 Constrained supply at Longford (Victoria's largest production source) due to an unplanned compressor outage and pipeline capacity constraints on the Moomba to Sydney Pipeline drove significant price increases in May 2023.

227 RBA, Understanding the East Coast Gas Market, March 2021, Reserve Bank of Australia.

228 While international price levels had decreased significantly from record highs in the years prior, they remained above the historical trend in mid-2023. International prices declined over 2024, returning to domestic price levels, with domestic prices briefly spiking above international levels in winter.

In 2024, international prices eased, returning to similar levels as domestic prices. However, local prices in winter increased temporarily above international price levels due to the numerous supply and demand factors present in the domestic market, particularly in the southern markets that experienced a prolonged stretch of cold weather.

Contract prices offered in the second half of 2023 for east coast supply across 2024, as observed by the ACCC, averaged $12.60 per GJ for producers and $17.30 per GJ for retailers, a decrease from levels observed in the preceding 6 months.[229] This was a significant decrease to the amount of offers exceeding $30 per GJ during the record high domestic prices over mid-2022.

Following announcements of potential government intervention to address the high prices, 2023 offer prices decreased markedly in late 2022. Producer offer prices fell to around $20 per GJ and short-term LNG netback prices also moderated from their peaks to just under $40 per GJ. Retail offers remained around $30 per GJ.[230] From 23 December 2022, the Competition and Consumer (Gas Market Emergency Price) Order 2022 (section 4.10.4) came into effect for 12 months, with nearly all producer contracts from this period decreasing to $12 per GJ or less. Since the introduction of the price cap, the ACCC observed an increase in the volume of gas sold under short-term gas supply agreements and traded on facilitated markets.[231] There was also a reduction in 2022 offers for supply in 2024 compared with 2021 offers for 2023 supply. Prices quoted for supply in 2023–24 fell from around $65 per GJ before the price cap to around $19 per GJ in April 2023.

Over 2023, gradual decreases in contract prices have coincided with a period of more stable domestic price levels from mid-2023 as the east coast experienced a mild winter peak demand period.

Mandatory Gas Code of Conduct ($12 reasonable price provision)

Following the introduction of the Competition and Consumer (Gas Market Emergency Price) Order (section 4.10.4), the Australian Government implemented a Mandatory Gas Code of Conduct (the Code) to replace the order on its expiry in 2023. The Code came into effect from 11 July 2023 with a 2-month transitional period allowed to 11 September 2023, with the aim to ensure users' ability to contract for gas at reasonable prices and on reasonable terms.

The Code adopted a $12 per GJ reasonable price provision and provides an exemptions framework to incentivise short-term supply commitments and investment to meet ongoing domestic medium-term demand. It also includes transparency obligations on uncontracted gas production and expected domestic availability, as well as conduct provisions and process standards for commercial negotiations. The first mandated review of the Code is due 1 July 2025. After the Code was finalised, volumes of 1 year or less transactions for delivery in 2024 increased, most likely due to improved pricing certainty for buyers and sellers.

229 Prices agreed under contracts for 2024 supply were down 26% for producers and 10% for retailers compared with the preceding 6 months. ACCC, Gas inquiry 2017–2030, interim report, June 2024, Australian Competition and Consumer Commission, p. 5.

230 ACCC, Gas inquiry 2017–2030, interim report, June 2023, Australian Competition and Consumer Commission, p. 11.

231 ACCC, Gas inquiry 2017–2030, interim report, June 2023, Australian Competition and Consumer Commission, pp. 12, 54.

4.3.2 Short-term transaction reporting

From 15 March 2023, information on east coast bilateral gas trades has been published on the Gas Bulletin Board that summarises the reporting of short-term transactions to AEMO as part of the new transparency measures.[232] The information reported covers bilateral trade between parties conducted outside of the AEMO-facilitated markets and includes transactions with a contract length of 12 months or less. Since the majority of gas trade up to 12 months in length is done bilaterally, this information materially improves the comprehensiveness of data available to the AER.[233] Figure 4.2 shows a breakdown by quarter of the traded transactions and the forward period of delivery since April 2023.

Figure 4.2 Traded versus delivered quantities

Note: Traded refers to the trade date of the short-term supply transaction, while delivered refers to the month the gas volume will be supplied. Where there is not enough trades or participants reporting in a period,the data is aggregated to a longer time frame.

Source: AER analysis of Gas Bulletin Board data.

The October to December quarter of 2023 marked a peak in short-term supply transactions reported, with 65.7 PJ traded – nearly 30 PJ more than the previous quarter. This surge appears driven by conditional producer exemptions being granted under the Gas Market Code and the resulting pricing certainty for sellers and buyers. There was a concentrated burst of activity taking place between November and December as participants finalised their contracting positions for 2024.[234] Of the total volume, 75% was contracted for 2024 delivery, with over half of these trades occurring within the $10 to $12 per GJ price range. Nearly two-thirds of trades priced above $12 per GJ were tied to the JKM futures index.[235]

For 2024 so far, approximately 90 PJ of short-term transactions have been reported. Almost one-third of these are for delivery between 2025 and 2027. Approximately half of the January to March 2024 trades were for deliveries in 2025 and 2026. April to June 2024 recorded a slight increase in trading volumes, reaching 45.7 PJ. Of this, 27.2 PJ (around 60%) was allocated for delivery across the last half of 2024 and around 20% over 2025 to 2027.

232 Department of Industry, Science, Energy and Resources, Regulatory amendments to increase transparency in the gas market, 19 November 2020.

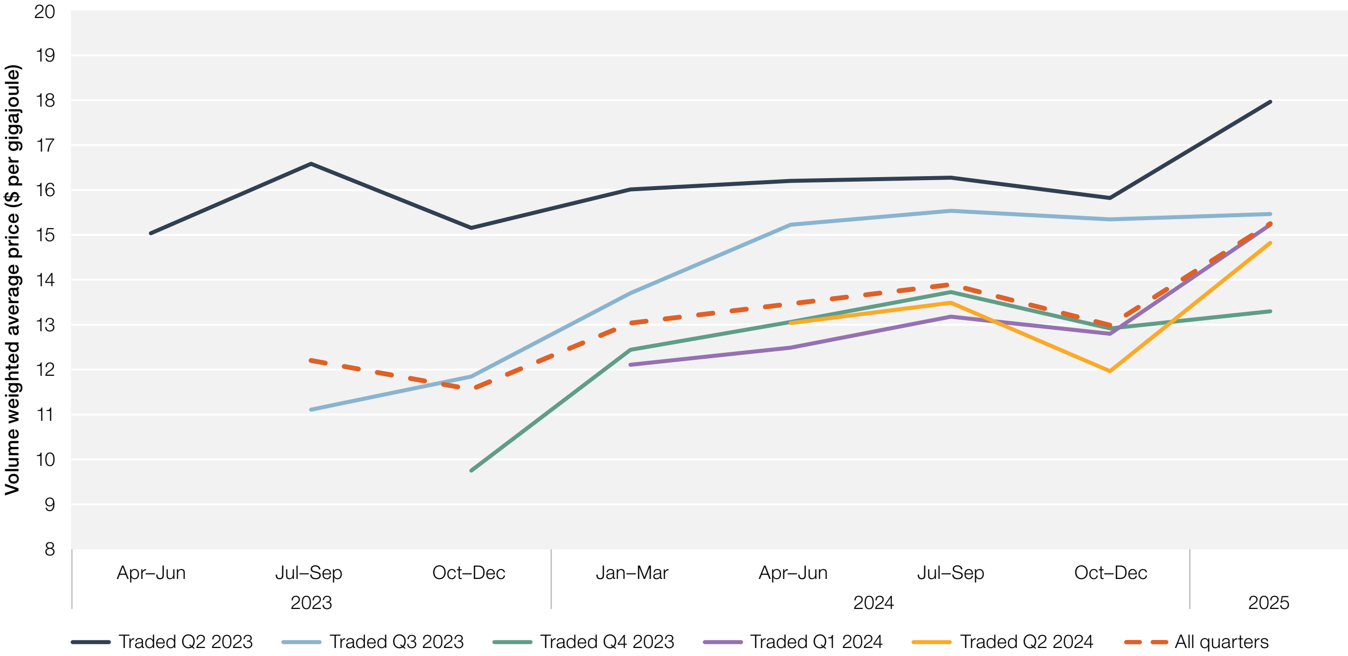
233 The AER published a special report in December 2023 providing analysis and insights into all short-term transactions reported up to 31 October 2023 to the Gas Bulletin Board. The report also includes feedback from industry stakeholders on the effectiveness of current reporting practices and recommendations to enhance this in future reporting. AER, Special report: Wholesale gas short term transactions reporting, Australian Energy Regulator, 6 December 2023.

234 ACCC, Conditional ministerial exemptions for gas suppliers, Australian Competition and Consumer Commission.

235 The Japan/Korea Marker (JKM) is the Northeast Asian spot price index for LNG delivered ex-ship to Japan and the Republic of Korea.

In 2023, the volume weighted average forward price curve for supply transactions declined quarter on quarter. April to June 2024 was the first quarter that average prices increased since reporting commenced (Figure 4.3).

Figure 4.3 Volume weighted average forward price curve based on the traded quarter



Note: The volume weighted average prices are based on the supply dates of the reported transactions in the quarter the transactions occurred. These prices exclude pricing structures linked to the STTM or DWGM. Where there is not enough trades or participants reporting in a period, the data has been aggregated.

Source: AER analysis of Gas Bulletin Board data.

Quarterly volume weighted prices were $12.21 per GJ for gas delivery over July to September 2023 and $11.57 per GJ for delivery over October to December 2023.[236] For gas deliveries in 2024, the volume weighted average prices ranged between $13 and $14 per GJ.

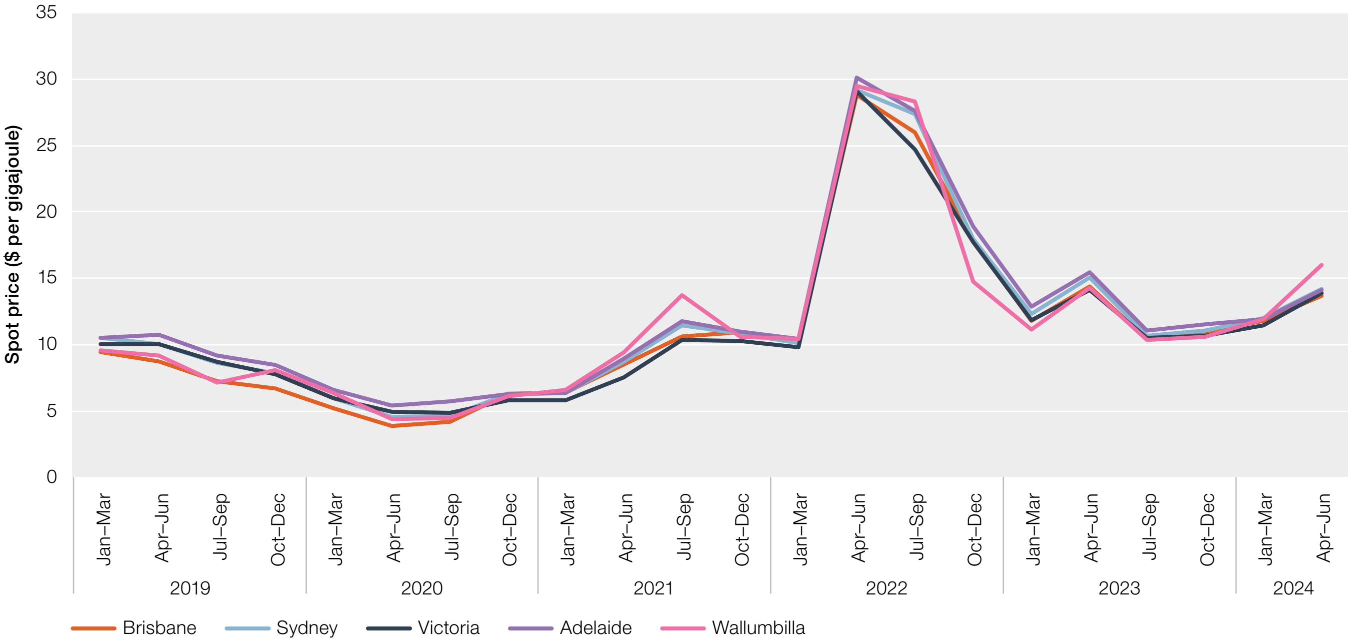
Looking ahead to 2025, forward prices are projected to average $15.26 per GJ based on observed trades to date. This increase is largely driven by the significant volume of contracts secured over the January to March quarter of 2024 at similar price levels. As the year progresses, particularly in the last quarter of 2024, we expect trading volumes for 2025 and beyond to increase as market participants finalise their contracts for the upcoming year. This ongoing activity indicates a market that continues to adjust and evolve in response to changing conditions and expectations.

236 The volume weighted average prices are based on the supply dates of the reported transactions and excludes pricing structures linked to the STTM or DWGM.

Spot market prices

Gas spot market prices over 2023 initially sat above historical price levels but stabilised from mid-2023 onwards. A temporary upturn in prices in the April to June quarter of 2024 primarily resulted from tight supply-demand conditions in Victoria over winter. However, quarterly prices in downstream markets remained below levels over the same period in 2023, despite much colder conditions in comparison to the mild 2023 winter (Figure 4.4).[237]

Figure 4.4 Eastern Australian gas market prices



Note: The Wallumbilla price is the volume weighted average price for day-ahead, on-screen trades at the Wallumbilla gas supply hub (WAL product location). Brisbane, Sydney and Adelaide prices are ex-ante. The Victorian price is the average daily weighted imbalance price.

Source: AER analysis of gas supply hub, Short Term Trading Market and Victorian Declared Wholesale Gas Market data.

Gas spot market prices stabilised from mid-2023

Lower prices from mid-2023 were influenced by an unusually warm winter driving lower gas market demand. In the July to September quarter of 2023, lower gas-powered generation and market demand saw prices reduce slightly below quarterly levels observed in 2021 ahead of the record highs in 2022. During the third quarter of 2023, higher renewable energy output and reduced electricity prices saw gas generation record its lowest July to September quarterly output since 2004.[238] Grid-scale variable renewable energy output reached an all-time quarterly high in the October to December quarter of 2023, with gas-powered generation falling slightly again.[239] Decreasing international export prices from late 2023 also put downward pressure on domestic gas prices heading into 2024.

In 2024, historically low gas market demand put further downward pressure on prices despite the return of higher volumes of exports from late 2023.[240] Short periods of suppressed gas prices also resulted in retailers offloading contracted supply into the downstream markets at the end of September. Additional export supply entered downstream markets in late-November due to an export carrier becoming stranded at the Curtis Island LNG facility (Figure 4.5).

237 Cold weather and constraints limiting production and transportation capacity drove up prices just before winter 2023, resulting in higher prices over the April to June quarter.

238 Black coal generation also fell to its lowest July to September quarterly average since the start of the NEM. AEMO, Quarterly Energy Dynamics Q3 2023, Australian Energy Market Operator, October 2023, p. 25.

239 AEMO, Quarterly Energy Dynamics Q4 2023, Australian Energy Market Operator, January 2024, p. 4.

240 This was despite a month of reduced supply capacity at Longford, Victoria's largest production facility, with participants utilising the high levels of storage at Iona to supply the market.

Gas spot market prices in 2024

From June 2023 to the end of April 2024, monthly average prices in downstream markets ranged from $8.82 per GJ in Victoria to $12.95 per GJ in Adelaide. Following the period of stable prices from mid-2023, prices increased above $13 per GJ from 20 May. This was driven by a combination of higher demand and constrained supply, which prevented Victoria's underground storage facility at Iona fully restocking ahead of winter. The price impacts of these events flowed through to other downstream markets in Sydney and Adelaide, and to a lesser extent in Brisbane.

Compared with the week before, Victorian demand increased by around 100–150 TJ per day from 21 May due to cold weather driving up residential heating demand. At the same time, gas-powered generation (GPG) demand increased across mainland regions in response to higher electricity demand. Increases in southern demand coincided with Victoria's largest supply source at Longford operating at reduced capacity during a period of offshore maintenance.[241] To meet the increased demand, participants drew down on Iona storage at an average of just over 300 TJ per day. Although gas flows south from Queensland had increased from the start of May, with further increases of around 100 TJ per day or more from late May, this did not correspond to additional interstate supply making its way into Victoria over the period of elevated prices that continued over the following week.

Following the period of relatively flat levels of downstream market trade over 2023, net trade volumes started to rise in May 2024 and reached over 6.5 PJ across June, returning to more typical trends that would be observed over the winter period. Day Ahead Auction activity was also high from June, with transportation capacity levels won by participants exceeding previous records for June and July.[242]

From June 2024 pipeline capacity expansions on the transmission corridor between Queensland and south-east Australian demand centres were completed, allowing for more gas supply to flow to southern markets (section 4.8.3). Despite this, similar price increases occurred on 4–5 June and 2 July, driven by the same factors that occurred in May, with further increases in demand levels driven by colder weather.[243] However, the most significant daily price increases occurred over 13 June to 24 June, with prices in downstream markets reaching a peak of $28 per GJ on 20 June (Figure 4.5). Tight supply and demand conditions in southern markets and elevated gas-powered generation requirements across mainland regions contributed to the price increases, with lower than expected supply from Longford in Victoria driving a greater reliance on Iona storage supply.[244] This led to the rapid depletion of Iona's underground gas storage levels despite significant gas flows south from Queensland. AEMO identified this as a potential threat to system security (section 4.5, Box 4.2).[245]

Figure 4.5 sets out an annotated timeline of key pricing events in 2023 and 2024 to date.

241 Capacity at the Longford production facility was capped at a bit below 550 TJ per day over May, around half the facility's nameplate capacity rating.

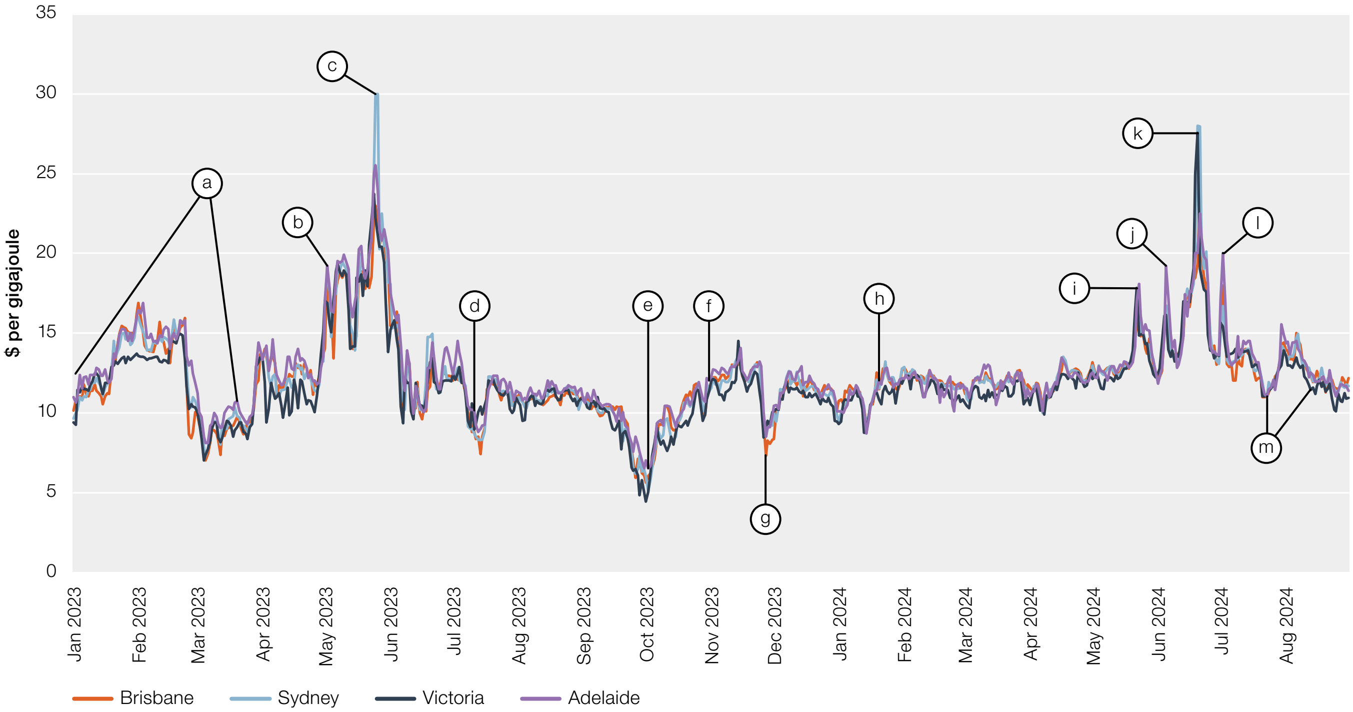
242 Auction capacity won in June totalled 13.9 PJ (close to 4.6 PJ higher than the record set the previous year), with capacity in July totalling 12.1 PJ (2.7 PJ higher than July 2023).

243 Maximum temperatures in Melbourne averaged just over 14 degrees over that period, with minimum temperatures averaging below 9 degrees. On 19 June, the temperature in Melbourne dropped to 1.4 degrees, contributing to prices spiking in downstream markets.

244 Longford provides most of Victoria's gas supply, with Iona the second largest supply source in the region.

245 AER, Wholesale markets quarterly – Q2 2024, Australian Energy Regulator, July 2024.

Figure 4.5 Daily gas spot prices



Note:

a 27 December 2022 to 19 January 2023 and 22 February to 8 March: QCLNG planned maintenance outages influencing additional production capacity becoming available to downstream market participants.

b May 2023: Cold weather and constrained supply from Longford influencing higher prices in Victoria, which flowed through to other markets.

c 24 to 26 May 2023: Limits on Moomba to Sydney Pipeline flows impact the Sydney market, resulting in constraint pricing and high ex-ante prices.

d 8 to 16 July 2023: Warmer weather driving a decrease in downstream market demand. An unseasonably warm winter resulted in the lowest observed July to September quarterly demand over the past decade.

e Late September 2023: Lower than expected gas demand led to retailers offloading contracted (take-or-pay) supply at low prices at the end of the quarter.

f Mid-October into November 2023: Higher export volumes put upwards pressure on domestic prices.

g Late November 2023: A boost in domestic sales from export supply due to an LNG export carrier becoming stranded at the Curtis Island export facility. The docked vessel became stranded on 22 November and prevented the refill of 3 LNG tankers before its departure on 1 December.

h From mid-January 2024: Increased price stability in downstream markets, with historically low market demand offsetting elevated LNG export flows.

i 21 to 23 May 2024: Cold weather driving increased heating demand, offshore maintenance constraining Longford supply and elevated mainland GPG demand.

j 4 to 6 June 2024: Cold weather demand and elevated GPG and delayed Longford ramp-up following maintenance.

k 18 to 22 June 2024: Continuing constrained output from Longford with high demand and high GPG, continued reliance on Iona storage supply and elevated Tasmanian GPG demand due to drought conditions reducing hydro-electric generation. A pipeline constraint in Victoria also resulted in significant ancillary payments to compensate for the scheduling of higher priced gas.

l 1 to 2 July 2024: High market demand and elevated GPG.

m 21 to 26 July and 11 August 2024 onwards: Reduced market demand and GPG eases price pressures, with an unseasonably warm end to winter in August.

Source: AER; AEMO (raw data).

Significant price variations in June 2024

During the period of elevated prices in June, an issue with a new pipeline segment in Victoria restricted the supply capability of facilities located in the west of the state.[246] This resulted in the requirement to source higher-priced supply from other supply points in the Victorian market, resulting in ancillary payments to recover increased supply costs. From 18 to 21 June, daily ancillary payments levels above $89,000 breached the AER's significant price variation reporting threshold of $250,000 on 2 occasions.[247] These events were investigated and summarised in a significant price variation report published on the AER website.

4.3.3 2023 local prices and international price trends

Annual domestic prices decreased over 2023 following unprecedented price increases in 2022. While prices reduced by 43% compared with 2022 levels, they still remained elevated – sitting around 34% higher than average downstream market prices in 2021.

Factors contributing to prices decreasing from 2022 levels included low market demand and gas generation levels across the year.

Linkages between domestic and international prices

The growth in Queensland's LNG exports from late 2020, combined with other factors including state-based moratoriums on gas development and a tightened supply-demand balance, has placed increasing pressure on east coast domestic markets. In previous years (2021 and 2022), domestic contract prices increased yet remained well below increases in international price levels, which were up almost 230%.[248]

From late 2021 during the Northern Hemisphere winter, competition between Asian, European and South American buyers combined with higher demand to replenish European storage levels, driving up prices in Asia. By mid-2022, domestic prices converged with surging international prices as unprecedented local price increases[249] coincided with a brief dip in international price levels (Figure 4.6).[250] After peaking in late 2022, international price levels reduced significantly into 2023 but remained elevated compared with historical levels.[251]

From mid-2023, domestic prices were on par with international price levels and remained relatively stable as international prices gradually increased out to the end of the year.[252] At the end of 2023, European storage inventories entered the October to December quarter at a record high of 97% full alongside record floating storage supply.[253] High storage over the quarter and a mild Northern Hemisphere winter suppressed demand,[254] reducing pressure on international prices into 2024 alongside increases in other sources of LNG supply.[255]

246 High vibration levels during low flow conditions at the Wollert compressor's Pressure Reduction Station on the eastern end of the Western Outer Ring Main (WORM) – see section 4.8.3 – necessitated the requirement for capacity reductions to test and locate the source of the problem.

247 On 19 and 21 June 2024, ancillary payments accrued to $354,957.62 and $341,944.79, respectively, across the gas days.

248 In prior years (2019 and 2020), domestic gas contract prices tended to track falling international prices, measured using LNG netback prices. LNG netback prices estimate the export parity price that a domestic gas producer would expect to receive from exporting gas rather than selling it domestically.

249 Local price increases drove multiple markets into administered price states, resulting from numerous overlapping factors. Higher international prices strengthening export incentives, NEM constraints impelling significant gas generation requirements, and high residential heating demand during a particularly cold winter, contributed to a very tight supply and demand balance across the east coast.

250 The Russian invasion of Ukraine in early 2022 drove other countries to diversify supplies in oil and gas, impacting global supply chains. Despite the curtailment of Russian gas supply to Europe, increases in underground storage levels saw international prices briefly dip below $30 per GJ in mid-2022. However, this was followed by subsequent Russian supply threats and pipeline flow reductions, and an explosion at Freeport LNG, which removed a significant amount of US LNG supply from the market.

251 Rising storage inventories, particularly in Europe, influenced the decline in international prices. However, domestic prices linked to international gas prices exceeded historical levels as domestic and international prices converged again in mid-2023.

252 While international price levels had decreased significantly from record highs in the years prior, they remained above the historical trend in mid-2023.

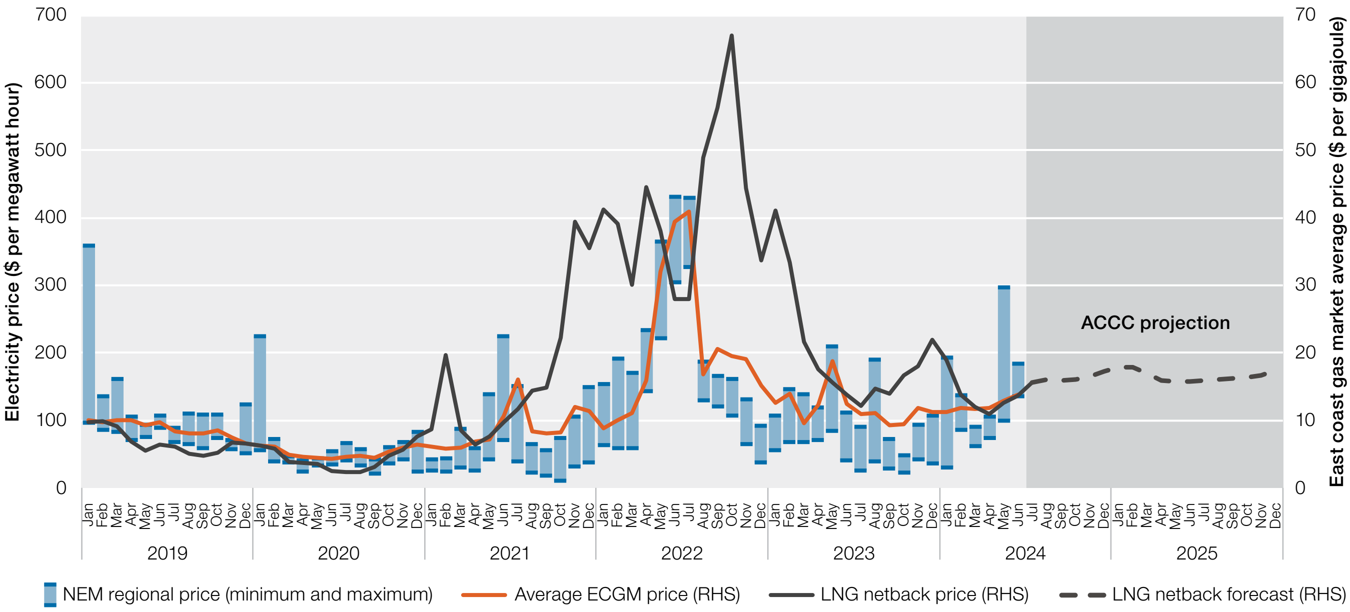
253 AER, Wholesale markets quarterly – Q4 2023, Australian Energy Regulator, January 2024.

254 Storage levels rounded out the quarter at 87% of capacity. Argus direct, *Europe LNG: Des prices tick down*, 29 December 2023.

255 LNG availability from the United States increased by 6% and Norway's availability was also up 1.5% following the resolution of unplanned outages from 2022.

In 2024, international LNG spot prices gradually decreased across January and February before starting to rebound slightly from March, with prices in February reaching some of the lowest levels observed over the past 2 years. By winter, local prices had risen above international price levels due to numerous supply and demand factors, particularly in the southern markets that experienced a prolonged stretch of cold weather (Figure 4.7).

Figure 4.6 Comparison of east coast gas market, NEM and LNG netback prices

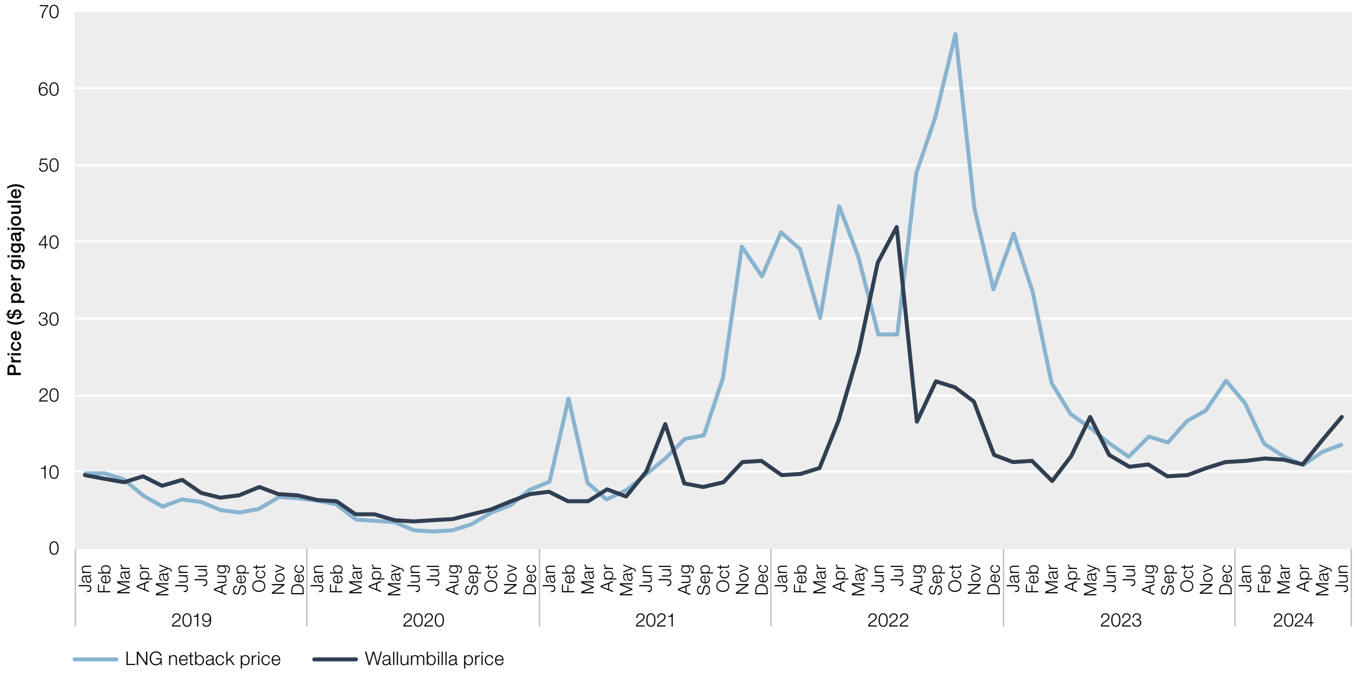


Note: ECGM is east coast gas market. NEM is National Electricity Market. The LNG netback price calculates the export parity price and subtracts the cost of liquefaction and transport required to produce and deliver LNG to international customers. LNG netback forecast 28 June 2024.

Source: AER analysis of NEM, Short Term Trading Market, Victorian Declared Wholesale Gas Market and ACCC LNG netback price data.

Seasonal factors are also strong drivers of international demand and prices for gas, typically increasing during the Northern Hemisphere winter. Policy measures that influence gas use and broader economic factors can also be strong drivers of changes internationally.

Figure 4.7 LNG netback and Wallumbilla prices



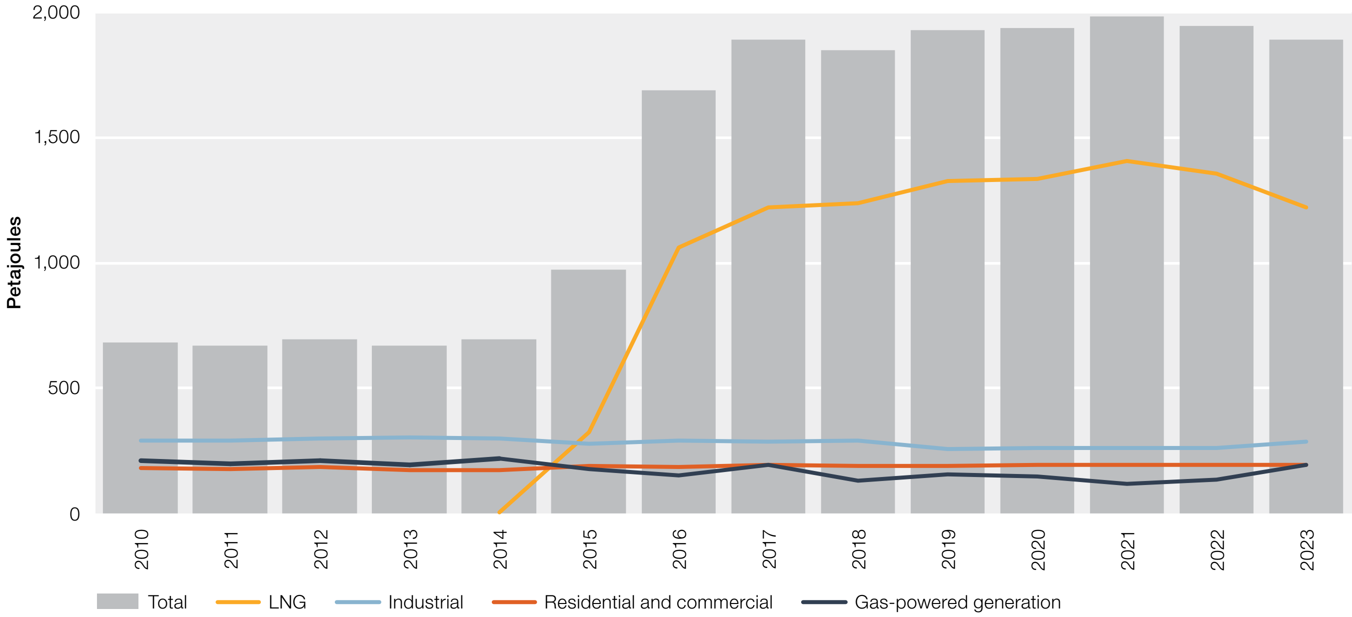
Note: The LNG netback price calculates the export parity price and subtracts the cost of liquefaction and transport required to produce and deliver LNG to international customers.

Source: AER analysis of gas supply hub data; ACCC (LNG netback prices).

4.4 Gas demand in eastern Australia

Around 70% of domestic gas production in eastern gas markets (excluding the Northern Territory) is exported and the balance is sold into the domestic market (Figure 4.8).

Figure 4.8 Eastern Australian gas demand



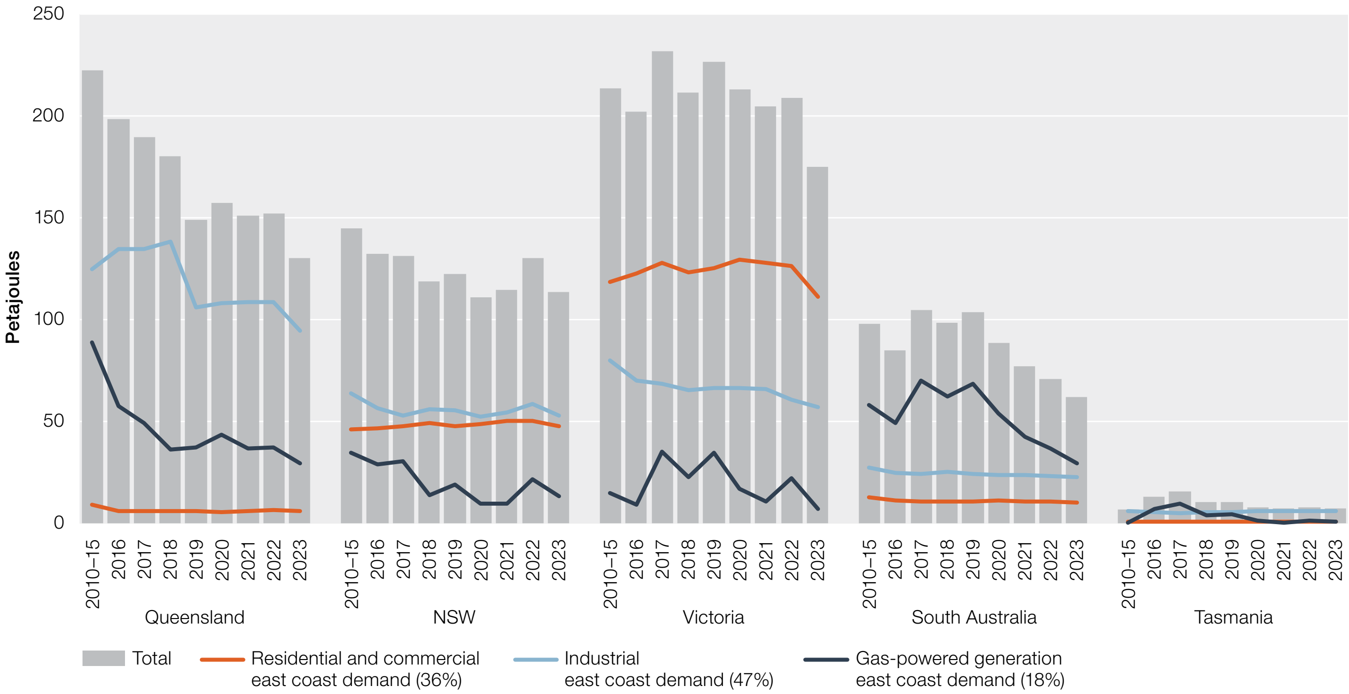
Source: AEMO, *2024 Gas Statement of Opportunities*, March 2024.

4.4.1 Domestic demand

Domestic customers in eastern Australia used around 490 PJ of gas in 2023 (Figure 4.9). These customers included industrial businesses, electricity generators, commercial businesses and households.

Industrial customers consumed 48% of gas sold to the domestic market. Gas is used as an input to manufacture pulp and paper, metals, chemicals, stone, clay, glass and processed foods. Gas is also a major feedstock in ammonia production for fertilisers and explosives.

Figure 4.9 Eastern Australian gas demand, by state



Note: Data for 2010–15 is average annual consumption over that period.
Source: AEMO, *2024 Gas Statement of Opportunities*, March 2024.

Residential and commercial customers accounted for 36% of domestic gas demand, but this share varied from state to state. For example, in Victoria more than 60% of gas is consumed by small residential and commercial customers, who use gas mostly for heating and cooking. In Queensland, where much fewer households are connected to a gas network, the share of gas consumed by residential and commercial customers falls to 5%.

The electricity sector is another major source of gas demand, accounting for 21% of domestic gas use in 2023, down from 29% in 2017. South Australia and Queensland used the most gas-powered generation (GPG) in 2023 (each using 37% of GPG in the NEM). The rapid responsiveness of gas-powered generators makes them suitable for meeting peak electricity demand and managing variable wind and solar generation. Consequently, the volume of gas used for electricity generation fluctuates with electricity market conditions. Long-term forecasting of expected usage for GPG in the NEM is difficult due to the unpredictability of relevant drivers such as weather, availability of other fuel types and unforeseen events.[256]

256 Multiple events, including baseload generation retirement, coal shortages during hot weather, bushfires and flooding, transmission outages, and prolonged coal generation maintenance outages and plant failures, have affected the NEM in recent years.

Gas-powered generation use in 2023 and 2024

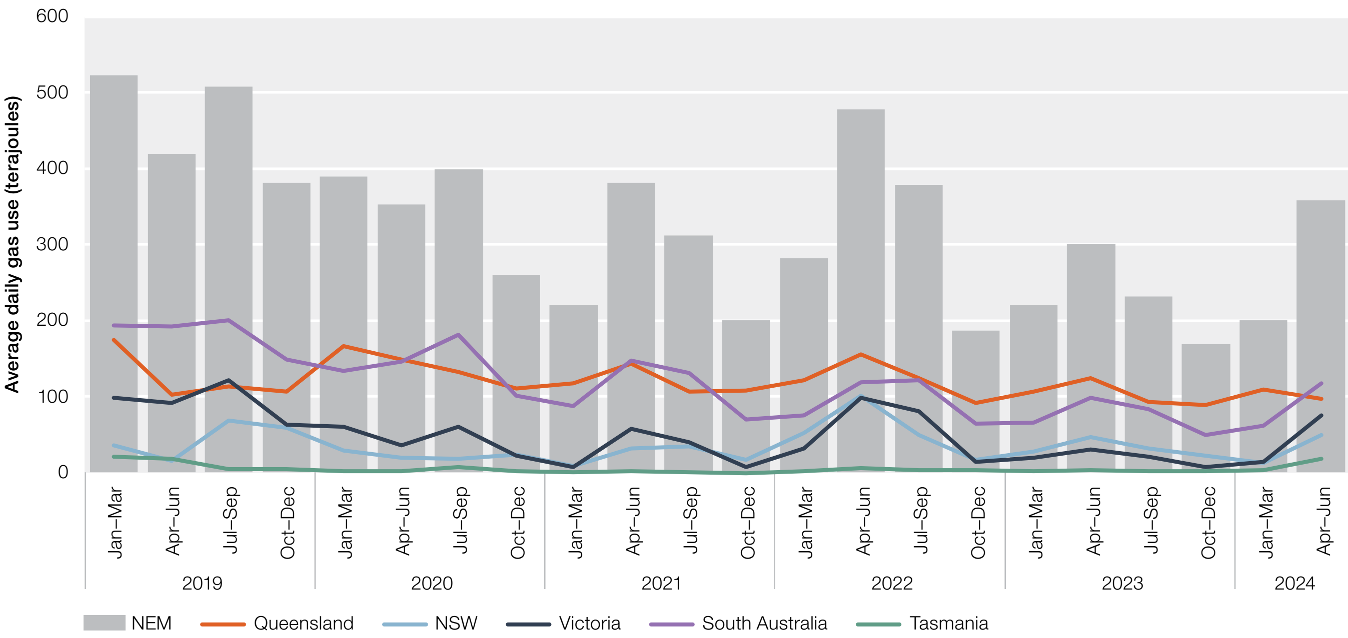
In 2023, gas-powered generation (GPG) gas usage was lower across mainland regions (Figure 4.10). New South Wales GPG gas usage reduced to almost half of 2022 GPG levels at 11.6 PJ, and the other states recorded their lowest yearly levels of GPG gas usage over the past decade, ranging from 7 PJ in Victoria to 37.6 PJ in Queensland.

GPG gas usage increased in the January to March quarter of 2024, but GPG demand was also at its lowest Q1 demand level observed over the past decade. In the April to June quarter, low wind and shorter days reduced wind and solar generation. This resulted in increased generation from higher priced gas and hydro generators, driving higher electricity prices in the southern regions.[257]

This illustrates the ongoing complexity of gas generation acting as a firming capacity in the NEM. Demand for GPG to fill in for low renewable generation output levels can be unpredictable at times and may coincide with elevated gas demand due to colder weather and electricity system constraints, potentially leading to gas shortfalls. Despite generally declining demand for gas across the east coast, GPG demand is projected to increase in the coming years unless new renewable sources of firming capacity can be found to replace it. AEMO's Integrated System Plan (ISP) forecasts flexible gas capacity of 8.8 GW will be needed by 2030–31, climbing to 15.4 GW by 2051–52.

Projections indicate 7.8 GW of the existing GPG fleet will still be in service by 2030. A total of 750 MW of committed generation, and 200 MW of anticipated GPG will be needed to avoid generation shortfalls between now and 2030. New generation capacity of 12.8 GW is needed by 2051–52.[258] At the same time, governments are taking actions to reduce consumption of natural gas in order to meet net zero commitments. These include electrification where possible and investments into alternative fuels where electrification is not suitable, such as industrial processes involving high temperatures or where methane is a feedstock rather than a source of energy. This poses challenges to the market in identifying least cost options for avoiding shortfalls while also minimising the creation of redundant investment. The various actions being taken to stabilise supply-demand balances are discussed further in section 4.10.

Figure 4.10 Quarterly gas demand for gas-powered generation



Source: AEMO; National Electricity Market (NEM) generation data and heat rates (gigajoules per megawatt hour).

257 AER, Wholesale markets quarterly – Q1 2024, Australian Energy Regulator, April 2024.
258 AEMO, 2024 Integrated System Plan (ISP), Australian Energy Market Operator, June 2024.

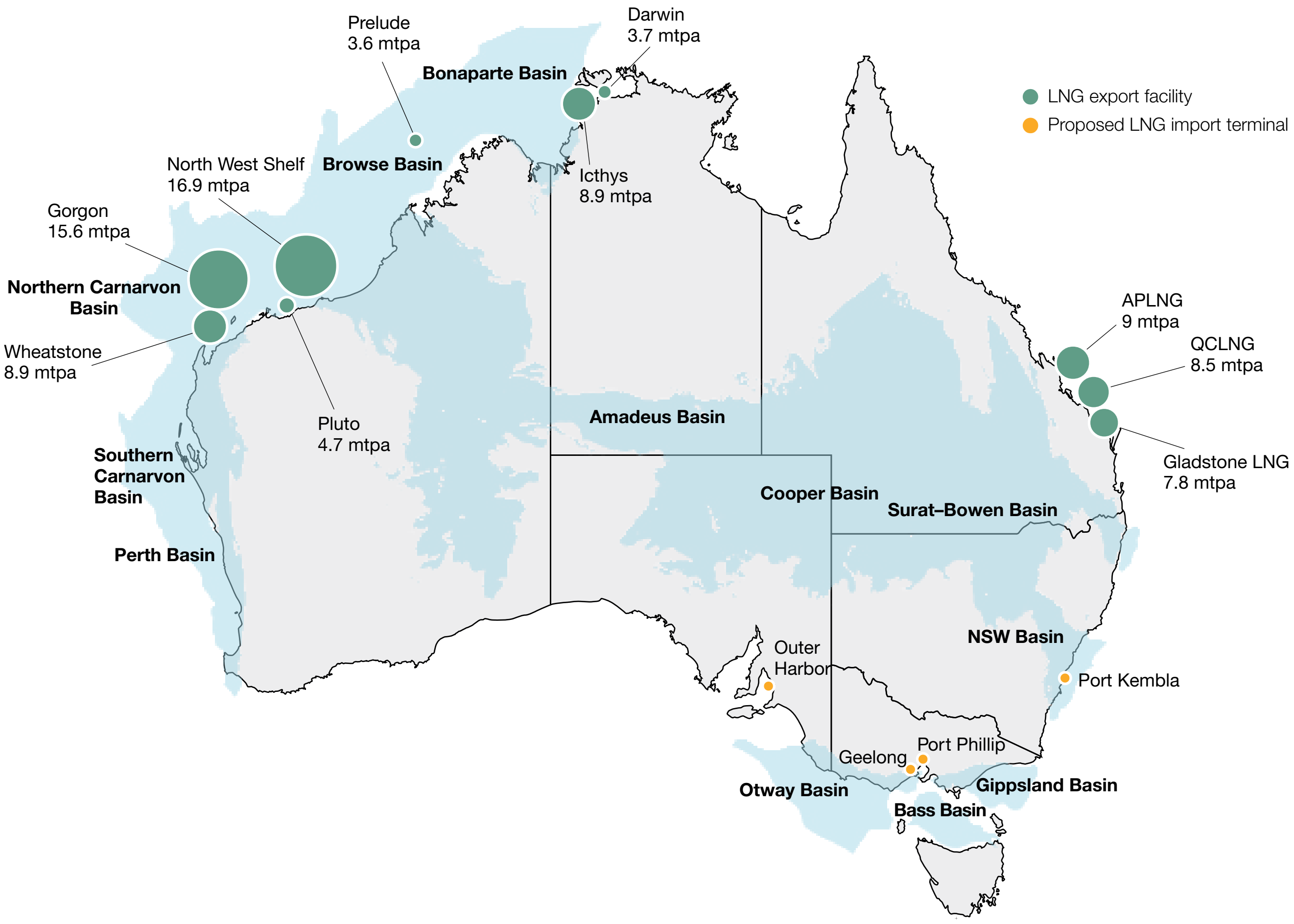
4.4.2 Liquefied natural gas exports

Most of the gas produced in eastern Australia is exported as liquefied natural gas (LNG).

In eastern Australia, export gas is liquefied in processing facilities in Queensland to make it economic to store and ship in large quantities (Table 4.1). Australia also operates 5 LNG projects in Western Australia and 2 in the Northern Territory (Figure 4.11).

In 2023 LNG exports totalled $74.7 billion, a historically high level but down from the 2022 total of $91 billion. Gas remains one of Australia's largest resource and energy exports behind coal and iron ore. Australia was the second highest exporter of gas in 2023 behind the United States, following the restart of Freeport LNG in Texas.[259]

Figure 4.11 Australia's LNG export projects



Note: Capacity in million tonnes per annum (mtpa). EPIK ceased development of a Newcastle import terminal due to the project being economically unfeasible.

Source: AER; DISER, Resources and energy quarterly, June 2024.

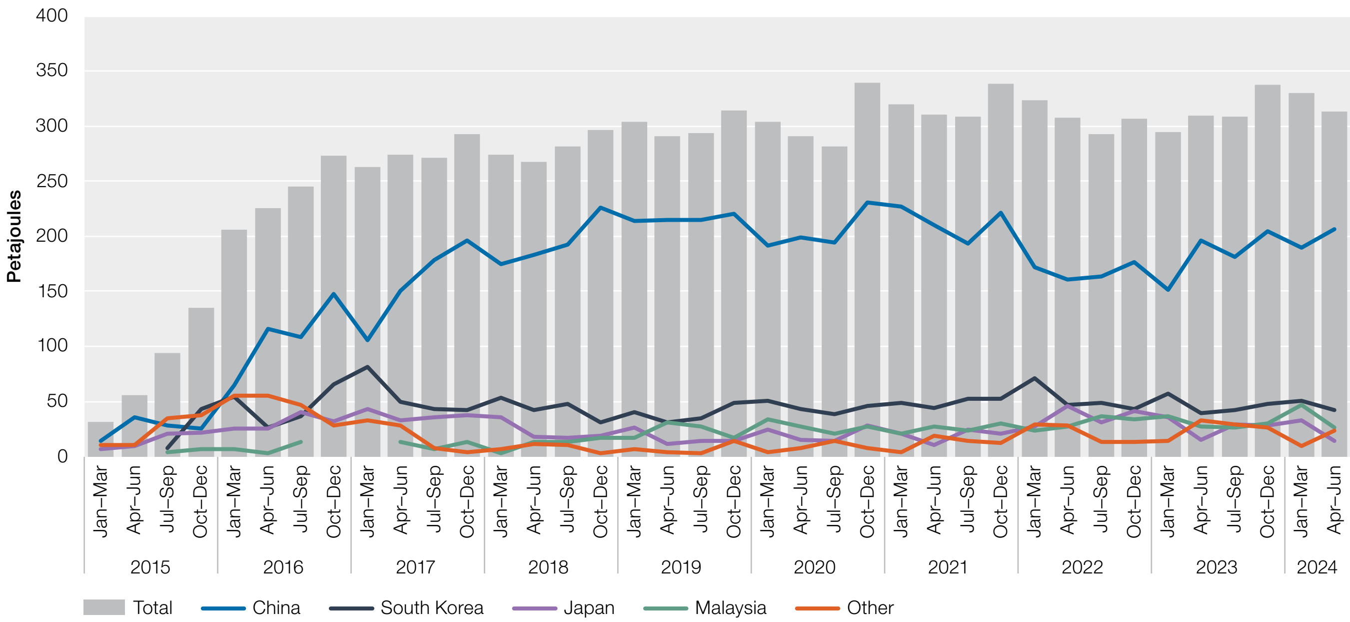
259 Department of Industry, Science, Energy and Resources, Resources and energy quarterly, March 2024.

Queensland's LNG industry comprises 3 major projects, which source gas mainly from the Surat–Bowen Basin:

- Queensland Curtis LNG (QCLNG) project has capacity to produce 8.5 million tonnes of LNG per annum (mtpa). Shell (73.75%), CNOOC (50% equity in Train 1) and Tokyo Gas (2.5% equity in Train 2) collectively own the project.
- Gladstone LNG (GLNG) project has capacity to produce 7.8 mtpa. Santos (30%), Petronas (27.5%), Total (27.5%) and Kogas (15%) collectively own the project.
- Australia Pacific LNG (APLNG) project has capacity to produce 9 mtpa. Origin Energy and ConocoPhillips (37.5% each) and Sinopec (25%) collectively own the project.

These LNG projects control close to 90% of 'proven and probable' (2P) reserves in eastern Australia.[260] They also source gas from other producers through long-term production contracts and spot markets to manage volatility and ensure they can meet their long-term exports supply obligations. East coast gas exports are typically lower mid-year, when the gas produced supplements increased domestic demand over winter, and higher over the rest of the year as Northern Hemisphere winter conditions drive up international demand.

Figure 4.12 Eastern Australian gas exports



Source: AER analysis using Gladstone Port Corporation data.

East coast LNG exports have risen consistently since they began in 2015, until 2022 when they reduced. They remained at relatively lower levels across 2023 compared with the record high volumes exported in late 2020 and 2021, but began to climb again from late 2023. Exports across the first half of 2024 rose to quarterly record levels of up to 330 PJ (Figure 4.12). In December 2023, total export pipeline deliveries to Curtis Island reached their highest daily flow rates above 4,300 TJ per day on 2 occasions.[261]

In 2023, China was the primary market for eastern Australian LNG, accounting for 59% of exports (733 PJ). This was a significant increase from the previous year's 674 PJ.[262] China's combined gas and LNG imports from Australia and other countries remained strong in 2024, increasing to a record level for July assisted by a scheduled rise in gas flows from Russia.

260 ACCC, Gas inquiry 2017–2030, interim report, December 2023, Australian Competition and Consumer Commission, December 2023, p. 27. 2P reserves represent proven and probable reserves (probable reserves are deemed 50% likely to be commercially recoverable).

261 On 22 December (4,338 TJ) and 31 December (4,341 TJ).

262 In 2022, high prices and lockdowns in China alongside higher pipeline supply from domestic production influenced reduced imports from Australia, with the country also sourcing additional imports from Russia.

International gas markets have been relatively stable over the past year, with no significant disruptions this year so far. While exports were at record levels for the April to June quarter, export demand declined in winter and the ramp-up in export flows did not impact the high level of domestic gas flows transported south from Queensland (Figure 4.22).

Northern Territory and Western Australia exports

The Northern Territory's LNG projects are Darwin LNG (3.7 mtpa capacity) and Ichthys LNG (8.9 mtpa capacity). Both projects connect to the territory's domestic gas market as emergency supply sources but otherwise produce gas for export.

Western Australia has 5 LNG projects with a combined capacity of around 50 mtpa – including the North West Shelf, which is Australia's largest LNG project by capacity (16.9 mtpa). The other projects are Gorgon (15.6 mtpa), Wheatstone (8.9 mtpa), Pluto (4.7 mtpa) and Prelude (3.6 mtpa).

4.5 Gas supply in eastern Australia

Gas supply to the northern gas market is largely supplied from Queensland's Surat–Bowen Basin. Gas is also sourced from the Cooper Basin in South Australia and was supplemented by supply from the Northern Territory from 2019 to 2024. Gas from the northern fields is required to supplement Victorian gas production to meet domestic gas demand in southern Australia over winter. At other times of the year, southern gas is also transported north to meet LNG export demand. Ensuring sufficient gas remains in Australia to service the domestic market is a key priority for governments. Both AEMO and the ACCC regularly assess and publish analysis of the future supply conditions and the likelihood of future shortfalls so that these can be addressed ahead of time.

4.5.1 Background

Southern states rely on local gas production to supply the majority of their demand levels. However, as production in southern states has slowed, gas has also been sourced from Queensland.

Victoria's Gippsland Basin output has been falling due to the depletion of legacy fields supplying the Longford gas plant.[263] From 2023, east coast gas users have become more reliant on northern production. While Gippsland's 2024 production forecasts were higher than the previous year's estimate, Gippsland's projected peak day production has been falling since 2022 and dropped to 767 TJ in mid-2024, representing a significant decrease compared with actual peak production levels prior to 2023.[264]

4.5.2 Current conditions

Despite historically low average gas demand levels in recent quarters, colder weather from late May 2024 drove up southern demand compared to winter 2023 when weather conditions were milder. Due to the significant changes in demand driven by cold weather, southern gas markets are persistently vulnerable to cold weather events. This year, tight supply and demand conditions have arisen with reduced production capability at Longford, Victoria's largest source of supply. This has increased participants' reliance on obtaining gas from southern storage and Queensland gas fields to meet demand in southern markets. Other events in the Northern Territory and Tasmania have also put upward pressure on the tight supply-demand conditions in southern markets.

263 Longford is the largest and most flexible source of southern gas supply.

264 Reduced production forecasts from 877 TJ per day until mid-2024 coincide with the retirement of Longford's Gas Plant 1, with the expected retirement of Gas Plant 3 later this decade set to leave only a single plant in operation. This will lead to a significant reduction in output from the facility's legacy fields. AEMO, 2024 Gas Statement of Opportunities, Australian Energy Market Operator, March 2024, p. 5.

Upcoming greenfield plans, such as the Senex Atlas, Cooper Otway and Santos Narrabri projects, are important in meeting demand but will not become available in the short term and will be insufficient to fill the longer-term supply gap.[265] AEMO's 2021 outlook had improved from previous years due to planning progress for Australian Industrial Energy's (AIE) Port Kembla LNG import terminal. However, despite pipeline expansions taking place to facilitate the delivery of this gas to east coast markets, AIE was unable to secure sufficient interest in contracting supply to justify the relocation of a floating storage and regasification unit to receive and supply the gas in coming years.

Longford production decline and increased reliance on Iona underground storage

Low production output from Longford beginning in early 2024 led to participants utilising Iona storage supply much earlier in the year than in 2023. Iona was at record high levels for the beginning of the year and replenished supplies from mid-February to a peak of 24 PJ in mid-April ahead of winter. The early onset of cold weather drove a rapid drawdown in storage levels from late May. This was exacerbated by prolonged supply capacity restrictions at Longford following planned maintenance that took longer than expected, and the facility was only able to gradually ramp up production capacity over June (section 4.5.3, Figure 4.16).

As a result, the heavy reliance on Iona storage supply caused a rapid drawdown on Iona's storage inventory, similar to the record rates of depletion observed in 2021 and 2022, despite record gas flows bringing gas south from Queensland (Figure 4.22).[266] On 19 June, AEMO highlighted the potential for upcoming supply issues in a system-wide notice to market participants. In early August, Iona's storage fell below 10 PJ (Figure 4.21) but began to recover over the rest of the month as winter weather conditions eased.

Due to the significant changes in demand driven by cold weather, southern gas markets are persistently vulnerable to cold weather events.

Box 4.2 AEMO East Coast Gas System Risk or Threat Notice[267]

On 19 June AEMO issued a system risk or threat notice, identifying the supply of gas in all or part of the east coast gas system may be inadequate to meet demand. The notice was implemented to remain in place until 30 September 2024, with AEMO outlining an expectation of an industry response to mitigate the system threat and prevent the requirement for market intervention.[268]

AEMO highlighted that reduced storage delivery capacity resulting from low inventory levels heightens the risk to winter supply adequacy on peak demand days.[269]

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265 EnergyQuest, *EnergyQuarterly*, June 2023, pp. 31–32.

266 Gas flows south this winter were well in excess of levels over 2021 and 2022. Higher flow rates on the north–south pipeline corridor were facilitated by the commissioning of the second stage of delivery capacity expansions in June, adding further compression capability on the South West Queensland Pipeline and Moomba to Sydney Pipeline (section 4.8.3).

267 AEMO, East Coast Gas System Risk or Threat Notice, Australian Energy Market Operator, June 2019.

268 AEMO expectations included:
- participants taking reasonable measures to maximise production and supply from Queensland for delivery to southern jurisdiction end users, to reduce the rate of storage depletion
- consideration of specific gas demand requirements (including GPG) and the supply sources required to meet that demand.

269 Other potential risks outlined by AEMO identified and included:
- gas supply and demand trends in southern jurisdictions and the impact of storage inventory depletion, particularly at Iona
- the combination of lower than forecast Longford production and high seasonal demand and GPG, which has already significantly impacted Iona's storage levels
- constrained Longford production and the expected impact on continued high withdrawals from southern storage
- expected storage depletion resulting from unplanned events impacting demand or supply
- the southern supply capacity impacts due to low or depleted storage inventory.

Iona plays a crucial role in supporting elevated demand through winter. Upgrades to the Iona storage facility in June 2023 have increased storage capacity to a nameplate rating of 24.4 PJ, with works to add another 3.3 PJ of storage capacity by 2026 (section 4.5.4). Additional compression and pipeline capacity expansions were also commissioned before winter, enabling higher gas flows from western Victoria to meet demand in the Victorian transmission system. This allows Iona to supply and refill from the Victorian market faster, but also increases participants' ability to draw down storage to critically low levels before the end of the peak winter demand period (section 4.8.3).[270]

Northern Gas Pipeline gas shortfall

As southern demand for gas from northern regions increases, supply previously provided to the east coast from the Northern Territory from 2019 has ceased. Production issues at the Blacktip offshore gas fields has led to the pipeline connection between Queensland and the Northern Territory being restricted. Demand on the Carpentaria Pipeline is now reliant on gas supplies from south-east Queensland to fuel industrial demand in the north-west of the state. Work is currently underway to convert the Northern Gas Pipeline to flow gas bidirectionally, allowing east coast supply to be delivered to the Northern Territory to fuel local gas generation, where supply shortfalls triggered a power outage in early February (section 4.8.5).

Tamar Valley power station returned to service in response to Tasmanian drought

Tasmanian gas demand also saw an upturn in late June, with continuing drought conditions impacting hydro-electric generation output. From 6 June, pre-emptive measures were put in place to maintain water storage levels in the state, resulting in the return to service of a gas generation unit at Tamar Valley to fill the gap in local electricity generation requirements.[271] This is the first time in 5 years the state's largest gas-fired generator has produced power, with gas requirements increasing gas flows on the Tasmanian Gas Pipeline by around 35 TJ per day.

Loss of containment event on the Queensland Gas Pipeline

On Tuesday 5 March a loss of containment on the Queensland Gas Pipeline (QGP) resulted in a large fire south-west of Rockhampton (Figure 4.13). AEMO directed Westside to divert gas supply from their Meridian gas production facility, the only main production source downstream of the fire, and issued curtailment directions to downstream consumers. A backflow process was also initiated on the adjacent GLNG export pipeline to support Meridian supply, with APLNG, GLNG, Meridian and Jemena coordinating the response to increase gas supply.

The large industrial users impacted by the incident were taken offline or run at minimum standby load for safety reasons, with some smaller regional towns also affected downstream of the QGP's Wide Bay offtake.

AEMO held a follow-up conference with industry stakeholders on 8 March to provide updates on expected repair timeframes. Subsequently, AEMO advised that welding repairs were completed on 12 March, which preceded further inspections, pipeline coating and backfilling of gas, and additional works on pressure protection systems.

From 17 March, the QGP was recommissioned at a reduced operating pressure, with Meridian supply directions being revoked as gas flows resumed on the affected pipeline segment.[272]

From Monday 18 March, pipeline flow and customer offtakes began ramping up from the 85 TJ per day limit via the Meridian Gas Plant, increasing to the expected maximum flow rate at reduced operating pressure of around 105 TJ.

The facility was ramped up to 118 TJ per day from mid-May. End users remain on restricted rates until a higher operating pressure can increase the maximum capacity to its usual limit of 145 TJ per day.[273]

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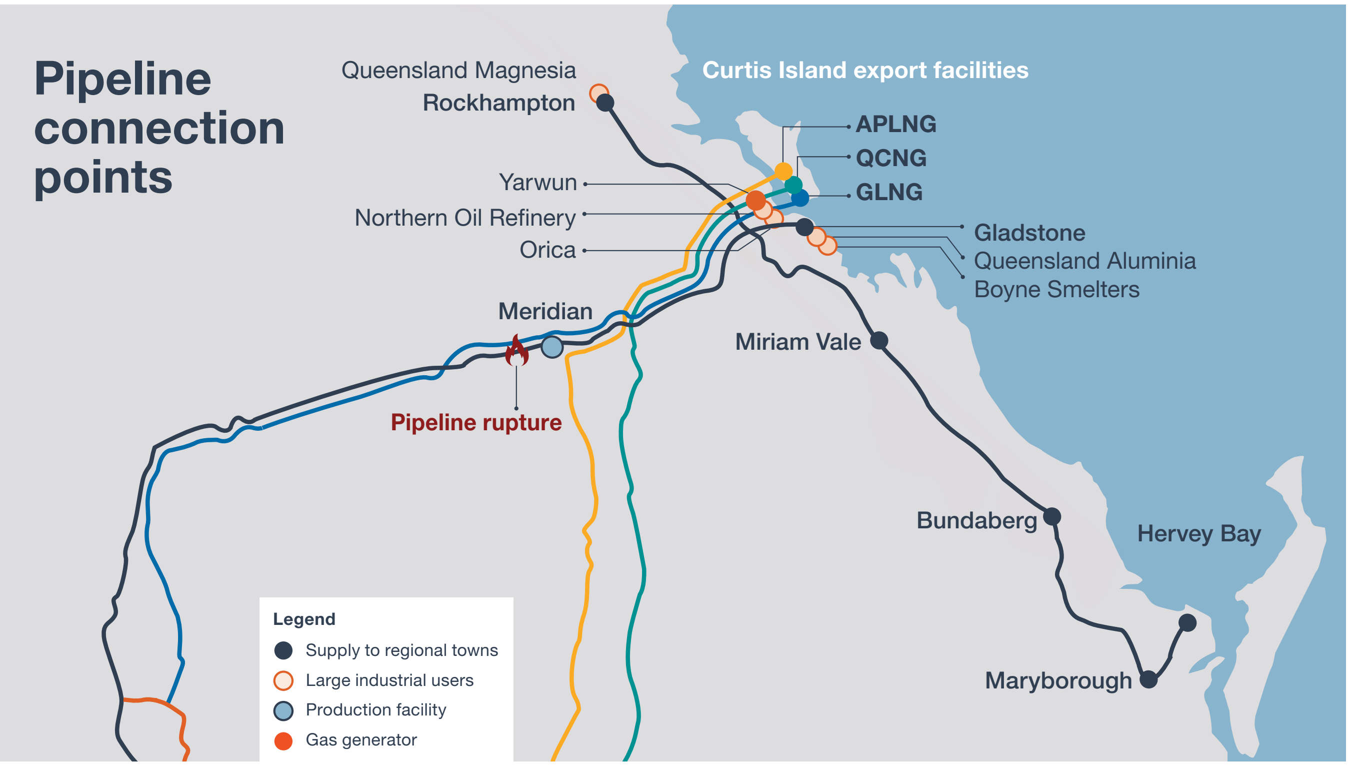
270 Low pressure levels significantly reduce withdrawal capacity when storage inventories fall below 6 PJ.

271 Renew Economy, Drought forces Tasmania to fire up its biggest gas plant for first time in five years, 8 August 2024.

272 Large industrial customer curtailments remained in place, but most large users had transitioned to contractual pro-rata allocations agreed with Jemena, the pipeline operator.

273 Information is current as at 22 August 2024.

Figure 4.13 Queensland Gas Pipeline and surrounding downstream infrastructure



Source: AER analysis using Gas Bulletin Board facility information and AEMO's detailed gas pipeline map.

4.5.3 Gas reserves and production

Eastern Australia had 36,493 PJ of 'proven and probable' (2P) gas reserves in June 2024, having produced almost 1,900 PJ of gas in 2023 (Table 4.1).

Ownership is highly concentrated in some gas basins, but more diverse across the east coast (Figure 4.1, Figure 4.14). APLNG owns the majority of reserves in eastern Australia through an incorporated joint venture with Origin Energy, ConocoPhillips and Sinopec.

Table 4.1 Gas basins serving eastern Australia

Gas basin	Gas production – 12 months to December 2023			2P gas reserves (June 2024)	
	Petajoules	Share of eastern Australian supply	Change from previous year	Petajoules	Share of eastern Australian reserves
Surat–Bowen (Qld)	1,516	80.5%	3%	29,206	80%
Cooper (SA–Qld)	78	4.1%	-3%	987	3%
Gippsland (Vic)	215	11.4%	–31%	1,434	4%
Otway (Vic)	38	2%	–21%	530	1%
Bass (Vic)	4	0.2%	–10%	20	0.1%
Sydney, Narrabri, Gunnedah (NSW)	0.3	0.02%	–88%	6	0.02%
Amadeus (NT)	15	0.8%	2%	210	1%
Bonaparte (NT)	17	0.9%	–33%	4,100	11%
Eastern Australian total	**1,883**	**–**	**–4%**	**36,493**	**–**
Domestic gas sales	457	–	–20%	–	–
LNG exports	1,426	–	3%	–	–

Note: 2P: proven and probable reserves estimated to be at least 50% sure of successful commercial recovery. Totals may not add to 100% due to rounding. Most production and reserves in the Surat–Bowen and NSW basins are coal seam gas. Production and reserves in other basins are mainly conventional gas.

Source: EnergyQuest, *EnergyQuarterly*, March 2024 and June 2024.

Queensland's Surat–Bowen Basin holds 80% of gas reserves in eastern Australia and supplied 81% of gas produced in 2023. Queensland's 3 LNG projects produced 95% of the basin's output in 2023.

Victorian basins, which account for 5% of eastern Australian reserves, have continued to decline due to anticipated decreases from Gippsland legacy fields. This is important because Victoria is the highest domestic consumer of gas. AEMO forecasts a steep decline in southern field production in the coming years. The Gippsland Basin is the largest Victorian basin, while the Bass and Otway basins are smaller.

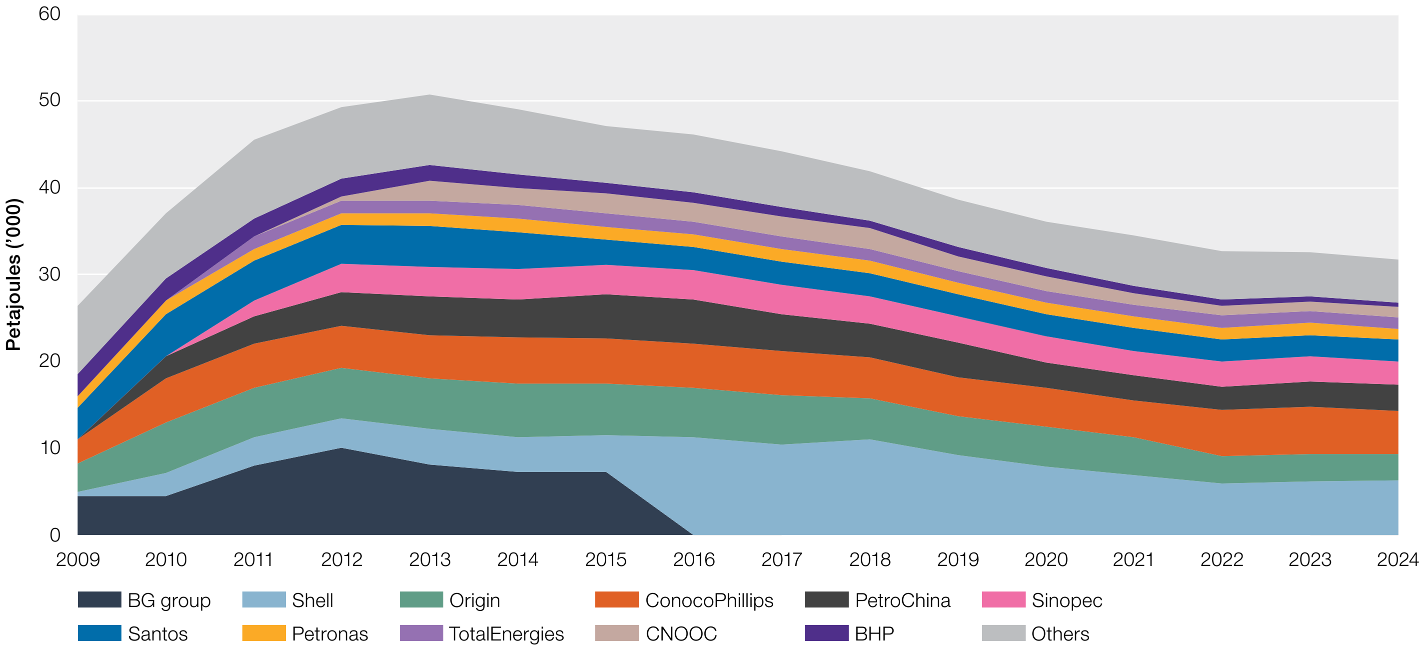
The Cooper Basin in central Australia has close to 1,000 PJ of eastern Australia's 2P reserves and accounted for 4% of gas production in 2023. Reserves in the basin have declined over the past decade. The Cooper Basin plays an important role as a 'swing' producer in managing seasonal and short-term supply imbalances in the domestic gas market.

NSW has significant contingent resources[274] (around 1,500 PJ) but only 6 PJ of 2P reserves and no current production since AGL's Camden facility ceased production in late August 2023. Santos received approval to develop reserves near Narrabri in the Gunnedah Basin but appeals against the approval have delayed the project. The final investment decision depends on project approvals being cleared (section 4.8.1).

The Northern Territory has the Bonaparte Basin and the smaller Amadeus Basin. These basins are estimated to have over 4,300 PJ of 2P reserves. Most gas produced is converted to LNG for export.

274 2C contingent resources are reserves that are estimated to be potentially recoverable from known deposits, but are not currently considered to be commercially recoverable.

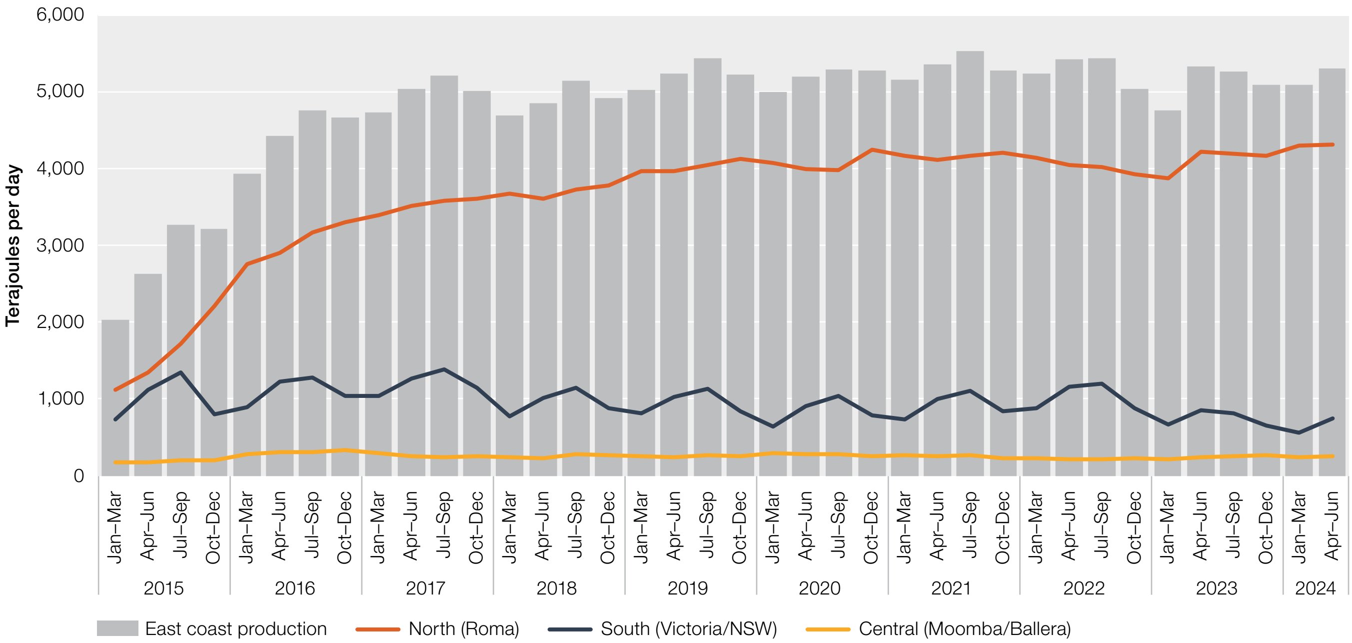
Figure 4.14 Market shares in 2P gas reserves in eastern Australia



Note: Aggregated market shares in 2P (proven and probable) gas reserves in the Surat–Bowen, Gippsland, Cooper, Otway, Bass and NSW basins. 2P reserves are those for which geological and engineering analysis suggests at least a 50% probability of commercial recovery.

Source: EnergyQuest, *EnergyQuarterly* (various years).

Figure 4.15 Eastern Australian gas production



Source: AER analysis of Gas Bulletin Board data.

Production output for the January to March quarter of 2023 was the lowest level recorded since 2018 (Figure 4.15). In 2024, lower production levels from Longford were partially offset by increased output from Queensland's Roma gas fields.[275] Roma production over the January to March and April to June quarters in 2024 reached record levels of 390 PJ and 392.4 PJ, respectively, similar to production output levels when exports were at a record high in late 2020.[276]

New gas supply from the Otway Gas Plant in Victoria increased from mid-June to over 150 TJ per day on average, reaching daily output levels close to 200 TJ.[277] Moomba production also continued to increase over late 2023, with average daily output close to 250 TJ across 2023 and 2024 to date.[278]

Longford production decline

Southern production has been particularly low in recent years, with Victoria's largest supply source at Longford running down reserves from its depleting legacy fields in the Gippsland Basin. Since 2023, supply levels from Longford have declined markedly compared with previous years (Figure 4.16). Projected 2024 availability for Longford published in March 2024 was comparable to actual production output over 2023. However, actual output in 2023 was influenced by low gas consumption and increased winter supply from Queensland last year, rather than reflecting available production capacity at that time.[279]

In 2024, continued production declines saw Longford's 35 PJ of supply over the January to March quarter drop to the lowest level recorded since the commencement of Bulletin Board reporting in mid-2008.[280] Production over the quarter was well below available capacity, even with planned maintenance from late January to mid-February reducing capacity levels lower than previously observed.[281] The following quarter also saw output fall to a record low for the period, due to a delayed ramp-up following planned maintenance scheduled to conclude in late May preventing supply levels reaching expected higher rates until late June.

275 Longford's production has been overtaken by QCLNG's Woleebee Creek facility in Queensland, which is now the largest production facility on the east coast. AEMO, Quarterly Energy Dynamics Q4 2023, Australian Energy Market Operator, January 2024, p. 4.

276 Queensland production exceeded 390 PJ when export demand reached a record 339.8 PJ in the last quarter of 2020. While exports levels were lower over the first half of 2024, they were record high levels for the January to March and April to June periods.

277 Production from Port Campbell (including the Otway and Athena gas plants) is forecast to increase from the 38 PJ produced in 2023 to 55 PJ in 2024, with the connection of new gas supply to the Otway Gas Plant including the Enterprise field in mid-2024 and the Thylacine West wells later in 2024. AEMO, 2024 Victorian gas planning report, Australian Energy Market Operator, March 2024, p. 9.

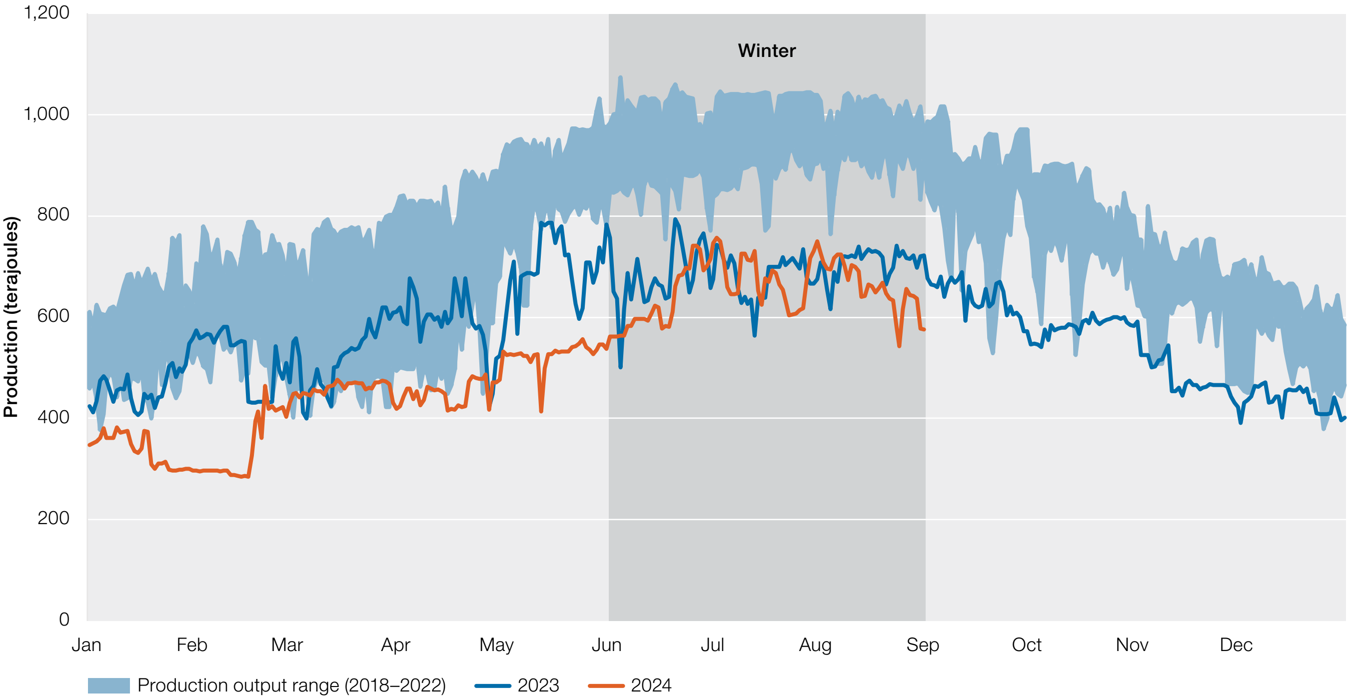
278 Average production in 2022 was just over 220 TJ per day. Increased production coincides with an increase in the number of wells drilled in the Cooper Basin throughout 2023. AEMO, Quarterly Energy Dynamics Q4 2023, Australian Energy Market Operator, January 2024, p. 57.

279 AEMO, 2024 Victorian gas planning report, Australian Energy Market Operator, March 2024, p. 9.

280 Available production capacity of 45 PJ was also at the lowest level recorded. AEMO, Quarterly Energy Dynamics Q1 2024, Australian Energy Market Operator, April 2024, p. 56.

281 Offshore maintenance at Longford from mid-January to mid-February saw participants draw down on Iona's underground storage inventories, which were at record high levels heading into 2024 following a mild 2023 winter.

Figure 4.16 Longford production levels since 2018



Source: AER analysis of Gas Bulletin Board data.

Gippsland region producers have advised that maximum peak day production capacity will reduce by 58% over the next 4 years, from 767 TJ per day in 2024 to 325 TJ per day in 2028.[282] Production in Gippsland is transitioning from old to new fields, but it is not yet clear how much the new gas fields can produce.[283] Production from the Longford plant has been falling and the plant is becoming less reliable, with plant constraints and maintenance outages increasingly disrupting production. Large reductions in Gippsland production reported in the 2023 Victorian gas planning report are still expected to occur in 2024 and 2027, with an additional reduction in 2028.[284]

Changing basin profiles

Activity in all gas basins across eastern Australia has evolved to meet the needs of the LNG industry. Production from the Surat–Bowen Basin is mainly earmarked for export. But supply from other eastern Australian basins rose between 2015 and 2017 to help LNG projects meet their export contracts. This shift accelerated a depletion of gas reserves in southern basins. AEMO and the ACCC have identified the ongoing depletion of southern gas fields as a significant risk to supply in the coming years.

Following government intervention in 2017, LNG producers diverted more gas to the domestic market. Over 2019 and 2020, Surat–Bowen Basin production increased (9%), largely matching LNG export growth (10%), while production from southern basins decreased by a similar proportion (10%). Over 2021, strong southern supply and gas flows north to support high exports coincided with export levels growing more than Queensland production increases. Gas shortfalls are expected to emerge from 2027 unless new sources of supply are made available.[285] Potential gas supply has

282 AEMO, 2024 Victorian gas planning report, Australian Energy Market Operator, March 2024, pp. 9, 49.

283 Projected production levels have included the committed Kipper compression project since the 2022 VGPR Update, which is expected to provide additional supply from October 2024.

284 Capacity is forecast to decrease to 700 TJ per day following the retirement of Gas Plant 1 scheduled from mid-September. This makes production capability reliant on the remaining 2 production trains, elevating the likelihood of production capacity halving in the event of an issue with either of the remaining plants.

285 This reflects lower forecast supply due to delays in anticipated regulatory approvals for new projects and problems with legacy gas fields. ACCC, Gas inquiry 2017–2025, interim report, June 2024, Australian Competition and Consumer Commission, July 2024, p. 7.

been identified by producers to reduce the risk of near-term shortfalls, but this is mostly conditional on the ability to obtain regulatory approvals and making final investment decisions (section 4.5.5). Import terminals may also help address supply gaps, but their viability is subject to international price movements and the ability to secure foundation customers to contract gas supplies.[286]

4.5.4 Gas storage

Storage facilities can store surplus gas produced in summer for use during higher demand winter periods, providing supply flexibility and quick delivery capability to meet peak demand requirements. Refill and drawdown rates for these facilities can be impacted by connected pipeline capacity and low storage levels, limiting the amount of gas in storage that can be replenished or delivered. Eastern Australia's gas storage capacity includes:

- Large facilities are using depleted gas fields in Queensland, Victoria and South Australia.
  - Iona underground storage (Victoria) has a nameplate storage capacity of 24.4 PJ, with a delivery capability of 570 TJ per day[287] – this is the second largest supply source in the south and can deplete and refill at a much higher rate than other east coast storage facilities. The facility typically refills with large quantities of gas, which are drawn down over the higher demand winter period (Figure 4.19).
  - Moomba Lower Daralingie Beds (LDB) storage (South Australia) has a nameplate storage capacity of 70 PJ, with a delivery capability of under 5 TJ per day (Figure 4.18).[288]
  - Silver Springs storage (Queensland) has a nameplate storage capacity of 45 PJ, with a delivery capability of 8 TJ per day (Figure 4.19).[289]
  - Roma Underground Gas Storage (RUGS, Queensland) has a nameplate storage capacity of 54 PJ, with a delivery capability of up to 60 TJ per day (Figure 4.18).[290]
- LNG storage is in smaller seasonal or peaking facilities located near demand centres – for example, the Newcastle LNG facility in NSW and the Dandenong LNG facility in Victoria (Figure 4.20)[291] – these facilities have relatively high supply rates, but depletion cannot be sustained for many days due to slow refill rates. The primary use for the Dandenong LNG facility is to store small volumes of gas to be injected quickly into the Victorian Transmission System to cater for short-term peak requirements and manage threats to system security.
- There are short-term peak storage services on gas pipelines, which are mostly contracted by energy retailers – for example, the Tasmanian Gas Pipeline stores gas that can be sold into the Victorian market at times of peak demand.

286 Import terminals will not replace the requirement to develop more domestic supply sources.

287 The maximum supply rate achieved in 2021 with a nameplate capacity of 530 TJ per day was 455 TJ.

288 Progressive depletion of storage levels has reduced delivery capacity to 10 TJ per day from late 2021, with current delivery capabilities now sitting around 5 TJ per day since April 2022.

289 Silver Springs delivery outlooks reduced to around 10 TJ per day from mid-October 2021 and have been sitting around 8 TJ per day or lower since 2022.

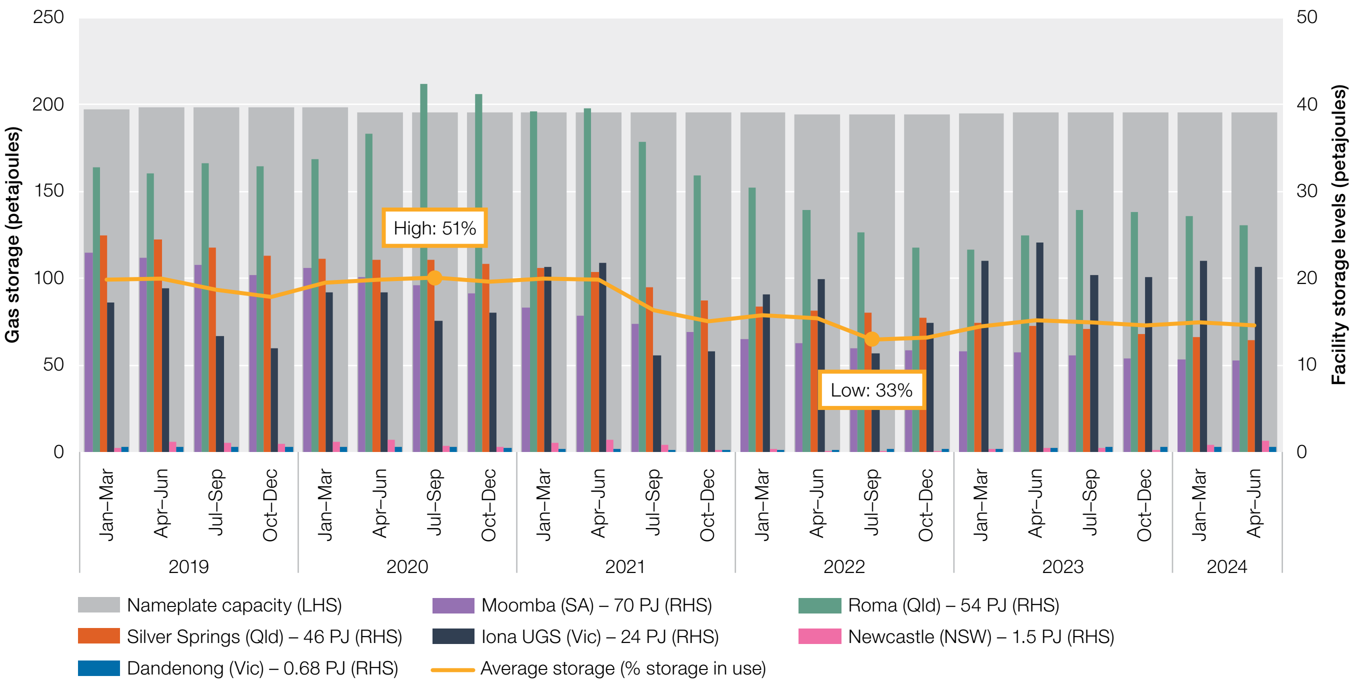
290 Short-term capacity outlooks for the Roma Underground Gas Storage facility can range from 25 TJ per day up to 60 TJ per day.

291 The Dandenong LNG storage facility reached record low levels in 2021 (since the commencement of the Declared Wholesale Gas Market in 1999), driven by a reduction in contracted capacity for winter. Following a rule change by the AEMC, AEMO now acquires uncontracted gas storage supply at the facility and acts as a buyer and supplier of last resort to mitigate potential supply shortfalls, ensuring the facility is at or near full capacity heading into winter.

The Dandenong LNG and Iona underground storage facilities are the only ones that currently provide storage services to third parties in the east coast gas market.[292] The importance of storage in managing supply and demand has risen since the LNG industry began operating, with some storage facilities drawn down to meet LNG export demand and replenished when prices were low. Large gas customers (particularly retailers) have secured their own storage capacity to manage supply risks and seasonal demand. Average storage levels have decreased since 2021 and in the July to September quarter of 2022 reached their lowest levels since reporting commenced in late 2016. This brought average storage levels down to one-third of capacity (Figure 4.17).[293] Iona entered 2024 above the record high storage level reached the previous year. However, high utilisation this winter has resulted in rapid depletion of inventories despite high levels of gas flowing south from Queensland. The drawdown of supply from other large facilities has also continued, with declining pressure in the storage wells constraining supply capability.[294] This demonstrates the dominant impact of weather-driven demand levels on supply adequacy for the southern states.

In contrast, some refilling at the Roma facility in Queensland over 2023 saw supply rates[295] return to higher levels, while refilling of the smaller Newcastle gas storage facility commenced in December 2022 and storage levels were at close to full capacity by late April 2024.[296] After 2024 winter utilisation, Newcastle storage levels had decreased to around one-third of full capacity by late August. Low daily supply capabilities at the Moomba and Silver Springs storage facilities mean they do not make a significant contribution to gas supply.

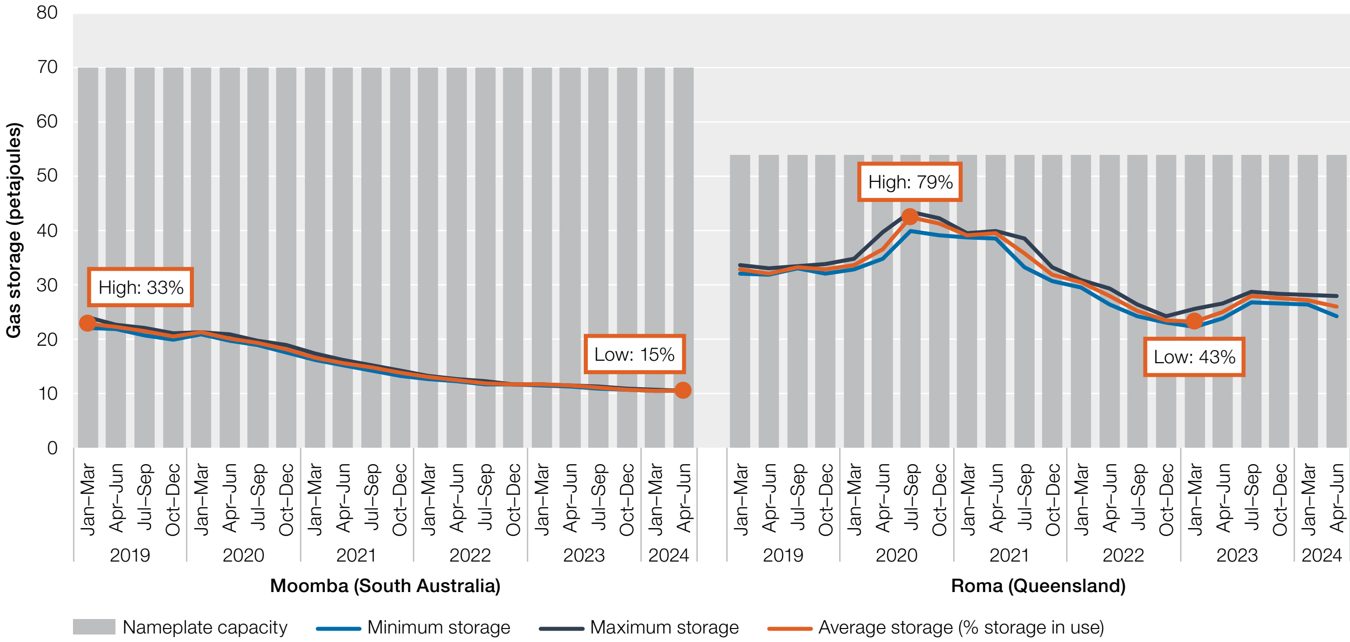
Figure 4.17 Gas storage in eastern Australia



Note: Petajoule (PJ) value next to each facility reflects nameplate capacity.
Source: AER analysis of Gas Bulletin Board data.

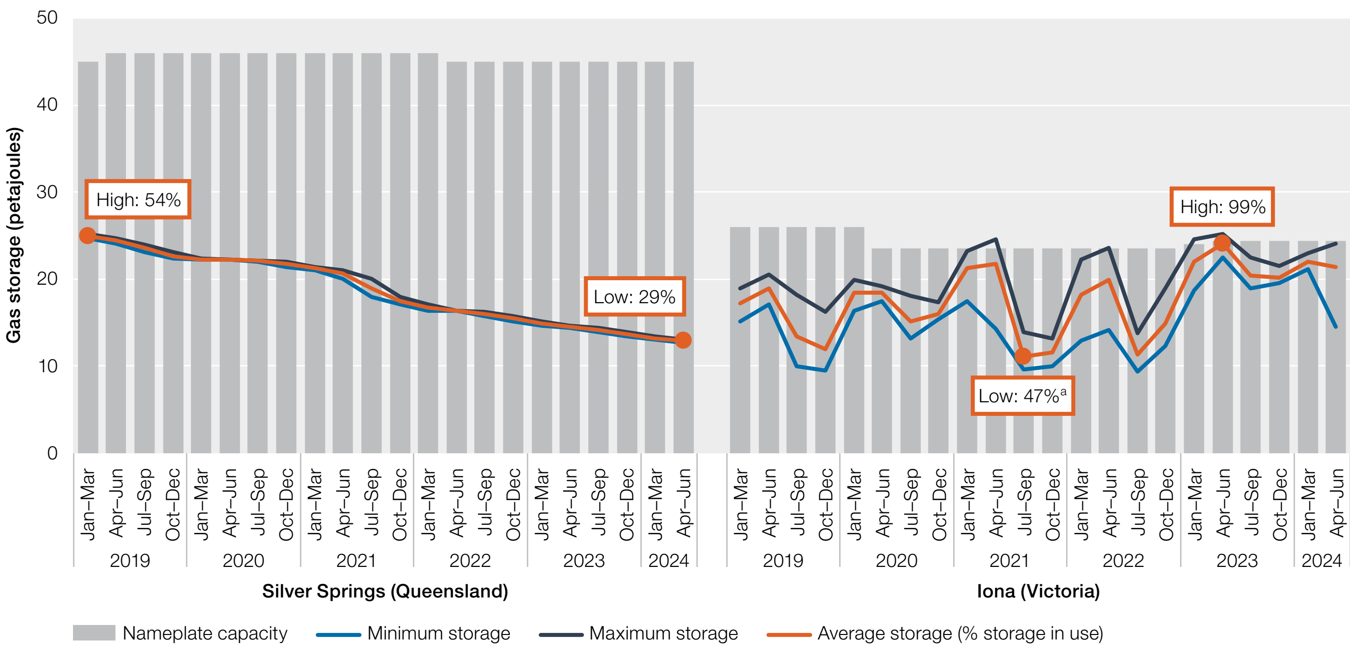
292 ACCC, Gas inquiry 2017–2030, interim report, December 2023, Australian Competition and Consumer Commission, December 2023, p. 127.
293 Storage levels fell to record lows across all east coast facilities in 2022, with this trend continuing at most facilities in 2023.
294 For example, Moomba has reduced its nameplate supply capability from 100 TJ per day when it commenced reporting in late 2016, with current storage levels below 11 PJ limiting its physical injection capacity as low as 3 TJ per day since June 2022.
295 Different levels of storage can impact the daily supply capability of storage facilities.
296 In June 2022, Newcastle gas storage reduced all the inventory in their LNG storage tank for the first time since the facility started operating. The facility filled to around one-third of capacity over winter 2023, with lower utilisation during a period of lower than usual demand.

Figure 4.18 Large gas storage facilities – Moomba (South Australia) and Roma (Queensland)



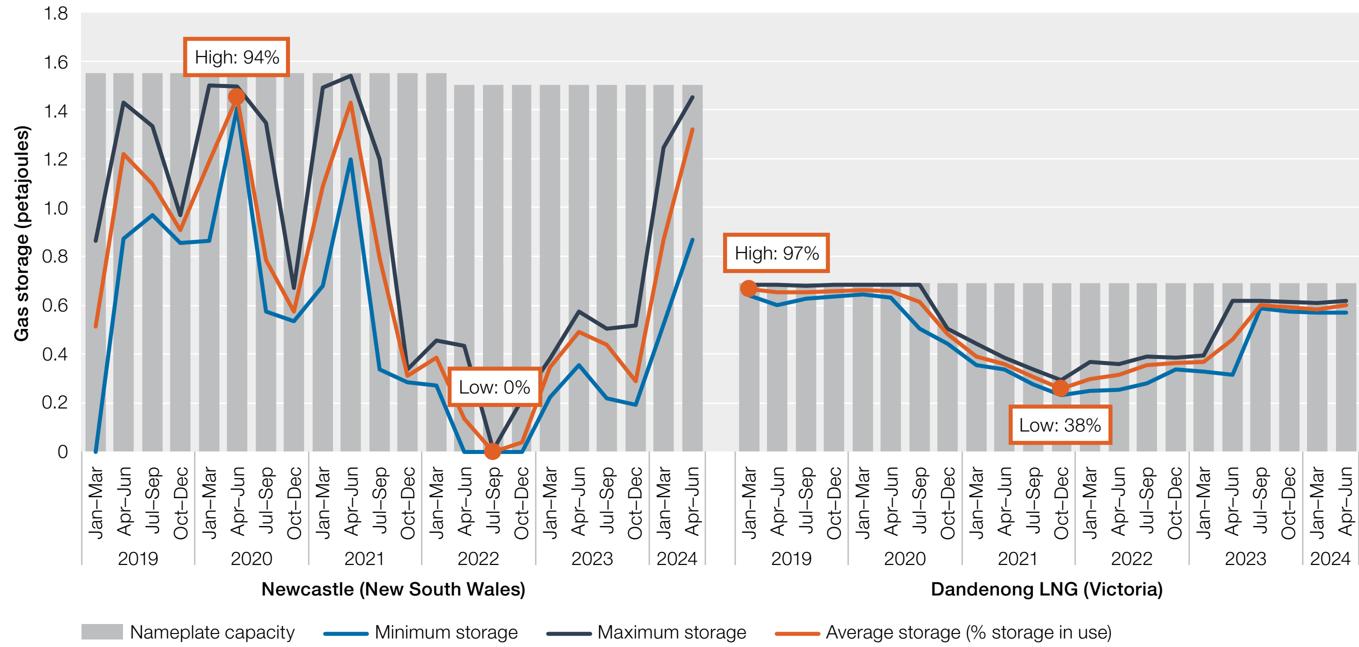
Source: AER analysis of Gas Bulletin Board data.

Figure 4.19 Large gas storage facilities – Silver Springs (Queensland) and Iona (Victoria)



Note: a Lower storage inventory, lower proportionally for October to December 2018.
Source: AER analysis of Gas Bulletin Board data.

Figure 4.20 Small LNG gas storage facilities – Newcastle (NSW) and Dandenong (Victoria)



Source: AER analysis of Gas Bulletin Board data.

Unlike other storage facilities, Lochard Energy's Iona underground gas storage facility (Iona) operates more dynamically with higher supply and refill rates and is an integral southern supply source during winter. Since 2018, upgrades to Iona have expanded storage capacity and supply capability in the Victorian gas market.[297]

Supply into the Victorian market is still limited by available pipeline capacity in the transmission system, but recent upgrades have effectively increased peak day supply capability to 530 TJ per day (section 4.8.3).[298] Both the facility and transmission system upgrades have resulted in the facility being better able to respond to daily supply requirements. However, much faster depletion of storage levels in recent years has demonstrated an increased risk of reducing storage inventories to critically low levels prior to the end of the peak winter demand period. To mitigate some of this risk, preparatory works have commenced on the Heytesbury Underground Gas Storage (HUGS) Project to expand storage capacity through the development of existing depleted gas fields.[299] This could potentially increase Iona's storage capacity by 3.3 PJ by 2026.

Victoria has become increasingly reliant on gas storage inventory from Iona. In 2021 and 2022, storage levels fell to their lowest point since reporting commenced (Figure 4.21). The significant drawdown on gas inventories reduced available supply capacity to very low levels by mid-winter in both years. The fast depletion in 2022 led AEMO to issue a notice of a threat to system security, which remained in place until 30 September.[300] Similar circumstances occurred in 2024 but the notice was revoked on 23 August due to the later improvement in gas supply and demand trends (section 4.5.2).[301] In contrast to the mild winter conditions that resulted in record high winter storage levels in 2023, similar storage drawdown in 2024 mirrored the high rates recorded over the preceding 2 years. This was the result of cold weather conditions from mid-May, which coincided with production issues at Longford.

297 Following Lochard's takeover from EnergyAustralia in 2015, the storage facility's supply capacity has expanded significantly from 390 TJ per day to 530 TJ per day (17 March 2021), 545 TJ per day (28 January 2022) and 558 TJ per day (1 January 2023). The most recent upgrade increased the facility's supply capability to 570 TJ per day in early 2024.

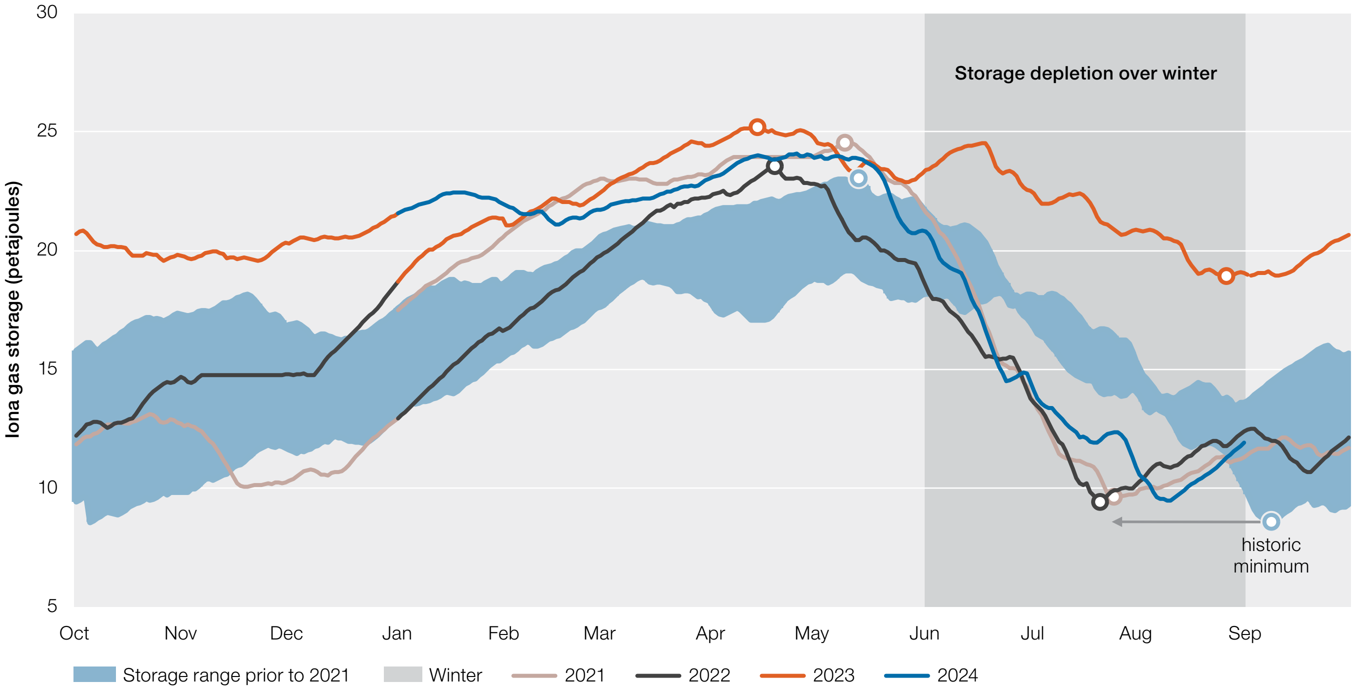
298 A new pipeline segment added to Victoria's transmission system's Western Outer Ring Main (WORM) and a second compressor at Winchelsea have been commissioned and are now operational. These upgrades have increased peak supply capacity to Melbourne by 83 TJ per day. AEMO, *2024 gas statement of opportunities*, March 2024, pp. 44, 55.

299 Lochard Energy, Heytesbury Underground Gas Storage (HUGS) Project.

300 The AEMO notice highlighted the possibility of reduced injection capability at Iona due to low pressure, increasing the risk of curtailment on peak demand days.

301 AEMO, Revocation of East Coast Gas System Risk or Threat Notice, Australian Energy Market Operator, 23 August 2024.

Figure 4.21 Iona underground storage, rapid winter depletion rates since 2021



Source: AER analysis of Gas Bulletin Board data.

In 2022, the much smaller Dandenong LNG storage facility fell to particularly low levels in June following a reduction in participants contracting supply. While much smaller than Iona, the facility plays an important role in mitigating curtailment during potential supply shortfalls, as well as providing critical system security to avoid pressure drops at the Dandenong city gate. Due to the high potential for the facility to be needed from winter 2023 as supply at Longford drops off, Energy Ministers submitted an urgent rule change giving AEMO power to contract underutilised LNG storage capacity in Victoria before winter 2023. The facility entered winter 2024 at close to full capacity. The facility ended winter with 11.9 PJ (49% of nameplate capacity) after refilling from 10 August.[302]

4.5.5 Outlook

Despite improved short-run supply forecasts, the longer-term outlook remains uncertain. Decreases in projected demand for gas generation, residential and commercial demand, and industrial gas usage have improved recent forecast shortfalls, but a projected 28 PJ shortfall is still expected in southern states in 2025.[303] Production is expected to become increasingly reliant on uncertain and undeveloped sources of supply, with Victoria's primary supply source having already declined due to legacy gas fields in the Gippsland Basin coming to the end of their productive lives. Potential supply shortfalls have been forecast to occur in southern states in the coming years and across the east coast from 2027.[304] High levels of demand over the peak winter period in 2024 have already displayed an increased risk of peak day shortfalls, with heavy reliance on Iona gas storage inventories despite significantly higher volumes of gas flowing south.[305]

302 An unseasonably warm end to winter put downwards pressure on market demand, which eased prices.

303 ACCC, Gas inquiry 2017–2025, interim report, June 2024, Australian Competition and Consumer Commission, July 2024, p. 25.

304 ACCC, Gas inquiry 2017–2025, interim report, June 2024, Australian Competition and Consumer Commission, July 2024, p. 33.

305 Storage depletion in 2024 mirrored the rapid rates of drawdown that occurred in 2021 and 2022, yet higher supply output from Longford in previous years reduced the requirement for gas to flow south from Queensland.

More supply and associated infrastructure is clearly needed, but projects proposed to increase production between 2026 and 2029 have been delayed, reportedly due to long regulatory approval processes and planned maintenance.[306] The speculative nature of unsanctioned new domestic supply sources, with a range of barriers including significant investment in infrastructure to bring gas to market, have led to producers finding it increasingly difficult to obtain finance to invest in fossil fuel projects.[307]

Further factors also contribute to uncertainty surrounding long-term supply conditions, including underperformance of developed resources and the potential for southern production to decline faster than expected. Forecasts also make assumptions about undeveloped resources – uncertain reserves, which are increasingly unreliable, depend on more speculative sources of supply. While some development proposals in eastern Australia have shown promising signs, others face significant regulatory hurdles linked to environmental concerns.

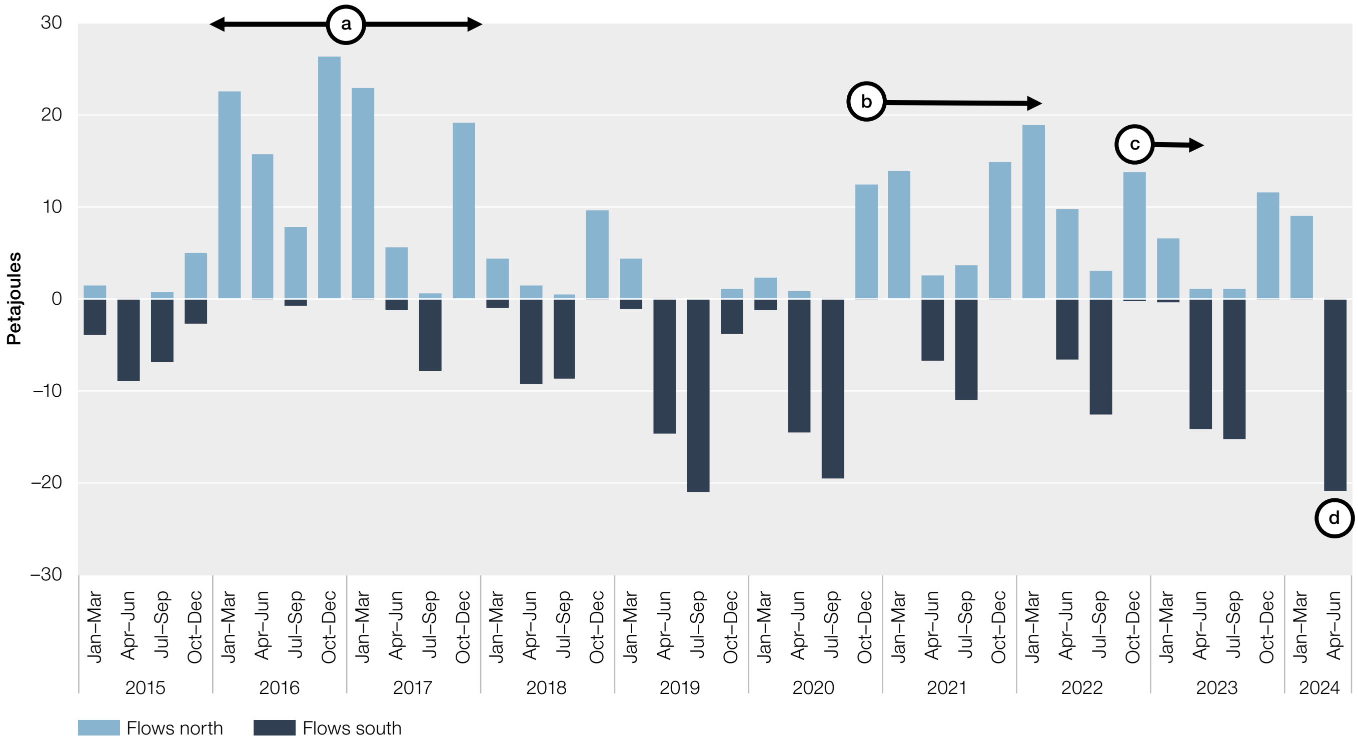
In response to ongoing supply uncertainty, the Australian and state governments have launched initiatives to encourage new projects to supply the domestic market (section 4.10).

306 ACCC, Gas inquiry 2017–2025, interim report, June 2024, Australian Competition and Consumer Commission, July 2024, p. 36.
307 ACCC, Gas inquiry 2017–2030, interim report, January 2023, Australian Competition and Consumer Commission, January 2023, p. 125.

4.6 Inter-regional gas trade

Domestic gas typically flows south in the Australian winter (to meet heating demand) and north in the Australian summer (the Northern Hemisphere winter) when Asia's LNG demand peaks (Figure 4.22).

Figure 4.22 North–south gas flows in eastern Australia



Note: Flows on the QSN (Queensland / South Australia / New South Wales) Link segment of the South West Queensland Pipeline (flowing through the Moomba location).

a 2016 to 2017: Increased southern production to meet LNG demand.

b Late 2020 onwards: record LNG exports continue to rise.

c Late 2022 onwards: LNG exports reduce closer to 2019 levels.

d Winter 2024: additional compressors commissioned on the Moomba to Sydney Pipeline and South West Queensland Pipeline in May and June. Expanded capacity facilitates record monthly gas flows south in June (close to 11 PJ).

Source: AER analysis of Gas Bulletin Board data.

Northerly gas flows increased from late 2020 in line with record export pipeline flows (Figure 4.12) and reduced flows south over winter periods (Figure 4.22, note b). Over the January to March quarter of 2024, flows remained predominantly north despite reduced production from Longford, with exports for the quarter at the highest level observed for the start of the year. While export flows for the April to June quarter continued at high levels, southerly flows increased significantly from May 2024, with demand to bring gas south exceeding capacity to do so.[308]

From June 2024, stage 2 capacity expansions increased the ability to bring more gas south on the South West Queensland Pipeline and Moomba to Sydney Pipelines (section 4.8.3). As a result of this and elevated southern market demand over winter, record gas flows south from Queensland were recorded for June 2024. Southerly flows reached close to 11 PJ and increased the quarterly quantity shipped south to a level equal to the record reached in 2019 (Figure 4.22, note d).

Activity on the Day Ahead Auction once again increased on the Moomba to Sydney Pipeline following the stage 2 expansion. This occurred primarily on routes bringing gas south from Moomba, which accounted for 98% of the record 3.5 PJ of capacity won in June. The South West Queensland Pipeline also experienced an increase in capacity won on routes to bring gas south, with more than 1.3 PJ accounting for over 90% of the quantity won in June.

308 Significant auction capacity was won on auction routes south on the MSP reaching almost 2.5 PJ for May 2024.

Data on trade flows may understate the extent of north–south gas trading. Some gas producers enter swap agreements to deliver gas to southern gas customers without physically shipping it along pipelines. An example is an agreement between Shell and Santos to swap at least 18 PJ of gas.[309] Under the agreement, Shell draws on its coal seam gas reserves to meet part of Santos's LNG supply obligations in Queensland, while Santos diverts gas from the Cooper Basin to meet demand in southern Australia.[310] The swap allows the producers to increase supply to the domestic market, while enabling Shell to avoid transporting gas on the South West Queensland Pipeline, which is contracted to near full capacity. To improve transparency, from 2023 participants' reporting requirements were expanded to encompass a range of bilateral arrangements, including physical swaps (section 4.11.1).

4.6.1 Gas transmission pipelines

Supply conditions depend on the availability of transmission pipeline capacity to transport gas to customers. Improving this availability, pipeline operators are considering a range of upgrades to extend or expand existing infrastructure. For example, in 2021 APA announced an expansion of the South West Queensland Pipeline and Moomba to Sydney Pipeline to increase delivery capacity from northern fields to southern markets. Two stages of this expansion have taken place, with each adding additional compression on both pipelines in mid-2023 and mid-2024 (section 4.8.3). An additional stage has been planned to be completed in two parts but the final investment decision has been delayed to at least the first half of 2025, with a further stage also in consideration.

Wholesale customers buy capacity on transmission pipelines to transport their gas purchases to destination markets. Around 20 major transmission pipelines transport gas to the eastern gas market (key pipeline routes are shown in Figure 4.1). Dozens of smaller pipelines fill out the transmission grid.

The eastern gas market's transmission system has evolved from a series of point-to-point pipelines, each transporting gas from a producing basin to a demand centre, into an integrated network. Many gas pipelines became bidirectional and gas increasingly flows across multiple pipelines to reach its destination. While the Northern Territory was connected to the east coast transmission pipelines in 2019, steadily declining output from the offshore Blacktip gas field led to the interim closure of the Northern Gas Pipeline (section 4.8.5). Access to capacity on key pipelines is important because it provides participants with more options to purchase and move gas between different regions. This ability to move gas gives participants a wider range of options in managing their portfolios across different regions, making it easier to arbitrage the purchase and sale of gas supply without the need to negotiate swap agreements.

Gas production and transmission pipelines assets are owned by separate companies. A gas customer must negotiate with a gas producer to buy gas and separately contract with one or more pipeline businesses to get the gas delivered. This separation adds a layer of complexity to sourcing gas, especially for smaller customers (section 4.6.2).

The range of services provided by transmission pipelines is expanding to meet the needs of industry as the market evolves. Pipeline operators no longer simply transport gas from a supply source to a demand centre. Gas customers now seek more flexible arrangements such as bidirectional and backhaul shipping, and park and loan services.[311]

Pipeline ownership

Australia's gas transmission sector is privately owned (chapter 5). The publicly listed APA Group is the largest owner of pipeline assets, with equity in 13 major pipelines, including key routes into Melbourne, Sydney, Brisbane and Darwin. Another major pipeline owner with equity in numerous pipelines is Jemena. The pipelines fall under different regulatory arrangements, now classified as either scheme or non-scheme pipelines under recent pipeline reforms (section 4.11.2 and Table 5.1).[312]

309 Santos, 'Santos facilitates delivery of gas into southern domestic market', media release, August 2017.

310 EnergyQuest, *EnergyQuarterly*, March 2020.

311 Pipelines with bidirectional flows can ship gas in both directions. Backhaul shipping is the 'virtual transport' of gas in a direction opposite to the main flow of gas. Parking gas is a way of temporarily storing gas in the pipeline by injecting more than is to be withdrawn. Loaning gas allows users to inject less gas into the pipeline than is to be withdrawn.

312 Full regulation pipelines have their prices assessed by the AER. Light regulation pipelines do not have their prices assessed by the AER, but parties can seek arbitration to address a dispute. Part 23 pipelines are subject to information disclosure and arbitration provisions. Exempt pipelines are subject to no economic regulation. Chapter 5 outlines the various tiers of regulation.

4.6.2 Pipeline access

Wholesale gas customers buy capacity on transmission pipelines to transport their gas purchases from gas basins. Gas production companies and gas pipelines are separately owned, so a gas customer must negotiate separately with producers to buy gas and with pipeline businesses to have the gas delivered. To reach its destination, gas may need to flow across multiple pipelines with different owners and use compression to facilitate the movement of gas.

Capacity on some pipelines is fully contracted to gas shippers, who do not fully use it. Access to transmission pipelines on key north–south transport routes is critical for gas customers. But if many critical pipelines have little or no spare, uncontracted capacity, it makes it difficult to negotiate access. In addition, many pipelines face little competition and may charge monopolistic prices.

Reforms introduced in March 2019 made it easier to access this capacity to pipelines and compression facilities, giving other parties an opportunity to procure capacity through trading platforms or win auctioned quantities – see section Pipeline capacity trading (Day Ahead Auction).

Capacity can be acquired in 2 ways through AEMO-facilitated markets. First, the capacity trading platform allows shippers to sell any capacity they do not expect to use. Second, any unused capacity not sold must be offered at a mandatory Day Ahead Auction. Any shipper can bid at the auction, which is finalised shortly after the nomination cut-off time a day in advance of the relevant gas day.

Auction revenues go to the pipeline, or facility operator, rather than the shippers that own the capacity rights. The auctions have a reserve price of zero and most settlements have occurred at no cost.[313]

Pipeline capacity trading (Day Ahead Auction)

Since the commencement of the auction in March 2019, over 330 PJ of contracted but unnominated pipeline capacity has been won across 16 of the 22 auction facilities (Figure 4.23).[314]

Around 80% of all capacity procured through the Day Ahead Auction has been won at the reserve price of zero dollars and almost two-thirds of this capacity has been won on 4 key pipelines: the South West Queensland Pipeline (SWQP) and Moomba Sydney Pipeline (MSP), which facilitate gas flows south and north between spot markets; the Eastern Gas Pipeline (EGP) and the Roma Brisbane Pipeline (RBP), which facilitate flows to several gas-powered generators. Around 20% of the remaining zero-dollar capacity has been won on the Wallumbilla B compressor (WCFB).[315]

Trading activity on the auction has continued to grow over 2023 and the first half of 2024, with trade over the January to March quarter 2024 (39.4 PJ) exceeding the record set over the same period in 2023.[316] Of this capacity, around one third or 13.4 PJ was traded on gas routes that transport gas between northern and southern markets (SWQP/MSP). The quantity won for the period on the SWQP set a record at close to 5.5 PJ and the WCFB also set a record of 10.8 PJ.

Despite decreasing markedly from the first quarter's record levels, quantities won across the April to June quarter 2024 continued to exceed previous record levels for the April to June quarter.

The Day Ahead Auction has improved market dynamics by enhancing competition, especially in southern markets. Access to low or zero cost pipeline capacity is allowing shippers to move relatively low-priced northern gas into southern spot markets, easing price pressure in those markets.[317]

The AER's *Pipeline capacity trading – two-year review* found Day Ahead Auction capacity increased liquidity in both upstream and downstream markets. It also reported on how the auction can indirectly ease supply costs for some gas-powered generators in the NEM.

313 Although participants can win capacity for $0 per GJ, additional charges and registration fees make the real cost slightly higher.

314 There has been no significant activity on the voluntary capacity trading platform since its introduction.

315 The Wallumbilla B facility can compress gas to a restricted specification, rather that the Australian Standard gas specification of the Wallumbilla A facility, allowing participants with the ability to provide gas at the restricted specification the opportunity to win capacity on the auction.

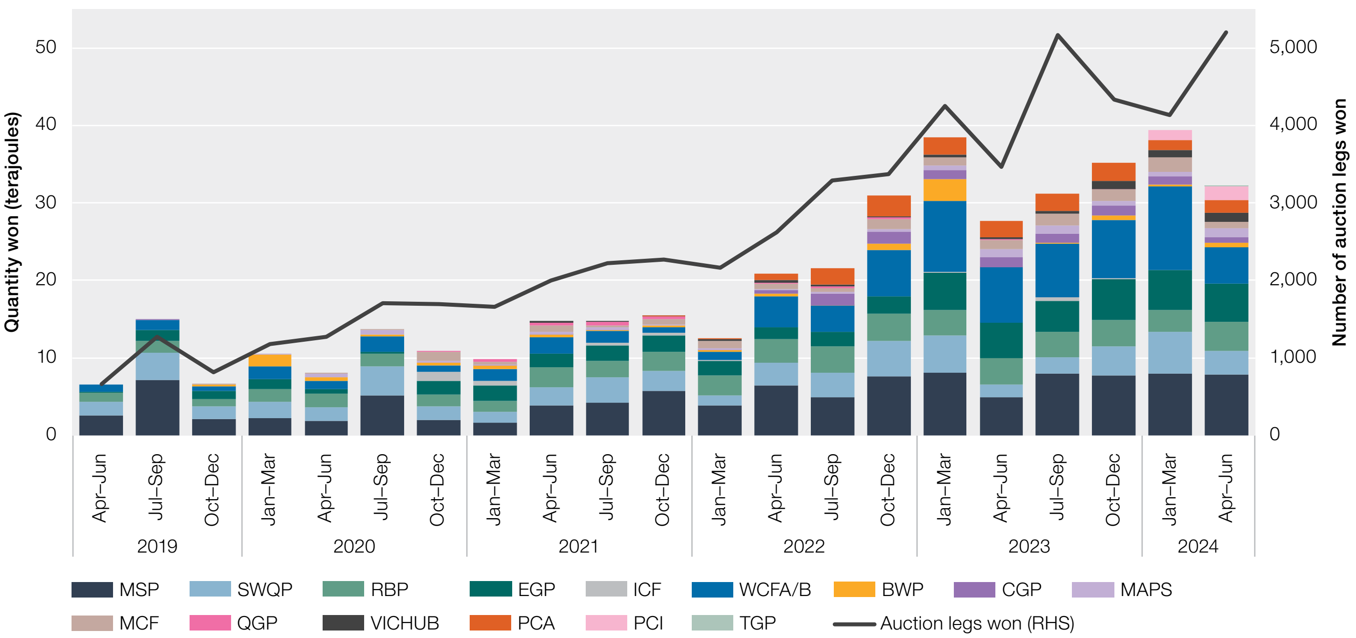
316 The January to March quarter record set in 2023 was 24% higher than all prior quarters since the auction commenced, and around 3 to 4 times higher than previous January to March quarters.

317 AER, Pipeline capacity trading – two-year review, March 2021, Australian Energy Regulator, p. 23.

However, auction activity on some pipelines remains relatively low. Under-utilisation may result from higher auction fees, which can discourage smaller players in particular. While most capacity is won at the reserve price of $0 per GJ, the total cost is higher, because participants need to pay pipeline and storage operators for facility use (which can include both fixed and variable fees). Smaller participants also may be required to provide credit support or collateral to use auction services – in some cases, these costs can be significant.

The AER recently released a focus report on the Day Ahead Auction, assessing the extent it has supported efficiency and competition in the east coast gas wholesale market.[318]

Figure 4.23 Day Ahead Auction quantities won, by facility



Note: BWP: Berwyndale to Wallumbilla Pipeline; CGP: Carpentaria Gas Pipeline; EGP: Eastern Gas Pipeline; ICF: Iona Compression Facility; MAPS: Moomba to Adelaide Pipeline; MCF: Moomba Compression Facility; MSP: Moomba to Sydney Pipeline; PCA: Port Campbell to Adelaide Pipeline; PCI: Port Campbell to Iona Pipeline; QGP: Queensland Gas Pipeline; RBP: Roma to Brisbane Pipeline; SWQP: South West Queensland Pipeline; TGP: Tasmania Gas Pipeline; VicHub (eastern Victoria); WCFA/B: Wallumbilla compression facilities.

Source: AER analysis of Day Ahead Auction data.

318 AER, Wholesale gas market focus report: Day Ahead Auction, Australian Energy Regulator, October 2024.

4.7 Trade in east coast gas markets

In 2023, upstream commodity trade remained strong in the Gas Supply Hub, supported by continued high trade levels for transportation capacity won through the Day Ahead Auction.

The continued decline of southern production reserves has left southern states more reliant on Queensland gas supplies going forward, with physical gas flows south in May, June and July this year, up significantly from previous years. This coincided with a rise in Day Ahead Auction capacity won on the Moomba to Sydney Pipeline to bring gas south, with capacity upgrades commissioned from May allowing for increased flows.

In downstream markets, the high levels of net trade observed over the middle of 2021 and 2022 diminished in 2023, with unseasonably warmer weather over winter driving lower domestic demand across the east coast. However, there were some periods of higher proportions of market trade coming from gas purchased through the markets in the January to March quarter of 2023 and again in late September and late November 2023, which put downward pressure on market prices (Figure 4.5).

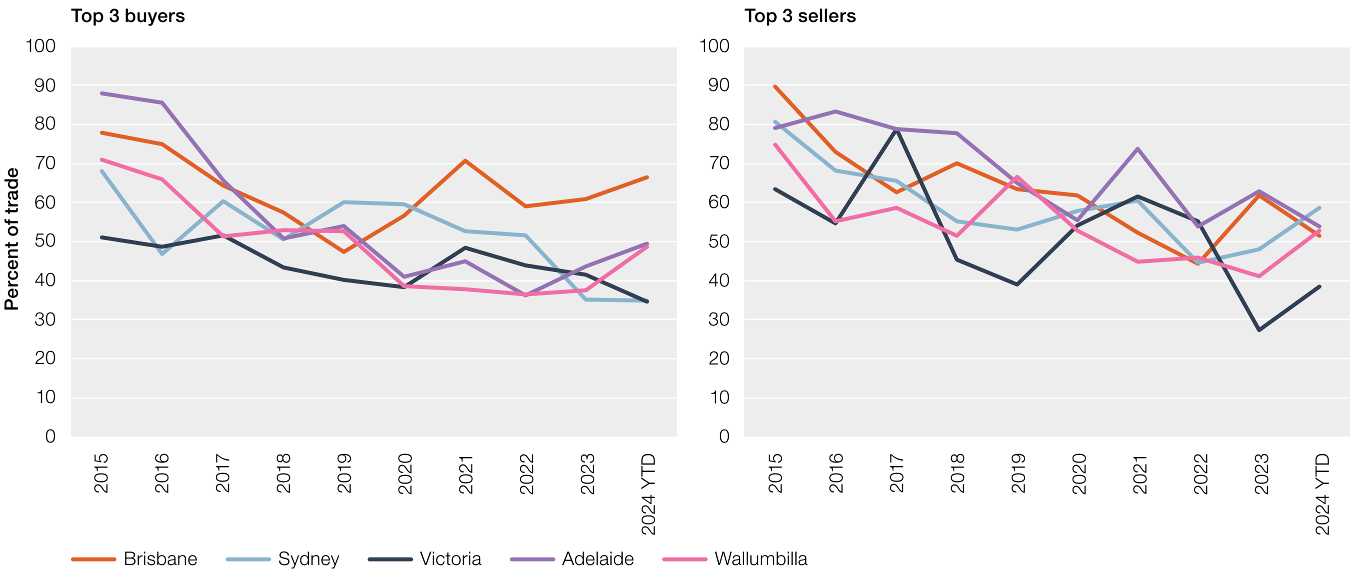
Net trade was generally flat into 2024 as prices remained stable, with lower domestic demand offsetting higher export levels until mid-May when colder weather drove increased demand and price levels. This influenced an increase in net trade quantities over the April to June quarter this year, particularly in Victoria where demand is higher, but not to the very high levels of 2021 and 2022.

In the Gas Supply Hub, strong trade from the October to November quarter of 2023 saw traded commodities exceed the previous record set in the July to September quarter of 2022, exceeding 13.2 PJ.[319] The Day Ahead Auction also set a record at 39.4 PJ of capacity won at auction, close to 1 PJ higher than the record set in the January to March quarter of 2023.

Trading profiles varied across the markets. The concentration of trades amongst the top 3 sellers increased in the Adelaide, Brisbane and Sydney STTM hubs over 2023, with decreases recorded in the other regions (Figure 4.24). In Victoria, the drop in the level of trade attributed to the top 3 sellers over 2023 was more pronounced, falling to 28% compared with 56% in 2022. Among the top 3 buyers, the proportion of gas purchased in 2023 was relatively similar to the previous year in the Wallumbilla Gas Supply Hub, Brisbane and Victoria. In Sydney, the proportion dropped from 52% in 2022 to 35% in 2023. Conversely, the top 3 buyers in Adelaide increased their share of net trades from 36% in 2022 to 44% in 2023.

319 High trade in mid-2022 coincided with high demand and unprecedented price volatility across the east coast, with gas traded through the Gas Supply Hub reaching 11.69 PJ over the July to September quarter.

Figure 4.24 Top 3 buyers and sellers in eastern Australian gas markets



Note: YTD: Year-to-date to 30 June 2024.
Source: AER analysis of data from the Gas Supply Hub, Short Term Trading Market and Victorian Declared Wholesale Gas Market.

4.7.1 Victoria's Declared Wholesale Gas Market (DWGM)

In 2023, 38 participants traded in the Victorian market. The market's participants include energy retailers, power generators and other large gas users, and traders. Volumes traded were down from 2021 and 2022, dropping 17% from the previous year with flatter levels of mid-year trade. However, despite this decrease the total of 27.4 PJ of gas traded exceeded levels set in the preceding years.

Production output from Victoria's main supply source at Longford has declined, leading to participants increasingly supplying the market with additional gas quantities via the Victorian Northern Interconnect through Culcairn. Despite the high levels of gas flowing to southern markets this winter through expanded capacity on the SWQP and MSP, the depletion of Iona's underground storage reserves in 2024 mirrored similarly high rates of storage inventory drawdown observed in 2021 and 2022, when southerly flows were lower.

The volume of trade in the Victorian gas futures market in 2023 was down 46% on the previous year. Ultimately, this quantity still accounts for only a small proportion (less than 5%) of the total volume traded in the spot market.

4.7.2 Gas Supply Hub (GSH)

In 2023, 24 participants traded at the gas supply hubs, 22 of which were active in trading both on-screen and off-screen products, with numerous off-market trades facilitated by a broker participant.[320] On average, participants executed around 420 trades per month in 2023 – an increase of 35% from 2022. LNG export businesses and gas producers were among the most active participants in 2023, accounting for 42% of transactions. Gentailers (28%) and traders (24%) had similar transaction numbers.[321]

LNG producers are large suppliers of gas into the hubs, although operational issues can limit their participation. In addition, the physical interconnection of LNG facilities allows them to trade easily among themselves. Some market participants have suggested the scale of the LNG producers' operations may involve greater volumes than the hubs can currently absorb. Other participants trading were large industrial users.

320 We consider a participant 'active' if it makes at least 12 trades in a year. The broker is not included as an active trader.
321 Gentailers are participants that own electricity generation assets and retail market portfolios.

In the first half of 2024, approaching winter, there was very little forward trade through the Gas Supply Hub, continuing the same trend observed the previous year. This was markedly different to the same periods in 2021 and 2022, where Gas Supply Hub trade materially exceeded gas delivered at the hub. This indicated a substantial volume of forward trade. This trend in previous years suggests participants sought to lock in gas supply approaching winter, whereas trading activity in 2023 and 2024 shows a trend towards more shorter-term trading for delivery closer to the date of trade. The lower volumes of forward trade suggest a greater reliance on spot market trade to meet participants' demand levels over winter. Trade volumes over the first half of 2024 were up 14% in comparison to the previous year, but most deliveries occurred closer to the date of trade, particularly for gas traded within 3 days of the delivery date (Figure 4.25).

Wallumbilla hub activity

Wallumbilla is the larger of the 2 primary hubs that make up the Gas Supply Hub. Users of the Wallumbilla hub include the LNG projects, gas-powered generators and trader participants taking advantage of the Day Ahead Auction to arbitrage prices between Wallumbilla and the downstream markets. Trade at the Wallumbilla hub represents the bulk of gas traded through the Gas Supply Hub.

In 2021, off-screen trade began to increase, with further growth in off-screen trades in 2022. While this trend continued in 2023 and the first half of 2024, the January to March quarter of 2024 saw an uptick in on-screen trading transacted on the trading platform, which accounted for 43% of quantities traded over the quarter. Over 2023, delivered quantities were on par with the record levels recorded the previous year above 35 PJ.

However, gas traded through the Wallumbilla hub represents only a small share of total gas traded, because many participants continue to favour bilateral, off-market arrangements. In 2023 gas traded through the Wallumbilla hub accounted for 15% of total gas flows through pipelines in the Wallumbilla bulletin board zone, roughly the same proportion as the previous year. In total, close to 38 PJ of gas was traded in 2023 and 19.5 PJ was traded across the first half of 2024.

Moomba hub activity

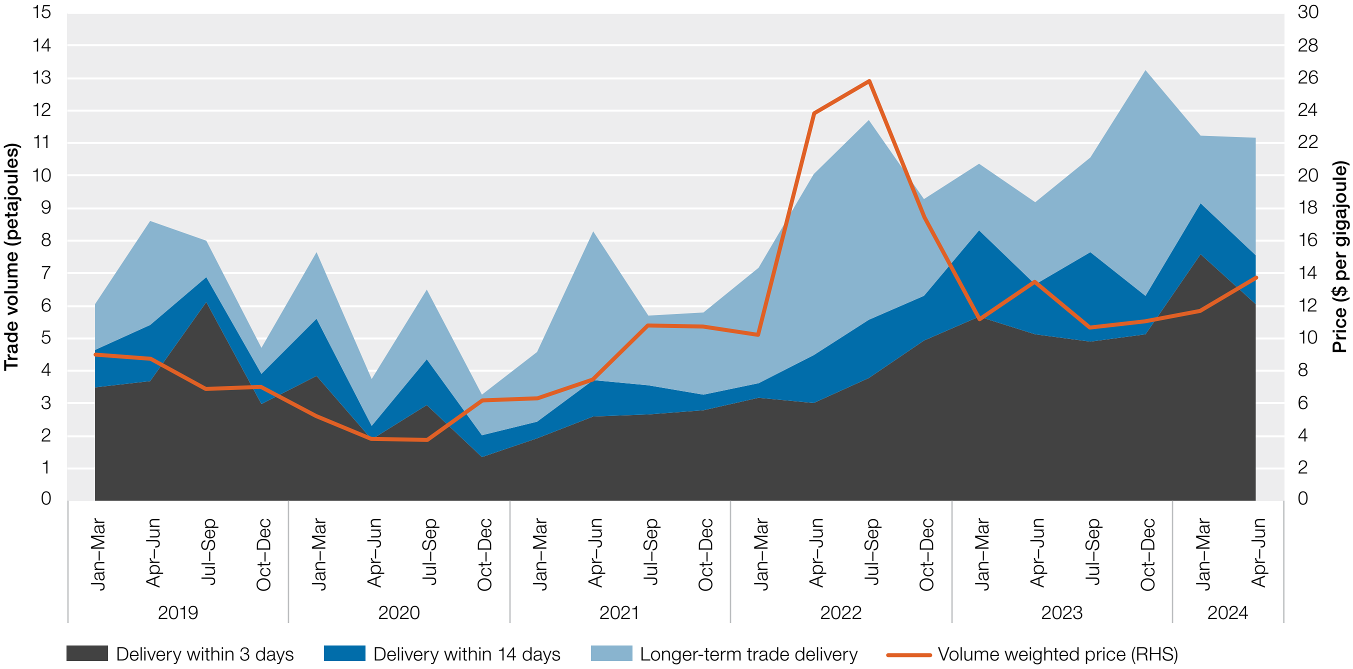
Trade at Moomba has been slow to develop. The first trade was executed in September 2017 and 141 trades were executed in 2019. Like Wallumbilla, trades at the Moomba location decreased significantly in 2020, declining further in 2021 before a very slight upturn in 2022. However, an upturn in 2023 saw traded quantities reach 1.75 PJ over the first half of 2023 and over 2 PJ was traded across the last half of the year. This was partially driven by an upturn in trade levels on the Moomba to Sydney Pipeline. In 2024, 2.6 PJ of gas was traded at Moomba, with increased trades delivered at points on the Moomba to Adelaide Pipeline, which accounted for around half of the trade across the first half of the year. While still significantly lower than trade levels at Wallumbilla, this represented around 11% to 12% of the total volume of gas traded through the Gas Supply Hub during those periods.

Victoria and Sydney activity

Trade levels at the Culcairn (Victoria) and Wilton (Sydney) trading locations have occurred in small volumes, reaching a total of 293 TJ and 3,279 TJ, respectively, to date.[322]

322 Quantities traded from 2021 up to 30 June 2024.

Figure 4.25 Gas supply hub – increase in shorter-term trade



Note: Volume weighted average price includes all GSH products (excluding capacity trading platform) at all locations, excluding brokered sales.
Source: AER analysis of gas supply hub data.

4.7.3 Short Term Trading Market (STTM)

In 2023, 38 participants traded in the Sydney STTM, 27 participants traded in the Adelaide market and 22 in the Brisbane market. The participants included energy retailers, power generators, large industrial gas users, gas producers and exporters, and traders. The markets are particularly useful for gas-powered generators because they can source gas at short notice when electricity demand is high (and offload surplus gas if electricity demand is low).

Shippers deliver gas for sale into the market and users buy the gas for delivery to energy customers. Many participants operate both as shippers and users but in effect trade only their net positions – that is, the difference between their scheduled gas deliveries into and out of the market. From the start of 2023 to mid-2024, quarterly trade levels accounted for 15.9% to 24.4% of the total quantities scheduled in the Sydney market and 15.1% to 17.8% in Brisbane. Brisbane has historically traded below 10% of market demand prior to 2023. In Adelaide, the proportion of trade reached record high levels above 30% in the January to March quarters of 2023 and 2024. In Sydney, which has the highest volume of traded quantities across the STTM hubs, trade levels across 2023 were down 24% from the previous year (16.2 PJ), with scheduled demand 9% lower (88.5 PJ).

Around 70% of domestic gas production in eastern gas markets (excluding the Northern Territory) is exported and the balance is sold into the domestic market.

4.8 Market responses to supply risk

Concerns about potential gas shortfalls have prompted a range of potential market responses. These include further gas development, LNG imports, transmission pipeline solutions and demand response. AEMO's *Gas Statement of Opportunities* reports have repeatedly highlighted the risk of both short-term and long-term shortfalls in the east coast gas markets, particularly due to the depletion of legacy gas fields in Victoria's offshore Gippsland Basin. However, several projects that could help fill the supply gap have either stalled, been postponed or abandoned.

4.8.1 Gas field development

Numerous projects have been progressing to bring additional supply to the domestic market:

- In Queensland, Senex agreed to supply 10% of the reserves of its Atlas expansion project (up to 42 PJ) in the Surat Basin to AGL and 14 PJ of gas to Orora's glassmaking plant over 10 years starting 2025. Senex also agreed to supply BlueScope's Port Kembla plant with 20 PJ of gas from 2026, following a similar contingent arrangement with Visy, contributing to a total of 130 PJ in deals from 2025. The Atlas expansion plans to increase annual production by 60 PJ by the end of 2025. An earlier expansion of the facility commissioned in the July to September quarter of 2022 saw production increase from 12 PJ to 18 PJ over the January to March quarter of 2023.
- Gas production from the Meridian joint venture increased to 3.1 PJ in the January to March quarter of 2023 (34 TJ per day) following the drilling of one development well. The WestSide/Mitsui partnership plans to drill 350 wells in the Bowen Basin to supply GLNG.[323]
- In Victoria, Cooper Energy announced plans to expand its Otway gas hub. After commencing production at the Athena gas plant (formerly Minerva) from mid-December 2021, the Otway Phase-3 Development (OP3D) project is targeted to bring additional gas to the market before winter 2025.[324] Cooper entered into a long-term gas sales agreement (GSA) with AGL to supply up to 10 PJ per year for up to 6 years.[325]
- Exxon Mobil announced funding of the Kipper Compression Project in the January to March quarter 2022, committing supply from 2024 and additional investment to develop and produce gas from the Kipper and Turrum fields over the following 5 years.[326] While additional gas is expected to be processed at Longford from 2026, supply is not expected to increase winter capacity to levels previously supplied by their depleting legacy field production.[327] In addition to the Turrum phase 3 project, the Gippsland Basin Joint Venture is considering the Longford Late Life Optimisation project to maximise production from depleting reserves later in the decade.[328]
- Beach Energy committed to the development of Geographe and Thylacine North and West fields to increase Port Campbell supply, including the drilling of 6 new production wells commencing in February 2021. From mid-May 2023, Otway's actual daily production output increased above 170 TJ (producing over 10 PJ in the April to June quarter of 2023). From mid-June 2024, daily production output reached close to 200 TJ (producing 11.9 PJ across the April to June quarter of 2024). Beach has also prioritised the ongoing development of its Yolla West field and deferred FID for Trefoil, which is now considered as potential supply.[329]
- In NSW, Santos proposed to develop 850 wells across its 95,000-hectare Narrabri gas project, with the potential to supply up to 200 TJ per day. The staged development was expected to provide up to 55 PJ per year in 2026, all of which is voluntarily committed to the domestic market. However, appeals against the project's approval have delayed any final investment decision, which now depends on project approvals being cleared.[330]

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323 The partners began supplying GLNG in 2015 under a 20-year deal linked to oil prices. EnergyQuest, *EnergyQuarterly*, June 2023, p. 122.
324 Athena sources gas from the Otway Basin's Casino, Henry and Netherby fields, some of which was formerly processed at Iona (Casino).
325 Cooper Energy, Gas Sales Agreement with AGL for the next phase of Otway Basin development and exploration, media release, 10 November 2022.
326 ExxonMobil, Opportunities for the Gippsland Basin and Australia's energy transition, 22 March 2022.
327 AEMO, 2023 Victorian gas planning report, Australian Energy Market Operator, March 2023, p. 63.
328 The project depends on the progression of the Turrum phase 3 project.
AEMO, 2023 Victorian gas planning report, Australian Energy Market Operator, March 2024, p. 63.
329 AEMO, 2023 Victorian gas planning report, Australian Energy Market Operator, March 2023, p. 63.
330 The Australian Government approved the project in November 2020, with the conditions of approval consistent with those set by the NSW Independent Planning Commission.

Regulatory barriers to gas development

In some states and territories, community concerns about environmental risks associated with fracking led to legislative moratoria and regulatory restrictions on onshore gas exploration and development.[331] Victoria, South Australia, Tasmania, Western Australia and the Northern Territory have onshore fracking bans in place, with varying degrees of coverage:

- The Victorian Government banned onshore hydraulic fracturing and exploration for and mining of coal seam gas or any onshore petroleum until 30 June 2020.[332] In March 2021 the government committed the ban on fracking and coal seam gas exploration to the Victorian Constitution.[333] Onshore conventional gas exploration recommenced from July 2021.
- In 2018 South Australia introduced a 10-year moratorium on fracking in the state's south-east. It introduced the moratorium by direction and announced its intention to legislate it. However, unconventional gas extraction is allowed in the Cooper and Eromanga basins. South Australia has no restrictions on onshore conventional gas.
- The Tasmanian Government banned fracking for the purpose of extracting hydrocarbon resources (including shale gas and petroleum) until March 2020. This has since been extended to 2025.[334]
- The Northern Territory has made 51% of the territory eligible for hydraulic fracturing. The decision covers much of the Beetaloo Basin, which holds most of the territory's shale gas resources.
- NSW has no outright ban on onshore exploration, but significant regulatory hurdles have stalled development proposals. Regulatory restrictions include exclusion zones, a gateway process to protect 'biophysical strategic agricultural land', an extensive aquifer interference policy, and a ban on certain chemicals and evaporation ponds.[335] The state's regulations also require community consultation on environmental impact statements and a detailed review process for major projects, as highlighted by the protracted process for Santos's Narrabri gas project.[336] Under an agreement reached in early 2020, the NSW and Australian governments set a target of increasing supply to the NSW market by 70 PJ per year.[337]

331 Hydraulic fracturing, also known as fracking, involves injecting a mixture of water, sand and chemicals at high pressure into underground rocks to release trapped pockets of oil or gas. A well is drilled to the depth of the gas or oil-bearing formation, then horizontally through the rock. The fracturing fluid is then injected into the well at extremely high pressure, forcing open existing cracks in the rocks, causing them to fracture and breaking open small pockets that contain oil or gas. The sand carried by the fluid keeps the fractures open once the fluid is depressurised, allowing oil or gas to seep out.

332 Department of Economic Development, Jobs, Transport and Resources (Victoria), Onshore gas community information, August 2017.

333 Victorian Government, Enshrining Victoria's ban on fracking forever [media release], March 2021.

334 Department of State Growth (Tas), Tasmanian Government policy on hydraulic fracturing (fracking) 2018, DSG website, accessed 28 May 2021.

335 Department of Planning and Environment (NSW), Initiatives overview, July 2018.

336 Department of Planning and Environment (NSW), 'Community views on Narrabri Gas Project to be addressed' [media release], 7 June 2017.

337 Prime Minister of Australia and Premier of New South Wales, 'NSW energy deal to reduce power prices and emissions' [media release], January 2020.

4.8.2 Liquefied natural gas import terminals

To address future supply concerns, market participants have proposed numerous gas projects to develop LNG import facilities on the east coast. Each project would involve importing LNG through floating storage and regasification units. Although development of import terminals has been delayed over the past year, proponents of these projects remain committed to their continuing development.[338]

- Due to uncertainty around the contracting of gas supply, AIE's terminal at Port Kembla (NSW) was reclassified by AEMO and removed from the list of anticipated projects feeding into forecast supply outlooks. In 2021 AIE and Jemena signed a project development agreement to connect to the Eastern Gas Pipeline (EGP), with modifications set to allow bidirectional flows to deliver gas to Sydney and Victoria (section 4.8.3). Jemena completed construction of the 12 km buried gas pipeline to connect the LNG Terminal to Jemena's EGP in December 2023, while physical construction at the LNG Terminal continues.[339]
- Venice Energy's Outer Harbour LNG project at Port Adelaide (South Australia) is projected to potentially supply gas by 2026.[340] However, gas deliveries to Victoria are currently constrained due to the SEAGas Pipeline, which is currently only able to flow gas out of Victoria, and the limited available capacity on the South West Pipeline.

  The first stage of enabling works for site preparation have been completed, with a new commercial agreement to guarantee the receipt of a floating storage regasification unit. Venice entered negotiations with Origin for exclusive use of the import terminal for 10 years, for an expected supply capacity of up to 446 TJ per day or 110 PJ per year.
- Viva Energy's Geelong (Victoria) Gas Terminal project is continuing to progress with a supplementary data request for the Environment Effects Statement required by the Victorian Minister for Planning. The terminal is forecast to supply up to 140 PJ per year, have a capacity of 620 TJ per day, and potentially be operational and available to the market as early as 2027.
- Vopak's import terminal in Port Phillip Bay (Victoria) is planned to have a supply capacity of up to 778 TJ per day, supply around 270 PJ per year and be operational in 2028.
- EPIK ceased development of a Newcastle import terminal in early 2023 due to the project being economically unfeasible.[341]

4.8.3 Transportation capacity expansion

To assist with reducing existing gas supply transportation constraints, pipeline expansions have been progressing to bring more gas south from Queensland, bring more gas from western Victoria into Melbourne, and provide upcoming import supply with the ability to provide gas to NSW and Victoria.

South West Queensland and Moomba to Sydney pipelines project

APA has been expanding the pipeline corridor through Queensland into NSW by adding additional compression on the South West Queensland Pipeline (SWQP)[342] and the Moomba to Sydney Pipeline (MSP).[343] The expansion enables more gas flow on pipelines where capacity has been fully or close to fully contracted.[344]

338 Energy Quest, *EnergyQuarterly*, June 2023, p. 23.

339 The forecast supply capacity of 500 TJ per day is projected to be available from 2026 following physical mechanical completion. AEMO, 2024 Victorian gas planning report, Australian Energy Market Operator, March 2024, p. 64.

340 AEMO, Gas Statement of Opportunities, Australian Energy Market Operator, March 2023, p. 65.

341 AEMO, Gas Statement of Opportunities, Australian Energy Market Operator, March 2023, p. 65; Mandurah Mail, Gas market volatility kills off $590m gas terminal, 3 February 2023.

342 The SWQP connects to the Northern Territory through the Carpentaria Gas Pipeline and is a gateway between large northern gas fields in Queensland (including the 3 Gladstone LNG projects) and southern regions with highly seasonal demand.

343 The MSP connects the Moomba hub in South Australia to southern markets in Sydney/ACT and Victoria (through Young and the Victoria/New South Wales Interconnector). Seasonal (non-peak) capacity on the MSP can be limited by up to 50% due to annual maintenance, while southern haul capacity on the VNI lateral can be limited by dynamic interactions between Young, Sydney and GPG requirements at Uranquinty.

344 ACCC, Gas inquiry 2017–2025, interim report, January 2022, Australian Competition and Consumer Commission, February 2022, p. 15.

Stage 1 of the expansion was completed by June 2023, increasing transportation capacity by 49 TJ on the SWQP (to 453 TJ per day) and by 30 TJ on the MSP (to 475 TJ per day).[345] Further stage 2 expansions on the pipelines added 2 more additional compressors, with commissioning completed by June 2024, increasing transportation capacity by 59 TJ on the SWQP (to 512 TJ per day) and by 90 TJ on the MSP (to 565 TJ per day). These were the first 2 of 4 stages, providing a 25% increase in transportation capacity.[346]

The additional proposed third stage includes a further expansion with increases to capacity on both pipelines. APA has deferred a final investment decision on stage 3, with an expected 6-to-12-month delay pushing a decision into the first half of 2025.[347] Stage 3 has been split into two parts: stage 3a and stage 3b:[348]

- Stage 3a consists of an additional compressor on the MSP between Moomba and Young and will increase the nominal capacity of the MSP by 34 TJ per day to 599 TJ per day.
- Stage 3b consists of an additional compressor between Young and Culcairn to provide a capacity increase of 41 TJ per day to Culcairn and further 5 TJ per day for the mainline MSP. Both stage 3a and stage 3b are currently in design phases.

APA is considering an additional stage, which would increase the MSP capacity to 657 TJ per day.

Despite the high levels of gas flowing to southern markets this winter through expanded capacity on the SWQP and MSP, the depletion of Iona's underground storage reserves in 2024 mirrored similarly high rates of storage inventory drawdown observed in 2021 and 2022.

South West Pipeline, Western Outer Ring Main (WORM) project

APA has also upgraded the Victorian Transmission System by building a 51 km high pressure transmission pipeline to address a key capacity constraint previously limiting the connection of existing gas supply from the west of the state to demand in the north and east. The WORM pipeline was commissioned in February 2024, increasing capacity on the South West Pipeline from 447 TJ per day to 530 TJ per day, facilitated by the addition of a second compressor station at Winchelsea. The transportation of gas is also assisted by the upgrade of the existing compressor station at Wollert.

The South West Pipeline (SWP) is a bidirectional facility that primarily transports gas from Port Campbell supply (gas from the Otway Basin and Iona underground storage) into Melbourne. The pipeline also supports refilling the Iona reservoir and transports gas west, fuelling the Mortlake power station and South Australia (through the SEAGas pipeline) during periods of lower demand. Limited capacity on the SWP restricts supply being provided from Port Campbell in the state's west.

AEMO forecasts show the SWP constraining flows towards Melbourne during peak demand periods, when the full capacity of the Iona underground gas storage (UGS) facility is most needed. Further expansions of the SWP are proposed, to bring its capacity in line with the capacity of Iona UGS (section 4.8.4), following completion of the WORM.[349]

345 Stage 1 of the expansion includes an additional compressor on the SWQP and an additional compressor between Moomba and Young on the MSP.

346 AEMO, 2022 Victorian gas planning report, Australian Energy Market Operator, March 2022. pp. 76–77.

347 Argus media, Australian pipeline operator APA has deferred a final investment decision (FID) for stage 3 of its planned east coast grid expansion, given potential rule changes for the South West Queensland pipeline (SWQP), 13 May 2024.

348 AEMO, 2023 Victorian gas planning report, Australian Energy Market Operator, March 2024, p. 64.

349 The Western Outer Ring Main (WORM) was one of 4 priority projects implemented to address shortfalls highlighted in the 2021 Victorian gas planning report.

Further expansions are not yet committed because they are subject to approval under APA's Access Arrangement. However, they have been proposed to increase supply capacity from Port Campbell to between 528 TJ and 570 TJ per day through pipeline augmentation (compression or looping) and up to 670 TJ per day with additional looping and/or compression.[350]

Eastern Gas Pipeline expansion project

The Eastern Gas Pipeline (EGP) is a unidirectional pipeline that transports gas from the Gippsland Basin (Victoria) into Sydney. In 2021 Jemena and AIE signed a project development agreement to connect the PKET import terminal (section 4.8.4) at Kembla Grange. If the project is developed, Jemena plans to modify the pipeline to allow for bidirectional flows, with an initial ability to supply 200 TJ into Victoria and up to 440 TJ towards Sydney per day.[351]

4.8.4 Storage expansion

Iona underground gas storage (UGS)

Lochard Energy upgraded their underground storage facility to increase supply capabilities to 570 TJ per day, with a recently commissioned South West Pipeline (SWP) expansion – the WORM pipeline upgrade – increasing transportation capacity into Melbourne to 530 TJ per day (section 4.8.3).

Further upgrades after the development of the Heytesbury Underground Gas Storage (HUGS) project have been proposed to add additional pipeline assets and approximately 3 PJ of additional storage capacity through construction of a new wellsite at Mylor, Fenton Creek and Tregony (MFCT) gas fields.[352] The project would increase Iona's capacity following the development of existing depleted reservoirs to provide additional storage space, with daily supply capacity increasing to 620 TJ.[353]

An increasing reliance on Iona following recent capacity expansions has enabled a more rapid drawdown rate of storage inventory levels. Due to low pressure levels, when Iona's storage inventory falls below 6 PJ withdrawal capability also decreases, potentially reducing to half of the facility's usual supply capacity. The Iona gas storage facility will continue to play a critical role in meeting southern gas demand requirements in winter due to declining output from Longford's legacy gas fields diminishing the supply capabilities at Victoria's largest supply source.

Golden Beach project

A proposed plant to process gas from the Golden Beach field in the Gippsland Basin could provide additional supply to assist with peak day demand in Victoria before operating as an underground storage facility. Golden Beach Energy received $32 million from the Australian Government in 2022 to accelerate development of the project.[354] The facility was projected to have a storage capacity of 12.5 PJ but would require 43 PJ of production to be procured over a 2-year period before being used as a storage facility.[355] In May 2023, the Minister for Energy and Resources accepted Golden Beach Energy's environment plan to drill the Golden Beach-2 appraisal well.[356] This was completed on 17 July 2023 with the post-drilling evaluation program also complete, including the drafting of the future development plan.

The facility is forecast to supply up to 35 PJ over 2 years from mid-2026 (delayed from 2025), with an initial delivery capacity of up to 125 TJ per day for winter 2026.[357]

350 AEMO, 2022 Victorian gas planning report, Australian Energy Market Operator, March 2022, p. 14.

351 Jemena completed construction of the 12 km buried gas pipeline to connect the LNG Terminal to Jemena's EGP in December 2023. The EGP could also be upgraded to flow 325 TJ per day to Victoria.
AEMO, 2024 Victorian gas planning report, Australian Energy Market Operator, March 2024, p. 64.

352 Lochard Energy, Our HUGS Project, April 2022.

353 AEMO, 2022 Gas Statement of Opportunities, Australian Energy Market Operator, March 2022, p. 55.

354 The Hon Angus Taylor MP, Unlocking critical local gas production and storage, 21 March 2022.

355 ACCC, Gas inquiry 2017–2025, interim report, January 2022, Australian Competition and Consumer Commission, February 2022, p. 68.

356 Earth Resources, Golden Beach Gas Project, 20 June 2023.

357 AEMO, 2022 Gas Statement of Opportunities, Australian Energy Market Operator, March 2024, p. 63.

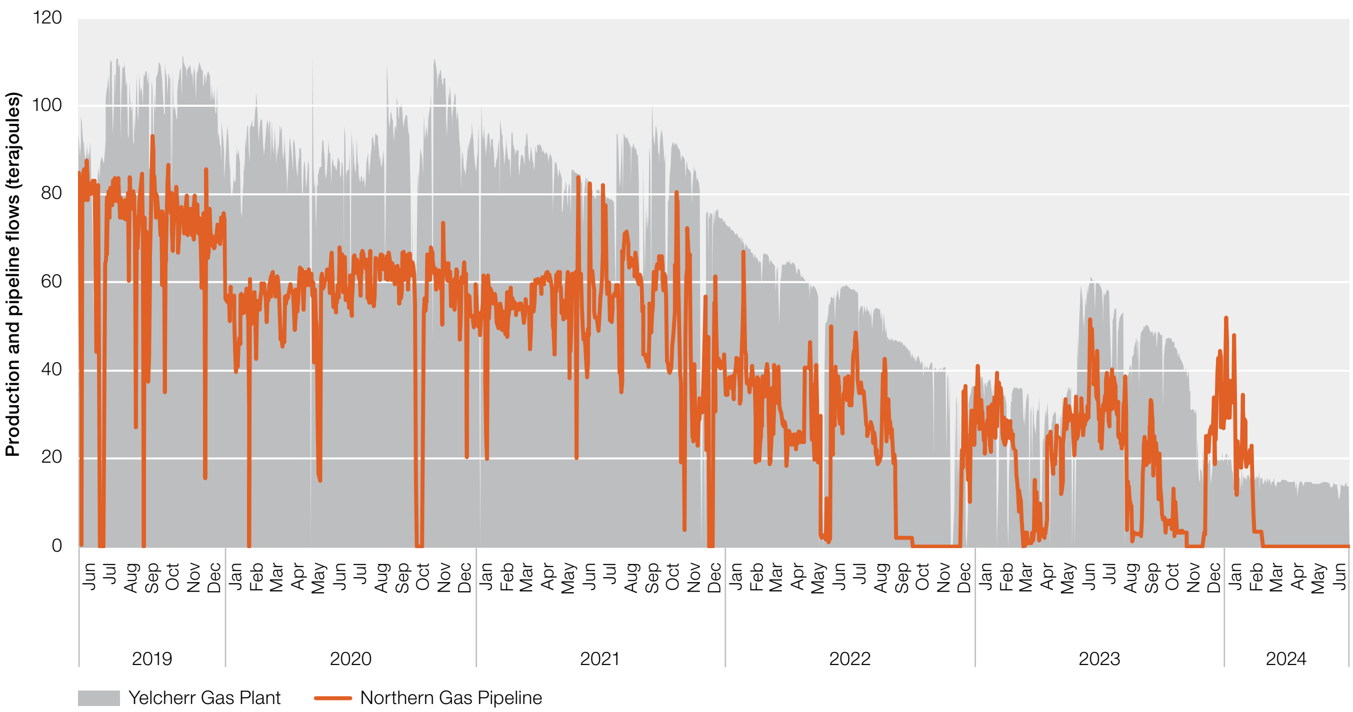
4.8.5 Northern Territory gas

From 2019, Jemena's Northern Gas Pipeline connected the east coast gas pipeline transmission system to supply in the Northern Territory. However, production issues at the offshore Blacktip gas field have led to the closure of the Northern Gas Pipeline.

Since the pipeline commenced operation, it has delivered more than 80 PJ of gas to the east coast. Initial supply across 2020 and 2021 saw pipeline deliveries average around 55 TJ per day before a decline from 2022. With the prospect of other potential gas sources being brought online in the Northern Territory, Jemena had planned to connect Beetaloo Basin supply to the Queensland's Wallumbilla gas supply hub and increase capacity on the pipeline from its nameplate 90 TJ per day up to 200 TJ per day by 2025.

Reduced flows on the pipeline from 2022 have mirrored production declines at the Yelcherr gas plant, the largest supply source in the Northern Territory sourcing gas from the offshore Blacktip gas field (Figure 4.26). Reduced supply from Blacktip led to average flows decreasing to just over 30 TJ per day over the first half of 2022 before production issues resulted in flows ceasing from October to mid-December 2022.[358] Subsequent flows averaged below 20 TJ per day, fluctuating up to a high of just over 50 TJ before the pipeline's closure from late February 2024. As a result, this has contributed to reduced supply and increased demand in the east coast markets, with supply on the Carpentaria Pipeline now requiring gas to be sourced from east coast production sources.

Figure 4.26 Northern Gas Pipeline flows and Yelcherr production decline



Source: AER analysis of Gas Bulletin Board data.

358 The low pressure in the pipeline forced Jemena to temporarily shut down the pipeline due to safety concerns, requiring Mount Isa to be supplied from east coast production sources.

Further to this, current supply conditions in the Northern Territory have been impacted by the Blacktip decline, with blackouts experienced across the region.[359] With gas generation being the primary source of electricity in the region, the government-owned Power and Water Corporation has sought to obtain gas supply from other sources to continue providing power, including offtake agreements with the Northern Territory LNG producers. Jemena also commenced works to make the Northern Gas Pipeline bidirectional to allow supply to be sourced from Queensland, which is expected to be completed by the end of 2024.[360] New reporting connection points were registered on the Gas Bulletin Board from 17 August 2024 in line with the scheduled commissioning of pipeline upgrades.[361]

These factors contribute to a heightened risk of supply shortfalls in the event of production outages and high gas-powered generation requirements, particularly if they coincide with peak winter demand in the southern markets that are increasingly reliant on Queensland gas supply.

4.8.6 Demand response

Volatile markets and the expiry of legacy gas supply agreements are prompting commercial and industrial (C&I) customers to take a more active role in gas procurement. Some customers have become direct market participants by engaging in collective bargaining agreements.

Some C&I users are exploring or implementing options such as purchasing gas directly from producers rather than retailers, using brokers to secure supply agreements, participating in gas markets and investing in new LNG import facilities.[362] Some users have lowered their gas use by changing fuels or increasing efficiencies. Others have also deferred large investments.

In addition, some C&I users are considering alternatives to gas, such as renewable energy, as longer-term options.[363] The suitability of options such as electrification or switching to green hydrogen, biomethane or other biofuels is set out in more detail in the *Future of Gas Strategy Analytical Report*.[364]

In the more immediate term, demand response has a key role in managing peak day shortfalls. Although a formal demand response mechanism is not yet in place in wholesale gas markets, the Energy and Climate Change Ministerial Council has requested the Australian Energy Market Commission (AEMC) introduce an administered demand response mechanism as part of a broader supplier of last resort mechanism (section 4.10.3). A study by ACIL Allen of suitability of C&I users to supply demand response indicates that up to 22 TJ per day could potentially be used to absorb shortfalls with 6 hours or less notice.[365]

Governments have also started enacting policy to reduce residential gas demand. The ACT initially removed mandatory gas connection requirements for new homes, before legislating a stop to new gas connections from 2023.[366]

Victoria's Gas Substitution Roadmap and Energy Upgrades program identified electrification as the best solution to achieve a short-term reduction to gas consumption levels for residential consumers.[367] The roadmap offers options and support for Victorian residential and small commercial consumers who are interested in switching from gas to solar or electricity.

Since 1 January 2024, all new homes in Victoria requiring a planning permit are required to be all-electric, with new homes and residential subdivisions no longer able to connect to the gas network.

359 ABC news, Gas supply interruption triggers widespread power outage from Darwin to Katherine, 6 February 2024.
360 ACCC, Gas inquiry 2017–2025, interim report, June 2024, Australian Competition and Consumer Commission, July 2024, p. 24.
361 The commissioning and testing phase is expected to be completed at the end of October 2024.
362 ACCC, Gas inquiry 2017–2025, interim report, January 2021, Australian Competition and Consumer Commission, February 2021, pp. 73–74.
363 ACCC, Gas inquiry 2017–2025, interim report, January 2020, Australian Competition and Consumer Commission, February 2020, p. 74.
364 DISR, Future Gas Strategy Analytical Report, Department of Industry, Science and Resources, 9 May 2024, accessed 19 August 2024.
365 AEMC, ECGS Supplier of Last Resort Mechanism, Australian Energy Market Commission, July 2024, p. 82. 22 TJ per day is calculated as 28% of 82 TJ per day, based on data obtained as part of the demand response study summarised in Appendix D.
366 ACT Government, ACT reaches milestone preventing new fossil fuel gas connections, media release, 8 June 2023.
367 AEMO, Gas Statement of Opportunities, Australian Energy Market Operator, March 2022, p. 23.

4.9 Compliance and enforcement activities

The AER's compliance and enforcement work ensures that important protections are delivered and rights are respected. It gives consumers and energy market participants confidence that energy markets are working effectively and in their long-term interests, so they can participate in market opportunities as fully as possible and are protected when they cannot do so.

Compliance work helps to proactively encourage market participants to meet their responsibilities and enforcement action is an important tool when breaches occur.

Each year, the AER identifies and publishes a set of compliance and enforcement priorities, some of which relate to participants in east coast gas markets.

For 2023–24, the AER's compliance and enforcement priority related to gas markets was to clarify obligations and monitor compliance with reporting requirements under the new Gas Market Transparency Measures.

4.9.1 Compliance with Gas Market Transparency Measures

New gas market transparency reforms were legislated in late 2022, following the passage into law of the National Gas Amendment (Market Transparency) Rule 2022. These reforms promote transparency in east coast gas markets through enhanced and expanded reporting of traded gas volumes and prices and the provision of information on overall gas supply adequacy to the Gas Bulletin Board and to AEMO's Gas Statement of Opportunities.

New participant reporting to the Gas Bulletin Board commenced on 15 March 2023. The AER has focused on the following activities:

- worked with AEMO and participants to clarify how short-term gas transactions should be reported, with guidance provided in AEMO's Gas Transparency Measures FAQ fact sheet,[368] and captured feedback from participants in our *Special report: Wholesale gas short term transactions reporting*, published on 6 December 2023[369]
- worked with field owners and AEMO to clarify how reserves and resource data should be reported to meet AER's compliance expectations, and updated our *Guidance Note: Reserves and Resources Reporting by Gas Field Owners* in August 2023[370]
- in April 2024, we published our analysis of the contracted and uncontracted reserve price assumptions submitted by gas field owners to the AER in our first *Wholesale gas reserves price assumption report*[371]
- started monitoring new obligations for participants to report under Part 27 and Part 18 of the Gas Rules, extending demand forecast reporting to retailers and large users. The reporting requirements came into effect ahead of winter 2023 and the AER has been monitoring compliance with registration and reporting obligations since that time.[372]

368 AEMO, Bulletin Board FAQs, Australian Energy Market Operator, accessed 8 September 2024.
369 AER, Wholesale gas short term transactions reporting, Australian Energy Regulator, 6 December 2023.
370 AER, Guidance Note – Reserves and Resources Reporting by Gas Field Owners, Australian Energy Regulator, 29 June 2023.
371 AER, Wholesale gas reserves price assumption report, Australian Energy Regulator, 15 April 2024.
372 *National Gas (South Australia) (East Coast Gas System) Amendment Act 2023* enhanced AEMO's ability to manage system supply adequacy, providing it with added functions and powers to monitor and manage any threat of east coast gas markets supply shortfalls.

4.9.2 Other compliance and enforcement activities

The AER also carried out the following activities, some of which relate to the AER's 2022–23 Compliance & Enforcement Priority 5 – Ensure timely and accurate gas auction reporting and demand forecasting in downstream wholesale gas markets by registered participants:

- issued a waiver to Evoenergy to continue to own and operate 2 natural gas distribution pipelines in NSW and the ACT[373]
- instituted proceedings against Santos for alleged breaches of important record keeping obligations in the National Gas Rules relating to the Day Ahead Auction for gas pipeline capacity, and secured Federal Court ordered penalties totalling $2.75 million[374]
- instituted proceedings against 4 Jemena subsidiaries for alleged large-scale failures to submit accurate auction quantity limits to AEMO for 4 pipelines and failure to ensure auction services were correctly scheduled for 3 pipelines[375]
- received payment from Jemena Northern Gas Pipelines totalling $135,600 for 2 infringement notices and accepted a court enforceable undertaking for alleged breaches related to Gas Bulletin Board accepted a court enforceable undertaking from Evoenergy to address concerns that Evoenergy breached its ring-fencing obligations[376]
- consulted on and published a new Annual Compliance Order, which came into effect on 1 July 2024 for the 2024–25 financial year – this order monitors the behaviour of gas pipeline service providers and supports the AER's monitoring obligations under s63A of the National Gas Law. To cover the intervening period, the AER issued an interim information request for the 2022–23 financial year and plans to issue a second interim information request in September 2024[377]
- began consultation on the AER Compliance Procedures and Guidelines (Gas) for gas pipeline service providers to assist market participants to better understand their compliance obligations, and our approach to new audit powers under the new framework.[378]

More detail on the AER's compliance and enforcement work is outlined in the Annual compliance and enforcement report 2023–24.

4.10 Government intervention in gas markets

In response to concerns around the adequacy of gas supplies to meet domestic demand and prolonged price volatility seen in 2022, the Australian Government and some state and territory governments have intervened in the market. This has included measures to Increase supply stability, reduce demand and limit price volatility, and provide additional monitoring powers to market bodies.

In 2017, the Australian Government directed the ACCC to use its compulsory information gathering powers to inquire into wholesale gas markets in eastern Australia. The inquiry was initially tasked to run until 30 April 2020, with successive governments extending the inquiry to 2025 (in July 2019) and then out to 2030 (in October 2022).[379]

373 AER, Evoenergy ring-fencing waiver November 2023, Australian Energy Regulator, accessed 8 September 2024.

374 AER, Santos Direct: breaches of the National Gas Rules, Australian Energy Regulator, accessed 8 September 2024.

375 AER, Jemena: alleged breaches of the National Gas Rules, Australian Energy Regulator, accessed 8 September 2024.

376 AER, AER accepts court enforceable undertaking from Evoenergy for ring-fencing breaches, Australian Energy Regulator, accessed 8 September 2024.

377 AER, Annual Compliance Order for gas pipeline service providers 2024, Australian Energy Regulator, 7 June 2024.

378 AER, AER begins consultation on the AER Compliance Procedures and Guidelines for gas pipeline service providers August 2024, accessed 8 September 2024.

379 ACCC, Gas inquiry 2017–2030, Australian Competition and Consumer Commission, accessed 24 May 2023.

Enhanced wholesale market monitoring

The National Energy Laws Amendment (Wholesale Market Monitoring) Bill 2023 (Amendment Bill) was proclaimed on 8 May 2024, enhancing the AER's wholesale market monitoring and reporting functions to include wholesale gas markets and electricity and gas contract markets. Access to contracts and related information will provide the AER with visibility of the underlying drivers influencing participant behaviour in gas and electricity markets, allowing for the examination of effective competition and whether wholesale markets are operating efficiently. Improved understanding and insights will allow for the enhancement of our existing suite of reports to provide timely and transparent information to relevant stakeholders throughout the energy transition.

The Amendment Bill requires the AER to develop a guideline outlining the scope of our wholesale market monitoring functions and related information collection and reporting activities. We remain committed to undertaking meaningful stakeholder engagement to develop a guideline that maximises the benefit of our reporting functions while minimising increased burden on participants reporting information to the AER. Following the publication of an Issues Paper on 21 March 2024,[380] a Draft Guideline was published for consultation on 2 July 2024.[381]

4.10.1 Australian Domestic Gas Security Mechanism

The Australian Domestic Gas Security Mechanism (ADGSM) empowers the Australian Government Minister for Resources to require LNG projects to limit exports, or find offsetting sources of new gas, if a supply shortfall is likely.[382] Since 2017, the Minister has been able to determine if a shortfall is likely in the following year and may revoke export licences if necessary to preserve domestic supply.

Following the introduction of this mechanism, Queensland's LNG producers entered agreements with the government, committing to offer uncontracted gas on reasonable terms to meet expected supply shortfalls.[383] They also committed to offer gas to the Australian market on competitive market terms before offering any uncontracted gas to the international market.[384] In 2023, following a review by the Australian Government Department of Industry, Science, Energy and Resources, the scheme was extended until 2030. The changes made to the ADGSM introduced more flexibility to activate the mechanism to secure domestic supply on a quarterly basis, rather than the yearly timeframe in the previous regulations.[385]

The new reforms came into place on 30 March 2023 with a newly negotiated Heads of Agreement with East Coast LNG Exporters in place until 1 January 2026. To prevent a gas supply shortfall, an additional 157 petajoules of gas was committed to the east coast market in 2023. The Australian Government decided not to activate the Australian Domestic Gas Security Mechanism (ADGSM) for the October to December 2024 quarter.

380 An issues paper was released for consultation through to 30 April 2024.
381 AER, Enhanced wholesale market monitoring guideline (2024), 2 July 2024, Australian Energy Regulator, accessed 12 September 2024.
382 Department of Industry, Science Energy and Resources, *Australian Domestic Gas Security Mechanism*, July 2018.
383 Department of Industry, Science, Energy and Resources, *Securing Australian domestic gas supply, DISER website*, accessed 28 May 2021.
384 The agreement specifically notes that LNG netback prices, as referenced by the ACCC, play a role in influencing domestic gas prices.
385 The Hon Madeline King MP, Reforms ensure domestic gas supply, protect long-term contracts, Minister for Resources and Minister for Northern Australia, media release, 30 March 2023.

4.10.2 Gas Supply Guarantee

The gas industry developed the Gas Supply Guarantee (GSG) as a mechanism to meet commitments to the Australian Government to ensure enough gas is available to meet peak demand periods in the NEM. The mechanism was originally scheduled to finish in March 2020, but the Australian Government extended the guarantee to March 2023, with a review recommending a further extension to March 2026.[386] The Gas Supply Guarantee has since been replaced by AEMO's new reliability and supply adequacy functions and powers under the National Gas Law and National Gas Rules, which came into effect in May 2023.[387]

AEMO triggered the GSG for the first time on 1 June 2022.[388] Following activation of the mechanism, gas producers in Queensland diverted gas into the domestic market and AEMO subsequently deactivated the mechanism the next day. AEMO reactivated the mechanism from 19 July 2022 following notification of a threat to system security (TTSS) in Victoria due to insufficient storage, after directing 2 generators to cease taking gas from the Victorian market until 30 September 2022 (the GSG and TTSS remained in effect until sufficient supply was available).[389]

In June 2024, AEMO issued a threat to system notice (section 4.5) but as at 1 September 2024 has not yet needed to intervene in the downstream markets.

4.10.3 Additional powers for AEMO to support reliability and supply adequacy

On 12 August 2022 Energy Ministers agreed to take a range of actions to support a more secure, resilient and flexible east coast gas market. These actions sought to build on actions taken ahead of winter 2023 to address east coast gas supply adequacy concerns that were raised in ACCC and AEMO reporting.

The actions included regulatory amendments providing additional powers to AEMO to manage gas supply adequacy and reliability risks to the east coast gas market:[390]

- data transparency to assess supply-demand trends and determine the likelihood of a threat to reliability or adequacy of gas supply
- identification, communication and publication of information about actual or potential threats to signal an east coast gas system response
- powers to issue directions to gas industry participants to resolve potential or actual threats to system security (including a compensation framework)
- the ability for AEMO to trade in natural gas to maintain or improve reliability or adequacy of gas supply.

A Bill giving effect to these changes commenced on 27 April 2023, alongside supporting regulations. The corresponding Rule amendments came into effect on 4 May 2023.[391]

In June 2024, the AEMC published the 'Better integrating gas into the ISP (gas)' rule change proposal. Alongside other proposals to enhance the ISP through improved consideration of demand-side factors and better integration of community sentiment, this rule change would require AEMO to publish gas market projections and undertake an expanded consideration of gas generation, supply and infrastructure, including costs, when preparing the ISP. It also requests changes to the NGR to ensure AEMO has the power to access, use and disclose information gathered for NGR purposes to support the gas analysis in the ISP.[392]

386 AEMO, Gas supply guarantee guidelines consultation final determination, Australian Energy Market Operator.
AEMC, Review of the Gas Supply Guarantee, Australian Energy Market Commission, 4 November 2021.

387 ACCC, Gas inquiry 2017–2030, Australian Competition and Consumer Commission, December 2023, p. 105.

388 AEMO, Gas supply guarantee, Australian Energy Market Operator, accessed 28 May 2021.

389 AEMO, AEMO takes further steps to manage tight gas supplies, Australian Energy Market Operator, 19 July 2022.

390 AEMO, East Coast Gas Reforms, Australian Energy Market Operator.

391 National Gas (South Australia) (East Coast Gas System) Amendment Act 2023; National Gas (South Australia) (East Coast Gas System) Amendment Regulations 2023; National Gas Amendment (East Coast Gas System) Rule 2023.

392 AEMC, Better integrating gas into the ISP (Gas), Australian Energy Market Commission, accessed 18 September 2024.

In July 2024, a further set of rule change proposals were provided to the AEMC (from DCCEEW) outlining longer-term solutions to manage threats to the east coast gas market:

- The 'ECGS Reliability standard and associated settings' rule change request proposes the introduction of a reliability standard for gas markets. This standard would be used to assess the sufficiency of the supply of covered gas and the capacity of relevant infrastructure. The level of the standard would reflect the value gas customers place on reliability (gas VCR) and would inform:
  - reliability settings such as price caps and floors in the facilitated markets
  - forecasts of any reliability shortfalls or credible risks to system resilience, as well as the communication of and actions to take for any risks or threats to reliability or adequacy of supply in the east coast gas system.

The VGCR would be set by the AER, similar to the AER's role in setting the VCR for electricity.[393]

- The 'ECGS Supplier of last resort mechanism' rule change request would give AEMO power to establish a storage reserve and/or reserve of any other gas service such as demand response or gas supply, and to use that reserve in the absence of a response from market participants, as a last resort. This mechanism would need to meet certain pre-conditions before being triggered. It would also require AEMO to maintain separate financial accounts for the mechanism and publish biannual reports on its Supplier of Last Resort activities. Consistent with the current rules, AEMO would also be required to publish post intervention reports and report to Energy Ministers on its east coast functions.[394]
- The 'Notice of closure for gas infrastructure' rule change request would extend the medium-term capacity reporting requirements in Part 18 of the NGR to require the reporting of planned closure of supply and delivery infrastructure at least 36 months before closure. It would apply to operators of production, pipeline, compression and storage facility infrastructure that meet the Bulletin Board reporting threshold.[395]

4.10.4 Competition and Consumer (Gas Market Emergency Price) Order

On 23 December 2022, the Competition and Consumer (Gas Market Emergency Price) Order 2022 came into effect for 12 months.[396]

The Order introduced a price cap on gas of $12 per GJ (not applicable in Western Australia) during the price cap period set as 12 months, effectively impacting 2023 gas supply. Generally, the price cap applied to gas producers and affiliates of gas producers (regulated producers).

Several exemptions to the cap included LNG exports, downstream market trade in the Short Term Trading Market (STTM) and Declared Wholesale Gas Market (DWGM), and retailers that met certain criteria. The cap also exempted near-term trades on the upstream Gas Supply Hub (GSH) exchange that occurred within a 3-day window of the delivery date, and provided the Minister powers to grant additional exemptions outside of the standard exceptions that were delegated to the ACCC.[397]

393 AEMC, ECGS Reliability standard and associated settings, Australian Energy Market Commission, 8 July 2024, accessed 8 September 2024.
394 AEMC, ECGS Supplier of last resort mechanism, Australian Energy Market Commission, 8 July 2024, accessed 8 September 2024.
395 AEMC, Notice of closure for gas infrastructure, Australian Energy Market Commission, 29 April 2024, accessed 8 September 2024.
396 Australian Government, Competition and Consumer (Gas Market Emergency Price) Order 2022, December 2022.
397 A list of exempted entities is available on the ACCC's website (Gas price exemptions register). The delegation commenced on 23 December 2022.

From 11 July 2023, as part of the Energy Price Relief Plan announced in December 2022, the Australian Government implemented a Mandatory Gas Code of Conduct.[398] The Code aims to ensure that east coast gas users can contract for gas at reasonable prices and on reasonable terms. It also includes a 2-month transitional period to allow companies to adapt to the conduct provisions, record keeping and process standards for commercial negotiations. The key elements of this code include:

- the price cap, initially set at $12 per GJ, with the first mandated review of the Code by 1 July 2025
- an exemptions framework to incentivise short-term supply commitments and incentivise investment to meet ongoing medium-term demand
- transparency obligations to increase visibility of uncontracted gas production and its expected availability to the domestic market
- conduct provisions aimed at reducing bargaining power imbalances between producers and gas buyers and establishing minimum conduct and process standards for commercial negotiations.

4.10.5 National hydrogen strategy

The Australian Government identified hydrogen as a potential alternative fuel to natural gas to facilitate emission reductions across energy and industrial sectors. This strategy has several elements:

- The government is looking at introducing hydrogen to the gas distribution network as part of the mix with natural gas, as well as other uses for hydrogen to replace natural gas when used as feedstock or in high-heat production processes such as smelting. Currently, hydrogen can be added to some existing gas pipelines at concentrations of up to 10% to supplement gas supplies and several trials are exploring the feasibility of this. Legislative changes have also been made to recognise the presence of hydrogen and other biofuels within the existing regulatory framework.[399]
- In July 2020 the Australian Renewable Energy Agency (ARENA) shortlisted 7 projects to be considered as part of its $70 million fund to develop large-scale electrolysers, 3 of which are based in eastern Australia.[400] In April 2023 ARENA launched a $25 million funding round to support research and development of large-scale renewable hydrogen.
- In December 2023 the Australian Government announced 6 shortlisted applicants for its Hydrogen Headstart Program, operated by ARENA. The program will provide up to $2 billion in revenue support for large-scale renewable hydrogen projects through production credits. The credit is intended to cover the current commercial gap between the cost of producing renewable hydrogen and its market price, enabling producers to offer hydrogen to users at a price that will encourage its use.
- In February 2024 the Australian Government announced the fifth location for regional hydrogen hubs in the Pilbara in Western Australia. Hydrogen hubs are locations where producers, users and exporters of hydrogen can work side by side to share infrastructure and expertise. Hydrogen hubs have been announced for the following sites:
  - the Pilbara and Kwinana in Western Australia
  - the Hunter in NSW
  - Bell Bay in Tasmania
  - Gladstone and Townsville in Queensland
  - Port Bonython in South Australia.

AEMO's ISP models a green energy export scenario to examine potential requirements of expanding the existing transmission system and present different options to replace retiring coal-fired generation assets.

Most recently, the Future of Gas Strategy has noted low-emission gases – such as biomethane, hydrogen, ammonia and e-methane – have the potential to substantially decarbonise gas supply chains.

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398 DCCEEW, Mandatory Gas Code of Conduct, Department of Climate Change, Energy, the Environment and Water, 11 July 2023.
399 Energy and Climate Change Ministerial Council, Extending the national gas regulatory framework to hydrogen and renewable gases, 14 July 2023.
400 ARENA, *Seven shortlisted for $70 million hydrogen funding round*, Australian Renewable Energy Agency, accessed 28 May 2021.

4.10.6 State-government schemes

State governments are responsible for different elements of gas infrastructure and exploration in Australia – for example, approving new gas exploration licences in their respective jurisdictions.

To encourage stability in the domestic supply of gas, the Queensland Government grants exploration authorities for 'domestic only' exploration tenements. As part of this grants program, it released almost 70,000 km^2 of land for exploration between 2015 and 2019, of which around 25% was reserved for domestic supply. The Queensland Government released a further 3,000 km^2 of land in September 2020, with over 15% tagged for domestic supply.[401] In 2021, the Queensland Government announced it would make 14,100 km^2 available for oil and gas exploration.[402] In June and July 2022, the Queensland Exploration Program released prospect tenders for petroleum and gas exploration (8 areas, 14,420 km^2) and greenhouse gas storage (14,500 km^2).[403]

In January 2020, through a memorandum of understanding with the Australian Government, the NSW Government committed to bringing new gas supplies to the domestic market. It set a target of injecting an additional 70 PJ of gas per year into the NSW market.[404]

In April 2021 the Australian and South Australian governments announced an agreement to invest in energy infrastructure and reduce emissions in South Australia. As part of this, the state set a target of an unlocking an additional 50 PJ per year by 2023.[405]

In April 2022 the Australian and Northern Territory governments signed an energy and emissions reduction agreement to deliver affordable and reliable power and unlock gas supplies to help prevent shortfalls in the market.

401 Queensland Government, 'Queensland gas exploration ramping up' [media release], September 2020.

402 Queensland Government, 2021 Queensland Exploration program, November 2021, accessed 28 June 2022.

403 Queensland Government, *Queensland Exploration Program, Business Queensland,* accessed 25 May 2023.

404 NSW Government, *Memorandum of understanding – NSW energy package*, 31 January 2020.

405 Australian Government, 'Energy and emissions reduction agreement with South Australia' [media release], April 2021.

4.11 Gas market monitoring reforms

The Energy and Climate Change Ministerial Council (ECMC), established in late 2022 to direct gas market reform for implementation by market bodies, agreed to an expedited package of carefully designed measures expanding the Australian Energy Regulator's (AER) gas and electricity market monitoring powers.[406] This follows the introduction of new laws providing the AER with greater powers to monitor wholesale gas and electricity markets, which was passed into legislation on 23 June 2022.[407]

The reforms stem from findings by bodies that include the AEMC, the ACCC and the Gas Market Reform Group on shortcomings in the current regulatory framework. The reforms aim to increase transparency in the gas market, improve the Gas Bulletin Board and improve the availability of information on market liquidity, prices and gas reserves.

4.11.1 Gas Bulletin Board reforms

The Gas Bulletin Board is a publicly accessible source of information. It began publishing data on 1 July 2008 and aims to make the gas market more transparent by providing up-to-date information on gas production, pipelines and storage options in eastern Australia.

Market participants can access detailed information from production and compression facilities on their daily nominations, forecast nominations, intra-day changes to nominations and capacity outlooks. This adds transparency to production outages, which informs market responses and helps maintain security of supply.

In the pipeline sector, operators must submit daily disaggregated receipt and delivery point data. The data includes information on flows at key supply and demand locations along pipelines.

The AER assesses the quality and accuracy of the data submitted by market participants against an 'information standard' to ensure the information presented on the Bulletin Board has integrity.

In June 2022 states adopted the National Gas Amendment (Market Transparency) Rule 2022, which extended reporting to large gas users and LNG processing facilities. These laws give the AER new powers to monitor information related to price and volume in the shorter-term bilateral gas contract market, including how gas is exported overseas and how it is traded in Australia. In particular, the AER now monitors subsets of information on the export, reserve, storage and domestic sale and swaps of gas to report more comprehensively on competition.

Price and reserves transparency

Transparency of price and other market information is critical for effective market functioning. The ACCC publishes data on LNG netback prices to help gas users negotiate more effectively with gas producers and retailers when entering new gas supply contracts.[408]

Reporting of new information commenced on 15 March 2023, requiring participants to provide information to AEMO through the Gas Bulletin Board. New information published on the Bulletin Board includes Reserves Resources Reporting and Facility Developments, LNG Transactions and Short Term Transactions.[409]

406 Department of Climate Change, Energy, the Environment and Water, Gas and electricity market monitoring powers, accessed 18 September 2024.
407 AER, AER welcomes new powers to keep watch on wholesale gas markets, news release, Australian Energy Regulator, 1 July 2022.
408 ACCC, Gas inquiry 2017–2030 – LNG netback price series, Australian Competition and Consumer Commission.
409 AEMO, Reserves Resources Reporting and Facility Developments and LNG and Short Term Transactions, Australian Energy Market Operator.

These reforms were designed to enhance transparency in the eastern and northern Australian gas markets, to address information gaps and asymmetries relating to:

- gas and infrastructure prices
- supply and availability of gas
- gas demand
- infrastructure used to supply gas to end markets.

More information on the introduction of regulatory amendments can be found on the energy.gov.au website.[410]

4.11.2 Pipeline reforms

Recent reforms to the National Gas Law (NGL) and National Gas Rules (NGR) have significantly changed the way gas pipelines are regulated. In March 2022, Energy Ministers agreed to a package of gas pipeline regulatory amendments to deliver a simpler regulatory framework. The reforms aim to limit the exercise of market power, facilitate better access to pipeline capacity and provide greater support for commercial negotiations between shippers and service providers through increased transparency of information and improvements to the negotiation framework and dispute resolution mechanisms.

Key changes have been made to the following elements:

- the greenfields incentive regime[411]
- regulatory powers to determine the form of regulation to which a pipeline should be subject
- service provider information disclosure requirements[412]
- numerous other clarifications and refinements.

Under the new regime, all transmission and distribution pipeline service providers are required to provide third party access where it is sought, subject to available exemptions.[413]

Pipelines (unless they hold a Category 1 exemption) are now required to publish actual prices payable instead of weighted average prices that they previously reported. There are also requirements on standalone compression and storage facility service providers to publish standing terms of services offered and information on individual prices paid by shippers.

The reforms also require the AER to regularly and systematically monitor service providers' behaviour and report on this to the Energy and Climate Change Ministerial Council (ECMC) every 2 years. The information that the AER must monitor and report on includes the actual prices charged, non-price terms and conditions for pipeline services, financial information reported by service providers, outcomes of access negotiations, service providers' compliance with ring-fencing requirements, dealings with associates and their compliance with other requirements of the NGL and NGR. An aggregated version of the ECMC report will also be published by the AER on its website as soon as practicable.[414]

More information on the new pipeline regulatory framework is available in chapter 5.

410 Department of Industry, Science, Energy and Resources, Regulatory amendments to increase transparency in the gas market, 19 November 2020.

411 Greenfields (new) pipeline projects are eligible for a greenfields incentive determination (which protects the pipeline from becoming a scheme pipeline for up to 15 years from commissioning) and a greenfields price protection determination (which specifies prices for pipeline services that are binding on an arbitrator in the event of an access dispute).

412 For pipeline service providers – Part 10 of the NGR and for standalone compression and storage facilities – Part 18A of the NGR.

413 Exemptions to reporting obligations are available to facilities with no third-party users, where facilities would be exempt from all reporting obligations. Single user pipelines, or those with a capacity of less than 10 TJ per day, can seek an exemption from the obligation to publish historical and service usage information.

414 Pursuant to section 63B(4) of the NGL.

4.11.3 Future of gas strategy and transition to net zero.

With Australia's commitment to net zero by 2050, governments have been consulting on how to shift from natural gas to renewable energy sources throughout the economy. The Australian Government released its Future Gas Strategy in May 2024, which explains the principles the Australian Government will use to guide policymaking about gas to support the transition to net zero. The guiding principles note the importance of gas remaining affordable for Australian users throughout the transition to net zero, and that gas and electricity markets must adapt to remain fit for purpose throughout the energy transformation. The strategy reiterates Australia's commitment to supporting global emissions reductions to reduce the impacts of climate change and reaching net zero emissions by 2050.[415]

In recognition of the uncertainty surrounding demand for gas, including gas-powered generation between now and 2050, governments have taken actions to better integrate gas assumptions into the Integrated System Plan. The AEMC released its consultation paper *Better integrating gas into the ISP (gas)*[416] on 20 June 2024, with an expected completion date of 19 December 2024.

The rule change proposal sets out several areas of specific gas analysis that are significantly influential over the development of the electricity system, including costs associated with gas infrastructure investments and the likelihood or commercial feasibility of GPG in the ISP, and availability of gas to service GPG in the quantity or price anticipated.

It would also require AEMO to develop projections about the future utilisation of gas infrastructure and collated pipeline closures or conversion dates. The intention is that the additional analysis will:

- allow AEMO to better consider whether alternatives to gas investments (such as storage) might be more economically beneficial for improving the optimal development path identified in the ISP
- provide more visibility to stakeholders about these options and their electricity sector alternatives, which may underpin more efficient market conduct
- better facilitate the transition to net zero in the electricity sector and better inform stakeholders on the future state of gas infrastructure throughout the transition.

415 DISR, Future Gas Strategy, May 2024 Australian Government Department of Industry, Science and Resources.
416 AEMC, Better integrating gas into the ISP (Gas), Australian Energy Market Commission, accessed 18 September 2024.

5 Regulated gas pipelines

Australia's gas pipeline infrastructure consists of transmission and distribution pipelines. The role of the transmission pipelines is to transport gas from upstream producing basins to major population centres, power stations, and large industrial and commercial plants. Smaller urban and regional distribution pipelines transport gas to customers in local communities.

This chapter covers the scheme pipelines regulated by the AER, which is the regulator in all states and territories except Tasmania and Western Australia.[417]

5.1 Snapshot

Across all transmission and distribution pipeline service providers for which the AER determines access prices, over the 12-month period to 30 June 2023:

- $1.6 billion in revenue was collected for providing access (selling capacity) to parties needing to transport gas, 9% less than in the previous year (section 5.7).[418]
- $797 million was invested in capital projects, 3.1% more than in the previous year and the most since 2016. Investments were primarily driven by new connections and mains replacements of old and substantially depreciated cast iron pipelines with pipelines made from polyethene or polyamide materials (section 5.10).
- $619 million was spent on operating costs, 5% more than in the previous year and the most since 2017 (section 5.11).

The AER did not review any access arrangement applications for transmission or distribution pipelines in the 12-month period to 30 June 2024.

417 The Economic Regulation Authority (ERA) administers separate regulatory arrangements in Western Australia. The Office of the Tasmanian Economic Regulator (OTTER) administers separate regulatory arrangements in Tasmania.

418 Excludes revenue earned by Amadeus Gas Pipeline (Northern Territory). Amadeus Gas Pipeline's actual revenue is confidential because it contains commercially sensitive information.

5.2 Gas pipeline characteristics

Pipeline service providers earn revenue by providing access (selling capacity) to parties needing to transport gas. These parties include:

- energy retailers seeking to buy natural gas in large volumes and onsell it to consumers
- commercial and industrial users
- liquefied natural gas (LNG) exporters, which buy gas directly from producers and contract with a pipeline service provider to transport it to export terminals.

The most common service provided by transmission pipelines is haulage – that is, transporting (or 'shipping') gas from an injection point on the pipeline to an offtake point further along. Haulage may be offered on a firm (guaranteed) or interruptible (only if spare capacity is available) basis. Some customers seek backhaul too, which is reverse direction transport. Gas can also be stored (parked) in a pipeline or stored in a connected storage facility, on a firm or interruptible basis.

As the gas market evolves, more innovative services are being offered, including compression (adjusting pressure for delivery), loans (loaning gas to a third party), redirection and in-pipe trades.

Transmission pipelines typically have wide diameters and operate under high pressure to optimise shipping capacity. An interconnected transmission grid links gas basins and retail markets in all states and territories other than Western Australia (Figure 5.1).

Distribution pipelines are installed underground and consist of high, medium and low-pressure mains. The high and medium-pressure pipes provide a 'backbone' that services high demand zones, while the low-pressure pipes lead off high-pressure mains to commercial and industrial customers and residential homes.

Distribution pipeline service providers transport gas to energy customers, but they do not sell gas. Energy retailers purchase gas from producers and purchase pipeline services (which includes transportation) from pipeline service providers. This combination of gas and pipeline services is sold as a packaged retail product to customers. Many retailers offer both gas and electricity products.

The services provided by transmission pipelines continue to evolve to meet changing market needs, but distribution pipelines tend to offer fairly standard services – namely, allowing gas injections into a pipeline, conveying gas to supply points and allowing gas to be withdrawn.

The combined value of the capital bases for scheme pipelines for which the AER sets access prices is around $13.3 billion.

Gas is distributed to most Australian capital cities, major regional areas and towns. Queensland and Victoria each have multiple pipeline service providers, while New South Wales (NSW), South Australia, Tasmania and the Australian Capital Territory (ACT) are each served by a single regulated service provider.[419] Gas is also distributed to export terminals in Queensland, where it is converted to LNG before being transported overseas via cargo ship.

In 2023, residential customers accounted for more than 97% of the total distribution customer base but only consumed around 42% of the total gas delivered within Australia. The other 3% of customers were either industrial or commercial customers and consumed the balance (58%) of the total gas delivered.

419 Some pipelines cross state or territory boundaries. For example, Australian Gas Network's Victorian pipeline and Evoenergy's ACT pipeline both extend into NSW. Some jurisdictions also have smaller unregulated regional pipelines, such as the Wagga Wagga pipeline in NSW.

The combined value of the capital bases for scheme pipelines for which the AER sets access prices is around $13.3 billion.[420] This comprises 3 transmission pipelines valued at $2.1 billion and 6 distribution pipelines valued at $11.2 billion. In total, the networks consist of around 80,000 kilometers of pipe and supply natural gas to more than 4.3 million residential customers and over 110,000 commercial and industrial customers (Figure 5.2 and Figure 5.3).

Box 5.1 Changing forms of regulation

Recent reforms to improve and simplify the gas pipeline regulatory framework have resulted in several significant changes to the National Gas Law and National Gas Rules (section 5.4).

Prior to the reforms, the National Gas Law provided for the following forms of regulation:

- full regulation for scheme pipelines
- light regulation for scheme pipelines
- Part 23 (National Gas Rules) regulation for non-scheme pipelines that provided third party access to pipeline services.

Under the reformed regulatory framework, gas pipelines are now classified as either:

- scheme pipelines, or
- non-scheme pipelines (section 5.4).

Expansions of the capacity of a pipeline are treated as part of the same pipeline.

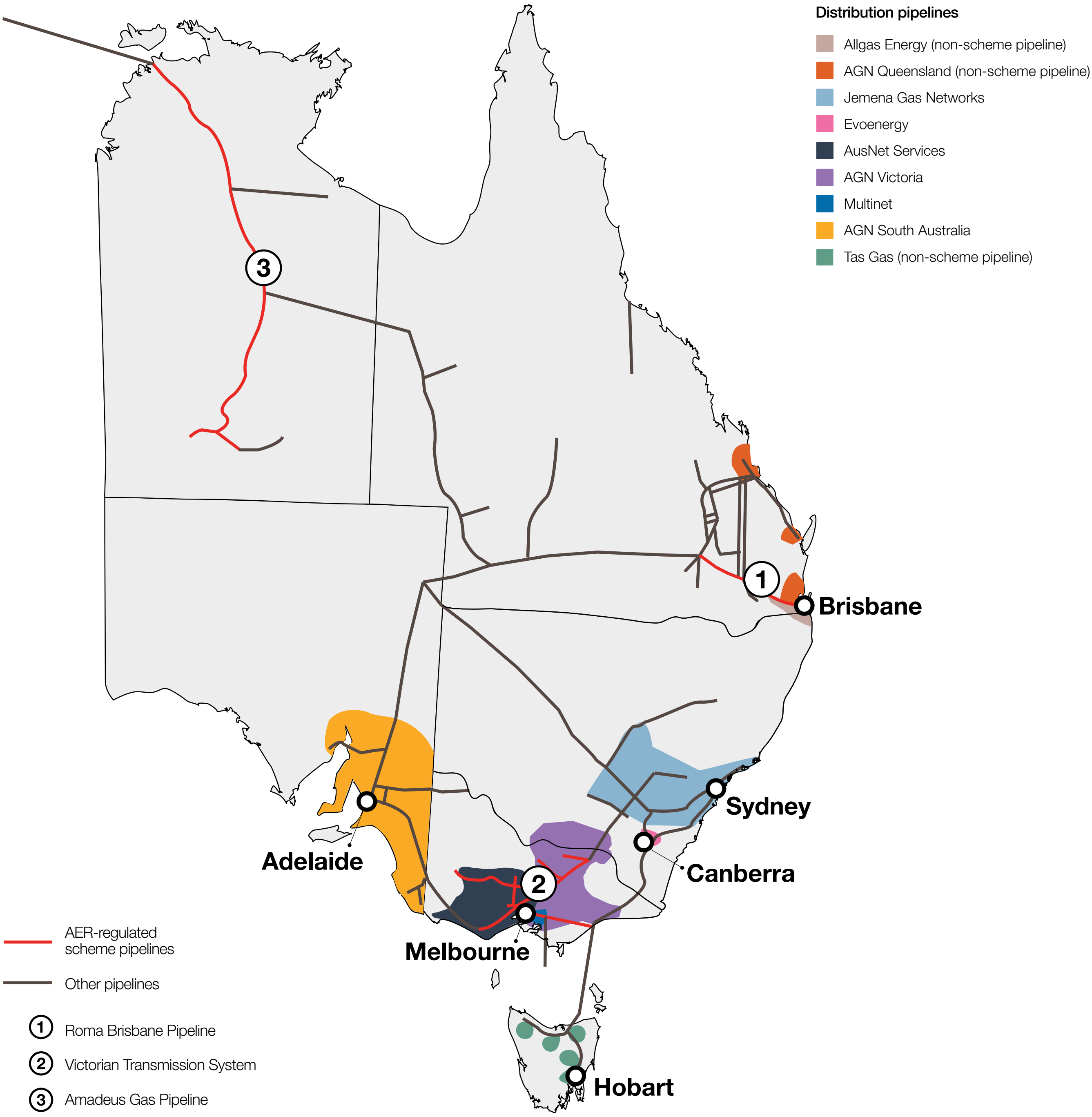
Previous publications of the State of the energy market focused on the pipeline service providers for which the AER assesses the terms and conditions of access to nominated reference services using a building block approach to assess the service provider's efficient costs (section 5.5.1). Before the reforms this included all fully regulated scheme pipelines.

In this report we continue to focus on the pipeline service providers we have focused on in the past.[a]

a Three transmission pipeline service providers – Roma Brisbane Pipeline (Queensland), APA Victorian Transmission System (Victoria) and the Amadeus Gas Pipeline (Northern Territory) – and 6 distribution pipeline service providers in NSW, Victoria, South Australia and the ACT.

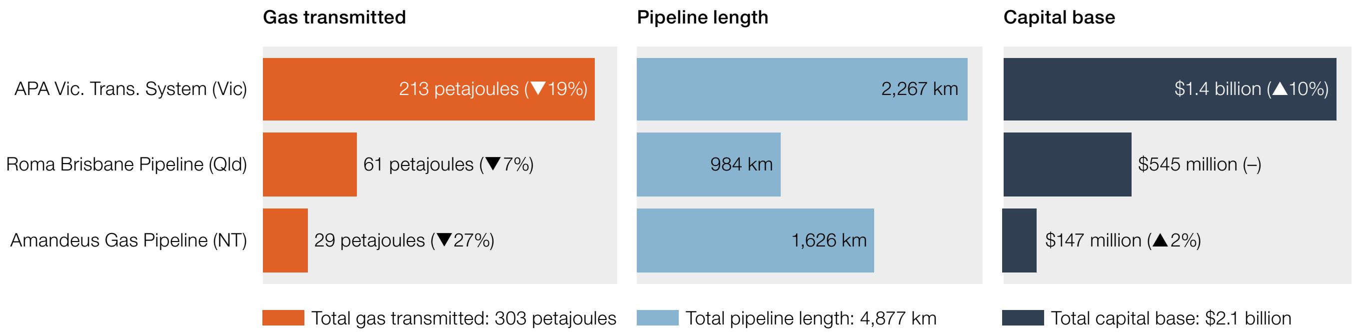
420 Capital bases capture the total economic value of assets that are providing pipeline services to customers. These assets have been accumulated over time and are at various stages of their economic lives.

Figure 5.1 Major gas transmission and distribution pipelines



Source: AER.

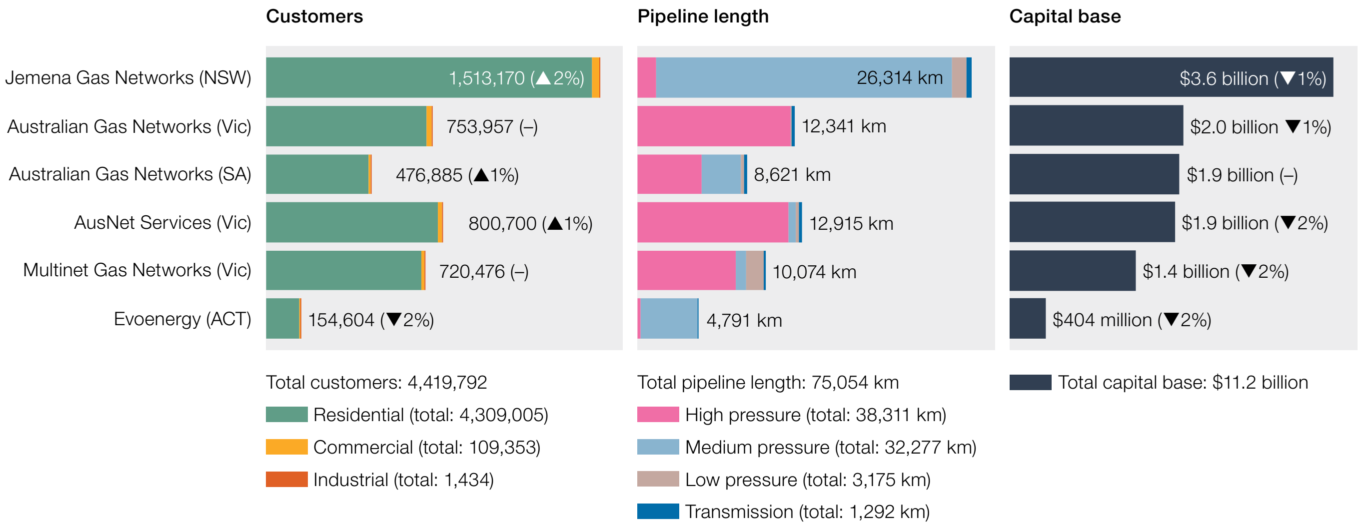
Figure 5.2 Gas transmission pipelines regulated by the AER



Note: Capital base is adjusted to June 2023 dollars. The capital base is the forecast value of pipeline assets based on the closing capital base at 30 June 2023, except for APA Victorian Transmission System (31 March 2023). Pipeline length includes looping where applicable. Looping refers to 2 or more lengths of pipeline along a route – for example, where the existing pipeline has been duplicated.

Source: AER access arrangement decisions and annual regulatory information notices (RINs).

Figure 5.3 Gas distribution pipelines regulated by the AER



Note: Capital base is adjusted to June 2023 dollars. The capital base is the forecast value of pipeline assets based on the closing capital base at 30 June 2023, except for the Victorian distribution pipelines (31 December 2023).

Source: AER access arrangement decisions and annual regulatory information notices (RINs).

5.3 Gas pipeline ownership

Australia's gas pipelines are privately owned. The publicly listed APA Group (APA) is Australia's largest pipeline service provider, with a portfolio mainly in gas transmission. Other sector participants include Jemena Gas Networks (Jemena, owned by State Grid Corporation of China and Singapore Power International) and Cheung Kong Infrastructure Holdings Limited (CKI Group), which operates Australian Gas Networks. State Grid Corporation of China and Singapore Power International also have interests in the publicly listed AusNet Services (Victoria).

Table 5.1 summarises the ownership structure of key gas transmission pipelines.

Table 5.1 Ownership of key gas transmission pipelines

Pipeline service provider	Location	Capacity (TJ/day)	Regulatory status	Owner
Roma Brisbane Pipeline	Qld	167 (145)	Scheme pipeline	APA Group
Longford to Melbourne Pipeline	Vic	1,160	Scheme pipeline	APA Group
Amadeus Gas Pipeline	NT	165	Scheme pipeline	APA Group
South West Queensland Pipeline (Wallumbilla to Moomba)	Qld–SA	512 (340)	Non-scheme pipeline (currently under review by AER)	APA Group
Queensland Gas Pipeline (Wallumbilla to Gladstone)	Qld	149 (37)	Non-scheme pipeline	Jemena (State Grid Corporation of China, 60%; Singapore Power, 40%)
Carpentaria Pipeline (South West Qld to Mount Isa)	Qld	119 (65)	Non-scheme pipeline	APA Group
GLNG Pipeline (Surat–Bowen Basin to Gladstone)	Qld	1,430	13-year no coverage	Santos, 30%; PETRONAS, 27.5%; Total, 27.5%; KOGAS, 15%
Wallumbilla Gladstone Pipeline	Qld	1,598	Non-scheme pipeline/ 15-year no coverage	APA Group
APLNG Pipeline (Surat–Bowen Basin to Gladstone)	Qld	1.760	12-year no coverage	Origin Energy, 37.5%; ConocoPhillips, 37.5%; Sinopec, 25%
Moomba to Sydney Pipeline	SA–NSW	565 (193)	Non-scheme pipeline	APA Group
Moomba to Adelaide Pipeline	SA	249 (85)	Non-scheme pipeline	QIC Global Infrastructure
Eastern Gas Pipeline (Longford to Sydney)	Vic–NSW	350	Non-scheme pipeline	Jemena (State Grid Corporation of China, 60%; Singapore Power, 40%)
Victoria Northern Interconnect	Vic–NSW	218 (224)	Scheme pipeline	APA Group
SEA Gas Pipeline (Port Campbell to Adelaide)	Vic–SA	251	Non-scheme pipeline	APA Group, 50%; Retail Employees Superannuation Trust, 50%
Tasmanian Gas Pipeline (Longford to Hobart)	Vic–Tas	129	Non-scheme pipeline	Palisade Investment Partners
Northern Gas Pipeline (Tennant Creek to Mount Isa)	NT–Qld	90	Non-scheme pipeline	Jemena (State Grid Corporation of China, 60%; Singapore Power, 40%)
Bonaparte Pipeline	NT	108	Non-scheme pipeline	Energy Infrastructure Investments (Marubeni, 49.9%; Osaka Gas, 30.2%; APA Group, 19.9%)

Note: TJ/day: terajoules per day. For bidirectional pipelines, reverse capacity is shown in brackets. The Victoria Northern Interconnect is part of the Victorian Transmission System.

Source: AER; ACCC, interim reports of gas inquiry 2017–2025; corporate websites; Gas Bulletin Board.

Table 5.2 summarises the ownership structure of key gas distribution pipelines.

Table 5.2 Ownership of gas distribution pipelines

Pipeline service provider	Location	Owner
Jemena Gas Networks	NSW	Jemena (State Grid Corporation of China, 60%; Singapore Power, 40%)
AusNet Services	Vic	Australian Energy Holdings No 4 Pty Limited
Multinet Gas Network	Vic	CK Infrastructure Holdings
Australian Gas Networks	Vic	CK Infrastructure Holdings
Australian Gas Networks	SA	CK Infrastructure Holdings
Evoenergy	ACT	ICONWater (ACT Government), 50%; Jemena, 50%
Allgas Energy	Qld	Marubeni, 40%; SAS Trustee Corp, 40%; APA Group, 20%
Australian Gas Networks	Qld	CK Infrastructure Holdings

Source: Corporate websites.

5.4 Regulatory objective and approach

One of the AER's key objectives is to deliver efficient regulation of monopoly electricity and gas infrastructure while incentivising networks to become platforms for energy services.[421] The National Gas Law and National Gas Rules set out the regulatory framework for gas pipelines.

In May 2023, Energy Ministers agreed to amend the national energy laws to incorporate an emissions reduction objective into the National Gas Objective.[422] The amended National Gas Objective seeks to promote efficient investment in, and efficient operation and use of, covered gas services for the long-term interests of consumers of covered gas with respect to:

- price, quality, safety, reliability and security of supply of covered gas
- the achievement of targets set by a participating jurisdiction
  - for reducing Australia's greenhouse gas emissions, or
  - that are likely to contribute to reducing Australia's greenhouse gas emissions.

On 1 February 2024, the National Gas Rules were amended to enable pipeline service providers to include expenditure that contributes to achieving emissions reduction targets in their access arrangement proposals. This amendment to the National Gas Rules will provide greater clarity to Australia's energy market bodies[423] for transitioning Australia's energy system to net zero by 2050.

The regulatory package of reforms introduced in March 2023 changed the way gas pipelines are regulated in order to increase market transparency and improve access to pipelines on fair terms. Under the reforms:[424]

- The 3 previous forms of regulation (full or light regulation for scheme pipelines, and non-scheme pipelines) have been condensed into 2 forms of regulation. Under the revised regulatory framework, gas pipelines are classified as either 'scheme' or 'non-scheme' pipelines and expansions of the capacity of a pipeline are treated as part of the same pipeline.
- The AER is now responsible for determining the form of regulation by applying a regulatory determination test.
- Pipeline service providers may apply to the AER for a greenfields incentive determination and a greenfield price protection determination before commissioning new pipelines.

421 ACCC and AER, ACCC and AER Corporate plan 2024–25, 30 August 2024, accessed 10 September 2024.

422 The National Electricity Objective (NEO), National Energy Retail Objective (NERO) and the National Gas Objective (NGO) govern and guide the Australian Energy Market Commission (AEMC) in all its activities under the relevant national energy legislation.

423 The Australian Energy Market Commission (AEMC), the Australian Energy Market Operator (AEMO), the Australian Energy Regulator (AER) and Western Australia's Economic Regulation Authority (ERA).

424 AER, Compliance bulletin – new obligations on gas pipeline, compression and storage service providers, Australian Energy Regulator, 7 June 2023, accessed 16 May 2024.

- All pipelines are subject to the same access negotiation and dispute resolution frameworks and ring-fencing requirements.
- The AER is responsible for introducing a new dispute resolution mechanism that includes mediation as an option for small gas shippers to use in pipeline access disputes.
- All pipeline service providers must publish prescribed transparency information under a unified information disclosure framework unless they hold an exemption. Additionally, standalone compression and storage facilities are required to publish standing terms and price information. The AER has a role in monitoring and reporting on this information and is scheduled to publish its first biennial gas pipelines report in early 2025.

In May 2024, the Essential Services Commission (Victoria) released its final decision on the Gas Distribution Code of Practice, which sets out the minimum standards for the operation and use of the Victorian gas distribution system.[425]

The new code will take effect on 1 October 2024 and will:

- enable the Essential Services Commission to use its enforcement powers to effectively monitor and enforce the rules on gas distributors, including through civil penalty provisions
- require gas distribution pipeline service providers to provide clear information to customers on their websites, including how customers can disconnect or abolish their gas connections.
- remove duplication with other regulations to streamline the regulatory framework.

The new code also removes inefficient incentives for new gas connections. From 1 January 2025, customers who may seek to establish a new gas connection will pay up-front installation costs for new gas connections, consistent with the current practice for new electricity and water connections.

The AER is responsible for determining the form of regulation by applying a regulatory determination test.

In August 2024, the Essential Services Commission of South Australia (ESCOSA) made a draft decision on the protections that Australian Gas Networks (South Australia) must deliver for consumers during its forthcoming (1 July 2026 to 30 June 2031) access arrangement period. The draft decision includes proposals to:

- extend the application of the Australian Gas Networks (South Australia) distribution licence so it also applies to distribution of hydrogen and other renewable gases
- continue monitoring network reliability and create service standards if required
- require that Australian Gas Networks (South Australia) reports directly to the public on aspects of its operational performance
- begin monitoring the timely provision of disconnection and abolishment services
- ensure that consumers receive information about how to disconnect from the gas network
- require Australian Gas Networks (South Australia) to seek the ESCOSA's approval if it proposes to disable any part of the gas distribution network in the future.
- create specific timeframes for reconnecting customers after de-energisation where Australian Gas Networks (South Australia) is obliged to do so by the National Energy Retail Rules
- make a series of changes to the Gas Metering Code to improve consistency with other regulatory instruments, provide for changes in the composition of gas and accommodate possible expanded use of digital meters.

ESCOSA will consider stakeholder and public feedback and make a final decision in early 2025.[426]

425 Essential Services Commission, New code of practice for gas distributors to apply from 1 October 2024, media release, Essential Services Commission, 9 May 2024.

426 ESCOSA, Australian Gas Networks regulatory framework review 2026–2031 – draft decision, Essential Services Commission of South Australia, 5 August 2024, accessed 12 August 2024.

5.4.1 Forms of regulation

Under the current regulatory framework, the form of regulation of a scheme or non-scheme pipeline can change if:

- the AER makes a determination that a scheme pipeline should become a non-scheme pipeline (a scheme pipeline revocation determination) or a non-scheme pipeline should become a scheme pipeline (a scheme pipeline determination)
- a non-scheme pipeline service provider elects for a pipeline to become a scheme pipeline (a scheme pipeline election).

The AER is also responsible for determining the level of regulation for new pipelines (through greenfields determinations) and the classification and reclassification of pipelines. This role was previously fulfilled by the National Competition Council and the jurisdictional minister.

Under the reforms, 'light regulation' has been abolished. All pipelines are now subject to a range of uniform access, transparency and ring-fencing requirements. Service providers operating scheme pipelines are subject to more comprehensive regulatory obligations, including:

- a regulatory-oriented access dispute process
- periodically submitting an access arrangement revisions proposal to the AER for approval[427]
- submitting a reference service proposal to the AER 12-months prior to submitting the relevant access arrangement revisions proposal.

In deciding whether a pipeline service should be specified as a reference service, the AER must have regard to the reference service factors specified in the National Gas Rules. Services which the AER determines meet the reference service factors will be determined to be reference services. Services which the AER determines do not meet the reference service factors will be treated as non-reference services.

Determining a service to be a reference service, as compared to it being a non-reference service, makes a significant difference to how the service is regulated. Reference services are subject to AER price regulation. That is, the AER sets maximum prices, or price caps, which gas network pipeline service providers may charge network users for reference services. Gas network pipeline service providers may choose to charge network users less than the price caps we determine but they may not charge more. Services the AER determines to be non-reference services are not subject to price regulation. This means gas pipeline service providers set their own charges for non-reference services.

All new pipelines will be non-scheme pipelines when they are commissioned.

In October 2024, the AER published its draft decision for the South West Queensland Pipeline (SWQP)[428] form of regulation review.[429] The draft decision is that the SWQP, owned and operated by APA Group, should remain a non-scheme pipeline, subject to lighter handed regulation.

The AER found the benefits of scheme regulation do not outweigh the increased costs of scheme regulation because:

- it is uncertain whether scheme regulation will substantially improve prices
- access under non-scheme regulation has the potential to improve in the future.

However, the AER also found that prices for SWQP services may be high and shippers face challenges in negotiating the terms and conditions of access to the pipeline. The AER has proposed to monitor prices, terms and conditions on the pipeline as capacity becomes available for contracting. If prices on the SWQP increase without reasonable cause, it could justify a further review of the form of regulation applied to this pipeline.

427 A pipeline is a scheme pipeline if it was a covered pipeline (other than a light regulation pipeline) immediately before 2 March 2023.

428 The South West Queensland Pipeline is a bidirectional transmission pipeline consisting of 2 parallel pipelines, linking Wallumbilla in South East Queensland to Moomba in South Australia.

429 AER, Form of regulation review: South West Queensland Pipeline – Draft decision, Australian Energy Regulator, 9 October 2024, accessed 16 October 2024.

The review of the SWQP is the first of a series of AER initiated form of regulation reviews. The SWQP was chosen as the first pipeline for a review due to its importance to the east coast gas system.

5.4.2 Pipeline classification and reclassification

In July 2024, the AER published a new version of the *Pipeline regulatory determinations and elections guide* outlining its functions and powers under Part 4 of the National Gas Law and chapter 2 of the National Gas Rules. The guide outlines how the AER will approach regulatory determinations and how stakeholders can make applications about the regulatory treatment of a pipeline.[430]

Under the reforms, the default position is that a pipeline is a distribution pipeline if it is classified as a distribution pipeline under its jurisdictional licence or authorisation. Similarly, a pipeline is a transmission pipeline if it is classified as a transmission pipeline under its licence/authorisation. For new pipelines, if the jurisdictional licence contains no classification, the pipeline service provider must apply to the AER for a classification decision.[431] A service provider may apply to the AER for reclassification if it considers it has been wrongly classified. The AER may also, on its own initiative, make a decision for a pipeline to be reclassified.

The first of the AER's scheduled biennial gas pipelines reports is due to be published in early 2025.

5.4.3 Greenfields pipeline projects

Before the reforms commenced, '15-year no coverage' determinations were made by the relevant minister on the recommendation of the National Competition Council. The minister was required to make the determination unless satisfied that all the coverage criteria were satisfied.

Under the reforms, a service provider for a greenfields pipeline project may apply to the AER (before commissioning) for a greenfields incentive determination. They may also apply for a greenfields price protection determination, either as part of the greenfields incentive determination application process or later if they obtain a greenfields incentive determination.[432]

5.4.4 Prescribed transparency information for pipelines

Part 10 of the National Gas Rules prescribes the transparency information requirements that apply to all scheme and non-scheme pipeline service providers. This information is to assist users of the pipeline in negotiations with the pipeline service provider.

Before the reforms, service providers of light regulation pipelines and non-scheme pipelines were required to prepare prescribed transparency information under Parts 7 and 23 of the National Gas Rules, respectively. These Parts are repealed and have been replaced by Part 10.

Exemptions from certain requirements are available for pipeline service providers that meet the exemption criteria. The requirements to prepare, publish and maintain the information set out in the National Gas Rules and the pipeline information disclosure guidelines are classified as 'tier 1'[433] civil penalty provisions under the National Gas (South Australia) Regulations.[434]

430 AER, Pipeline regulatory determinations and elections guide, Australian Energy Regulator, 30 July 2024, accessed 2 August 2024.
431 AGS, Legal briefing – Gas pipeline reforms, 17 March 2023, accessed 16 May 2024. Legal briefing – Gas pipeline reforms
432 AGS, Legal briefing – Gas pipeline reforms, 17 March 2023, accessed 16 May 2024.
433 Tier 1 provisions carry maximum penalties for corporations of $10 million or, if greater, 3 times the benefit obtained from the breach if this can be determined, or if not, 10% of annual turnover.
434 Government of South Australia, National Gas (South Australia) Regulations, accessed 16 May 2024.

5.4.5 Ring-fencing requirements

Under the reforms, all pipelines are subject to a set of requirements that previously only applied to some pipelines.[435] Pipeline service providers must comply with ring-fencing provisions regarding related businesses, and provisions regarding associate contracts. The requirement is classified as a conduct provision and 'tier 2' civil penalty provision under the National Gas (South Australia) Regulations.[436]

The National Gas Rules provide for a service provider to apply to the AER for an exemption from the ring-fencing requirements. As at 1 August 2024, 2 exemptions were in place – APT Pipelines (Northern Territory)[437] and Meridian SeamGas Joint Venture and WestSide Corporation Limited.[438] In these cases, the AER considers that the costs of complying with the ring-fencing obligations outweigh any associated public benefit.

5.4.6 Monitoring and surveillance

Under the reforms, the AER is required to monitor the behaviour of pipeline service providers, including the prices charged for pipeline services, the information published by pipeline service providers, outcomes of access negotiations, dealings with associates and compliance with ring-fencing requirements.

The first of the AER's scheduled biennial gas pipelines reports is due to be published in early 2025.

In addition to these recently assigned monitoring and surveillance responsibilities, the AER already publishes an annual electricity and gas networks performance report. The report provides an in-depth analysis of key outcomes and trends in the operational and financial performance of the transmission and distribution pipelines that, under the new framework, are classified as scheme pipelines.

5.5 How gas access prices are set

Pipeline service providers earn revenue by selling capacity to customers needing to transport gas. A customer purchases access to that capacity under terms and conditions that include an access price. The AER sets access prices for gas pipelines in eastern Australia and the Northern Territory under broadly similar rules to those applied to electricity networks (chapter 3).

As with electricity, the AER uses a building block approach to assess a gas pipeline service provider's revenue needs (section 5.5.1). The AER draws on a range of inputs to assess efficient costs, including cost and demand forecasts and revealed costs from experience. Unlike electricity, the approach is not formalised in published guidelines. An exception is the allowed rate of return assessment, for which a common AER guideline applies to both electricity and gas.

Gas pipelines are capital intensive and require significant investment to install, operate and maintain the necessary infrastructure. This gives rise to a natural monopoly industry structure, where it is more efficient to have a single pipeline service provider than to have multiple providers offering the same service.

Because monopolies face little competitive pressure, they have opportunities and incentives to charge higher prices than they could charge in a competitive market. This monopolistic environment poses risks to consumers because pipeline charges make up around 40% of a residential customer's gas bill (Figure 6.3 in chapter 6). To counter these risks, the role of the AER as the economic regulator is to replicate the incentives that pipeline service providers would face in a competitive market (that is, to control costs, invest efficiently and not overcharge consumers).

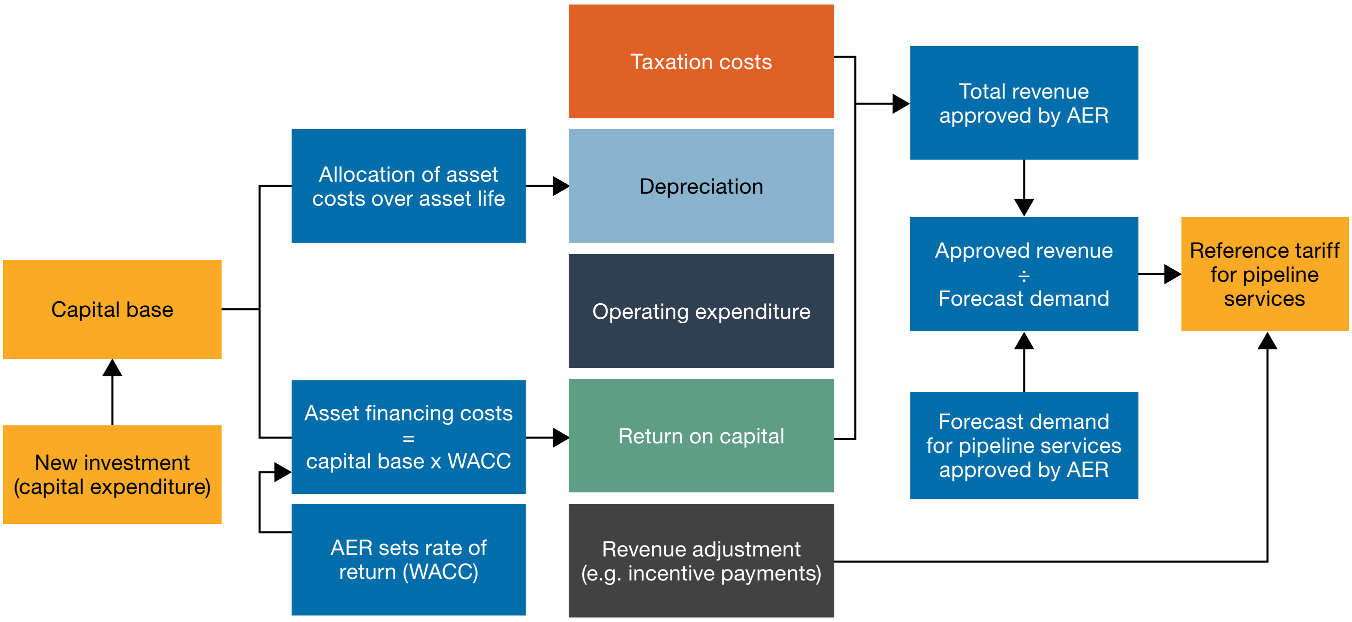
435 AGS, Legal briefing – Gas pipeline reforms, 17 March 2023, accessed 16 May 2024.
436 Government of South Australia, National Gas (South Australia) Regulations, accessed 14 June 2023.
437 AER, Final decision on APTNT's ring fencing exemption application, Australian Energy Regulator, 17 August 2011.
438 AER, Final decision on ring fencing exemption application for Meridian SeamGas Joint Venture and WestSide Corporation, Australian Energy Regulator, 25 July 2012.

5.5.1 Building blocks of gas pipeline revenue

The AER uses a building block approach to assess a gas pipeline service provider's revenue needs (Figure 5.4). Specifically, it forecasts how much revenue the service provider will need to cover:

- a return to investors that fund the pipeline service provider's assets and operations
- efficient operating and maintenance costs
- asset depreciation costs
- taxation costs.

Figure 5.4 How gas pipeline revenue and charges are set



Note: WACC: weighted average cost of capital. Revenue adjustments from incentive schemes encourage pipeline businesses to manage their operating and capital expenditure efficiently and to innovate.

Source: AER.

Operating and maintenance costs are forecast to account for around 39% of revenue requirements (35% for transmission and 40% for distribution) in the current access periods.

Pipeline assets have long lives, and investment costs are recovered over the economic life of the assets. The amount recovered each year is called depreciation and reflects the lost value of pipeline assets each year through wear and tear and technical obsolescence.

Additionally, the shareholders and lenders that fund these assets must be paid a commercial return on their investment. Those returns are forecast to absorb around 37% of revenues (52% for transmission and 35% for distribution) in the current access periods. The returns are calculated by multiplying:

- the value of the pipeline service provider's capital base
- the rate of return that the AER allows based on the forecast cost of funding those assets through equity and debt.[439]

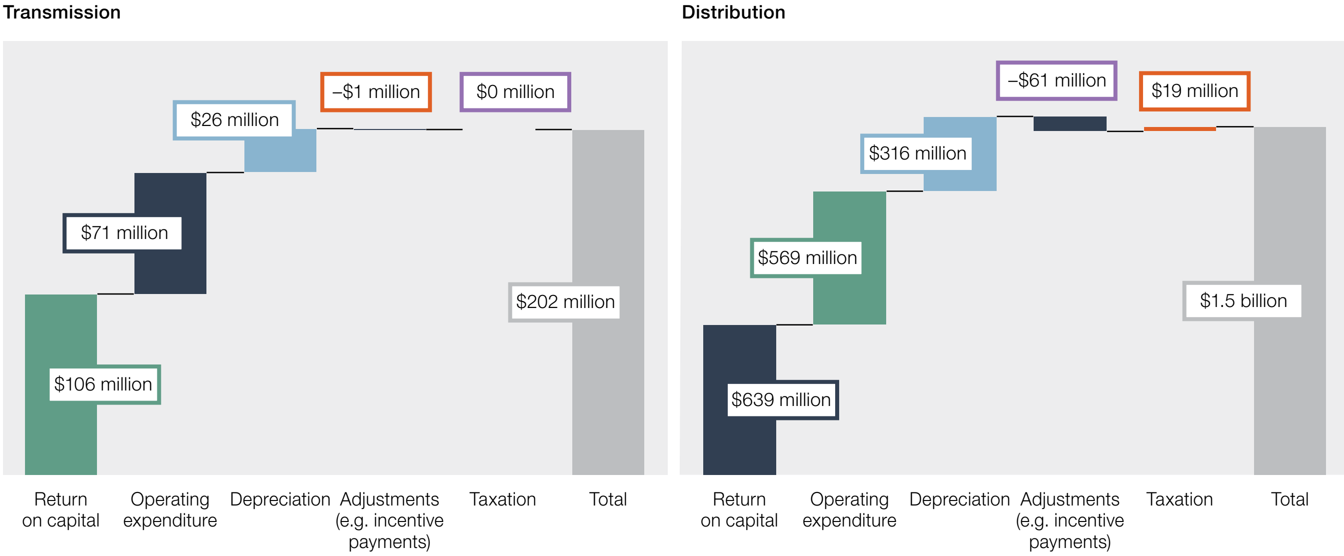
Overheads, taxation and other costs account for the remainder of a pipeline's revenue.

439 The return on equity is the return that shareholders of the business will require for them to continue to invest. The return on debt is the interest rate that the pipeline service provider business pays when it borrows money to invest.

Figure 5.5 illustrates the composition of pipeline revenues in the current gas transmission and distribution access arrangements.

Pipeline service providers can also earn additional revenue through regulatory incentive schemes that encourage the efficient management of operating and capital expenditure programs (section 5.5.2).

Figure 5.5 Composition of average annual gas pipeline revenues



Note: Composition of average annual gas pipeline revenue – current periods as at 1 July 2024. All data are adjusted to June 2023 dollars.
Source: Post tax revenue modelling used in AER determination process.

5.5.2 Incentive schemes

The National Gas Rules provide scope for pipeline service providers to earn financial rewards by outperforming efficiency targets (and incur financial penalties for underperformance). An efficiency carryover mechanism allows service providers to retain, for up to 6 years, efficiency savings in managing their operating costs. In the longer term, service providers must share efficiency gains with their customers by passing on around 70% of the gains through lower access prices. The mechanism is similar to the efficiency benefit sharing scheme (EBSS) in electricity (chapter 3, Box 3.4). The difference is that if the proposed application of the scheme is accepted by the AER, it is written into the service provider's access arrangement rather than being set out in a general guideline.

Several pipeline service providers proposed the application of a capital expenditure sharing scheme (CESS) in their most recent access arrangement. The National Gas Rules do not mandate such schemes, but they do allow the AER to approve their use to incentivise service providers to efficiently maintain and operate their pipelines.

The Victorian distribution pipeline service providers were the first to implement a CESS approved by the AER as part of their 2018–22 access arrangements. The AER subsequently approved Jemena Gas Networks' (NSW) request for a CESS for its 2020–25 access arrangement and requests by Australian Gas Networks (South Australia) and Evoenergy (ACT) for their 2021–26 access arrangements. To date, no transmission service providers have sought to participate in a CESS.

The CESS for gas pipeline service providers operates in a similar way to the CESS for electricity networks (chapter 3, Box 3.3). It allows a service provider to earn financial rewards by keeping new investment spending below forecast levels (and incur financial penalties for investing above forecast). In later access arrangements, the service providers must pass on 70% of savings to customers through lower charges.

The CESS carries a risk of encouraging service providers to inflate their investment forecasts. To mitigate this risk, the AER scrutinises whether proposed investments are efficient. The design of the CESS ensures deferred expenditure does not attract rewards so that service providers are not incentivised to defer critical investment needed for safe and reliable pipeline operation. A network health index ensures that rewards depend on the service provider maintaining current service standards.

Other incentives applied to electricity networks – such as those relating to service performance and demand management – are not available to gas pipeline service providers.

5.5.3 Timelines and processes

Once a pipeline service provider submits an access arrangement proposal, the AER has 6 months (plus optional stop-the-clock time at certain stages) to make a final decision on the access arrangement. The assessment period can be extended by up to 2 months, with a maximum of 13 months to render a decision.

The AER consults with pipeline customers and other stakeholders during the assessment process. As part of this consultation, the AER publishes a draft decision on which it seeks stakeholder input to inform its final decision. At the completion of a review, the AER publishes a final access arrangement decision that sets the reference tariff that a pipeline service provider can charge its customers. The AER annually reviews pipeline tariff variations to ensure they are consistent with its decision.

The AER assesses access arrangements on a rolling cycle. The (typically) 5-year review cycle helps create a stable investment environment but also risks locking in inaccurate forecasts.

Countering this risk, the National Gas Rules include ways of managing uncertainties. The AER can approve cost pass-throughs if a specified event (such as a regulatory change or natural disaster) imposes significant costs on the pipeline service provider that were not forecast. A pipeline service provider may also approach the AER to pre-approve a contingent investment project if the need to do so was uncertain at the time of the access arrangement decision. A pre-approval allows a service provider to roll the project into the capital base in the forthcoming access arrangement if pre-determined conditions are met.

In October 2020, the Victorian Government changed the timing of the Victorian distribution pipeline service providers' access arrangements from calendar to financial regulatory years.[440] To implement the change, the 1 January 2018 to 31 December 2022 access arrangement period was extended to include a 6-month transition period. The current access arrangement periods began on 1 July 2023.

For the purposes of this report, data relating to the 6-month period from 1 January 2023 to 30 June 2023 has been annualised. We acknowledge that this process may impact the accuracy of some reporting measures; however, we expect these issues to be resolved when we report on a full regulatory year in next year's report.

5.5.4 Consumer engagement

An important focus of gas pipeline regulation is how constructively a pipeline service provider engages with its consumers in developing an access arrangement proposal. Although not mandated in the National Gas Rules, evidence of constructive engagement can give the AER confidence that the service provider is genuinely committed to meeting its consumers' needs and preferences. Robust consumer engagement can lay the foundation for the AER to accept elements of an access arrangement proposal, including capital and operating expenditure forecasts.

The AER's framework for considering consumer engagement in pipeline access arrangement determinations is set out in the *Better Resets Handbook*.[441]

440 Victorian legislation, National Energy Legislation Amendment Act 2020, 20 October 2020, accessed 1 August 2024.

441 AER, Better Resets Handbook – Towards consumer-centric network proposals, Australian Energy Regulator, 18 November 2022, accessed 26 June 2023.

5.5.5 Road to net zero by 2050

Australia now has a legislated carbon emissions target of net-zero greenhouse gas emissions by 2050 and a National Gas Objective that includes achievement of emissions reductions targets. The Future Gas Strategy maps the Australian Government's plan for how gas will support our economy's transition to net zero in partnership with the world.[442]

The strategy's objectives are to:

- support decarbonisation of the Australian economy
- safeguard energy security and affordability
- entrench Australia's reputation as an attractive trade and investment destination
- help our trade partners on their own paths to net zero.

State and territory governments are already taking measures to reduce residential and small commercial consumers' reliance on gas.

In November 2020, the NSW Government released its Electricity Infrastructure Roadmap – a 20-year plan to transform the state's electricity system into one that is affordable, clean and reliable for everyone.[443] Gas will continue to play an important role in the energy transition and the NSW Government aims to maximise investments through its Electricity Infrastructure Roadmap and renewable energy zones (REZ).

In October 2022 the Victorian Government released its Gas Substitution Roadmap – a plan to help Victoria reduce the cost of energy bills and cut carbon emissions.[444] Victoria is taking steps to speed up the transition to renewable energy with the goal of achieving a 45–50% reduction in emissions by 2030, 75–80% reduction by 2035 and net zero by 2045.[445] To achieve its targets, Victoria must cut emissions across the entire economy, including the gas sector, which contributes around 17% of the state's net greenhouse gas emissions.

The Gas Substitution Roadmap offers options and support for Victorian residential and small commercial consumers who are interested in switching from gas to solar or electricity. Switching from gas to efficient electric appliances will help households to save money on their energy bills. The Gas Substitution Roadmap indicates that converting an existing home with solar panels from dual-fuel to all-electric can save around $1,700 per year on energy bills, in addition to the approximately $1,000 of savings per year generated by the solar PV system.[446]

The pace of change in Victoria has continued to accelerate with the introduction of rule changes to reduce new and existing gas connections. Since 1 January 2024, all new homes in Victoria requiring a planning permit are required to be all-electric. This means new homes and residential subdivisions that require a planning permit can no longer connect to the gas network.

The ACT Government's Climate Change and Greenhouse Gas Reduction (Natural Gas Transition) Amendment Bill 2022 established the legal framework to end new fossil fuel gas connections in the ACT.[447] In June 2024, the ACT Government announced its intention to invest in an all-electric, zero emissions future for Canberra with the release of a new Integrated Energy Plan (IEP). The IEP sets out the next stage of work for the ACT's transition over the next 20 years, including a range of government commitments to support consumers through the transition.[448]

Gas underpins a wide range of economic activity in Australia and globally, with secure gas supplies being a core component of energy security for many economies. Australia's domestic climate action is progressing against a backdrop of growing global momentum to deliver the goals of the Paris Agreement. Therefore, emissions from gas must reduce significantly.[449]

442 Australian Government, Future gas strategy, Department of Industry, Science and Resources, 25 June 2024, accessed 10 September 2024.
443 NSW Government, Electricity infrastructure roadmap, 20 November 2020, accessed 9 September 2024.
444 Victorian Government, Victoria's Gas Substitution Roadmap, Department of Energy, Environment and Climate Action, accessed 11 June 2023.
445 Victorian Government, Victoria's Gas Substitution Roadmap, Department of Energy, Environment and Climate Action, accessed 18 July 2024.
446 Assuming a 6.6 kW solar PV system.
447 ACT Government, ACT reaches milestone preventing new fossil fuel gas connections, media release, 8 June 2023.
448 ACT Government, Electrifying Canberra, media release, 19 June 2024.
449 Australian Government, Future Gas Strategy Analytical Report, Department of Industry, Science and Resources, 9 May 2024, accessed 12 August 2024, p. 3.

Australian contracts for LNG exports will expire between 2030 and 2035. Within the Asian region to which Australia currently exports LNG, demand for LNG is expected to continue to 2050 and beyond and consultation indicates continued demand for secure exports from Australia. The future role of Australia's existing pipeline infrastructure will depend on the broader role of gas, both domestically and abroad.

5.5.6 Regulating gas pipelines under uncertainty

In November 2021, the AER published an information paper, 'Regulating gas pipelines under uncertainty', which discussed the potential implications of a decarbonised future energy mix on the long-term gas demand forecast and the expected economic lives of gas pipeline assets.[450]

The information paper explained how these potential implications may affect the AER's regulatory approaches when undertaking access arrangement reviews for service providers operating scheme pipelines now and in the future. It canvassed a range of potential options, including their costs and benefits, for managing the pricing risk and stranded asset risk that may arise from a potential material decline in gas demand in the future. These options include:

- accelerating asset depreciation (Box 5.3)
- providing ex-ante risk compensation
- removing redundant assets from capital base
- removing capital base indexation
- revaluating capital base
- introducing exit fees
- increasing fixed charges.

The paper also discussed how the uncertainty in future gas demand (section 5.6.1) can affect specific aspects of the AER's regulatory decisions, such as:

- the assumed payback period of pipeline investment in expenditure assessments
- the incentives that regulated service providers may have in substituting capital and operating expenditure
- whether it is in the long-term interests of gas consumers to preserve optionality when evaluating capital investments that are for repurposing gas networks[451]
- the increased demand risk that regulated service providers may face under price cap regulation if gas demand falls persistently.

In its 2023–28 access arrangements for the Victorian gas transmission and distribution pipelines, the AER:

- changed the way costs are recovered for gas disconnections to encourage consumers to disconnect safely through permanent abolishment of their gas connection instead of the cheaper temporary disconnection option
- 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.

The AER noted that these were interim measures and may not be suitable for greater rates of declining demand for gas. Abolition of gas connections and accelerated depreciation are discussed in Box 5.2 and Box 5.3.

450 AER, AER tackles gas pipeline regulation in an uncertain future, Australian Energy Regulator, November 2021.
451 Future hydrogen users are not currently considered as gas consumers under the National Gas Law or National Gas Rules.

5.6 Recent AER access arrangement decisions

The AER did not review any access arrangement applications for transmission or distribution pipelines in the 12-month period to 30 June 2024.

Table 5.3 provides a comparative summary between the AER's final decisions on the access arrangements in place for the current access period and those in place in the previous access period.[452]

Table 5.3 AER gas revenue determinations – current access arrangements

NSP	Revenue (forecast)	Capital expenditure (forecast)	Operating expenditure (forecast)
Transmission	$986m (▼1.7%)	$296m (▼23%)	$351m (▲10%)
Distribution	$7.4b (▼5.1%)	$3.1b (▼11%)	$3.2b (▲14%)
Total	$8.3b (▼4.7%)	$3.4b (▼13%)	$3.6b (▲13%)

Source: AER estimates.

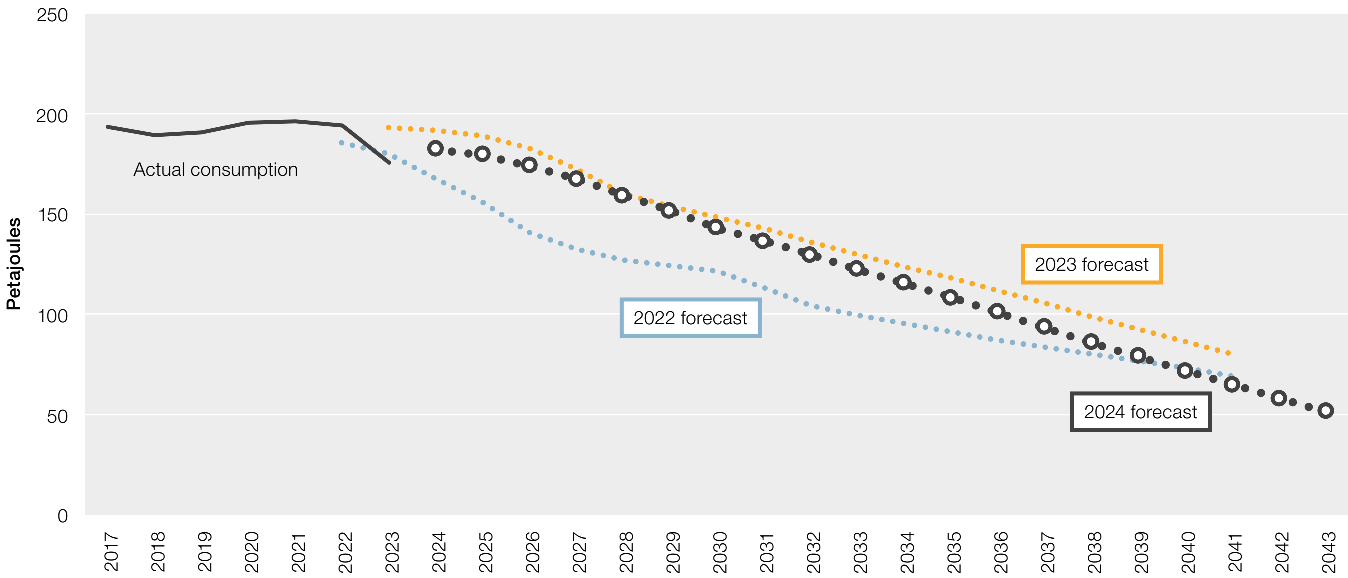
5.6.1 Gas consumption and demand forecasts

The Australian Energy Market Operator (AEMO), through its *Gas Statement of Opportunities* (GSOO),[453] forecasts the adequacy of gas supplies to meet the needs of consumers in central and eastern Australia. The 'step change' scenario is now considered the most likely scenario, wherein consumer actions lead to rapid and significant continued investment in orchestrated consumer energy resources (CER) and include electrification of the transportation sector.

AEMO's forecasts reflect assumptions about connections and population growth and the impacts of energy efficiency investments, gas fuel-switching such as electrification, gas prices and climate change. Electrification remains the most significant driver of forecast declining residential/commercial consumption, with a total anticipated demand reduction of around 50 petajoules (PJ) in 2030 increasing to about 170 PJ at the end of the outlook period. Further, new homes in all jurisdictions are increasingly likely to be built without a gas connection (Figure 5.6).

452 The current access arrangement period is the arrangement in place at 1 July 2024.
453 AEMO, Gas Statement of Opportunities, Australian Energy Market Operator, 21 March 2024, accessed 17 May 2024.

Figure 5.6 AEMO's forecast gas consumption – residential/commercial customers

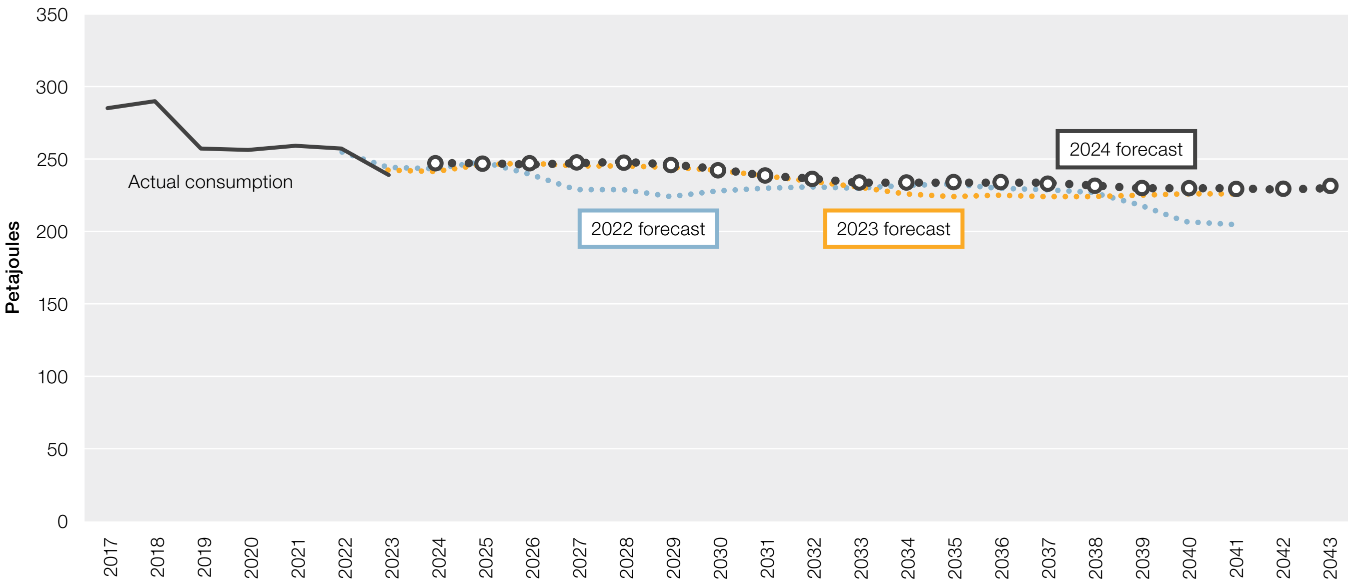


Note: Residential and commercial customers include consumers on volume-based tariffs. Forecasts represent the most likely scenario in AEMO's Gas Statement of Opportunities: 2022 step change scenario, 2023 orchestrated step change (1.8°C) scenario, 2024 step change scenario.

Source: AEMO, Gas Statement of Opportunities, March 2024.

Gas consumption in the industrial sector is forecast to remain relatively stable over the short term before reducing in the 2030s due to a combination of electrification and reduced demand from large industrial loads. The impact of electrification on the industrial sector is expected to be slower and less pronounced than for the residential and commercial sectors, due to the difficulty and/or high cost of technologies to electrify high heat processes (temperatures exceeding 400°C). Apart from retrofitting site equipment, the increased power requirements could also call for electricity network upgrades. Additionally, a significant share of natural gas usage in industry is for chemical feedstock, for which electricity is not a substitute without complementary changes in technology and processes (Figure 5.7).

Figure 5.7 AEMO's forecast gas consumption – industrial customers



Note: Industrial customers include large customers such as fertiliser producers, mineral processing, primary metal, paper and chemical producers, oil refineries, large food processors and mining. Any onsite electricity generation that consumes gas is also included. Forecasts represent the most likely scenario in AEMO's Gas Statement of Opportunities: 2022 step change scenario, 2023 orchestrated step change (1.8°C) scenario, 2024 step change scenario.

Source: AEMO, Gas Statement of Opportunities, March 2024.

Transformation in the energy system and the explicit policy goal of reaching net zero emissions by 2050 create considerable uncertainties in forecasting future gas demand. While the decline in the demand for gas is expected to accelerate, there is considerable uncertainty as to how quickly the acceleration will happen, what the path to small customer 'electrification' will look like and whether any existing gas pipelines will have any ongoing role in transporting hydrogen or biogas.

Declining throughput on remaining connections will put upwards pressure on the price of gas haulage. If this eventuates, it will likely encourage further decline in demand and an increase in customers leaving the network, causing self-reinforcing upwards pressure on tariffs for remaining customers. In a report for Energy Consumers Australia, CSIRO and Dynamic Analysis undertook modelling of how this scenario may arise under AEMO's 'step change' scenario.[454]

While declining demand is already having an impact on growth-driven elements of forecast expenditure, its impact on other drivers of expenditure is expected to happen more slowly. The AER closely scrutinises proposed capital and operating expenditure to ensure the customers who are still reliant on gas are paying no more than necessary for a safe, reliable and secure supply. While declining demand is already having an impact on growth driven elements of forecast expenditure, its impact on other drivers will be slower. The obligation on pipeline service providers to continue to offer the same services while meeting the same regulated standards means many costs will not necessarily fall as demand falls. This makes it difficult to avoid increases in costs per customer under the current regulatory framework.

454 CSIRO and Dynamic Analysis, Consumer impacts of the energy transition: Modelling report, Energy Consumers Australia, July 2023, pp. 21–22, accessed 17 May 2024.

Box 5.2 Temporary disconnection versus permanent abolishment of gas connections

Through our assessments of AusNet Services', Australia Gas Networks' and Multinet Gas Networks' 2023–28 access arrangements, the AER became aware that some customers seeking to move away from gas have sought temporary disconnection measures over the safer, permanent removal of connection assets.

Energy Safe Victoria, the regulator responsible for electricity, gas and pipelines safety, considers that when a customer chooses to stop using gas at their premises, permanent abolishment of the connection is required. Failure to do so impedes the pipeline service providers from meeting their safety obligations.

However, permanent abolishment of a gas connection (by removing the pipeline assets and closing off the connection or premises to the mains) is more costly than temporarily stopping the withdrawal of gas through the meter. As such, the cost of permanently disconnecting the premises has been a deterrent for customers wanting to move away from gas.

To narrow the price difference between temporary and permanent gas disconnection services, and the associated safety risks it appears to be creating, the AER has determined an upfront cost of $220 for connection abolishment with the remainder added to the regulated revenue we use to set haulage tariffs and shared between all customers.[a]

This is not a change to the total costs that distribution pipeline service providers will be allowed to recover for connection abolishment services. It only changes the way in which costs are recovered.

We acknowledge this is not a long-term solution.

Energy Safe Victoria is committed to working with the distribution pipeline service providers to understand whether other methods may be more appropriate than permanent abolishment.

a AER, AER decision supports Victorian gas consumers in energy transition, Australian Energy Regulator, 2 June 2023, accessed 12 May 2024.

5.7 Revenue

All gas transmission and distribution service providers operating scheme pipelines are regulated under a weighted average price cap. Pipeline service providers can earn above or below forecast revenue over time due to changes in demand. If actual demand exceeds forecast demand, the service provider keeps the additional revenue. Conversely, if actual demand is less than forecast revenue, the service provider is exposed to the shortfall.

5.7.1 Revenue in 2023

Over the 12-month period to 30 June 2023, $1.6 billion in revenue was collected for providing access (selling capacity) to parties needing to transport gas, 9% less than in the previous year.[455]

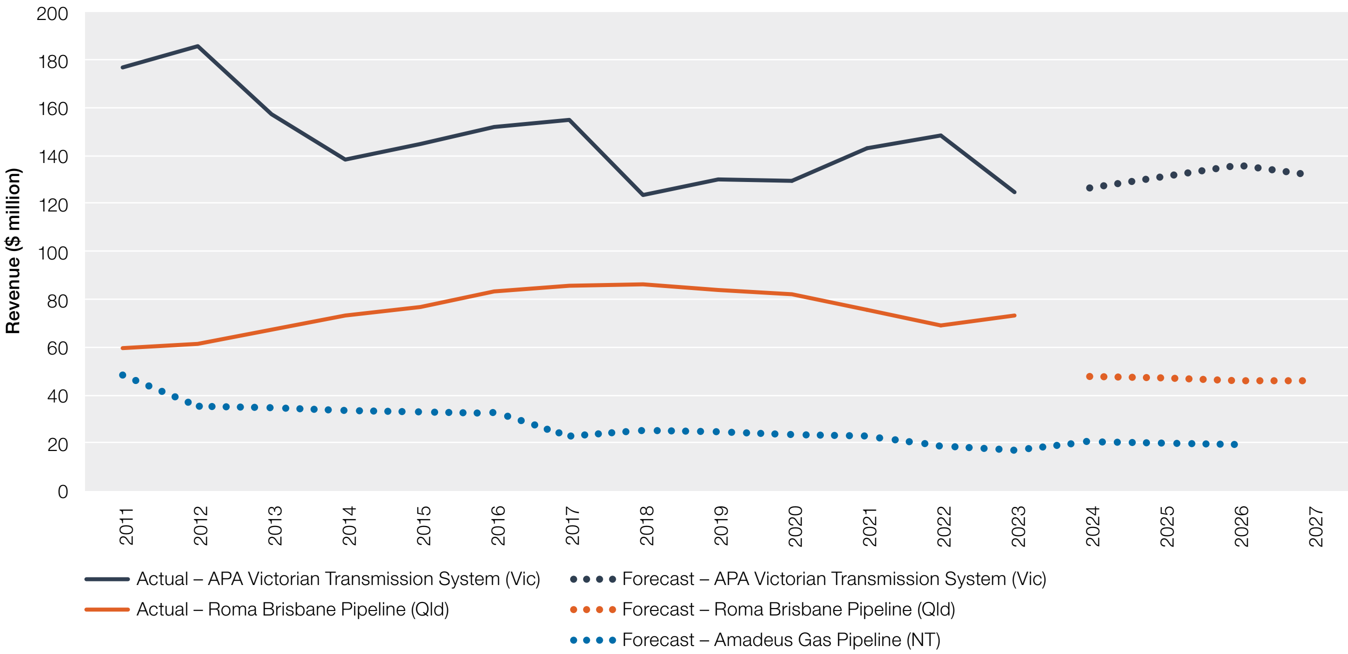
Table 5.4 provides a summary of the revenue that pipeline service providers earned in 2023 and how it compared with previous years.

Table 5.4 Revenue in 2023 – key outcomes

Service type	Revenue (actual) (2023)	Revenue (actual) (compared with 2022)	Revenue (actual) (compared with peak)
Transmission (excl. Amadeus Gas Pipeline)	$198m	▼$19m (▼9%)	▼$49m (▼20%) (2012)
Distribution	$1.4b	▼$145m (▼9%)	▼$465m (▼25%) (2015)
Total	$1.6b	▼$165m (▼9%)	▼$489m (▼23%) (2015)

Note: Amadeus Gas Pipeline's actual revenue is confidential because it contains commercially sensitive information.
Source: AER estimates.

Figure 5.8 Revenue – gas transmission pipelines

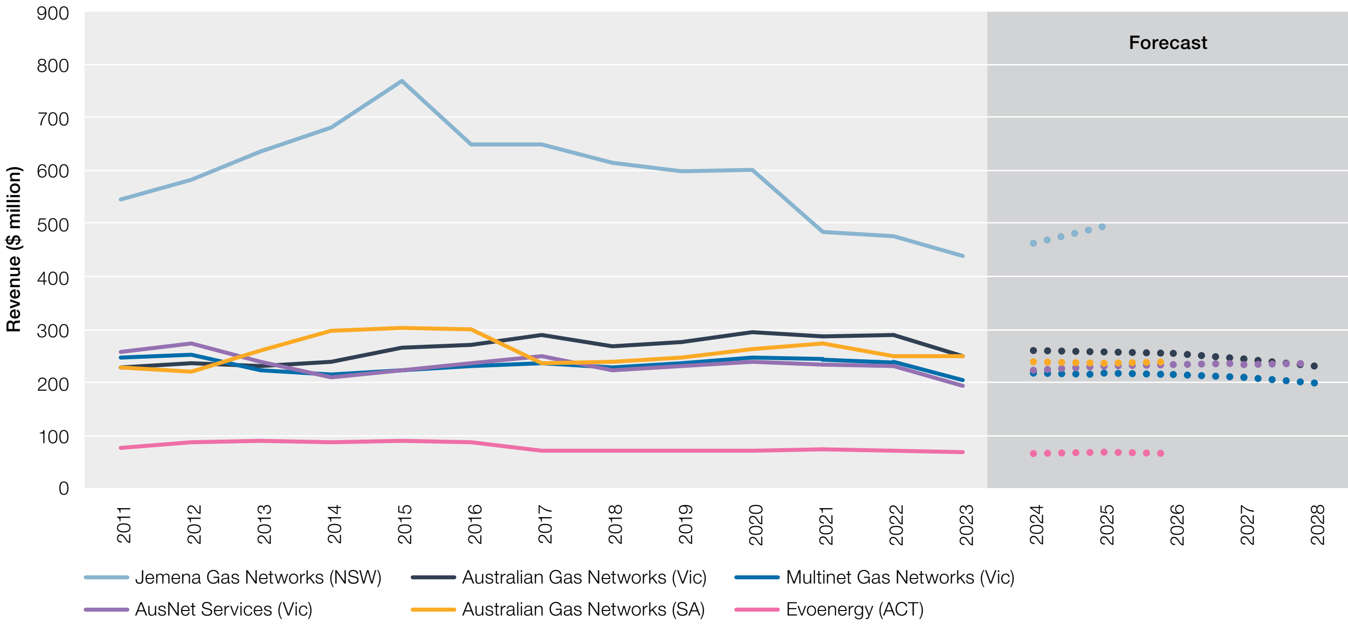


Note: All data are adjusted to June 2023 dollars. APA Victorian Transmission System (Vic) reports on a calendar year basis (year ending 31 December). All other pipeline businesses report on a financial year basis (year ending 30 June). The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018). Amadeus Gas Pipeline's (Northern Territory) actual revenue data is confidential.
Source: AER modelling; annual reporting RIN responses.

Revenues for most of the distribution pipeline service providers are forecast to decrease in the current access arrangement period. These forecast decreases are driven by the reductions in return on capital (section 5.9) and net tax allowance offsetting the forecast increases in operating expenditure and depreciation.

455 Excludes revenue earned by Amadeus Gas Pipeline (Northern Territory). Amadeus Gas Pipeline's actual revenue is confidential because it contains commercially sensitive information.

Figure 5.9 Revenue – gas distribution pipelines



Note: All data are adjusted to June 2023 dollars. Up until 31 December 2022, Victorian gas pipeline service providers reported on a calendar year basis (year ending 31 December). From 1 July 2023, Victorian pipeline service providers will report on a financial year basis. No revenue forecasts were developed for the Victorian pipeline service providers for the 6-month transition period (1 January 2023 to 30 June 2023). All other distribution pipeline service providers report on a financial year basis (year ending 30 June). The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018).

Source: AER modelling; annual reporting RIN responses.

Costs of capital and inflation have been increasing in recent years, both of which put upward pressure on gas pipeline revenue drivers (section 5.9), similar to what has occurred for electricity networks. Any increases in a pipeline service provider's allowed rate of return will be reflected in forecast revenue through the return on capital building block (section 5.5.1).

Specific investment requirements will also increase pipeline costs, so additional revenue is still needed to cover some new projects. For example, APA Victorian Transmission System has justified the need for capital expenditure to finance its South West Pipeline and Western Outer Ring main projects. These projects were deemed necessary to avert shortfalls and increase capacity between existing sources of natural gas supply.[456]

5.8 Capital base

The capital base for a gas pipeline service provider represents the total economic value of assets that provide services to customers. The value of the capital base substantially impacts a service provider's revenue requirement.

Capital investment approved by the AER is added to a service provider's capital base, on which future returns are earned.

Although the forecast demand for natural gas continues to decline (section 5.6.1), new gas infrastructure investments and ongoing asset maintenance are necessary to ensure the reliability and safety of gas supply. The impact of new investment adds to the value of the capital base, the cost of which will be recovered across a declining base of customers, pushing gas prices up for those remaining customers.[457]

456 AER, APA Victorian Transmission System – Access arrangement 2023–27, Australian Energy Regulator, 9 December 2022, accessed 2 December 2024.

457 AER, Submission to Victoria's Gas Substitution Roadmap consultation paper, Australian Energy Regulator, 2 August 2021, accessed 11 June 2023.

Box 5.3 Accelerated depreciation to address asset stranding risk

In its final decisions on the 2023–28 access arrangements for the Victorian gas transmission and distribution pipelines, the AER allowed for some accelerated depreciation of assets. The combined value of asset bases to be recovered across these Victorian pipelines for their remaining lives is around $6 billion. Bringing forward the recovery of assets while pipeline use remains relatively high has increased costs to consumers of the pipeline in the short term, but reduced the pool of depreciation to be recovered from consumers in the future when pipeline use is expected to be lower.

Accelerating the rate at which assets are depreciated is pertinent given the uncertain future for gas pipelines in Victoria. It is important to take small steps now to manage the equitable recovery of the cost of the assets from what will be a declining, and sometimes vulnerable, customer base over time.

AEMO forecasts a material decline in gas volumes over the next 20 years (section 5.6.1). There is also considerable uncertainty around likely medium to long-term forecast volumes of customer abolishment (Box 5.2). Further, the future role for hydrogen and other renewable gases is uncertain at this time.

The Victorian Government's Gas Substitution Roadmap commits to achieve net zero emissions by 2050 (section 5.5). This will likely mean a limited role for natural gas beyond this date. The roadmap includes several initiatives that will reduce the role for gas in Victoria, such as incentives for residential customers to switch to electric appliances, the removal of planning provisions requiring new housing developments to connect to gas and higher energy efficiency requirements for housing.

These changes are likely to eventuate, but the pace of change remains uncertain. We consider that approving some amount of accelerated depreciation is consistent with our information paper 'Regulating gas pipelines under uncertainty' (section 5.5.5), wherein we stated, '… the opportunity and flexibility for adjustment is greatest when we act as soon as we can to minimise the adverse impact of a decline in gas demand'.

The AER seeks to strike a balance between determining an appropriate level of accelerated depreciation and the impact it will have on price stability (section 5.5.1). For example, we did not allow the full amount of accelerated depreciation sought by some Victorian gas distribution service providers. We instead allowed a smaller start to accelerated depreciation that balanced the price impacts in the short term with the need for longer-term price stability.

We consider that accepting some accelerated depreciation leaves open the option to change course at future reviews, where more accelerated depreciation or reversals at a future date may be required to promote efficient growth (including negative growth) of the market as required under the National Gas Rules.

The declining demand for gas is not unique to Australia. In July 2024, scientific journal Cell Press published a journal highlighting the issue of regulating gas transportation infrastructure in Europe. According to Cell Press:

'… the era of widespread fossil gas consumption across Europe will also come to an end as the world decarbonises it energy use.' 'At the moment, regulation in most European countries treats gas distribution broadly as if they are expected to operate in perpetuity, though there are some exceptions.' [As is the case in Australia, the declining demand for gas] 'poses a significant challenge for policy makers: if fewer customers use gas, how is the decline of the system managed and who pays for it…?'

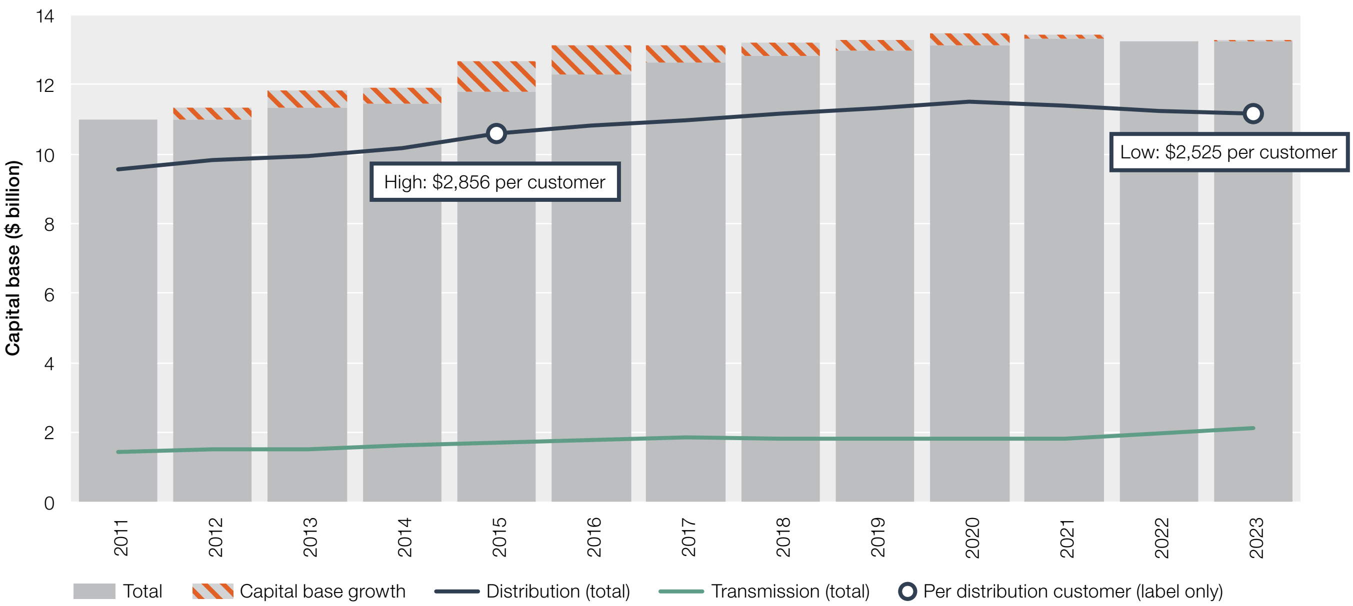
'The Netherlands is making far-reaching changes via a combination of accelerated depreciation and local authority powers. In the current regulatory period (2022–26), distribution system operators are permitted to depreciate investments in their grids on a cost-reflective basis which recognises a shrinking grid. This is intended to align the costs with the actual use of the network, with connection points expected to decrease in the medium term. Furthermore, gas distribution system operators receive compensation for the costs of dismantling the gas distribution networks and for removing connection points. … UK regulator Ofgem has consulted on future network regulation, which includes a proposal to accelerate financial depreciation rates and smooth their impacts in line with expected disconnection rates'.[a]

a Rosenow, et al., The elephant in the room: How do we regulate gas transportation infrastructure as gas demand declines?, One Earth, 19 July 2024 (purchased journal).

5.8.1 Capital base in 2023

As at 30 June 2023, the total combined value of the capital base for gas pipeline service providers was $13.3 billion, an increase of $31 million from the previous year (Figure 5.10).

Figure 5.10 Value of gas pipelines assets (capital base)



Note: All data are adjusted to June 2023 dollars. Victorian pipeline service providers report on a calendar year basis (year ending 31 December). All other pipeline service providers report on a financial year basis (year ending 30 June). The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018).

Source: AER modelling.

5.9 Rates of return

The shareholders and lenders that finance a gas pipeline service provider expect a return on their investment. The rate of return estimates the financial return a pipeline service provider's financiers require to justify investing in the business. It is a weighted average of the expected returns needed to attract both equity and debt funding. Equity funding is provided by shareholders in exchange for part ownership of a pipeline service provider, while debt funding is provided by an external lender such as a bank. Given this weighted approach, the rate of return is sometimes called the weighted average cost of capital (WACC).

The AER sets an allowed rate of return based on a benchmark efficient entity, but a service provider's actual returns can vary from the allowed rate. The difference can be due to several factors, such as the impact of incentive schemes, efficiency improvements, forecasting errors or the pipeline service provider adopting a different debt or tax structure to the benchmark efficient entity. Some differences may be temporary if caused by revenue over-recovery or under-recovery under a revenue cap or the revenue smoothing process. The AER calculates allowed returns each year by multiplying the capital base (section 5.8) by the allowed rate of return.[458]

Lower financing costs and updated estimates of rate of return parameters contributed to the average allowed rate of return declining from around 10% at the beginning of the 2010s, to less than 6% from 2018 (Figure 5.11). This reduction translated to significantly lower forecast pipeline revenue requirements.

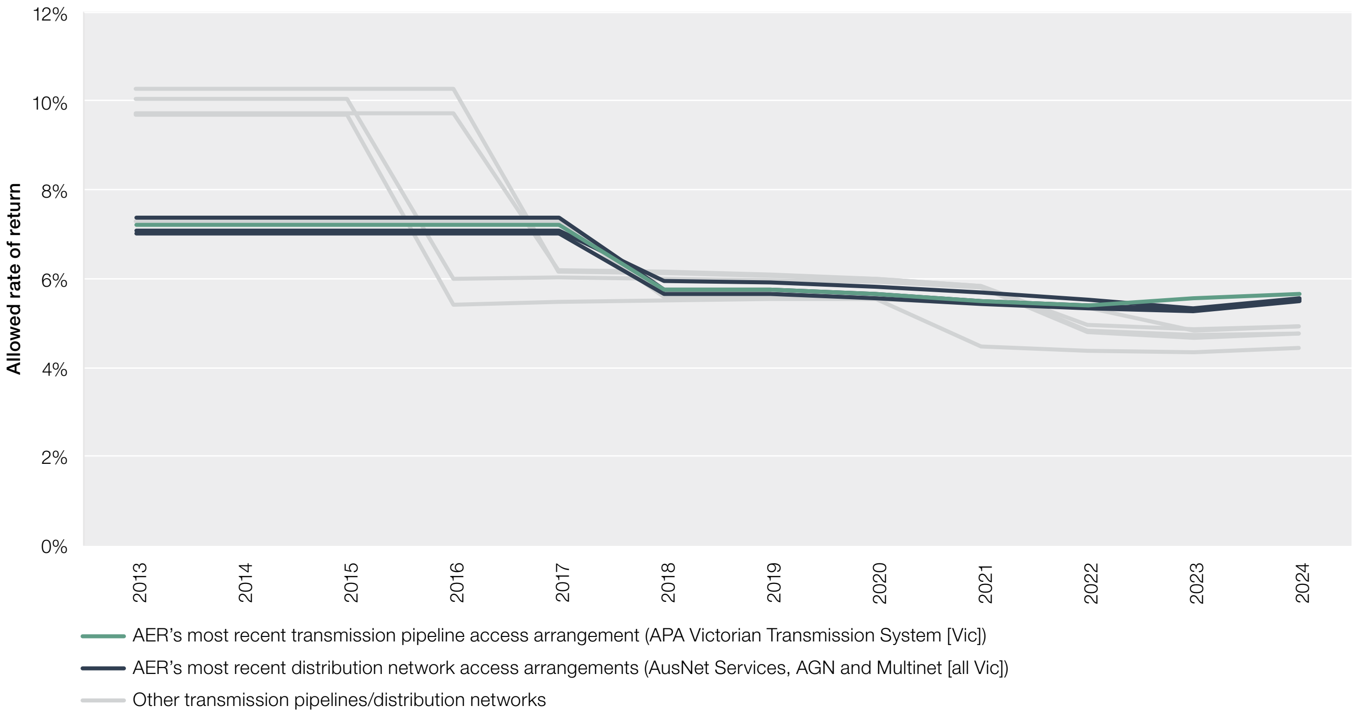
Legislation introduced in 2018 provided for the AER to make binding rate of return determinations that apply to all regulated pipeline service providers.

458 For example, if the rate of return is 5% and the capital base is $10 billion, then the return to investors is $500 million. This return forms part of a gas pipeline business's revenue needs and must be paid for by customers.

In February 2023, the AER released its latest rate of return instrument (the 2022 Instrument). The rate of return is a key component used to determine the amount of revenue network service providers can recover from customers. The AER sets the rate of return to cover the cost of capital of an efficient service provider.

In March 2024, the AER released an updated version of the February 2023 Instrument, which binds all access arrangements from 25 February 2023 until the next revision of the Instrument.[459]

Figure 5.11 Allowed rate of return



Note: Allowed rate of return = nominal vanilla weighted average cost of capital (WACC).

Source: AER decisions on gas pipeline access arrangements; AER decision following the remittal by the Australian Competition Tribunal and Full Federal Court.

Recently, some key inputs into rates of return have increased. For example, the risk-free rate is an important driver of allowed returns on equity and is estimated using required returns on Commonwealth Government Securities (CGSs), also known as Australian Government bonds. Since January 2020, annual yields on 10-year CGSs have ranged from 0.61% (March 2020) to 4.94% (November 2023). Over the 12-month period to July 2024, annual yields on 10-year CGSs averaged around 4.24%.[460]

459 AER, Rate of Return Instrument 2022, Australian Energy Regulator, accessed 18 April 2024.

460 RBA, Capital Market Yields – Government Bonds – Daily – F2, Reserve Bank of Australia, accessed 10 July 2024.

5.10 Capital expenditure

Capital expenditure (i.e. investment) requirements differ between the gas transmission and distribution sectors.

Investment in gas transmission typically involves large capital projects to expand existing pipelines (through compression, looping or extension) or constructing new infrastructure. Additionally, some transmission pipelines have been re-engineered for bidirectional flows.

Investment in gas distribution mainly comprises augmentation (expansion) of existing systems to cope with new customer connections, such as for new housing estate developments. Older pipelines also require replacement programs for deteriorating infrastructure. For regulated service providers operating scheme pipelines (Table 5.1), the AER assesses whether investments are prudent and efficient based on criteria in the National Gas Rules.

Long-term demand risk can influence the AER's regulatory decisions on pipeline investments. Demand forecasts that underpin the need for new investments are carefully scrutinised.

Changes in demand can lead to pipeline assets becoming 'stranded', wherein they are prematurely written down, devalued or even reclassified as liabilities. The costs to maintain a gas pipeline do not decrease in proportion to gas demand decline.[461] Regulated service providers will incur ongoing maintenance and replacement costs to maintain safe and reliable reference services for the remaining customers on the network, subject to any partial shutdowns of the network, for as long as the gas pipeline assets remain in use.

5.10.1 Capital expenditure in 2023

Over the 12-month period to 30 June 2023, pipeline service providers invested $797 million in capital projects, $24 million (3.1%) more than in the previous year and $60 million (8%) more than was forecast. The significant increase in capital expenditure on transmission pipelines in 2022 and 2023 was driven by APA Victorian Transmission System's expansion of the South West Pipeline and its construction of the Western Outer Ring Main project.

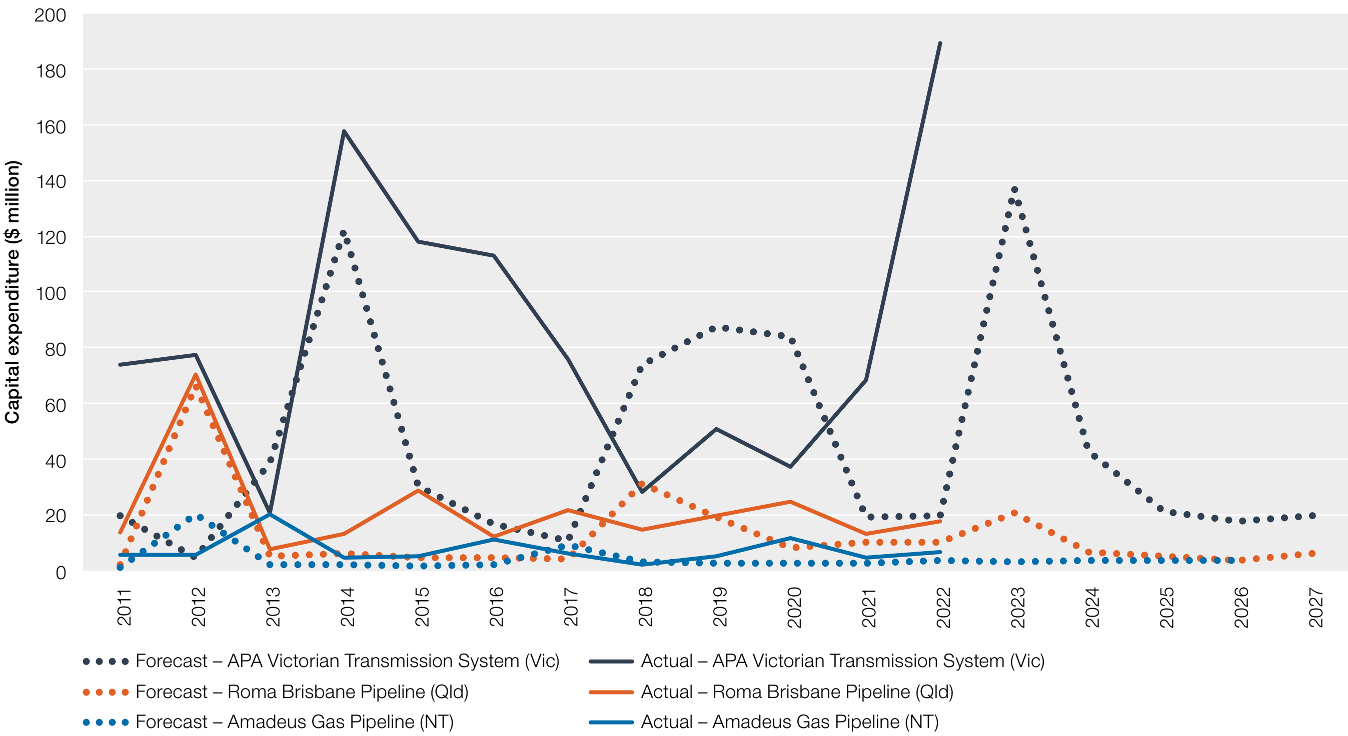
Table 5.5 provides a breakdown of the amount of investment that pipeline service providers undertook in 2023 and how this compared with previous years' expenditure and forecasts.

Table 5.5 Capital expenditure in 2023 – key outcomes

Service type	Capital expenditure (2023)	Capital expenditure (compared with 2022)	Capital expenditure (compared with peak)
Transmission	$209m (▲30% than forecast)	▼$4m (▼2.1%)	▼$4m (▼2.1%) (2022)
Distribution	$588m (▲1.9% than forecast)	▲$28m (▲5%)	▼$159m (▼21%) (2015)
Total	$797m (▲8% than forecast)	▲$24m (▲3.1%)	▼$102m (▼11%) (2015)

461 Lucas Davis, Catherin Hausman, Energy Institute at Haas, Who will pay for legacy utility costs?, March 2022.

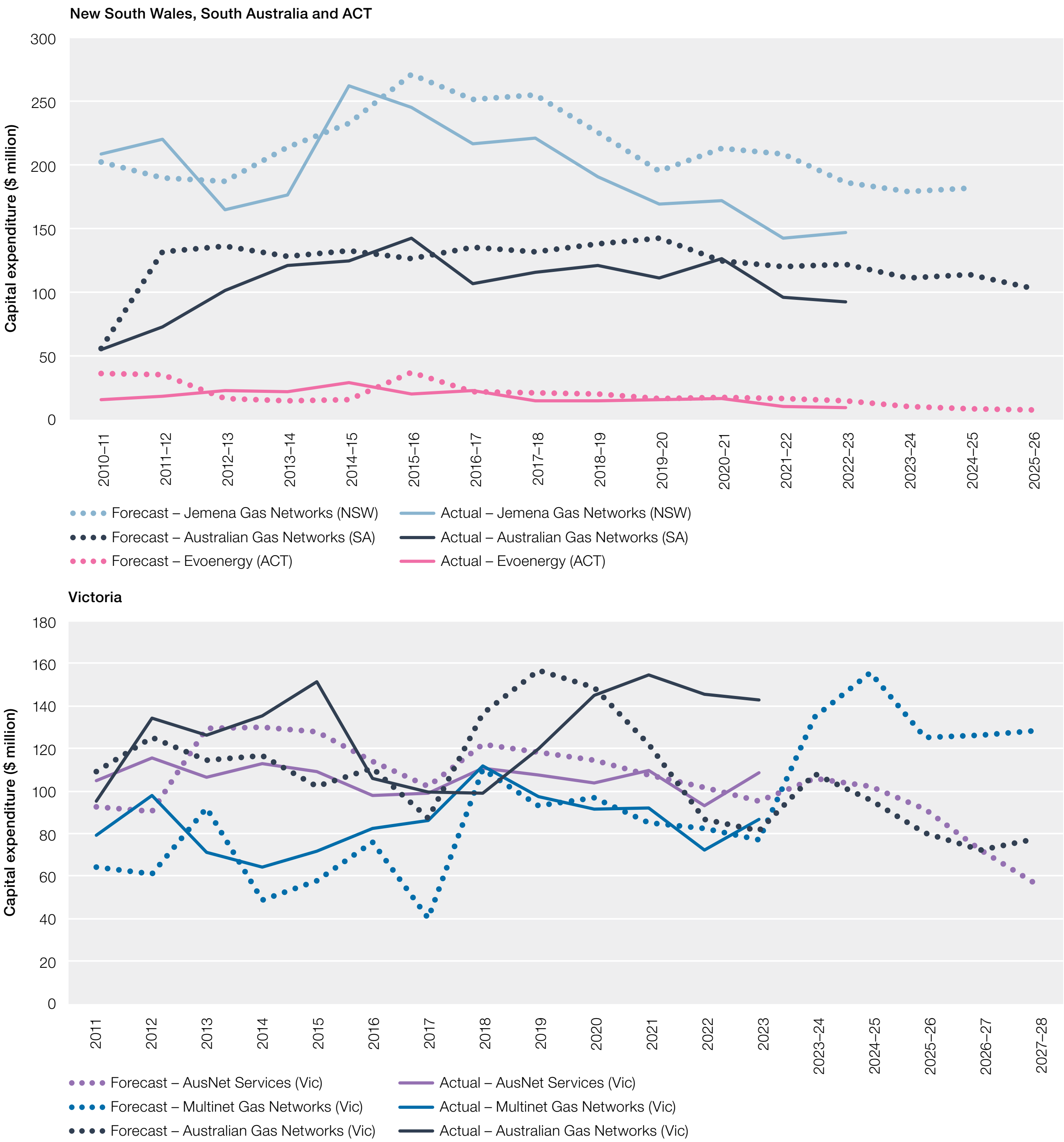
Figure 5.12 Capital expenditure – gas transmission pipelines



Note: All data are adjusted to June 2023 dollars. APA Victorian Transmission System (Vic) reports on a calendar year basis (year ending 31 December). All other pipeline service providers report on a financial year basis (year ending 30 June). The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018).

Source: AER modelling; annual reporting RIN responses.

Figure 5.13 Capital expenditure – gas distribution pipelines



Note: All data are adjusted to June 2023 dollars. Up until 31 December 2022, Victorian pipeline service providers reported on a calendar year basis (year ending 31 December). From 1 July 2023, the Victorian pipeline service providers report on a financial year basis. To enable reporting on equivalent terms, forecasts for the Victorian pipeline service providers for the 6-month transitional period (1 January to 30 June 2023) have been doubled. All other pipeline service providers report on a financial year basis (year ending 30 June). The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018).

Source: AER modelling; annual reporting RIN responses.

5.11 Operating expenditure

Pipeline service providers incur operating and maintenance costs that absorb around 42% of their annual revenue (35% for transmission and 43% for distribution) (Figure 5.5). When assessing a pipeline service provider's efficient operating and maintenance costs, the AER considers cost drivers such as forecast customer growth, expected productivity improvements, changes in labour prices, and changes in the regulatory environment. Pipeline service providers are also subject to an efficiency carryover mechanism, which incentivises them to reduce operating expenditures where efficient to do so.

5.11.1 Operating expenditure in 2023

Over the 12-month period to 30 June 2023, pipeline service providers spent $619 million on operating costs, $29 million (5%) more than in the previous year, but $76 million (11%) less than was forecast.

Table 5.6 provides a breakdown of pipeline service providers' operating costs in 2023 and how this compared with previous years' expenditure and forecasts.

Table 5.6 Operating expenditure in 2023 – key outcomes

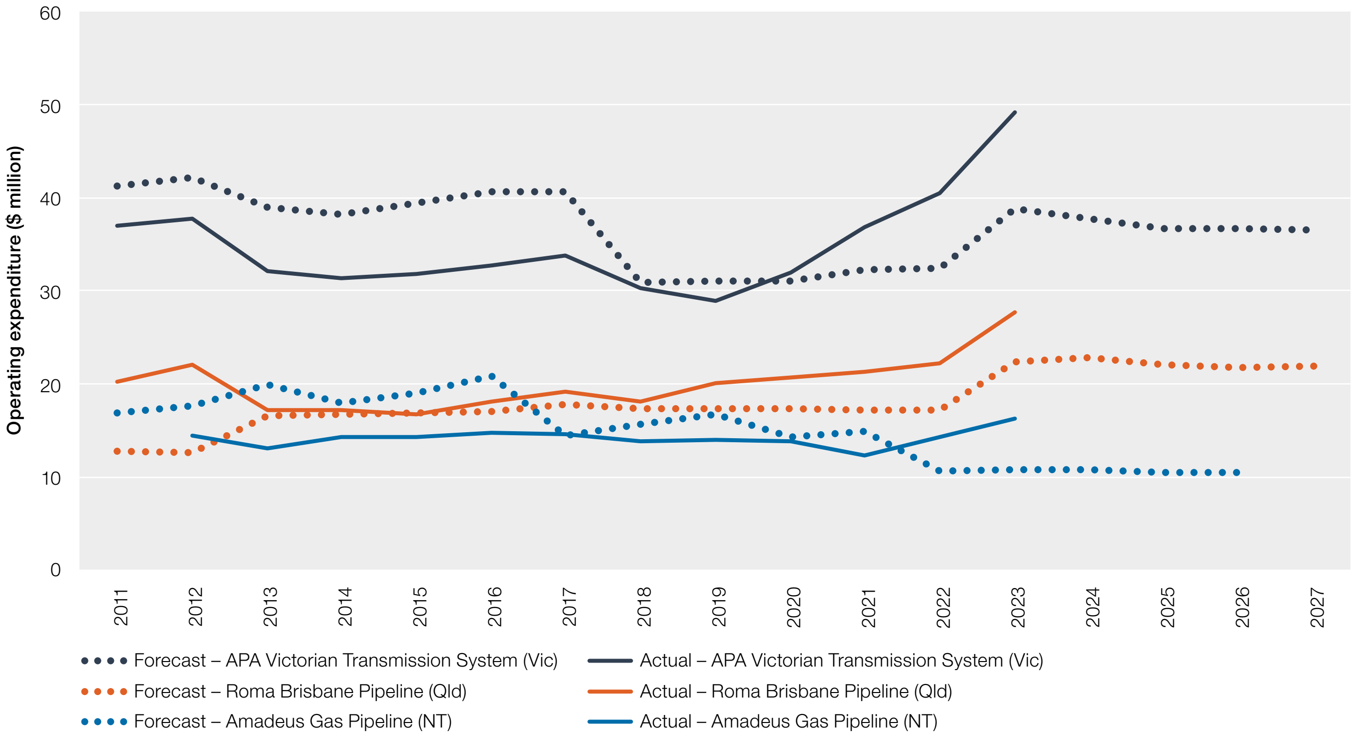
Service type	Operating expenditure (2023)	Operating expenditure (compared with 2022)	Operating expenditure (compared with peak)
Transmission	$93m (▲29% than forecast)	▲$16m (▲21%)	2023 = peak
Distribution	$526m (▼15% than forecast)	▲$13m (▲2.6%)	▼$33m (▼6%) (2012)
Total	$619m (▼11% than forecast)	▲$29m (▲5%)	▼$14m (▼2.3%) (2012)

The differing trends in transmission and distribution pipeline service providers operating expenditure is quite pronounced. In each of the 4 years since 2019, transmission pipeline service providers have overspent against forecast by an average of 18% (Figure 5.14). Conversely, in each of the 6 years since 2017, distribution pipeline service providers have underspent against forecast by an average of 11% (Figure 5.15).

Over the 6-year period to 2023, Multinet Gas Networks (Victoria) and Australian Gas Networks (South Australia) have underspent by 23% and 20%, respectively. However, these underspends may be attributed to ongoing cost savings stemming from the purchase of the pipelines in 2017[462] and 2014,[463] respectively.

462 Australian Financial Review, FIRB approves Cheung Kong's DUET acquisition, 20 April 2017, accessed 2 August 2024.
463 Australian Gas Networks, Australian Gas Networks – Our History, accessed 2 August 2024.

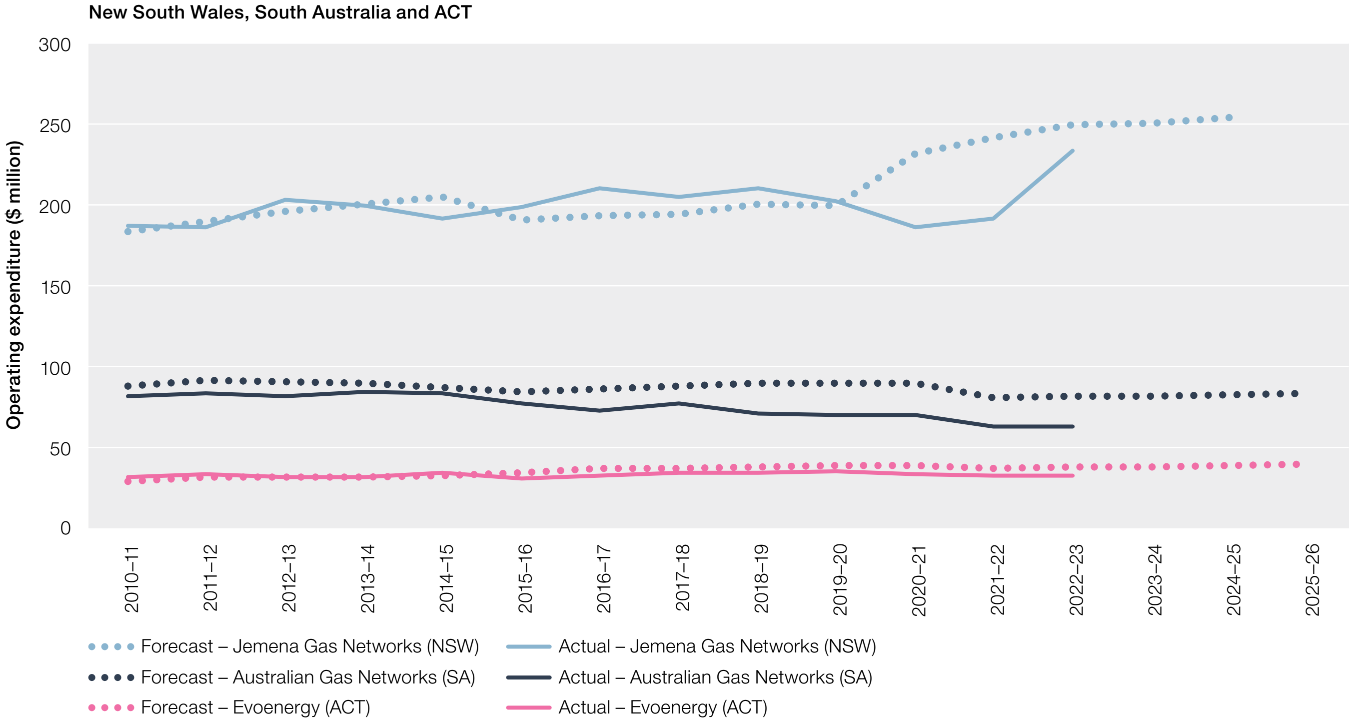
Figure 5.14 Operating expenditure – gas transmission pipelines

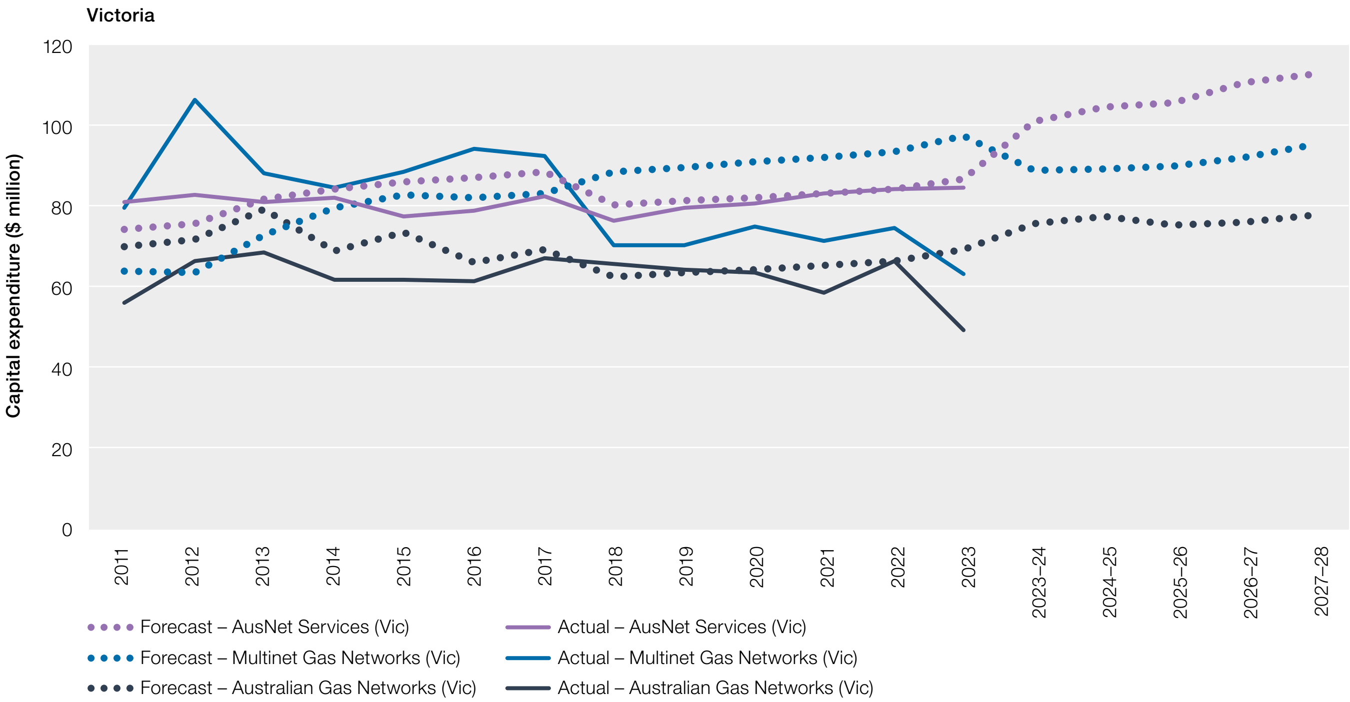


Note: All data are adjusted to June 2023 dollars. APA Victorian Transmission System (Vic) reports on a calendar year basis (year ending 31 December). All other pipeline service providers report on a financial year basis (year ending 30 June). The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018).

Source: AER modelling; annual reporting RIN responses.

Figure 5.15 Operating expenditure – gas distribution pipelines





Note: All data are adjusted to June 2023 dollars. Up until 31 December 2022, Victorian pipeline service providers reported on a calendar year basis (year ending 31 December). From 1 July 2023, the Victorian pipeline service providers report on a financial year basis. To enable reporting on equivalent terms, forecasts for the Victorian pipeline service providers for the 6-month transitional period (1 January to 30 June 2023) have been doubled. All other pipeline service providers report on a financial year basis (year ending 30 June). The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018).

Source: AER modelling; annual reporting RIN responses.

6 Retail energy markets

Retail energy markets are the final link in the energy supply chain, providing an interface for energy retailers and energy service providers to sell electricity, gas and energy services to residential and small business customers.[464] The National Energy Customer Framework (NECF) and the Energy Retail Code of Practice (Victoria) regulate the sale and supply of electricity and gas to retail customers.[465]

Retailers purchase energy either from direct contracts with suppliers or from wholesale markets and onsell it to consumers.[466] Consumers are generally able to choose the provider they purchase energy from based on the price and suitability of services available.[467]

Retailers are exposed to financial risk through spot price volatility in wholesale energy[468] markets. To manage this, most retailers purchase hedging contracts that limit part or all of the wholesale price they pay (chapter 2, section 2.5). Hedging enables retailers to offer stable prices to consumers, so that consumers have more predictable energy bills instead of bearing the financial risk of more volatile wholesale energy prices.

Consumers continue to seek more autonomy over their energy costs through installation of consumer energy resources – such as rooftop solar and home batteries. Residential solar photovoltaic (PV) installed in the National Electricity Market (NEM) now exceeds 20 gigawatts (GW), following almost 3 GW of rooftop solar capacity added by consumers in the 2023–24 financial year (chapter 2,

464 Residential customers and small business customers (that consume energy at business premises below the upper consumption threshold) are considered 'small customers' under the National Energy Retail Law. The term 'small customers' is used throughout this report to refer to both residential and small business customers. Where required, the terms 'residential' and 'small business' are used separately.

465 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 30 August 2024.

466 Electricity generally must be purchased through the National Electricity Market, but gas is more likely to be purchased directly from suppliers (around 85%) than through the domestic east coast gas market.

467 Consumers in embedded networks – such as those in some apartment buildings, retirement villages or caravan parks where the site owner sells the electricity – may have less opportunity to choose a retailer. This could be because of the different metering and wiring arrangements of the embedded network, or lack of authorised retailers that will provide an 'energy only' contract. Consumers experiencing vulnerability may also face challenges in choosing a retailer (see section 6.6.7 for more information).

468 The word 'energy' is used throughout this chapter when it refers to both electricity and gas. The words 'electricity' and 'gas' are used separately when required.

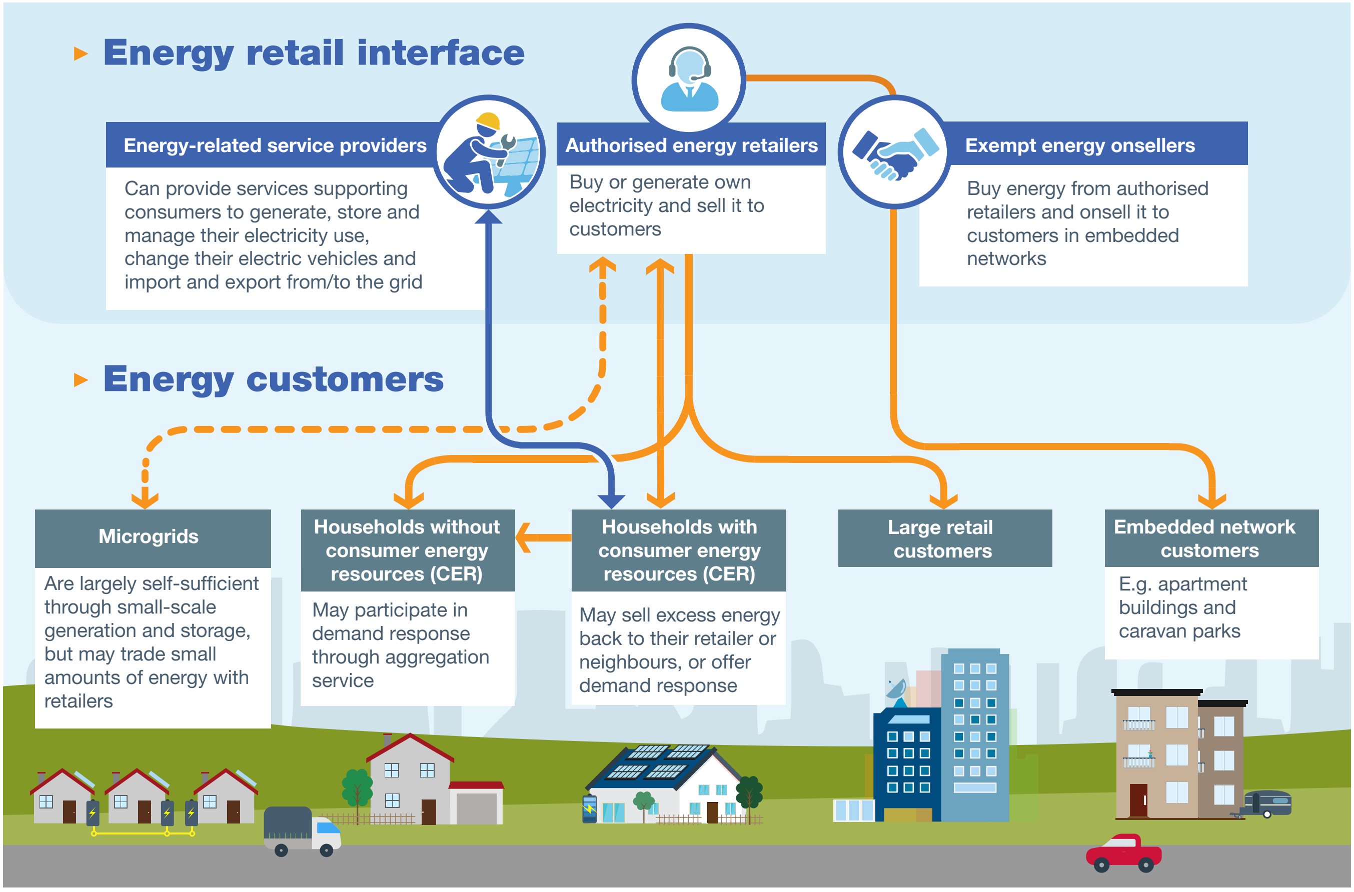
section 2.8.1). This is equivalent to 25% of registered generation capacity across the NEM, making rooftop solar the fuel source with the highest registered capacity across the NEM (chapter 2, Figure 2.14).[469]

Despite some easing of wholesale electricity costs following the significant market events of winter 2022,[470] consumer energy costs remain high by historical standards (chapter 2, Figure 2.3). With broader cost-of-living pressures, increasing network prices and general inflation, retail prices are expected to remain high (section 6.4.1). In 2023–24, bills for customers on standing offers increased compared with the previous year in Queensland, New South Wales, South Australia, the ACT and Tasmania.[471] Bills for customers on market offers increased less markedly than standing offer customers.

Gas bills increased for all customers except those on market offers in some remote Queensland network areas. Gas bills for customers on standing offers increased significantly more compared with those on market offers in all NEM regions. As with 2022–23, Victorian gas customers experienced the most significant increases in 2023–24 (Figure 6.4 and Figure 6.5). Further analysis and more up-to-date data will be provided in the AER's forthcoming Annual retail markets report 2023–24.[472]

With energy affordability continuing to be a priority, governments have implemented measures such as fuel price caps on coal and gas and new power bill relief funds to ease cost-of-living pressures.

Figure 6.1 Retail energy market supply chain



469 Capacity generated by rooftop solar is subtracted from demand (rather than traded in the NEM). With rooftop solar output records set over the summer of 2022–23, when rooftop solar reached a record 11,504 MWh, the rapid uptake of rooftop solar continues to be the major contributing factor to reduced grid demand.

470 In 2022, multiple factors combined to put extreme upward pressure on prices in the NEM. These included coal plant outages, coal supply issues, domestic gas supply shortfalls and hydro generating constraints. For more information see AER, June 2022 market events report, Australian Energy Regulator, 14 December 2022.

471 Standing offer bills remained stable for customers in the Ergon Energy network (Queensland), which has historically remained stable. Customer bill data is calculated based on available offers displayed over time on government price comparison websites Energy Made Easy and Victorian Energy Compare. Pricing data is aggregated across multiple pricing areas within some electricity and gas distribution networks.

472 The AER's Retail performance reporting includes the Annual retail markets report published in November and Retail energy market performance updates published quarterly.

Box 6.1 The AER's role in retail energy markets

The Australian Energy Regulator (AER) protects consumers by regulating the market to ensure they pay no more than necessary for safe, reliable and affordable energy, and by ensuring energy businesses comply with the rules.

We regulate retail energy markets in jurisdictions that have implemented the National Energy Retail Law, including electricity and gas customers in Queensland, New South Wales (NSW), Victoria (electricity connection for retail customers only), South Australia, the Australian Capital Territory (ACT) and Tasmania (electricity customers only). We protect residential and small business energy consumers (particularly vulnerable consumers) while enabling consumers to participate in energy markets.

We are responsible for:

- setting a price cap on standing offers for electricity in South East Queensland, NSW and South Australia – this cap also acts as a reference price for market offers
- maintaining an energy price comparator website (energymadeeasy.gov.au) to help residential and small business customers understand the range of offers in the market, make better choices about those offers and be aware of their rights and responsibilities when dealing with energy providers
- assessing applications from businesses looking to become energy retailers and granting exemptions from the requirement to hold a retailer authorisation
- administering a retailer of last resort scheme, which protects customers and the market if an energy retailer fails
- developing guidance notes for energy retail, wholesale, distribution and transmission markets, and corporate and consumer matters
- monitoring and enforcing compliance (by retailers, exempt sellers and distribution network service providers) with obligations in the Retail Law, Rules and Regulations
- approving policies energy retailers must implement to assist customers who are facing financial hardship and looking for help to manage their bills
- monitoring the NEM and reporting on market performance and energy businesses, including information on trends on energy affordability and customers experiencing hardship.

6.1 Retail market snapshot

Since the last *State of the energy market* report:

- Energy bills for consumers remain high compared with historical levels (section 6.4). An increase in electricity bills for customers on standing and market offers is observable in all NEM regions in 2023–24 compared with the previous year. Gas bills for customers on market offers saw an increase in every jurisdiction, except for Queensland, where there was a marginal reduction. For electricity and gas customers on standing offers, bills increased more than for those on market offers in most regions.
- Broader cost-of-living pressures and increased customer debt levels indicate some consumers are not well-placed to absorb continuing increases in energy prices.
- In its 2024–25 Budget, the Australian Government provided $1.8 million over 4 years to implement a range of consumer-focused energy retail reform measures. These included support for consumers switching to a better deal with just 'one click' and up to $3.5 billion towards an Energy Bill Relief Fund to provide electricity rebates of up to $300 for eligible households and $325 for eligible small businesses. State and territory governments commenced rolling out the rebate schemes in all NEM regions in July 2024. This is in addition to the existing state-based rebate and concession schemes established by state and territory governments.

- Following the 19 July 2024 Energy and Climate Change Ministerial Council meeting, Hon Chris Bowen MP, Minister for Climate Change and Energy submitted a rule change request to the Australian Energy Market Commission (AEMC) to amend the National Energy Retail Rules (NERR). The rule change is part of a package of proposed rule changes to improve energy affordability and consumer protections.[473]
- The AER's calculation of the electricity default market offer 2024–25 (DMO 6) was modified this year to better take into account the treatment of smart meter customers within the forecasting approach. Since DMO 5 (2023–24), the AER has observed wholesale costs easing off while network costs have increased, and that increased retail costs were mostly offset in many regions by the lower allowances (including margins) that AER allowed retailers. These movements have resulted in overall prices decreasing in NSW and South Australia and increasing in southeast Queensland.[474]
- The AER is progressing broader strategies to support energy equity and affordability, including advocating for new consumer protections, and better addressing the needs of consumers experiencing payment difficulties. These include the Game Changer Report, the Final advice to government on future consumer protections, and the Towards energy equity strategy. These strategies they seek to address the AER's concerns about the impact market developments on consumers experiencing vulnerability, who may be less able to adopt technology, modify their energy use or shop around for a cheaper energy contract.

6.2 Retail energy market regulation

Five jurisdictions – Queensland, NSW, South Australia, Tasmania and the ACT – apply a common national framework for regulating retail energy markets. The framework applies to electricity retailing in all 5 jurisdictions and to gas retailing in Queensland, NSW, South Australia and the ACT.

The Retail Law operates alongside the Australian Consumer Law to protect small energy consumers in their electricity and gas supply arrangements. It sets out protections for residential consumers and small businesses.[475] Victoria does not apply the national framework but applies similar regulatory provisions.[476]

The Retail Law and equivalent arrangements in Victoria focus on consumer protections related to the traditional retailer–customer relationship in buying electricity and gas. Protections are generally stronger for consumers supplied through an authorised retailer than consumers in embedded networks or entering solar power purchase agreements.[477]

State and territory-based regulators regulate electricity prices in regional Queensland, Victoria, Tasmania and the ACT.[478] Since 1 July 2019 the AER has set caps on 'standing offer' prices[479] for electricity through the default market offer (DMO). The DMO applies in jurisdictions without state-based price regulation (section 6.4).

473 AEMC, Assisting hardship customers, Australian Energy Market Commission, accessed 11 September 2024.

474 For more analysis on drivers for network cost increases in all jurisdictions see AER, Final Determination – Default market offer prices 2024–25, Australian Energy Regulator, 1 July 2024.

475 The thresholds for who meets the criteria of a residential customer or small business varies between jurisdictions. For example, in jurisdictions where the Retail Law applies, it includes those consuming fewer than 100 megawatt hours (MWh) of electricity or 1 terajoule (TJ) of gas per year. For electricity, in South Australia, small electricity customers are those consuming fewer than 160 MWh per year. In Tasmania, the threshold is 150 MWh per year.

476 Changes to the Victorian framework, including recommendations adopted from the Thwaites *Independent review into the electricity & gas retail markets in Victoria* (August 2017), have seen greater divergence between the Victorian and national frameworks.

477 Embedded networks are smaller, localised private networks that distribute energy to sites such as apartment blocks, retirement villages, caravan parks and shopping centres. They operate alongside major distribution networks under a similar, but different regulatory framework (see section 6.2.3). A solar power purchase agreement is a contract where a business provides, installs and maintains the solar panels in exchange for the consumer agreeing to buy the energy produced by the system at an agreed price for an agreed period.

478 These include the Queensland Competition Authority in regional Queensland, Essential Services Commission in Victoria, Independent Commission and Regulatory Commission in the ACT and Office of the Tasmanian Economic Regulator in Tasmania.

479 Standing offers apply where a customer does not enter a market contract. The terms and conditions of standing offers are prescribed in the National Energy Retail Rules and include consumer protections not required in market retail contracts, such as access to paper billing, minimum periods before bill payment is due, a set period for reminder notices, and no more than one price change every 6 months.

This chapter focuses on the 5 jurisdictions where the AER has regulatory responsibilities, but also covers the Victorian market where applicable. Western Australia and the Northern Territory apply separate regulatory arrangements and are not covered in this report, except where data from those jurisdictions is necessary to provide insights into broader energy consumer issues or assist in comparative analysis between the NEM and other energy systems.

6.2.1 Sellers and resellers of energy services

Market participants that sell and resell energy and services to consumers are classified into:

- those authorised as retailers under the Retail Law
- those exempt from the requirement to be authorised[480]
- those offering energy products and services beyond the scope of the Retail Law – such as energy management services, solar and storage products and off-grid energy systems.

Only customers of authorised retailers enjoy the full protections in the Retail Law, which is administered and enforced by the AER. Other consumers may be covered by the broader Australian Consumer Law, which is administered and enforced jointly by the Australian Competition and Consumer Commission (ACCC) and state and territory consumer protection agencies.[481]

6.2.2 Authorised energy retailers

Under the Retail Law a person must hold a retailer authorisation (unless exempt from the requirement) to sell electricity or gas. The AER issues retailer authorisations and seeks to ensure compliance with consumer protection and other obligations under the Retail Law and Retail Rules. An authorisation covers energy sales to consumers in all 5 participating jurisdictions.[482]

While Victoria is part of the NEM, the Victorian Essential Services Commission (ESC) is also responsible for authorising new retailers into the energy market.

6.2.3 Exempt energy sellers

An energy seller may apply[483] to the AER or the ESC (Victoria) for an exemption from authorisation if it only intends to supply energy services to:

- a limited customer group (for example, at a specific site or incidentally through a relationship such as a body corporate)
- supplement its customers' primary energy connection
- sell or supply electricity ancillary to telecommunication services, such as data centres.

As at August 2024, over 3,600 unique businesses were registered in the AER's public register of exemptions to onsell energy within an embedded network (that is, a small private network whose owner supplies energy to other parties connected to the network).[484] Examples of entities that might be exempt sellers are shopping centres, retirement villages, caravan parks and apartment complexes or remote/rural communities where energy is generated and sold off-grid. Solar power purchase agreement providers are also covered by the AER's and ESC's exemptions frameworks.

480 In Victoria, where the Retail Law does not apply, retailers must hold a licence issued by the Essential Services Commission or seek an exemption from this requirement.

481 Queensland has implemented additional provisions about selling electricity using card-operated meters and model terms and conditions for standard retail contracts for card-operated meters. These are contained in the National Energy Retail Law (Queensland) and National Energy Retail Law (Queensland) Regulation 2014.

482 See the AER website for a public register of authorised retailers and authorisation applicants.

483 Some energy sellers have 'deemed' exemptions, and do not need to apply or register with the AER before receiving the exemption. Examples can include a site-owner selling metered electricity or gas to fewer than 10 customers within the limits of the site.

484 The number of unique businesses registered as exempt energy sellers does not equate to the number of embedded network sites, as a business may onsell to customers across multiple sites.

The Australian Energy Market Commission (AEMC) cited stakeholder estimates that up to 500,000 consumers purchase electricity through embedded networks.[485] Exemption holders must follow strict conditions and meet a range of obligations to their customers (detailed in the AER's guidelines). Conditions are based on the obligations that apply to authorised retailers and distribution network service providers, but are a lighter, less prescriptive form of regulation.[486]

6.2.4 AER review of retail performance data

The *AER (Retail Law) Performance Reporting Procedures and Guidelines* establish how energy retailers report data on their performance – as relates to the National Energy Retail Law (NERL) – to the AER.[487] The AER recently reviewed the Guidelines to better enable data collection and monitor retail market outcomes without imposing unnecessary costs on retailers.[488] On 28 August 2024 the AER released the final version of the updated Guidelines.[489] Key changes include:

- introduction of new indicators to improve the visibility of customers that retailers have specific requirements to support (for example, customers in embedded networks, on life support and impacted by family violence)
- refinement of several indicators to improve definitional clarity and comparability between retailers
- expansion of a range of indicators to gain greater reporting precision and explanatory value
- removal of indicators that may no longer add value.

6.3 Energy bills

Energy retailers communicate with their customers, including through their bills. Energy bills show a customer's energy consumption over a period of time, tariffs, daily supply charges and other fees and discounts. Information on bills can enable consumers to compare their current offer with others available to them. Independent comparator websites provided by the AER (energymadeeasy.gov.au) and the Essential Services Commission (Victoria) (compare.energy.vic.gov.au) enable customers to input their bill usage data and details of the household type and location to access energy bill usage data directly from AEMO and assess their current offer against other market offers available to them (section 6.7.9).

Customers who regularly review and, when necessary, change to a better offer usually pay lower prices. This is particularly evident in energy bill data for 2023–24 which showed a significant increase in bills of customers on standing offers compared with those on market offers for most NEM regions (Figure 6.4 and Figure 6.5). Energy bills for consumers have continued to rise since 2021–22 (section 6.4). In 2023–24, standing offer and market offer prices increased compared with the previous year, with the largest increases in standing offer prices. Following the release of default market offer 6 (DMO 6) (2024–25) on 1 July 2024, market offer and standing offer prices for electricity may decrease between August and October as retailer offers are adjusted and billing cycles are completed.

However, retail energy offers can vary significantly, and hundreds of offers may be available to customers at any one time, particularly for electricity customers. Advertised offers frequently change, as do the terms and charges attached to an offer over time. Customers routinely report finding it difficult to compare and determine which offer is best for their situation. The AER's Better Bills Guideline (Version 2) seeks to address this.

485 AEMC, Updating the regulatory frameworks for embedded networks, Australian Energy Market Commission, 20 June 2019.
486 Embedded networks for gas are not regulated by the AER, and remain a local matter for states and territories.
487 AER, Performance reporting procedures and guidelines (retail law) 2019, Australian Energy Regulator, 1 January 2019.
488 AER, Retail performance reporting procedures and guidelines (2024 update), Australian Energy Regulator, 10 July 2024.
489 AER, AER (Retail Law) Performance reporting procedures and Guidelines – Version 4, Australian Energy Regulator, 28 August 2024.

6.3.1 Better Bills Guideline

Consumers expect bills to be simple, easy to understand and a source of information about how and when to pay. However, energy bills have historically been cluttered, complex and confusing, creating an unnecessary barrier for consumers to participate effectively in energy retail markets and find the best deal.

The AER's updated Better Bills Guideline (Version 2) limits the amount of content allowed at the front of a bill (both electricity and gas) so that consumers can see the essentials at first glance. It requires the retailer to clarify whether they have a better offer available under the heading 'Could you save money on another plan?'. Elsewhere on the bill, retailers must include a simple summary of the existing plan, stating the key features and when any benefits are due to expire, and provide further clarity on the self-read information.[490]

In July 2023, the AER notified authorised retailers that the guideline applies to all small customers of an authorised retailer, including those within embedded networks. The AER has made various decisions under section 37 of the guideline to require retailers to include information about Australian Government and state government energy relief rebates on small customer bills.[491] Retailers were required to comply with the new elements of the guideline from 30 September 2023.

The guideline aims to make it easier for consumers to:

- pay their energy bill
- understand the bill calculation and ensure their bill conforms to their contract
- query their bill
- access interpreter services and seek financial assistance
- report a fault or emergency
- understand their usage to help them use energy efficiently, compare offers and consider new types of energy services.

6.3.2 Components of electricity bills

Retail electricity bills are largely reflective of the cost of producing and supplying electricity. A typical residential electricity retail bill comprises the following costs:

- wholesale electricity purchased through spot and hedge wholesale markets (including managing the risk of wholesale price volatility and price variances across regions)
- network costs, including transporting electricity through transmission and distribution networks, feed-in tariffs for rooftop solar PV systems and metering costs
- costs associated with complying with environmental schemes, such as renewable energy targets and energy efficiency measures
- servicing customers, including provision of billing and customer service
- marketing campaigns to attract and retain customers
- the retailer's margin (profit).

The proportion of each cost as a component of electricity bills varies by jurisdiction, by retailer and over time.

490 AER, Better Bills Guideline (Version 2), Australian Energy Regulator, 30 January 2023.

491 Decisions were made on 10 August 2023, 27 September 2023 and 28 June 2024. See AER, Better Bills Guideline (Version 2), Australian Energy Regulator, 30 January 2023.

Wholesale costs

Wholesale costs are a significant component of electricity bills. Retailers purchase electricity in wholesale markets to sell to customers. Retailers generally charge their customers fixed prices for electricity but need to purchase energy at variable prices in wholesale markets. This means that retailers are exposed to price risk, where they may need to purchase electricity at higher prices than they charge their customers. Retailers generally manage this risk by considering price volatility when setting retail contract prices and by entering hedge contracts that lock in prices for their future wholesale purchases (chapter 2). Alternatively, they might own generation assets or enter demand response contracts to manage risk (section 6.7.4).

Network costs

The AER regulates network charges, which cover the efficient costs of building and operating electricity networks and provide a return to the network service provider's financiers. Across the NEM, distribution costs are the largest component of network costs. Transmission costs are the next biggest component and metering costs make up the balance.

Several factors will have an impact on network costs, such as where the customer is being served (central business district, urban or rural), area density and local terrain. Network costs are generally higher for consumers located in less densely populated areas. The relative efficiency of each network service provider also partly explains differences in network costs (chapter 3, section 3.15.1).

There are likely to be upward pressures on regulated network costs over the next few years, driven by inflation, the impact of higher interest rates and forecast increases in capital expenditure (chapter 3, section 3.13). While this may put upward pressure on retail electricity costs, it may be offset by expected downward trends in wholesale electricity costs (section 6.4).

Environmental costs

Environmental costs are associated with environmental schemes at both national and state levels. These fall into 3 main categories:

- Large-scale renewable energy target (LRET), which provides a financial incentive to encourage investment in large-scale renewable energy generation projects.
- Small-scale renewable energy schemes (SRES), which provide incentives to households and businesses to invest in small-scale renewable energy systems.
- Jurisdictional green schemes, such as state and territory-based energy efficiency improvements for households and businesses, rebates for customer energy resources and feed-in tariffs for rooftop solar.

Most environmental costs relate to complying with the LRET and SRES. These costs are incurred by retailers and passed on to customers.[492]

Retail costs

Retail costs fall into 2 main categories:

- Costs of servicing customers, such as managing billing systems and debt, handling customer enquiries and complying with regulatory obligations. These costs do not vary significantly across jurisdictions.
- Customer acquisition and retention costs, such as marketing and other activities to gain or retain customers. These costs tend to be higher in jurisdictions with high rates of customer switching. In theory, these costs should be offset by reduced retailer profit margins that are driven down due to competition, but there is a risk that competition may increase energy bills for customers if the costs of competing outweigh competition benefits from efficiency and innovation.

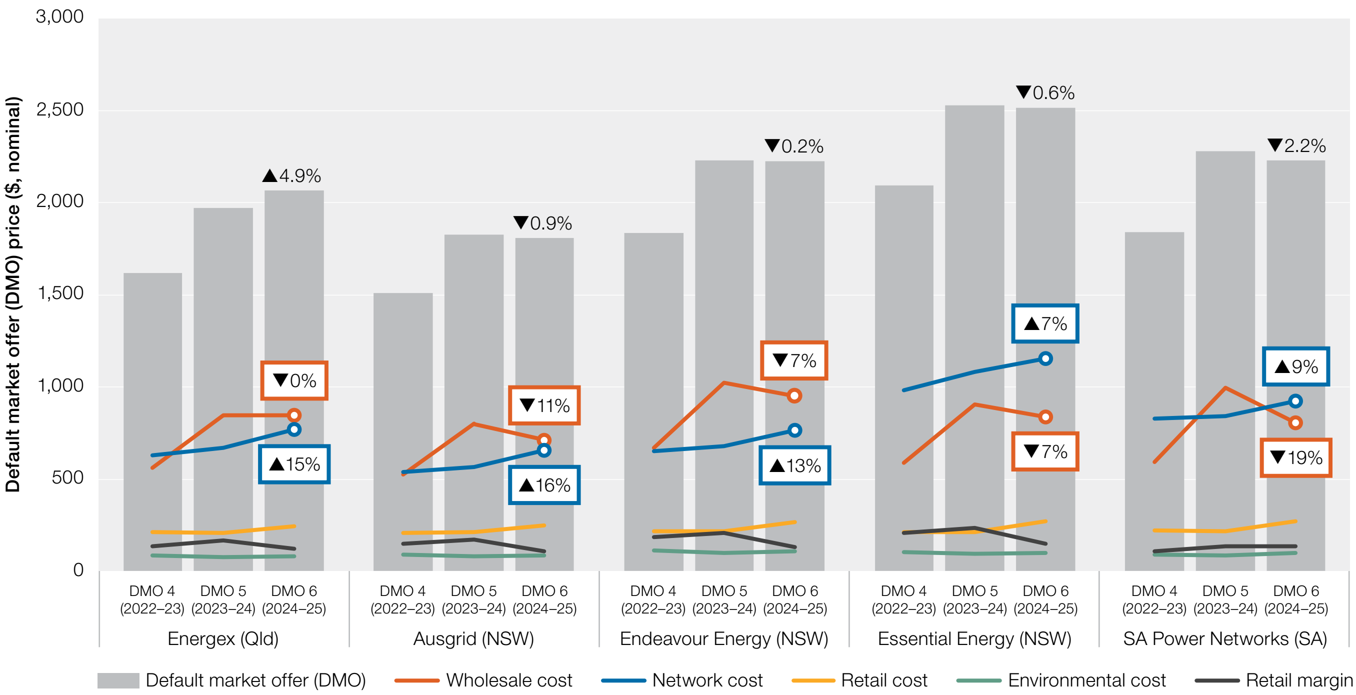
492 AER, Final Determination – Default market offer prices 2024–25, Australian Energy Regulator, 1 July 2024.

6.3.3 Components of the default market offer

The AER calculates a representative retail price for electricity each year known as the default market offer (DMO) reference price. The cost components of each DMO reference price include wholesale, network, environmental and retail costs and margin. The DMO acts as both a price cap for standing offers, and a reference price that discounts and market offers must be measured against. The role of the DMO is further discussed in Box 6.2.

In June 2024, the AER published the DMO 6 determination, which took effect from 1 July 2024. Figure 6.2 illustrates the proportions of each cost component and changes from the preceding years.[493]

Figure 6.2 Components of the default market offer



Note: Comparison of cost components calculated for the 2022–23 (DMO 4), 2023–24 (DMO 5) prices and 2024–25 (DMO 6) prices, for residential customers without controlled load. Prices include GST. Values are nominal. In previous years this data was measured in cents per kilowatt hour and included totals for all NEM regions, enabling like-for-like comparison to Figure 6.3. As at September 2024, this data was unavailable for 2024.

Source: AER, Default market offer prices 2023–24, July 2024.

Components of DMO 6 (2024–25) compared with the previous year are notably different. Calculated wholesale costs increased significantly from DMO 4 to DMO 5 (from between 30% and 40% to between 50% and 69% of the overall retail price). Over that same period, network, environmental and retail costs remained relatively stable.

DMO 6 shows reductions in wholesale costs as a proportion of electricity bills, between 7% to 19% lower for residential customers without controlled load in South Australia and NSW and remaining stable in South East Queensland. This is attributable to downward movements in most contract prices and changes in the shape of customer load profiles. The load profile to model costs in South Australia – where a 19% decrease in wholesale costs was calculated – saw the greatest impact since DMO 5 (compared with all other NEM regions covered by the DMO).[494]

493 For more information about methodological changes in the calculation of DMO 6 compared with previous years, see AER, Default market offer prices 2024–25, Australian Energy Regulator, 1 July 2024.

494 AER, Final Determination – Default market offer prices 2024–25, Australian Energy Regulator, 1 July 2024.

Conversely, network cost components have notably increased in all NEM regions (ranging from 7% to 16%). In NSW's Essential Energy network and South Australia, network costs now represent a higher proportion of electricity bills than wholesale costs.[495] Network costs in South Australia have increased across all customer types and are largely driven by the recovery of previous under-recoveries of allowed distribution revenue, inflation and a cost pass-through for the River Murray flood event.[496]

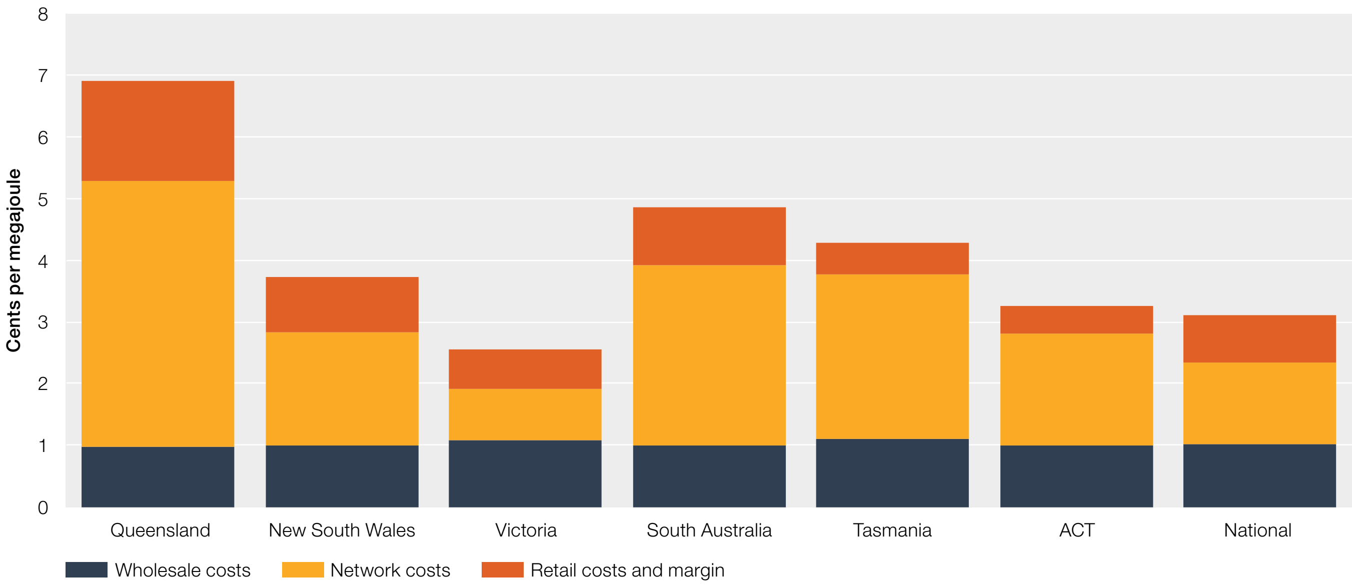
The DMO 6 decision adjusted how it calculated the retail allowance, by separately calculating retail margin and competition allowance. The DMO 6 final determination was mindful of the underlying impacts of economic conditions on energy consumers, including increased inflation, cost-of-living pressures and electricity affordability.[497]

Section 6.4 provides more detail on the outlook for retail electricity prices.

6.3.4 Components of gas bills

The composition of a retail gas bill is less transparent than it is for electricity due to the relative fragmentation of gas markets, the different regulatory arrangements applying to gas pipelines and the absence of a regulatory responsibility to periodically analyse the different cost components.[498] The most recent comprehensive data (published in 2017) show that nationally, gas pipeline charges were the most significant part of the retail gas bill, making up over 40% of a residential gas bill in that year, on average.

Figure 6.3 Composition of a residential bill – gas



Note: Data are estimates at 2017. Average residential customer prices excluding GST (real $2018–19). Percentages may not add to 100% due to rounding.

Source: Oakley Greenwood, Gas price trends review 2017, March 2018.

495 AER, Final Determination – Default market offer prices 2024–25, Australian Energy Regulator, 1 July 2024.

496 For more analysis on drivers for network cost increases in all jurisdictions see AER, Final Determination – Default market offer prices 2024–25, Australian Energy Regulator, 1 July 2024.

497 The Final DMO 6 determination did not apply a competition allowance as the AER uses CPI as the primary metric where the quarterly CPI exceeds the Reserve Bank of Australia's target range on a material and sustained basis. See AER, Final Determination – Default market offer prices 2024–25, Australian Energy Regulator, 1 July 2024.

498 Further, the NEM regions covered in section 6.3.4 differ from section 6.3.3. This is because data used by Oakley Greenwood to determine the composition of a residential gas bill included all NEM regions and national data. The AER's DMO only applies to distribution networks across Queensland, NSW and South Australia. Equivalent electricity bill component data has not been available in 2023 and 2024.

Analysis suggests that residential retail gas bill prices remained relatively steady from 2017 until 2022 (Figure 6.5), when they began to increase following the record high wholesale gas prices during 2022. Due to the historical lack of transparency in pricing in gas wholesale markets and segments of gas transportation, it is difficult to estimate the current composition of a retail gas bill with confidence. However, a range of indicators suggest that changes in both level and proportion of wholesale gas costs in retail bills since the 2017 analysis in Figure 6.3 may be material.

In June 2021, the ACCC published an analysis of gas retail bill components from 2014 to 2018, observing that retail margins up to 2018 reflected the influence of legacy gas contracts with cheap prices.[499] The ACCC anticipated that from 2021, wholesale costs and retail margins would be impacted by wholesale market conditions at the time of renegotiation, by the prices at which retailers were able to replace legacy contracts with new gas supply agreements, and by the extent of competition in the gas retail market.[500]

More recent data provided to the AER by regulated gas distribution networks (known as 'scheme' pipelines) indicates, on average, distribution costs as a proportion of a typical customer's gas bill have reduced. These now range from 23% to 54% (average 34%) for residential customers and 13% to 50% (average 28%) for small business customers.[501] However, additional transport costs are also borne by customers for pipelines whose revenue is not regulated by the AER. Prices paid to transport gas on these pipelines are instead negotiated through bilateral contracts with retailers and will impact the proportion of network costs that make up a retail gas bill.[502]

Each year, gas distribution network service providers submit tariff variation notices to the AER containing the tariffs they propose to charge customers to recover revenues for the upcoming year. On 31 October 2023, the AER released the final decision of our review of gas distribution network reference tariff variation mechanisms and declining block tariffs. The review found that it is unclear how changes in network tariff structures would affect retail gas tariffs imposed on their customers, as retailer billing pricing structures appear to differ across states and territories and retailers. It is possible that changes in how network costs are calculated may not be replicated in the calculation of retail gas pricing structures.[503]

More analysis on gas wholesale markets and regulated gas pipelines is set out in chapters 4 and 5.

499 A breakdown of retail gas bill components was provided as annual averages combining all East Coast Gas Market regions from 2014 to 2018 (see ACCC, Gas inquiry 2017–25 interim report, Australian Competition and Consumer Commission, January 2022). Data is not comparable to the breakdown of retail bill components by jurisdiction as provided in Figure 6.3, which is used to inform State of the energy market report analysis.

500 ACCC, Gas inquiry 2017–25 interim report, Australian Competition and Consumer Commission, January 2023, section 5.

501 AER analysis of access arrangement determinations available on AER website.

502 The exception to this is transport capacity sold through the Day Ahead Auction, where the price is set by an auction and regularly allocates spare capacity at $0 (chapter 4).

503 AER, Final decision – Review of gas distribution network reference tariff variation mechanism and declining block tariffs, Australian Energy Regulator, October 2023.

6.3.5 How retail prices are set

Energy retailers in southern and eastern Australia are responsible for setting prices for energy market offers. Market offers are energy contracts advertised by retailers that are actively entered into by customers. Alongside market pricing, government agencies regulate prices for electricity standing offers. Standing offers are contracts that customers are placed on by default if they do not enter into a market contract for their energy supply.[504]

Between 2009 and 2016, electricity retail price regulations were removed in Victoria, South Australia, NSW and South East Queensland following a determination by the AEMC that markets in those states were effectively competitive. However, in July 2018, the ACCC's Retail electricity pricing inquiry 2017–18 determined that customers on standing offers were paying excessively high prices, disproportionately impacting customers experiencing vulnerability and/or facing barriers to participate in the market.[505]

In July 2019, and in response to subsequent market reviews, governments commenced implementing price control mechanisms for customers on standing offers, as summarised in Table 6.1.[506]

Table 6.1 Price controls by NEM region

Region	Mechanism	Administrator	Approach
South East Queensland New South Wales South Australia	Default market offer	AER	Sets a cap on standing offer electricity prices for residential and small business customers and provides a reference price for comparing offers.
Victoria	Victorian default offer	Essential Services Commission	Sets a cap on standing offer electricity prices for residential and small business customers and provides a reference price for comparing offers.
Regional Queensland	Annual pricing proposal and government subsidy	AER / Queensland Competition Authority	Determines an annual regulated electricity price for residential and small business customers to enable comparison of offers. No price cap is imposed. The Queensland Government subsidises Ergon Energy so that regional customers do not pay more than customers in South East Queensland.
Tasmania	Standing offer price approvals	Office of the Tasmanian Economic Regulator	Sets a cap on standing offer electricity prices for residential and small business customers with a regulated retailer and provides a reference point for comparing offers.
ACT	Price regulation of electricity supply	ACT Independent Competition and Regulatory Commission	Sets a cap on electricity prices for residential and small business customers with authorised retailer ActewAGL and provides a reference point for other customers comparing offers.

Source: AER, Default market offer prices 2024–25 – Final determination, May 2023; ESC, Victorian Default Offer, accessed 18 August 2024; Queensland Competition Authority, Regional customers, accessed 21 August 2024; Tasmanian Economic Regulator, Pricing – Approvals, accessed 21 August 2024; Independent Competition and Regulatory Commission, Price Regulation of Electricity Supply, accessed 21 August 2024.

Gas price deregulation occurred along similar timeframes to electricity, but gas price controls have not been reintroduced. In July 2017, NSW became the last jurisdiction to deregulate retail gas prices for small customers.

504 AER, Default market offer prices 2022–23 – Final determination, Australian Energy Regulator, May 2023, accessed 5 September 2023, section 3.1.
505 ACCC, Retail Electricity Pricing Inquiry, Australian Competition and Consumer Commission, accessed 30 August 2024.
506 Price controls in Table 6.1 apply to standing offers except for regional Queensland where it applies to all electricity contracts.

Box 6.2 Default market offer

The default market offer (DMO) is the maximum price an electricity retailer can charge a standing offer customer each year based a set amount of usage.[507] DMO prices vary by customer type, including residential customers with controlled load, residential customers without controlled load and small business customers without controlled load. A customer might be on a standing offer when their market offer expires or if they have never switched to a retailer's market offer.

The scheme was introduced in 2019, following concerns raised by the ACCC that standing offer contracts:

- were not working as an effective safety net
- were unjustifiably expensive, with retailers having incentives to increase standing offer prices as a basis to advertise artificially high discounts
- penalised customers who had not taken up a market offer, making them a form of 'loyalty tax'.

The DMO prices also act as a reference against which retailers must compare their market offers to make it easier for consumers to compare offers across providers.

The AER determines DMO prices each year for residential and small business customers in NSW (Endeavour, Essential Energy and Ausgrid), South East Queensland (Energex) and South Australia (SA Power Networks). The scheme caps how much retailers can charge in their standing offers, but it does not cap customers' bills. The DMO scheme provides a fallback for those who do not engage in the market and has reduced unjustifiably high standing offer prices.

6.3.6 Prohibition of Electricity Market Misconduct (PEMM) laws

In June 2020 the Australian Government introduced further price protections for electricity. Under Part XICA (which relates to prohibited conduct in the energy market) of the *Competition and Consumer Act 2010*, retailers are required to pass on decreases in the costs of electricity to small customers where they have experienced sustained and substantial reductions in their underlying costs of procuring electricity. Part XICA also prohibits certain behaviour by market participants in relation to access to electricity hedging contracts and spot market bidding.

The ACCC is responsible for investigating contraventions of Part XICA and published guidelines in May 2020, noting that it will routinely monitor developments in costs as part of its Electricity Monitoring Inquiry, as well as considering complaints received that relate to reductions in relevant costs.[508] The ACCC closely monitors the electricity sector's compliance with its obligations under the *Competition and Consumer Act 2010*, the Australian Consumer Law and the Electricity Retail Code, including taking enforcement action against companies for non-compliance.

On 10 June 2024, the Treasurer established a review of the effectiveness of Part XICA. The ACCC anticipates engaging in the review, which must include consideration of:

- any impacts on electricity market performance, including market efficiency, equity, reliability, affordability, emission reduction and investment outcomes
- any other factors relevant for an assessment of the effectiveness of the amendments on the Australian electricity sector and economy.

507 Customers on standing offers may pay more than the DMO price if they use more electricity than the annual usage amount assumed when determining the DMO.

508 ACCC, Guidelines on Part XICA – Prohibited conduct in the energy market, Australian Competition and Consumer Commission, 11 May 2024.

6.4 Retail energy prices

Retail electricity prices remain historically high despite some easing of wholesale electricity costs in the NEM since the record high prices in winter 2022 (chapter 2, Figure 2.3). As wholesale price fluctuations tend to be reflected in future retail contracts, there is usually a time lag between changes to spot prices and retailers' experienced costs due to retailers' aggregate hedging behaviour.[509]

Price volatility in wholesale electricity markets has risen dramatically in the last few years. The potential for more frequent high-priced events in the future remains high while our generation sources transition to a renewables-based system and sufficient firming resources such as batteries and demand-side participation are fully integrated (chapter 2, section 2.3.1). For now, wholesale markets remain vulnerable to supply or demand shocks; challenges include reliability issues with ageing coal-fired generators, reliance on gas-powered generation as southern domestic gas production winds down, and the increasingly peaky shape of consumer demand.

Similar to electricity, 2022 was a volatile year for retail gas prices. Despite a downward trend following the high prices experienced in mid-2022 (chapter 4, Figure 4.2), wholesale prices remain historically high. However, seasonal spikes in mid-2023 and mid-2024 were much smaller compared with the same period in 2022. Wholesale gas cost increases can take longer to flow through to retail prices compared with electricity. With anticipated southern supply constraints, retail gas prices may face upward pressure.

Retail energy costs may also face upward pressure due to inflation and increased costs in managing debt for residential and small business customers. For electricity, costs associated with meeting the AEMC's recommendation to accelerate deployment of smart meters to 100% of small customers by 2030[510] could also result in higher retail costs. Further information about retail costs will be provided in the AER's forthcoming Annual retail markets report 2023–24, which will be released in November 2024.

6.4.1 Retail electricity price movements

In electricity markets, electricity bills for customers increased in all regions in 2023–24 (Figure 6.4). Across all regions, electricity customers on standing offers typically paid more for their energy than customers on market contracts, with material differences between standing and market offer customer bills in NSW and Victoria.

Being on a market contract does not guarantee that a customer will receive the lowest possible energy prices because there is a large price range across these offers. However, customers on a market contract typically pay lower prices compared with those on a standing offer.

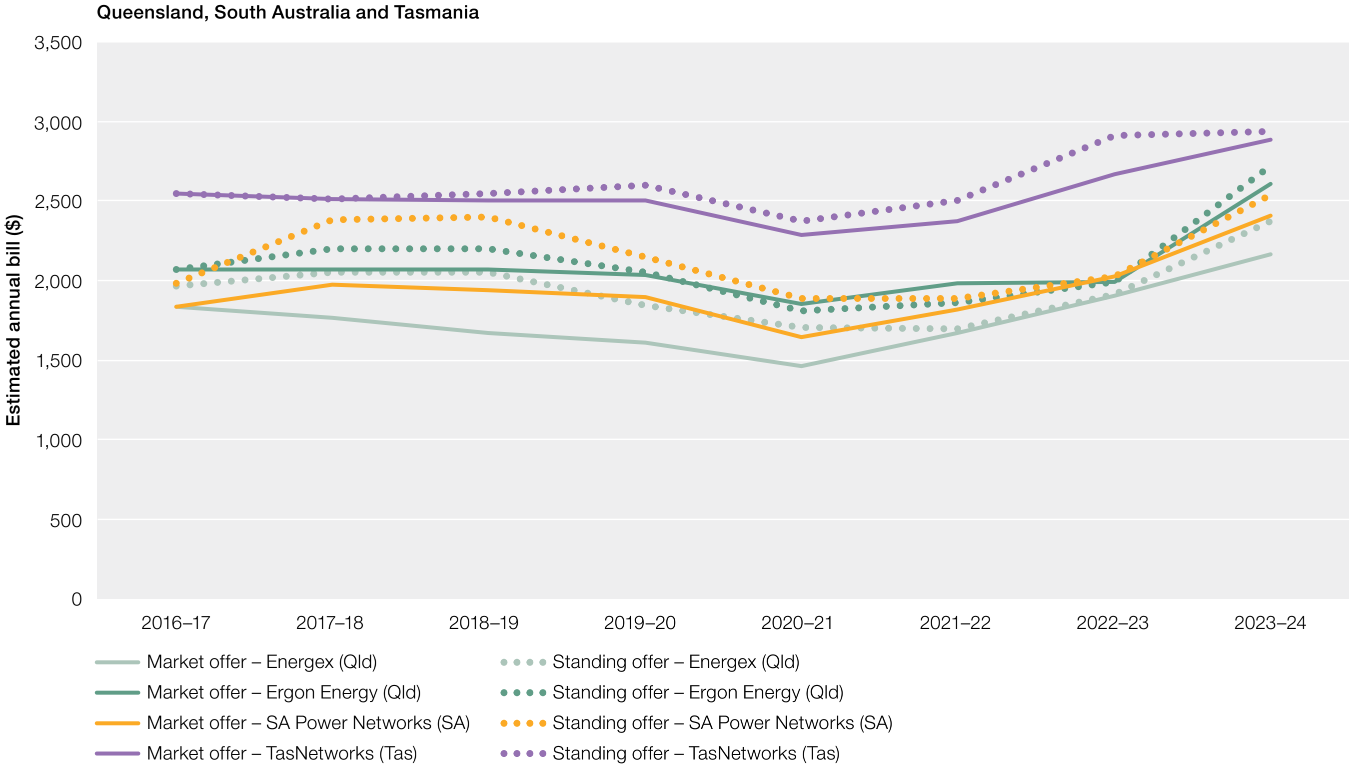
The AER's electricity network revenue determinations for the current regulatory period (2025–29) are estimated to increase retail energy bills for residential households by 0.2% per year on average across all NEM regions (chapter 3, section 3.10). The most significant driver of this increase is the forecast costs to replace assets reaching the end of their life and increased costs of electricity transmission infrastructure, which are passed on to distribution network service providers to recover from their customers (chapter 3, section 3.13.2). In coming years, the impact of higher inflation and costs of capital will also flow through to network costs. With new jurisdictional scheme costs, such as the NSW Renewable Energy Zones, and previously under-recovered distribution revenues in some regions, network costs are likely to maintain upward pressure on electricity prices.

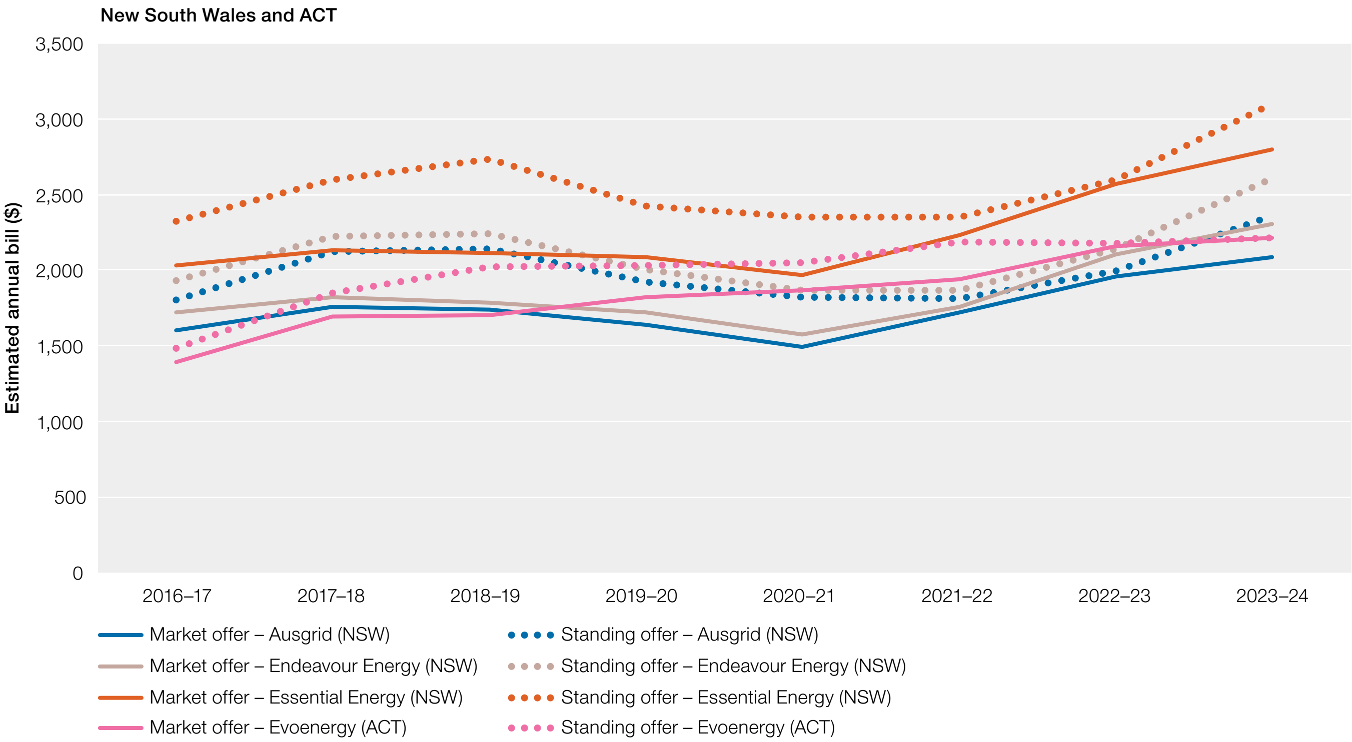
Overall changes in retail energy prices are difficult to predict, with uncertainty over whether lower wholesale energy prices in the future will be enough to offset the increased network costs.

509 ACCC, Inquiry into the National Electricity Market report – November 2022, Australian Competition and Consumer Commission, accessed 11 September 2024, pp. 12–13.

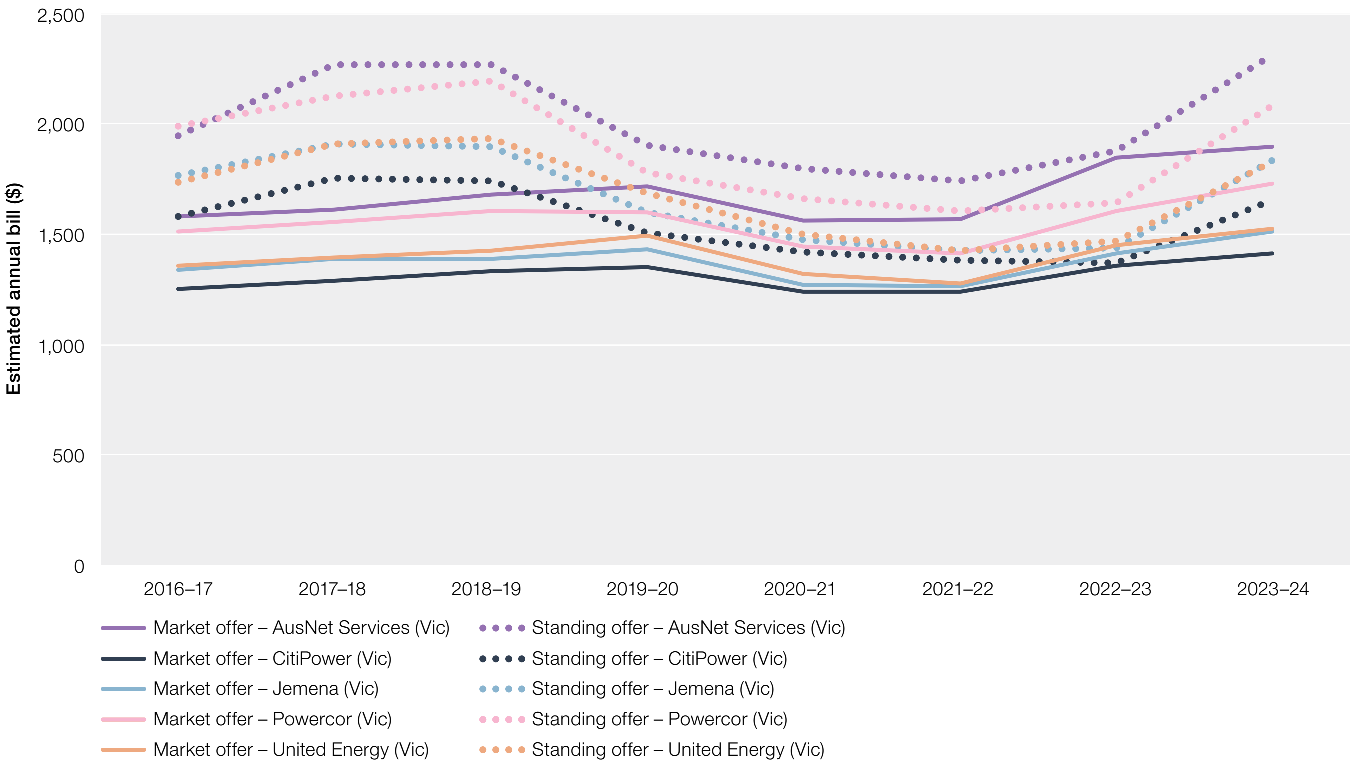
510 AEMC, Review of the regulatory framework for metering services, Australian Energy Market Commission, 30 August 2023.

Figure 6.4 Electricity bills for customers on market and standing offers





Victoria



Note: Ergon Energy's standing offer prices are set by the Queensland Competition Authority (QCA). TasNetworks' standing offer prices are set by the Office of the Tasmanian Economic Regulator (OTTER). Standing offer prices on the Victorian distribution networks are set by the Essential Services Commission (ESC). Evoenergy's standing offer prices are set by the Independent Competition and Regulatory Commission (ICRC). Energex, SA Power Networks, Ausgrid, Endeavour Energy and Essential Energy's standing offer prices are set by the retailers (capped at DMO). Based on single rate offers for residential customers and average consumption in each distribution area. Average consumption for 2020–21 has been applied to all periods. Some offers listed may not be available to all customers in a distribution area. The AER will update its analysis on more recent offers in the Annual retail performance report 2024. On Ergon Energy's network a few market offers are available and some offers are restricted to specific geographic areas.

Source: AER analysis using offer data from Energy Made Easy (AER) and Victorian Energy Compare (DELWP). Consumption based on Economic benchmarking regulatory information notice (RIN) responses.

6.4.2 Retail gas price movements

Despite some easing of wholesale electricity costs following the significant market events of winter 2022, average prices remain high compared with historical levels in several regions (chapter 2, Figure 2.3). Gas bills for customers on market and standing offers increased in every jurisdiction, except Queensland, compared with the previous year. In Queensland, market offers decreased marginally while standing offers increased to a smaller extent than in other regions (Figure 6.5).

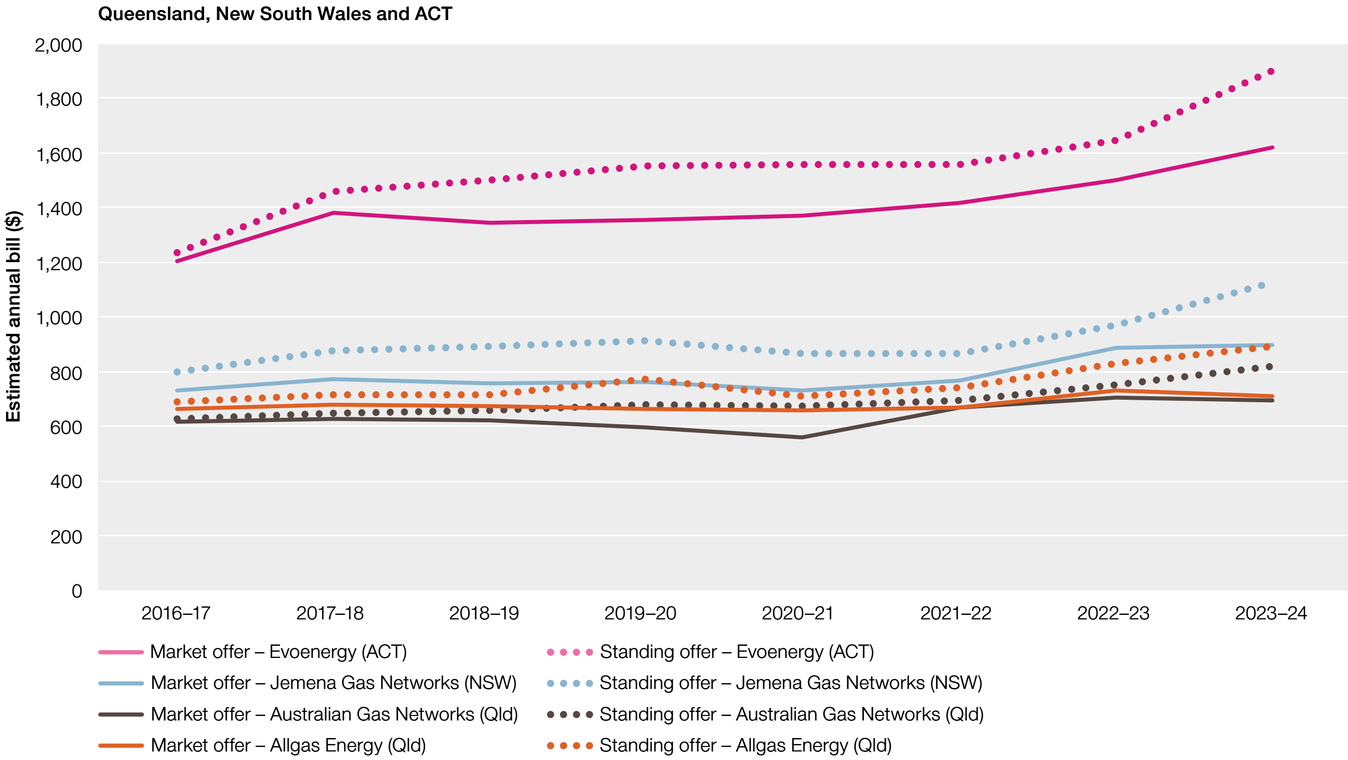
Estimated annual customer bills in 2023–24 ranged from $693 in Queensland to $2,344 in Victoria, where customers use significantly more gas (section 6.5). Standing offer prices for gas were also higher across jurisdictions, with significant increases seen in Victoria, the ACT and NSW, and smaller increases in Queensland and South Australia (Figure 6.5).[511]

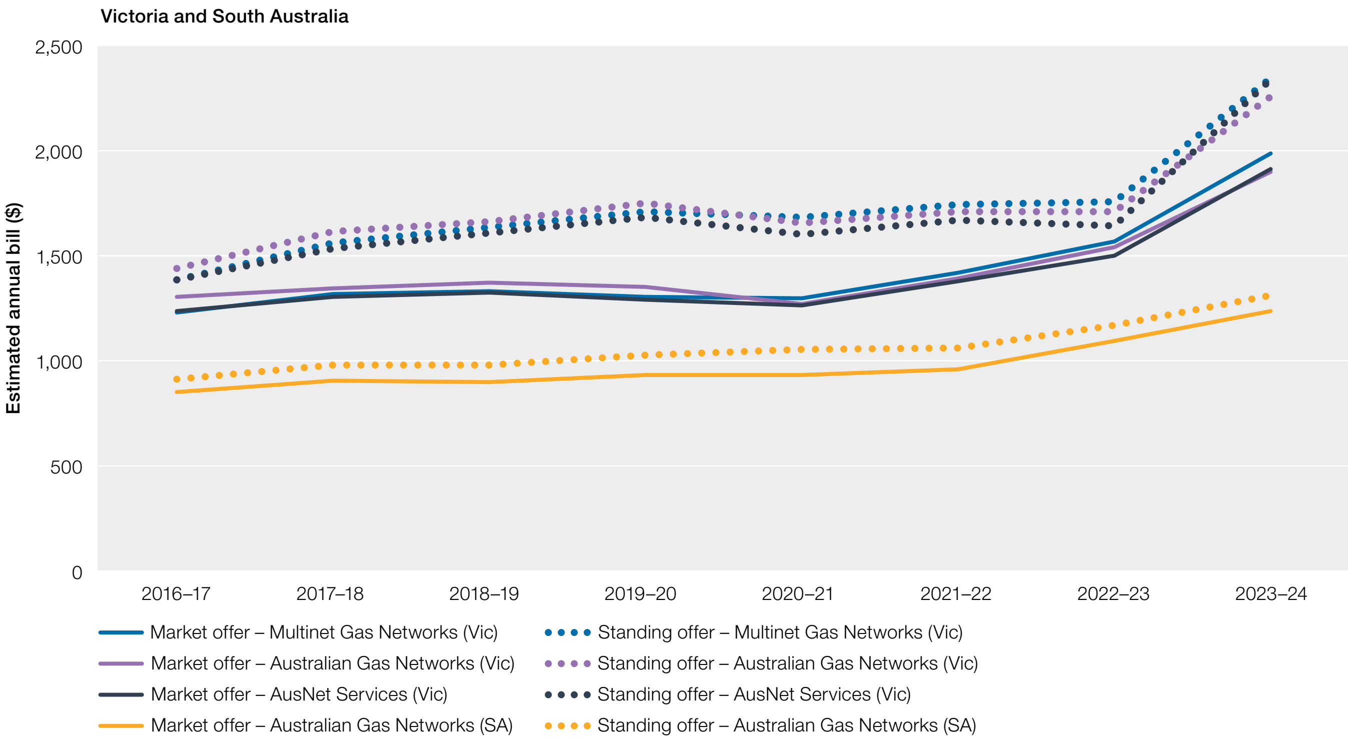
Colder weather from late May 2024 drove up southern demand compared to the previous year when weather conditions were milder. Due to the significant changes in demand driven by cold weather in the April to June quarter, contracted gas pricing saw an increase impacting regions with high domestic users of gas. Customers may see increases from August to October 2024 in their gas costs when billing cycles are due for completion (Figure 6.5).

Beyond 2024, there are concerns for the sufficiency of domestic supply as southern production begins to reduce. Combined with state governments implementing policies to phase out residential gas use as part of Australia's net zero by 2050 commitments, the outlook for retail gas prices remains subject to considerable uncertainty.

511 Estimated annual customer bills for generally available flat rate offers, by distribution company.

Figure 6.5 Gas bills for customers on market and standing offers





Note: Based on offers for residential customers and estimated consumption in each jurisdiction.

Source: AER analysis using offer data from Energy Made Easy (AER) and Victorian Energy Compare (DELWP). Consumption based on Frontier Economics report to the AER, *Residential energy consumption benchmarks*, December 2020.

6.5 Energy use

Consumers' energy costs are split between fixed charges and charges based on how much energy consumers use. Usage charges are the largest component of energy bills for most households.[512] A consumer's energy use significantly impacts energy affordability (section 6.6). Energy use varies by household size, how energy efficient the house is, appliance quality, heating and cooling needs and lifestyle. Some consumers use both electricity and gas, and others only use electricity. This means that a consumer's use of electricity or gas on its own may not be indicative of their total energy consumption.

Residential customers in Tasmania use the most electricity (per customer) in the NEM. Key drivers of greater electricity and gas use are climate (with greater heating requirements in some jurisdictions) and the penetration of gas as an alternative fuel. In Tasmania, very few households use gas. Most households in Victoria have both electricity and gas connections, resulting in the lowest average household electricity consumption.

Customers in colder climates tend to use the most gas (such as those in Victoria and the ACT). Gas use in these jurisdictions is 6 to 7 times higher in winter than over summer.[513] Queensland customers use the least gas due to having a warmer climate.

Over the past 10 years, the overall amount of electricity that residential consumers have demanded from the NEM has decreased. This is largely driven by households using electricity generated by rooftop solar PV systems. As at 30 June 2024, rooftop solar provides over 20 GW of registered capacity connected to the NEM, equivalent to 25% of generation capacity. This makes rooftop solar the fuel source with the highest registered capacity across the NEM (chapter 2, Figure 2.14).[514]

Improved energy efficiency of new homes and appliances is also contributing to reducing grid demand. Minimum energy efficiency ratings for new residential houses were first introduced in 2004 through the Nationwide Housing Energy Rating Scheme (NatHERS) and energy efficiency ratings for appliances were introduced in 2012 through the Greenhouse and Energy Minimum Standards (GEMS).[515]

NatHERS takes into account differences in climate – Australia is divided into 69 separate 'climate zones' created using average temperatures in that area. The climate zone is a required input into the calculation of a home's energy efficiency rating so that a similar rating for 2 houses in different climate zones equates to similar levels of energy use for heating and cooling.[516]

As part of the AER's consultation on its Retail guidelines review, stakeholders noted that energy use by some consumers in off-grid remote areas in Queensland, South Australia, Northern Territory and Western Australia is increasingly being driven by temperature extremes.[517] This means their energy use is likely much higher than the regional averages. Many of these customers are on prepayment meters (also referred to as 'card-operated' meters) and are more vulnerable to harm if their electricity is disconnected during an extreme temperature event.

512 Most energy offers include usage charges as well as a fixed supply charge. Some offers also include membership fees or additional charges for metering.

513 Frontier Economics, Residential energy consumption benchmarks, final report for the Australian Energy Regulator, December 2020, accessed 15 September 2022, p. 26.

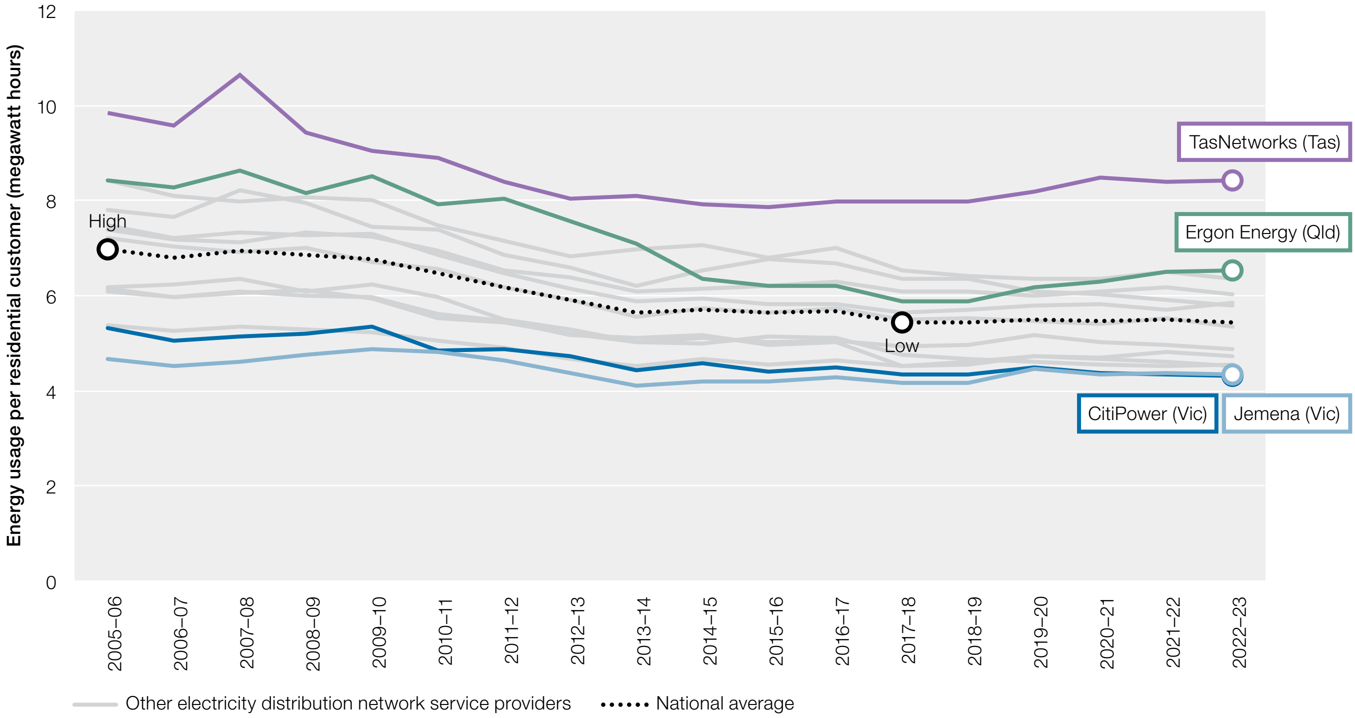
514 Capacity generated by rooftop solar is subtracted from demand (rather than traded in the NEM). With rooftop solar output records set over the summer of 2022–23, when rooftop solar reached a record 11,504 MWh, the rapid uptake of rooftop solar continues to be the major contributing factor to reduced grid demand.

515 NatHERS was initiated in 1993 by the Australian and New Zealand Minerals and Energy Council to provide a standardised approach to rating the thermal performance of Australian homes. GEMS came into effect on 1 October 2012, when the GEMS Act was established to create a national framework for appliance and equipment energy efficiency in Australia.

516 NatHERS, Climate Zones and Weather Files, Nationwide House Energy Rating Scheme, accessed 1 October 2024.

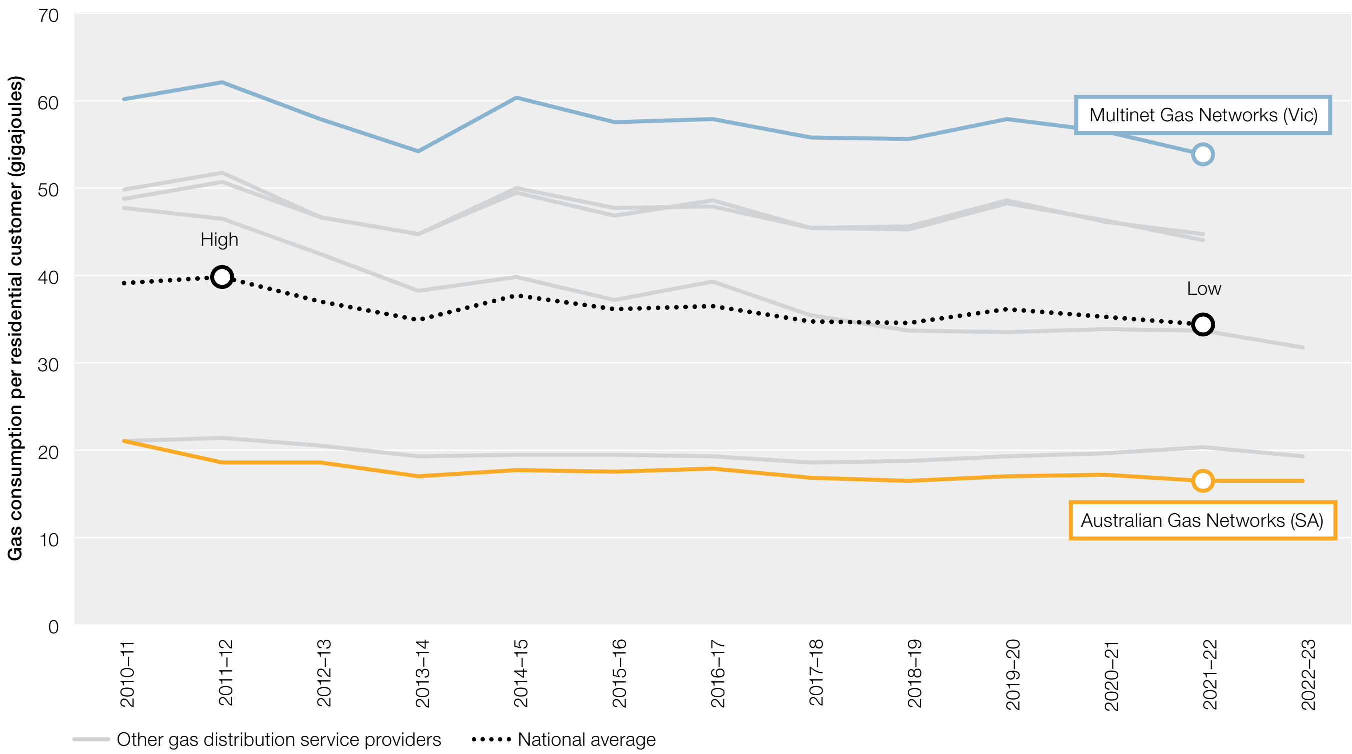
517 ANU, Submission – Retail Guidelines review issues paper, Australian National University, August 2024.

Figure 6.6 Energy use per residential customer – electricity



Source: Regulatory information notices (RIN) responses.

Figure 6.7 Energy use per residential customer – gas



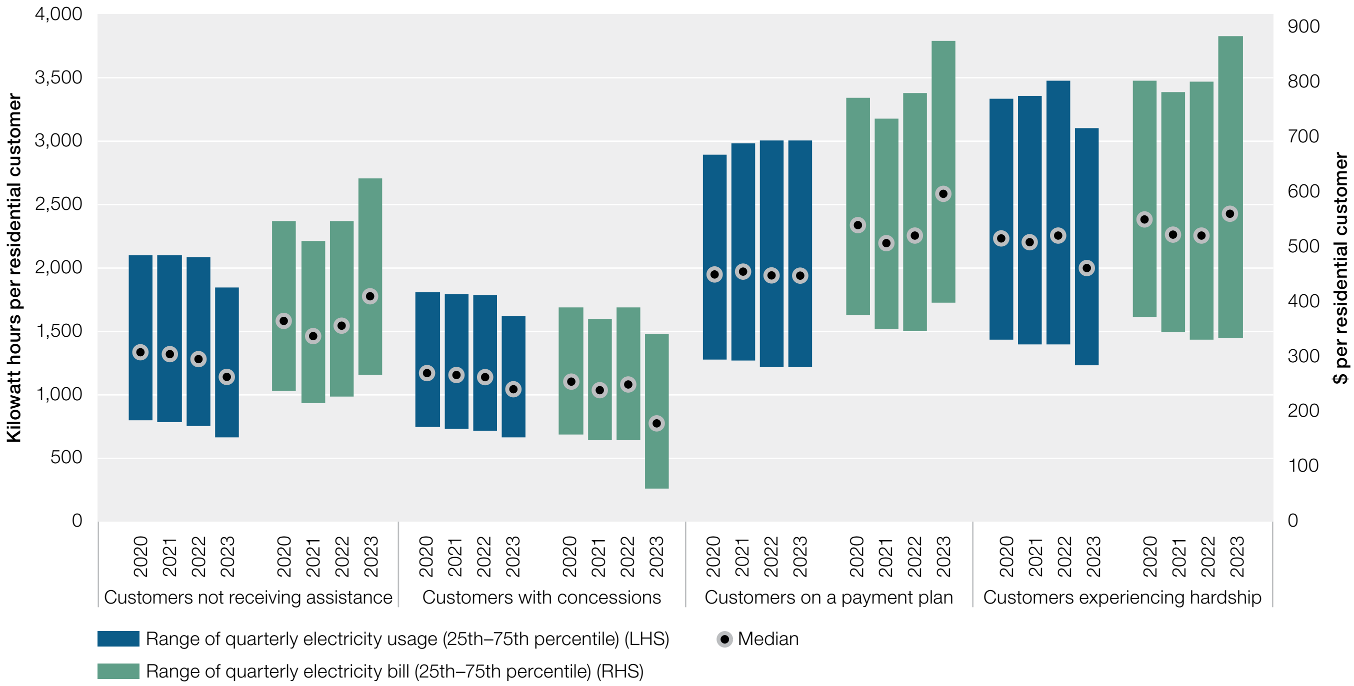
Source: Regulatory information notices (RIN) responses.

As energy markets transition to renewable energy, the reported average energy use indicators are likely obscuring a widening gap between households that have the capacity to adopt new technology or modify energy use, and those that do not. This could be due to cost, residential tenancy laws or other barriers. The former group is likely experiencing a substantial reduction in electricity use, while electricity use among other households has likely remained relatively consistent over time, and these customers may be spending more on electricity compared with 10 years ago.

Considering the main drivers of the reduction in energy use – rooftop solar and energy efficient housing – are not equally accessible to all consumers, it is not surprising that at a more granular level, a disparity in energy use across different customer types can be observed when comparing consumers experiencing financial difficulties.

Figure 6.8 shows that customers not receiving assistance[518] and those on concession use significantly less energy compared with those on payment plans and/or in hardship arrangements, who accordingly have higher bills.

Figure 6.8 Electricity use, by residential customer type



Note: Data labels show the respective range in electricity usage and electricity bills in 2022.
Source: ACCC, Inquiry into the National Market, June 2024.

518 Protections include concessions that are applied to energy bills, payment plans and hardship arrangements. Insights from this data assumes that consumers without protections have been correctly identified as not eligible for them.

6.5.1 Impact of energy efficiency of homes on energy use

The energy efficiency of homes plays a vital role in reducing emissions and the cost of energy bills. Consumers living in homes with poor thermal efficiency are using more energy and spending more on heating and cooling to stay comfortable.

There is a significant deficit in average thermal efficiency of existing homes compared with the new 7-star minimum standard. Data from NatHERS research shows that the ratings of existing homes is estimated to be less than 2 stars out of 10.[519]

Research between 2016 and 2018 found that 81.7% of new housing is designed to meet only minimum NatHERS requirements and 98.5% of existing housing stock falls below optimum economic and energy performance.[520] Improving thermal efficiency of residential housing is a key priority of the Australian Government's National Energy Performance Strategy.[521]

On 19 July 2024 the Australian Government published the Home Energy Ratings Disclosure Framework, which sets out a national approach for assessing the energy performance of homes and providing performance ratings and certificates at the point of sale or lease of a house.[522]

State and territory governments have primary responsibility for setting disclosure requirements for the energy efficiency of residential buildings. The framework aims to complement existing disclosure, improve the implementation of these schemes and encourage a consistent approach across states and territories.[523]

Studies by project partners under the Reliable Affordable Clean Energy (RACE) for 2030 program have also explored different upgrades to existing homes and the impact on energy use.[524] Under their modelling of detached 4-bedroom houses in Victoria, NSW and Western Australia, energy use was reduced by between 18% and 99% (Table 6.2) depending on which of the 4 different upgrade options were applied.

Table 6.2 Reductions in energy use for upgraded homes compared with baseline

Upgrades	Annual energy use (electricity and gas) in Victoria (kWh)	Annual energy use (electricity and gas) in NSW (kWh)	Annual energy use (electricity and gas) in Western Australia (kWh)
Baseline	12,655	9,604	9,827
Upgrade 1 – improved roof, wall and floor insulation, pipe lagging and draught sealing	8,734 (31%)	7,918 (18%)	7,603 (23%)
Upgrade 1 + Upgrade 2 – addition of ceiling fans, reverse cycle air condition and double-glazed windows	7,298 (42%)	7,815 (19%)	7,215 (27%)
Upgrade 1 + Upgrade 3 – efficient appliances, LED lighting and a clothesline to reduce the need for a dryer	5,210 (59%)	3,476 (64%)	3,577 (64%)
Upgrade 1 + Upgrade 4 – addition of solar PV and a hot water heat pump	2,169 (83%)	669 (93%)	710 (93%)
All upgrades	103 (99%)	0 (100%)	4 (100%)

Note: Examples of baseline homes include: a detached home with a usable area of 202 m^2, living area with dining and kitchen, 4 bedrooms, 2 bathrooms, a theatre room and garage; or a terraced home with a usable area of 124 m^2 distributed across 2 floors, including a living and dining room, 3 bedrooms, one bathroom, 2 balconies and a carport. Percentage in brackets is percentage reduction compared with baseline.

Source: DISER, Race for 2030, Pathways to scale: Retrofitting One Million+ homes, p. 45.

519 COAG Energy Council, Report for achieving low energy existing homes, Australian Government, Canberra, 2019.

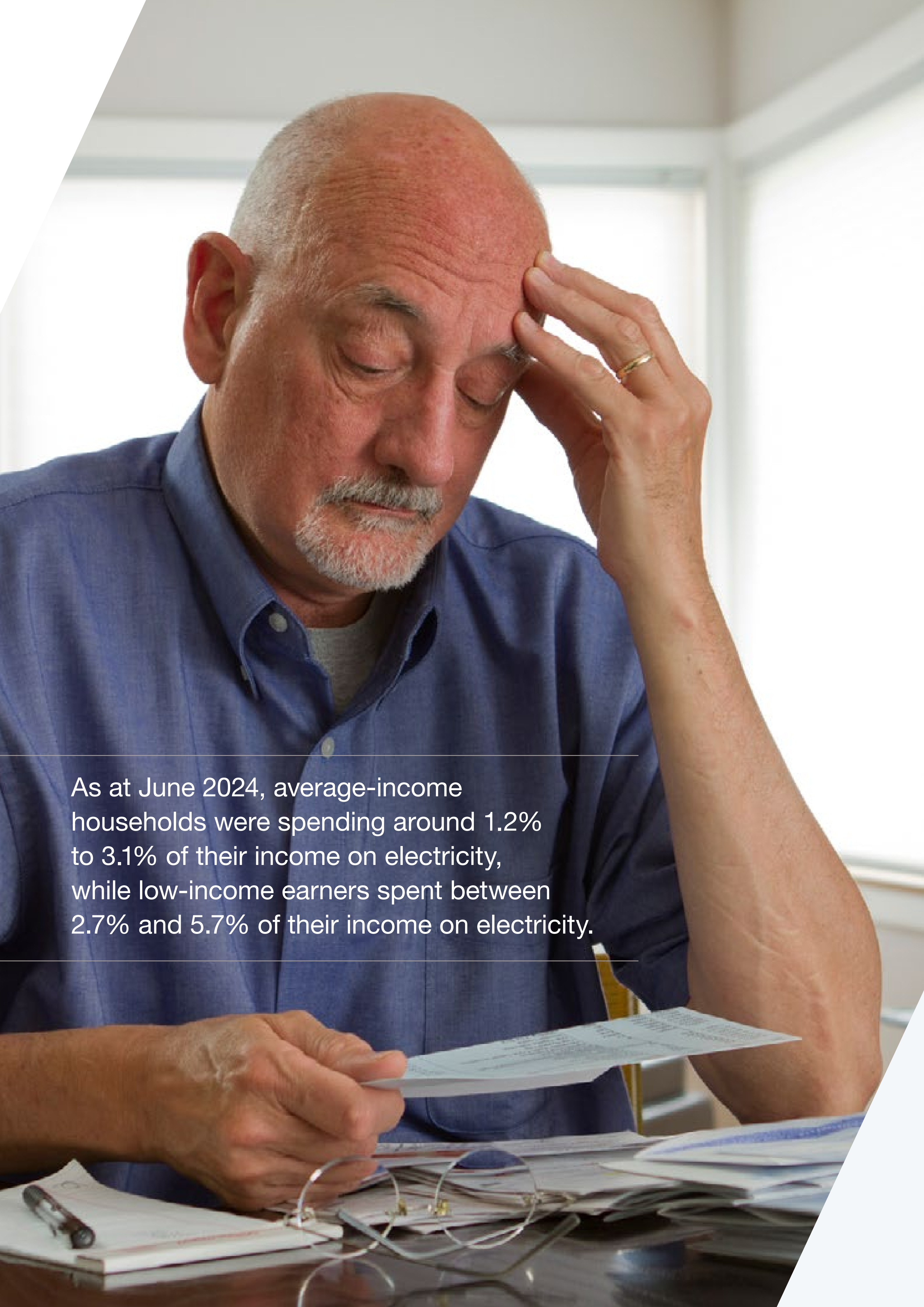
520 G Moore, S Berry & M Ambrose, 'Aiming for mediocrity: the case of Australian housing thermal performance', Energy Policy, 2019, 132:602–610.

521 DCCEEW, National Energy Performance Strategy, Department of Climate Change, Energy, the Environment and Water, April 2024, accessed 19 September 2024.

522 DCCEEW, Home Energy Ratings Disclosure Framework – Version 1, Department of Climate Change, Energy, the Environment and Water, 2024.

523 DCCEEW, Home Energy Ratings Disclosure Framework – Version 1, Department of Climate Change, Energy, the Environment and Water, 2024.

524 The RACE for 2030 Cooperative Research Centre is a 10-year, $350 million Australian research collaboration involving industry, research, government and other stakeholders.



As at June 2024, average-income households were spending around 1.2% to 3.1% of their income on electricity, while low-income earners spent between 2.7% and 5.7% of their income on electricity.

6.6 Energy affordability

Energy is an essential service. It is essential to people's daily lives, health, wellbeing and employment. An equitable energy market should provide affordable and reliable energy, be inclusive of all consumers and should not create or compound harms and barriers to participation. Energy equity, particularly affordability, remains a significant concern in energy markets.

Energy affordability is impacted by a customer's energy needs, energy contract and prices, income, living costs and ability to participate effectively in energy markets. Energy bills can be a significant burden for households even in times of relatively low energy prices. Additional strains will be felt by consumers as the broader cost of living in Australia continues to rise.[525]

Energy price increases can place significant strain on low-income households. A longitudinal study on low-income households in Australia found that a 1% increase in electricity prices leads to a 0.44% increase in energy expenditure and a 0.09% decrease in food expenditure.[526] For those near poverty, the same price increase cuts food spending by 0.2%. Energy price increases, in combination with poor energy performing homes and inadequate income support payment, is causing acute financial and social disadvantage and having tangible impacts on the physical and mental wellbeing of impacted householders.[527]

Retail energy prices paid by consumers depend on where a customer lives, the network services required to supply their energy, competition between retailers in their area, the customer's ability to identify an appropriate energy plan, and whether the customer is eligible for a concession or rebate to help manage their energy costs.

This means that affordability challenges are not split evenly across all consumer types. The evidence suggests that affordability differs substantially based on factors such as geographical location and income level. For example, retail energy prices are typically higher in regional and remote areas than in urban areas, mostly due to higher 'per customer' network costs required to operate geographically longer networks to areas with lower population density.

On the mainland, estimated annual customer electricity bills in 2023–24 ranged from $1,413 for a customer in urban Victoria to $3,102 for a customer in rural NSW.[528] This difference is likely driven by both electricity prices and energy use profiles. Regional differences are also driven by gas consumption across regions. For example, Victoria, being the highest user of gas, has the lowest proportion electricity bill and the highest proportion gas bill.

As at June 2024, average-income households were spending around 1.2% to 3.1% of their income on electricity, while low-income earners spent between 2.7% and 5.7% of their income on electricity (Figure 6.9).[529]

While this will be partly offset by the Australian Government's Energy Bill Relief Fund in 2024–25 and other cost-of-living rebates, it will be important for retailers to actively identify and support customers with challenges paying bills through payment plans and hardship programs.

Consumer protections in Victoria are under the auspices of Victoria's Essential Services Commission. Victorian data is excluded from some charts in this section because comparable data was unavailable at the time of publication.[530]

525 All 5 Living Cost Indexes rose between 3.7% and 6.2% in 2023–24, see ABS, Selected Living Cost Indexes, Australia, Australian Bureau of Statistics, 7 August 2024.

526 Science Direct, Energy poverty and food insecurity: Is there an energy or food trade-off among low-income Australians?, *Energy Economics*, July 2023.

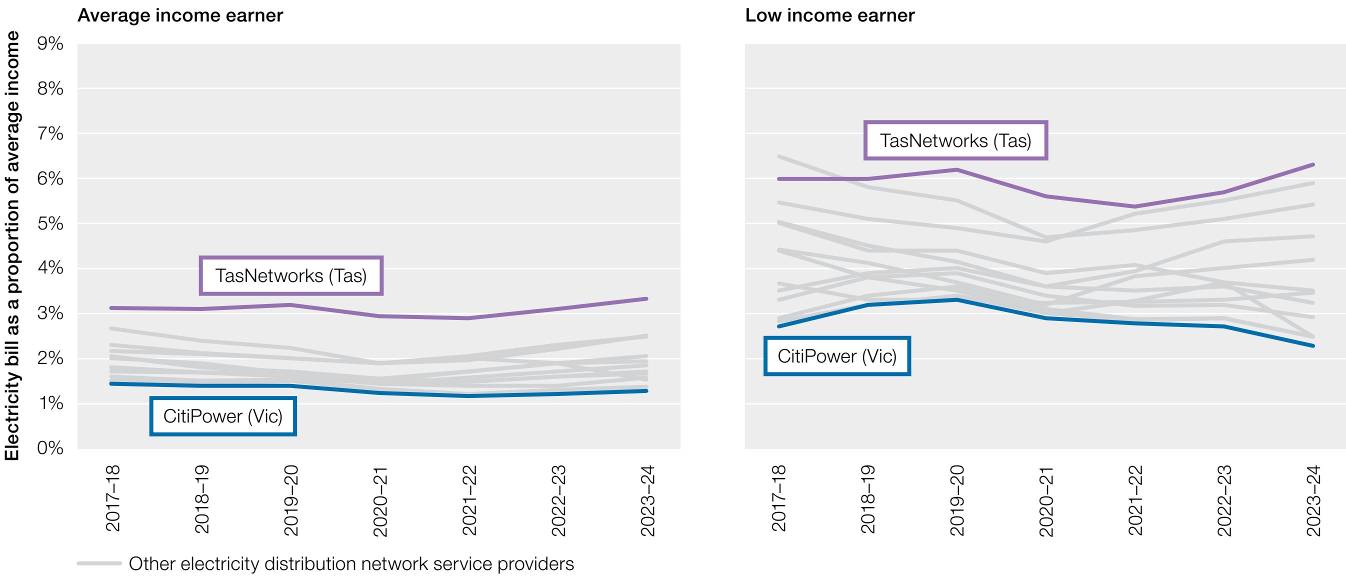
527 ACOSS, Energy and Cost of Living Snapshot – October 2023, accessed 11 September 2024.

528 Estimated annual customer bills for generally available flat rate offers by distribution company.

529 J Fry, et al. Energy poverty and food insecurity: Is there an energy or food trade-off among low-income Australians?, *Energy Economics*, vol. 123, July 2023.

530 Further information and metrics relating to consumer protections in Victoria is available at ESC, Victorian Energy Market Report – June 2024, Essential Services Commission, 27 June 2024.

Figure 6.9 Affordability of median market offers – electricity

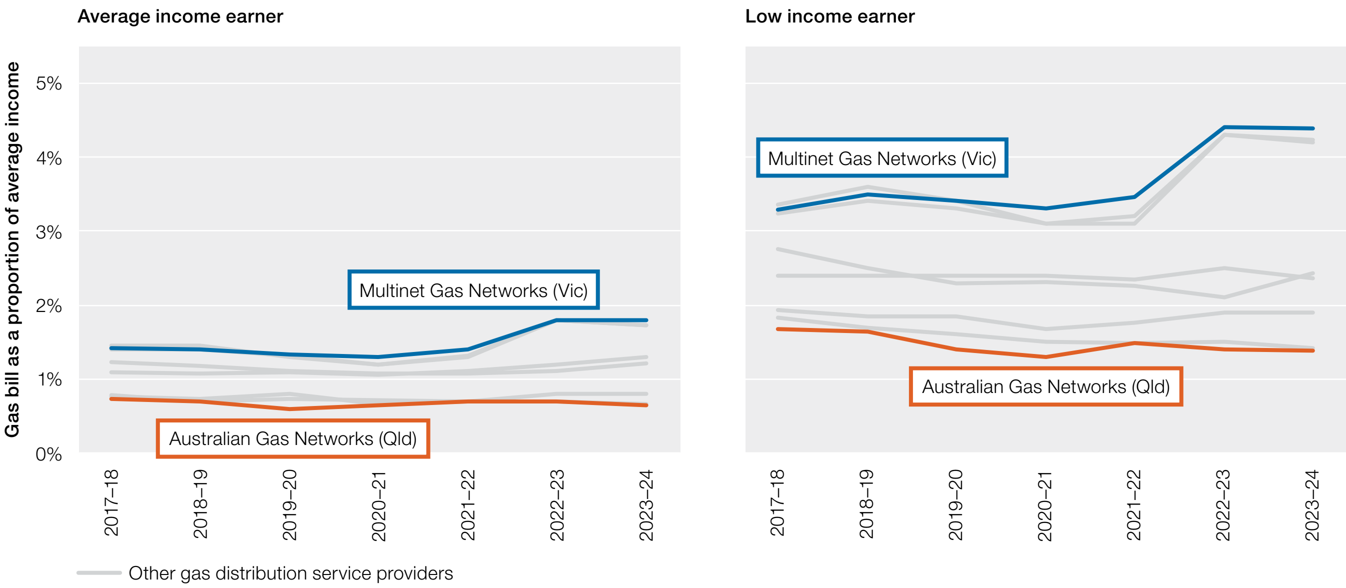


Note: Based on offers for residential customers in each jurisdiction. Average household consumption for the financial year ending June of each period was used in annual bill calculations. Proportion refers to mean disposable income. Use of average incomes across jurisdictions may overstate affordability in regional areas, where average incomes are typically lower than across the jurisdiction more broadly.

Source: Offer data from Energy Made Easy (AER) and Victorian Energy Compare (DELWP). Consumption estimates based on Economic benchmarking regulatory information notice (RIN). Income data are unpublished ABS estimates of household disposable income.

Gas bills as a proportion of income had remained static since 2017–18 in most jurisdictions, at around 0.7% to 1.8% of the average earners' income in 2022–23. Gas bills as a proportion of income have spiked for Victorian customers to 1.8% for average income earners and 4.4% for low-income earners. Because customers in Victoria use a lot more gas than customers in other regions, increased gas prices (due to both local supply and international prices) have a greater impact relative to their income, as it makes up more of their overall energy usage.

Figure 6.10 Affordability of median market offers – gas



Note: Based on single rate offers for residential customers and average consumption in each distribution area. Using mean disposable income for all and low-income households by state or territory. Use of average incomes across jurisdictions may overstate affordability in regional areas, where average incomes are typically lower than across the jurisdiction more broadly.

Source: Offer data from Energy Made Easy (AER) and Victorian Energy Compare (DELWP). Income data are unpublished ABS estimates of household disposable income. Consumption based on Frontier Economics report to the AER, Residential energy consumption benchmarks, December 2020.

6.6.1 Disparity of energy affordability between different types of consumers

Customers experiencing vulnerability[531] are likely to face additional challenges keeping energy bills low because they may be less able to implement some of the most effective means of reducing energy bills, including modifying energy use, making home energy efficiency upgrades, adopting new technologies and shopping around for better deals. As such, customers experiencing vulnerability are more susceptible to periods of high energy prices and disproportionately represented in the number of customers experiencing debt, hardship and disconnection.[532]

Consumers living in older, less energy-efficient homes could be spending significantly more on their energy use according to the *RACE for 2030 H2: Opportunity Assessment Enhancing home thermal efficiency Final Report May 2023*, which notes that retrofitting an existing Australian home and reducing home energy use by up to 9,000 kilowatt hours (kWh) per year could reduce an average home energy bill by up to $1,600 per year.[533]

Having both the autonomy and the resources to modify energy use plays an important role in energy affordability. There are 2 key aspects of this:

- In terms of energy efficiency, autonomy is an issue that affects people based on both housing tenancy (e.g. renters/owners) and housing type (e.g. apartment/house).
- Resources is a separate issue that relates to whether customers can pay the upfront costs (or have the necessary time, knowledge, capacity and equipment to research and then implement energy efficiency improvements.[534]

Autonomy also plays a role in modifying energy use in other ways. For example, consumers who have higher or less flexible energy needs because of caring responsibilities or health issues, or who are unable to shift energy use because of the nature of their work or are affected by family violence, may have less ability to respond to dynamic price signals or modify their energy use. The AER's *Annual retail markets report 2022–23* provides more in-depth assessments of affordability.[535]

6.6.2 Policy measures and regulatory reforms aimed at improving affordability

Energy price relief

In December 2022, the Australian Government launched its Energy Price Relief Plan to address energy affordability.[536] Measures under the plan included temporary and ongoing coal and gas price caps, an investment scheme to unlock investment in clean dispatchable capacity to support reliability and mitigate the risk of future price shocks, and an Energy Bill Relief Fund to provide targeted energy bill relief for residential and small business customers.

Following the Australian Government's $1.5 billion program to deliver electricity bill rebates for eligible households, an Energy Bill Relief Fund was established for 2024–25. The Fund is providing $3.5 billion to apply electricity bill rebates to Australian households and small business customers in 2024–25 to ease cost-of-living pressures.[537]

All Australian households will receive a $300 rebate and eligible small businesses will receive $325 from the Australian Government, to be paid in quarterly instalments on the electricity bill throughout 2024–25.[538]

531 In undertaking retail data affordability analysis, the AER groups customers based on income levels. However, for context in this section the AER's definition of 'customers experiencing vulnerability' is drawn from AER, Towards energy equity strategy, Australian Energy Regulator, 20 October 2022, p. 4.

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

533 DISER, Race for 2030, Pathways to scale: Retrofitting One Million+ homes, Department of Industry, Science and Resources, December 2021, accessed 6 September 2024, p. 31.

534 Calculation based on ECA respondents to question *How likely would you be to use smart appliances to reduce the cost of your household's energy bills?* and AER analysis of underlying data.

535 AER, Annual retail markets report 2022–23, Australian Energy Regulator, 30 November 2023.

536 DCCEEW, Energy Price Relief Plan, Department of Climate Change, Energy, the Environment and Water, accessed 16 September 2024.

537 DCCEEW, Energy Bill Relief Plan, Department of Climate Change, Energy, the Environment and Water, accessed 30 August 2024.

538 DCCEEW, Energy bill relief fund 2024–25, Department of Climate Change, Energy, the Environment and Water, accessed 6 September 2024.

In addition, the Queensland Government announced the $1,000 Cost-of-Living Rebate to support households in 2024–25.[539] The NSW Government funds rebate programs for electricity and gas customers, including NSW Family Energy Rebate, Low Income Household Rebate, NSW Gas Rebate, Life Support Rebate, Medical Energy Rebate and Seniors Energy Rebate.[540] The South Australian Government offers a range of energy rebates and concessions to support residents to manage their energy costs, such as the SA Concessions Energy Discount Offer and an Emergency Electricity Payment.[541]

Energy efficiency of homes

The Australian Government, along with state and territory governments, has been developing policies and frameworks to improve the energy efficiency of existing homes. These include:

- National Framework for Disclosure of Residential Energy Efficiency Information helps potential buyers and renters understand the energy efficiency of homes before making decisions.
- National Framework for Minimum Rental Energy Efficiency Requirements sets minimum energy efficiency standards for rental properties to ensure that tenants live in more energy-efficient homes.
- Improvements to Energy and Appliance Efficiency Programs aim to enhance the overall energy efficiency of appliances and buildings.

Several state and territory governments have introduced initiatives specifically targeting low-income households to improve their energy efficiency:

- In Victoria, the Household Energy Savings Package provides energy-efficient heating and cooling systems for low-income households and upgrades for social housing properties. It also includes a $300 Power Saving Bonus for eligible concession program recipients.
- In the ACT, the ActSmart Household Energy Efficiency Program, run by St Vincent de Paul, offers free assessments and practical advice to lower-income households to reduce their energy and water bills.
- In South Australia, the Retailer Energy Productivity Scheme provides free or discounted energy efficiency services, although it is not specifically for low-income households. Additionally, a virtual power plant project provides solar and home battery systems to eligible Housing SA tenants at no cost.

Sections 6.6.3 to 6.6.6 provide an interim update on customer debt, payment plans, hardship programs and disconnections. This data will be more thoroughly examined in the AER's forthcoming Annual retail markets report 2023–24, due for publication in November 2024.

The AER's quarterly retail performance reports provide more detail on the data and interdependencies between the different debt assistance and financial difficulty metrics provided by retailers.[542]

6.6.3 Assisting customers in energy debt

The AER's *Performance Reporting Procedures and Guidelines* define energy debt as the dollar amount owed (in arrears) to the retailer for the sale and supply of gas or electricity, excluding other services, which has been outstanding to the energy retailer.[543] The number of customers repaying debt excludes customers on hardship programs and non-active debts that retailers may still have on record. Customers with energy debt may be experiencing difficulties that have resulted in an inability to meet their bill repayments.

539 Queensland Government, Cost of living rebate 2024-25, accessed 23 September 2024.
540 EWON, Rebates and assistance, Energy and Water Ombudsman NSW, accessed 23 September 2024.
541 South Australian Government, Energy bill concessions, accessed 23 September 2024.
542 AER, Retail Performance Reporting, Australian Energy Regulator, accessed 28 August 2024.
543 AER, Explanatory statement – (Retail Law) Performance reporting procedures and Guideline, Australian Energy Regulator, 28 August 2024.

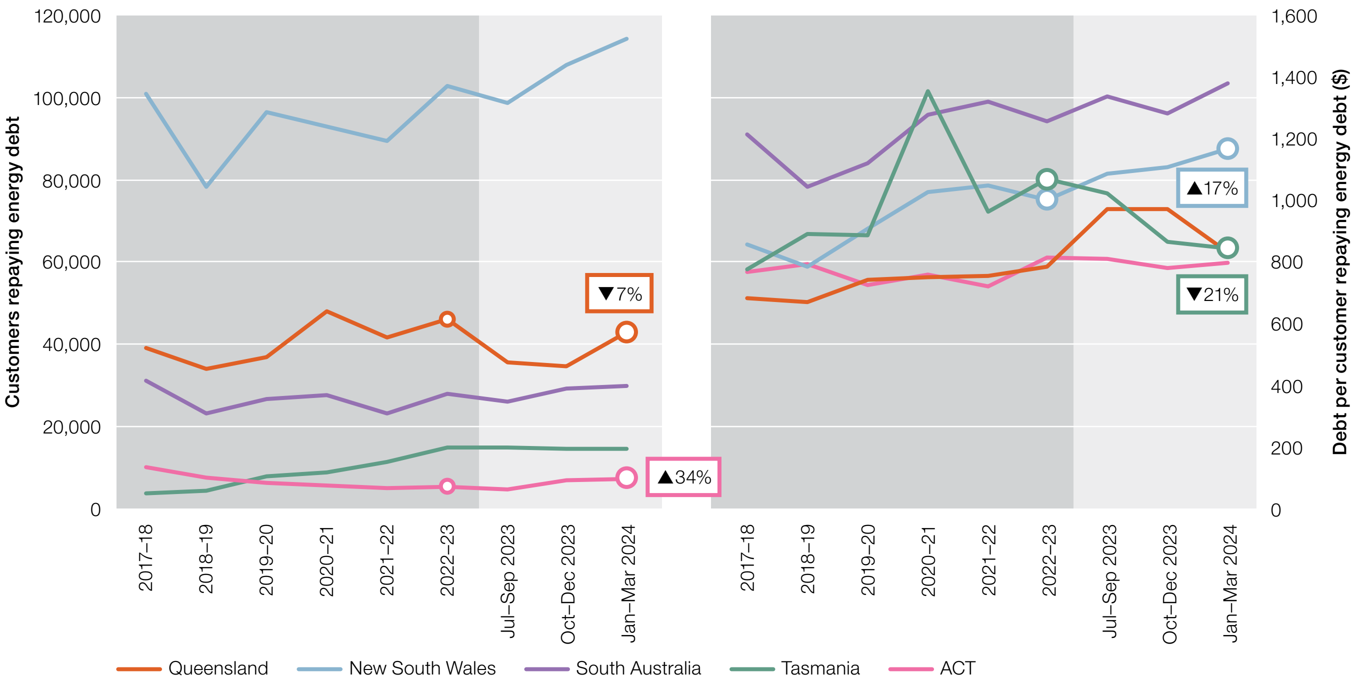
The proportion of customers in energy debt and the average level of debt provide an insight into:

- the extent to which customers are experiencing difficulty paying their energy bills
- whether customers in certain jurisdictions are more susceptible to experiencing difficulty paying their energy bills
- whether retailers are effectively assisting their customers to meet their energy debt repayments.[544]

As at March 2024[545], the overall number of customers across NEM regions with energy debt had increased by 6% since 30 June 2023, though there were mixed results by region. The biggest increases in customers with energy debt were in the ACT (34%) and NSW (11%). Queensland and Tasmania saw decreases in the number of customers in energy debt (–7% and –2%, respectively) (Figure 6.11).

Energy debt has some seasonality, with energy debt levels rising after periods of extreme temperatures. As at March 2024, our most recent data at the time of this report's development, the average amount of debt per customer increased in NSW (17%), South Australia (10%) and Queensland (6%) compared with June 2023. The ACT saw a small decrease of 2% and Tasmania saw a much more significant decrease of 21%. Queensland's hot and humid summer weather at the start of 2024 drove higher than usual demand and put upward pressure on debt levels present in March 2024. Further analysis and more up-to-date data will be provided in the forthcoming Annual retail markets report 2023–24, due for publication in November 2024.

Figure 6.11 Residential customers in energy debt



Note: Based on electricity and gas customers with an amount owing to a retailer that has been outstanding for 90 days or more. Excludes customers that have entered into hardship programs.

Source: AER, *Quarterly retail performance report, Q3 2023–24*, June 2024.

544 AER, Annual retail markets report 2022–23, Australian Energy Regulator, 30 November 2023.

545 Figures based on data from June 2023 to March 2024, annual figures to 30 June 2024 are reported in the AER Annual retail markets report.

Retailers are required to assist consumers experiencing payment difficulties in accordance with the Retail Law, Retail Rules and the AER's Customer Hardship Policy Guideline. This includes offering flexible payment options, such as payment plans and Centrepay, informing customers about government concessions and financial counselling, reviewing the appropriateness of market contracts, and providing energy efficiency strategies if required.

Retailers must tailor payment plans to customers' financial capacities and must waive late payment fees and, in some regions, early termination fees for hardship customers. While practical assistance for other consumers is limited to payment plans, prepayment meter customers experiencing difficulties must be offered a standard meter at no cost and referred to relief programs. Under certain circumstances, retailers can refuse payment plans to those who have defaulted on previous plans or committed energy-related offenses.[546]

Box 6.3 Reviewing payment difficulty protections in the National Energy Customer Framework

In our *Towards energy equity* strategy, the AER committed to considering whether improvements can be made to the National Energy Customer Framework to ensure that consumers experiencing payment difficulty receive effective assistance.

In November 2023, the AER commenced a review of payment difficulty protections to identify whether change is needed to ensure that consumers experiencing payment difficulty are proactively identified, engaged early and supported appropriately with assistance that is tailored to their individual circumstances. Through this review, the AER is also considering the consumer energy debt threshold for disconnection and opportunities to improve engagement so that disconnection is truly a last resort. As part of this, we have consulted extensively with stakeholders on:

- the effectiveness of existing protections for consumers experiencing payment difficulty, including who is eligible for these protections, what retailers must do to identify, engage with and assist consumers experiencing payment difficulty
- whether there are opportunities to strengthen protections for consumers experiencing payment difficulty, including opportunities to improve customer engagement
- the benefits and limitations of other frameworks and approaches, including the Victorian payment difficulty framework and approaches in other sectors
- the costs and benefits of potential changes to the framework, including the impacts of potential changes on retailer costs and the benefits and limitations of harmonising payment difficulty protections across the national energy market.

The AER intends to publish a report exploring the case for change and next steps in late 2024.

546 AER, Review of payment difficulty protections in the National Energy Customer Framework, Australian Energy Regulator, May 2024.

6.6.4 Payment plans

Under the Retail Law, retailers are obligated to provide payment plans to customers who they believe may be experiencing payment difficulties.[547] Payment plans allow settlement of overdue amounts in periodic instalments and are typically the first assistance offered by retailers to customers who show signs of payment difficulties, although other forms of assistance such as tariff and concession checks may also be provided. The AER's Sustainable Payment Plans Framework guides retailers on negotiating affordable payment plans with customers. The framework has been adopted by most retailers servicing small customers.

The AER monitors data on debt levels as well as the number of customers identified to be in hardship or on payment plans. While it is concerning that debt and hardship are increasing, the increase in customers on payment plans can also indicate earlier and more effective retailer engagement and may result in fewer disconnections. As at 31 March 2024[548], there was an increase in customers participating in payment plans across all NEM regions for both gas and electricity.

6.6.5 Hardship programs

The Retail Law requires energy retailers in Queensland, NSW, South Australia, the ACT and Tasmania to develop and maintain a customer hardship policy that outlines how they identify and assist customers facing difficulty paying their energy bills. The AER's Customer Hardship Policy Guideline requires retailers ensure their programs are easily accessible and include standard statements explaining how they will help customers. It puts greater onus on retailers to identify customers who may need assistance and provides broader support that is not limited to being offered a payment plan.[549]

Assistance under a retailer's hardship program can include:

- extensions of time to pay a bill and tailored payment options
- advice on government concessions and rebate programs
- referral to financial counselling services
- review of a customer's energy contract to ensure it suits their needs
- energy efficiency advice, such as an energy audit, and help to replace appliances to help reduce a customer's bills
- waiver of late payment fees.

Under the Retail Rules, retailers must take into consideration a customer's capacity to pay when establishing payment plans for hardship customers and some customers experiencing payment difficulty.

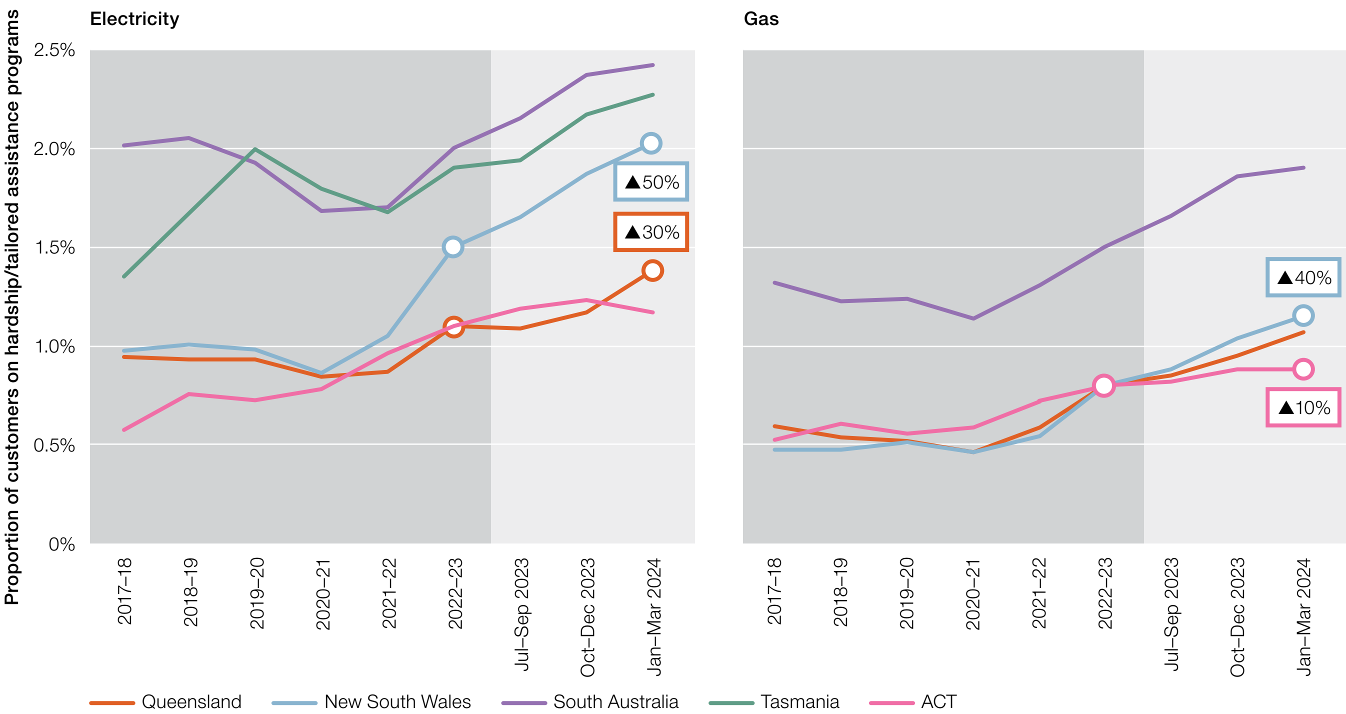
547 National Energy Retail Law (South Australia) Act 2011, Part 2, Division 7, Section 50–Payment plans.
548 Figures based on data from June 2023 to March 2024, annual figures to 30 June 2024 are reported in the AER Annual retail markets report.
549 AER, Hardship protections a right not a privilege, media release, Australian Energy Regulator, 29 March 2019, accessed 28 August 2024.

As at 31 March 2024, the proportion of residential electricity customers on hardship programs compared with June 2023 increased slightly in NSW which experienced a 0.1% increase to 1.2% (approximately 20,400 customers). South Australia had a 0.4% increase to 2.4% (approximately 3,700 customers) and Tasmania also had a 0.4% increase to 2.3% (approximately 1,000 customers). Queensland experienced a 0.3% increase to 1.4% (approximately 6,700 customers) and the ACT increased by 0.1% to 1.2% (approximately 100 customers).

The proportion of residential gas customers on hardship programs increased over the same period. NSW experienced a 0.4% increase to 1.2% (approximately 6,100 customers), Queensland experienced a 0.3% increase to 1.1% (approximately 600 customers), South Australia experienced a 0.6% increase to 1.9% (approximately 1,800 customers) and the ACT experienced a 0.1% increase 0.9% (approximately 100 customers) (Figure 6.12).[550]

However, it is notable that there was also a 28% decrease in average debt at the start of a hardship program, which may indicate that retailers engaged with customers experiencing debt more promptly and effectively compared with the previous year.[551] Analysis in the AER's forthcoming Annual retail markets report 2023–24 will provide a more complete picture of the AER's affordability metrics, including data on: customers successfully exiting hardship programs, customers excluded from hardship due to non-payment, reasons for entering the hardship program and length of hardship programs.

Figure 6.12 Residential customers on hardship programs



Note: The y axis represents % of customers in hardship and the percentage movements identified in the charts correlate with movements in percentages.

Source: AER, *Quarterly retail performance report, Q3 2023–24*, June 2024.

550 AER, Quarterly retail performance report, Q3 2023–24, Australian Energy Regulator, 28 August 2024.
551 AER, Quarterly retail performance report, Q3, 2023–24, Australian Energy Regulator, 28 August 2024.

6.6.6 Disconnecting customers for non-payment

Under the Retail Law, disconnection for non-payment of bills is a last resort option and can only occur after the strict processes set out in the Retail Rules have been followed.[552]

Disconnection is not permitted at all in certain circumstances – such as when a customer's premises are registered as requiring life support equipment, when a customer on a hardship program is meeting their payment obligations or where a customer's debt is below $300. There are also specific times during which consumers are protected from disconnection, including afternoons, evenings, Fridays, weekends, public holidays, and between 20 and 31 December. The Rules also protect customers in some jurisdictions from disconnection during an extreme weather event, and there are additional protections for customers affected by family violence.

The rate of disconnections remains significantly lower than in pre-COVID-19 years. This is encouraging as the AER's Statement of Expectations directing retailers not to disconnect small customers during COVID-19 lapsed on 30 June 2021.[553] The persistence of low disconnection rates for both electricity and gas small customers suggests ongoing behavioural change by retailers (Figure 6.13 and Figure 6.14). Where disconnection did occur, average customer debt levels at the time of disconnection were higher than in the previous year.

Customers with prepayment meters who are under the remit of the NECF also have a range of protections, including access to hardship programs and a requirement for the retailer to offer a switch to a post-pay meter if they are identified as experiencing payment difficulty. However, some jurisdictions have implemented local instruments to allow for energy retailers with customers on prepayment meters to derogate from the requirements set out under the NECF.

While some of those customers may have adequate protections in place via local instruments, some may not and are at much higher risk of energy insecurity. Recent data shows high rates of disconnections experienced by prepayment meter customers in the Northern Territory and South Australia.[554]

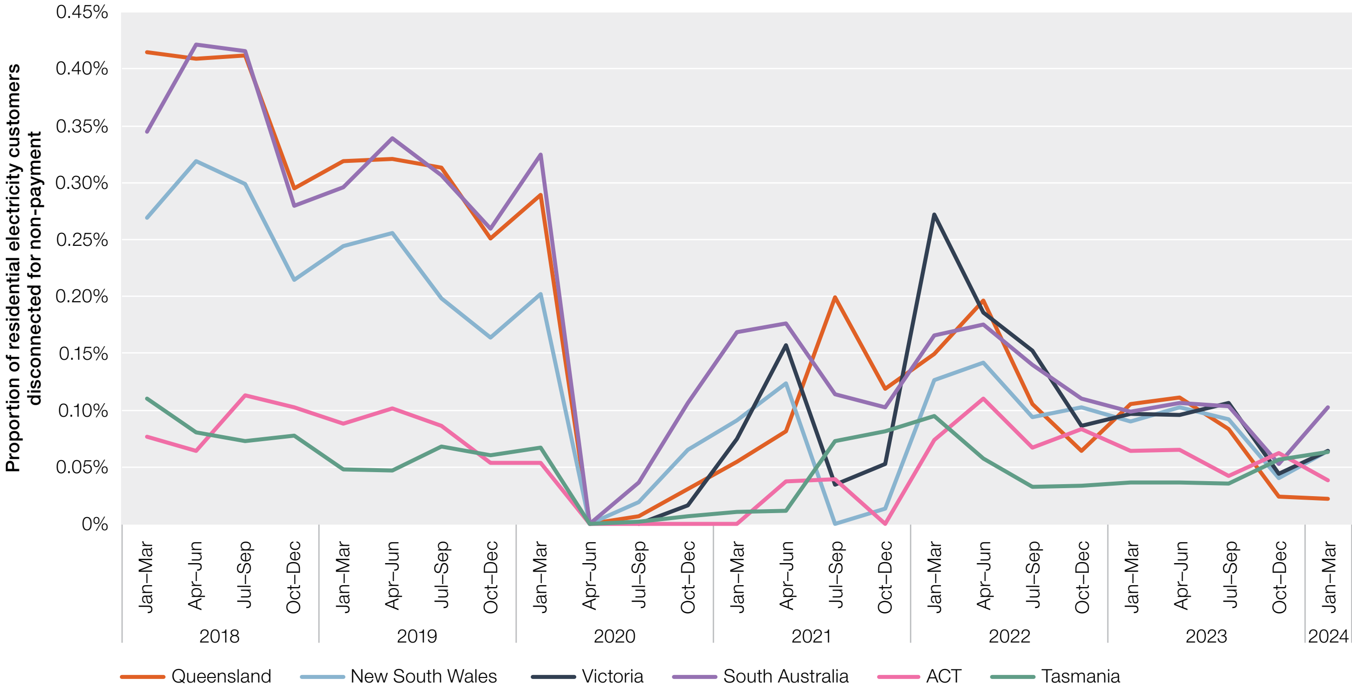
552 National Energy Retail Rules, Version 8, Part 6, accessed 6 September 2024.

553 AER, Statement of Expectations of energy businesses: Protecting customers and the energy market during COVID-19, Australian Energy Regulator, 29 June 2021.

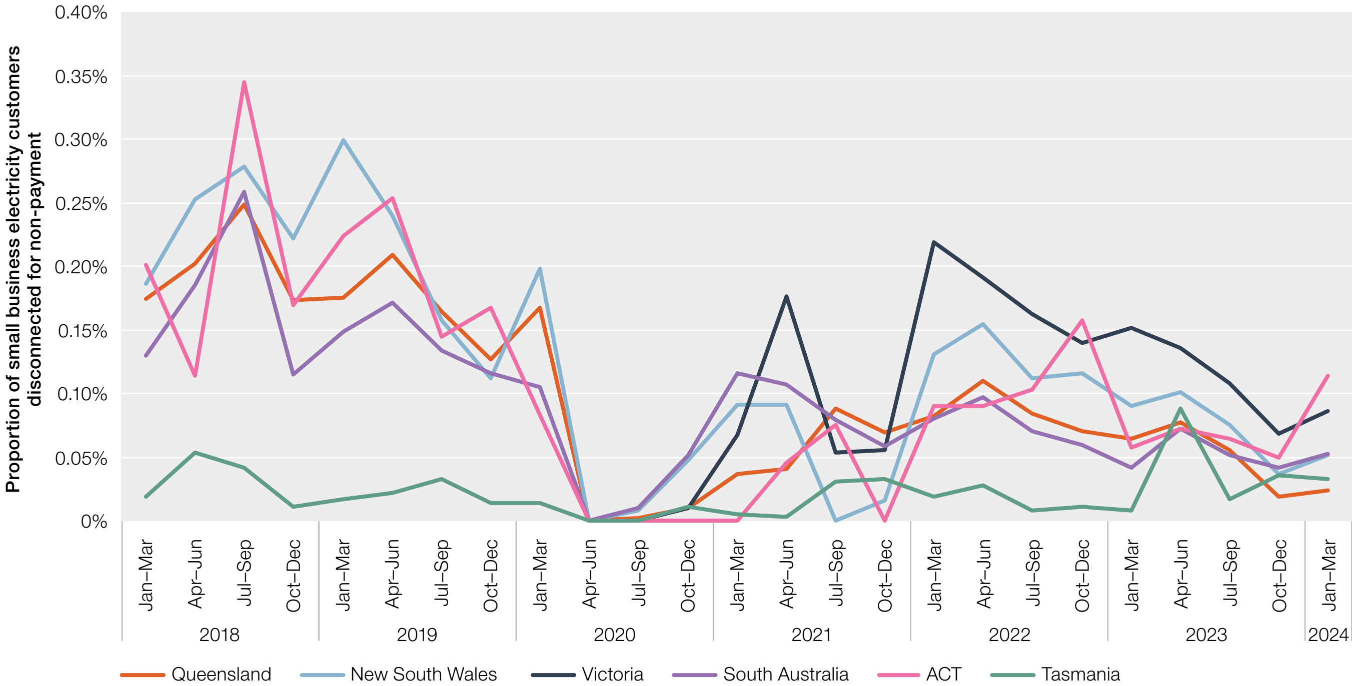
554 Utilities Commission of the Northern Territory, Northern Territory Electricity Retail Review 2022–23, May 2024, accessed 6 September 2024.

Figure 6.13 Disconnection for failure to pay – electricity

Residential



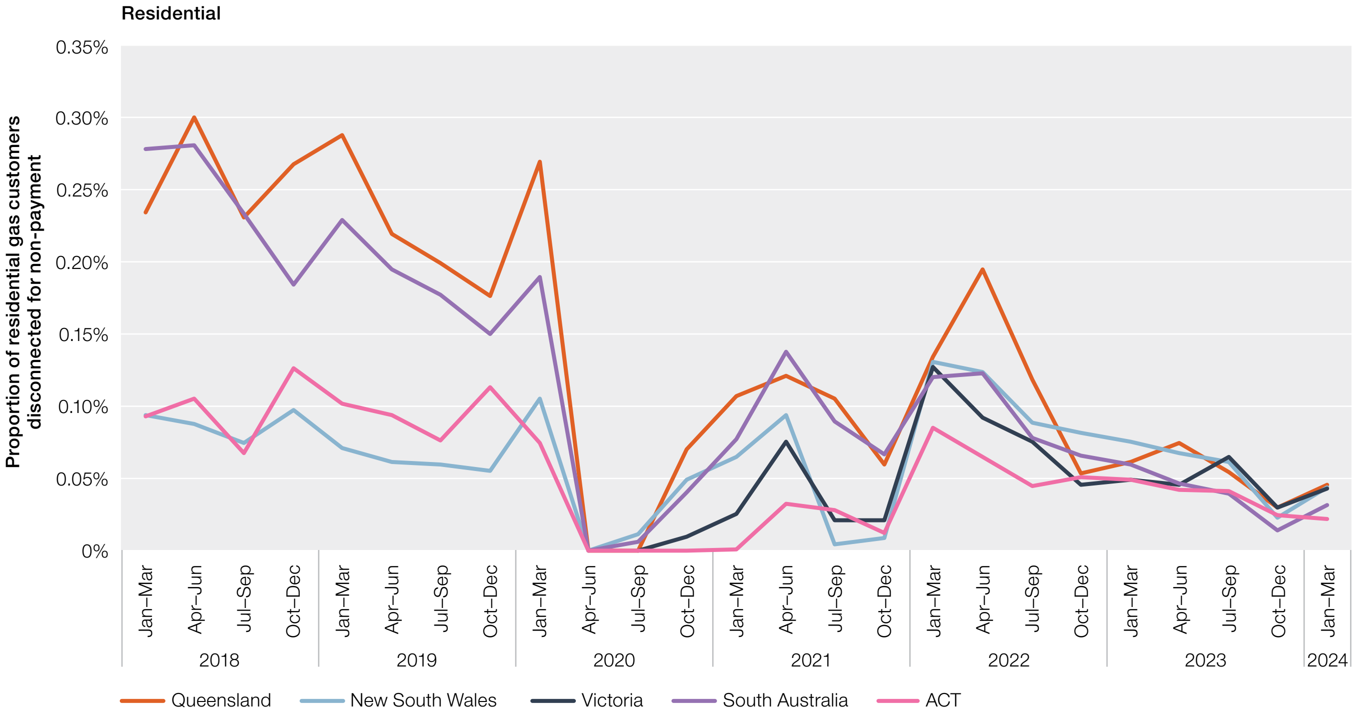
Small business

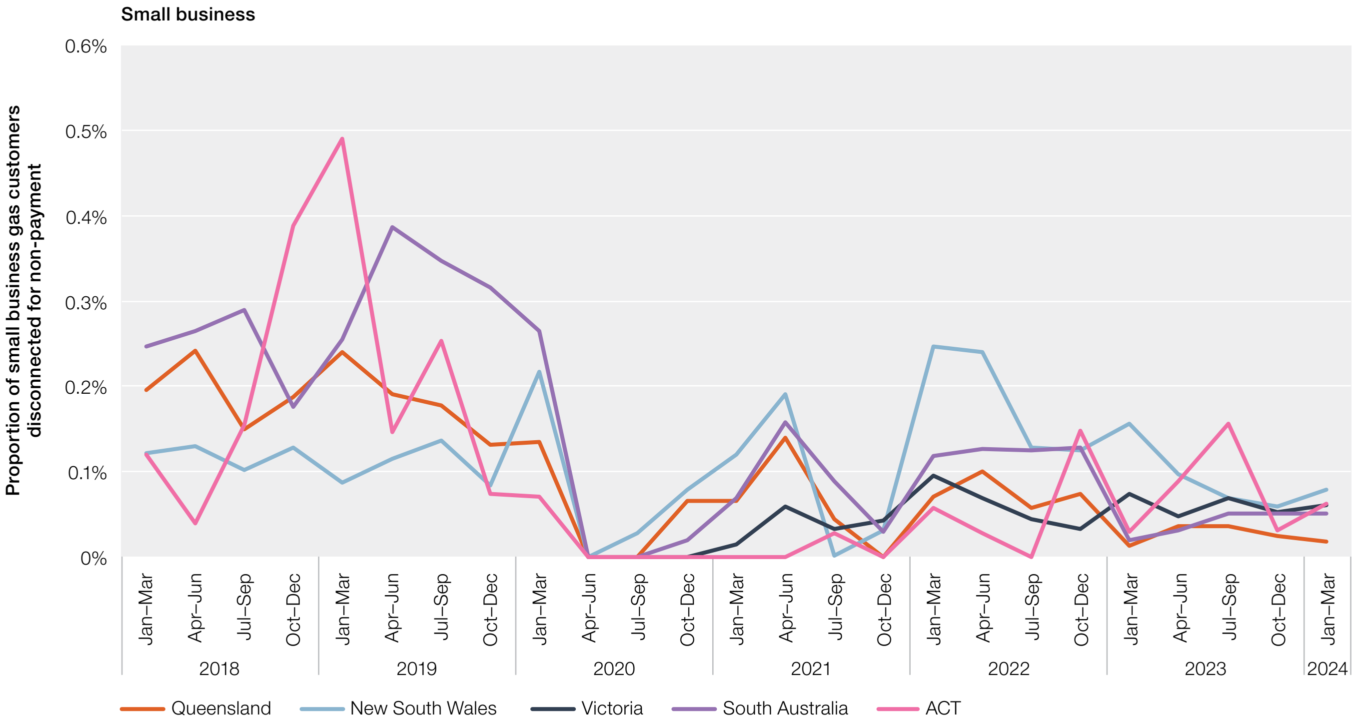


Note: Based on customers with an amount owing to a retailer that has been outstanding for 90 days or more, at 31 March 2024, for all states except Victoria, which is at 30 June 2024.

Source: AER, *Quarterly retail performance report, Q3 2023–24*, June 2024; ESC, Victorian energy market dashboard and historical data, accessed 30 June 2024.

Figure 6.14 Disconnection for failure to pay – gas





Note: Based on customers with an amount owing to a retailer that has been outstanding for 90 days or more, at 31 March 2024, for all states except Victoria, which is at June 2024.

Source: AER, *Quarterly retail performance report, Q3 2023–24,* June 2024; ESC, Victorian energy market dashboard and historical data, accessed 30 June 2024.

6.6.7 Improving our approach to consumer vulnerability

In October 2022 the AER launched Towards energy equity – A strategy for an inclusive energy market.[555] This strategy is focused on reducing barriers to participation, supporting consumers experiencing payment difficulty, ensuring the consumer voice is heard in sector reforms and improving affordability by reducing the cost to serve energy consumers.

The strategy outlines 15 actions that the AER will deliver over 3 years, in alignment with 5 core objectives:

- improve identification of vulnerability
- reduce complexity and enhance accessibility for energy consumers
- strengthen protections for consumers facing payment difficulty
- use the consumer voice and lived experience to inform regulatory design and change
- balance affordability and consumer protections by minimising the overall cost to serve.

Over the last year, the AER has made significant progress on several actions in the strategy:

- consulting on a draft toolkit to help consumer-facing energy businesses better identify and support consumers experiencing vulnerability, with the final toolkit to be published later this year
- undertaking a compliance review and evaluation research activities for the Better Bills Guideline, which was implemented in full on 30 September 2023
- commencing a review of the AER exemptions framework for embedded networks, including consultation on an issues paper
- completing extensive consultation for the Review of payment difficulty protections in the National Energy Customer Framework, including early engagement meetings with over 40 stakeholders, focus groups with 23 consumers, stakeholder workshops attended by 39 representatives from industry, consumer advocacy and community support organisations, and a listening session with 36 representatives from culturally and linguistically diverse communities.

On 13 August 2024 the AER, along with state and territory governments, provided recommendations through the Game Changer Report that the Australian Government implement a comprehensive reform package to improve outcomes for consumers facing financial hardship.[556] The package aims to address vulnerability throughout the entire energy consumer journey and recognises that vulnerability can change over time.

Key components of the package include:

- incentives for retailers to identify and assist vulnerable consumers early
- enhanced support for those with significant debt burdens to break the cycle of energy debt
- upgrades to concession and rebate systems to ensure consumers automatically receive their entitled discounts and can switch retailers without losing benefits
- improved access to financial counselling for consumers to help manage their payment difficulties
- automatic placement of hardship plan consumers on the best available offer
- debt relief for those who cannot meet their energy costs, funded by a shared industry pool and supported by financial counsellors or community organisations.

In November 2023 the Energy and Climate Change Ministerial Council decided to progress work on the sector-wide 'game changer' reforms to ensure consumers are adequately protected against potential harms arising from new energy services.[557] The CER Roadmap recognises that careful development of regulation and programs is required to ensure that the deployment and use of CER allows the distribution of benefits to all energy consumers, avoids costs to those unable to invest and ensures access, particularly for people vulnerable to or experiencing hardship.[558]

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

556 AER, Game Changer Report, Australian Energy Regulator, accessed 13 August 2024.

557 ECMC, Meeting Communique, Energy and Climate Change Ministerial Council, 24 November 2023.

558 DCCEEW, National Consumer Energy Resources Roadmap, Department of Climate Change, Energy, the Environment and Water, 18 July 2024.

6.7 Competition in retail energy markets

Competition in retail energy markets is necessary to stimulate innovation and ensure better quality, lower cost products and services for consumers. The AER's role in delivering consumer protections – such as monitoring and reporting on market performance, enforcement and compliance activities, provision of price comparison services, setting the default market offer reference price and regulating monopoly infrastructure – must be balanced to ensure market competition isn't unnecessarily hindered.

The ACCC's June 2018 Retail Electricity Pricing Inquiry found that retail electricity competition had not sufficiently benefited consumers. Since then, regulatory reforms have aimed to boost retailer competition in a way that benefits consumers, providing information to help them better engage with the market and compare retail offers. This could lead to more competitive prices and improved products.

Because customers of exempt sellers embedded networks may not benefit from the same customers protections available to other consumers, they may face additional barriers to accessing the benefits of retail competition. For example, switching retailers can require a significant investment of time and money and only a small number of embedded network customers (generally small businesses) have successfully transferred away from their embedded network's incumbent retailer. The AER has undertaken a range of compliance and enforcement activities to improve outcomes for customers in embedded networks, including introducing obligations to ensure embedded network customers can access hardship protections and ombudsman schemes (section 6.8.4).

Consumers experiencing vulnerability may not have the opportunity to shop around for the best market offer. It is important these consumers are not further disadvantaged by higher energy bills. As the energy system transitions to more dynamic energy use and more complex price signals, the regulatory framework will need to incentivise innovation that includes appropriate safeguards for all consumers, regardless of their level of engagement or energy literacy.

6.7.1 Market concentration

Origin Energy, AGL Energy and EnergyAustralia (collectively referred to as 'Tier 1' retailers) are the largest energy providers in Australia. Tier 1 retailers have a significant share in the residential electricity and gas markets of NSW and South Australia and a lesser, but still substantial, portion of the Queensland and Victorian markets. Although their market share continues to decline, as of March 2024, they still served at least 60% of electricity customers and 80% to 90% of gas customers (Figure 6.16).

Growth in the number of alternative (Tier 2) retailers can contribute to effective retail competition by providing a more diverse mix of offers in the market.[559] A growth in the number of Tier 2 retailers was observable from 2017 but this has slowed since winter 2022 (Figure 6.15). Tier 2 retailers continue to improve market share, but they are doing so at a slower rate.

Since the market conditions of winter 2022, smaller retailers have reported that it is harder to manage exposure to volatile wholesale electricity prices. Volatility in wholesale energy costs may subdue interest from new market entrants until wholesale prices stabilise.[560] Access to competitively priced hedging contracts had already been identified by standalone retailers as early as 2020 as a barrier to entry and further expansion.[561]

559 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).

560 AER, Wholesale electricity market performance report – December 2022, Australian Energy Regulator, 15 December 2022, p. 56.

561 AEMC, 2020 Retail Energy Competition Review, Australian Energy Market Commission, 30 June 2020, accessed 15 September 2022.

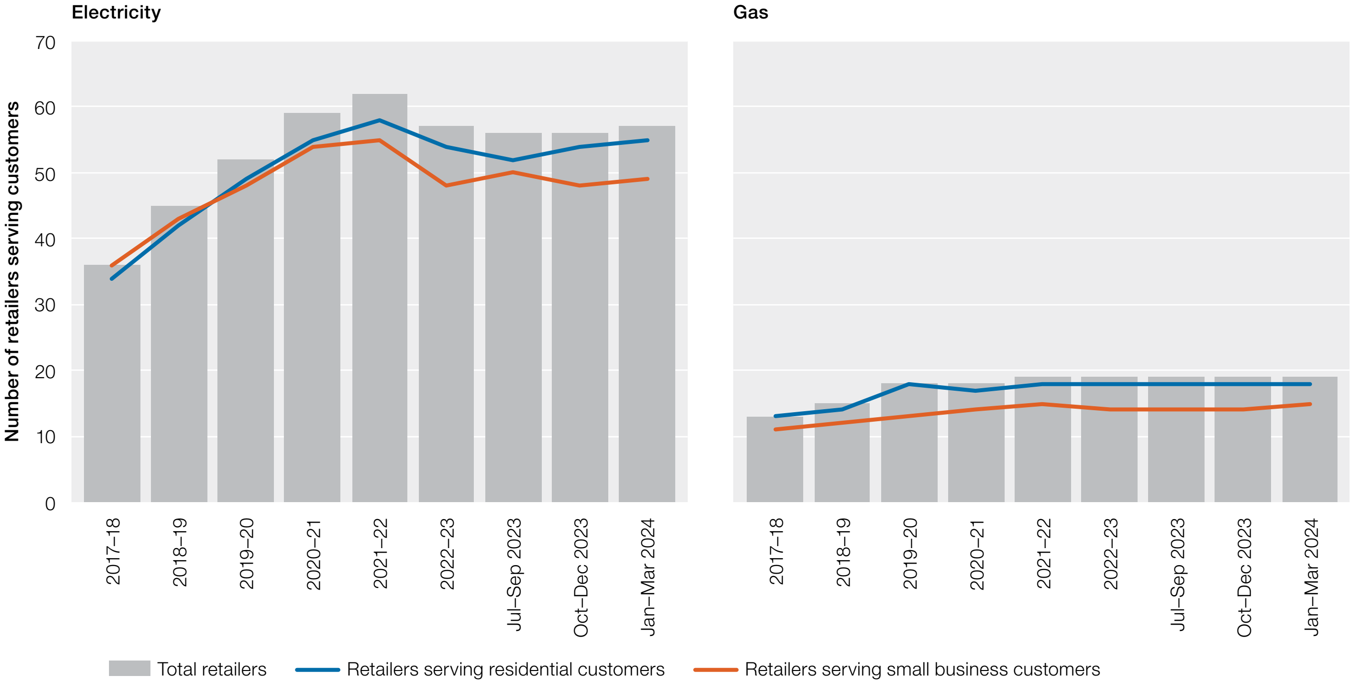
Regions with stronger levels of continuous retail price regulation are also heavily concentrated, including Ergon Energy in regional Queensland, Aurora Energy in Tasmania and ActewAGL. These primary retailers are government-owned (wholly or in part) businesses with little activity outside their home jurisdiction and were previously the sole regulated provider of retail electricity in that jurisdiction.[562] Due to a lack of competition and ongoing price regulation, the degree of market concentration in those regions remains stable (Figure 6.16).

Consumers experiencing vulnerability may not have the opportunity to shop around for the best market offer.

Gas markets are generally less competitive and have much higher levels of concentration than electricity markets given their smaller scale and persistent issues in sourcing gas and pipeline services in some jurisdictions (Figure 6.17).

The upstream east coast gas market is heavily concentrated, with 3 major LNG producers and their associates dominating it. Although the ACCC's Gas Inquiry December 2023 interim report identifies potential new supply sources held by emerging market players and smaller producers, these are impeded by various challenges.[563]

Figure 6.15 Energy market – number of retail brands



Source: AER, *Quarterly retail performance report, Q3 2023–24*, June 2024; ESC, Victorian energy market dashboard and historical data, accessed 30 June 2024.

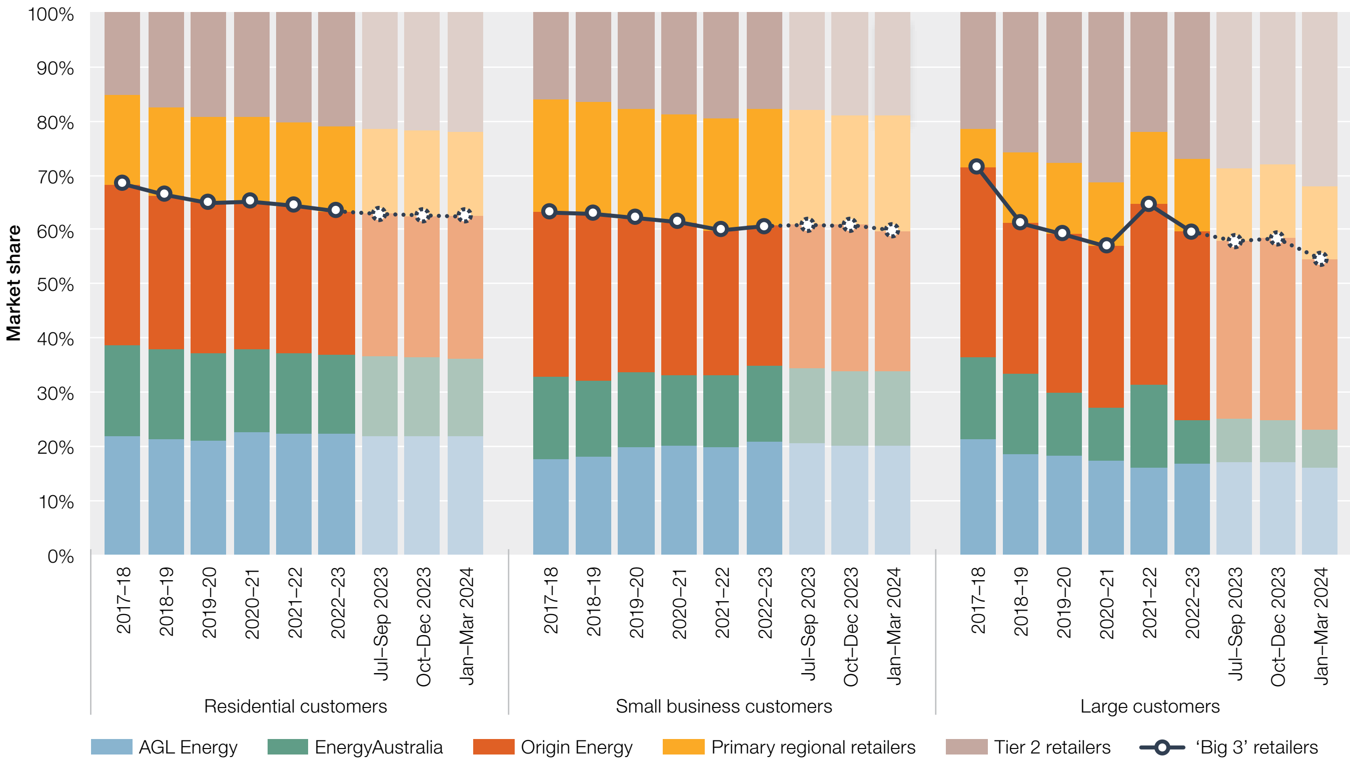
562 AER, Annual retail market report 2021–22, Australian Energy Regulator, 30 November 2022.
563 ACCC, Gas Inquiry 2017-2030, Interim update on east coast gas market, June 2024, Australian Competition and Consumer Commission.

6.7.2 Electricity

Between 1 July 2023 and 31 March 2024, the number of customers serviced by Tier 1 retailers decreased 0.16%, whereas the number of Tier 2 customers increased by 5.4%. Tier 2 retailers have increased their share of small customers in each year since at least 2016–17.[564]

While the Retailer of Last Resort (RoLR) scheme[565] continues to operate, no retailers exited the market through the scheme between 1 August 2023 and 31 July 2024. From 30 July 2024, amendments to the *National Energy Retail Law (Victoria) Act 2024* and the National Energy Retail Law (Victoria) Regulations 2024 (Regulations) give the AER the responsibility of managing RoLR events across the National Energy Customer Framework and in Victoria. From 30 July 2024, where the AER issues a RoLR notice due to the occurrence of a specified RoLR event and revokes the failed national retailer's retail authorisation, section 49B(2) of the *Electricity Industry Act 2000* (Victoria) automatically revokes the Victorian licence of that retailer.[566]

Figure 6.16 Energy retail market share – electricity



Note: All data as of 31 March 2024. Data includes customers in Queensland, NSW, South Australia, Tasmania and the ACT. Some differences may occur between annual and quarterly data to account for retailers revising their data when making their annual submission.

Source: AER, *Retail markets quarterly, Q3 2023–24*, June 2024.

In NSW, the big 3 retailers serve 75% of electricity customers, making it the most concentrated jurisdiction. Snowy Hydro (owned by the Australian Government and trading as Red Energy and Lumo Energy) serves 11% of small customers, with the remaining 14% served by other Tier 2 retailers.[567]

564 Retail customer numbers are not available prior to 2016–17.

565 The Retailer of Last Resort (ROLR) scheme allows for prompt transfer of customers to a new retailer if their existing retailer fails or loses their authorisation. This provides continuity for customers' energy supply without AEMO having to bear the risk of failing retailers defaulting on their energy purchases.

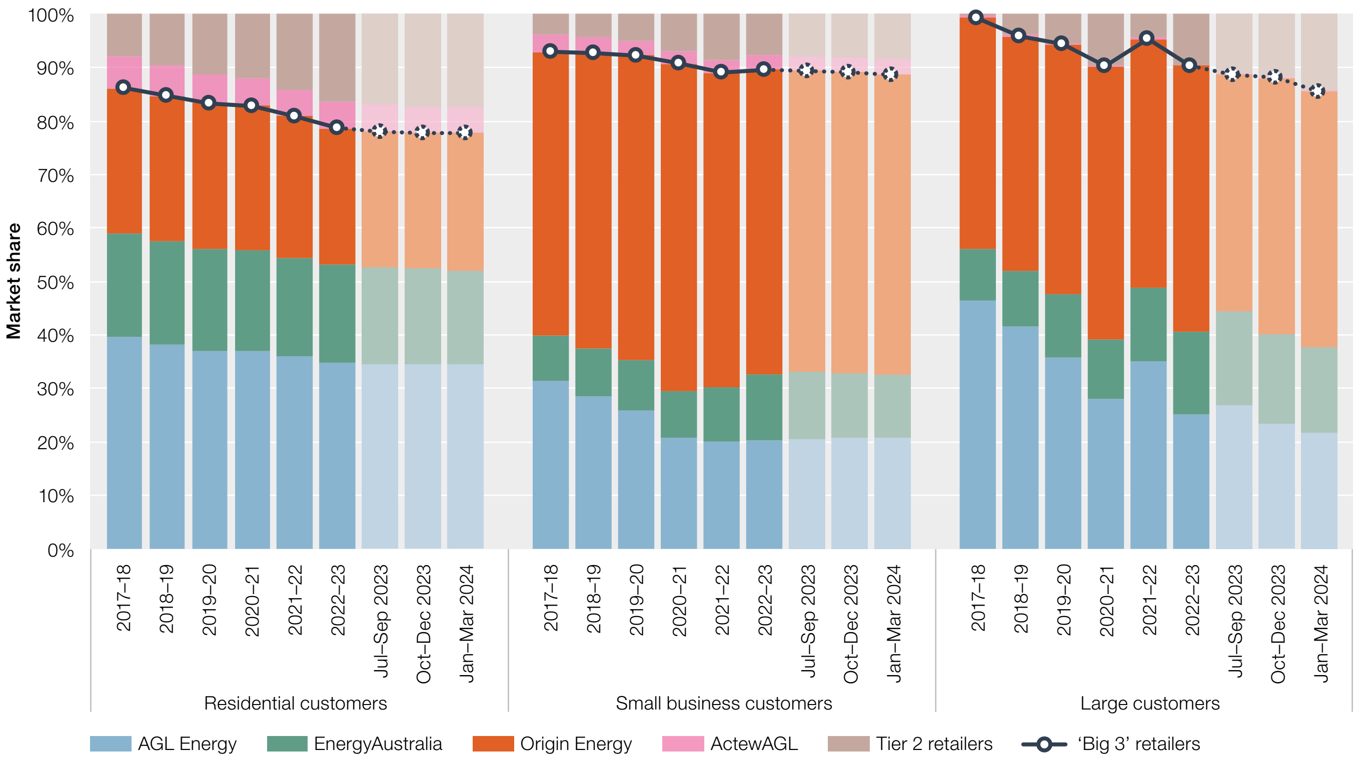
566 For more background on these amendments please see AER, AER ensures continued supply for former Maximum Energy customers, Australian Energy Regulator, 2 August 2024.

567 Use of state-wide data masks levels of market concentration within some parts of regions with multiple distribution zones (Queensland and NSW). For example, market concentration is likely to be higher in regional NSW than in Sydney.

6.7.3 Gas

As with electricity, AGL Energy, Origin Energy and EnergyAustralia are the dominant retailers in the gas market, serving just over 1.6 million residential customers (78% of a total 2.1 million).[568] In the 9 months from June 2023, the big 3 retailers' share of the small customer market decreased from 78.7% to 77.8% and over the same period Tier 2 retailers increased their share of the market.[569] In gas markets, the big 3 retailers have continued to lose their small customer market share to Tier 2 retailers since 2016–17 (Figure 6.17).

Figure 6.17 Energy retail market share – gas



Note: All data as of 31 March 2024. Data includes customers in Queensland, NSW, South Australia and the ACT.
Source: AER, *Quarterly retail performance report, Q3 2023–24*, June 2024.

568 Includes customers in Queensland, NSW, South Australia and the ACT. Does not include Victoria.
569 AER, Quarterly retail performance report Q3, 2023–24, Australian Energy Regulator, 28 June 2024.

6.7.4 Vertical integration

Vertical integration in the electricity sector refers to companies that operate in both generation and retail markets. Referred to as 'gentailers', they have been in operation for many years and include all Tier 1 providers in the NEM (AGL, Origin and EnergyAustralia), and several Tier 2 retailers that own major generation assets. Tier 1 gentailers have a significant share of the residential electricity and gas markets in NSW, South Australia, Queensland and Victorian, serving at least 60% of residential and small business electricity customers and 80% to 90% of residential and small business gas customers (Figure 6.16).

Gentailers may be able to better manage price fluctuations, theoretically reducing the need for complex financial strategies to hedge against market volatility and enabling them to offer lower prices to consumers. However, gentailers often need to employ financial strategies just as complex as pure retailers to balance their positions (being a gentailer does not necessarily mean avoiding complexities in retail markets). Gentailers can pose challenges for independent retailers who do not undertake integrated operations, because reduced trading activity in financial markets can make it tougher for them to compete as independent retailers are heavily reliant on financial hedging techniques to manage risks of price volatility. Our forthcoming wholesale electricity market performance report will provide further analysis on vertical integration in wholesale energy markets.[570]

6.7.5 Customer engagement

Between 80% and 90% of energy customers are on a market offer contract (Figure 6.18). Customers who can actively participate in retail energy markets can research market offers and enter a market contract with their retailer of choice.[571] Market contracts allow retailers to tailor their energy products, offering different tariff structures, discounted prices, carbon offsets, non-price incentives, billing options, fixed or variable terms and other features.

Customers without a market contract or whose market contract has expired are placed on a standing offer with the retailer that most recently supplied energy at their premises (or, for new connections, with the retailer designated for that area). Standing offers are intended to provide a safety net for customers unable or unwilling to engage in the market, with prescribed terms and conditions and a suite of consumer protections that the retailer cannot change (section 6.3.5).

While customers on market contracts have generally paid less than those on standing contracts, in 2022–23 prices for both market and standing contract customers seemed to be converging (section 6.4.1). However, data for 2023–24 shows this is no longer the case most regions, with standing offers increasing (relative to market offers) in all jurisdictions besides Tasmania and the ACT (Figure 6.18). The largest increases in standing offers compared with market offers was observable in Victoria (section 6.4.1). The Victorian Government regulates standing offer prices under its Victorian Default Offer, which may account for variations in pricing compared with the AER's DMO regions.[572]

Most standing offer customers have contracts with Tier 1 retailers. This reflects the position of these retailers as incumbents – the retailer that purchased the customer base at the time retail contestability was introduced – allowing them to retain customers that have never taken up a market contract and may face additional barriers to actively participate in the market. Customers on standing offers are likely to pay more for their electricity bills than those on market offers.

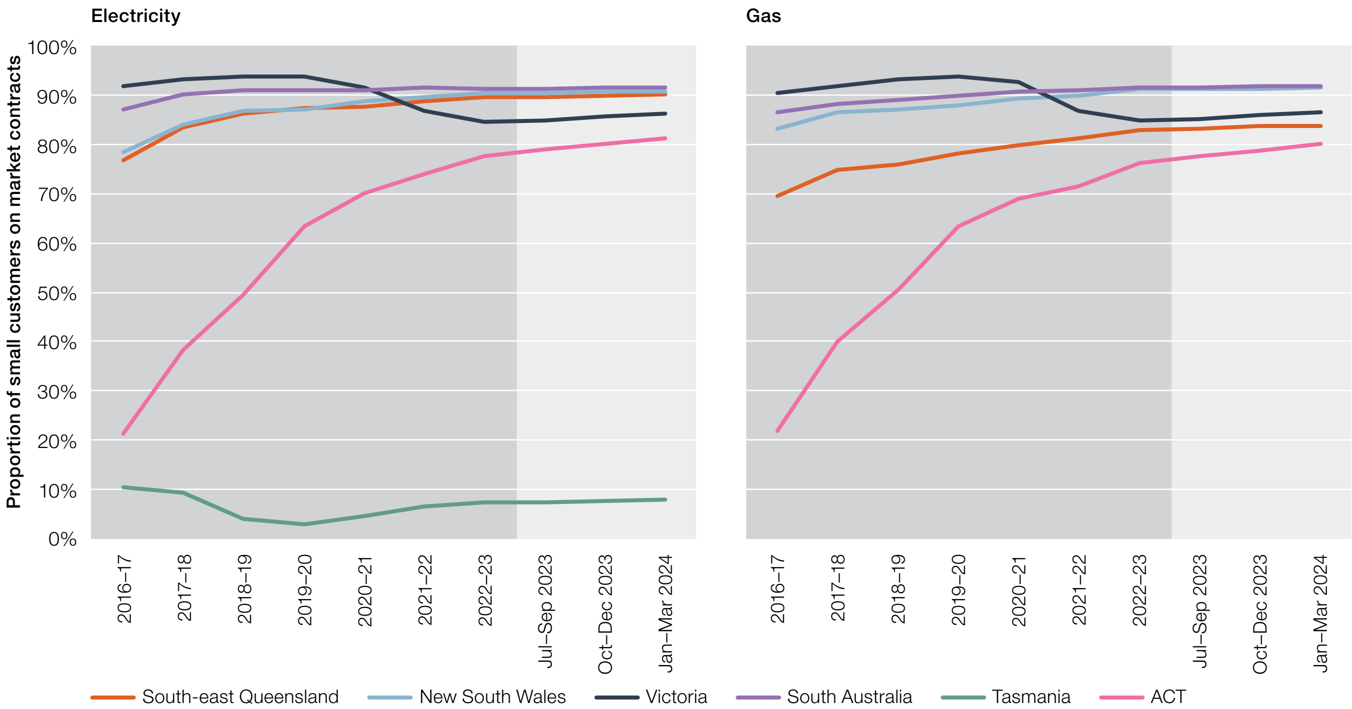
570 The report is due for publication in December and will be accessible via the AER's wholesale performance reporting page.

571 While full retail contestability applies in all regions, not all customers can access offers from a retailer other than their host retailer. Further, many customers within embedded networks are still limited to energy supply through their embedded network operator.

572 ESC, Victorian Default Offer 2023, Essential Service Commission (Victoria), 1 July 2024

However, in regions serviced by primary regional retailers, most customers are on standing offers. As partially government-owned retailers with ongoing price regulation, they have maintained strong market concentration, faced limited retail competition and have delivered relatively stable pricing for customers. As such, small customers in those areas have had less motivation and opportunity to pursue market offers. In Tasmania, new entrant retailers have offered market contracts to residential customers since early 2019, but the proportion of customers on market contracts remains much lower compared with other regions. The Tasmanian Government set standing offer prices that attracted Aurora Energy's market customers to switch back to the standing offer (Figure 6.18).[573]

Figure 6.18 Small customers on market contracts



Note: Standing and market offer shares are based on the number of small customers at 31 March 2023 except Victoria (June 2023). Queensland electricity numbers exclude customers in regional Queensland, who largely remain on standing offers.

Source: AER, *Retail markets quarterly, Q3 2023–24*, July 2024; Victorian energy market dashboard and historical data, accessed 23 August 2024.

573 Office of the Tasmanian Economic Regulator, Electricity pricing explained, accessed 18 September 2024.

6.7.6 Consumer participation

Competition in retail energy markets is intended to drive innovation, resulting in a wider range of products and services to meet different customer preferences and demands. However, for a range of reasons, many consumers face barriers to actively participate in the market and secure the best offer for their situation. This can exacerbate existing structural inequalities, whereby those who can least afford it are paying higher energy rates.

To remain on the best possible plan, customers need to continuously review, compare, renegotiate or switch market contracts to maintain better prices. For example, in June 2024 the ACCC reported that customers able to switch between market contracts benefit from accessing the best available offer and discounts to attract new customers; the median residential market offer customer pays between 5% and 10% lower effective prices than the median standing offer customer for most usage levels.[574]

A reasonable degree of energy literacy is required to identify the best possible plan. Despite the safeguards provided by standing offers and reforms to make retail energy bills easier for customers to understand section 6.3.1)[575], customer surveys regularly report that customers still find the energy market difficult to navigate.

In June 2024, Energy Consumers Australia (ECA) reported that 30% of Australians do not feel there is enough easy-to-understand information available to make informed decisions about energy.[576] Further, marketing strategies that make it difficult and time-consuming for customers to directly compare offers reinforces a lack of trust and reduces levels of engagement.

Reforms in 2019 sought to make it easier for customers to compare offers by simplifying and standardising how retailers must present offers. The reforms require advertised discounts to be quoted against a common 'reference bill', being the default market offer set by the AER (section 6.3.3).

The Better Bills Guideline, which was implemented in full on 30 September 2023, also seeks to make it easier for consumers to engage with the energy market by providing information to help them understand and compare their plan, identify whether their retailer may be able to provide a better offer, and consider options for new types of energy services (section 6.3.1).

The AER has also developed a suite of translated, shareable content for consumers who speak a language other than English.[577] The content, some of which is translated into 8 languages, provides information on:

- how to save money on energy bills
- how to get help when having trouble paying bills or if having a dispute with a retailer
- what happens if their energy provider goes out of business.

Market developments such as the rollout of smart meters and new dynamic tariffs are adding additional layers of complexity to the market, making it harder for consumers to confidently engage. Other major barriers to consider include lack of trust towards energy institutions, providers and the government, and a lack of a single source of easy-to-understand information.[578]

574 ACCC, Inquiry into the National Electricity Market – June 2024 report, Australian Competition and Consumer Commission, 3 June 2024.

575 AER, Better Bills Guideline (Version 2), Australian Energy Regulator, 28 June 2024.

576 ECA, Evidence base to support the development of an effective communications campaign for energy consumers, Energy Consumers Australia, 27 July 2023.

577 AER, Translated information to help energy consumers, Australian Energy Regulator, accessed 30 August 2024.

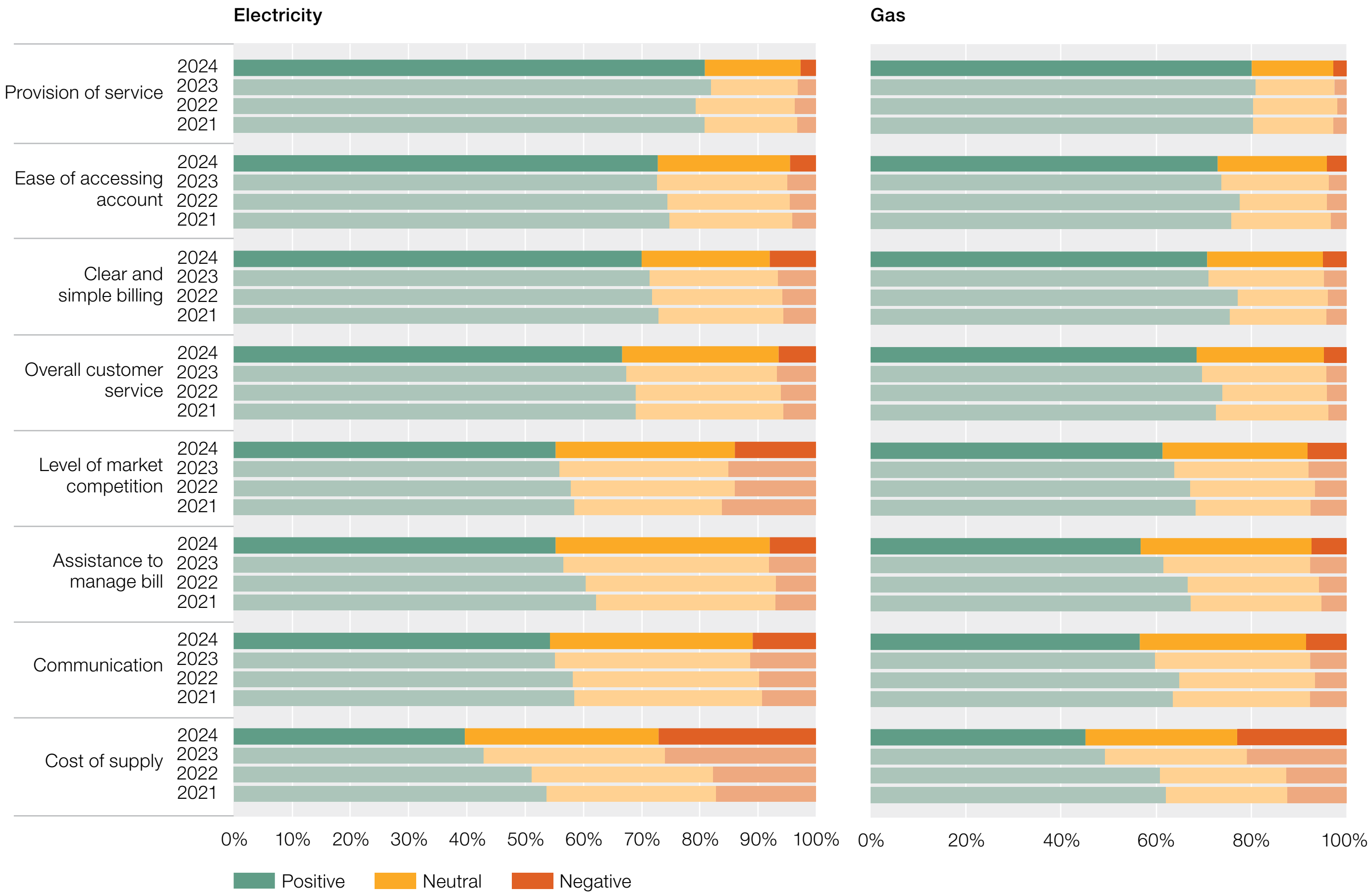
578 ECA, Evidence base to support the development of an effective communications campaign for energy consumers, Energy Consumers Australia, 27 July 2023.

6.7.7 Consumer satisfaction

A customer's level of satisfaction with retail energy markets depends on several factors and can be influenced by price, perceived value for money, reliability, customer service, confidence in engaging with the market, technology uptake, ability to switch and retailer behaviour.

Results from the ECA's June 2024 survey reported an overall increase in positive sentiment since 2022, but noted that the cost of supply was an increasing concern, with 'dissatisfaction with value for money' being one of the main reasons for customer switching (Figure 6.19).

Figure 6.19 Responses from energy consumer sentiment survey



Source: Energy Consumers Australia, *Energy consumer sentiment survey*, June 2024.

6.7.8 Consumer data right

The Australian Government is extending the Consumer Data Right (CDR) to cover the energy sector.[579] This will allow consumers to authorise their energy retailer share their historical energy use data with an accredited service provider. Giving consumers the right to safely share their data (such as their current energy deal and consumption patterns) with third parties should make it easier for them get a better deal on a range of energy products and services, while promoting competition between retailers.

Tier 1 retailers were required to comply with non-complex consumer data requests from 15 November 2022, and for complex requests from 15 May 2023. Compliance timeframes for other retailers has varied between November 2021 and May 2024, depending on the number of customers and complexity of the data request.[580]

6.7.9 Price comparison websites and switching services

The variety of product structures, discounts and other inducements can make it difficult for energy customers to compare retail offers. Due to the fundamental role shopping around has in delivering savings to consumers, some customers use comparator websites to manage the complexity and range of offers in the market. Independent price comparator websites are run by the AER and Victorian Government.

The AER operates an online price comparator Energy Made Easy (energymadeeasy.gov.au) to help small customers compare market offers. The website shows all generally available offers and has a benchmarking tool that allows consumers to compare their electricity use with similar-sized households in their area. The website is available to consumers in jurisdictions that have implemented the Retail Law (Queensland, NSW, South Australia, Tasmania and the ACT). The Victorian Government operates a similar online price comparator, Victorian Energy Compare (compare.energy.vic.gov.au).

Comparison websites and brokers can provide consumers with a quick and easy way of engaging in the market, but some services may not provide customers with the best outcomes. For example, commercial comparator websites may only show offers of retailers affiliated with the site. Commercial comparators also typically require retailers to pay a commission per customer acquired or a subscription fee to have their offers shown. These arrangements are opaque to the customer. Commissions may vary across listed retailers, creating incentives for websites to promote offers that will most benefit the comparator business rather than show the cheapest offer for the customer. Government-operated comparison sites avoid this bias by listing all generally available offers in the market.

The AER's ongoing programme of work to enhance the Energy Made Easy platform suggest that future reliance on benchmarks may diminish. While current benchmarks remain broadly useful, their relevance is expected to decrease as the market evolves and more tailored data becomes available. Given the costs and limited benefits of maintaining the benchmarks, the regulatory requirements for periodic updates may no longer be the most effective approach.

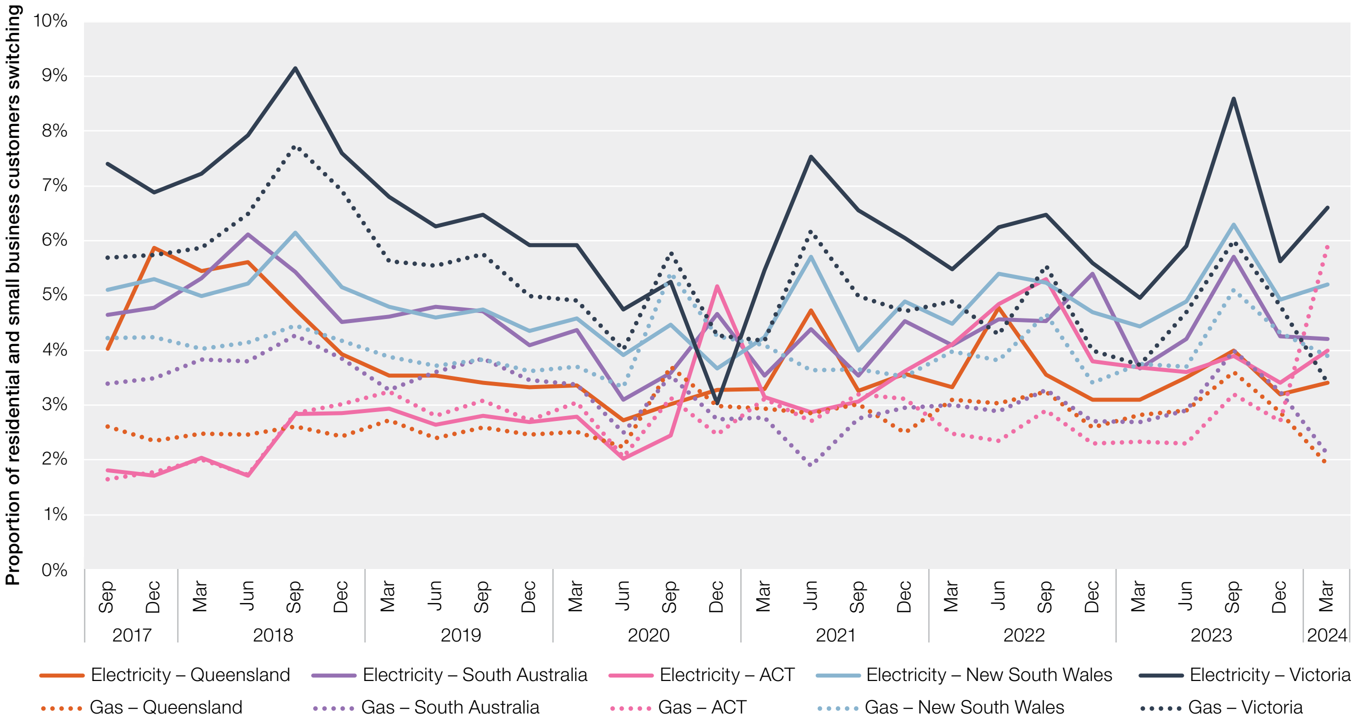
579 Australian Government, Consumer Data Right rollout, accessed 3 September 2024.
580 Australian Government, CDR in the energy sector, accessed 3 September 2024.

6.7.10 Customer switching

The rate at which customers switch retailers can indicate the level of engagement in the market. But switching rates should be interpreted with care – switching may be low in a competitive market if retailers deliver good-quality, low-priced services that give customers no reason to change. Data on switching rates does not capture customer movements to new contracts with the same retailer, so it understates customer activity in the market. Conversely, switching data captures when an existing customer moves house and signs a new contract, even if it is with the same retailer (thus overstating customer activity).

Switching rates are typically lower in gas than in electricity. This may reflect fewer retailers participating in gas, meaning less choice and fewer potential customer savings. As a secondary fuel, gas is also typically a lower cost for consumers, so it may not receive the same attention.

Figure 6.20 Switching activity – small customers



Source: AER, *Quarterly retail performance report, Q3 2023–24*, June 2024.

Reforms introduced in December 2019 aimed to make it easier for customers to switch retailer by allowing them to transfer within 2 days of a cooling-off period expiring.[581] The intention of this change was to limit retailers relying on 'save' activity (retailers contacting customers who try to switch and giving them a better offer to encourage them to stay) rather than competing for outside customers by offering better products and services, and to allow customers faster access to prices and products they want.

In many markets, engagement by even a limited number of customers can drive lower prices and product improvements that benefit all consumers. This is less true for energy markets, where retailers can easily identify and then price discriminate against inactive customers. Many market offers include benefits that expire after one or 2 years – customers who do not switch regularly may find themselves paying higher prices than necessary. As a result, a critical part of the AER and other regulators' reform agenda is supporting consumers to understand impending changes in their energy contract and helping them find better offers, either with the same or an alternative retailer.

581 AEMC, National Energy Retail Amendment (Reducing Customers' Switching Times) Rule 2019 No. 2, Australian Energy Market Commission, 19 December 2019, accessed 2 September 2024.

For example, the National Energy Retail Rules require energy retailers to notify small customers before any change in their benefits and provide advance notice of any price change.[582] In Victoria, retailers must also prominently display their 'best offer'[583] on customers' bills at least once every 100 days (except where a customer has agreed to a billing cycle greater than 100 days, in which case it is at least once during that billing cycle) along with advice on how to access it. The Better Bills Guideline has brought this requirement to the rest of the NEM jurisdictions.

At the end of a fixed-term contract, retailers are required to notify customers in writing about their options, including setting up a new contract or switching to another retailer. They must also inform customers that if they choose not to enter a new market contract, they will be switched to a standing offer.

Despite recent reforms aimed at enhancing consumer access to better offers, switching activity remains relatively unchanged so far. Observing improvements in competitive outcomes for consumers through switching data alone is challenging without incorporating other factors, such as customer satisfaction and energy affordability metrics.

6.7.11 Retailer activity and barriers to entry

Following the significant market events of winter 2022, the steady growth of new retailers entering the market slowed (Figure 6.15). The high, volatile wholesale prices and reduced liquidity in contract markets following these events likely deterred new entrants, compromising innovation and competition in the market.[584] However, a slight uptick of new retailers entering the market is evident.

While 2022 events were unprecedented, retailers have noted other barriers to entry such as the reintroduction of standing offer price caps. In South Australia, limited access to competitive risk management contracts has been a barrier to entry or expansion, with almost half of all retailers in 2020 considering that contract market liquidity in South Australia was too low.[585]

Access to reasonably priced gas and pipeline capacity have been identified as barriers to entry and expansion, particularly in Victoria:[586]

- The Pipeline Capacity Trading and Day Ahead Auction reforms that commenced in March 2019 sought to reduce these barriers by increasing transparency in the gas market and improving access to unused pipeline capacity through a day-ahead auction and a capacity trading platform. Volumes won on the DAA have been increasing year-on-year, with significant capacity regularly won at $0. The AER published a report on the effectiveness of the DAA in October 2024.[587]
- Exploring and producing gas from less certain sources can be risky and expensive due to policy uncertainties and regulatory hurdles. The ACCC has recommended several measures, including lifting bans on new gas projects, improving the speed and fairness of gas development approvals, easing the infrastructure and regulatory challenges for small producers, and better planning and competition for pipelines needed to deliver new gas supplies.[588]

582 AEMC, National Energy Retail Amendment (Notification of the end of a fixed benefit period) Rule 2017 No. 2, Australian Energy Market Commission, 7 November 2017; AEMC, National Energy Retail Amendment (Advance notice of price changes) Rule 2018 no. 3, Australian Energy Market Commission, 27 September 2018.

583 Using a customer's past usage and comparing what they pay on their current offer against the cheapest generally available offer.

584 ACCC, Inquiry into the National Electricity Market – November 2022 Report, Australian Competition and Consumer Commission, 23 November 2022.

585 AEMC, 2020 Retail Energy Competition Review, Australian Energy Market Commission, 30 June 2024.

586 AER, Wholesale gas market focus report: Day Ahead Auction, Australian Energy Regulator, 3 October 2024.

587 AER, Wholesale gas market focus report: Day Ahead Auction, Australian Energy Regulator, 3 October 2024.

588 ACCC, Gas Inquiry 2017-2030, Interim update on east coast gas market, June 2024, Australian Competition and Consumer Commission.

6.7.12 Product differentiation

In a competitive market, retailers offer a range of products and services to attract and retain customers. Energy retailers compete primarily on price. But since the introduction of standing offer price caps and restrictions around discounting, retailers are looking to differentiate their products in other ways.

Retailers can differentiate products by offering more price certainty or, alternatively, rewarding customers who are willing to be flexible in how and when they use energy. As technology improves, more products offering energy management services or linking to batteries, solar PV output or electric vehicles, including delivering additional revenue to consumers through virtual power plants, are becoming more common (section 6.9).

Some retailers also offer other incentives, such as carbon offsets, sign-up discounts and product add-ons and rewards, or they partner with other businesses. Bundling of products such as phone and internet alongside energy has also increased.

In 2023, 96% of residential customers on plans that cost more than 25% above the default rate were on plans with conditional discounts. These discounts can make it hard for customers to compare plans because they're based on varying prices. Even with large conditional discounts, customers are still paying close to the default rate and would pay more if they didn't get their discount. This suggests that these customers could benefit from switching their energy plans. The average conditional discount for this group is 29%, showing they haven't changed their plan or retailer in the last 3 years despite new rules on these discounts.[589]

6.7.13 Offer structures

Retailers package their costs (wholesale energy, network charges and environmental costs) with a retail margin and develop a range of retail offers using different pricing structures to appeal to different consumers. Retail offers include:

- Fixed charges – usually called a 'daily supply charge' or 'service charge' – which include charges for grid connection, metering, administration, billing costs and environmental fees.
- Variable charges, which are based on the amount of electricity consumed and, increasingly, the time of day that electricity is consumed – demand charges may also be included.

Electricity retailers typically use one or more of the following tariff structures for the variable charges in their offers:[590]

- Flat rate – a tariff with a single rate charged per kWh regardless of when usage occurs.
- Block retail – a tariff with a variable rate depending on the amount of electricity used in a day or over a billing period – for instance, one rate for the first 10 kWh of electricity used in a day and another rate for anything above that. Block tariffs are more commonly used by businesses than residential customers.
- Time-of-use – a tariff with a variable rate that depends on the time of day the electricity is consumed – for instance, higher pricing at peak times (typically late afternoon to early evening) and lower at off-peak times (overnight or during the day). This is used to better reflect the prices retailers pay for electricity and to encourage consumers to shift any flexible electricity use away from peak times to improve grid utilisation.

589 ACCC, Inquiry in the National Electricity Market: December 2023 Report, Australian Competition and Consumer Commission, 15 December 2023.
590 Gas offers have less variability in tariff structure, with flat tariffs typically applied. Usage charges may vary based on the overall volume of gas consumed and the time of year.

- Controlled load – a tariff typically applied to a particular appliance, such as pool pumps and hot water systems, and connected via a separate meter circuit. The appliance(s) can only be used at certain times of the day, typically during off-peak periods with electricity supply either operated by the distributor or the retailer. These tariffs are also used to reflect the prices retailers pay for electricity and improve grid utilisation but also enable the consumer to ‘set and forget’ consumption for the appliance.
- Demand tariff – a tariff with a variable rate based on a customer’s demand (the total amount of electricity drawn from the grid at a point in time). It is intended to encourage consumers to shift any flexible electricity use to off-peak periods, or ‘smooth out’ electricity use. A demand tariff may include other variable elements, such as time-of-use elements and the amount consumed. Demand charges may be applied as a daily rate based on the highest demand over a certain period, or on highest demand during high demand during peak periods only. They are typically more ‘cost-reflective’ because it is those peaks in demand that drive up investment costs. Even one day of high use at peak times will lead to higher charges for the whole period applicable under the retailer’s tariffs.
- Feed-in tariffs – credits for electricity fed into the grid by customer energy resources such as rooftop solar PV systems and, in some instances, home batteries.

A well-integrated approach to the increased prevalence of consumer energy resources could offset significant network costs into the future. To achieve this, retailers must innovate to help consumers benefit from price signals, including consumers that remain on flat tariffs.

Retailers package their offer structures to appeal to different consumers. For example, consumers with low energy use may prefer an offer with a lower fixed charge but higher usage charges, while a consumer with flexibility around when they use energy may prefer an offer with lower off-peak charges or free weekend energy use. Customers will want choices between fixed rate and time-of-use tariffs and retailers can and should provide this. All retailers are required to notify customers ahead of changes and this is monitored by the AER.

Retail tariff structures do not have to reflect their underlying network tariff structures Networks providers have recently started designing cost-reflective tariffs that have lower charges during the day – for example, ‘solar soak’ periods – to encourage consumers to use electricity during this time (chapter 3, section 3.8.2). However, cost-reflective retail tariffs may not be suitable for all consumers as some are unable to modify their energy use for a range of reasons (section 6.6.1).

New dynamic products are emerging as battery storage systems and electric vehicles become more affordable and as accessibility to consumer energy data improves (section 6.9). Some of these products have a time-of-use pricing structure but with rates set to encourage charging/discharging of batteries or electric vehicles at specific times. These products may also come with ‘add-on’ services, such as automated systems that learn consumers’ electricity use patterns and charge/discharge batteries to maximise value. Some offers allow consumers to become part of a virtual power plant that aggregates multiple household solar and battery systems to provide power for network support or frequency control ancillary services or to engage in wholesale price arbitrage.

Some retailers are trialling other price structures. Fixed price or subscription tariffs, where customers pay a (yearly or monthly) fee based on their typical electricity use, focus on simplicity and bill certainty. At the other end of the pricing spectrum, tariffs that pass through to wholesale market spot prices allow consumers to dynamically interact with the wholesale market. These tariffs are best suited to consumers with battery storage who can adjust their use of grid-supplied electricity during high price periods.

Similar to conditional discounting, dynamic products could cost consumers much more if they are unable to align their energy use to the terms of the agreement. Because of this, they may only be suited to some types of consumers.

A well-integrated CER could offset significant network costs.[591] To achieve this, retailers will need to innovate to help consumers benefit, including customers that remain on flat tariffs. This will require investing in technology and strategies that meet consumer and system needs without requiring additional engagement.

6.7.14 Non-price competition

In addition to competing on price and tariff structure, many retailers offer other incentives to entice customers. Financial incentives may include credit for continuing with a plan for a minimum period, for signing up online or through a partnering business, or for referring a friend to the retailer.

Many retailers provide reward schemes that offer discounts and deals on a variety of products and services. These schemes often include non-financial benefits such as carbon offsets for electricity usage and supplementary products like digital subscriptions. Retailers are increasingly collaborating with other businesses to bundle services and attract customers seeking the convenience of a single provider. For instance, some retailers offer rooftop solar PV, battery and EV charging solutions, as well as discounts on streaming platforms, home internet and mobile phone plans.

6.8 Compliance, enforcement and customer complaints

Compliance and enforcement outcomes are a major part of the AER's regulatory toolkit. The AER seeks to ensure compliance with national energy laws so that consumers and energy market participants can have confidence that energy markets are working effectively and in their long-term interests. Compliance and enforcement work focuses on non-compliance that poses significant harm to all consumers, particularly consumers experiencing vulnerability and/or disadvantage.[592] The AER's 2023–24 compliance and enforcement priorities relating to retail markets were:

- improving outcomes for customers experiencing vulnerability, including by improving access to retailer hardship and payment plan protections
- making it easier for consumers to understand their plan and engage in the market by focusing on compliance with billing and pricing information obligations including the Better Bills Guideline.

The AER's proceedings against AGL Retail Energy Limited and 3 other subsidiaries of AGL Energy Limited (together, AGL), which commenced in the Federal Court on 16 December 2022, were finalised on 23 August 2024. The Federal Court found that AGL breached the National Energy Retail Rules by failing to notify and refund customers for overcharges obtained from Centrepay payments. The AER is seeking pecuniary penalties, declarations, implementation of a compliance program and costs.[593]

On 20 October 2023, the AER instituted proceedings in the Federal Court against CAM Engineering and Construction Pty Ltd (CAM Engineering) for allegedly failing to become a member of the Energy and Water Ombudsman NSW (EWON) scheme, in breach of the AER's Retail Exempt Selling Guideline.[594]

The AER alleges that CAM Engineering did not join EWON until 22 July 2022, despite obtaining its retail exemption on 11 March 2021 and the AER issuing numerous reminders and warnings. During this 16-month period, energy customers of the village did not have access to EWON's important dispute resolution service.

591 This includes the full range of possible sources of CER. See Australian Government, National consumer energy resources roadmap – Powering decarbonised homes and communities, 19 July 2024, accessed 8 August 2024, p. 9.

592 To see the full remit of AER's compliance and enforcement work see AER, Annual compliance and enforcement report 2023–24, Australian Energy Regulator, 26 July 2024.

593 AER, Court finds AGL breached overcharging rules in relation to Centrepay payments, Australian Energy Regulator, 23 August 2024.

594 AER, Retail Exempt Selling Guideline – July 2022, Australian Energy Regulator, accessed 28 August 2024.

Other key compliance and enforcement activities in retail markets in the 2023–24 financial year included:

- accepting a court enforceable undertaking from Trinity Place Investments Pty Ltd to contact and refund customers after it admitted to overcharging consumers for electricity by approximately $34,000 between December 2019 and January 2023
- accepting a court enforceable undertaking from 5 Origin Energy subsidiaries admitting to 1,973 breaches of the requirement to provide information packs to life support customers, with Origin undertaking to make a $1 million community-based contribution to organisations assisting people using life support equipment
- receiving payment of $135,600 for 2 infringement notices issued to Ergon Energy Queensland Pty Ltd for alleged failures relating to life support registration and deregistration obligations
- proactively reviewing retailers' family violence policies to ensure retailers are complying with new family violence protections that commenced in May 2023 under the Retail Rules
- finalising a round of spot checks of retailers' compliance with customer hardship obligations
- written communication to remind retailers of their obligations – for example, to notify customers ahead of changes to electricity prices and charges.[595]

The AER has also undertaken and progressed numerous compliance and enforcement actions to ensure a secure and reliable energy supply and that Australia's energy markets operate efficiently and competitively.[596] This includes activities relating to the wholesale markets and networks, in addition to retail markets. The AER's compliance functions cover all NEM regions, excluding the energy retail market in Victoria, which is regulated by the Essential Services Commission (Victoria).[597]

More detail on the AER's compliance and enforcement work is outlined in the Annual Compliance and Enforcement report 2023–24.[598]

6.8.1 Compliance and enforcement priorities for 2024–25

The AER has settled its compliance and enforcement priorities for 2024–25. In response to feedback from stakeholders the 5 priorities are the same as the previous year's:

- Improving outcomes for customers experiencing vulnerability, including by improving access to retailer hardship policies and access to hardship and payment plan protections.
- Making it easier for consumers to understand their plan and engage in the market by focusing on compliance with billing and pricing information obligations, including the Better Bills Guideline and tariff change notification requirements.
- Supporting power system security and an efficient wholesale electricity market by focusing on generators' compliance with offers, dispatch instructions, bidding behaviour obligations and providing accurate and timely capability information to AEMO.
- Improving market participants' compliance with performance standards and standards for critical infrastructure.
- Monitoring and enforcing compliance with reporting requirements under the new Gas Market Transparency Measures.

The AER will continue to monitor all facets of the energy market, while focusing on the priority areas, and will proactively work to improve compliance and address harm including by taking enforcement action where appropriate.

595 Other industry letters include information about providing energy plan information on energy made easy, expectations around HelpPay and expectations on hardship obligations.
596 Further information is available in AER, Annual compliance and enforcement report 2023–24, Australian Energy Regulator, 26 July 2024.
597 With the exception of the Retailer of Last Resort (RoLR) scheme, which the AER is now responsible for in Victoria.
598 AER, Annual compliance and enforcement report 2023–24, Australian Energy Regulator, 26 July 2024.

6.8.2 Life support

The AER has an enduring priority to ensure retailers comply with obligations under the Retail Law that safeguard customers requiring life support equipment. All retailers and distribution network service providers operating under the Retail Law and Retail Rules are required to comply with these obligations.

The AER has taken significant actions to enforce compliance with the life support obligations stipulated in the Retail Rules, which are crucial for protecting vulnerable customers. On 20 June 2024, the AER accepted a court enforceable undertaking from Origin Energy, acknowledging 1,973 breaches of rule 124(1)(b). These breaches involved failures to provide necessary information packs to customers with life support needs. Origin Energy's resolution included an independent review of its compliance systems and a $1 million community contribution to support affected individuals. Additionally, Origin admitted to over 5,000 breaches of the National Energy Retail Law and Retail Rules, including failures to register life support needs promptly and to provide required information.

In another enforcement action, Ergon Energy was fined $135,600 on 30 April 2024 for violating life support regulations. The infringement notices were issued due to Ergon Energy's failure to register a customer who required life support equipment and improper deregistration of a customer's premises without issuing required notices. These breaches had the potential to adversely affect customers by depriving them of necessary protections. The AER continues to monitor compliance closely, ensuring that breaches of these critical obligations are addressed with appropriate penalties and corrective measures.

6.8.3 Embedded networks

Embedded networks are smaller, localised private networks that distribute energy to multiple customers at sites such as apartment blocks, retirement villages, caravan parks and shopping centres. They operate alongside major distribution networks under a similar, but different regulatory framework. In most cases, the embedded network operator buys energy from an energy retailer and onsells it to the occupants of the site. Many consumers in embedded networks are likely to have lower incomes and be more likely to experience vulnerability. To improve outcomes for consumers in embedded networks, the AER introduced new obligations on exempt sellers under version 6 of the Retail Exempt Selling Guideline, released in July 2022.[599]

The updated guideline introduces a new hardship policy condition to ensure residential customers in embedded networks who experience payment difficulties due to hardship can access adequate support to better manage their energy bills.

To support compliance with the updated guideline, the AER:

- published a range of fact sheets clearly explaining the rights and obligations of exempt sellers and their customers[600]
- engaged widely with ombudsmen, industry and consumer groups, including through webinars and public forums, to raise awareness about issues experienced by customers in embedded networks[601]
- published translated and easy English fact sheets for small businesses and consumers, outlining their rights and protections[602]
- published practical steps that off-market customers can take if their exempt seller fails, including alternative retailer options
- wrote to all exempt sellers to inform of their obligations under the new policy and continues to monitor and address inquiries from a range of stakeholders.[603]

In November 2023, the AER commenced a review of its exemptions framework for embedded networks and published an issues paper for public consultation.[604] This review is currently ongoing. Key concerns raised by stakeholders include the inherent vulnerability of consumers in embedded networks and the disadvantage associated with challenges they may face accessing competitive energy offers.

The AER maintains ongoing investigations relating to embedded networks, including an alleged failure by an embedded network operator to join an energy ombudsman scheme and alleged failures to undertake appropriate registrations with AEMO or the AER while owning, operating or controlling an embedded network.

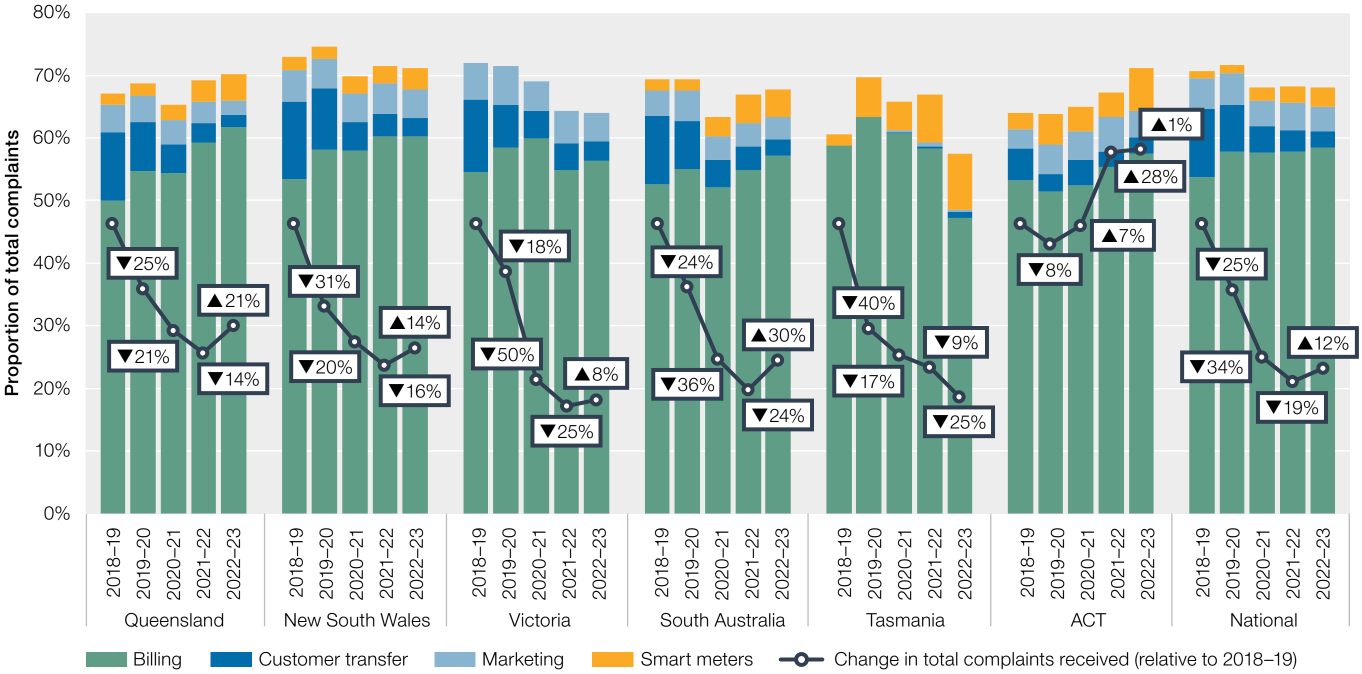
599 AER, Retail Exempt Selling Guideline, Australian Energy Regulator, 15 July 2022.
600 AER, AER releases factsheets on exempt selling, Australian Energy Regulator, 28 July 2022.
601 EWON, Embedded Networks awareness campaign, Energy & Water Ombudsman NSW, accessed 2 September 2024.
602 AER, Consumers in embedded networks, Australian Energy Regulator, accessed 30 August 2024.
603 AER, Annual Compliance and Enforcement Report 2023–24, Australian Energy Regulator, accessed 30 August 2024.
604 AER, Review of the AER exemptions framework for embedded networks, Australian Energy Regulator, 30 November 2023.

6.8.4 Customer complaints

Customer complaints can cover issues such as billing discrepancies, wrongful disconnections, the timeliness of transferring a customer to another retailer, supply disruptions, credit arrangements and marketing practices. Customers can lodge a complaint directly with their retailer in the first instance. If a customer is unable to resolve an issue with their retailer, they can then take the complaint to the jurisdictional energy ombudsman scheme, which offers free and independent dispute resolution.

The number of complaints received by energy retailers increased markedly across all jurisdictions in 2022–23 except in Tasmania, where complaints decreased by 25% (Figure 6.21). Overall, the number of complaints received by retailers across the NEM increased 12% The increase in complaints related to billing (13%) can be attributed to concern about rising and unexpectedly high bills including where tariffs changes have occured after installation of a smart meter (section 6.9.2). Other billing issues include errors, incorrect tariffs, estimation of energy use, fees and charges and back billing.

Figure 6.21 Complaints received, by energy retailers

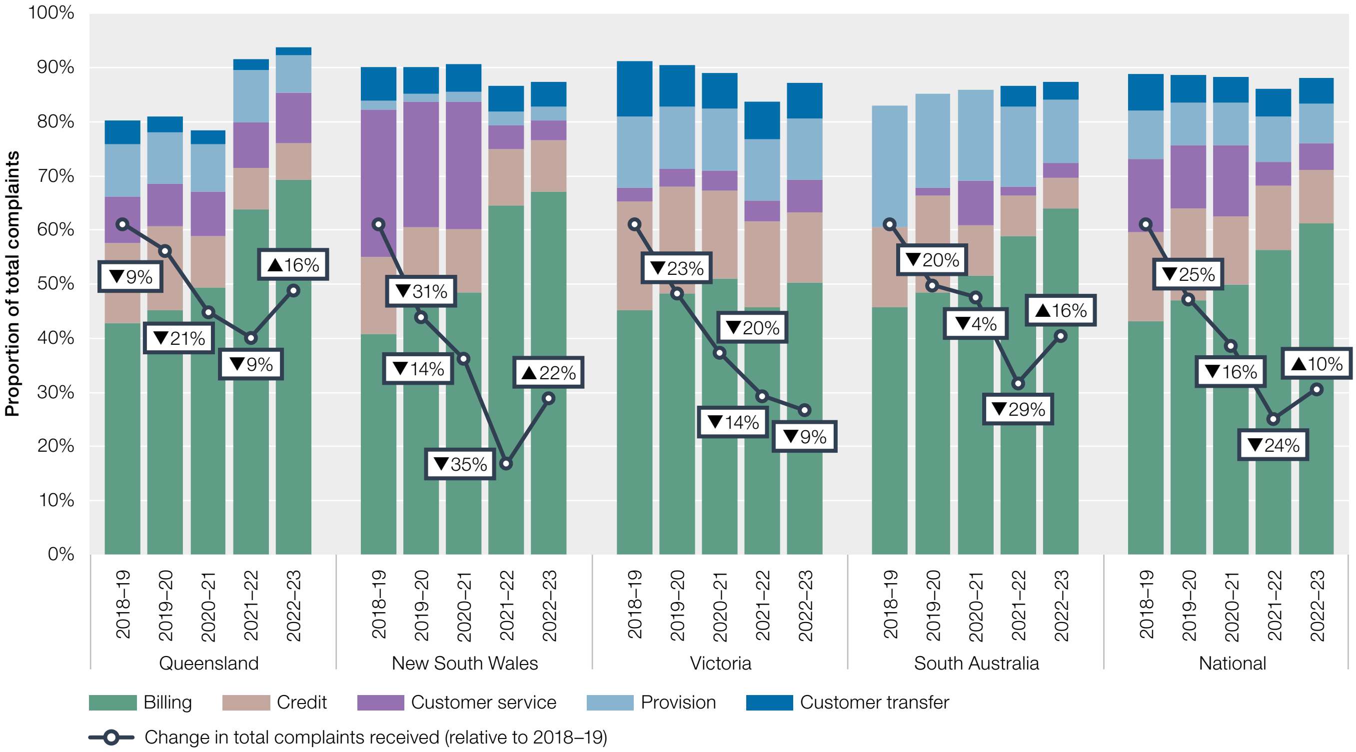


Note: Billing includes complaints about prices, billing errors, payment arrangements and debt recovery practices. Customer transfer includes complaints about timeliness of transfer, disruption of supply due to transfer and billing problems directly associated with a transfer. Marketing includes complaints about sales practices, advertising, contract terms and misleading conduct. Smart meters includes all complaints related to metering contestability. Complaints do not sum to 100% as some customer complaints defined as 'other' are not included in the above data. 'Other' complaints relate to issues outside the retailer's control – for example, complaints about price rises due to wholesale and network costs.

Source: AER, *Retail markets quarterly, Q3 2023–24*, May 2024; ESC, Victorian energy market dashboard and historical data as of 30 June 2024.

The overall number of electricity and gas complaints received by jurisdictional energy ombudsmen schemes in 2022–23 increased in all regions, except for Victoria (Figure 6.22). Because ombudsmen schemes require customers to raise complaints with their retailer in the first instance, assessing retailers' complaint data in conjunction with ombudsman complaint data can provide an indication of the effectiveness of retailers' dispute resolution outcomes.

Figure 6.22 Complaints received, by jurisdictional energy ombudsmen



Note: Annual change in total complaints data includes all cases recorded by ombudsman schemes for electricity and gas industries. Annual change in total complaints data includes enquiries and complaints in relation to energy retailers, distribution networks and embedded network operators. Specific complaint type data includes all cases recorded by ombudsman schemes for electricity, gas and water industries. The proportion of water related complaints is immaterial.

Source: Annual reports by ombudsman schemes in Queensland, NSW, Victoria and South Australia.

Cost-of-living pressures continue to significantly influence consumer sentiment in the energy market, with concerns about affordability and trust remaining high since the 2022 energy market disruptions. Many consumers, particularly those under financial stress, find it difficult to access necessary support, and tend to choose immediate relief options like rebates over long-term solutions such as energy-efficient appliances.[605]

605 ECA, Energy Consumer Sentiment Survey, June 2024, Energy Consumer Australia, accessed 27 August 2024.

6.9 Adapting to the changing energy market

As the NEM transitions to clean energy, Australian governments are collaborating under the National Energy Transformation Partnership to help transform energy systems to achieve economy-wide net-zero greenhouse gas emissions by 2050.[606] Energy consumers are an integral part of the transition.

Over the past 2 decades, rooftop solar has become the gateway technology to an emerging suite of consumer energy resources (CER). Many consumers have benefited from rooftop solar, home batteries electric vehicles and participating in virtual power plants.

The AER defines CER as distributed energy resources that are owned or leased by residential and small-business consumers (or groups of consumers) that:

- generate or store electricity
- can alter demand in response to external signals,
- includes consumer loads that are flexible and efficiently optimised either through automation or direct behavioural response.[607]

The AER's Consumer energy resources (CER) strategy 2023 aims to support consumers to own energy resources and use those resources to consume, store and trade energy as they choose. The CER strategy articulates AER's objectives and actions to achieve consumer benefits from CER in relation to network integration, efficient signals and incentives, consumer empowerment and safeguards and standards.[608]

The Australian Government has developed a national CER roadmap to coordinate and optimise CER uptake, put downward pressure on overall system costs and bills, and broaden access to CER (Box 6.4).[609] This roadmap seeks to unlock economic opportunities associated with the transition at least-cost to consumers, while ensuring a reliable, affordable, clean energy supply is available to all Australian households, businesses and communities. An update on progress towards CER integration is provided in Table 6.3.

Energy retailers and energy service providers are offering an increasing array of products and services to unlock the value of CER.[610] Incentives for charging vehicles during off-peak times and increasing the value of home energy storage systems through price arbitrage[611] will encourage broader consumer engagement in CER. On the grid-side, appropriate integration of CER can help manage minimum and peak demand and provide crucial system services while balancing the need for investment in network upgrades, large-scale generation and energy storage.[612]

The AER will continue to work with government and market bodies to protect and empower consumers throughout the transition, and to implement measures to help all Australians to realise the benefits such as downward pressure on prices and a more reliable, clean energy supply.

606 DCCEEW, National Energy Transformation Partnership, Department of Climate Change, Energy, the Environment and Water, 12 August 2022, accessed 6 September 2024.

607 AER, Consumer energy resources strategy, Australian Energy Regulator, 3 April 2023.

608 For more information see AER, Consumer energy resources strategy, Australian Energy Regulator, 3 April 2023.

609 DCCEEW, National Consumer Energy Resources Roadmap, Department of Climate Change, Energy, the Environment and Water, accessed 6 September 2024.

610 AEMC, AEMC unveils new rules to boost consumer energy resource benefits, media release, Australian Energy Market Commission, 15 August 2024.

611 Price arbitrage refers to purchasing energy at times of low cost and selling it back to the grid during periods of high pricing.

612 DCCEEW, Consumer Energy Resources Roadmap, Department of Climate Change, Energy, the Environment and Water, accessed 13 August 2024.

Box 6.4 National Consumer Energy Resources (CER) Roadmap

2024

- Interoperability standards developed to ensure CER devices work as intended, can communicate with each other and maintain cybersecurity.
- Draft National Energy Equity Framework delivered to increase the understanding of vulnerability and hardship in Australia's energy system.
- Costs and benefits of improving voltage management examined to lead to lower costs for consumers.
- Options identified for harmonising CER connection processes, including EV chargers.

2025

- Options developed to enable consumers to export and import more power to and from the grid.
- Removal of barriers to enable bidirectional electricity flow from and to EVs enabled with vehicle-to-grid technology, to allow consumers with EVs to send back to their home or the grid.
- Distribution levels markets roles and responsibilities defined.
- Roles and responsibilities for distribution level power system operations defined.
- Energy reform package for consumers facing hardship implemented: improves outcomes for consumer who cannot access the market.
- Backstop mechanisms in place: emergency response to ensure operational security.

2026

- Voluntary CER cyber standards and technical specifications available: ensures CER devices are safe from cyber threats.
- Consumer protections stabilities: to increase consumer trust.
- Communication framework and strategy ensure CER benefits are understood by all consumers.
- National regulatory framework for CER operational sets enforces CER standards.

2027

- Data sharing arrangement inform planning and enable future markets: to enable consumer participation.
- Secure communication systems established a national entity to manage public key infrastructure to operate and manage authentication of CER communications.
- New market offers and tariffs structure enabled: allow consumers to extract greater benefits.
- More equitable access to CER benefits: policies in place.

2028

- Further consumer protections delivered: to increase consumer trust.
- New consumer support: to empower consumers in high CER future.

2030

- CER are integral part of Australia's secure affordable and sustainable electricity systems.[613]

Table 6.3 outlines some of the key areas of progress in relation to the CER Roadmap.

613 Content adapted from DCCEEW, National Consumer Energy Resources Roadmap, Department of Climate Change, Energy, the Environment and Water, 18 July 2024. The reference to the smart meter rollout in the Roadmap was originally targeted for 2029, whereby all homes would be fitted with a smart meter. However, due to stakeholder concerns about negative customer experiences due to retail tariff changes following smart meter installation, this timeframe has been extended and will be finalised when the AEMC releases the final rule in November 2024.

Table 6.3 Progress towards CER integration

Reform area	Progress
Update governance and compliance arrangements for technical standards to ensure CER technologies can effectively integrate with the NEM and communicate across different parties within the market, including AEMO, electricity distribution network service providers and retailers. Effective governance of standards helps to promote integration of consumer energy resources, as well as system security and reliability.	The AEMC has published a final report with recommendations for implementing CER technical standards, including their regulation by jurisdictions and energy market bodies.[614] DCCEEW has developed a CER Roadmap and is progressing a CER technical standards workstream.[615]
Provide policy direction and advice on the implementation of flexible export limits, allowing export limits on consumer energy resources to be varied based on available network capacity.	On 31 July 2023, the AER released a set of priority actions for flexible export limit implementation, focusing on 4 themes of increased consistency across jurisdictions, increased transparency, stronger governance and increased consumer understanding.[616]
A draft change to allow aggregated consumer energy resources (CER) to be scheduled and dispatchable in the National Electricity Market (NEM). The draft also aims to address unscheduled price-responsive resources by. Including a short-term incentive payment to drive participation in dispatch. Introducing a monitoring and reporting functions to understand the forecasting challenges and errors from unscheduled price-responsive resources.[617]	On 25 July 2024, the Australian Energy Market Commission (AEMC) made a draft determination for a preferable draft electricity rule (and no draft retail rule) in response to a rule change request from AEMO. The draft rule introduces a monitoring and reporting obligation for AEMO to identify the presence and issues created by increased unscheduled price-responsive resources.[618] The AER will then assess the efficiency implications and costs associated with these issues.
A change to the electricity rules to allow consumers to engage a separate provider for their CER (such as EV charging, solar panels and/or battery devices), and facilitate the active participation of consumer energy resources and flexible demand in the provision of market services.	On 15 August 2024, the AEMC introduced a rule to enable: • large customers to engage multiple energy service providers to manage and obtain more value from their CER • energy service providers to separate and manage 'flexible' CER from 'passive' loads (such as fridges and lights) for small and large customers, leading to more options for consumers • customers to use in-built measurement capability in technology such as EV chargers, eliminating the need for separate meters.[619]
Review the consumer protections framework to ensure it remains fit for purpose in a transitioning retail energy market in which consumers can purchase new energy services (e.g. load management and virtual power plant services) that go beyond traditional retail services.[620]	On 20 December 2023, the AER released its final advice on consumer protections for future energy services for Energy Ministers' consideration.[621] The advice presents the case for reforming the NECF to ensure it can continue to protect consumers in an evolving energy market.

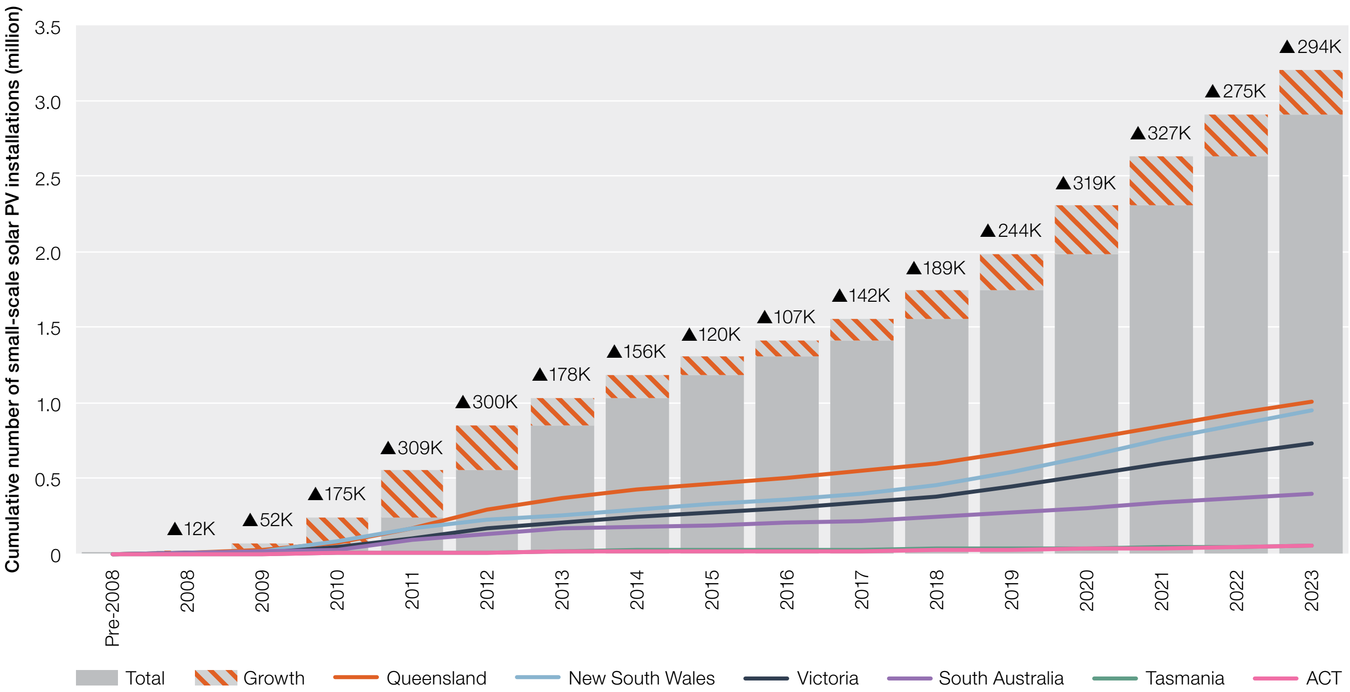
614 AEMC, Final report: Review into consumer energy resources technical standards, Australian Energy Market Commission, 21 September 2023.
615 DCCEEW, National Consumer Energy Resources Roadmap, Department of Climate Change, Energy, the Environment and Water, 18 July 2024.
616 AER, Review of regulatory framework for flexible export limit implementation, Australian Energy Regulator, accessed 2 September 2024.
617 AEMC, Integrating price-responsive resources into the NEM, Australian Energy Market Commission, 25 July 2024.
618 AEMC, Integrating price-responsive resources into the NEM, Australian Energy Market Commission, 25 July 2024.
619 AEMC, Unlocking CER benefits through flexible trading, Australian Energy Market Commission, Rule determination, 15 August 2024.
620 AER, Review of consumer protections for future energy services, Australian Energy Regulator, 9 December 2022.
621 AER, Review of consumer protections for future energy services – Final advice, Australian Energy Regulator, 23 November 2023.

6.9.1 Rooftop solar PV

The uptake of rooftop solar PV systems continues to grow across the NEM. There were over 294,000 new installations in 2023 and, as of January 2024, more than 3.2 million households and businesses have installed rooftop solar PV systems (Figure 6.23). Ongoing subsidies provided by the Australian Government and some state governments, combined with the falling costs of solar PV systems, have helped sustain the growth in new installations.

As at 30 June 2024, more than 20 GW of total installed rooftop solar capacity was registered across NEM regions, an increase of almost 3 GW from the previous year (chapter 2, Figure 2.14). This makes rooftop solar the fuel source with the highest registered capacity across the NEM (chapter 2, Figure 2.14).[622]

Figure 6.23 Small-scale solar PV installations



Note: Small-scale generation units have a capacity of no more than 100 kilowatts (kW) and a total annual electricity output of less than 250 megawatt hours (MWh).

Source: Clean Energy Regulator, *Postcode data for small-scale installations*, data as at 8 August 2024.

Consumers may sell unused electricity produced by solar PV systems to their retailer, in exchange for a feed-in tariff; generally, a flat per kilowatt hour value and not linked to the actual value of the excess electricity to the NEM. Excess solar PV generation has created network congestion, resulting in some networks setting a low limit (curtailment) to the amount of electricity that consumers can export to the grid at any time in order to avoid congestion during peak periods.[623]

622 Capacity generated by rooftop solar is subtracted from demand (rather than traded in the NEM). With rooftop solar output records set over the summer of 2022–23, when rooftop solar reached a record 11,504 MWh, the rapid uptake of rooftop solar continues to be the major contributing factor to reduced grid demand.

623 For information on solar curtailment, see Solar curtailment for minimum system demand events, SA Power Networks, accessed on 20 September 2024.

To address this curtailment, the AER has developed a guidance note to facilitate the implementation of flexible export limits.[624] Flexible export limits aim to maximise the amount of CER output that can be exported into the network while minimising the need for network augmentation to accommodate the increased CER penetration. It also seeks to ensure that distribution network service providers only curtail CER outputs when and where it is necessary to maintain network security, thereby making better use of existing network capacity and supporting greater CER participation in the NEM.

To help shape consumer behaviour to shift both demand and solar exports to more cost-efficient times of the day, the AER has administered a network tariff reform program. In April 2024 the AER approved the future use of export reward tariffs, which will reward consumers for exporting electricity when it is most needed and apply charges for exporting large amounts of solar into the grid at times when it is not needed.[625] Export reward tariffs will complement flexible export limits to support efficient integration of customer exports into the NEM. However, further actions are to be addressed in the CER Roadmap.

AEMO's ISP notes that successful integration of CER will offset up to $11 billion in network augmentation costs, and it is important that these savings are returned to consumers. Curtailment of consumers' energy exports should be minimised, and network service providers should carefully assess what investments in storage and other distribution network modifications are available to efficiently reduce curtailment of consumers' CER assets.

Pricing incentives may also be used to incentivise consumers to time their exports to when additional energy is needed in the grid, avoiding contributing to congestion during peak periods for solar generation. On 17 November 2023 the AER issued an Export limit guidance note for consultation, to provide clarity on the regulatory framework required to effectively implement export limits.[626] This provides guidance to distribution network service providers as the CER Roadmap progresses.

6.9.2 Smart meter rollout

Smart meters are essential for consumers to access CER and participate in demand response. Smart meters measure how much electricity is used at a premises and at what times. This data is shared in 5-minute or 30-minute intervals with the customer, retailer and network operator. Access to more granular data allows for retailers to charge different prices depending on when the electricity is consumed.

A well-managed smart meter rollout can help optimise the grid, resulting in fewer outages, less need for costly infrastructure upgrades, increased penetration of cheaper renewable energy and, ultimately, put downward pressure on energy bills for consumers. As with other energy transition technologies, there is risk of some users being 'left behind', unable to take advantage of innovative technologies and retail offers if the smart meter rollout does not ensure appropriate safeguards are in place to protect consumers.

In April 2024, the AEMC published a draft determination and draft rule seeking to efficiently accelerate the deployment of smart meters to all customers and achieve universal uptake by 2030.[627] In July 2024, the AEMC announced it is extending a final determination on the proposed target date of the smart meter deployment to allow for further consultation on consumer protections noting stakeholder concerns about potential negative impacts on customers following smart meter installations, such as unexpectedly high bills due to changes in tariff structures.[628] The final determination is expected in November 2024.

624 AER, Network tariff reform, Australian Energy Regulator, accessed 4 October 2024.
625 AER, Export reward tariffs and you, Australian Energy Regulator, accessed 4 October 2024.
626 AER, Export limit guidance note, Australian Energy Regulator, 17 November 2023.
627 AEMC, Draft rule determination – Accelerating smart meter deployment, Australian Energy Market Commission, 4 April 2024.
628 AEMC, AEMC extends smart meter rollout decision to consult further on consumer safeguards, media release, Australian Energy Market Commission, 4 July 2024.

To date, the AEMC has recommended the following consumer protections be implemented during the smart meter rollout:

- improved safeguards for consumers against unexpected cost increases and improved information for informed decision-making, as well as improved meter installation processes
- effective use of smart meter data, by ensuring consumers can access their own electricity use data in real time and ensuring distribution network service providers can access power quality data in their service area to better support efficient network operation and planning, for consumers' long-term benefit
- the requirement for customers to give their explicit informed consent for any changes to retail tariffs for 3 years after a smart meter is installed
- designated retailers that are required to offer all customers for which they are the designated retailer a flat tariff offer – this would be implemented by jurisdictions.[629]

Progress towards the rollout remains sporadic across NEM jurisdictions except Victoria. In Victoria, nearly all small customers have a smart meter (96% to 99% depending on customer segment and distribution network service provider) due to a mandated rollout of smart meters to households and small businesses that began in 2006. In other NEM regions the rollout is slower, ranging from 26% to 66%.[630]

Smart meters have driven a notable increase in customers on time of use and demand tariffs in South Australia and South East Queensland, rising to 32% and 17% of customers respectively by the July to September quarter of 2022 compared with the previous year.[631] A review of billing data for customers on these tariffs found that while they generally pay similar rates to those on flat tariffs, there is significant variation in actual bills and many could save money on a more suitable plan.[632] While time of use and demand tariffs can be advantageous if customers adjust their usage according to price signals, some customers may end up paying more if they cannot shift their electricity use.

The AER supports the AEMC's recent review of smart meter rules and implementation timeline to enhance customer experience and protections. The following infographic shows the core reforms required to deliver the benefits that smart meters offer.[633]

629 AEMC, Review of the regulatory framework for metering services – Final report, Australian Energy Market Commission, 30 August 2023.

630 The proportion of small customers with smart meters varies by customer segment and distribution network service provider. For the latest data see AER, Electricity DNSP Operational performance data 2006-22, Australian Energy Regulator, 7 July 2023.

631 ACCC, Inquiry into the National Electricity Market - June 2024 Report, Australian Competition and Consumer Commission, accessed 27 August 2024.

632 The AER notes that for a range of reasons, not all consumers are able to change their plan. ACCC, Inquiry into the National Electricity Market - June 2024 Report, Australian Competition and Consumer Commission, accessed 27 August 2024.

633 Note that the universal smart meter deployment target date of 2030 is currently under review, see AEMC extends smart meter rollout decision to consult further on consumer safeguards, media release, Australian Energy Market Commission, 4 July 2024.

Table 6.4 Reforms to deliver the benefits that smart meters offer

Core reforms to deliver the benefits that smart meters offer	
Accelerated deployment of smart meters	• opens new possibilities for innovative products and services, expanding customers' control of and choices around their energy use • lower costs to customers of meter reads and installations • provides for a modern, data-enabled energy system • underpins the cost-effective decarbonisation of the energy market • supports better integration of CER and a safer and more secure energy system.
Access to power quality data	• DNSPs can better manage their networks to reduce network costs for customers • saves energy, minimises network safety risks, and lifts hosting capacity.
Supporting reforms to enable the core reform program	
New customer safeguards	• protect customers from potential upfront charges and exit fees for new meters • builds social license for the smart meter acceleration program.
Improving the customer experience	• helps maintain social license for the acceleration program • ensures that customers can access the full suite of benefits that smart meters provide.
Reducing installation barriers	• supports delivery efficiencies, and therefore cost savings, in the accelerated deployment of smart meters.
Improved meter testing and inspections	• helps minimise costs for industry and customers • supports a 2030 universal smart meter deployment target.

Source: AEMC, Accelerating smart meter deployment.

6.9.3 Demand response and demand flexibility

Demand response means adjusting electricity drawn from the grid based on price changes or other signals to help maintain grid stability. When many households make small adjustments to their electricity use at the right times, it can greatly benefit the grid, which increasingly relies more on intermittent renewable energy sources like wind and solar. The benefits of demand response will progressively be seen in postponed and/or avoided network investment. However, demand response can also reduce the need for extra generation or large-scale storage to support variable wind and solar power.

Customers with smart meters can participate in demand response programs run by retailers, distribution network businesses or third-party service providers. The simplest demand response programs offer consumers financial incentives to reduce electricity consumption at certain times of the day or when they receive an alert from their retailer or network service provider.

Demand flexibility refers to more sophisticated programs that include technologies to 'orchestrate' the operation of household appliances such as water heaters, pool pumps and air conditioning as controllable, flexible loads to support grid stability. Increasingly, CER such as rooftop solar PV, household batteries and electric vehicle chargers are being included in demand flexibility. Demand flexibility can be implemented in real time in response to market signals, network constraints or generation shortfalls (price-responsive) or scheduled in advance at times of known electricity supply abundance (scheduled). However, new technologies, market processes and ways of engaging with consumers are necessary to optimise the potential benefits to the grid. The Australian Government is investing in projects that demonstrate how demand flexibility can improve systems, market integration and empower customers.[634]

Consumers are encouraged to participate in flexible demand response via 2 primary mechanisms:

- price signals and tariffs to incentivise consumers to shift consumption to reduce their energy bills
- programs that provide direct payments to consumers who shift their demand.[635]

For example, retailers may offer tariffs with lower rates during the middle of the day to align with solar generation and lower grid demand, and electric vehicle charging tariffs to incentivise charging during non-peak times. Other incentives include network 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.

While the use of cost-reflective pricing through measures such as time of use tariffs makes sense, comparing, choosing and making the best use of these tariffs is challenging to some consumers due complexity.[636] The AER's Better Bills Guideline seeks to address this by requiring retailers to make it easy for customers to understand their billing and to notify customers if they may be better off on another deal.[637]

The AER acknowledges the potential consumer risks associated with cost-reflective tariffs if they are not implemented correctly, and that further work is needed to help consumers navigate more complex pricing systems. Orchestrated CER is forecast to provide 65% of the NEM's generation by 2050.[638] Therefore, it is critical the introduction of new services and participation from diverse sources like batteries and virtual power plants are suitable for all types of consumers. This will ensure that the risk is not shifted back to consumers at the same time they are providing the capital investment that is offsetting grid scale generation and network augmentation costs.[639]

634 ARENA, Flexible Demand, Australian Renewable Energy Agency, accessed 6 September 2024.
635 ECA, Supporting demand flexibility in the energy sector transition, Energy Consumers Australia, February 2023, accessed 6 September 2024.
636 ARENA, Flexible Demand State of-Play in Australia Report, Australian Renewable Energy Agency, accessed 30 August 2024.
637 AER, Better Bills Guideline (Version 2), Australian Energy Regulator, 30 January 2023.
638 Energy Decarb Pty Ltd, Energy Decarb Submission to the Australian Energy market Operator's (AEMO) Draft 2024 Integrated System Plan (ISP), 16 February 2024.
639 ARENA, Flexible Demand State of Play in Australia Report, Australian Renewable Energy Agency, accessed 30 August 2024.

6.9.4 Home batteries and electric vehicles

Battery storage and smart appliances enable consumers to optimise their electricity use, reducing the amount of power they need to withdraw from (and inject into) the network. As the global shift to renewable energy progresses, battery storage is increasingly vital to address the intermittency of sources like wind and solar. In Australia, the mix of renewables in the NEM is increasing and reached a record high of 72% in October 2023.[640] Placing batteries near homes with high rooftop solar use helps cut down on transmission costs and reduces energy losses during transport.

The rate of home battery installations in Australia is increasing each year. The Clean Energy Council estimates that in Australia, roughly 56,000 home batteries were installed in 2023, up from around 43,000 in 2022 and 37,000 in 2021.[641] The estimated total number of home battery installations as at 30 December 2023 was 254,550 systems.[642] With approximately 3.2 million Australian homes having rooftop solar as at 30 December 2023, this means fewer than one in 13 solar-equipped households have batteries. AEMO sees a significant opportunity in encouraging solar households to install and coordinate battery storage systems to enhance intra-day load shifting at a household level, helping to optimise the grid and keep downward pressure on energy costs.[643]

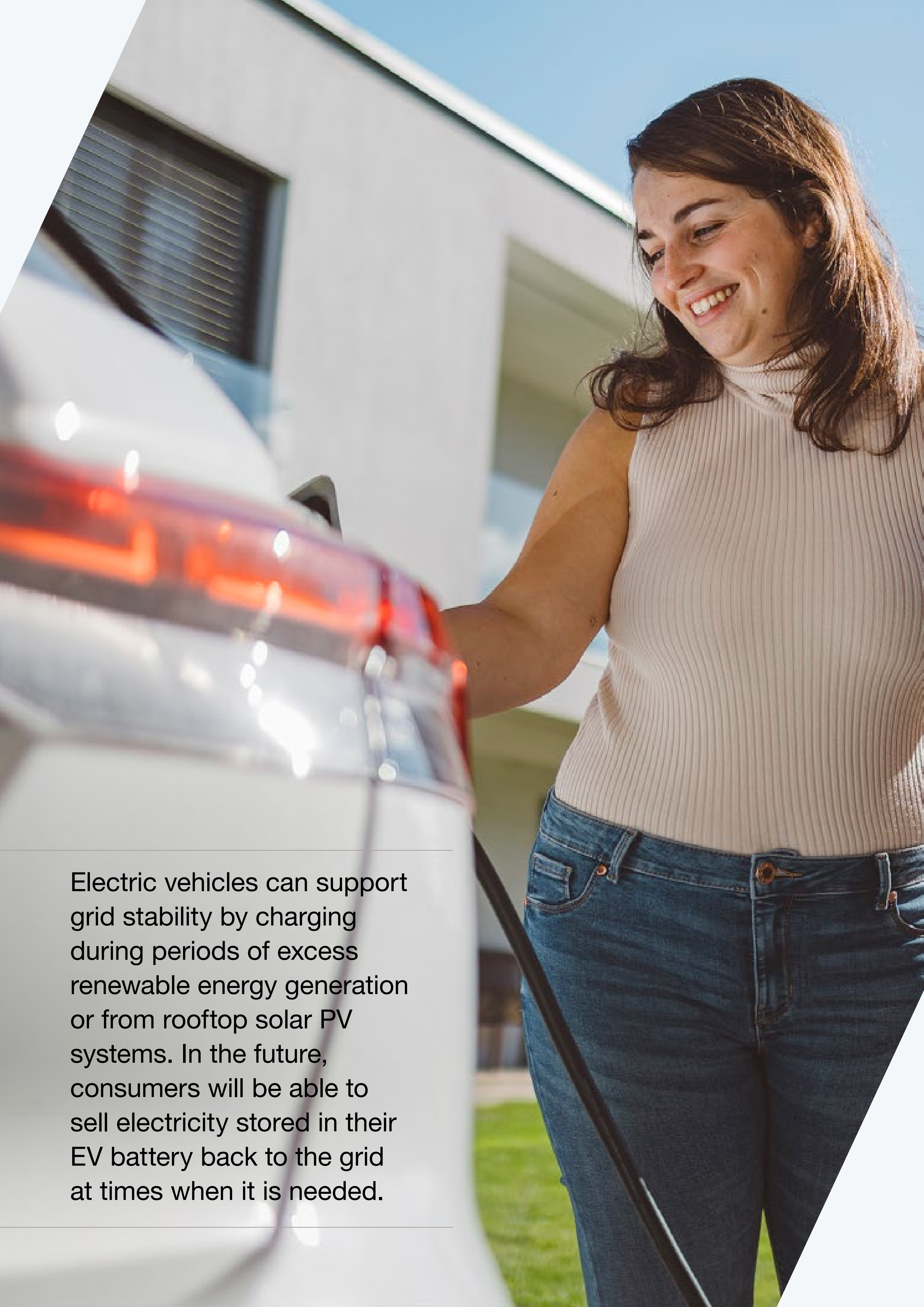
Electric vehicle (EV) uptake in Australia has been slower than in other developed countries but is beginning to accelerate as costs fall and charging infrastructure is expanded. New EV purchases in Australia more than doubled in 2023, compared with 2022, with the total number of EVs on Australian roads now exceeding 180,000. Almost 99,000 electric vehicles were sold in Australia in 2023, up from around 40,000 in 2022 and 21,000 in 2021.[644]

Similar to household batteries, there is an opportunity for electric vehicles to support grid stability by sending and selling electricity back to the grid at times of high demand/low supply. 'Vehicle-to-grid' (V2G) technology has been largely non-existent in the Australian market, but benefits have been demonstrated in small trials internationally. As a result, the Australian Government has funded $2.73 million towards V2G trials.[645] V2G can benefit customers with EVs by sending electricity from their EV battery back to the grid at times of peak demand for a credit. Because EVs also provide transport, enabling V2G technology may provide consumers with an alternative to purchasing both an EV and a home battery, reducing upfront costs.

While the Australian EV market has a long way to go to align EV adoption with our climate targets, the nation is heading in the right direction. This is in large part due to the support the Australian Government and state and territory governments have given for the adoption of electric vehicles and the recognition the role this technology has to play in achieving emission reduction targets.

In April 2023, the Australian Government launched its first National Electric Vehicle Strategy to boost EV adoption through collaboration on national standards, data sharing, affordability, infrastructure development, fleet procurement and education. A key component of this strategy is the upcoming New Vehicle Efficiency Standard to be finalised in 2024, which aims to lower CO_2 emissions by promoting fuel-efficient and electric vehicles. Additionally, in April 2023 a $39.3 million funding initiative was announced to expand Australia's EV charging network, with 117 new fast-charging sites planned for national highways.

640 AEMO, Quarterly Energy Dynamics Q4 2023, Australian Energy Market Operator, 25 January 2024.
641 CEC, Clean Energy Australia 2024, Clean Energy Council, 13 March 2024.
642 Sunwiz, 2023's record-breaking battery market in charts, accessed 11 September 2024.
643 AEMO, Integrated System Plan 2024, Australian Energy Market Operator, 26 June 2024, accessed 11 September 2024.
644 Electric Vehicle Council, Australian Electric Vehicle Industry Recap 2023, accessed 30 August 2024.
645 ARENA, Realising Electric Vehicle-to-Grid Services, Australian Renewable Energy Agency, accessed 6 September 2024.



Electric vehicles can support grid stability by charging during periods of excess renewable energy generation or from rooftop solar PV systems. In the future, consumers will be able to sell electricity stored in their EV battery back to the grid at times when it is needed.

6.9.5 Community-scale batteries

Community-scale batteries[646] are an emerging energy storage solution with much greater capacity than a single home battery, but significantly less than a grid-scale battery system. Community-scale batteries allow participating consumers to send any excess electricity generated from their rooftop solar to the community-scale battery system for storage and later use during peak times. Consumers without rooftop solar may also participate and use the stored energy at peak times to help lower energy bills.[647]

With typical storage capacities of around 100 kW up to 5 MW, a single community-scale battery system could serve up to several hundred nearby homes and small businesses.[648] Community-scale batteries may also benefit the market more broadly with the potential to play an integral role in Australia's transition to a decentralised, lower emissions grid.[649]

Community-scale batteries are regulated under the National Electricity Law (NEL) and National Electricity Rules (NER), and the National Energy Retail Law (NERL) and National Energy Retail Rules (NERR). They are also regulated under jurisdictional energy laws in some states and territories and may be required to comply with additional AEMO and AER requirements, depending on the system's location, technical features and operating model.[650]

In the NEM, the most common form of community-scale batteries are 'in-front-of-the-meter' systems connected to the main grid. Those batteries may be owned by the local distributor, local council, community group, retailer or other third party. However, there are also 'behind-the-meter' systems, which are connected behind a customer's existing grid connection point and generally co-located with other CER. These can be owned by individual customers, businesses or third-party service providers.

The Australian Government is delivering a $200 million grant program in recognition of the multiple benefits community-scale batteries can unlock.[651] A number of state and territory programs and trials are also underway.[652] Retailers are increasingly participating in community-scale battery schemes as the asset owner or in partnership with a distribution network service provider, and several retailers have been conditionally approved to receive Australian Government funding to develop and install community-scale batteries across NEM regions.[653]

Notwithstanding the potential for community-scale batteries to unlock significant value through lower bills for participating customers, improved grid stability and contributing to Australia's emissions reduction targets, current barriers include:

- the cost of batteries, which remains higher than the market anticipated several years ago
- limited access to revenue streams such as capacity schemes and frequency controlled ancillary services
- lack of consumer awareness and knowledge
- limited dynamic tariff structures.[654]

646 Also defined as 'neighborhood batteries' and may be referred to as 'energy-as-a-service' as part of a broader suite of technological solutions.

647 More information is available from Energy Innovation Toolkit, a service operated by the AER in collaboration with AEMC, AEMO, ARENA and the Essential Services Commission, accessed 11 September 2024.

648 Brattle Group, prepared for ECA, Unlocking the Value of Community-Scale Storage for Consumers, Energy Consumers Australia, November 2023, accessed 12 September 2024.

649 ARENA, Implementing Community-Scale Batteries, Australian Renewable Energy Agency, December 2020, accessed 12 September 2024.

650 Australian Government, Energy Innovation Toolkit, accessed 11 September 2024.

651 DCCEEW, Community Batteries for Household Solar program, Department of Climate Change, Energy, the Environment and Water, accessed 12 September 2024.

652 For example, the Victorian Government's 100 Neighborhood batteries program and the South Australian Government's emPowering SA program, accessed 11 September 2024.

653 DCCEEW, Community Batteries for Household Solar program, Department of Climate Change, Energy, the Environment and Water, accessed 12 September 2024.

654 Brattle Group, prepared for ECA, Unlocking the Value of Community-Scale Storage for Consumers, Energy Consumers Australia, November 2023, accessed 12 September 2024.

The AER is supporting further trials to overcome barriers and unlock the benefits. On 3 February 2023, the AER published a final decision to grant a class waiver that would enable distribution network services providers to lease battery capacity to third parties for batteries funded under the Australian Government's Community Batteries for Household Solar Program, subject to certain controls and criteria.[655] The AER also published a Guidance note for market participants.[656]

The AER, in partnership under the Energy Innovation Toolkit, has also provided a hypothetical case study of the development of a community-scale battery.[657] The case study seeks to identify and unpack some of the key regulatory issues that a proponent may encounter in development a community-scale battery system, including national, state and territory regulations.

6.9.6 Standalone power systems

Standalone power systems generate and distribute electricity but are not physically connected to the main grid. Standalone power systems can serve an individual or community (microgrids) and usually consist of renewable generation units, battery storage and back-up generation. Improvements in energy storage and renewable generation technology are enabling more customers to take up this form of energy supply.

Standalone power systems can have several benefits over a grid-connected system, including:[658]

- improved reliability for customers who are currently connected to the grid by relatively poor performing overhead lines
- lower network costs for all NEM customers compared with the alternative solution of replacing and maintaining long stretches of overhead lines or providing expensive underground alternatives
- being more environmentally friendly when standalone power systems use renewable generation.

Following a rule change by the AEMC in 2022, the integration of standalone power systems into the NEM has become more feasible through 'DNSP-led SAPS'.[659] The rule change allows standalone power systems to be treated as part of the network, ensuring that customers receive the same protections and services as those with grid connections, despite being disconnected from the physical grid. This shift aims to enhance service delivery and cost-effectiveness for remote and off-grid customers.[660]

In some regional and remote areas, standalone power systems are increasingly becoming a viable alternative to traditional grid infrastructure. These systems typically include renewable energy sources, battery storage and backup generators, and can serve individual homes or small communities. Recent implementations in Bulahdelah and Moruya showcase their cost-effectiveness compared with maintaining extensive power lines. The Bulahdelah system, featuring a 10.6 kW solar array, a 16 kWh battery and a 15 kVA diesel generator, illustrates how these off-grid setups provide the same level of service as grid-connected systems while reducing maintenance costs and offering significant savings as infrastructure expenses rise and system costs decline.[661]

655 AER, Distribution ring-fencing class waiver for batteries funded under the Community Batteries for Household Solar Program – February 2023, Australian Energy Regulator, accessed 12 September 2024.

656 AER, Guidance note - Distribution ring-fencing class waiver for batteries funded under the Community Batteries for Household Solar Program – February 2023, Australian Energy Regulator, accessed 12 September 2024.

657 Australian Government, Energy Innovation Toolkit, accessed 11 September 2024.

658 AER, Updating instruments for regulated stand-alone power systems, Australian Energy Regulator, August 2022, accessed 13 September 2024.

659 AEMC, National Electricity Amendment (Regulated stand-alone power systems) Rule 2022, Australian Energy Market Commission, 17 February 2022.

660 One step off the grid, Networks embrace stand-alone power as solar and batteries beat out poles and wires, accessed 30 August 2024.

661 One step off the grid, Networks embrace stand-alone power as solar and batteries beat out poles and wires, accessed 30 August 2024.

6.9.7 Towards an inclusive energy transition

Broadly, and in the longer term, all customers are and will continue to benefit from well-managed CER integration into the NEM. Increased rooftop generation puts downward pressure on energy costs and fewer greenhouse gas emissions will improve public health and environmental outcomes. However, consumers able to purchase and effectively operate CER assets will generally experience the benefits of lower bills sooner than those unable to do so.[662] There is a risk this could worsen equity gaps between consumers (section 6.6). To offset this, additional support is required for consumers experiencing barriers to engagement.

These barriers could arise through factors such as not having the literacy or numeracy skills to navigate the energy market, dealing with ill physical or mental health, or having limited financial resources or autonomy over their energy use. Consumer groups and governments are implementing strategies aiming to improve consumer equity in relation to increasing CER integration in the NEM.

On 10 August, ECA published its report *Stepping Up: A smoother pathway to decarbonising homes*.[663] The report recommends enhanced and coordinated planning across all tiers of government to avoid worsening the gap between households that can actively participate in transitioning energy markets and those that cannot. This would include measures such as:

- encouraging customer uptake of electric vehicles to leverage the ability for electric car batteries to optimise the grid and reduce energy prices
- reducing barriers for apartment dwellers and renters to electrify their homes
- carefully planning for the decline of household gas use, ensuring safeguards are in place for consumers less able to transition as prices likely escalate.[664]

Under the CER Roadmap, the Australian Government has established a CER Working Group and several CER Taskforce-led projects. The aim of these projects is to ensure continued strong uptake of CER and emerging products, such as virtual power plants, by providing a safe and fair market for CER and ensure the benefits are shared with all consumers regardless of their ability to engage with the market.[665] The CER Roadmap articulates 3 national reform priority areas:

- extending consumer protections for CER
- more equitable access to the benefits of CER
- provision of information about CER to empower consumers.

Under the CER Roadmap, several projects have been developed to support these priority areas. Projects will be delivered by the CER Taskforce in collaboration with the AER, ECA, AEMC, DCCEEW and an Energy Transformation Enablers Working Group.[666]

On 25 July 2024, the AEMC self-initiated a review to consider the role of electricity pricing, products and services to support the diverse needs of customers.[667] Part of the review includes the role of CER, in the context of the CER Roadmap, in realising the benefits of CER for all energy consumers, including those without CER. As retail markets are the main interface between consumers and energy markets, the AER will continue to implement strategies such as *Towards energy equity* to identify and support consumers with diverse needs (section 6.6.7).[668]

662 There are some exceptions to this, such as the SA Government's Virtual Power Plant program, involving installations of rooftop solar and home battery systems on Housing SA homes at no cost to tenants, with all Housing SA tenants able to access lower electricity rates under the program. See DEM, South Australia's Virtual Power Plant, Department for Energy and Mining, accessed 6 September 2024.

663 ECA, Stepping Up: A smoother pathway to decarbonising homes, Energy Consumers Australia, accessed 2 September 2024.

664 ECA, Stepping Up: A smoother pathway to decarbonising homes, Energy Consumers Australia, accessed 2 September 2024.

665 DCCEEW, National Consumer Energy Resources Roadmap, Department of Climate Change, Energy, the Environment and Water, 18 July 2024.

666 For further information about these projects, see DCCEEW, National Consumer Energy Resources Roadmap, Department of Climate Change, Energy, the Environment and Water, 18 July 2024.

667 AEMC, Electricity pricing for a consumer-driven future, Australian Energy Market Commission, 25 July 2025.

668 AER, Towards energy equity – a strategy for an inclusive energy market, Australian Energy Regulator, 20 October 2022, accessed 6 September 2024.

Consumers in a vulnerable situation are more likely to face multiple barriers compared to other consumers. These households could live in thermally poor housing and experience trade-offs between the cost of their energy bills and maintaining comfortable heat levels in their homes. This balance can inhibit their access to pay for upfront for energy upgrades to improve their home's thermal efficiency, to reduce future bills.[669] With these challenges, these households may not be well-placed to absorb the full benefits of developments including dynamic tariffs for energy bills and smart meters.

The Australian Government is partnering with state and territory governments to deliver the $300 million Social Housing Energy Performance Initiative under the Household Energy Upgrade Fund; one step towards retrofitting existing homes across Australia.[670]

The AER's vision is that consumers can own and use CER to consume, store and trade energy as they choose in support of the broader long-term interest of all energy consumers. The AER will continue to work with the Australian Government and state and territory governments to progress these reforms through the taskforce and stakeholder reference groups.

669 DISER, Race for 2030, Pathways to scale: Retrofitting One Million+ homes, Department of Industry, Science, Energy and Resources, December 2021.

670 DCCEEW, National Energy Performance Strategy, Department of Climate Change, Energy, the Environment and Water, April 2024, accessed 19 September 2024.

Abbreviations

ABS	Australian Bureau of Statistics
ACCC	Australian Competition and Consumer Commission
ACOSS	Australian Council of Social Service
ACT	Australian Capital Territory
ADGSM	Australian Domestic Gas Security Mechanism
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AFMA	Australian Financial Markets Association
AGN	Australian Gas Networks
APA	Australian Pipeline Agency
APLNG	Australian Pacific LNG
ARENA	Australian Renewable Energy Agency
ASX	Australian Securities Exchange
bps	basis points
CDR	Consumer Data Right
CEC	Clean Energy Council
CER	consumer energy resources
CESS	Capital Expenditure Sharing Scheme
CKI	Cheung Kong Infrastructure
CPI	consumer price index
CSIS	Customer Service Incentive Scheme
DCCEEW	Department of Climate Change, Energy, the Environment and Water
DELWP	Department of Environment, Land, Water and Planning
DISER	Department of Industry, Science, Energy and Resources
DMIAM	Demand Management Innovation Allowance Mechanism
DMIS	Demand Management Incentive Scheme
DMO	default market offer
DNSP	distribution network service provider
DWGM	Declared Wholesale Gas Market
EBSS	Efficiency Benefit Sharing Scheme
ECA	Energy Consumers Australia

ECGM	east coast gas market
ECGS	east coast gas system
EGP	Eastern Gas Pipeline
ENA	Energy Networks Australia
ERA	Economic Regulation Authority
ESC	Essential Services Commission
ESCOSA	Essential Services Commission of South Australia
ESV	Energy Safe Victoria
EV	electric vehicle
EWON	Energy and Water Ombudsman NSW
FCAS	frequency control ancillary services
FEX	FEX Global
GBB	Gas Bulletin Board
GEMS	Greenhouse and Energy Minimum Standards
GJ	gigajoule
GLNG	Gladstone Liquefied Natural Gas
GPG	gas-powered generation
GSA	gas sales agreement
GSG	Gas Supply Guarantee
GSH	Gas Supply Hub
GSL	guaranteed service level
GSOO	Gas Statement of Opportunities
GW	gigawatt
GWh	gigawatt hour
HUGS	Heytesbury Underground Gas Storage
ICRC	Independent Competition and Regulatory Commission
IRR	Interim Reliability Reserve
ISDA	International Swaps and Derivatives Association
ISP	Integrated System Plan
JKM	Japan/Korea Marker
km	kilometre
kV	kilovolt
kW	kilowatt
kWh	kilowatt hour
LNG	liquefied natural gas
LRET	large-scale renewable energy target
m	million (used in financial contexts)
MAIFI	momentary average interruption frequency index
MJ	megajoule
MTFP	multilateral total factor productivity
mtpa	million tonnes per annum
MVAh	megavolt-ampere hour
MW	megawatt

MWh	megawatt hour
NCC	National Competition Council
NCP	net contract position
NECF	National Energy Customer Framework
NEM	National Electricity Market
NER	National Electricity Rules
NERL	National Energy Retail Law
NERO	National Energy Retail Objective
NERR	National Energy Retail Rules
NGL	National Gas Law
NGO	National Gas Objective
NGR	National Gas Rules
NSW	New South Wales
NT	Northern Territory
OTTER	Office of the Tasmanian Economic Regulator
PASA	Project Assessments of System Adequacy
PCA	Port Campbell to Adelaide Pipeline
PCI	Port Campbell to Iona Pipeline
PJ	petajoule
PV	photovoltaic
QCA	Queensland Competition Authority
QCLNG	Queensland Curtis LNG
QGP	Queensland Gas Pipeline
QIC	Queensland Investment Corporation
Qld	Queensland
QNI	Queensland to New South Wales Interconnector
RAB	regulatory asset base
RACE	Reliable Affordable Clean Energy
RBA	Reserve Bank of Australia
RERT	Reliability and Emergency Reserve Trader
RET	Renewable Energy Target
REZ	Renewable Energy Zone
RIN	regulatory information notice
RIT	regulatory investment test
RIT-D	regulatory investment test for distribution
RIT-T	regulatory investment test for transmission
RoLR	Retailer of Last Resort
RRO	Retailer Reliability Obligation
SA	South Australia
SAIDI	system average interruption duration index
SAIFI	system average interruption frequency index
SAPS	standalone power systems
SCADA	supervisory control and data acquisition

SRES	small-scale renewable energy scheme
STPIS	service target performance incentive scheme
STTM	Short Term Trading Market
Tas	Tasmania
TJ	terajoule
TJ/day	terajoules per day
TW	terawatt
TWh	terawatt hour
UGS	underground storage
V2G	vehicle-to-grid
VCR	value of customer reliability
Vic	Victoria
VNI	Victoria to NSW interconnector
VPPs	virtual power plants
WA	Western Australia
WACC	weighted average cost of capital
WCFB	Wallumbilla Compressor Facility B
WORM	Western Outer Ring Main
YTD	year-to-date

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