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).

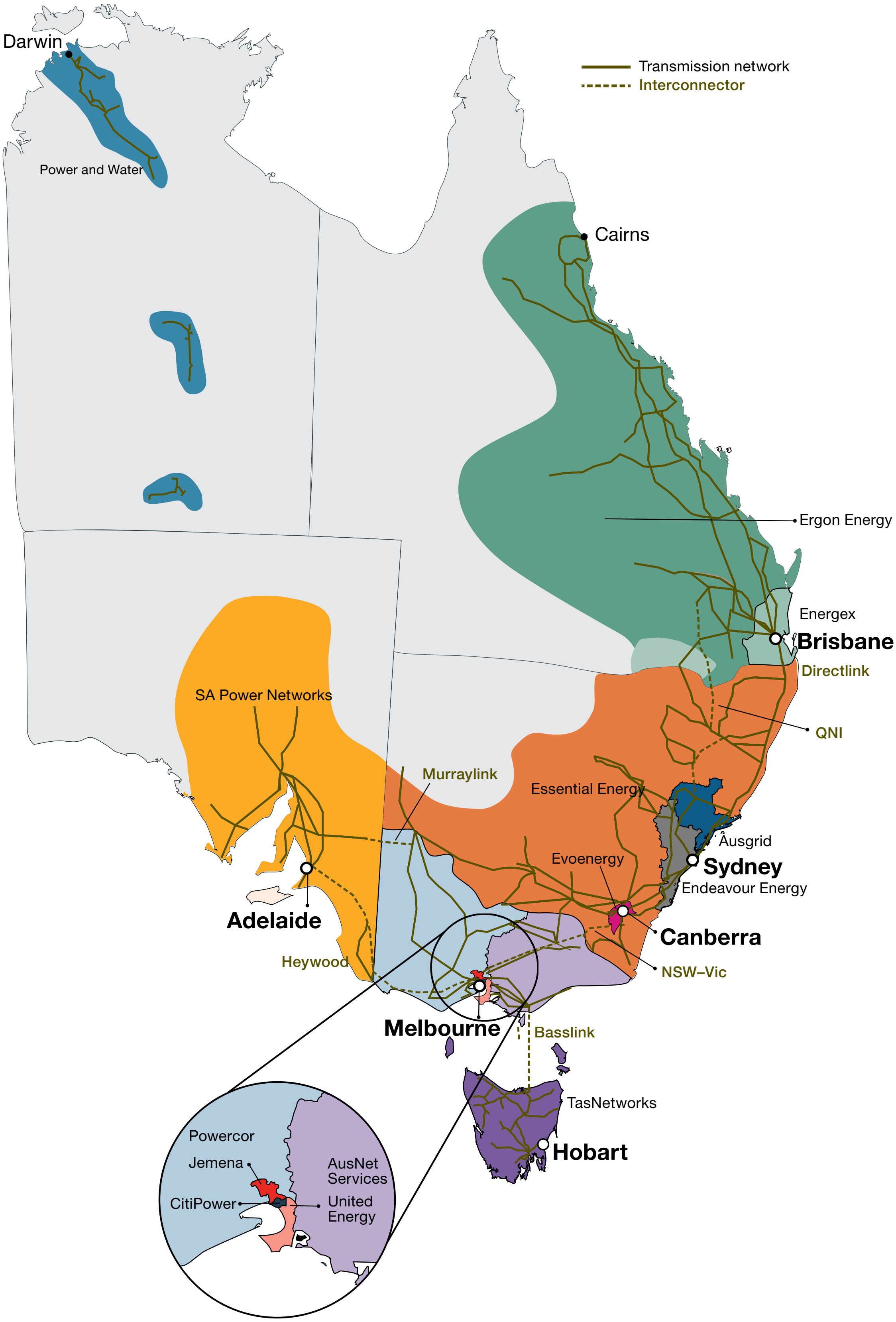
63 On 19 May 2023, APA Group lodged an application to the AER seeking to convert Basslink's network services from market network services to prescribed transmission services. The AER will assess APA Group's request to convert Basslink concurrently with undertaking the 1 July 2025 to 30 June 2030 revenue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

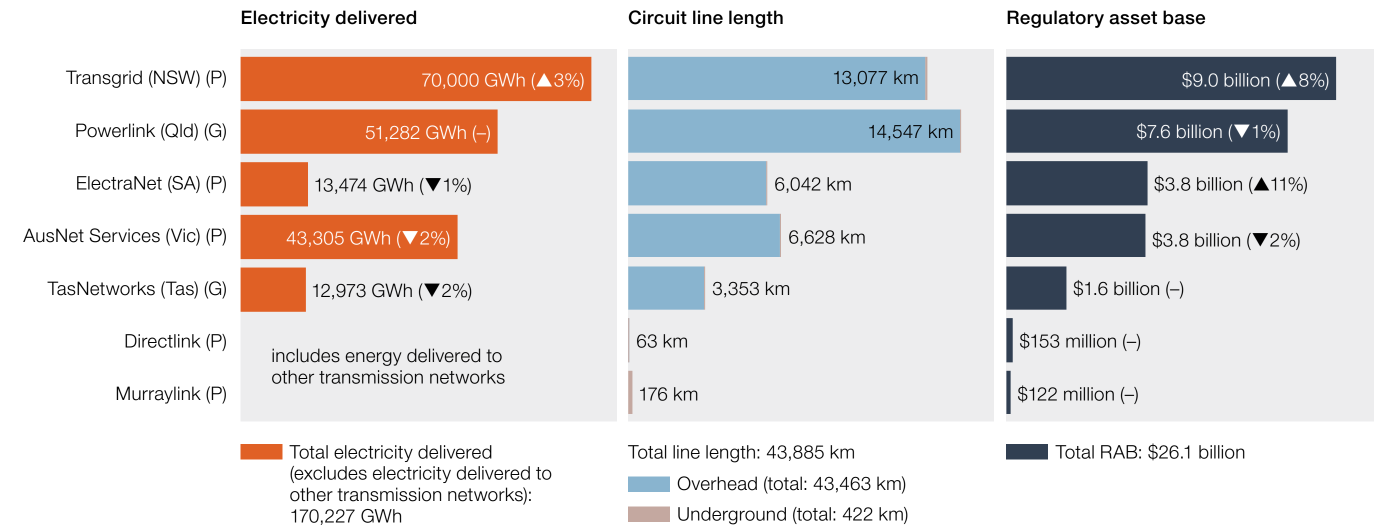
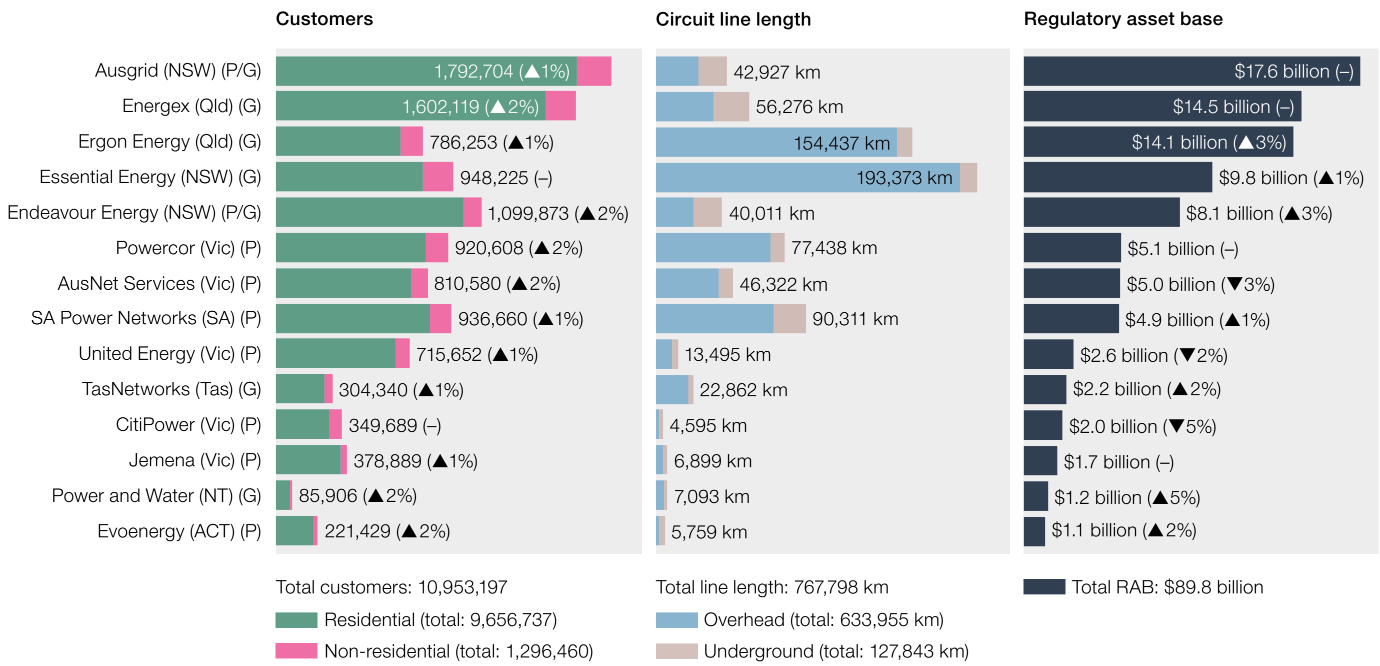


Figure 3.3 Electricity networks regulated by the AER – distribution



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).

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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:

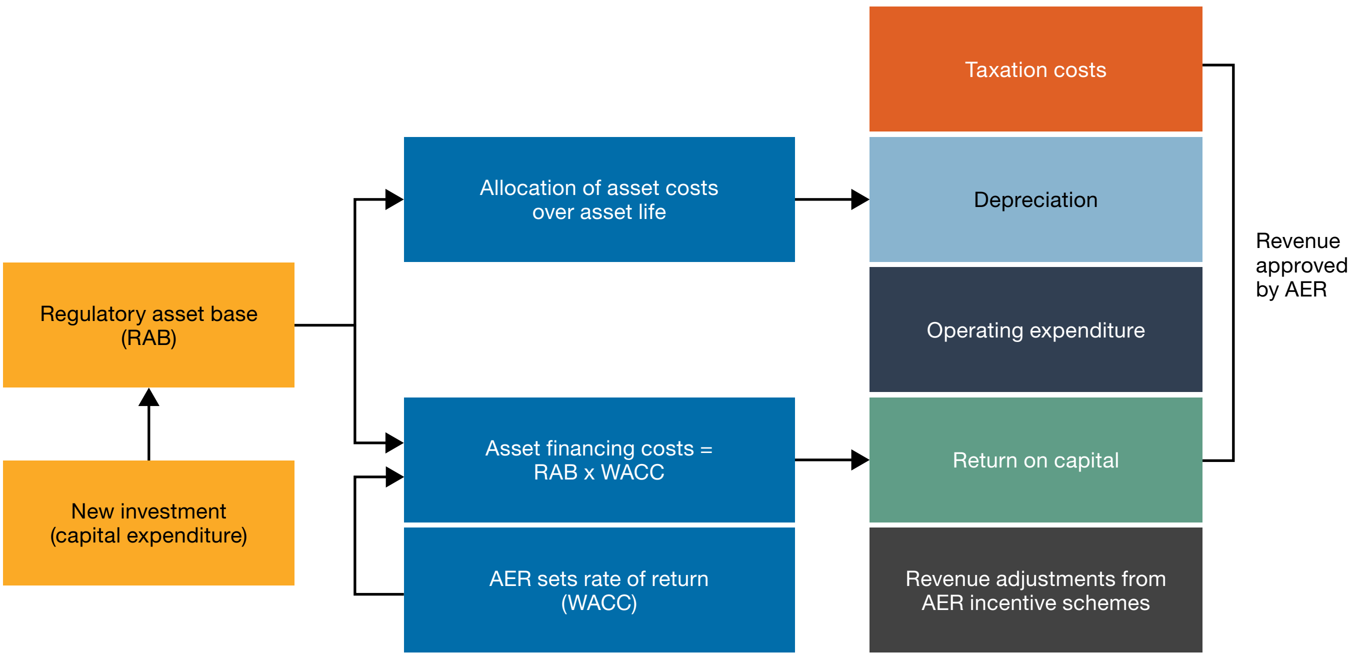
- a return to the investors that fund its assets and operations
- efficient operating and maintenance costs
- asset depreciation costs
- taxation costs.

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.

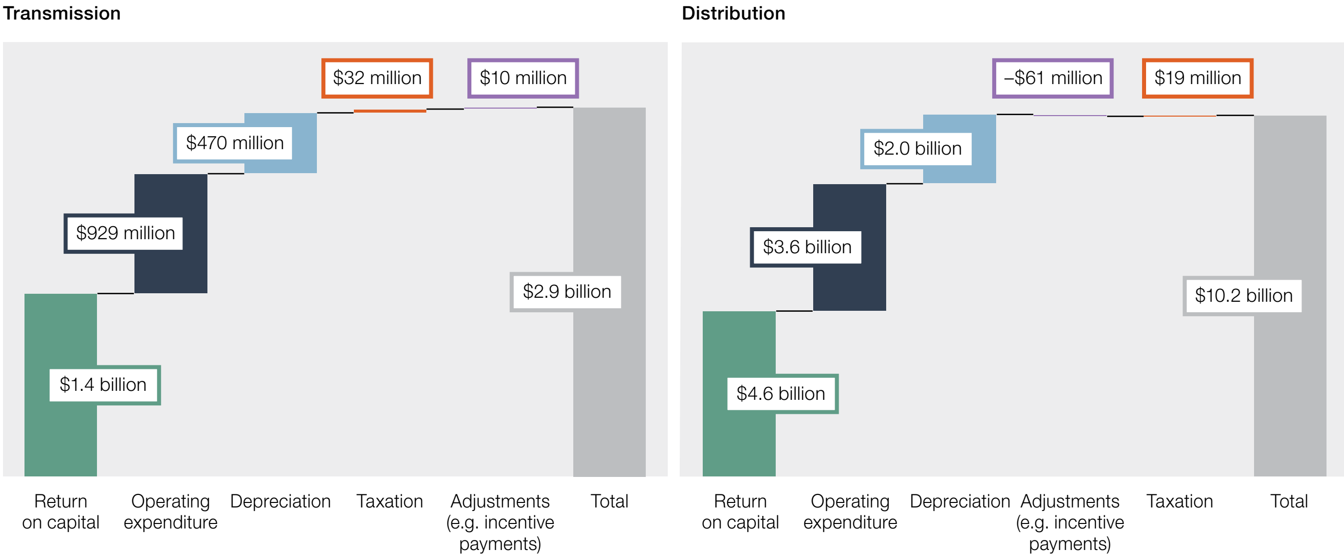
Additionally, the shareholders and lenders that fund these assets require a return on their investment. The AER sets the allowed rate of return (also called the weighted average cost of capital (WACC)) (section 3.12). The size of this return depends on:

- 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.

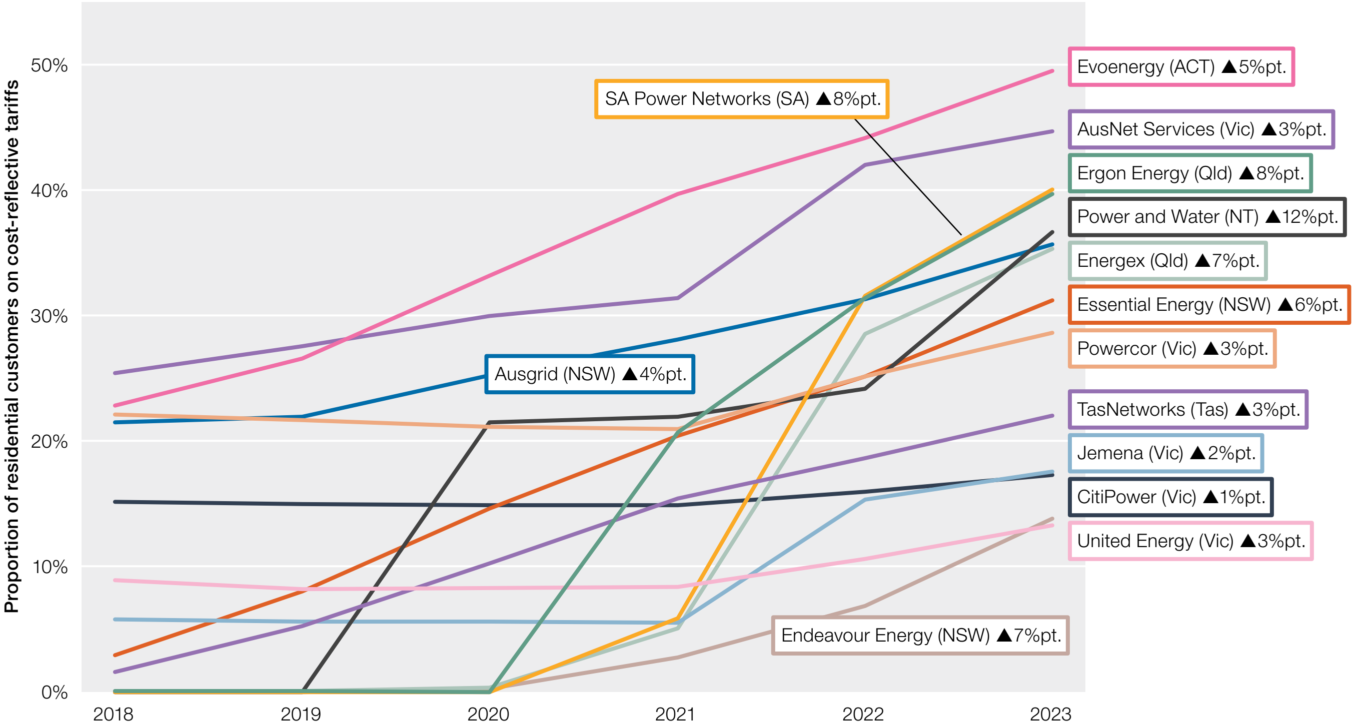
Export reward tariffs were introduced on 1 July 2024 by distribution network service providers in NSW. Network service providers are not required to introduce export reward tariffs and any proposed export reward tariff is subject to the AER's approval as part of the tariff structure statement process. 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

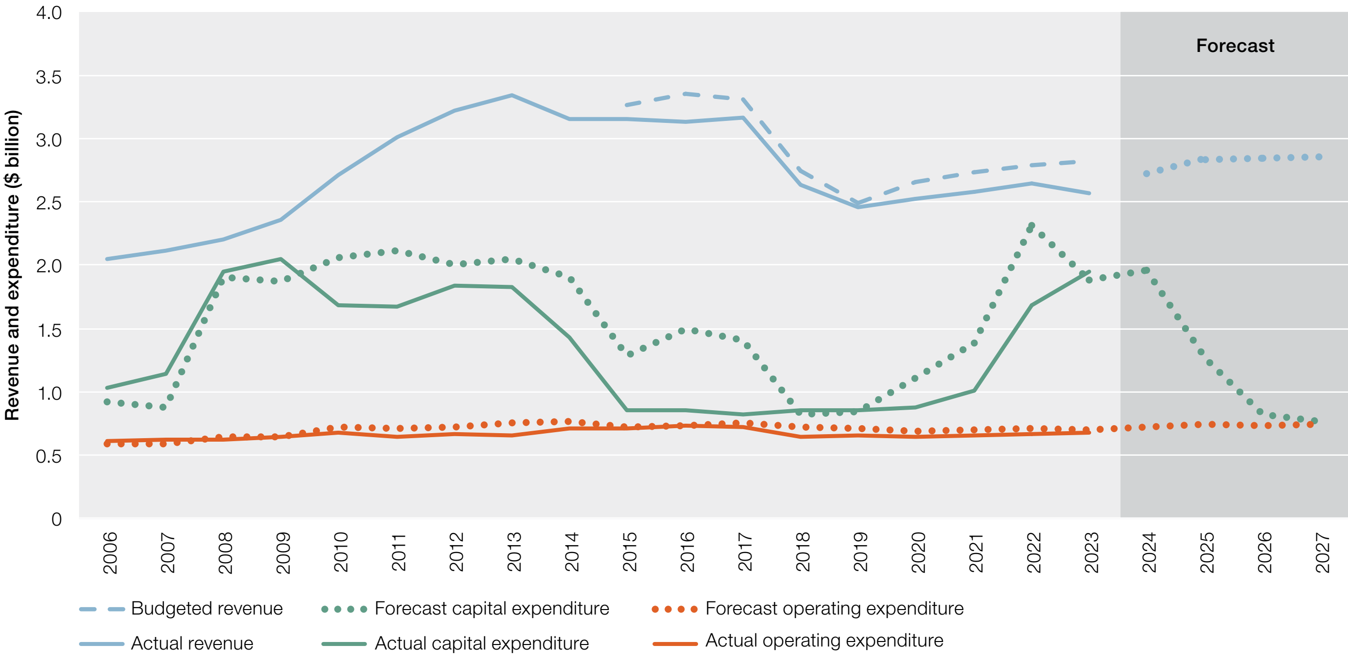
Service type	Revenue (actual) (2023)	Revenue (actual) (compared with 2022)	Revenue (actual) (compared with peak)
Transmission	$2.6b	▼$82m (▼3.1%)	▼$778m (▼23%) (2013)
Distribution	$9.9b	▼$290m (▼2.8%)	▼$4.7b (▼28%) (2015)
Total	$12.5b	▼$372m (▼2.9%)	▼$5.2b (▼27%) (2015)

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.

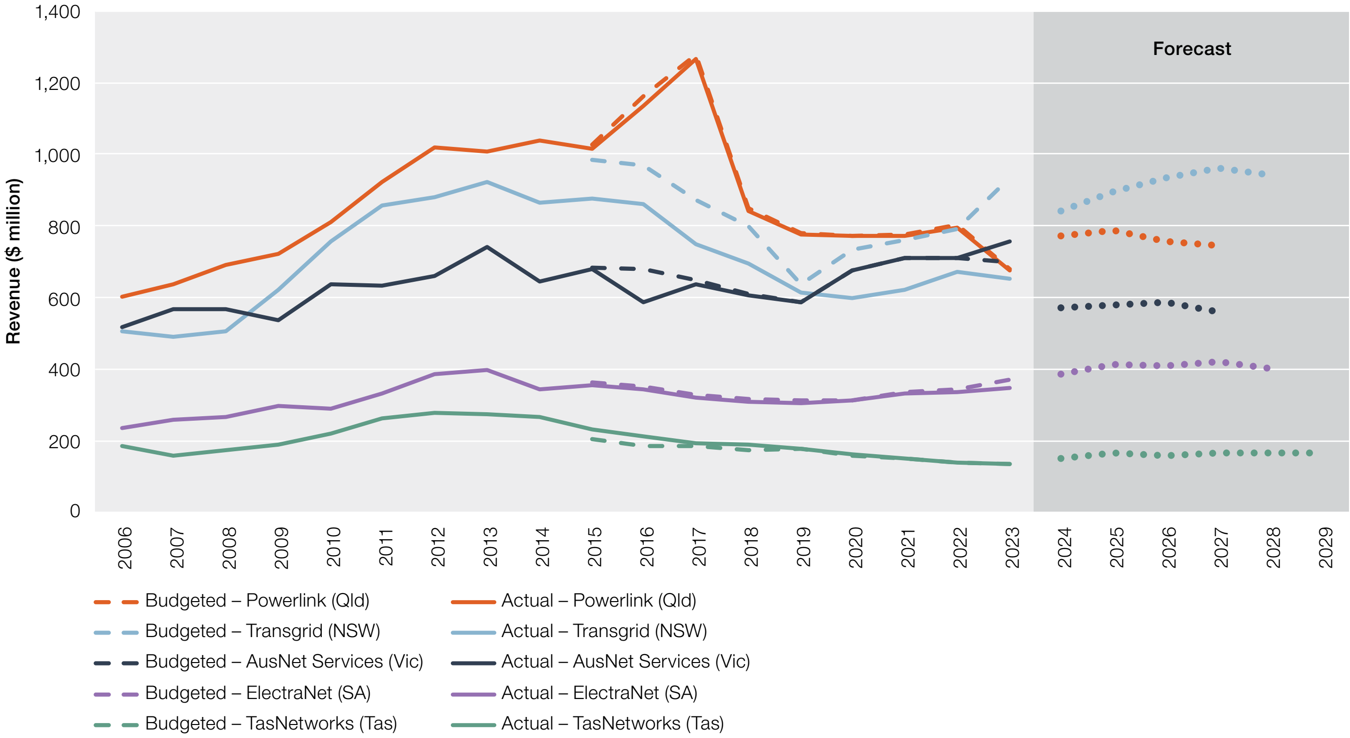
Figure 3.7 Revenue and key drivers – electricity transmission networks (aggregate)



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.

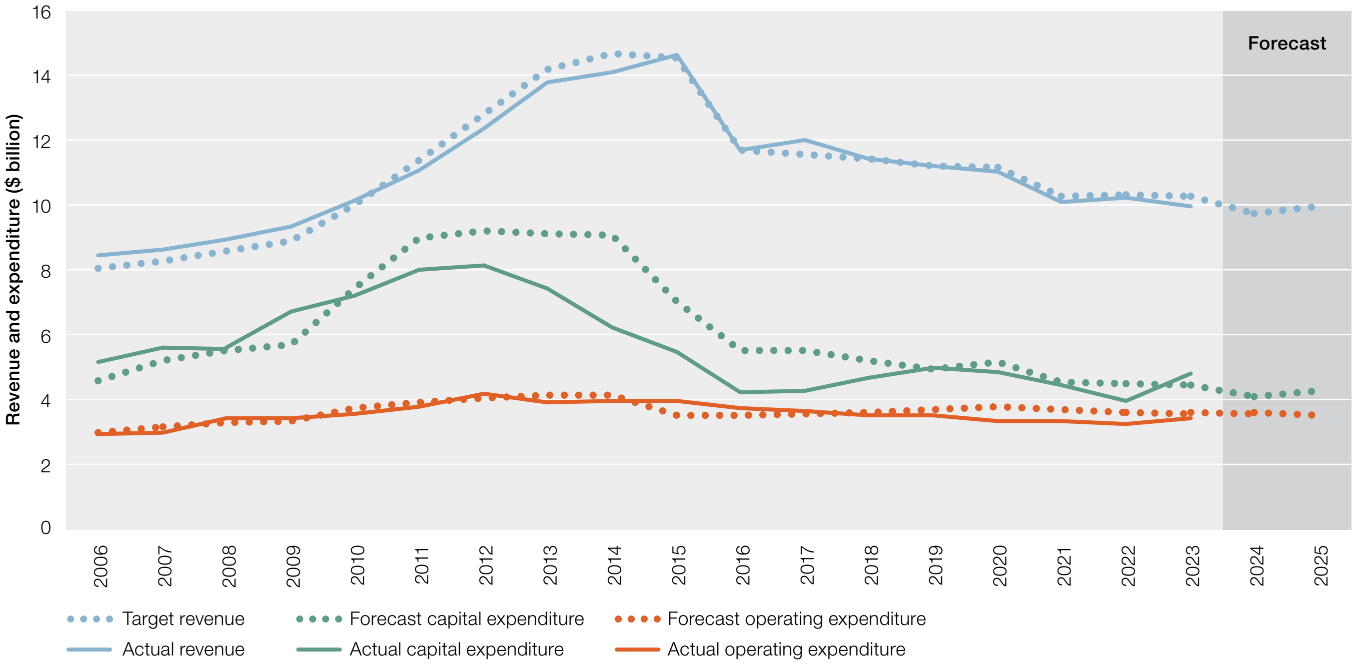
Figure 3.8 Revenue – electricity transmission networks



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.

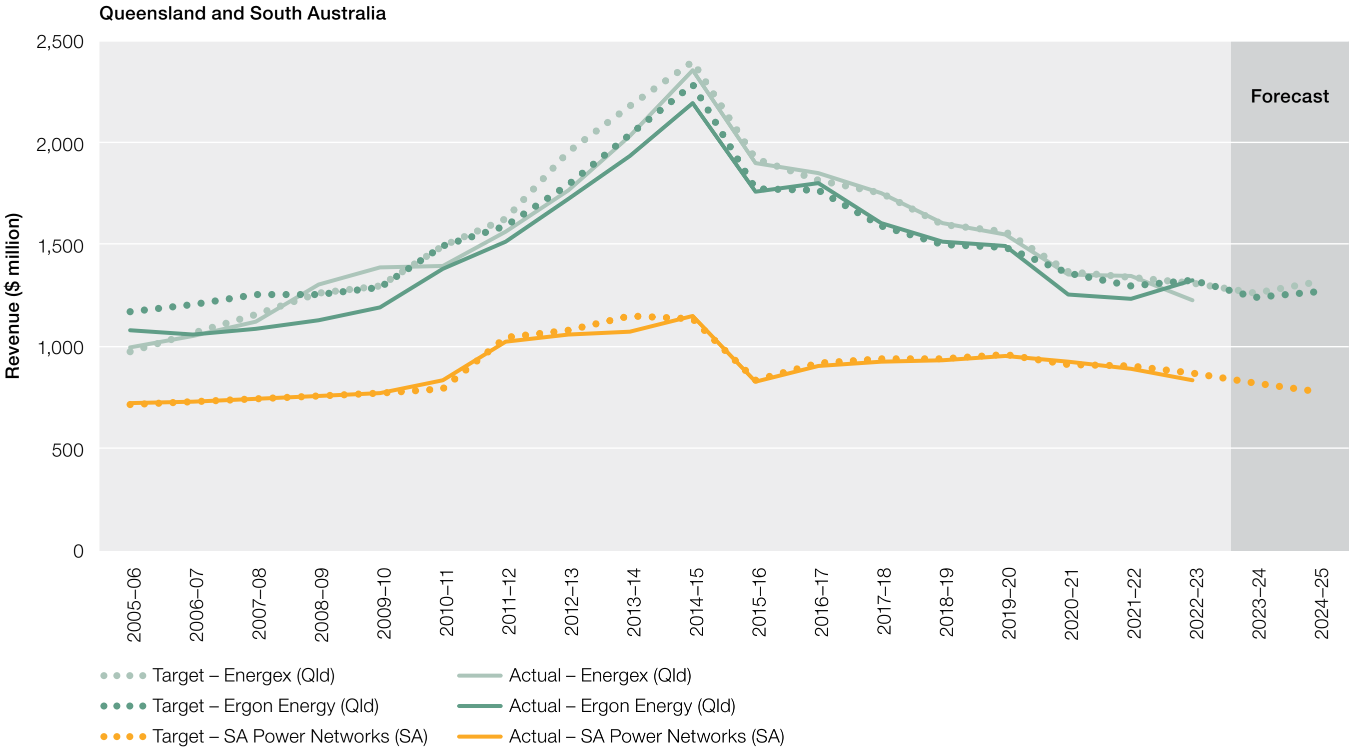
Figure 3.9 Revenue and key drivers – electricity distribution networks (aggregate)

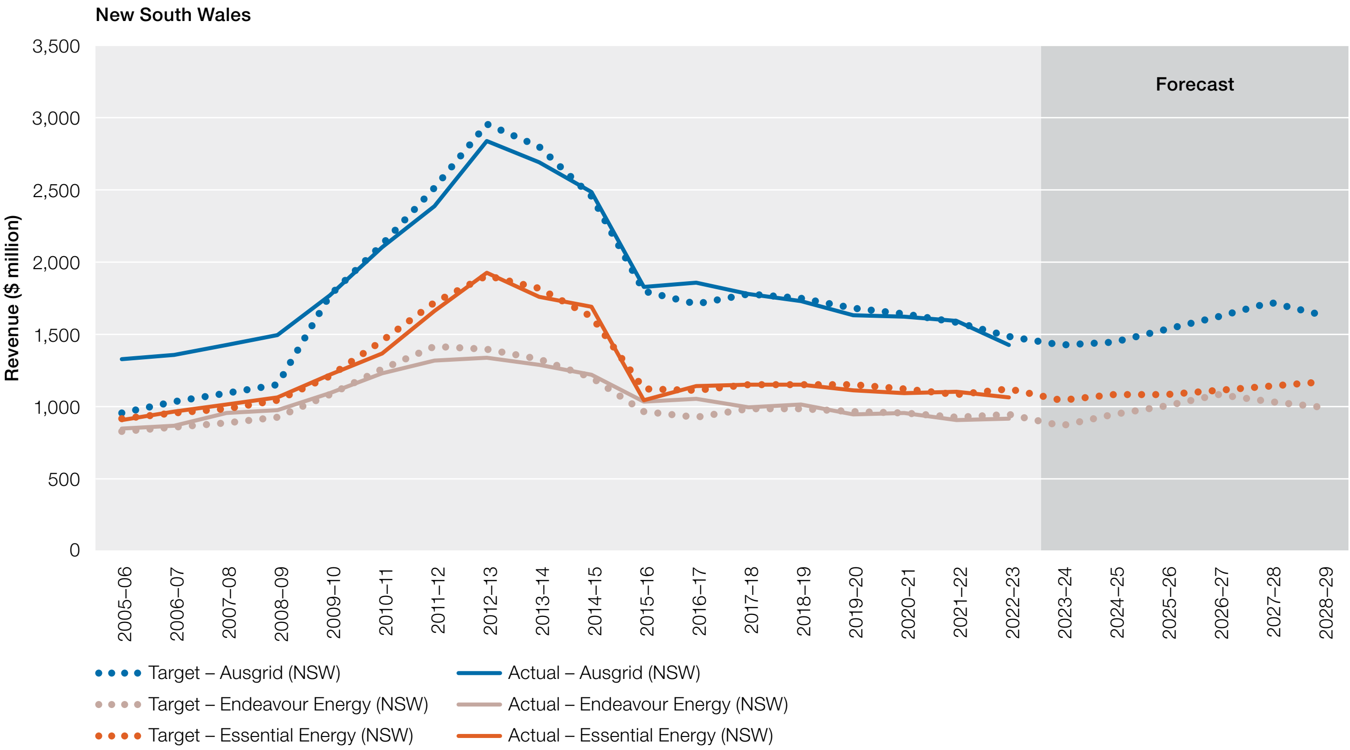


Note: All data are adjusted to June 2023 dollars. The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018). The exception is the Victorian networks, which until year end 2020 reported on a 1 January to 31 December basis. Target revenue 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.

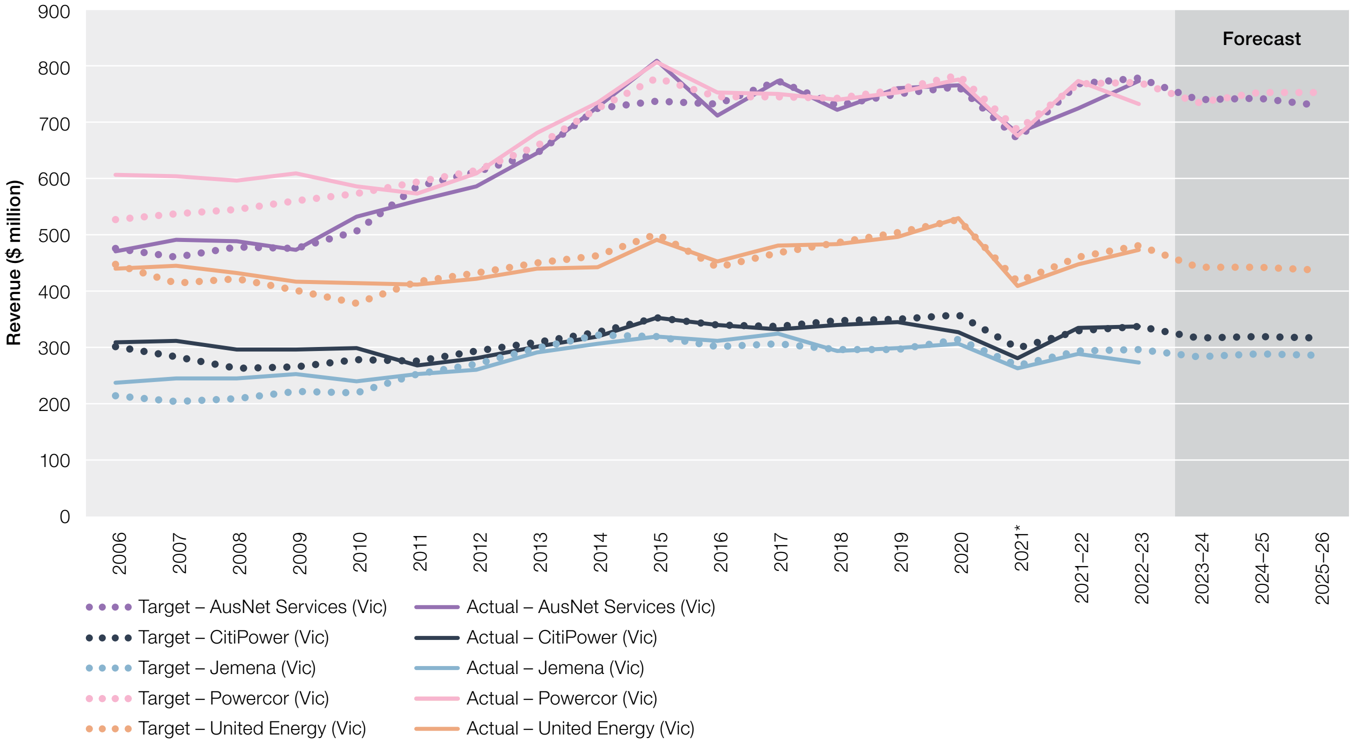
Source: Revenue: economic benchmarking RIN responses; capital expenditure: AER modelling, category analysis RIN responses; operating expenditure: AER modelling, economic benchmarking RIN responses.

Figure 3.10 Revenue – electricity distribution networks

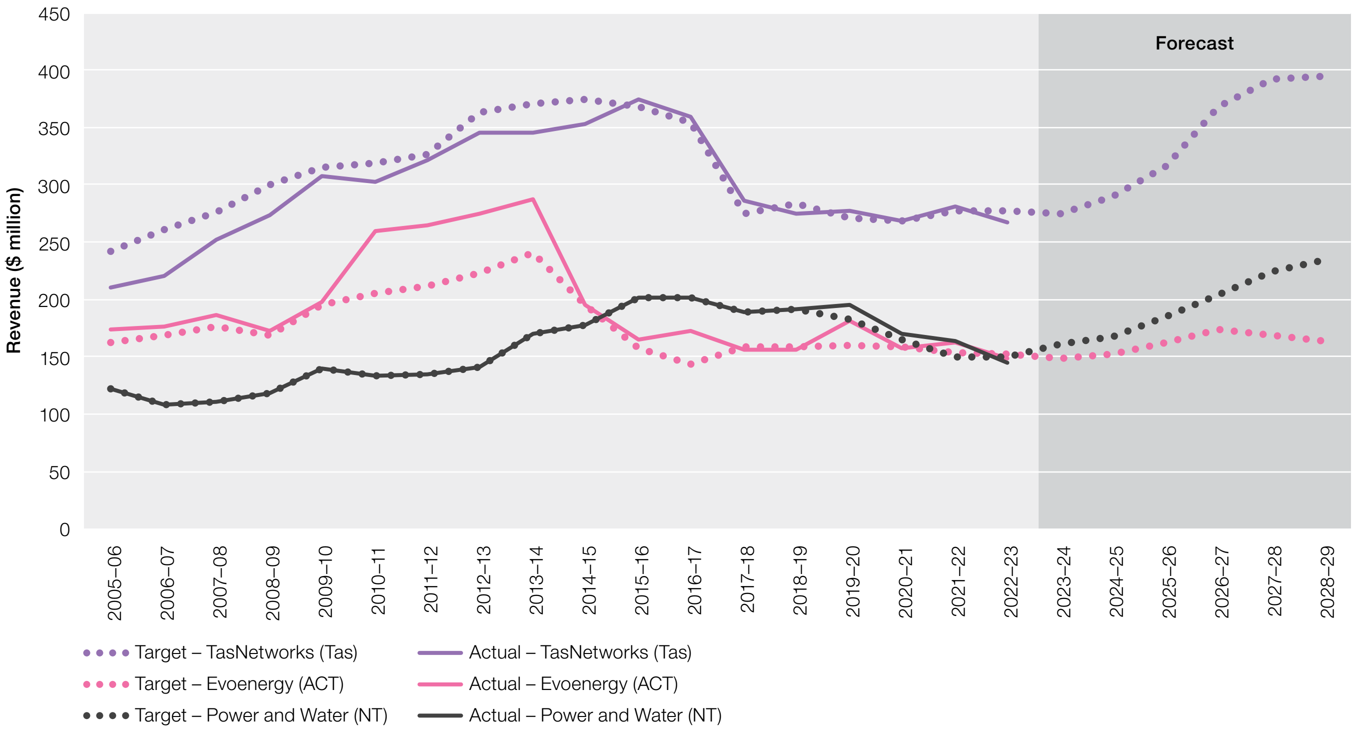




Victoria



Tasmania, ACT and Northern Territory

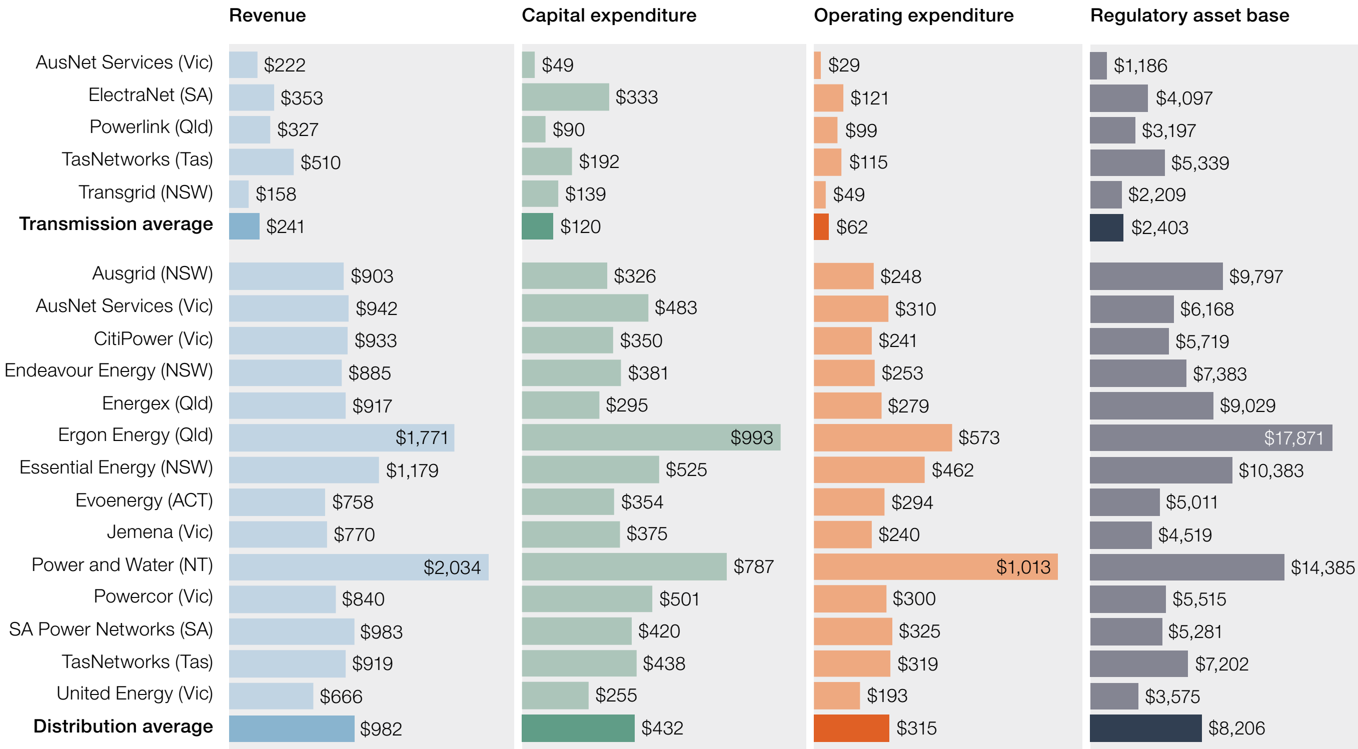


Note: All data are adjusted to June 2023 dollars. Most network service providers report on a 1 July to 30 June basis. The exception is the Victorian networks, which until year end 2020 reported on a 1 January to 31 December basis. Target revenue for the Victorian distribution networks for the 2021 year 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.

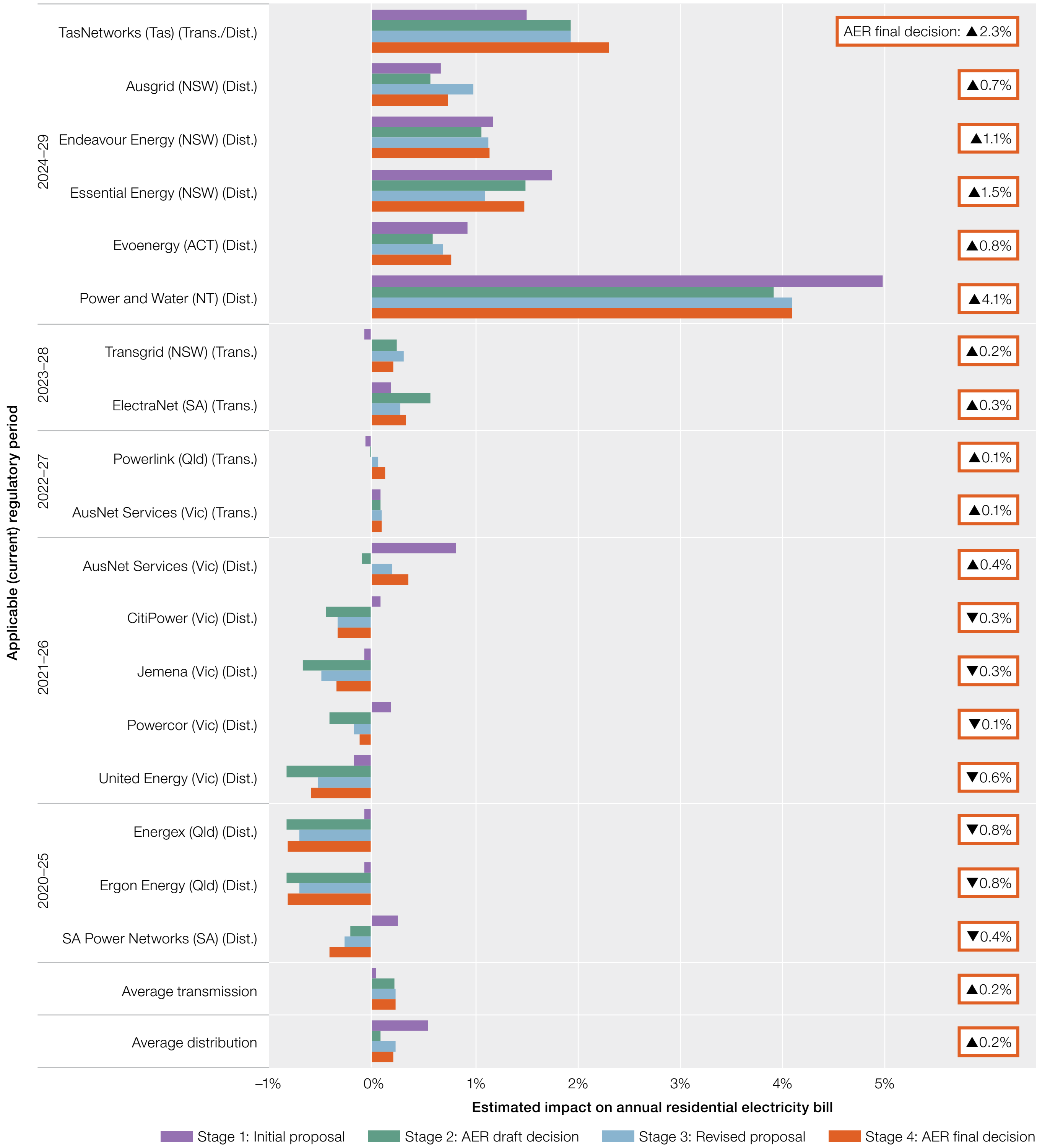
Among other factors, the annual processes update prices for changes in the consumer price index (CPI). Since June 2021, CPI has increased significantly. Over the 12 months to December 2023, applying to network prices over 2024–25, CPI increased by 4.1%. CPI growth has eased but remains relatively high 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.

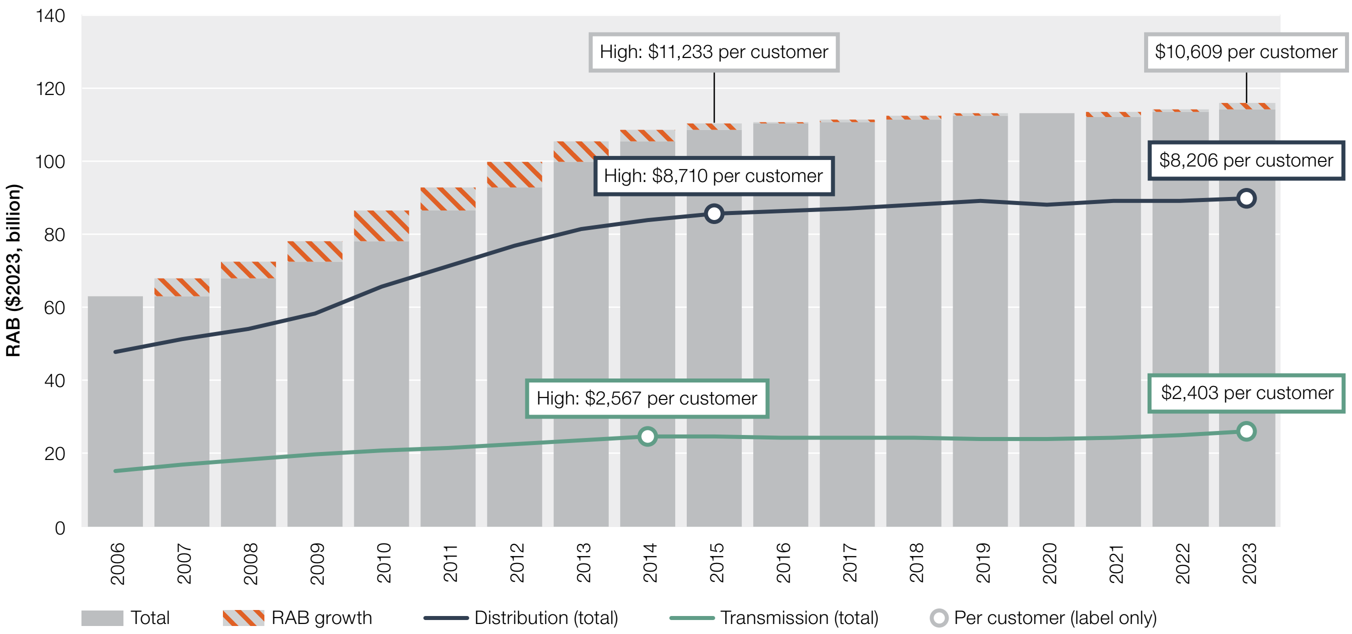
Escalating investment inflated the value of the total electricity network RAB from $63.2 billion in 2006 to $105.3 billion in 2013 – an increase of around 8% per year. Since then, network investment has steadied, as has the growth in the value of the total network RAB. From 2014 to 2023 the value of 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).

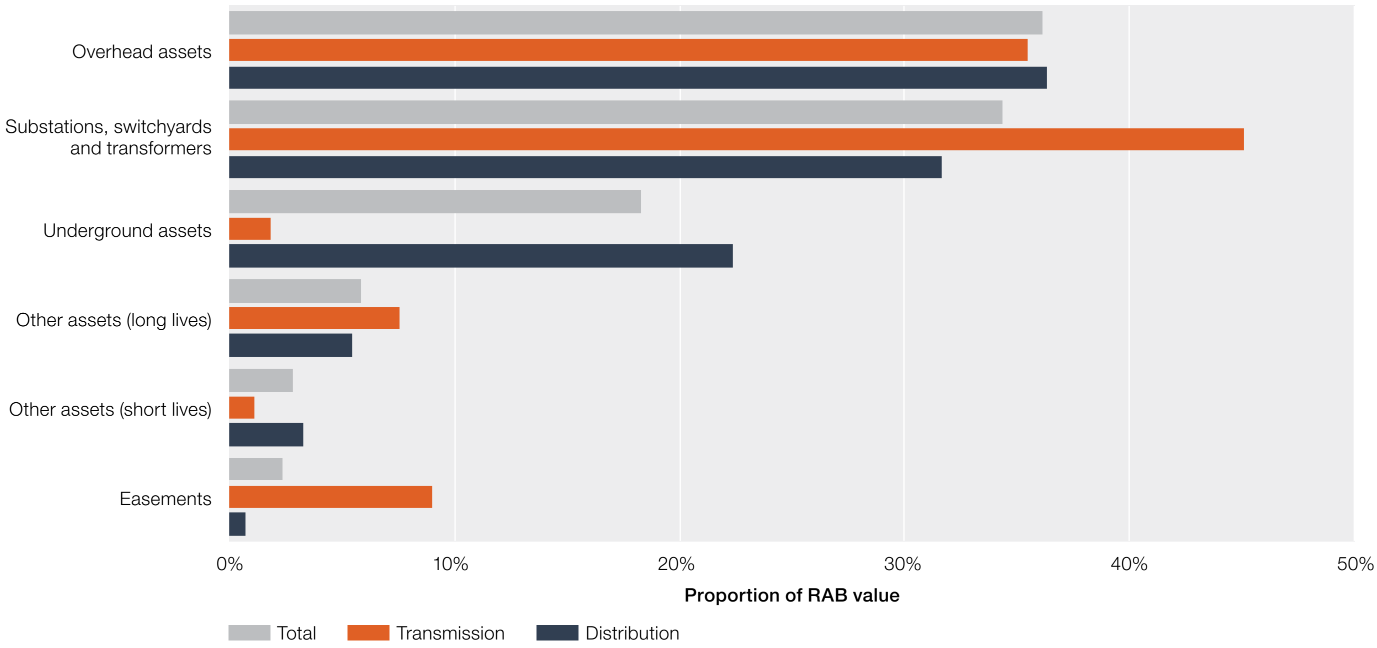
125 The AER is required by the National Electricity Rules (NER) to assess applications by network service providers to amend their regulatory revenue determination to include the revenue required for a contingent project. Contingent projects are major network infrastructure assets that have been flagged 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.

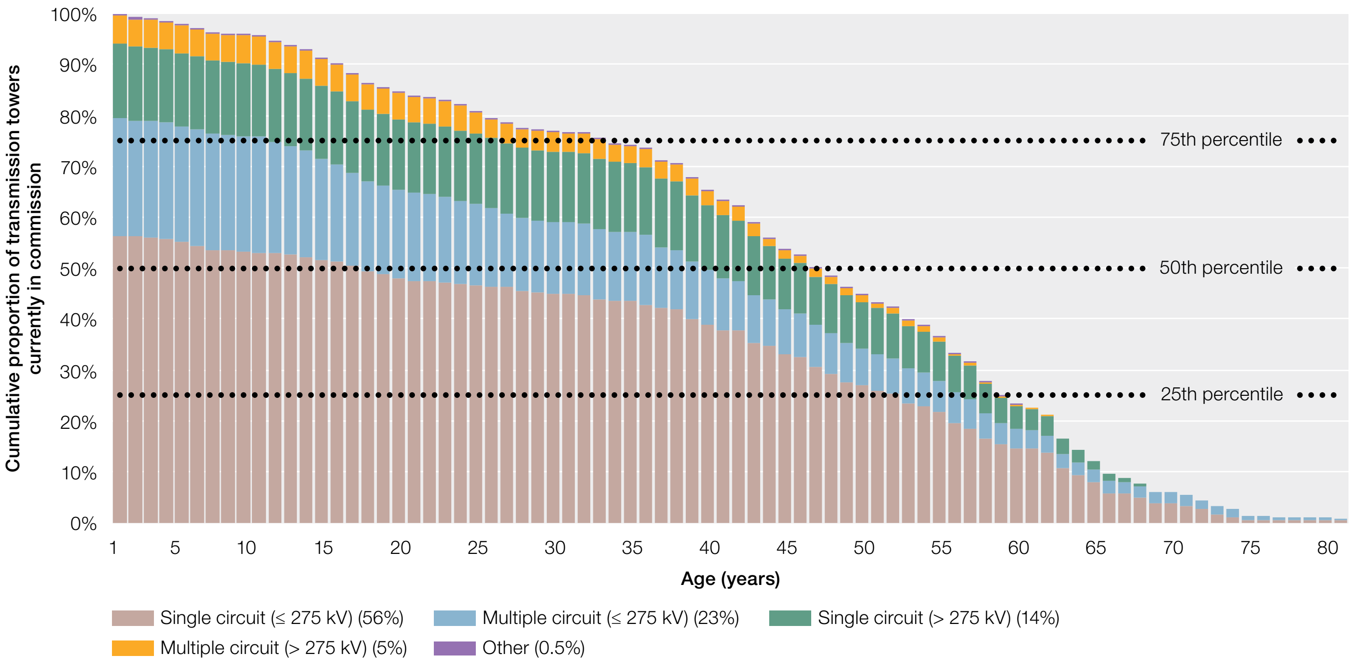
127 AER, Draft decision – Attachment 5 – Capital expenditure – Essential Energy 2024 to 2029, Australian Energy Regulator, September 2023.
128 P Sumerling and W Prest, Stobie Poles, SA History Hub, History Trust of South Australia, accessed 14 December 2020.
129 ABC News, Stobie poles are a South Australian 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.

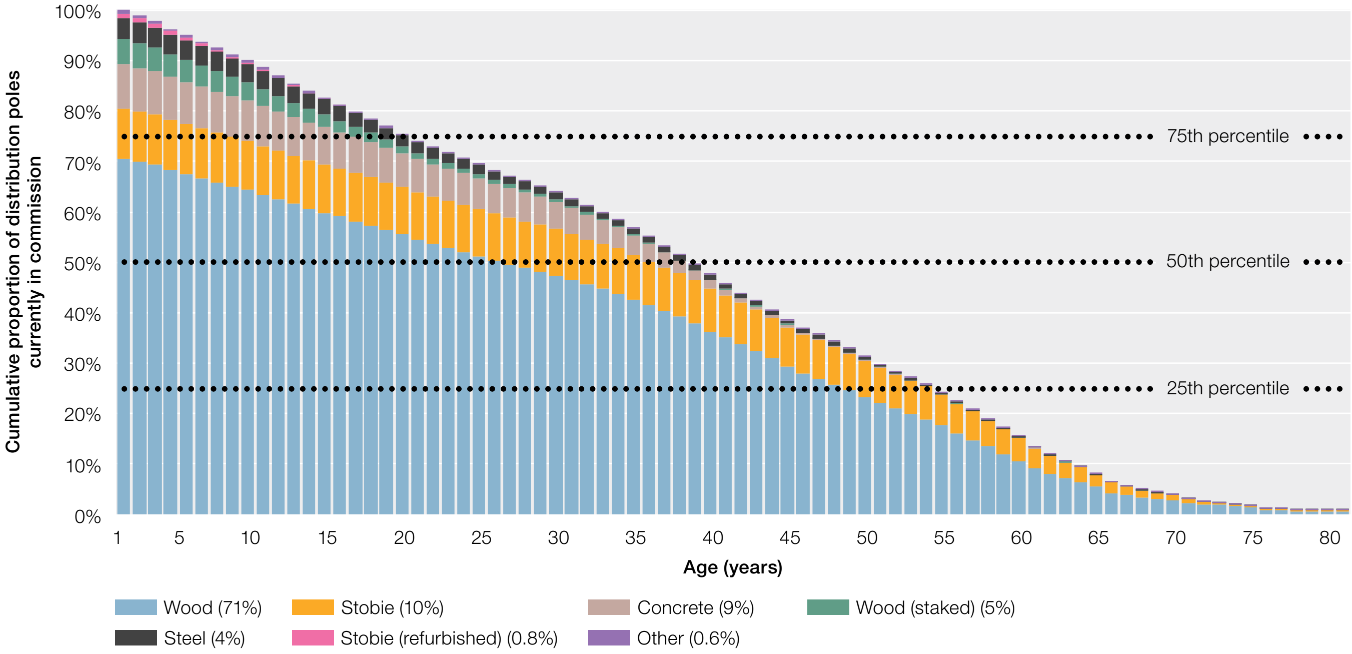
The asset age profiles shown in Figure 3.15 and Figure 3.16 provide an overview of the age of the towers and poles currently in commission across the collective transmission and distribution networks. However, we note the asset age and the types of towers and poles vary considerably between each network.

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.

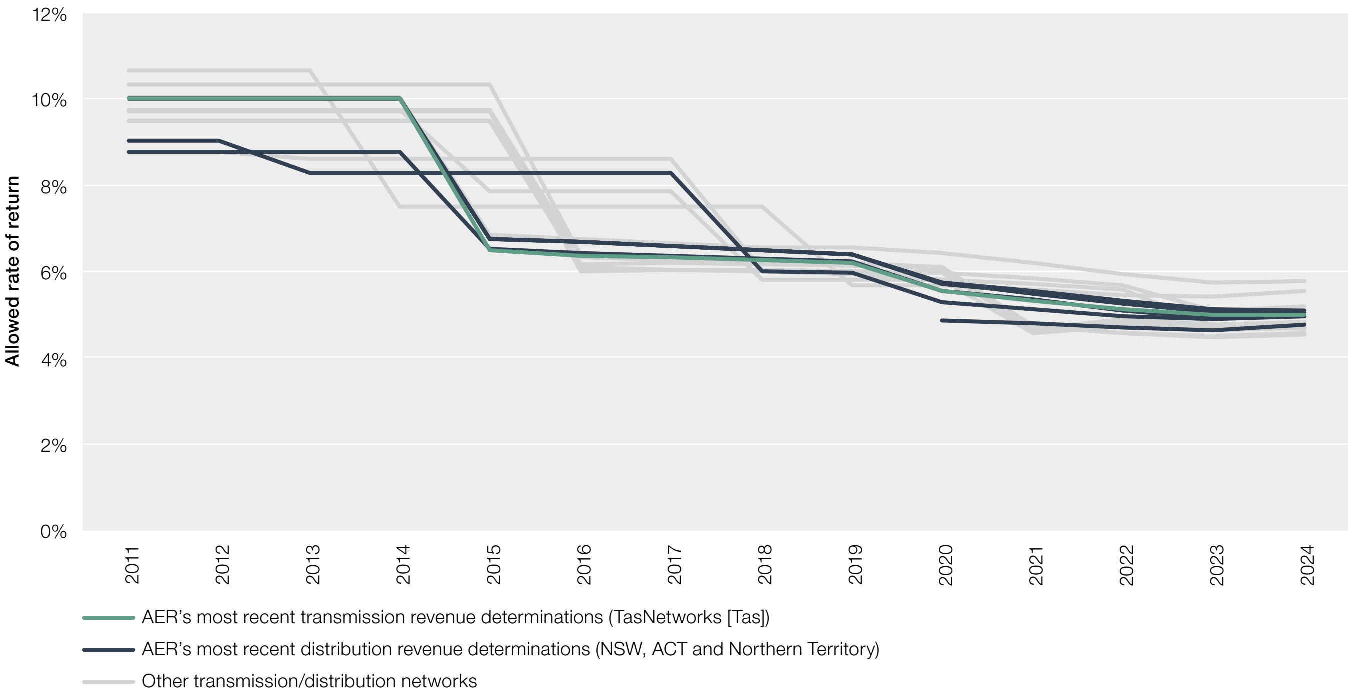
Because electricity networks are capital intensive, returns to investors typically make up around 45% (50% for transmission, 44% for distribution) of a network service provider's total revenue allowance. As such, a small change in the allowed rate of return can have a significant impact on both a network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

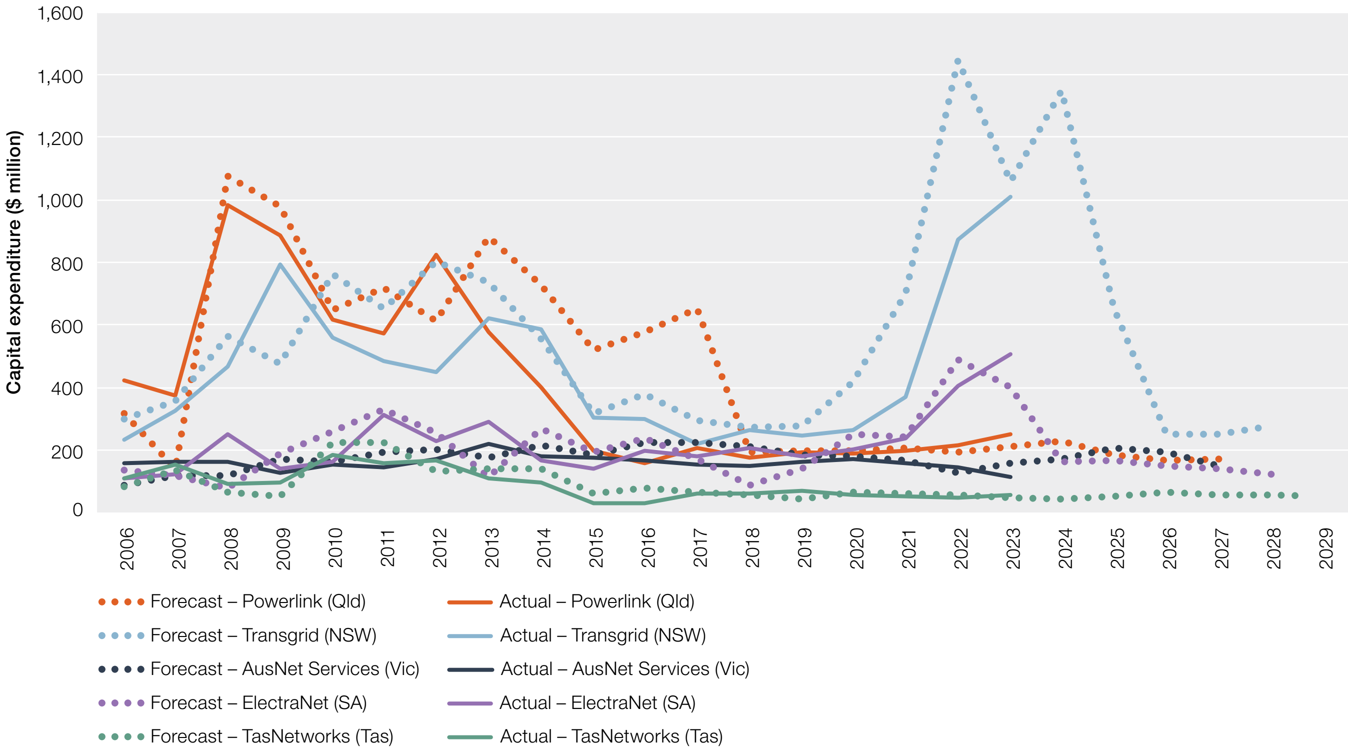
HumeLink, a proposed 500 kilovolt transmission line that will connect Wagga Wagga, Bannaby and Maragle and expand Transgrid's transmission network in NSW was identified as a staged actionable ISP project in AEMO's 2020[140] and 2022[141] ISPs and was confirmed to be actionable in AEMO's 2024 ISP.[142]

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.

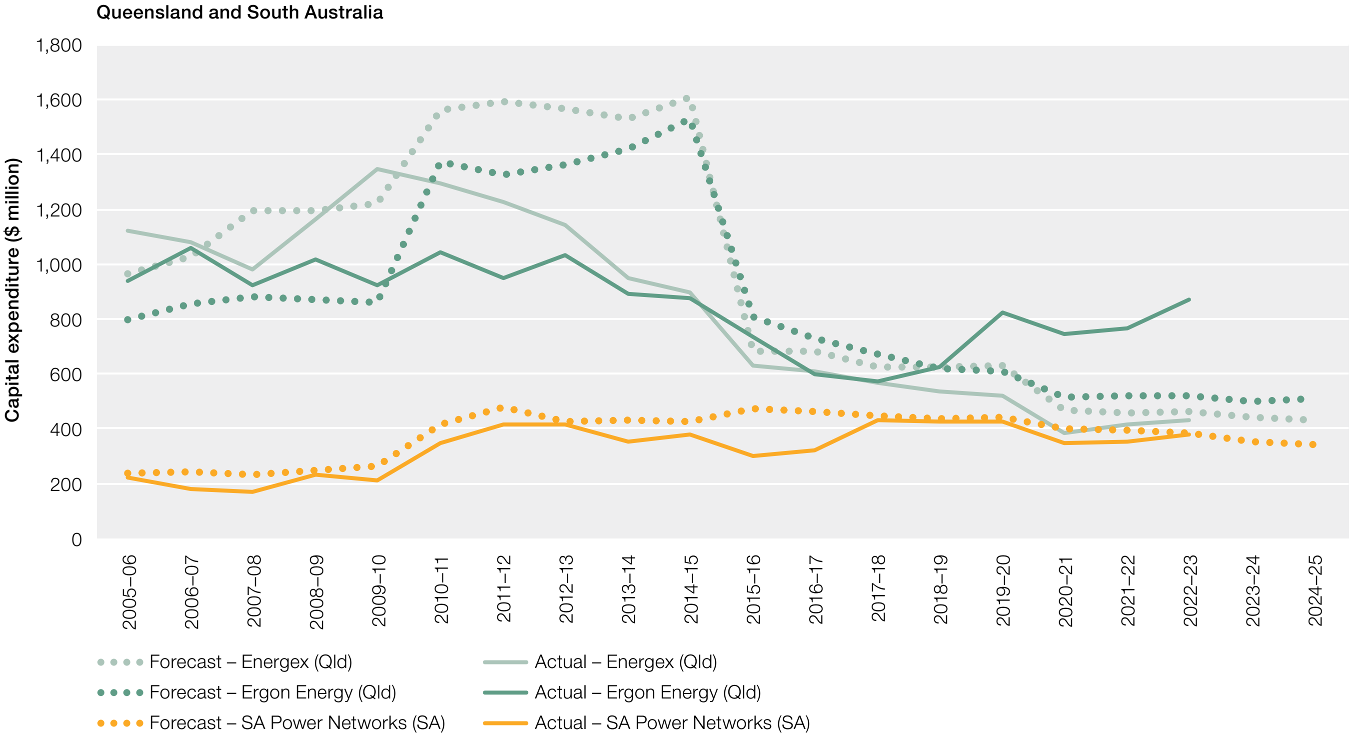
Source: AER modelling; annual reporting RIN responses.

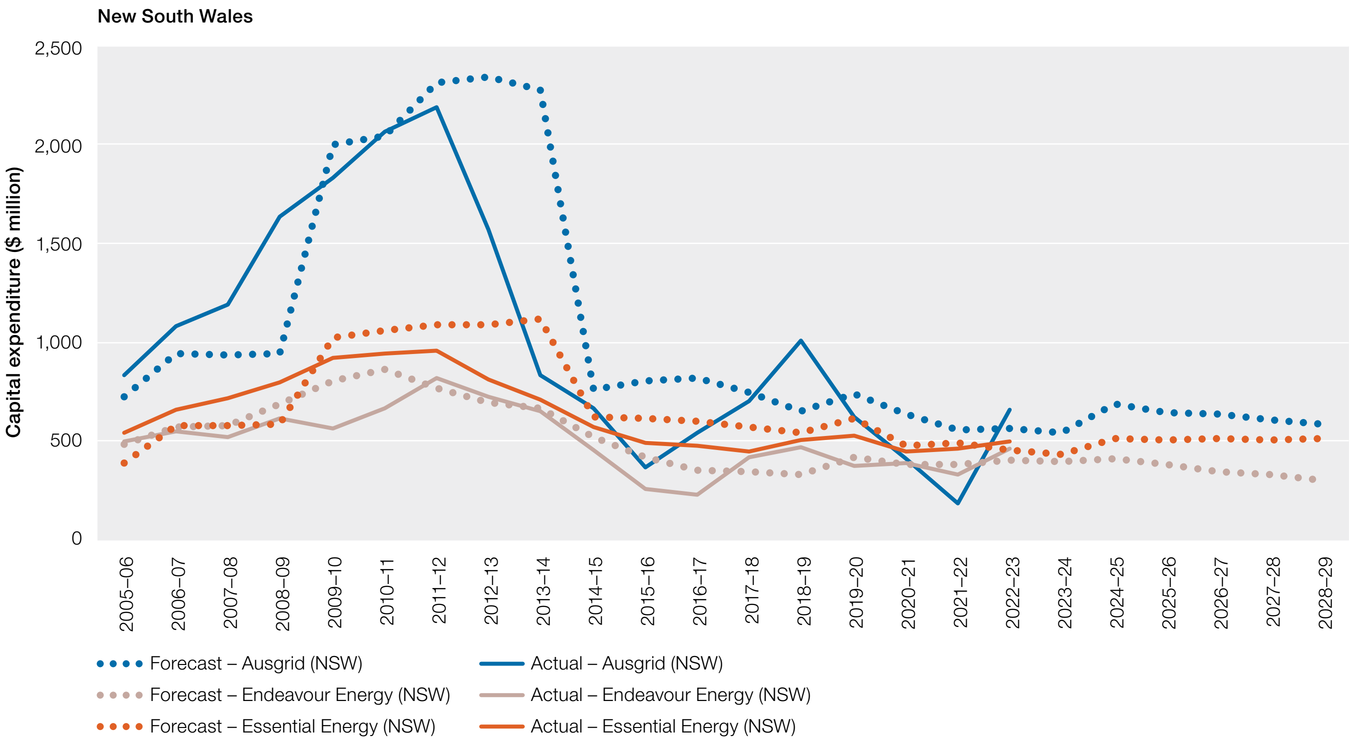
In 2023, Ergon Energy (Queensland) materially overspent against forecast capital expenditure for the fourth consecutive year. Ergon Energy submitted that overspends were driven by the need to address priority network safety programs, including defect rectifications and remediation works.[143]

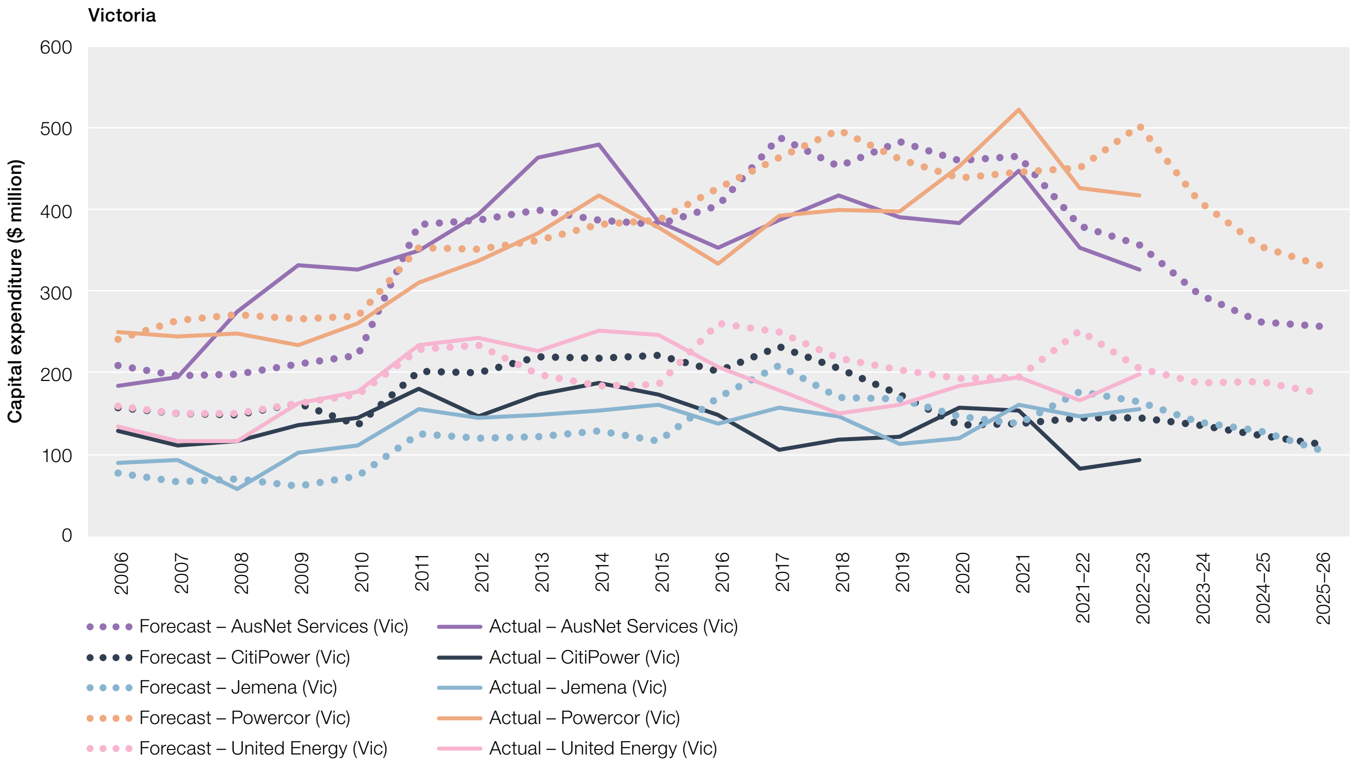
If the AER considers that over expenditure against the approved capital allowance is efficient, the excess spending, or a proportion thereof, may be added to the RAB (section 3.11). Conversely, if the AER considers over expenditure to be inefficient, the excess spending may not be added to the RAB. Instead,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

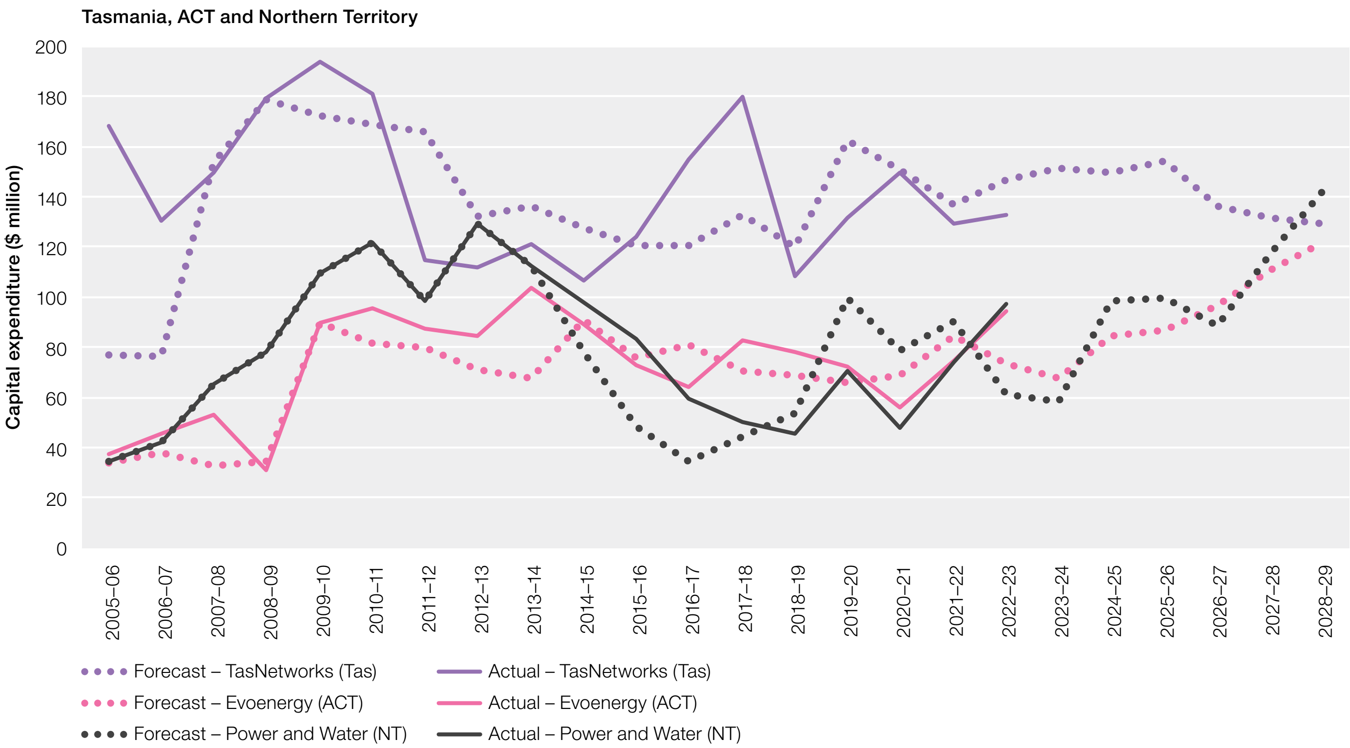
143 Ergon Energy, 2021-22 and 2022-23 Annual reporting RINs, 31 October 2022 and 2023.

Figure 3.19 Capital expenditure – electricity distribution networks









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).

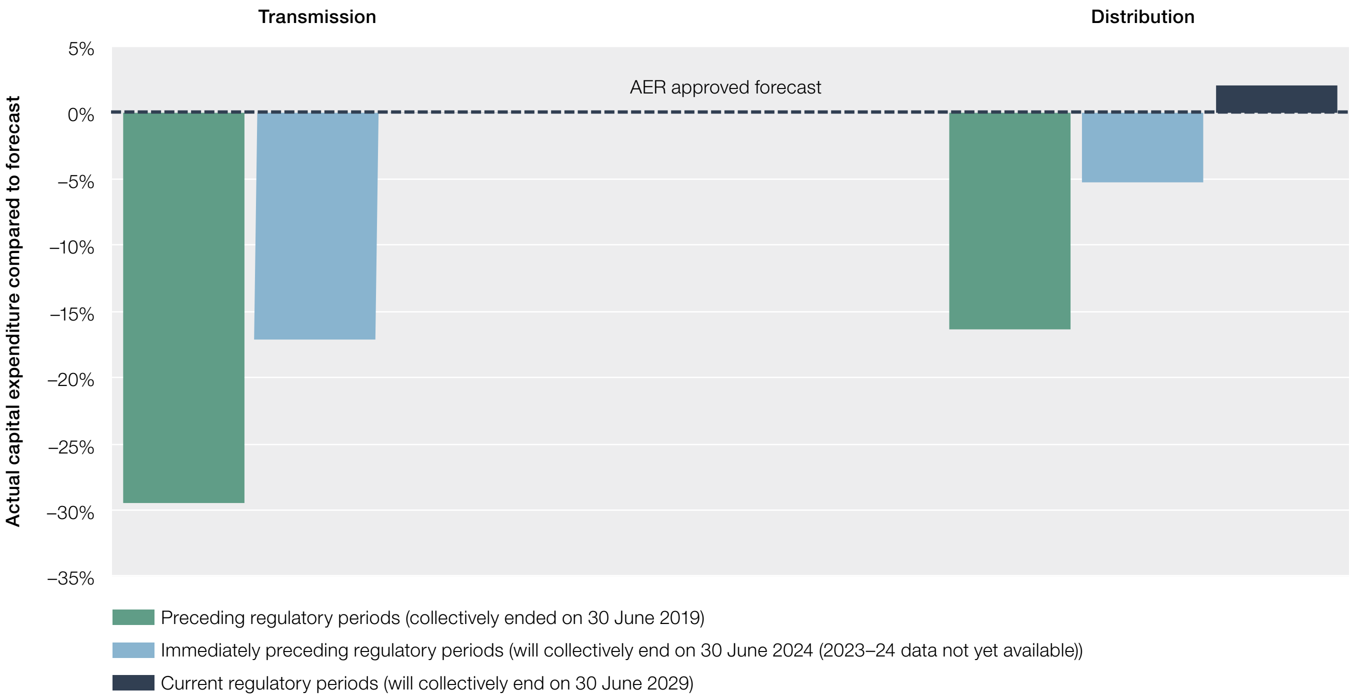
In the 4-year period from 2006 to 2009, network service providers invested $2.7 billion (10%) more on capital projects than was forecast. In 2006, governments and the AEMC changed the rules to incentivise greater investment to address concerns that network investment was not keeping pace with projected 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.

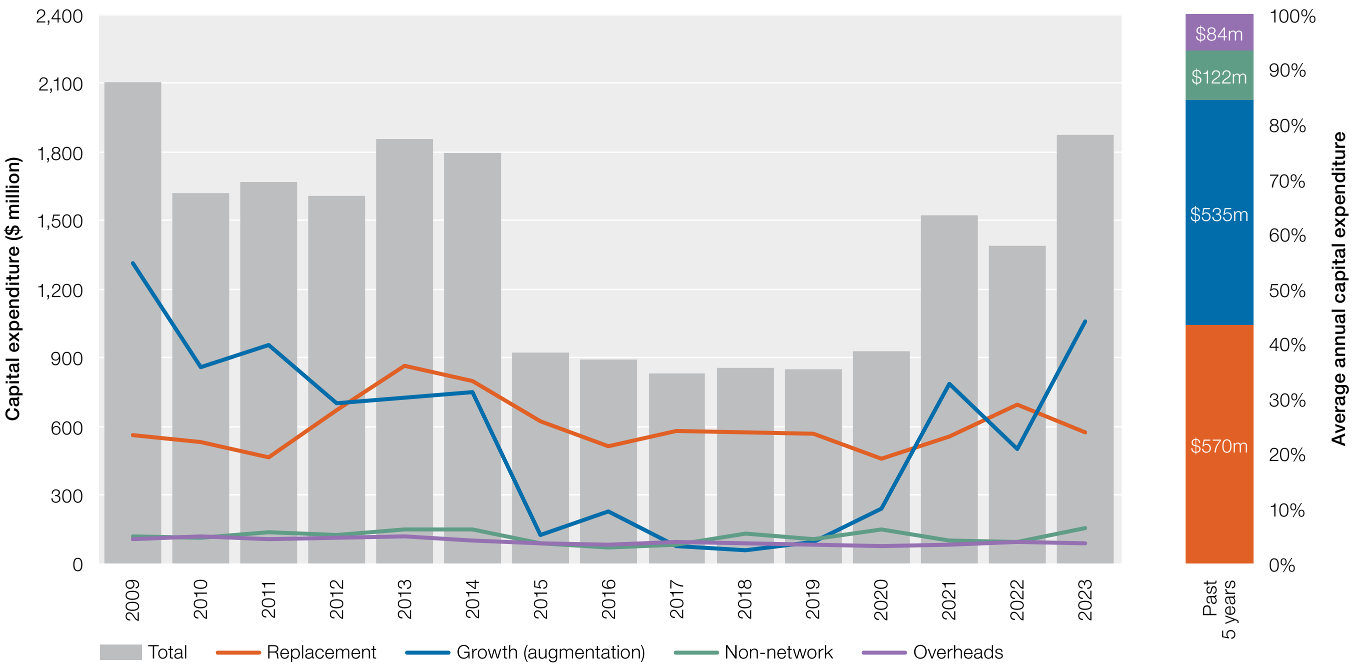
3.13.3 Changing composition of investment

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)



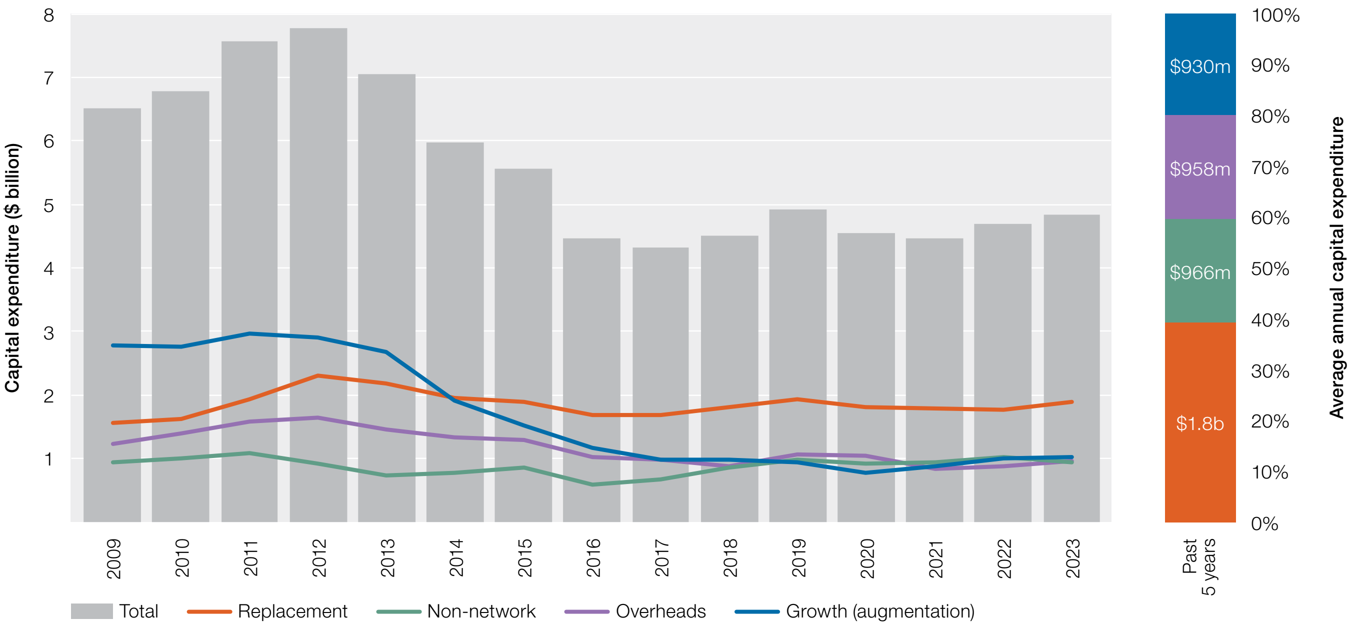
Note: All data are adjusted to June 2023 dollars. The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018). Augmentation of the Victorian transmission network is carried out by AEMO; hence, AusNet Services reports $0 expenditure for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

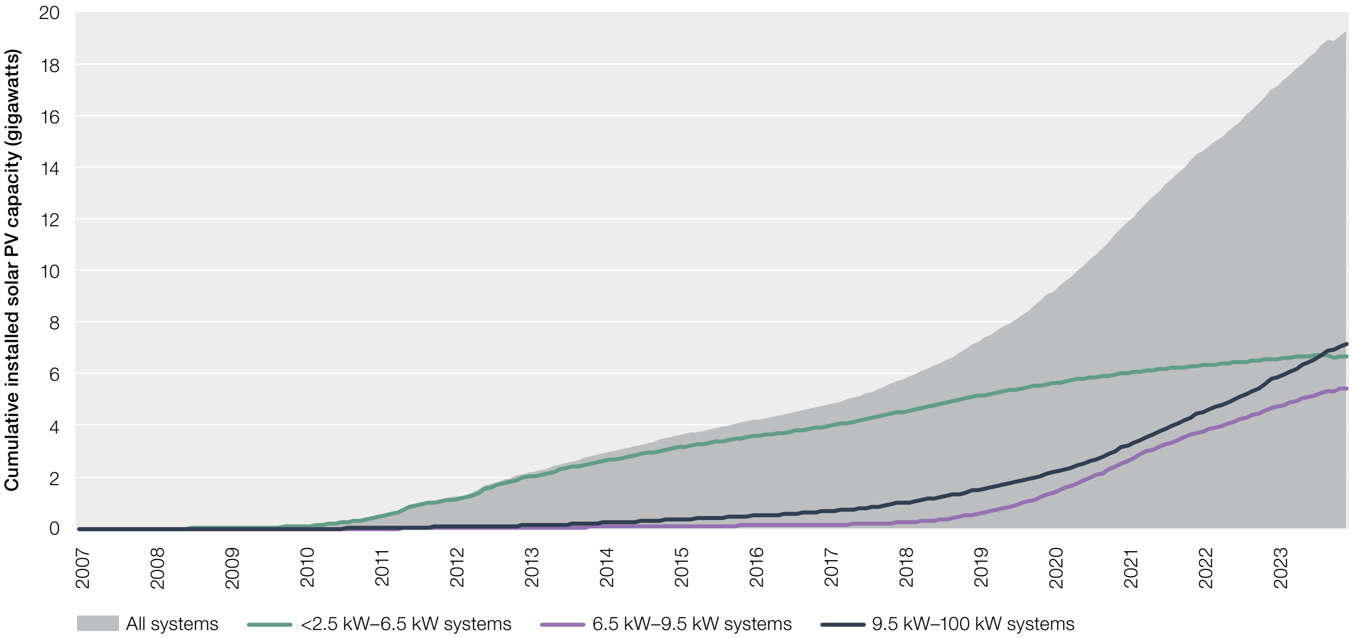
The uptake of rooftop solar photovoltaic (PV) systems has grown exponentially over the past decade. As a result of this rapid growth, integration of consumer energy resources such as solar PV, batteries and electric vehicles now presents a significant, emerging area of network expenditure.

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.

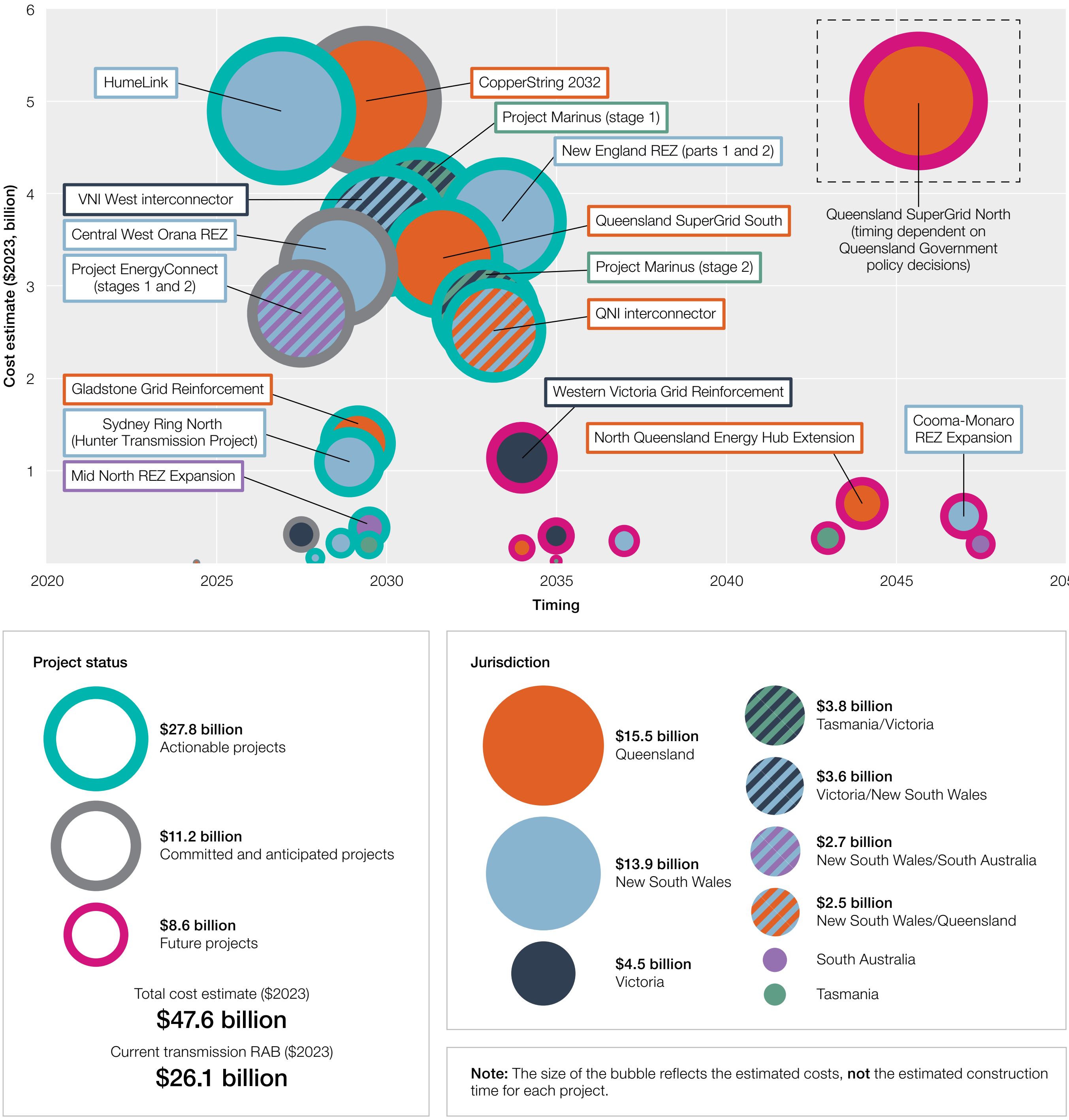
160 AEMO, 2024 Integrated System Plan, Australian Energy Market Operator, June 2024.

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



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]

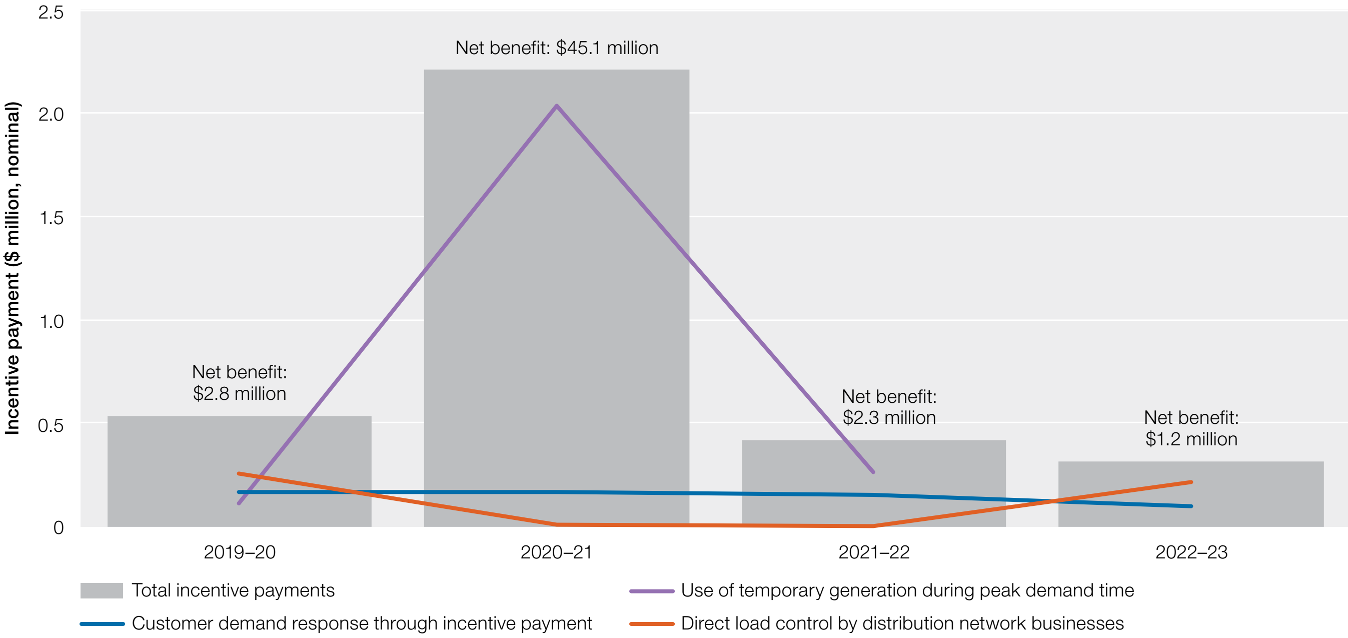
173 Eligible projects are set out in the AER's revenue determinations for each network service provider.

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.

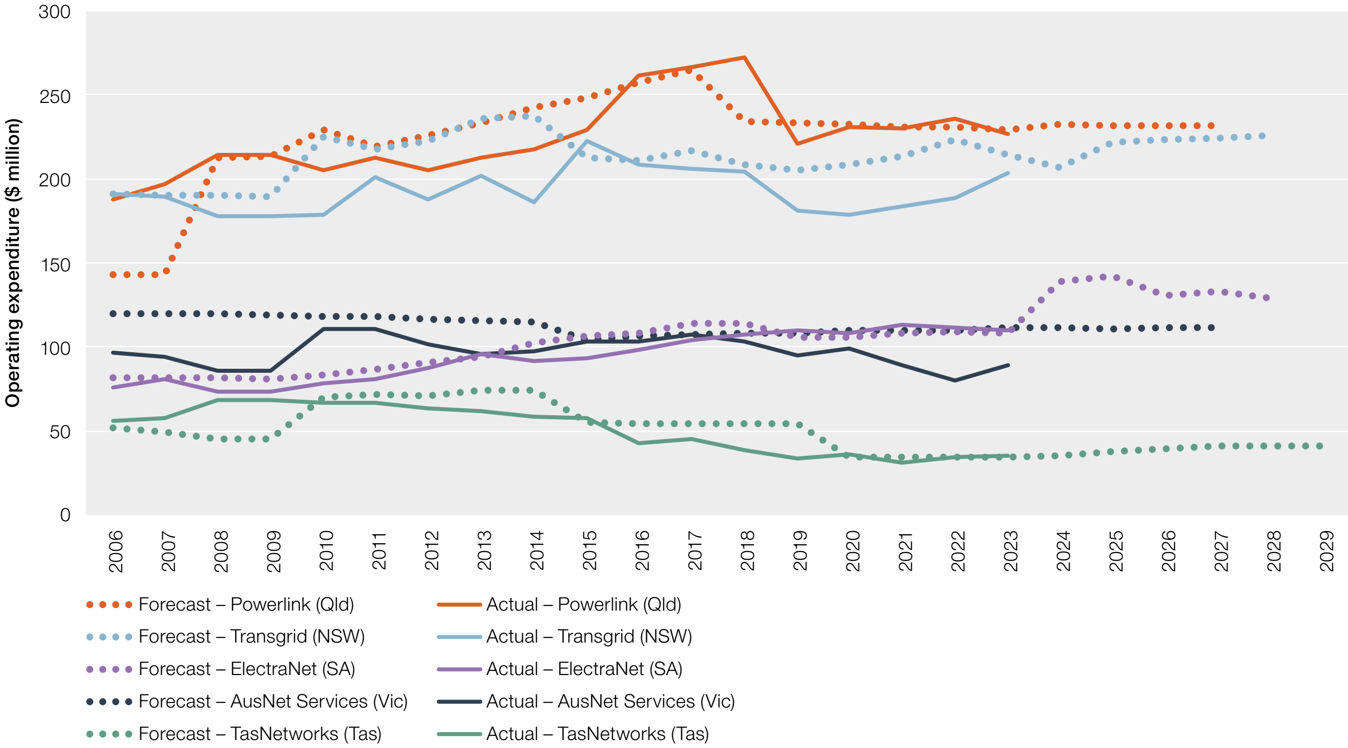
Table 3.8, Figure 3.26 and Figure 3.27 provide a summary of the operating expenditure outlaid in 2023 and how this compared with previous years' expenditure and forecasts.

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.

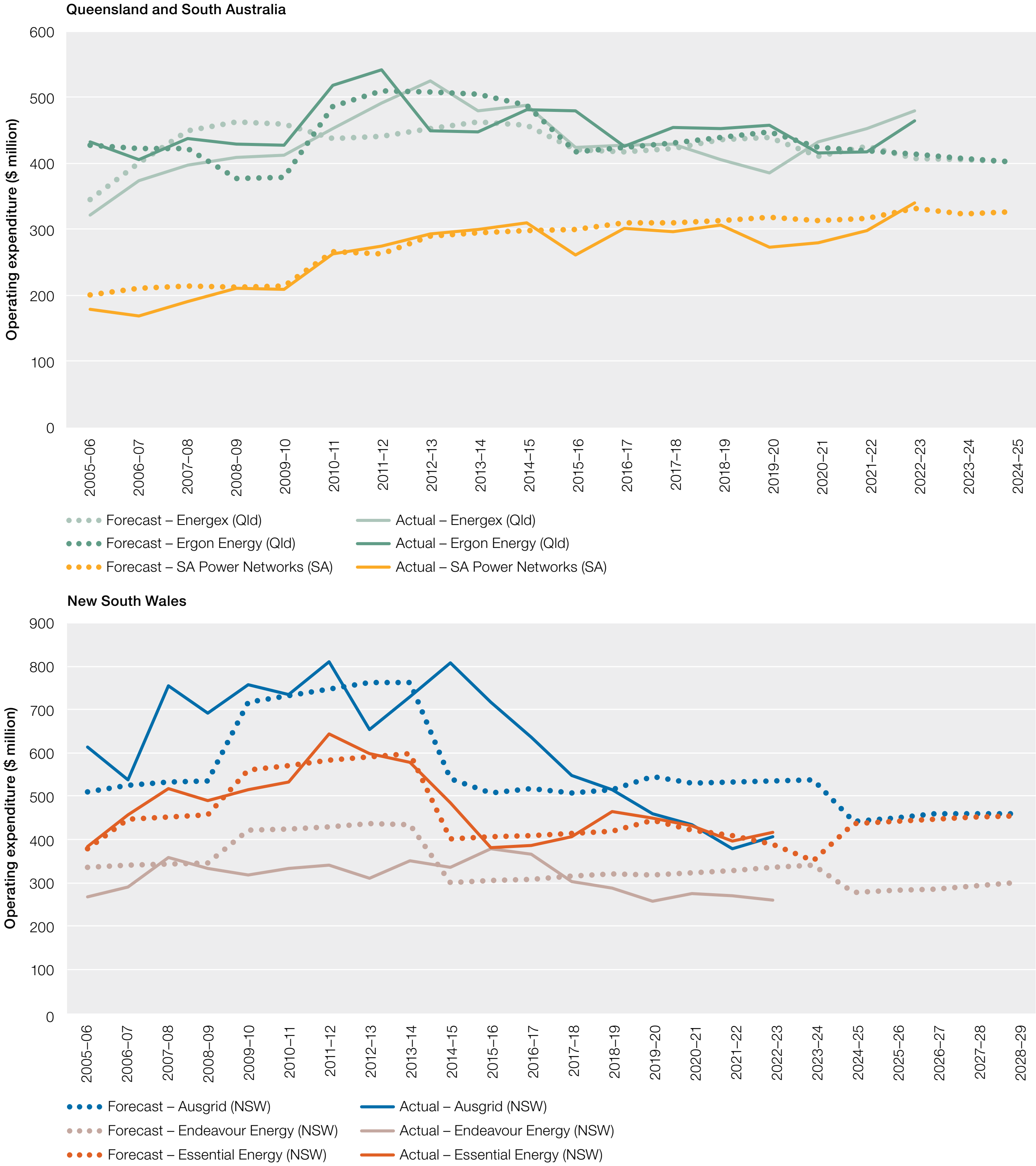
Figure 3.26 Operating expenditure – electricity transmission networks



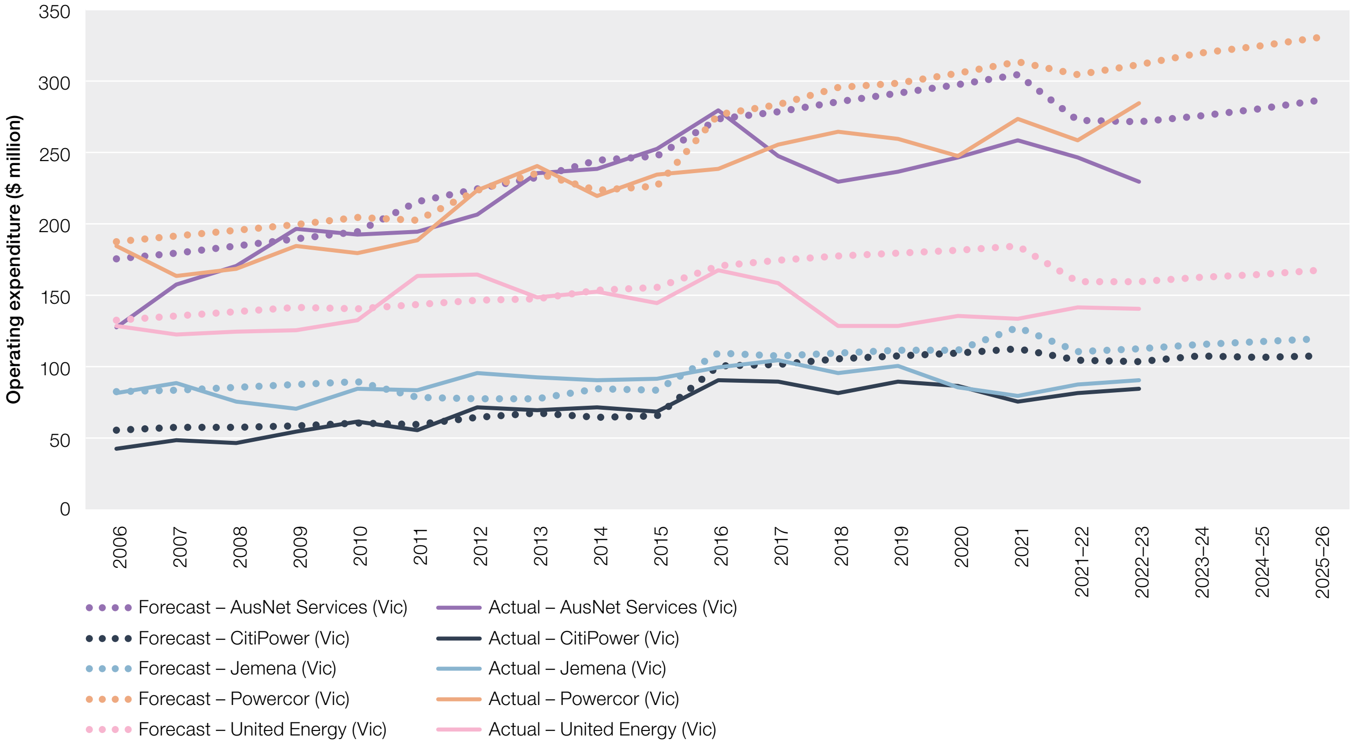
Note: All data are adjusted to June 2023 dollars. The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018). Assumptions are set out in the Figure 3.7 notes.

Source: AER modelling; annual reporting RIN responses.

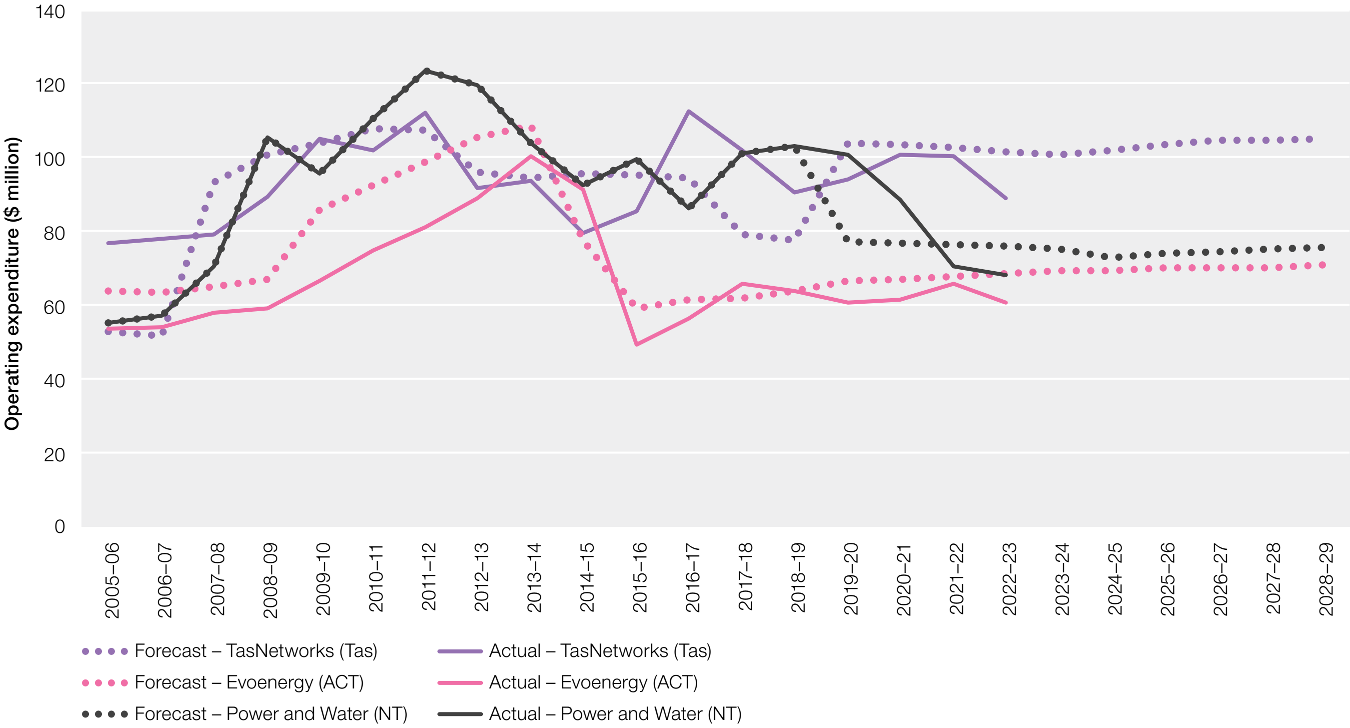
Figure 3.27 Operating expenditure – electricity distribution networks



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).

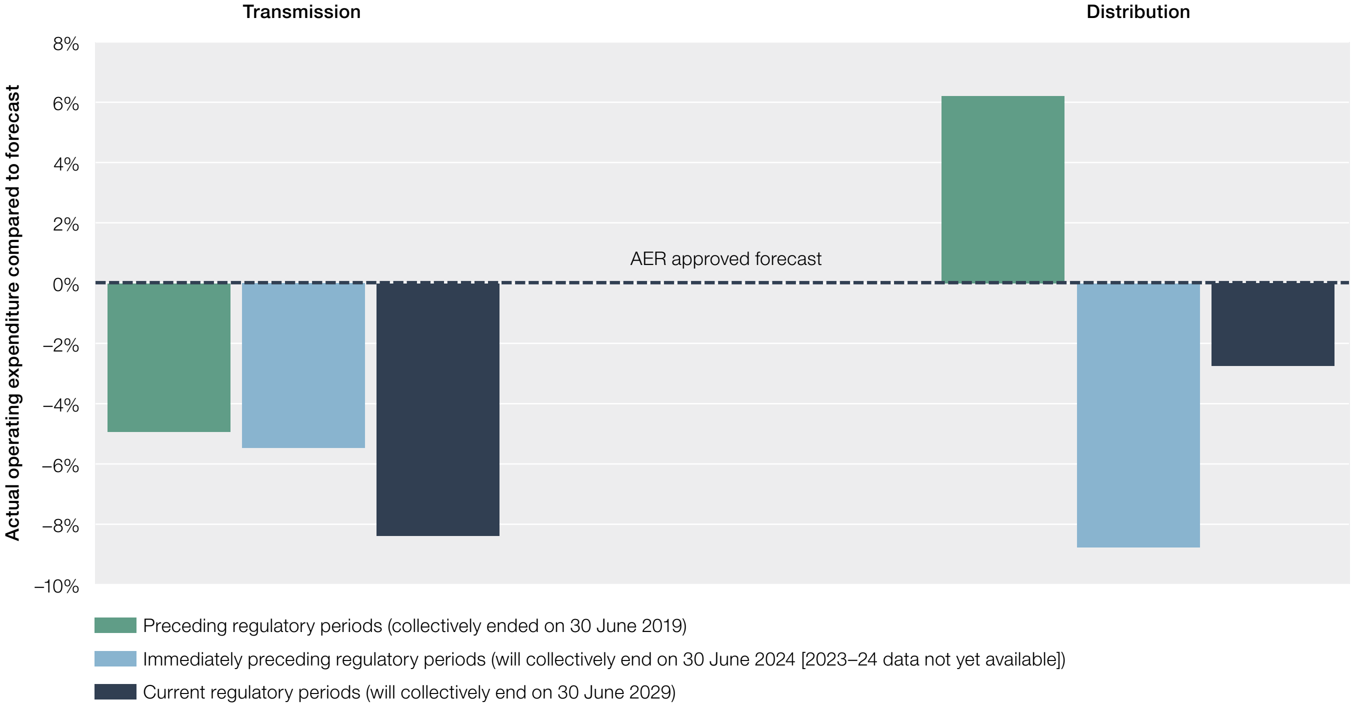
A number of network service providers implemented efficiencies in managing their operating expenditure from 2015, when the AER widened its use of benchmarking to identify operating inefficiencies in some networks.

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

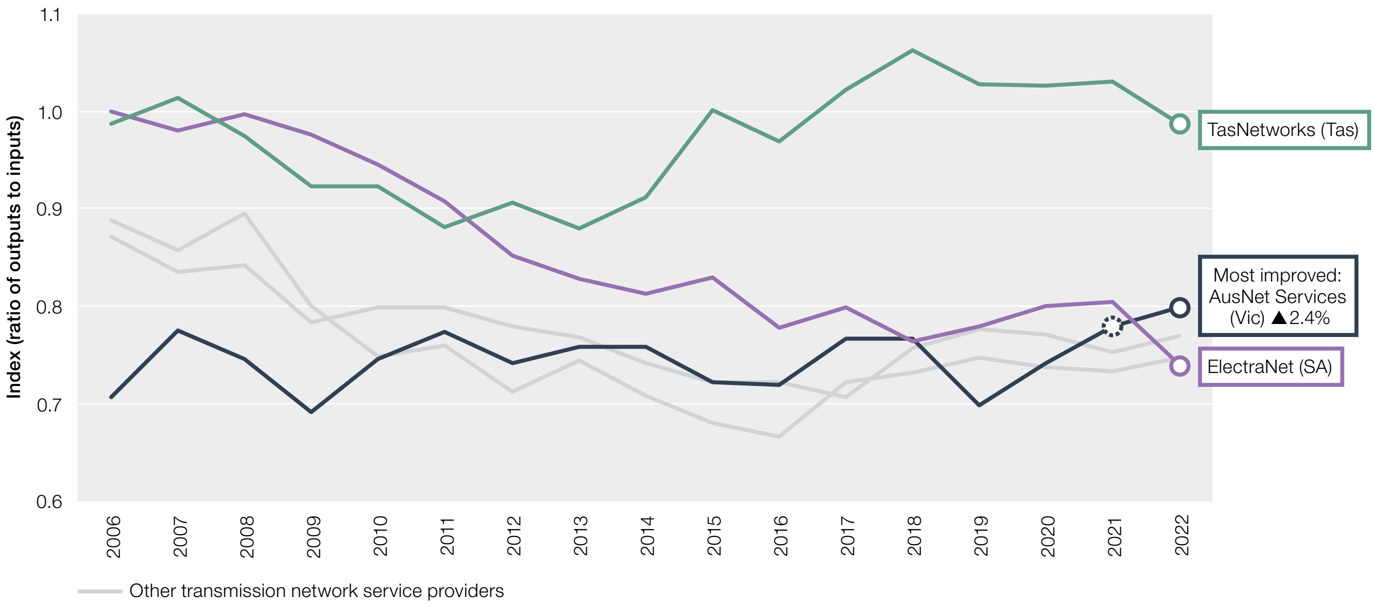
Productivity for transmission network service providers[182] decreased by 0.4% in 2022, primarily due to reductions in reliability[183] on the Powerlink (Queensland), ElectraNet (South Australia) and TasNetworks (Tasmania) networks.[184]

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

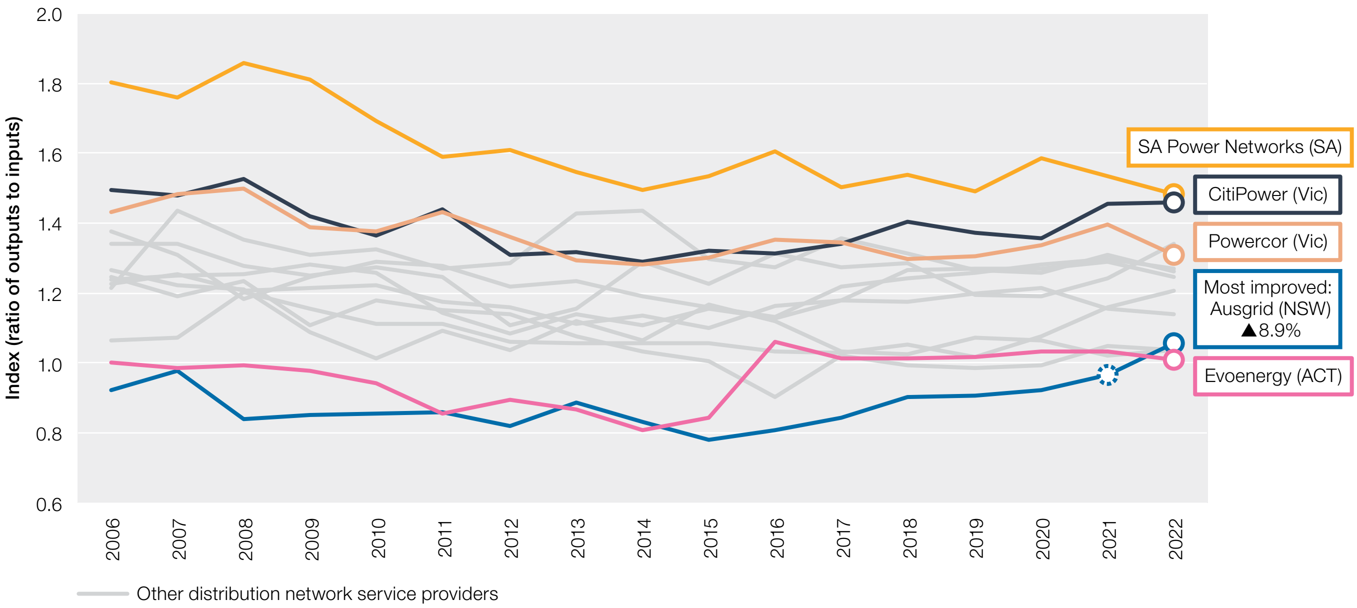
Productivity for distribution network service providers[186] decreased by 0.2% over 2022, primarily due to decreases in reliability caused by storm events impacting all but one network service provider. The decrease in productivity in 2022 marked only the second year since 2015 – the other year being 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

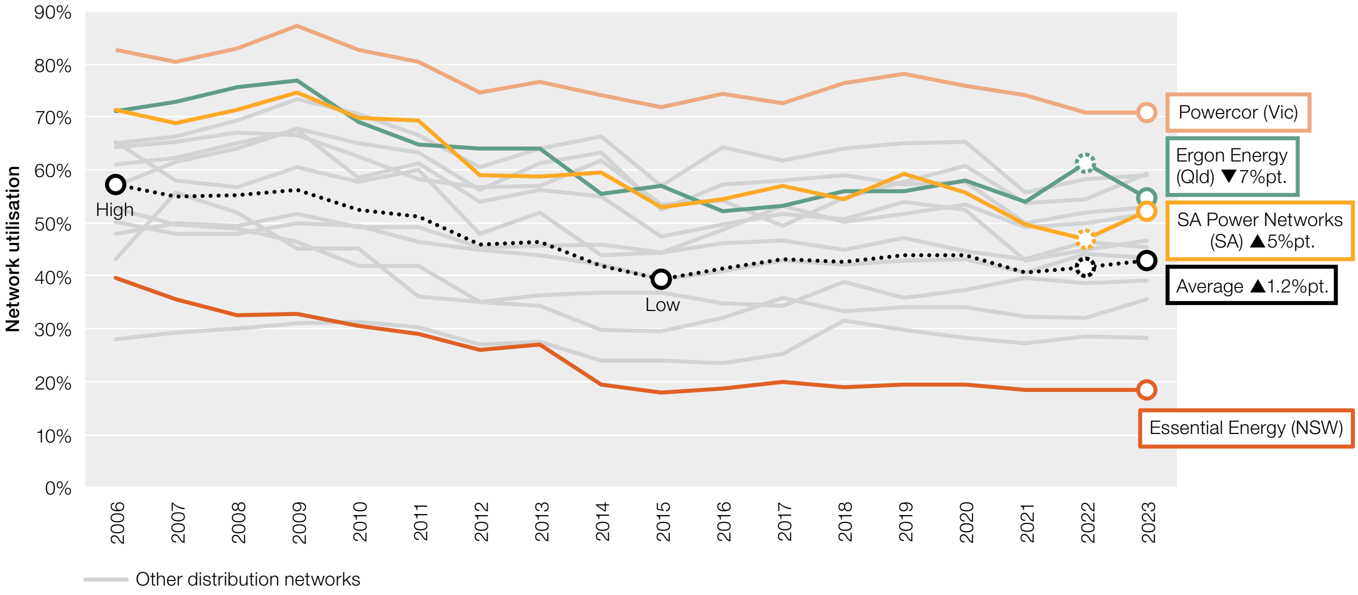
The network utilisation rate indicates the extent to which a network service provider's assets are being used to meet the needs of consumers at times of maximum demand. The utilisation rate can be improved through efficiencies such as using demand response (instead of new investment in assets) to meet 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.

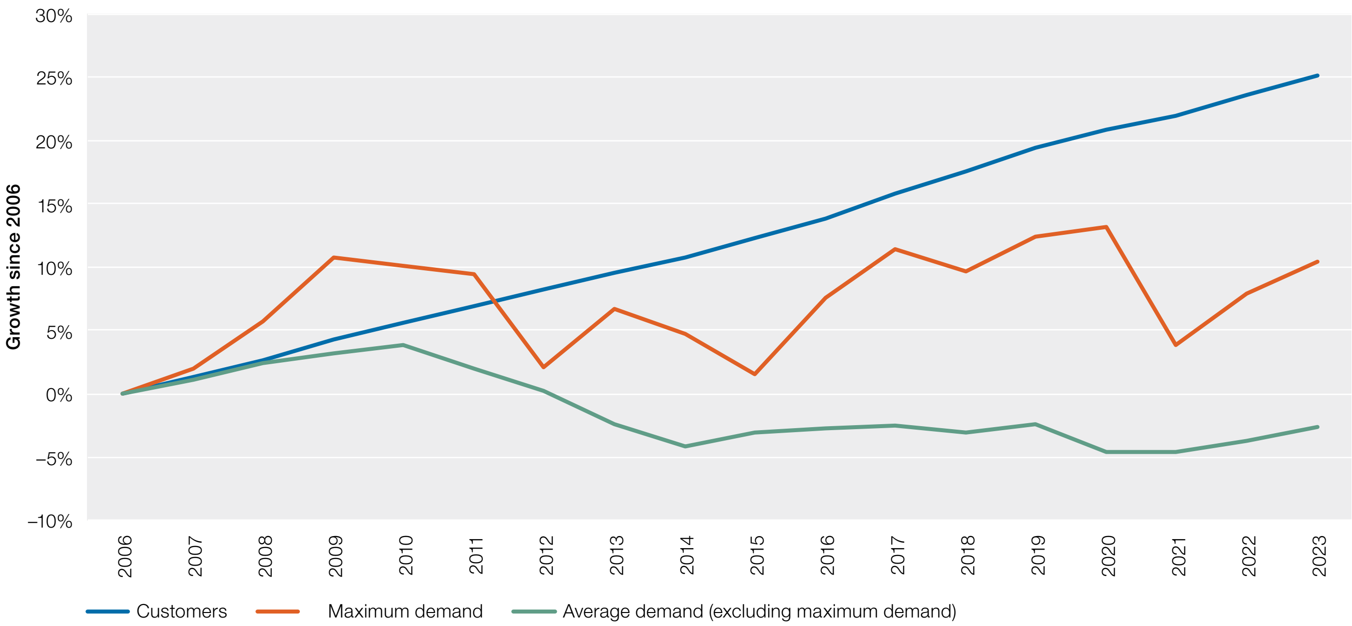
191 University of Technology Sydney, Empowering tomorrow's energy by redefining network utilisation, 8 February 2024, accessed 12 March 2024.

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



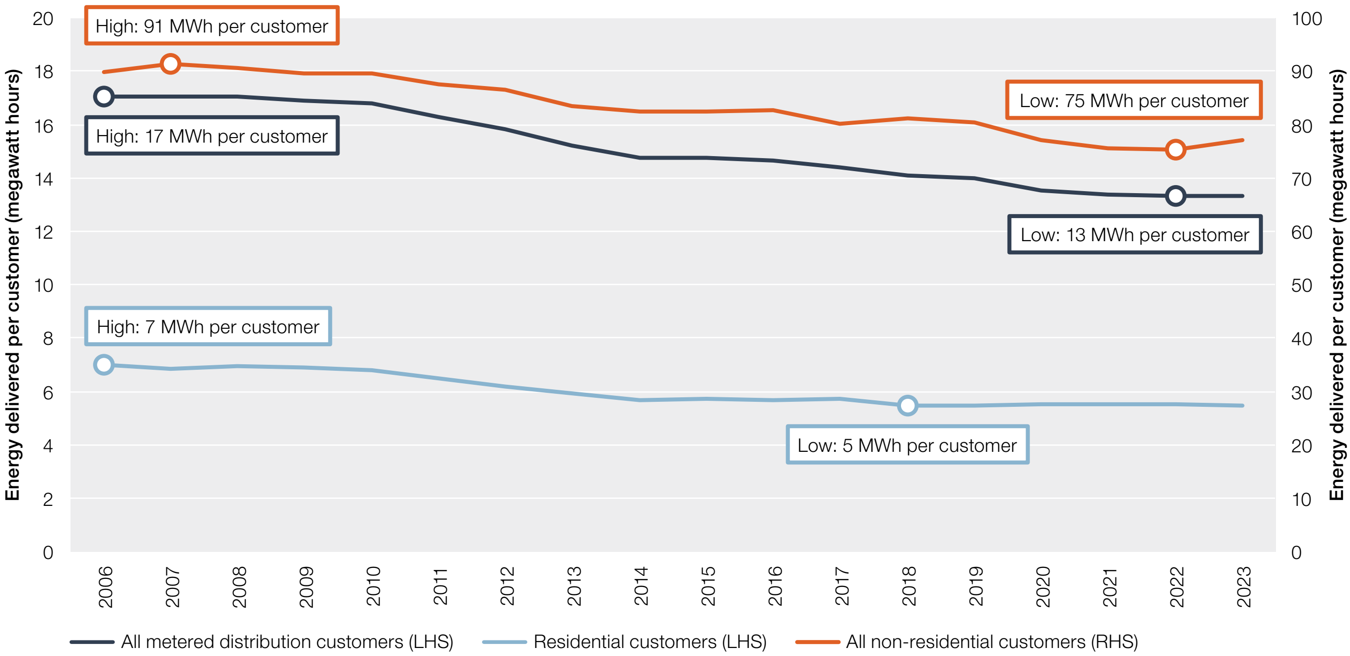
Note: Maximum demand is the network sum of non-coincident, summated raw system maximum demand (megawatts). Non-maximum demand is the total energy delivered (gigawatt hours) for the year, excluding the energy delivered at the time of maximum demand divided by hours in the year minus one. The data show 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]

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.

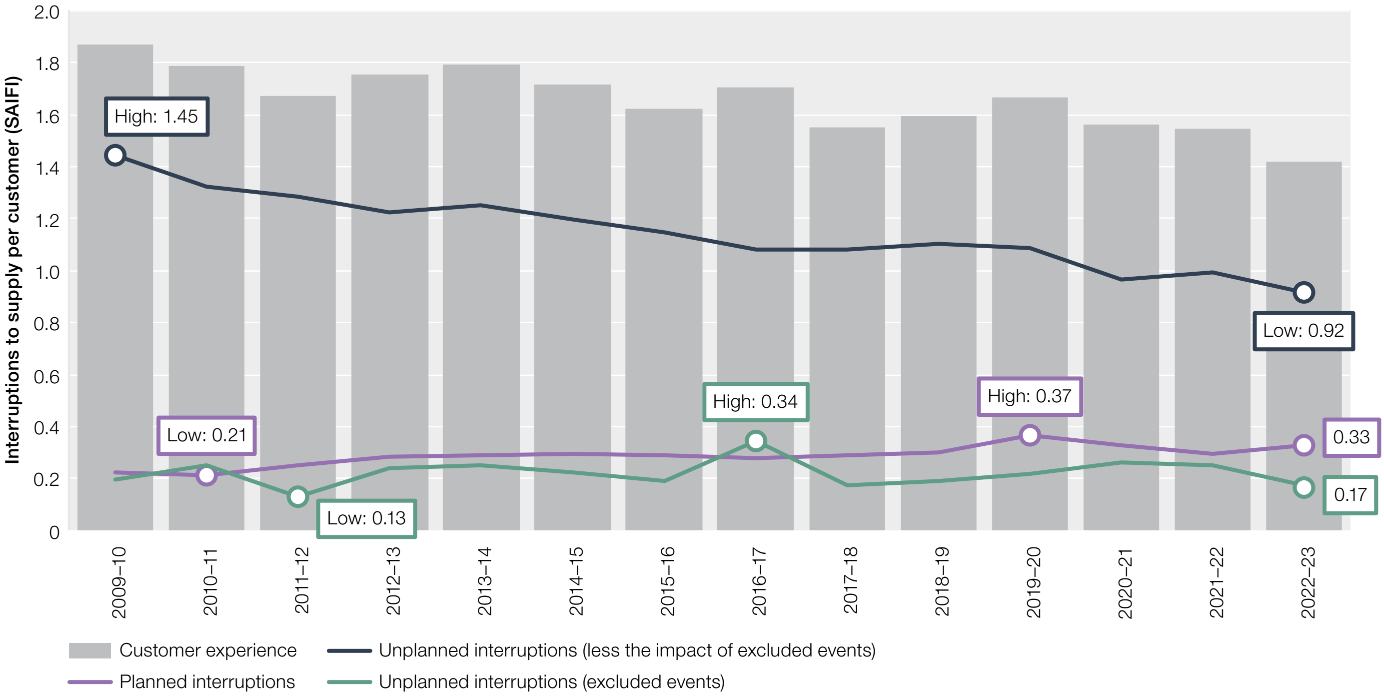
3.16.4 Distribution network reliability in 2022–23

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.

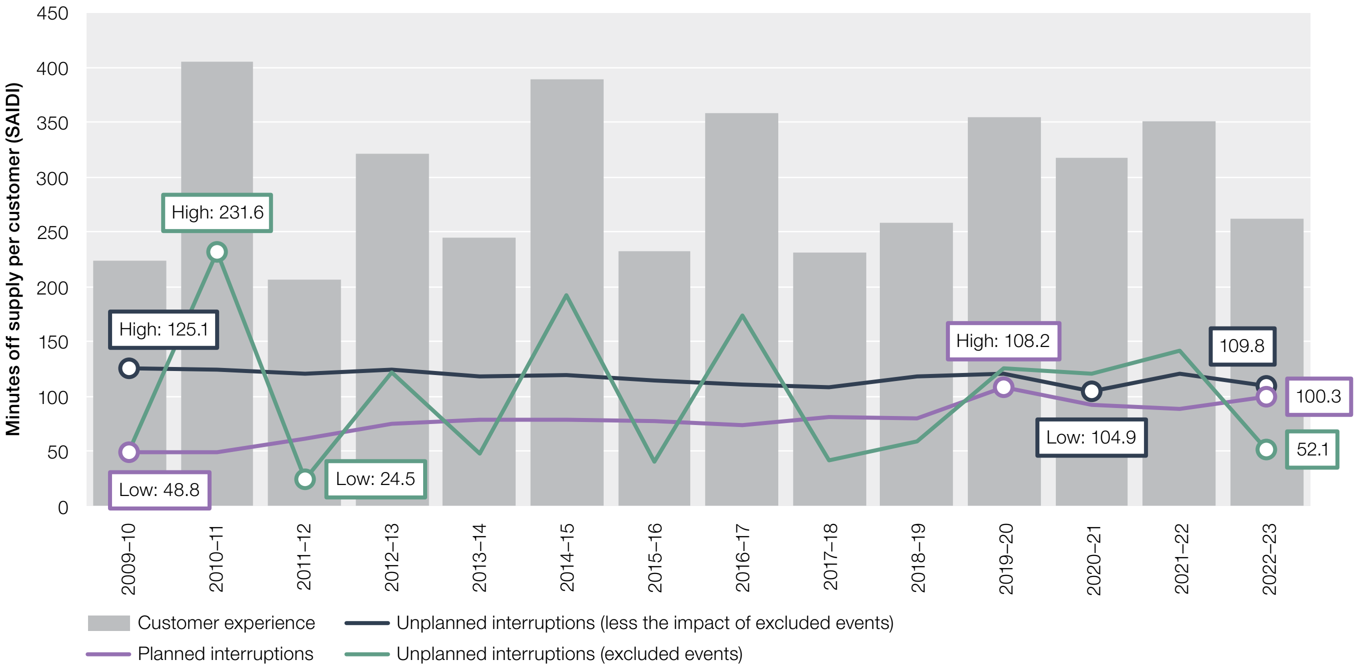
Source: AER modelling; category analysis regulatory information (RIN) responses.

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.

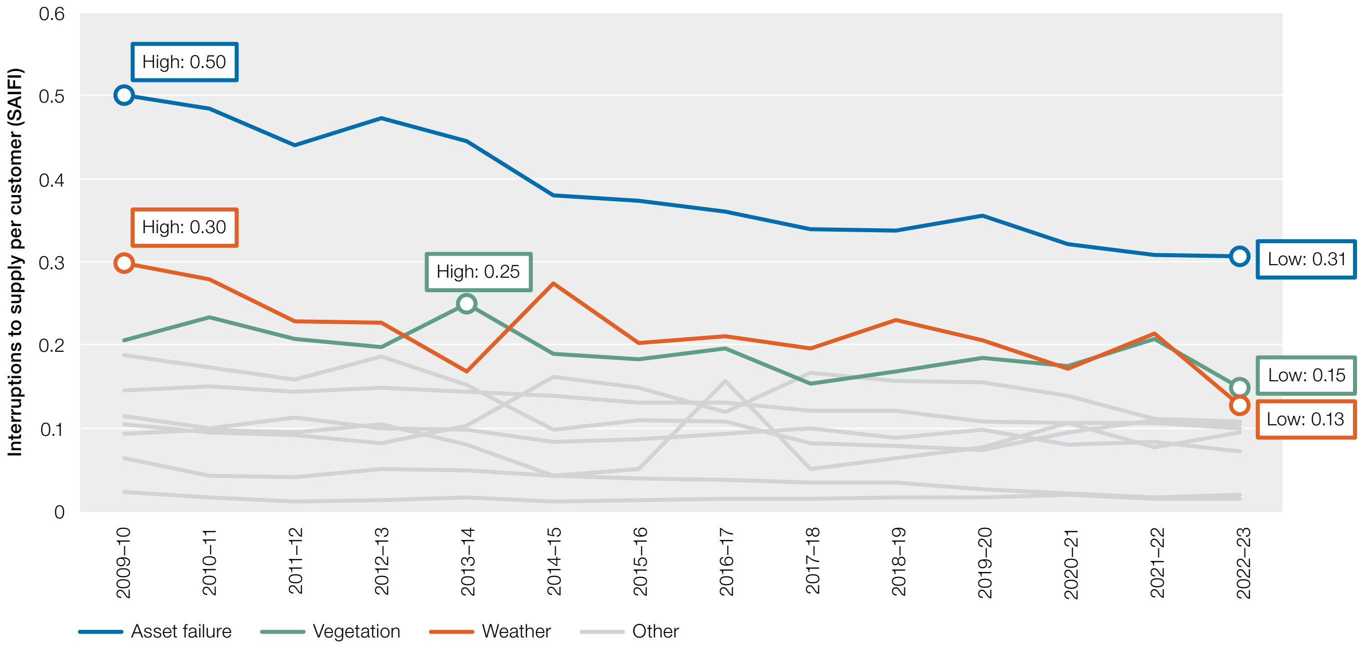
Source: AER modelling; category analysis regulatory information (RIN) responses.

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

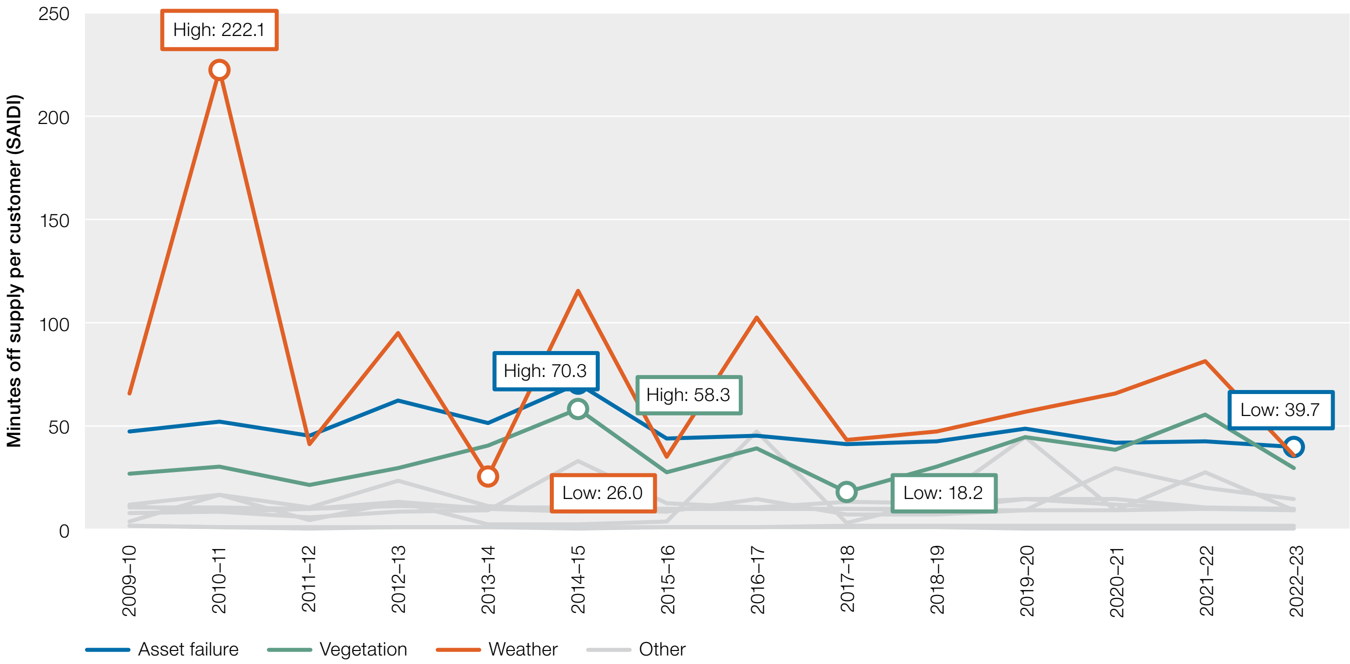


Note: SAIFI: system average interruption frequency index.
Data in Figure 3.36 shows interruptions to supply that lasted longer than 3 minutes. This is consistent with the definition of a sustained interruption in the AER's current service target performance incentive scheme (STPIS) (version 2.0, November 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.

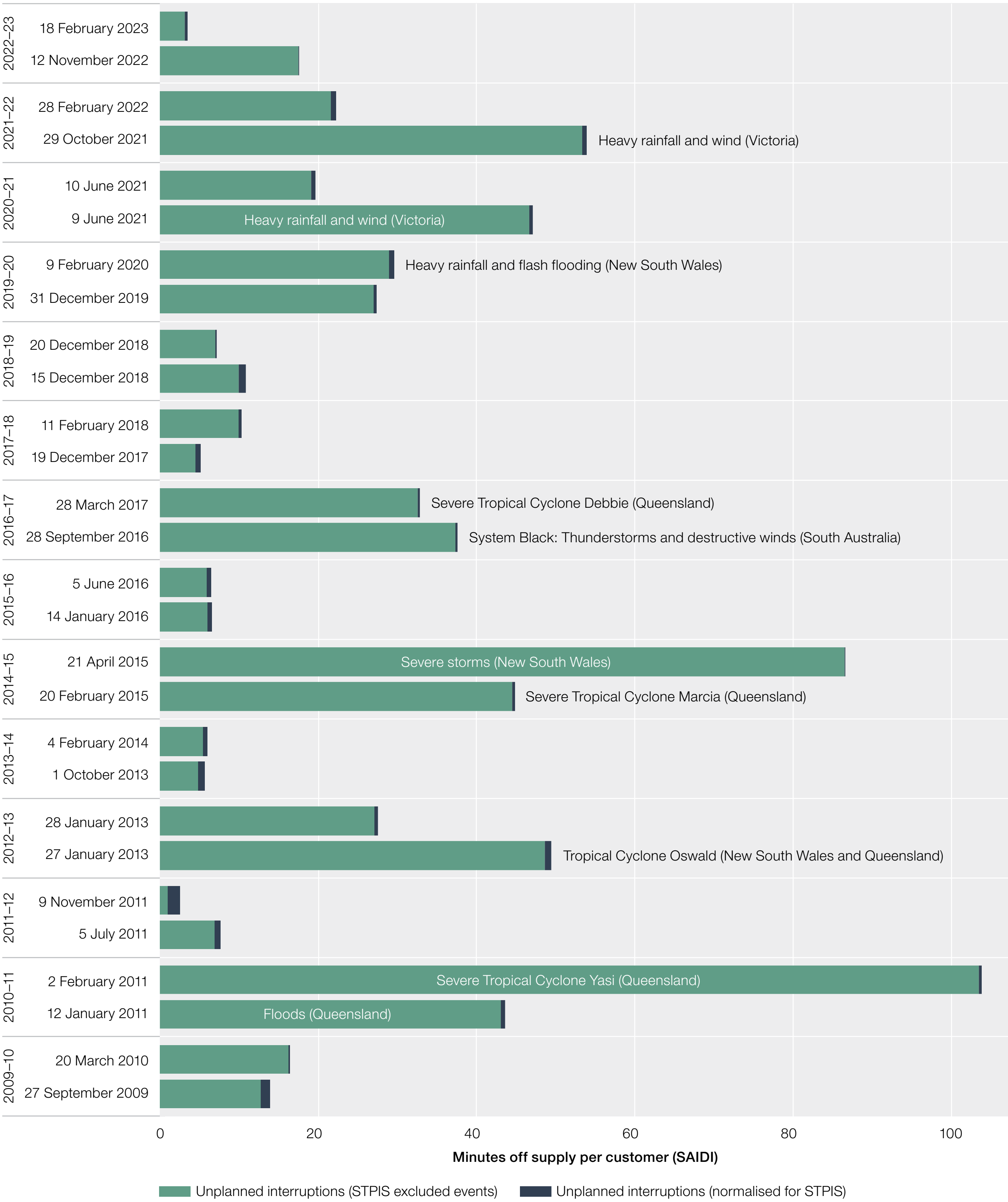
Due to the sheer size of the NEM, which operates on one of the world's longest interconnected power systems, the impact of a severe weather event in one region, or on a specific network within a region, can have little or no impact on neighbouring regions or networks.

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

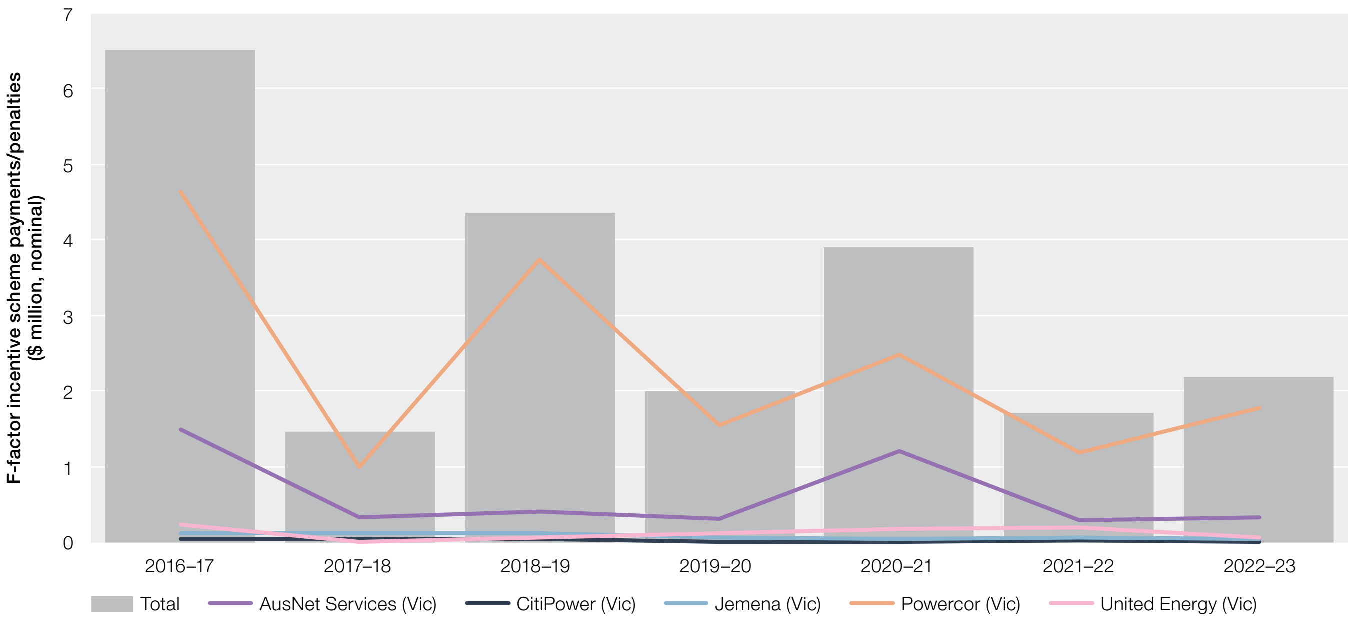
The AER administers the Victorian Government's f-factor scheme, an initiative that provides financial incentives to Victorian distribution service providers to minimise the number of fire starts within their networks in high fire danger zones and times.

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.