Electricity networks

Australia's electricity infrastructure consists of transmission and distribution networks, as well as smaller standalone regional systems. Together, these networks transport electricity from generators to residential and industrial customers. 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.

4.1 Snapshot

In 2023, the AER finalised revenue determinations for transmission network service providers Transgrid (NSW) and ElectraNet (South Australia), and the Murraylink interconnector (between South Australia and Victoria). The determinations set target revenue controls for those service providers through to 30 June 2028.

Across all transmission and distribution network service providers, over the 12-month period to 30 June 2022:

- Revenue earned for delivering core regulated services[1] was 0.1% lower than in the previous year, marking the eighth consecutive year of decreases in aggregated transmission and distribution network revenue (section 4.9).
- Expenditure on capital (investment) projects was the lowest since 2017 and 11% lower than in the previous year (section 4.13).
- Despite the decline in capital expenditure asset bases continued to grow, driven by investment on ElectraNet's (South Australia) and Transgrid's (NSW) transmission networks. Asset bases are forecast to grow at an accelerated rate as several major transmission projects progress (sections 4.11 and 4.13.6).
- Operating expenditure was at its lowest since 2007; 1.2% lower than in the previous year and 5% lower than the average operating expenditure over the previous 5 years (section 4.14.1).
- Customers experienced 3% more frequent and 15% longer unplanned interruptions to supply than in the previous year[2] — noting the previous year saw a record low frequency of interruptions. Major weather events had significant impact on the overall customer experience (section 4.16.4).

4.2 Electricity network characteristics

Transmission networks provide the link between generators located away from population centres and consumers by transporting high voltage electricity to major load centres. Electricity is injected from points along the transmission grid into the distribution networks that deliver electricity to residential homes and commercial and industrial premises. When electricity enters a distribution network, it is stepped down to lower voltages for safe delivery to consumers. Distribution networks consist of poles and wires, substations, transformers, switching equipment, and monitoring and signalling equipment.

Distribution 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 7).

Electricity networks traditionally provided a one-way delivery service to consumers. However, the role of electricity networks is evolving as technology continues to change how electricity is generated and used. Many small-scale generators such as rooftop solar systems are now embedded within distribution networks, resulting in two-way electricity flows along the networks. Energy users 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, its use is expected to continue to grow over the coming years.[3]

Alongside the major distribution networks, smaller localised 'embedded' networks distribute energy to sites such as apartment blocks, retirement villages, caravan parks and shopping centres. Electricity is delivered from the distribution network to a single connection point at these sites, then sold by the embedded network operator to tenants or residents. While consumers within embedded networks may still have the option to buy electricity from an authorised energy retailer, they may have difficulty doing so because of the way the network has been wired or because energy retailers may not want to sell to a consumer inside an embedded network. The revenues of embedded networks are not regulated.

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

2 After removing the impact of interruptions to supply deemed to be beyond the control of the network service providers.

3 AEMO, Current inputs, assumptions and scenarios, Australian Energy Market Operator, 28 July 2023.

4.3 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 are linked by cross-border interconnectors. Three interconnectors (Queensland–NSW, Heywood, and Victoria to NSW) are owned by the state governments and 3 interconnectors (Directlink, Murraylink and Basslink) are privately owned (Figure 4.2). The transmission network also directly supplies energy to large industrial customers, such as rail companies, mines and mineral processing facilities.

The transmission grid connects with 13 distribution networks.[4] Consumers in Queensland, NSW and Victoria are supplied 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 serviced by single distribution service providers operating within each jurisdiction (Figure 4.1 and Figure 4.3).

The Northern Territory has 3 separate distribution networks – the Darwin–Katherine, Alice Springs and Tennant Creek systems – all owned by Power and Water Corporation. The 3 networks are classified as a single distribution network for regulatory purposes but do not connect to each other or the NEM.[5] The AER regulates all major network service providers in the NEM, other than the Basslink interconnector linking Victoria and Tasmania.[6] It also regulates the Northern Territory's distribution network.

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

- Project EnergyConnect – a new 330 kilovolt (kV) double-circuit interconnector between South Australia and NSW
- incremental upgrades to the transfer capacities of the existing Victoria to NSW (VNI Minor) and Queensland–NSW (QNI Minor) interconnectors (section 4.13.6).

The combined value of the regulatory asset bases (RABs) for the electricity networks regulated by the AER is around $105.8 billion.[7] This comprises 7 transmission networks valued at $23.1 billion and 14 distribution networks valued at $82.7 billion. In total, the networks operate more than 800,000 kilometres of lines and deliver electricity to more than 10.8 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.[8]

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

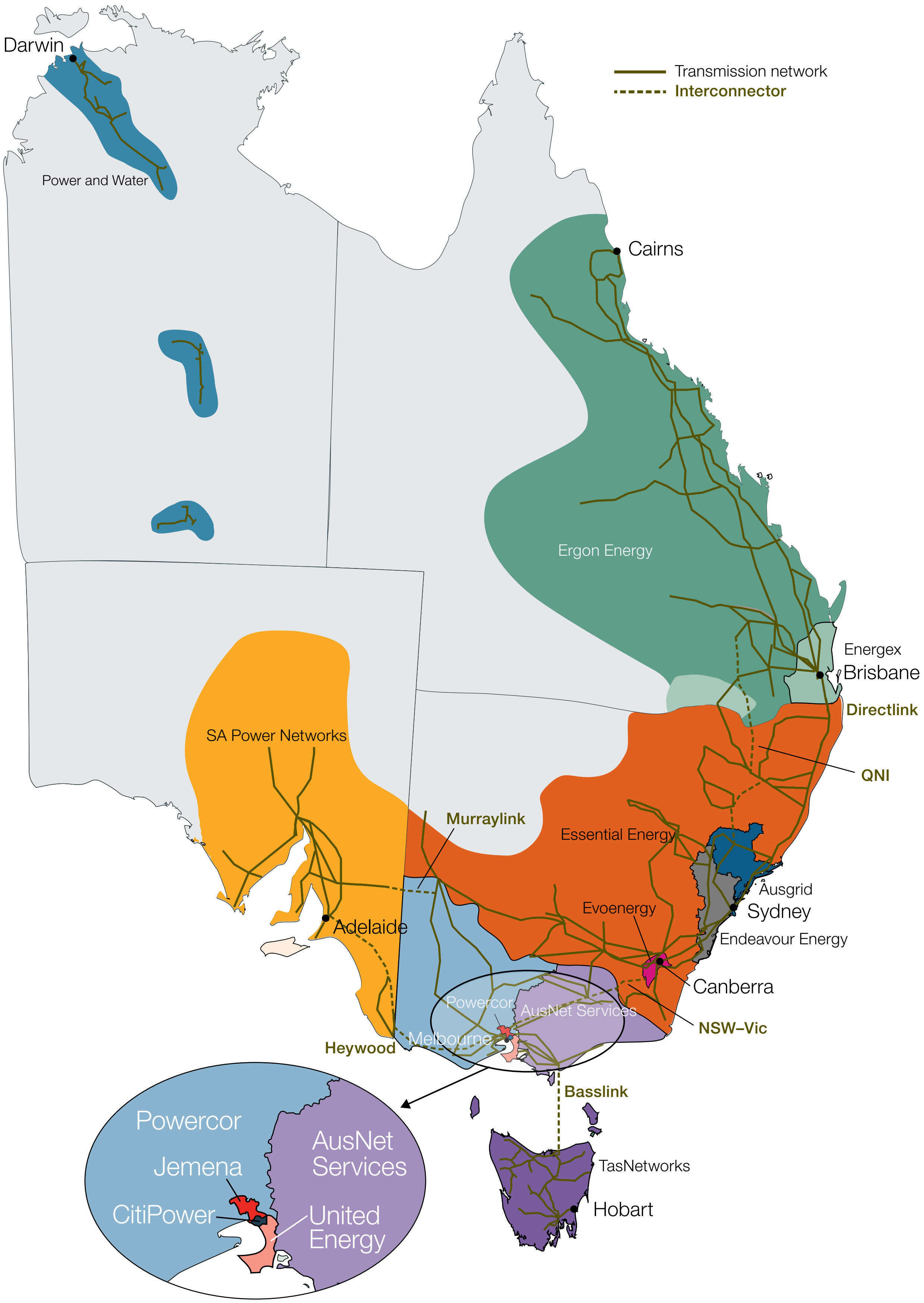
5 For this reason, any text or charts within this chapter that refer to 'whole of NEM' do not include Power and Water (NT).

6 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.

7 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.

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

Figure 4.1 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 4.2 Electricity networks regulated by the AER – transmission

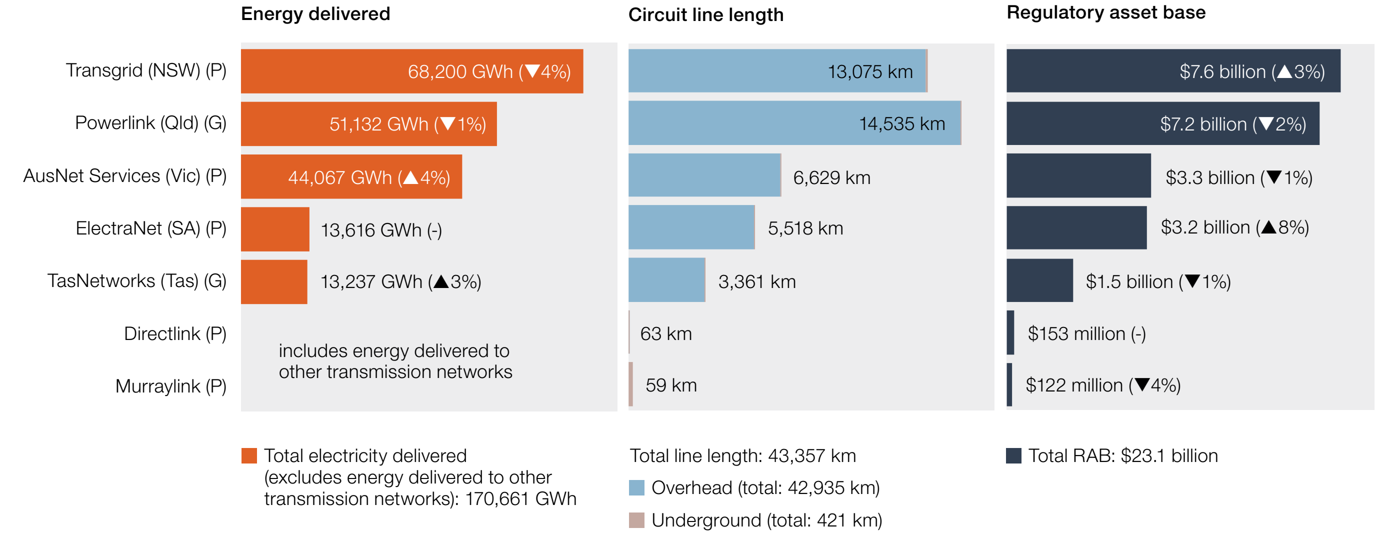
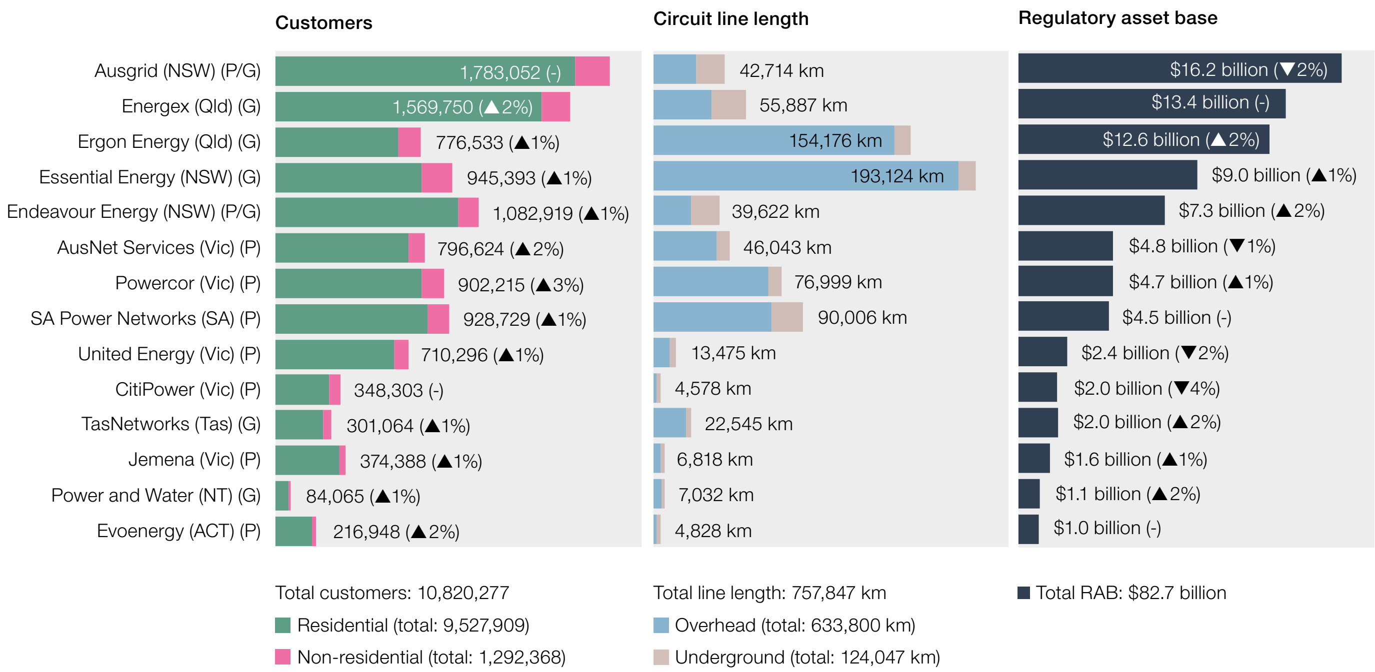


Figure 4.3 Electricity networks regulated by the AER – distribution



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 2022 dollars. Line length and regulatory asset base are as at 30 June 2022 (31 March 2022 for AusNet Services transmission). Electricity transmitted is for the year to 30 June 2022 (year to 31 March 2022 for AusNet Services). Customer numbers, line length and asset base are as at 30 June 2022 for the distribution networks. For regulatory purposes, Northern Territory transmission assets are treated as part of the distribution system. Energy delivered is a measure of total energy transported through the transmission networks. The information reported includes energy delivered to distribution networks, pumping stations and directly connected end users. Energy delivered to other transmission networks is included in the data for individual transmission network but has been excluded from the total.

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

4.4 Network ownership

Australia's electricity networks were originally government owned, but many 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 industry segments. 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 4.8.2). For example, Queensland's state-owned Ergon Energy provides both distribution and retail services in regions outside south-east Queensland.

4.5 How network prices are set

Electricity networks are capital intensive and require significant investment in order to build and operate the required 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 environment poses risks to consumers, given network charges currently make up around 40% of a residential electricity bill (Figure 7.2 in chapter 7). 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 efficiently and not overcharge consumers).

4.5.1 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 4.13.4).[9]

The National Electricity Law and the National Electricity Rules set the framework that the AER administers when regulating electricity networks. The regulatory objective of the National Electricity Law is 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 AER's regulatory toolkit to pursue this objective is wide ranging (Box 4.1), but one of its fundamental roles is to set the maximum revenue that a network service provider can earn from its customers for delivering electricity. 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. Network revenues are then capped at this level for the regulatory period, which is typically 5 years.[10]

9 ACCC and AER, ACCC and AER Corporate plan 2023–24, 31 August 2023, accessed 5 September 2023.

10 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.

Box 4.1 The AER's role in electricity network regulation

Every 5 years the AER sets a cap on the revenue that a network service provider can earn from its customers. 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 revenue limits
- 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
- publishing information on the performance of network service providers, including benchmarking and profitability analysis
- monitoring whether network service providers properly assess the merits of new investment proposals
- promoting and enforcing compliance with regulations, including connections policies and ring-fencing.

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 4.7)
- reviewing and refining our incentive schemes and guidelines to ensure they remain relevant and fit for purpose
- publishing information on network profitability
- reviewing how rates of return and taxation allowances are set for energy networks (section 4.12).

In November 2021, the AER was appointed as a regulator under the *Electricity Infrastructure Investment Act 2020* (NSW) (EII Act). The AER is now responsible for making revenue determinations for network operators authorised by the independent Consumer Trustee, or authorised or directed by the Minister, to undertake a network infrastructure project (including in a Renewable Energy Zone (REZ)). The AER is required to determine the prudent, efficient and reasonable capital costs for both contestably procured and non-contestable network infrastructure projects. Other key functions undertaken by the AER include:

- determining annual amounts to be recovered from each of the NSW distribution network service providers to provide for the functions under the EII Act
- approving a risk management framework developed by the Consumer Trustee to protect the interests of NSW electricity consumers in connection with the risks associated with long-term energy service agreements
- reviewing tender rules proposed by the Consumer Trustee for competitive tender processes for the procurement of long-term energy service agreements.

As part of the determination process, a network service provider submits a proposal to the AER setting out the amount of revenue it considers it will need to cover the costs of providing a safe and reliable supply of electricity. The AER assesses the proposal and forms an opinion on the reasonableness of the service provider's forecasts and the efficiency of its proposed expenditure. If the AER is not satisfied the 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.

In conducting its assessment of a network service provider's revenue proposal, the AER draws on a range of inputs, including expenditure forecasts, benchmarking and revealed costs from past expenditure. It engages closely with stakeholders from an early stage of the process, including before the network service provider lodges a formal proposal (section 4.7).

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. The AER does not determine the service provider's capital programs or projects.

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.[11]

4.5.2 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:

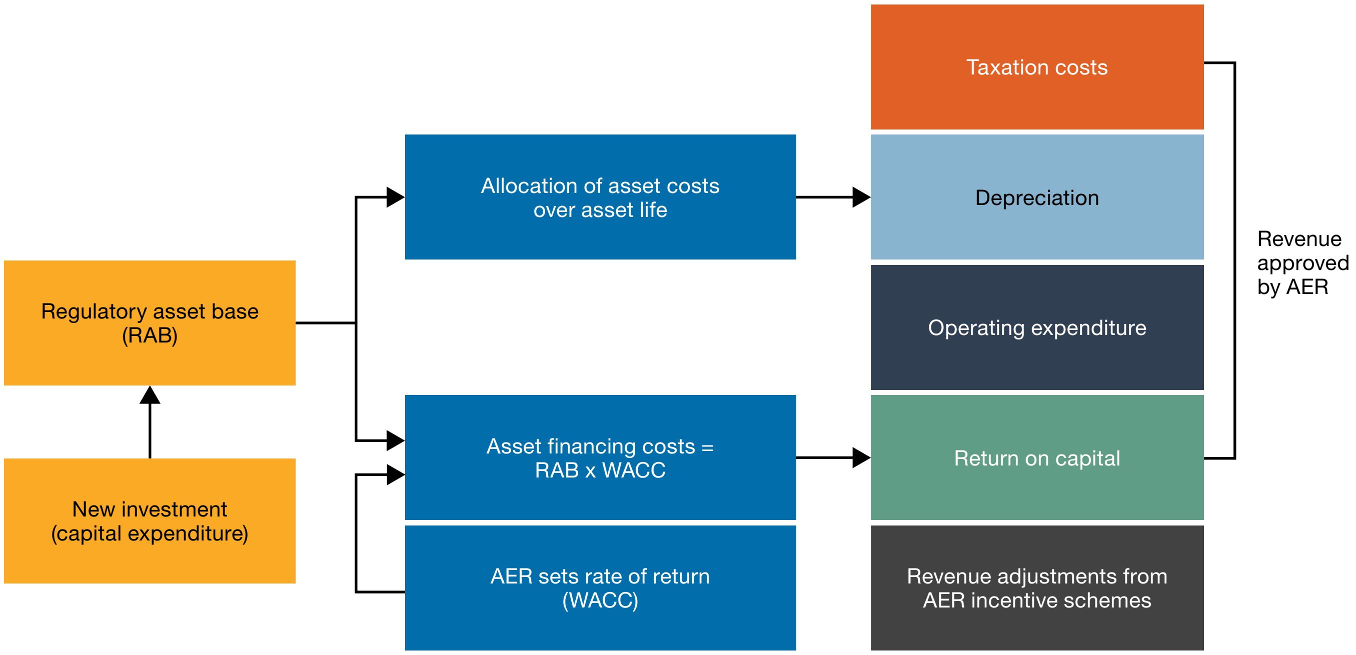
- a commercial return to investors that fund its assets and operations
- efficient operating and maintenance costs
- asset depreciation costs
- taxation costs.

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.

While network service providers are entitled to earn revenue to cover their efficient costs each year, this revenue does not include the full cost of investment in new assets made 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 4.4).

The regulatory asset base (RAB) includes the total remaining economic value of assets in a network, to be recovered through depreciation over time. 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 4.4 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.

11 AER, Guidelines, schemes, models & reviews, Australian Energy Regulator, accessed 15 December 2022.

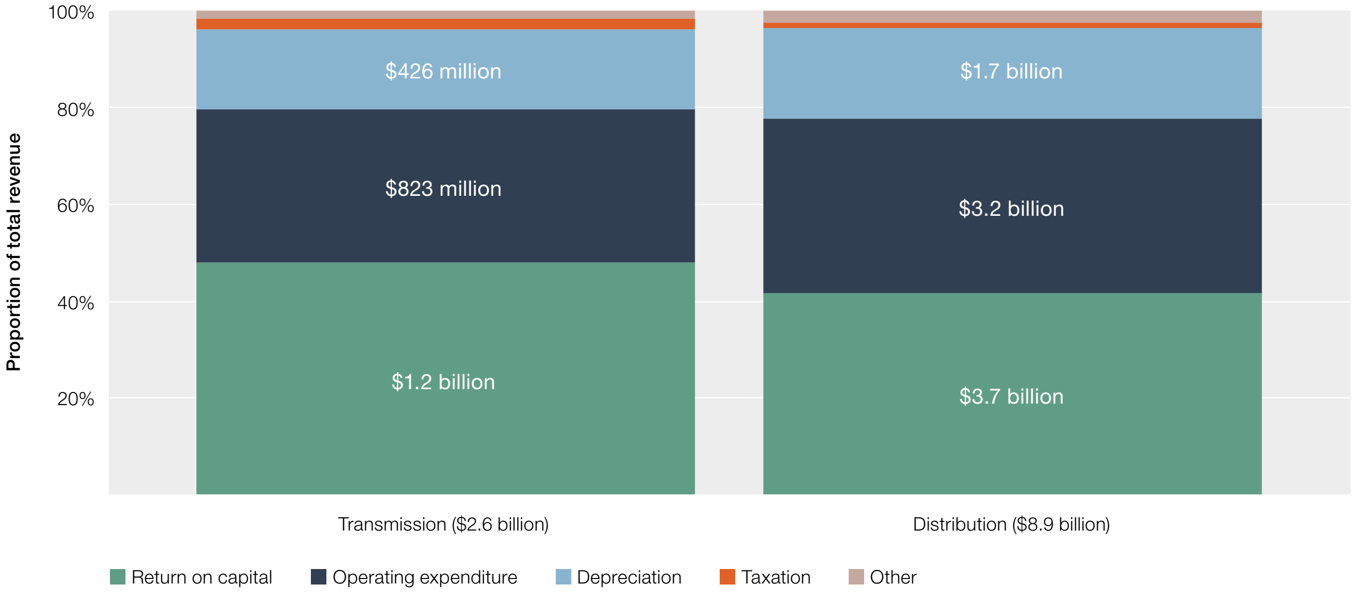
Additionally, the shareholders and lenders that fund these assets must be paid a commercial return on their investment. The AER sets the allowed rate of return (also called the weighted average cost of capital (WACC)) (section 4.12). The size of this return depends on:

- the value of the network's regulatory asset base (RAB)
- the 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.[12]

Overall, the return on capital takes up the largest share of network revenue, accounting for 43% of total revenue across all networks (Figure 4.5).

Sections 4.11 to 4.14 examine major cost components in more detail.

Figure 4.5 Composition of average annual electricity network revenue



Note: Composition of average annual electricity network revenue – current periods as at June 2023. All data are adjusted to June 2022 dollars.
Source: Post-tax revenue modelling used in AER determination process.

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

4.6 Recent AER revenue determinations

In 2023, the AER published its final revenue determinations for transmission network service providers Transgrid (NSW) and ElectraNet (South Australia), and the Murraylink interconnector (between South Australia and Victoria) for the 5-year period ending 30 June 2028 (Table 4.1).

Table 4.1 Recent AER electricity network revenue determinations

Service provider	Revenue (forecast)	Capital expenditure (forecast)	Operating expenditure (forecast)	Annual impact on residential bill
Transgrid (NSW)	$4.1b (▲3%)	$2.4b (▼35%)	$1.0b (▲3%)	▲0.2%
ElectraNet (South Australia)	$1.9b (▲15%)	$690m (▼51%)	$625m (▲25%)	▲0.3%
Murraylink (interconnector)	$77m (▼4%)	$12m (▼62%)	$23m (▼3%)	-

Note: Changes in revenue and expenditure are in relation to forecasts from the previous regulatory periods. Bill impact is the change in the average annual customer bill compared with the customer bill in the final year of the previous period, adjusted for inflation, assuming retailers pass through outcomes of the determination.

Source: AER estimates.

The key driver of the higher forecast revenues for Transgrid and ElectraNet is the allowed rate of return, which is higher than the rate applied in the previous period.[13] This reflects an increase in interest rates compared with those in the previous period, meaning the cost for network service providers to obtain the capital needed to run their businesses has increased. Forecast revenues were also affected by an increase in operating expenditure – driven by insurance costs, new investment to improve cyber security and (for ElectraNet) the forecast increases in circuit line length associated with the Eyre Peninsula Link and Project EnergyConnect.

4.7 Refining the regulatory approach

The regulatory framework is not static. The regulatory process increasingly focuses 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 seeks to encourage network service providers to better engage with consumers and have consumer preferences drive the development of network proposals.[14] If a network proposal is developed in line with the expectations set out in the Handbook, the AER will be better placed to undertake a more targeted review of the proposal rather than the standard, more detailed review.

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

In March 2023, the AER expressed that it was encouraged to see several network service providers had used the Handbook when formulating regulatory proposals, particularly regarding the scope and quality of consumer engagement.[15]

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

14 AER, Better Resets Handbook – Towards consumer centric network proposals, Australian Energy Regulator, 9 December 2021.

15 AER, AER releases issues papers on 2024–29 revenue proposals, Australian Energy Regulator, 28 March 2023.

Before publishing the Handbook, the AER had trialled the 'New Reg' process with Victorian distribution service provider AusNet Services. The New Reg process offered an enhanced, more open approach to how network service providers incorporate consumer perspectives in developing their regulatory proposals.

Additionally, the AER's Consumer Challenge 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.[16]

4.7.1 Aligning business and consumer interests

The regulatory process is complex and often adversarial. In this environment, consumers 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 improve consumer engagement.

To help consumers engage in the regulatory process, the AER publishes informative documents – including fact sheets that simplify technical language – and holds public forums. The AER's Consumer Challenge Panel also provides a mechanism for consumer perspectives to be voiced and considered.

Several network service providers are experimenting with early engagement models to better reflect consumer preferences and perspectives in framing their regulatory proposals – for example, running 'deep dive' workshops.

Early engagement offers the potential to expedite the regulatory process, reducing costs for both service providers and consumers. Effective consumer engagement can contribute to the AER accepting significant components of a network service providers' revenue proposal.

Service providers are increasingly looking to maintain open and ongoing dialogue with stakeholders throughout the regulatory period, rather than engaging intensively once every 5 years when a proposal is being considered.

In its 2022 draft decision, the AER recognised that ElectraNet (South Australia) had demonstrated sincerity and a desire to engage collaboratively with consumers in the development of its initial revenue proposal for the current regulatory period.[17]

Conversely, the AER considered Transgrid's consumer engagement to be a missed opportunity to demonstrate that a strong engagement culture has been embedded into its business-as-usual operations since its previous determination.[18]

We note the AER is not the only industry body focusing on consumer engagement. Each year Energy Networks Australia[19] and Energy Consumers Australia[20] recognises Australian energy networks that demonstrate best practice consumer engagement. In September 2022, 2 electricity distribution network service providers were shortlisted for the Consumer Engagement Award – Endeavour Energy (NSW) for its engagement with the community by planting 1,000 trees in response to the devastating 2019–2020 bushfires, and Essential Energy (NSW), for its 'Customer Journey Mapping' initiative to gain better insight on customer experiences.[21]

The award was ultimately won by 3 gas distribution networks that collaborated to design and deliver a single, integrated consumer and stakeholder engagement program as part of their regulatory reset engagement plans (section 6.5.3 in chapter 6).

In August 2023, distribution network service providers Ausgrid (NSW), Endeavour Energy (NSW) and SA Power Networks (South Australia) were shortlisted for the 2023 Consumer Engagement Award. The judging panel also commended Power and Water (Northern Territory) for its recent consumer engagement strategy.[22]

16 AER, Consumer Challenge Panel, Australian Energy Regulator, accessed 30 May 2023.

17 AER, ElectraNet 2023-28 - Final decision - Overview, Australian Energy Regulator, 28 April 2023, accessed 10 May 2023.

18 AER, Transgrid 2023-28 - Final decision - Overview, Australian Energy Regulator, 28 April 2023, accessed 10 May 2023.

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

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

21 ENA, Consumer engagement report, Energy Networks Australia , 15 December 2022.

22 ENA, Consumer engagement awards shortlist announced, media release, Energy Networks Australia, 18 August 2023. The winner of the 2023 Consumer Engagement Award had not been announced when this report was published.

4.7.2 Changes to revenue setting approaches

The AER frequently reviews and updates key aspects of its revenue setting approaches.

In February 2023, the AER released its latest rate of return instrument (the 2022 Instrument).[23] 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.

The 2022 Instrument is largely consistent with the 2018 Instrument but has been updated to reflect the latest data and market conditions. 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 4.12).

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 we publish and use in our network revenue determinations.

4.7.3 Review of incentive schemes

In April 2023, the AER published its final decision on its review of incentive schemes for network service providers.[24] The review forms part of the AER's strategic objectives for 2020–2025 to improve its approach to regulation by being more efficient and focusing on outcomes that matter most to consumers.

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

A key reason the AER conducted 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. In aggregate, the efficiency benefit sharing scheme (EBSS), capital expenditure sharing scheme (CESS) and the service target performance incentive scheme (STPIS) payments have added up to $1.2 billion (2%) of revenues over the past 5 years. Consumers had also questioned the extent to which network service providers are being rewarded for expenditure overforecasting rather than efficient spending, particularly in the context of capital expenditure.

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 will continue to apply the incentive schemes, but with several modifications to the CESS. These modifications will require amendments to the AER's *Capital Expenditure Incentive Guideline*.[25]

Sections 4.10, 4.14 and 4.16 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.[26]

23 AER, Rate of Return Instrument 2022, Australian Energy Regulator, accessed 22 March 2023.

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

25 AER, Capital expenditure incentive guideline for electricity network service providers, Australian Energy Regulator, April 2023.

26 AER, Electricity network performance reports, Australian Energy Regulator, accessed 11 July 2023.

4.8 Reforms to support new technologies and services

In August 2023, the Australian Energy Market Commission (AEMC) published its final report setting out several recommendations and options to accelerate the deployment of smart meters in the National Electricity Market (NEM).[27] Smart meters are essential for the availability of more cost-reflective tariff structures and are likely to play an important role supporting the energy transition.

The AEMC's proposed reforms target all consumers having access to smart meters by 2030.

As one of a broader suite of innovations in network and communication technology – including interactive household devices and energy management and trading platforms – smart meters support change in energy markets. These innovations allow consumers to access real-time information about, and make informed decisions in managing, their energy use. If consumers choose to voluntarily reduce their energy use from the grid in peak periods (by shifting energy use or relying on battery storage), it can delay the need for costly network investment. Moreover, since demand for energy imports is increasingly at its minimum when solar generation is high, shifting consumption from peak periods can help reduce the costs of supply, manage minimum demand constraints (such as voltage issues) and draw more energy from a low emissions fuel source.

Previously, the roll-out of smart meters was market-led as part of the 'Power of Choice' reforms, which also included more cost-reflective network pricing (section 4.8.1) and incentives for demand management as a lower cost alternative to network investment (section 4.13.9).

The emergence of electric vehicles (EVs) can also help consumers manage their energy needs. The Australian Renewable Energy Agency (ARENA) is funding projects to assess different approaches to optimise the use of EVs. In April 2023, ARENA announced $70 million in funding to support innovation and management of charging stations, as part of the Driving the Nation funding pool.[28] Other projects funded by ARENA include the Depot of the Future Vehicle Electrification Project, testing the impact of large-scale fleet EVs[29], and the Jemena Dynamic EV Charging Trial, testing dynamic management of EV home charging.[30]

More generally, the Distributed Energy Integration Program (DEIP) – a collaboration of government agencies, market authorities, industry and consumer associations – aims to enhance consumers' benefits from using consumer energy resources, including benefits from access and pricing reforms.[31] The DEIP has also run a series of task forces to explore issues relating to integrating EVs into the energy system.

Improvements in energy storage and renewable generation technology are making it increasingly possible for some consumers to go off-grid. Standalone systems or microgrids – where a community is primarily supplied by local generation with no connection to the main grid – are gaining traction, particularly in regional communities that are remote from existing networks.

In 2020, the AEMC proposed rule changes to enable distribution network service providers to supply their customers using standalone power systems where it is cheaper than maintaining a connection to the grid.[32] The AEMC identified additional benefits of these systems, including improved reliability and reduced bushfire risks.[33] These proposed changes were made to the National Electricity Rules in February 2022 following a series of changes in the national electricity and retail laws.[34]

Under the reforms, customers who receive standalone systems will retain all of their existing consumer protections, including access to retail competition and existing reliability and safety standards. Cost savings arising from the use of lower cost standalone systems will flow through to all users of the distribution network through lower network prices.

27 AEMC, Final report – Review of the regulatory framework for metering services, Australian Energy Market Commission, 30 August 2023.

28 ARENA, ARENA targets better, more frequent EV charging stations, media release, Australian Renewable Energy Agency, 20 April 2023.

29 ARENA, Depot of the Future Vehicle Electrification Project, ARENAWIRE, Australian Renewable Energy Agency, last updated 2 May 2023.

30 ARENA, Jemena Dynamic Electric Vehicle Charging Trial, ARENAWIRE, Australian Renewable Energy Agency, last updated 8 February 2023.

31 The DEIP's Access and Pricing Working Group developed a rule change proposal on the prohibition on export charging, which the AEMC approved in its decision published June 2021.

32 Usually a combination of solar PV, batteries and a backup generator.

33 AEMC, Final report – updating the regulatory frameworks for distributor-led stand-alone power systems, Australian Energy Market Commission, May 2020.

34 AEMC, New rules allow distribution network businesses to roll out stand-alone power systems in the NEM, Australian Energy Market Commission, February 2022.

4.8.1 Tariff structure reforms

Traditionally, most households and small businesses have been charged the same network tariff component for using the distribution network regardless of how and when they use energy (that is, flat/single rate or non-cost-reflective network tariffs). Because flat tariffs are independent of when and how electricity is used, they don't reflect the relatively higher costs of a network built to supply electricity during peak periods. This means some consumers, such as those who primarily use electricity during peak periods, may not pay their full share of network costs under single rate tariff structures, while other consumers may pay more than their full share.

Importantly, distribution service providers do not charge network tariffs directly to end customers. Rather, network tariffs are charged to retailers, who then package the tariffs together with the cost of wholesale energy and other costs in their retail price offers to end customers. The network component makes up around 40% of a customer's final retail bill (Figure 7.2 in chapter 7). The retailer may pass on the network tariff signal as is or repurpose it into a different retail offer. It is up to the end customer to choose a retail offer that suits their needs.[35]

The National Electricity Rules require distribution service providers to make network tariffs more cost-reflective, to signal to retailers the true cost of their customers' use of the network.[36] The AER supports and encourages the reform to more cost-reflective tariffs through the tariff structure statement process.

Tariff reform can encourage more efficient use of networks, delay the need for network augmentation and investment, and spread network costs more equitably. Initially, reform focused on signalling costs during peak demand periods (which historically drove network investment). Recent reform has involved sending price signals to efficiently integrate consumer energy resources – such as rooftop solar, batteries and EVs – into distribution networks. This includes sending price signals to encourage the use of solar energy in the middle of the day to avoid excess solar (minimum demand) on the network.

Distribution network service providers are required to submit their tariff structure statements to the AER every 5 years, as part of the wider revenue determination process. With each tariff structure statement, network service providers are required under the National Electricity Rules to progressively move towards more cost-reflective tariffs.[37]

Progress towards increasing the number of customers seeing and responding to tariff signals of network costs has included:

- simplifying tariffs and modifying peak windows to provide clear, consistent signals
- designing tariffs that more closely reflect network costs, including two-way tariffs
- applying an 'opt-out' or mandatory assignment policy that increases the number of end customers whose retailers will face these more cost-reflective tariffs (a development from 'opt-in' assignment policies)
- integrating network pricing with areas such as network planning, demand management and direct procurement of network services; and trialling alternative approaches.

In August 2021, the AEMC made a rule change to integrate consumer energy resources, such as small-scale solar and batteries, more efficiently into the electricity grid. The key aspects of the rule change included providing clear obligations on distribution network service providers to provide export services, enabling new network tariff options that reward customers and strengthening customer protections and regulatory oversight by the AER.[38]

The rule change seeks to better manage minimum demand issues, support effective consumer energy resources integration and enable future market designs in which consumer generation and storage play a larger role.

Distribution network service providers may now signal the cost of serving energy export as well as energy consumption, where providing the export service imposes a cost on the network (also called two-way pricing). This means that customers with solar could be rewarded for exporting at times when the network needs it or charged

35 Energy Made Easy (www.energymadeeasy.gov.au) is a free Australian Government energy price comparison service for households and small businesses in NSW, Queensland, South Australia, Tasmania and the ACT that can be used to find and compare home and small business electricity and gas plans. The Victorian Government's Victorian Energy Compare website (compare.energy.vic.gov.au) offers the same service for households and small businesses in Victoria.

36 AEMC, National Electricity Amendment (Distribution Network Pricing Arrangements) Rule 2014, rule determination, Australian Energy Market Commission, November 2014.

37 Distribution network service providers are now moving into the third round of submitting tariff structure statements.

38 AEMC, Final determination – Access, pricing and incentive and incentive arrangements for distributed energy resources, Australian Energy Market Commission, 12 August 2021, accessed 20 January 2022.

for exporting if it contributes to minimum demand. The rule change requires the AER to publish export tariff guidelines for the implementation of any two-way pricing that may be introduced in distribution network service providers' next round of tariff structure statements.[39]

Under the National Electricity Rules, subject to revenue recovery limits, distribution network service providers can trial alternative tariff structures (sub-threshold tariffs) during the regulatory period to support the introduction of innovative tariff structures. Network service providers have responded with a broad range of trials to explore innovative tariff approaches, covering solar sponges, EVs, critical peak pricing and two-way pricing. Examples of trials include:

- Ausgrid (NSW) – a super off-peak tariff trial with an additional 4-hour 'super off-peak' charge, used to encourage EV owners to charge their EVs away from the network peak.
- Essential Energy (NSW) – 2 trial tariffs aimed at large businesses – a sun soaker, two-way tariff trial and a weekly demand tariff trial. These trials are specifically aimed at helping customers with peaky loads, such as irrigators and EV charging stations, to manage their loads.
- SA Power Networks (South Australia) – a small business tariff trial with high peak prices, aimed at encouraging businesses with flexible load to shift energy use to during the day or overnight.
- Jemena (Victoria) – a community battery tariff trial for batteries with capacity up to 500 kVA. The purpose of this trial is to gain insights into the behaviour of battery operators in response to price signals.

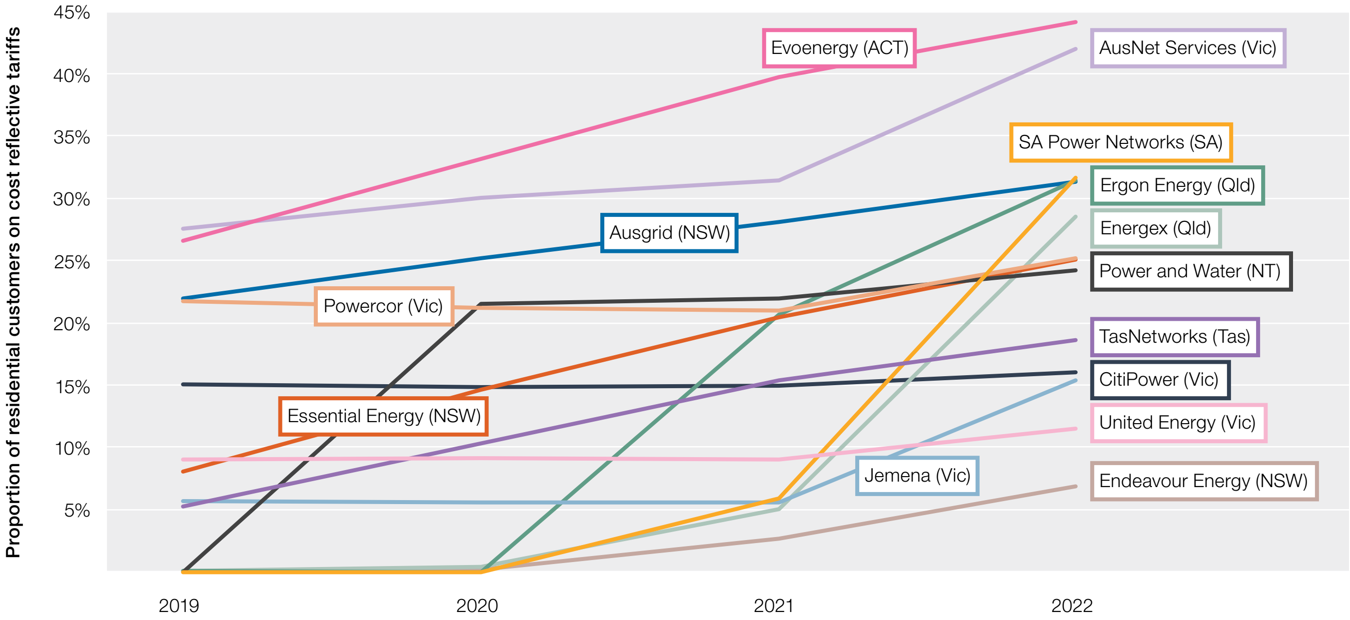
An example of the AER progressing cost reflectivity is its approval of SA Power Networks' use of a 'solar sponge' tariff for its residential customers. The solar sponge network tariff offers a lower charge during the day, when solar output is highest, to encourage customers to use electricity when it is more plentiful and less costly. Raising demand for grid-supplied electricity during the day can help manage voltage issues and thermal overloads associated with minimum demand, while shifting demand away from the evening peak when there is heavy strain on the network and costs are higher. SA Power Networks also introduced a demand tariff that offers discounted time of use rates and a seasonal peak demand component.

Other distribution network service providers have also incorporated, or plan to incorporate, 'solar soak' or 'solar sponge' tariffs to encourage energy use during the day. For example, Essential Energy (NSW) has proposed a tariff with export and reward charges, as well as low consumption prices during the day, to be its default residential cost-reflective tariff from 2028.

The National Electricity Rules require distribution network service providers to make their suite of tariffs progressively more cost reflective with each tariff structure statement. Figure 4.6 shows the proportion of residential customers whose retailer is facing cost-reflective network tariffs. We expect the proportion to continue to increase as distribution network service providers assign customers with smart meters to cost reflective tariffs, and more smart meters are rolled out.

39 AER, Export Tariff Guidelines, Australian Energy Regulator, 19 May 2022.

Figure 4.6 Residential customers on cost-reflective tariffs



Source: Annual RIN responses.

To date, the limited uptake of smart meters for residential and small business consumers outside Victoria has been a barrier to applying cost-reflective network tariffs. Smart meters, which measure electricity use in 30-minute blocks, are essential for most cost-reflective network tariffs to be applied.

In jurisdictions other than Victoria, where almost 100% of small consumers have smart meters, the rollout of smart meters is market-led. Installation rates vary across jurisdictions. New and replacement meters installed for residential and small business consumers must now be smart meters and other consumers can negotiate for a smart meter as part of their electricity retail offer. At 30 June 2022, around 57% of residential customers in the NEM had metering capable of supporting cost-reflective tariffs (including smart meters and manually readable interval meters).

Changes to the National Electricity Rules in 2017 transferred responsibility for metering from distribution network service providers to retailers. Additionally, from February 2019 retailers have been required to provide consumers with electricity meters within 6 business days of a property being connected to the network or with replacement meters within 15 days.[40]

In 2023, the AEMC reached the view that the roll-out of smart meters has progressed too slowly and recommended a larger role for distribution network service providers to expediate the roll-out.[41] The AEMC recommends distribution network service providers schedule the retirement of existing legacy meters and retailers take responsibility for replacing the retired meters with smart meters.

4.8.2 Ring-fencing

When 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 objective of ring-fencing is to provide a regulatory framework that promotes the development of competitive markets. It does this by providing a level playing field for third party providers in new and existing markets for contestable services.[42] Effective ring-fencing arrangements are an important mechanism for promoting increased choice of service providers for consumers and more competitive outcomes in markets for energy services.

Ring-fencing aims 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.

40 AEMC, National Energy Retail Amendment (Metering Installation Timeframes) Rule 2018, rule determination, December 2018, Australian Energy Market Commission, accessed 14 February 2022.

41 AEMC, Final report – Review of the regulatory framework for metering services, Australian Energy Market Commission, 30 August 2023.

42 The 2015 Power of Choice reforms (section 4.8) required the AER to develop the distribution ring-fencing guideline.

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

Under the distribution ring-fencing guideline, all distribution network service providers are required to annually report on their compliance to the AER. Despite the slight increase in 2022–23 the AER has generally observed fewer compliance issues and breaches since 2017–18. When breaches have occurred, distribution network service providers have generally communicated promptly with the AER, acted quickly to remediate any potential harms, and put a plan in place to prevent breaches from reoccurring. The introduction of civil penalties in February 2020 has continued to encourage improved compliance.

In December 2022, the AER granted a class waiver enabling distribution network service providers to provide reliability and emergency reserve trader (RERT) services using voltage management.[43] These services were identified by AEMO as a potential low-cost way of maintaining power system reliability. To help the AER monitor potential impacts on customers, distribution network service providers that provide services under the class waiver must provide additional quarterly reports. The information provided in these reports will help the AER to monitor the potential impacts on customers until the waiver expires on 15 April 2025.

The AER granted a further class waiver in February 2023 for distribution network service providers to install community-scale batteries with funding from the Australian Government's Community Batteries for Household Solar Program.[44] The waiver introduced additional conditions to prevent cross-subsidisation and discrimination and ensure consumers received the benefits from the program. This class waiver was tightly targeted to the expected 400 batteries under the program, noting that the benefits may be maximised in some instances by allowing batteries to provide both network and non-network services.

In March 2023, the AER released an updated ring-fencing guideline for electricity transmission networks.[45] The previous guideline was published by the Australian Competition and Consumer Commission (ACCC) in August 2002. Although several minor amendments were made to the guideline over the years, it had not changed substantially since its initial publication despite significant changes in the regulatory landscape and electricity market.

The amendments in the updated guideline seek to ensure the guideline remains fit for purpose in a changing regulatory landscape and electricity market.

The updated guideline took effect from 1 March 2023. The introduction of civil penalties for breaches of transmission ring-fencing requirements is expected to encourage compliance with the updated guideline.

4.9 Revenue

Electricity network businesses earn revenue for providing services to customers. While some services are regulated, others are provided through competitive markets. For transmission network service providers, this report focuses exclusively on components of revenues associated with delivering regulated services, referred to as prescribed transmission services. For distribution network service providers, it focuses exclusively on revenues associated with providing regulated distribution services – standard control services.[46]

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 the network service providers' allowed returns on debt, cost pass-throughs (section 4.9.3) and other factors. Interest rates and inflation are factors outside both the network service providers' and the AER's control. These uncontrollable factors are expected to place upwards pressure on the network service providers' allowed revenue in future years.[47]

43 AER, Reliability and Emergency Reserve Trader (RERT) via voltage management — Ring-fencing class waiver, Australian Energy Regulator, December 2022, accessed 26 July 2023.

44 AER, Batteries funded under the Commonwealth Government's Community Batteries for Household Solar Program – Ring-fencing class waiver, Australian Energy Regulator, February 23, accessed 26 July 2023.

45 AER, Ring-fencing guideline - electricity transmission - version 4, Australian Energy Regulator, March 2023, accessed 16 March 2023.

46 Standard control services may include network, connection and metering services. These services make up the bulk of the services provided by distribution businesses and are regulated by the AER.

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

4.9.1 Revenue in 2022

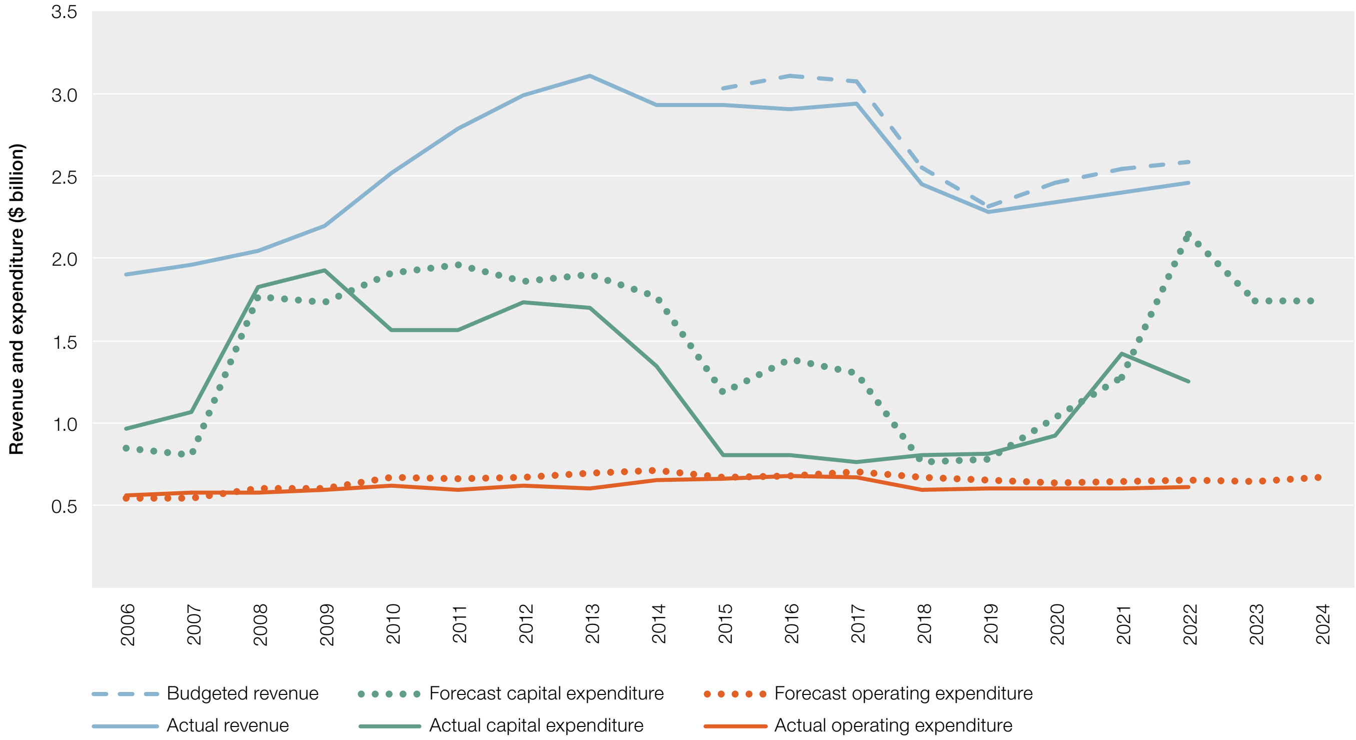
In 2022, network service providers earned $12 billion for providing services to customers, $10 million (0.1%) less than in the previous year. This marked the eighth consecutive year of decreases in aggregated transmission and distribution network revenue.

Table 4.2 and Figure 4.7 to Figure 4.10 provide a summary of the revenue network service providers earned for providing services to customers in 2022 and how it compared with previous years' targets and actuals.

Table 4.2 Revenue in 2022 – key outcomes

Service type	Revenue (actual) (2022)	Revenue (actual) (compared with 2021)	Revenue (actual) (compared with peak)
Transmission	$2.5b	▲$61m (▲3%)	▼$646m (▼21%) (2013)
Distribution	$9.4b	▼$71m (▼0.7%)	▼$4.0b (▼30%) (2014)
Total	$11.9b	▼$10m (▼0.1%)	▼$4.5b (▼27%) (2014)

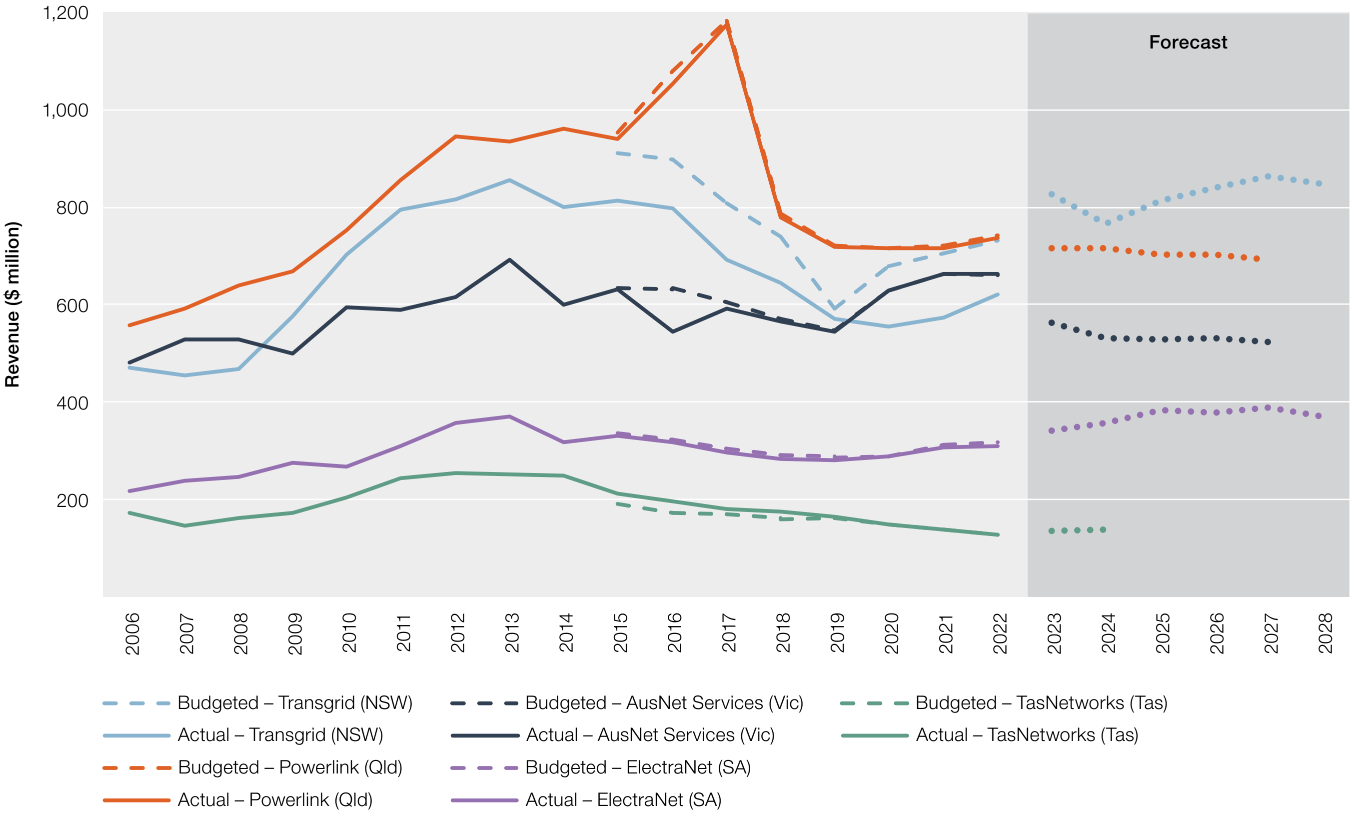
Figure 4.7 Revenue and key drivers – electricity transmission networks (aggregate)



Note: All data are adjusted to June 2022 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 4.7 reflects the revenues 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.

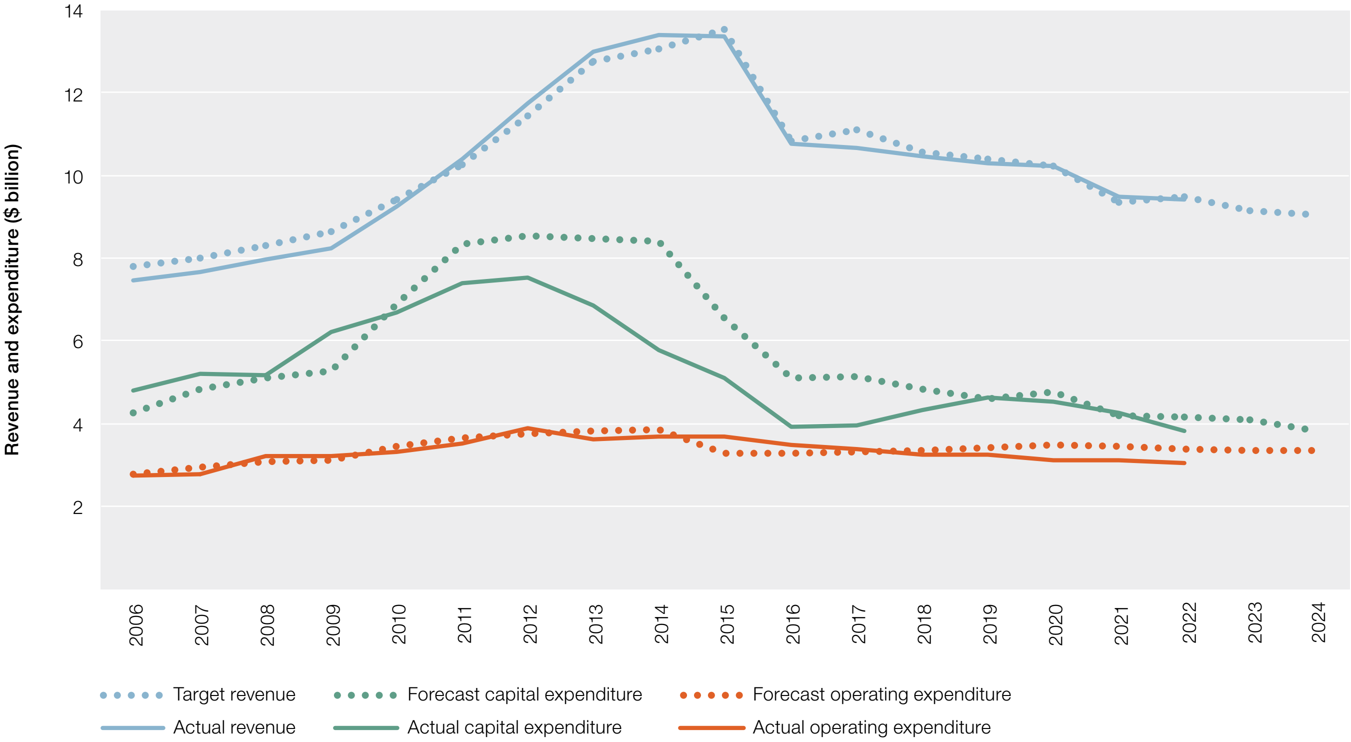
Figure 4.8 Revenue – electricity transmission networks



Note: All data are adjusted to June 2022 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 4.8 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. Assumptions are set out in the Figure 4.7 notes.

Source: AER modelling; annual reporting RIN responses.

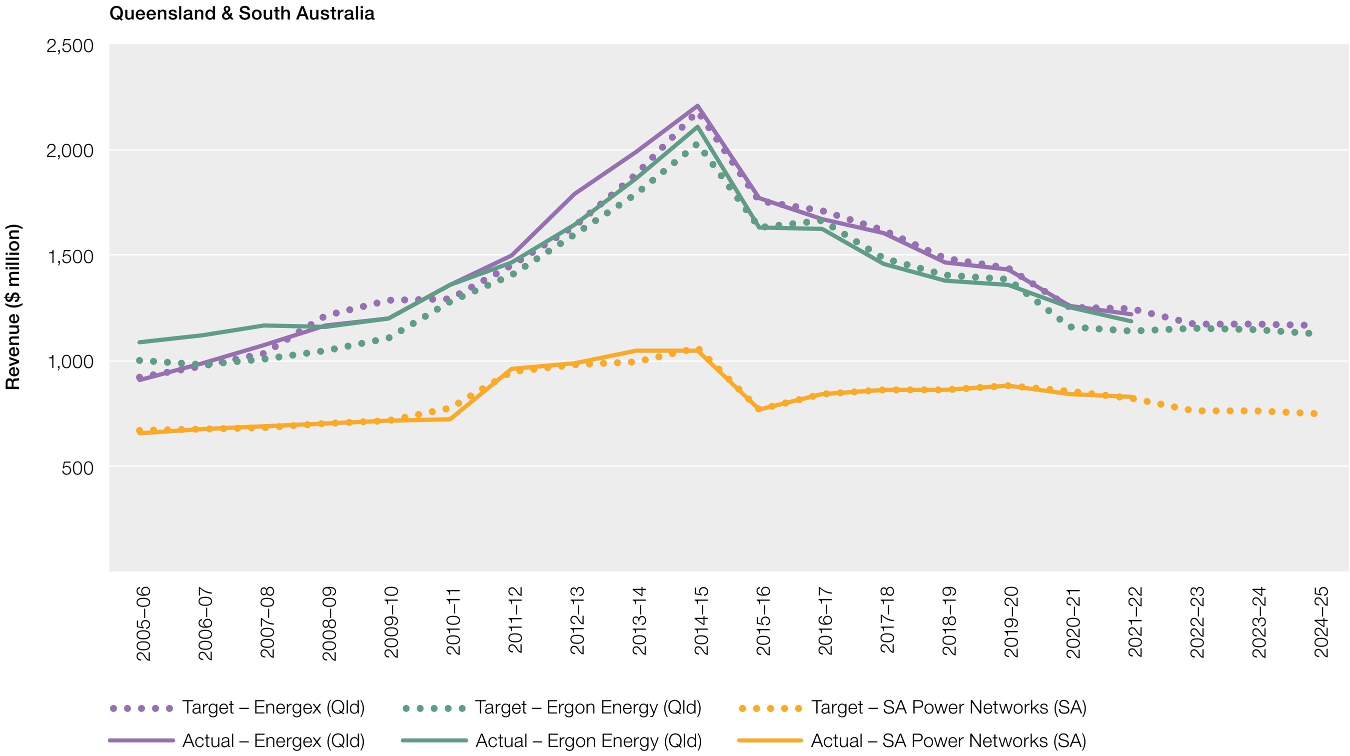
Figure 4.9 Revenue and key drivers – electricity distribution networks (aggregate)

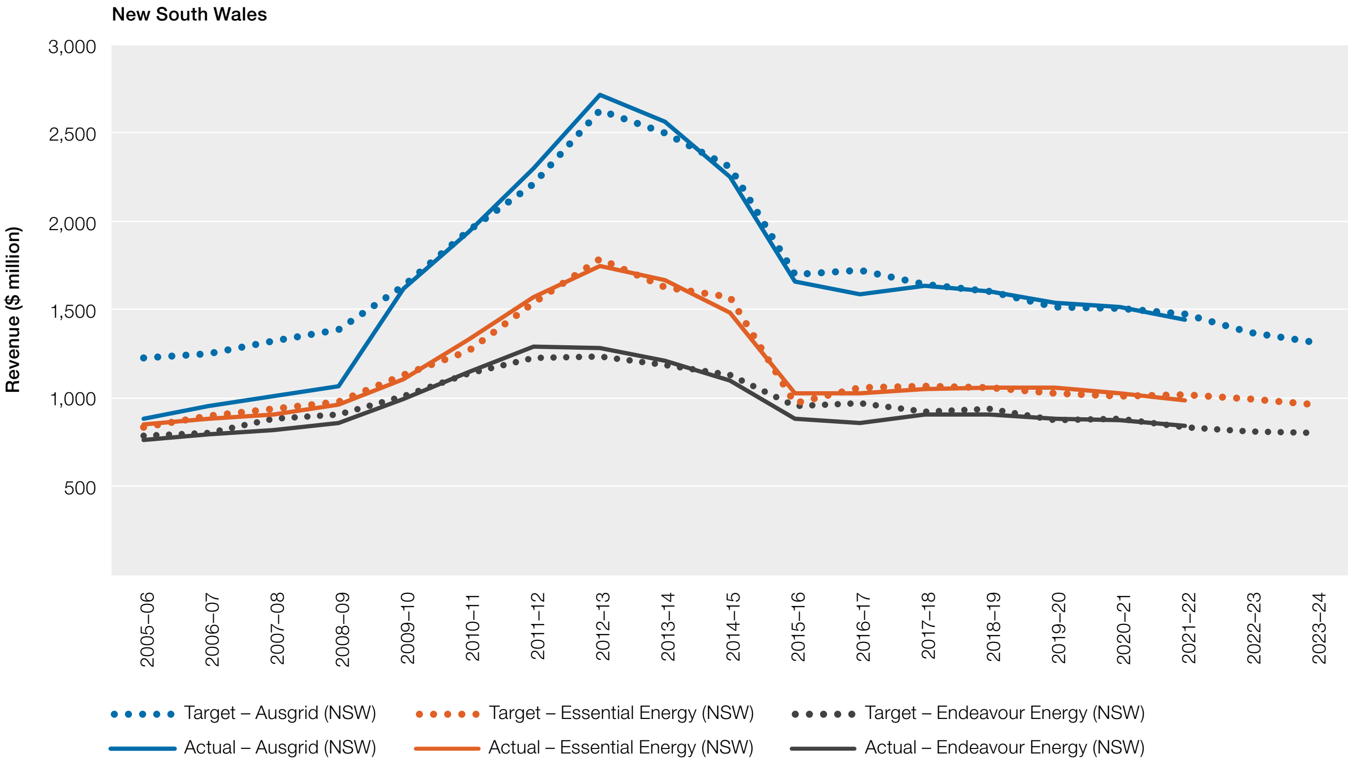


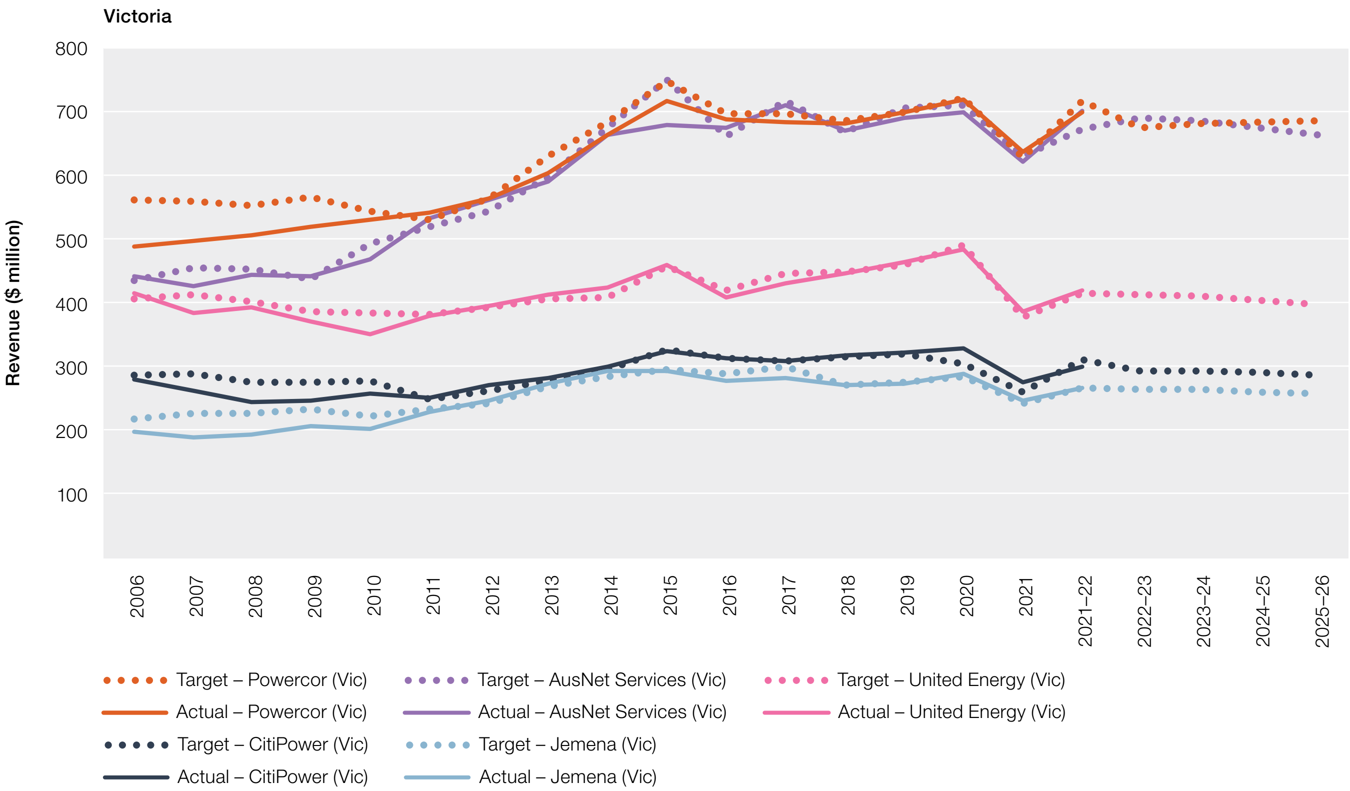
Note: All data are adjusted to June 2022 dollars. The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018). Target revenue is derived from regulatory determinations but adjusted to present it on a comparable basis to actual revenues. 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. 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.

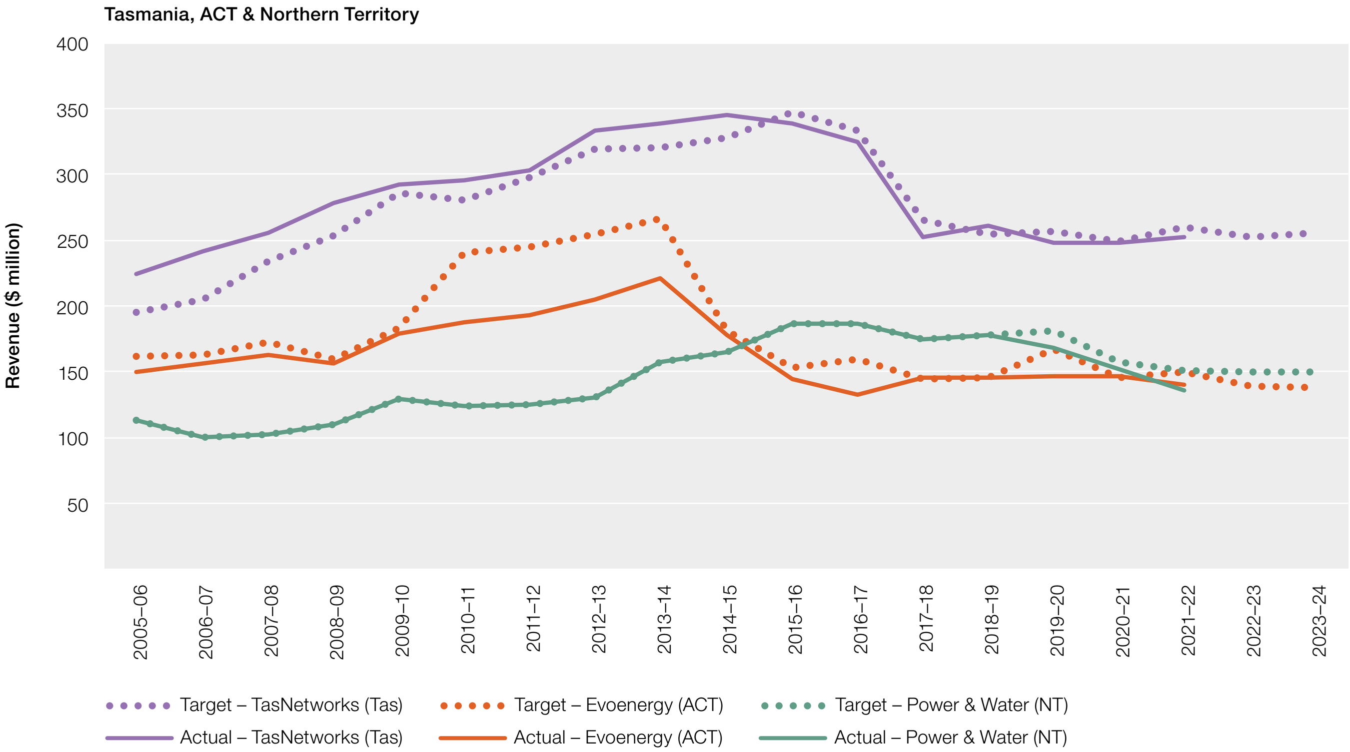
Source: Revenue: economic benchmarking RIN responses; capital expenditure: AER modelling, category analysis RIN responses; operating expenditure: AER modelling, economic benchmarking RIN responses.

Figure 4.10 Revenue – electricity distribution networks







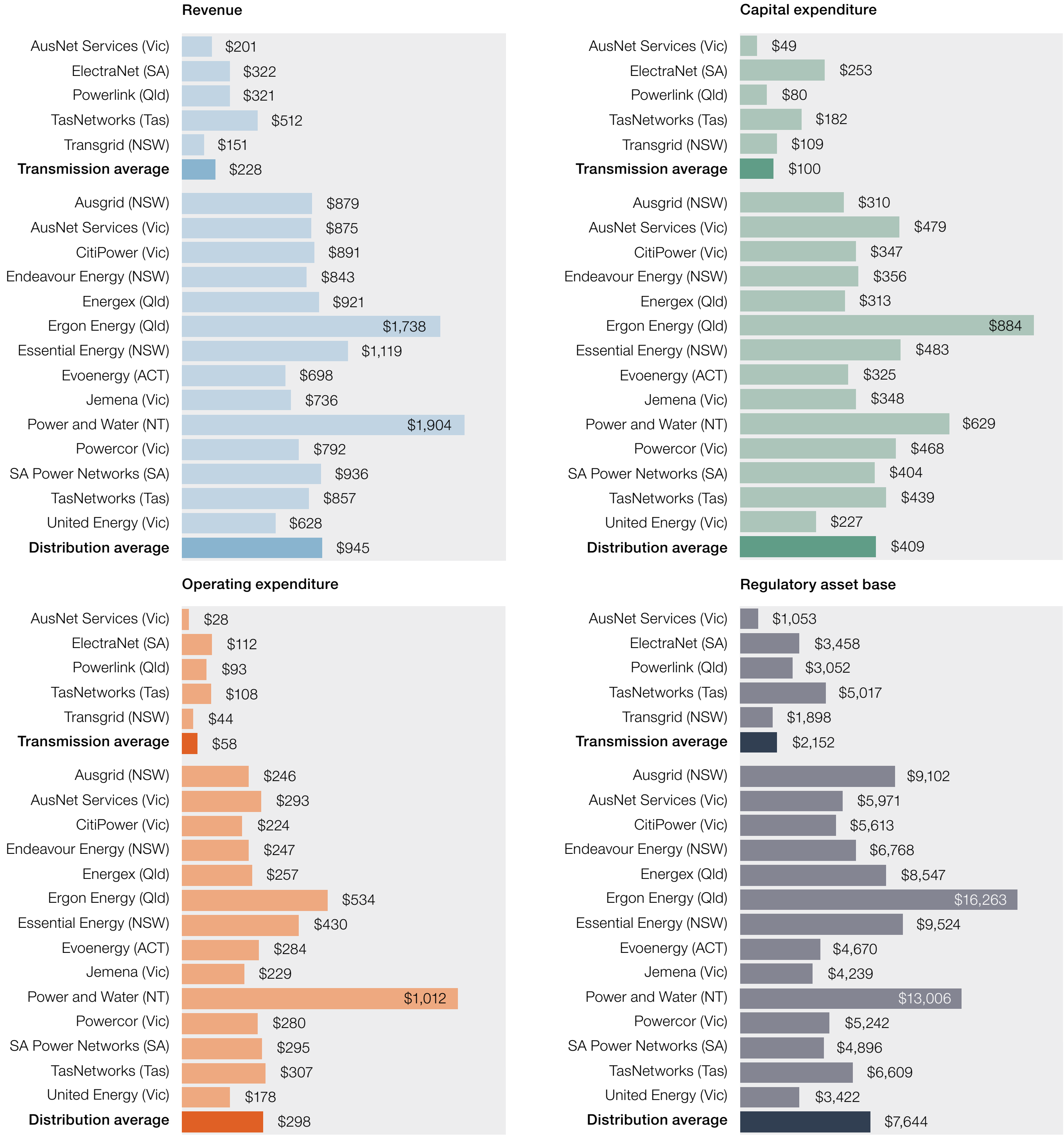


Note: All data are adjusted to June 2022 dollars. Most network businesses report on a 1 July to 30 June basis. The exception is the Victorian networks which have reported on a 1 January to 31 December basis. The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018). 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 4.11 summarises key financial indicators for electricity networks on a per customer basis, which allows for greater comparability across networks.[48 49]

Figure 4.11 Average per customer metrics – 2018 to 2022 (5 years)



Note: All data are adjusted to June 2022 dollars. In 2022 residential customers (a customer who purchases energy 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 Jemena (Victoria) and 82% for Essential Energy (NSW) – the differences did not materially affect the 'per customer' metric. Revenue, capital expenditure and operating expenditure are the annual averages over the 5 years to 30 June 2022. RAB is the actual closing RAB at 30 June 2022. For regulatory purposes, Northern Territory transmission assets are treated as part of the distribution system.

Source: AER revenue determinations and economic benchmarking RINs.

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

49 Transmission networks 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.

Forecast revenue for electricity network service providers is translated into a path of 'X-factors', which are locked in at the beginning of the regulatory period. 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.

Table 4.3 provides a summary of the AER's revenue determinations for all electricity network service providers for the current regulatory periods.

Table 4.3 AER electricity network revenue determinations – current regulatory period

Service type	Revenue (forecast)	Capital expenditure (forecast)	Operating expenditure (forecast)	Annual impact on residential bill
Transmission	$12.9b (▼3%)	$5.0b (▼29%)	$3.4b (▲2%)	▲0.1%
Distribution	$46.6b (▼15%)	$20.0b (▼18%)	$16.9b (▲0.9%)	▼0.4%
Total	$59.5b (▼12%)	$25.0b (▼21%)	$20.3b (▲1.2%)	▼0.3%

Note: The current regulatory period is the period in place at 1 July 2023. Changes in revenue and expenditure are in relation to forecasts from the previous regulatory periods. Bill impact is the change in the average annual customer bill compared with the customer bill in the final year of the previous period, adjusted for inflation, assuming retailers pass through outcomes of the determination.

Source: AER estimates.

The key drivers behind lower revenues for most of the network service providers have been the changes in the allowed return on capital and, to a lesser extent, the net tax allowance. In the previous cycle of regulatory determinations, the allowed rate of return had decreased from the prior regulatory period, driven by lower interest rates. This led to significant downward pressure on network revenue. Recently that trend has reversed as interest rates have increased alongside higher inflation, putting upward pressure on network revenues.

4.9.2 Trends in network revenue

Revenues for network service providers increased by around 7% per year from 2006 to 2015, when network charges accounted for around 43% of retail electricity bills. The increases were more pronounced in Queensland and NSW than elsewhere. The drivers of these increases are set out in more detail in past State of the energy market reports. Key factors included:

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

Cost pressures began to ease when electricity demand 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 approved for some network service providers fell to around 4.6% in 2022 (section 4.12).

Energy rule reforms phased in from 2015 also helped stem the growth in network revenue. The reforms, which explicitly linked network costs to efficiency factors, encouraged network service providers to better control their operating costs.

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 new 5-year regulatory cycles. However, consumers will continue to pay for the overinvestment in network assets from 2006 to 2013 for the remainder of the economic lives of those assets, which may be up 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 that overinvestment.[50] The Australian Competition and Consumer Commission (ACCC) supported this position, particularly for government-owned networks in Queensland, NSW and Tasmania.[51]

Since 2017 network revenues have decreased, driven by a significant reduction in target revenue for the NSW based networks in 2015 and followed by a subsequent significant reduction for the Queensland based networks in 2016.

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 the network service providers, the AER now publishes information on network profitability. The AER's annual electricity network performance report provides detailed analyses of key operational and financial trends as well as key profitability measures.[52] The network performance report enables 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 investment on capital projects. Operating expenditure has always been lower than capital expenditure, but the difference 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 2015 weakening investment led to decreases in capital expenditure. In 2016 the amount of capital (53%) and operating (47%) expenditure almost reached parity. In recent years operating expenditure has eased as network service providers (especially distribution) implemented efficiency programs (section 4.14).

4.9.3 Pass-through events

The AER is responsible for assessing cost pass-through applications, wherein a network service provider may apply to seek the recovery of 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 4.4 summarises the cost pass-through applications approved by the AER in the 12-month period to 30 June 2023.

50 T Wood, D Blowers, K Griffiths, Down to the wire – a sustainable electricity network for Australia, Grattan Institute, March 2018.

51 ACCC, Retail Electricity Pricing Inquiry – final report, Australian Competition and Consumer Commission, June 2018.

52 AER, Electricity network performance reports, Australian Energy Regulator, accessed 11 July 2023.

Table 4.4 Cost pass-throughs

Network service provider	Pass-through event	AER approved ($ nominal)	Recovery period
Powerlink (Queensland)	Network support	$0.3 million	2023–24
Transgrid (NSW)	Network support	–$10.6 million	2023–24
ElectraNet (South Australia)	Insurance	$5.3 million	2023–24
ElectraNet (South Australia)	Network support	$2.2 million	2023–24
TasNetworks (Tasmania)	Network support	$0.2 million	2023–24
AusNet Services (Victoria)	Tax costs	$55.9 million	2023–24
Murraylink ((South Australia–Victoria)	Connection charge	–$0.9 million	2023–24
Energex (Queensland)	Natural disaster	$18.1 million	2024–25
Ausgrid (NSW)	NSW Roadmap Electricity Infrastructure Fund	$61.5 million	2023–24
Endeavour Energy (NSW)		$48.9 million	2023–24
Essential Energy (NSW)		$27.8 million	2023–24
Essential Energy (NSW)	Natural disaster	$2.2 million	2023–24
Powercor (Victoria)	Regulatory obligation	$14.0 million	2023–24 to 2025–26
SA Power Networks (South Australia)	Service standard	$5.8 million	2023–24 to 2024–25

Source: Cost pass-throughs.

4.10 Network charges and retail bills

Electricity network charges made up around 40% of a residential customer's energy bill in 2022 (Figure 7.2 in chapter 7). Distribution network services accounted for most of the costs (73% to 78%), with transmission network service costs (up to 21%) and metering costs making up the balance. Jurisdictional scheme costs, collected through network charges, are also material in some cases. For example, in the ACT, jurisdictional schemes relating mainly to large-scale feed-in tariffs:

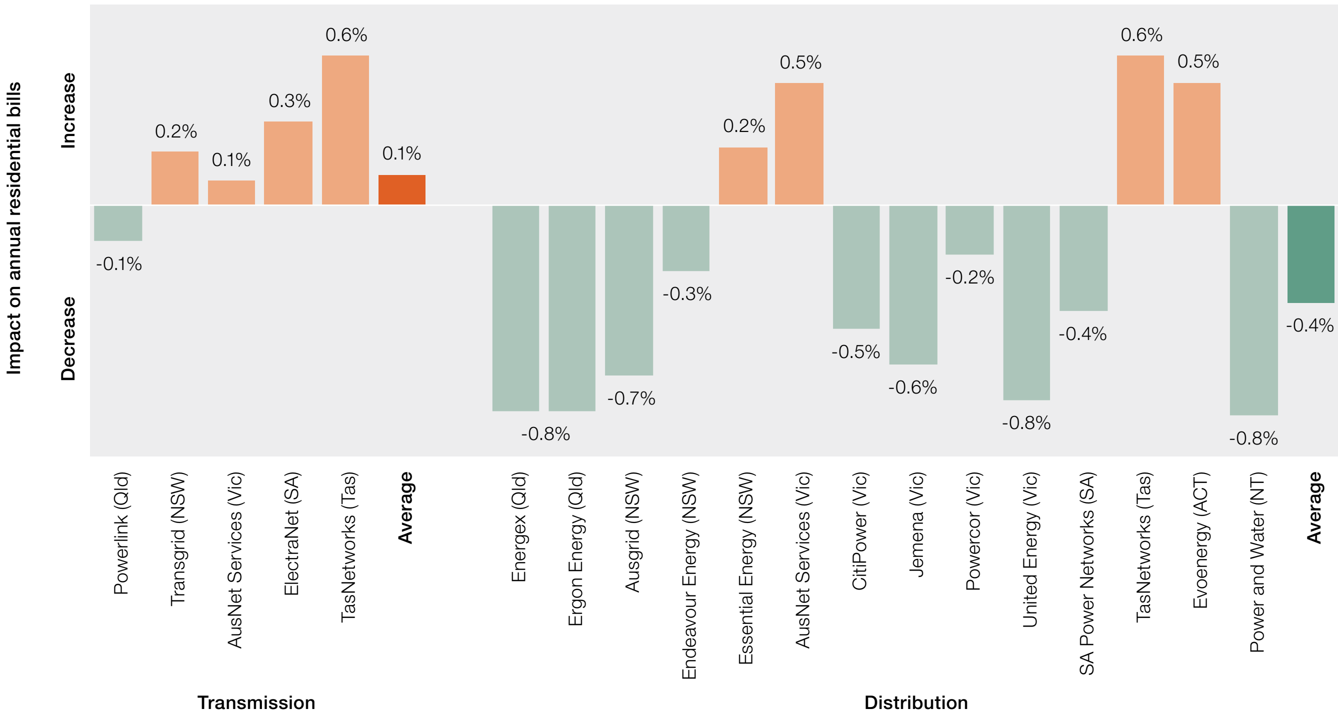
- materially increased energy bills over 2021–22, accounting for over 20% of total network charges[53]
- will materially reduce energy bills over 2022–23, accounting for a reduction of 30% in total network charges.[54]

The AER's most recent revenue determinations decreased residential energy bills by an average of 0.3% per year across all states and territories. This is the culmination of an average 0.1% increase in transmission costs and an average 0.4% decrease in distribution costs (Figure 4.12).

53 AER, Statement of reasons: Evoenergy's annual pricing proposal, Australian Energy Regulator, May 2021.

54 AER, Statement of reasons: Evoenergy's annual pricing proposal, Australian Energy Regulator, May 2023.

Figure 4.12 Impact of AER revenue determinations on residential customer electricity bill



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. The data account for changes in only network charges, not changes in other bill components. Outcomes will vary among customers, depending on energy use and network tariff structures.

Source: AER revenue determinations; additional AER modelling.

The most significant changes to network charges generally arise in the first year of a regulatory period. Recent examples range from a 9% reduction for Power and Water (Northern Territory) to a 1.6% increase for AusNet Services (Victoria). As part of its revenue determination process, the AER 'smooths' the initial revenue forecast to minimise volatility in prices over the regulatory period. Through this approach, initial changes are generally followed by stable prices or modest increases in later years.

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.

Among other factors, the annual processes update prices for changes in the consumer price index (CPI). Since June 2021, CPI has increased significantly. For example, over the 12 months to December 2022, applying to network prices over 2023–24, CPI increased by 7.8%. The Reserve Bank of Australia acknowledges it will take some time for inflation to return to the 2–3% target band. The central forecast is for headline inflation to decline to 4.5% by the end of 2023 and to reach 3% by mid-2025.[55] As these inflation results feed into annual pricing over coming years, they will continue to put upward pressure on prices.

55 RBA, Statement of Monetary Policy, Reserve Bank of Australia, August 2023.

4.11 Regulatory asset base

The regulatory asset base (RAB) for a network service provider represents the total economic value of assets that provide network services to customers.[56] 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.

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 network service provider 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.

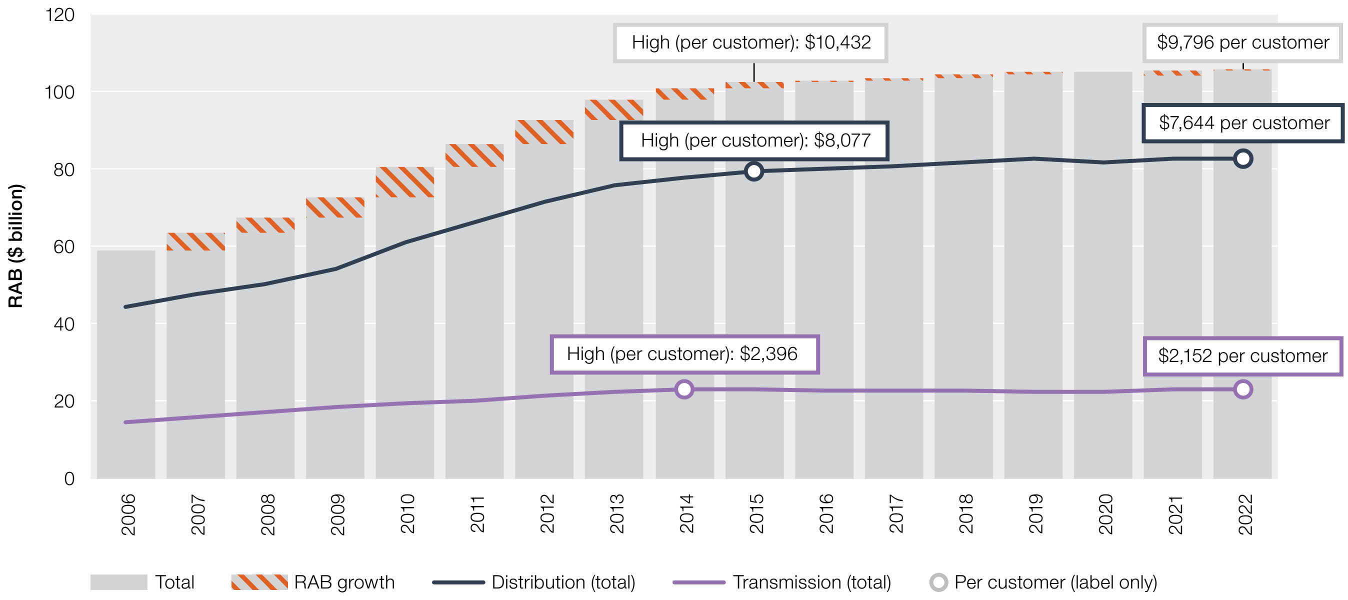
Escalating investment inflated the value of the total electricity network RAB from $58.7 billion in 2006 to $97.8 billion in 2013 – an increase of around 8% per year. Since then, network investment has steadied, as has the growth in the value of the total network RAB. From 2014 to 2022 the value of the total network RAB continued to grow but at a considerably slower rate of around 1% per year.

Recent RAB growth has been most pronounced for the ElectraNet (South Australia) and Transgrid (NSW) transmission service providers. This includes expenditure on Project EnergyConnect, which is a major transmission investment developed and approved through a regulatory investment test (RIT) (section 4.13.7). This trend is forecast to continue as major transmission network projects required to enable the reliable supply of low carbon energy enter development (section 4.13.6).

4.11.1 Regulatory asset base in 2022

As at 30 June 2022 the total combined value of the RAB for electricity network service providers was $105.8 billion, an increase of $378 million (0.4%) from the previous year (Figure 4.13).

Figure 4.13 Value of electricity network service provider assets (regulatory asset base)



Note: All data are adjusted to June 2022 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.

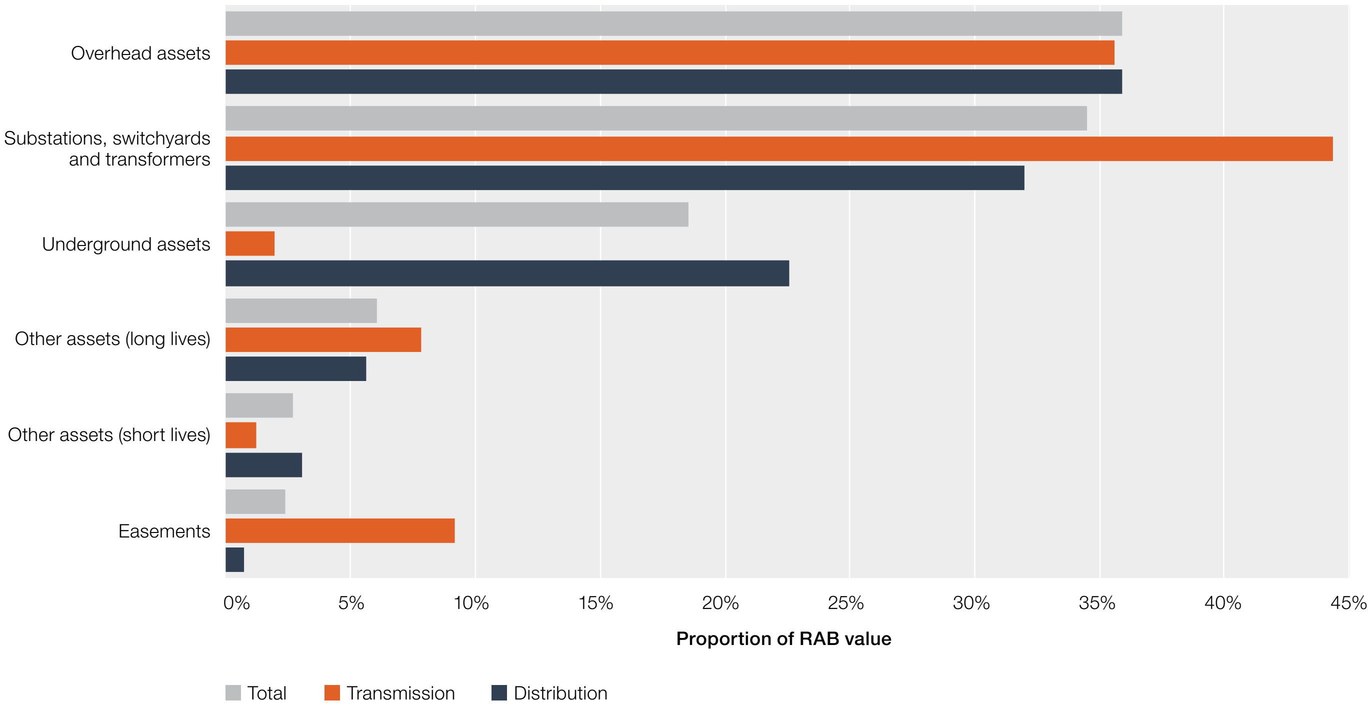
Network service providers receive a guaranteed return on their RAB. For this reason, they have an incentive to overinvest if their allowed rate of return exceeds their actual financing costs. Previous versions of the National Electricity Rules enabled significant overinvestment in network assets, which partly drove the sharp rise in network revenue from 2006 to 2015 (section 4.9). Under reforms introduced in 2015, the AER may remove inefficient investment from a network service provider's asset base if the service provider overspent its capital allowance, to ensure customers do not pay for it.

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

4.11.2 Overhead support structures

A network service provider's RAB is made up of many assets, which can be disaggregated 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 4.14).

Figure 4.14 Disaggregated value of electricity network assets (regulatory asset base)



Source: Economic benchmarking RIN responses.

Transmission towers and distribution poles are installed by network service providers to support overhead powerlines. Transmission towers are predominately made of steel, but distribution poles can be 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.

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 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.[57] 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.[58]

SA Power Networks' distribution network consists of more than 70,000 kilometres of overhead powerlines. However, overhead network assets only make up around 18% 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 considerably large size of the network service area.

57 P Sumerling and W Prest, Stobie Poles, SA History Hub, History Trust of South Australia, accessed 14 December 2020.

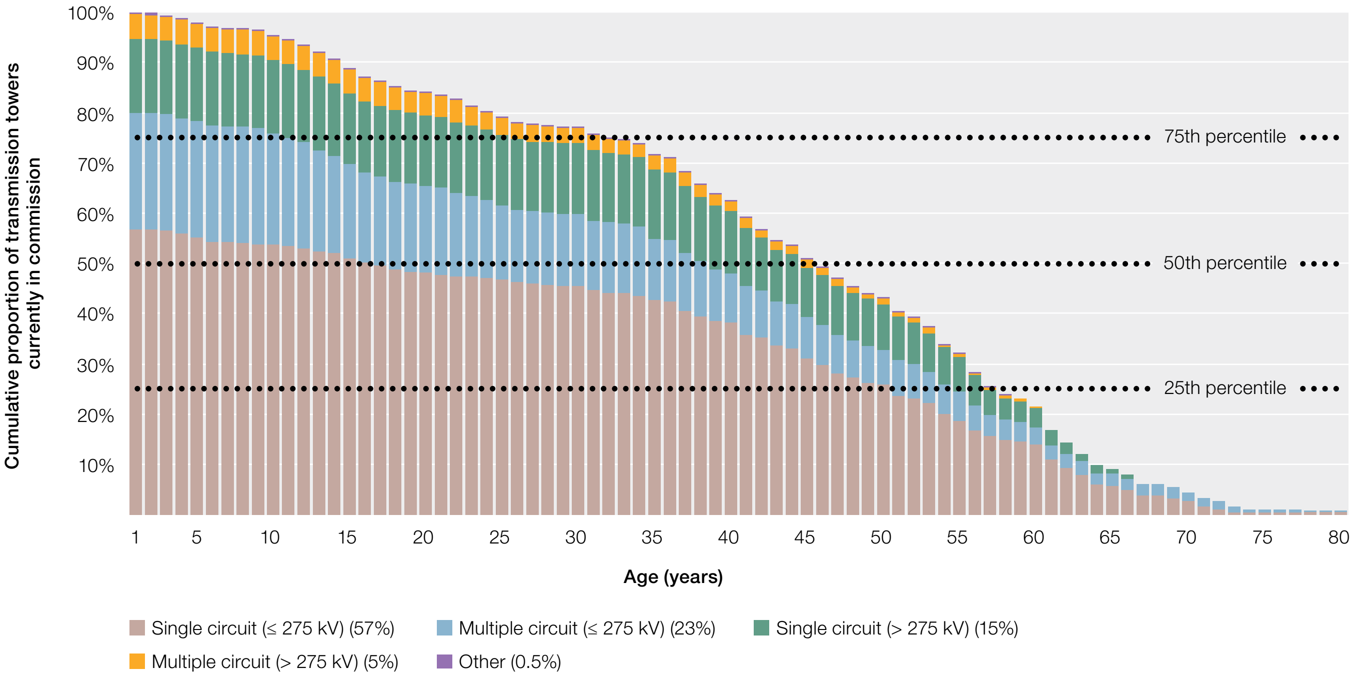
58 ABC News, Stobie poles are a South Australian icon, but how did they come about?, 31 March 2023, accessed 19 April 2024.

Due to the hard-wearing and near-indestructible nature of the distribution poles used in South Australia, the average age of SA Power Networks' poles in commission is significantly higher than those in any other network in the NEM.[59] 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, Evoenergy (ACT) and CitiPower (Victoria) 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 4.15 and Figure 4.16 provide an overview of the age and quantity of towers and poles currently in commission. However, the asset age and tower/pole types vary considerably between the different networks.

Figure 4.15 Electricity transmission network towers

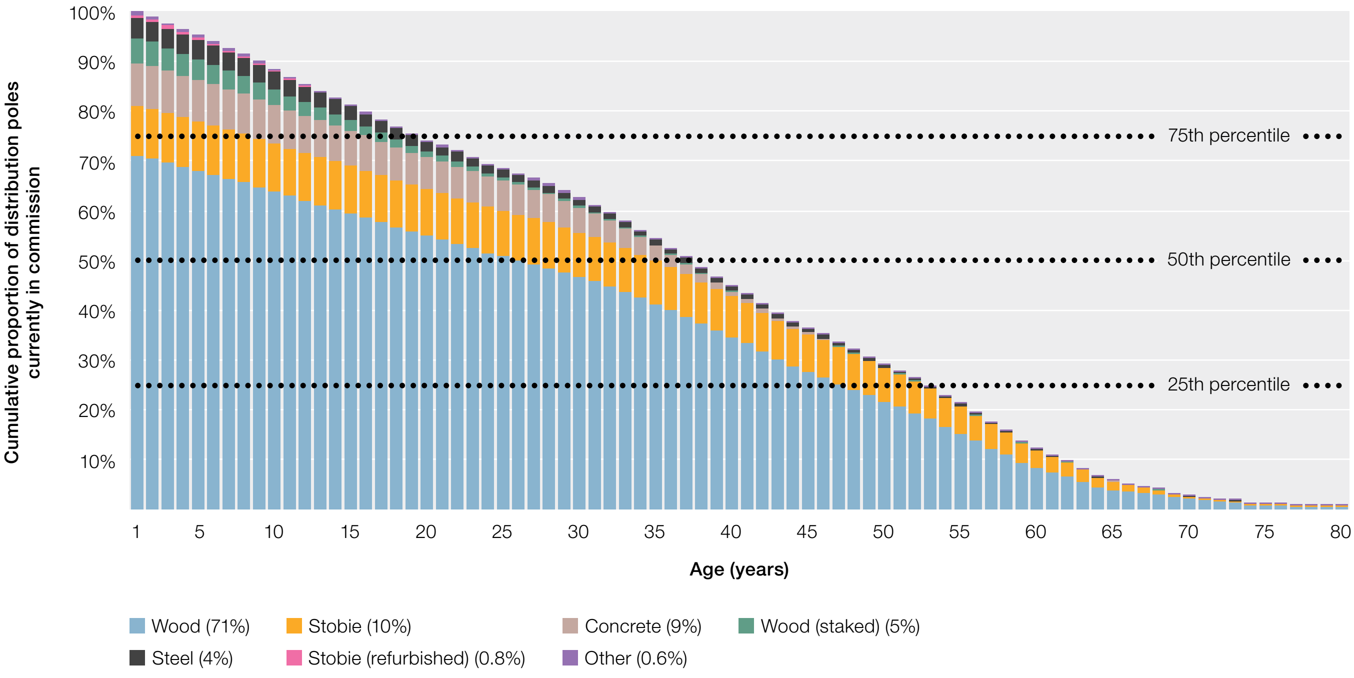


Note: kV: kilovolt.

Source: Category analysis RIN responses.

59 Despite the comparatively strong nature of Stobie poles, the extreme weather event in South Australia in November 2022 severely damaged a number network assets (ABC News, Storm clean-up continues as some northern SA communities lose access to phone services, 14 November 2022, accessed 23 March 2023).

Figure 4.16 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.

4.12 Rates of return

The shareholders and lenders that finance a network service provider expect a commercial 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 4.11) by the allowed rate of return.[60]

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 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 30% to 50% of a network service provider's total revenue allowance. A small change in the allowed rate of return can have a significant impact on network revenue and a customer's energy 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%.[61] 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.

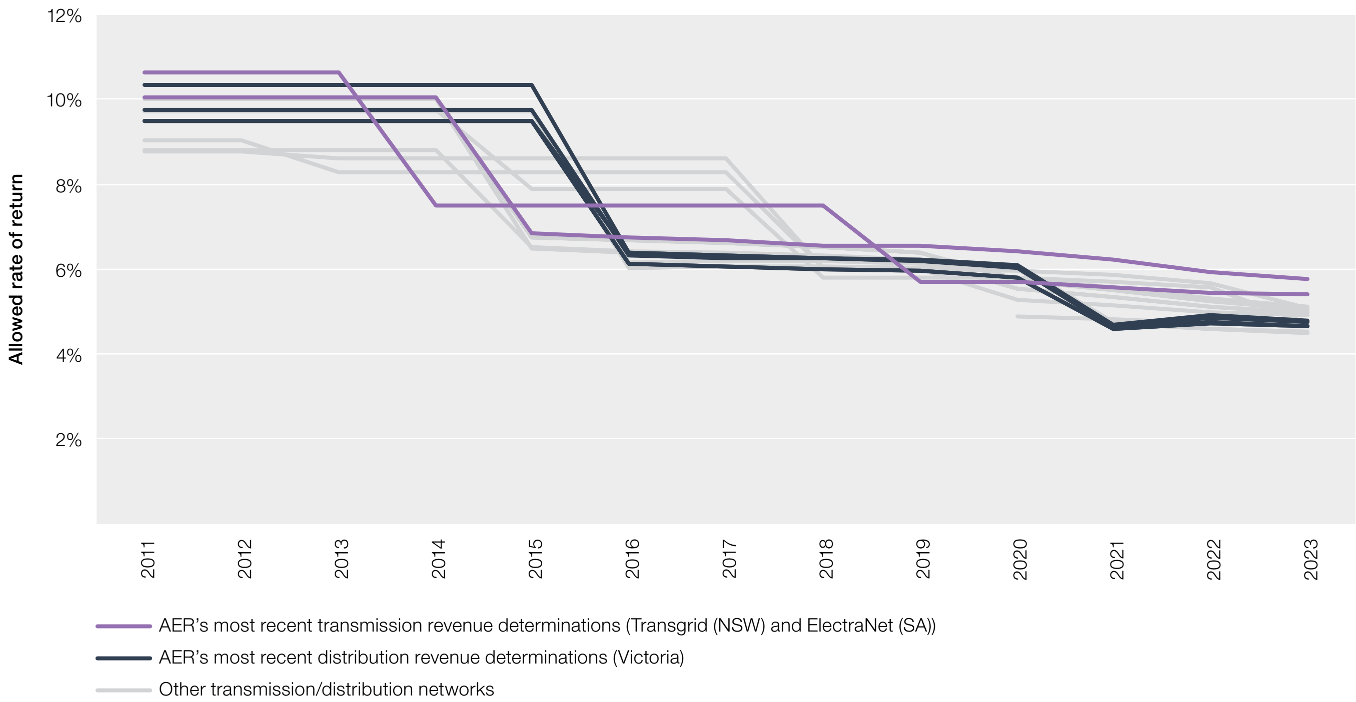
60 For example, if the rate of return is 5% and the RAB is $50 billion, then the return to investors is $2.5 billion. This return forms part of a network service provider's revenue needs and must be paid for by energy customers.

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

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 4.17). The Australian Competition Tribunal increased some allowed rates of return following appeals by the 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 4.17).

Figure 4.17 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.

Recently, some key inputs into rates of return have increased. For example, the risk-free rate is an important driver of allowed returns on equity and is estimated using required returns on Commonwealth Government Securities (CGSs), also known as Australian Government bonds. Annual yields on 10-year CGSs were as low as 0.6% in March 2020, but over 2023 (to mid-July) averaged around 3.6%. Similarly, annual yields on 5-year CGSs were as low as 0.25% in November 2020 but over 2023 (to mid-July) averaged around 3.4%.[62] If risk-free rates, or other key inputs, continue to increase they 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.[63]

In February 2023 the AER released its latest rate of return instrument, which binds all regulatory determinations from 25 February 2023 until the next revision of the Instrument.[64]

62 RBA, Capital Market Yields – Government Bonds – Daily – F2, Reserve Bank of Australia, accessed 14 July 2023.

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

64 AER, Rate of Return Instrument 2022, Australian Energy Regulator, accessed 22 March 2023.

4.13 Investment

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.

4.13.1 Capital expenditure in 2022

In 2022, network service providers outlaid $5.1 billion of investment (capital) expenditure, $605 million (11%) less than in the previous year and $1.2 billion (19%) less than was forecast. This ended a 4-year period of successive increases in network investment.

Table 4.5, Figure 4.18 and Figure 4.19 provides a summary of the capital expenditure outlaid in 2022 and how this compared with previous years' expenditure and forecasts.

Table 4.5 Capital expenditure in 2022 – key outcomes

Service type	Capital expenditure (2022)	Capital expenditure (compared with 2021)	Capital expenditure (compared with peak)
Transmission	$1.2b (▼42% than forecast)	▼$171m (▼12%)	▼$677m (▼35%) (2009)
Distribution	$3.8b (▼8% than forecast	▼$434m (▼10%)	▼$3.7b (▼49%) (2012)
Total	$5.1b (▼19% than forecast)	▼$605m (▼11%)	▼$4.2b (▼45%) (2012)

Note: Excludes AER determinations on transmission interconnectors.

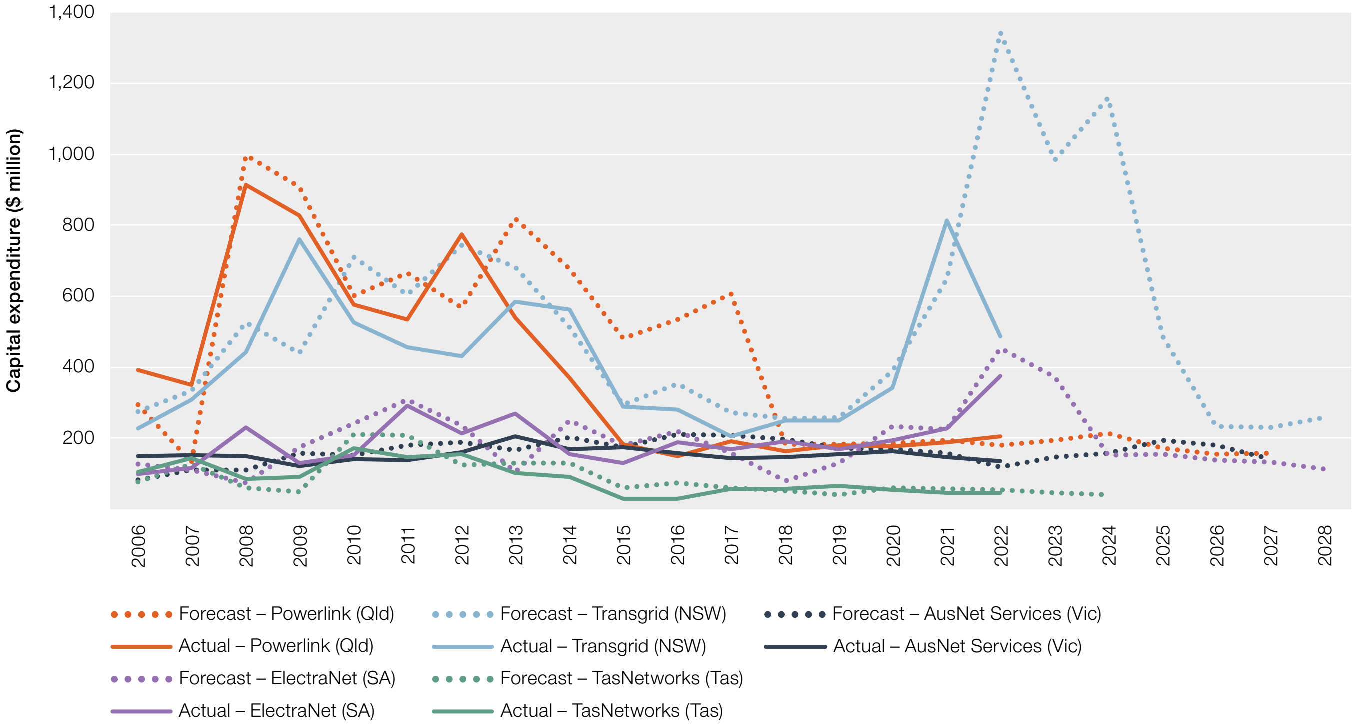
Significant investment in the transmission network is forecast to continue over the next few years (Figure 4.18). Between 2022 and 2026 the modelled cost of actionable Integrated System Plan (ISP) projects under the 2022 ISP – specifically Project EnergyConnect (Transgrid and ElectraNet) and the Queensland–NSW interconnector (QNI) project (Transgrid) – was around $12.7 billion.[65]

Further significant investment is also forecast for Transgrid's HumeLink project – a new 500 kilovolt transmission line that will connect Wagga Wagga, Bannaby and Maragle. Transgrid expects to commence construction on HumeLink in 2024.[66]

65 AEMO, 2022 Integrated System Plan, Australian Energy Market Operator, June 2022, p. 15.

66 Transgrid, HumeLink – fact sheet, accessed 18 September 2023.

Figure 4.18 Capital expenditure – electricity transmission networks

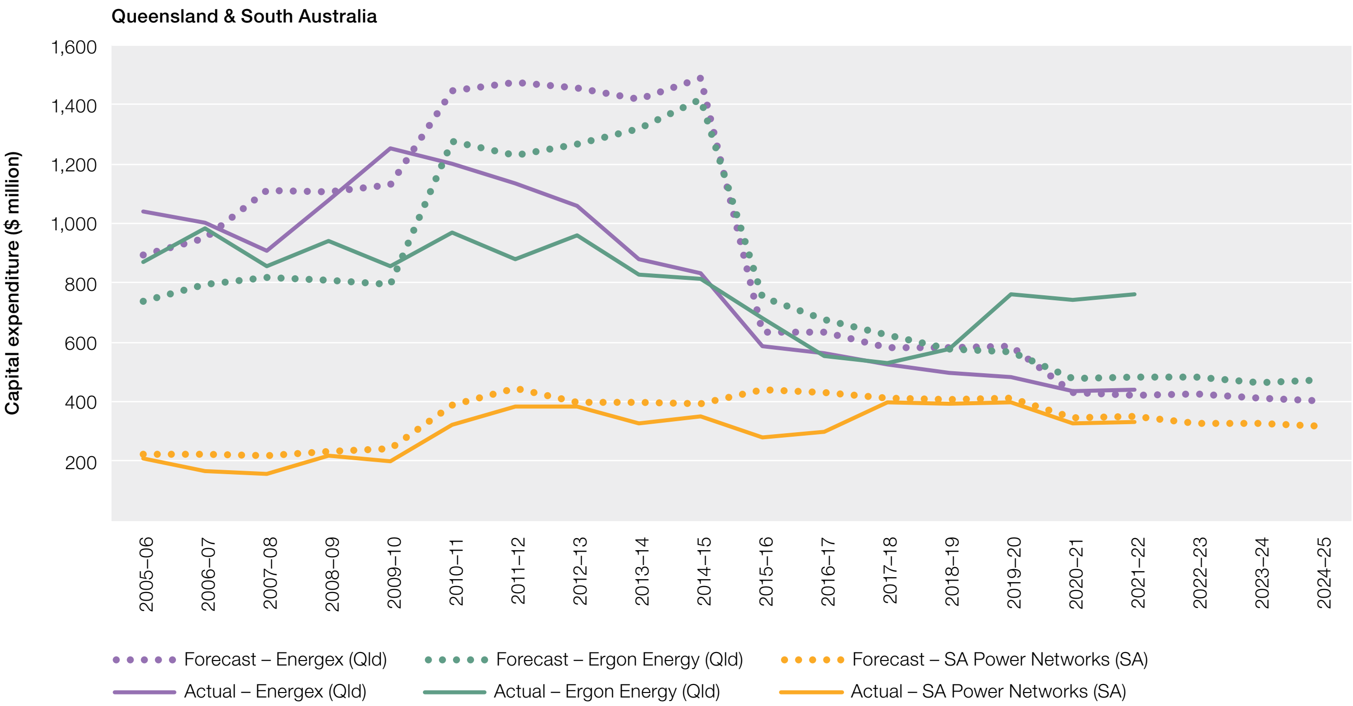


Note: All data are adjusted to June 2022 dollars. The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018). Assumptions are set out in the Figure 4.7 notes.

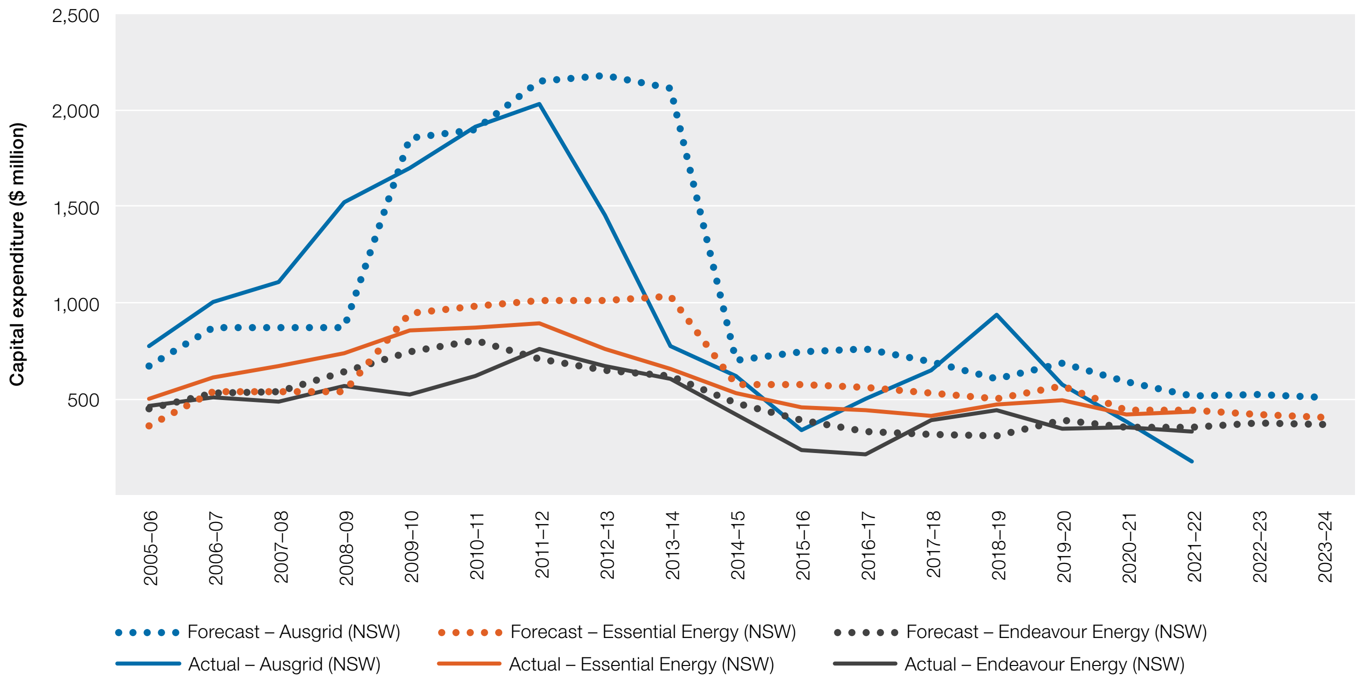
Source: AER modelling; annual reporting RIN responses.

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

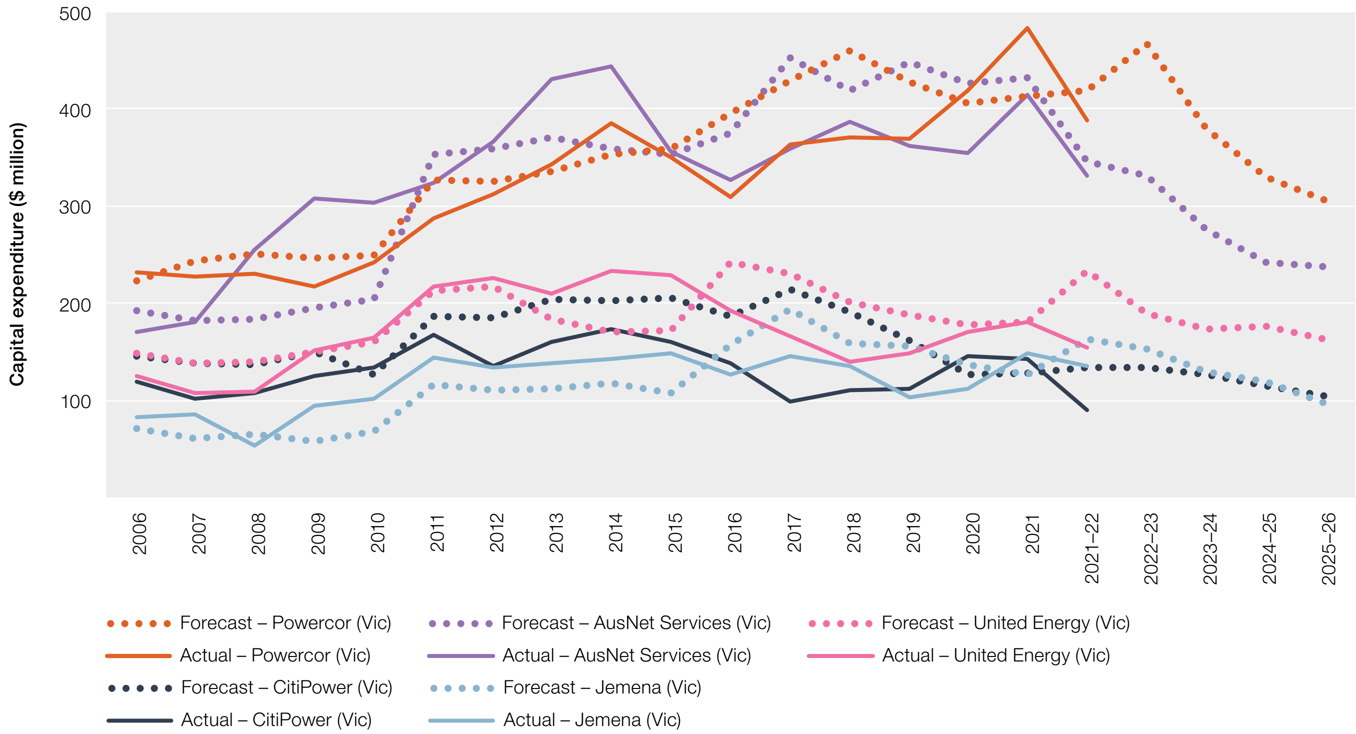
Figure 4.19 Capital expenditure – electricity distribution networks

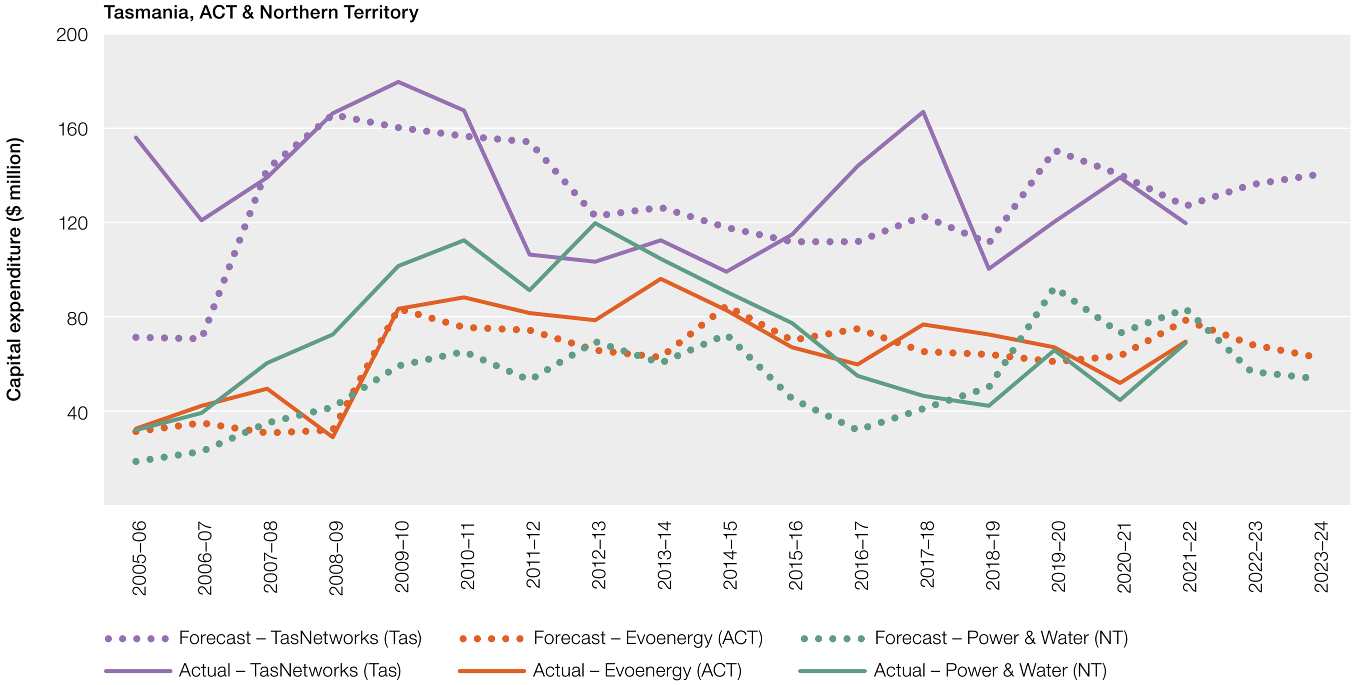


New South Wales



Victoria





Note: All data are adjusted to June 2022 dollars. In July 2021, Victorian distribution network service providers transitioned from reporting on a calendar year basis to a financial year basis. Assumptions are set out in the Figure 4.9 notes.

Source: AER modelling; annual reporting RIN responses.

Ergon Energy (Queensland) submitted that its substantial overspends in 2021 and 2022 were due to the need to address priority network safety and defect rectification programs, including defect rectifications and remediation works.[67]

4.13.2 Investment trends

Total investment in the electricity networks increased by an average of 8% per year from 2006 to 2012, when it peaked at $9.3 billion (Figure 4.7 and Figure 4.9).

In the 4-year period from 2006 to 2009, network service providers invested $2.6 billion (11%) more on capital projects than was forecast. However, this trend of overspending was soon to be reversed, with service providers underspending by $13.6 billion (18%) against forecast over the following 9 years (from 2010 to 2018) (Figure 4.20).

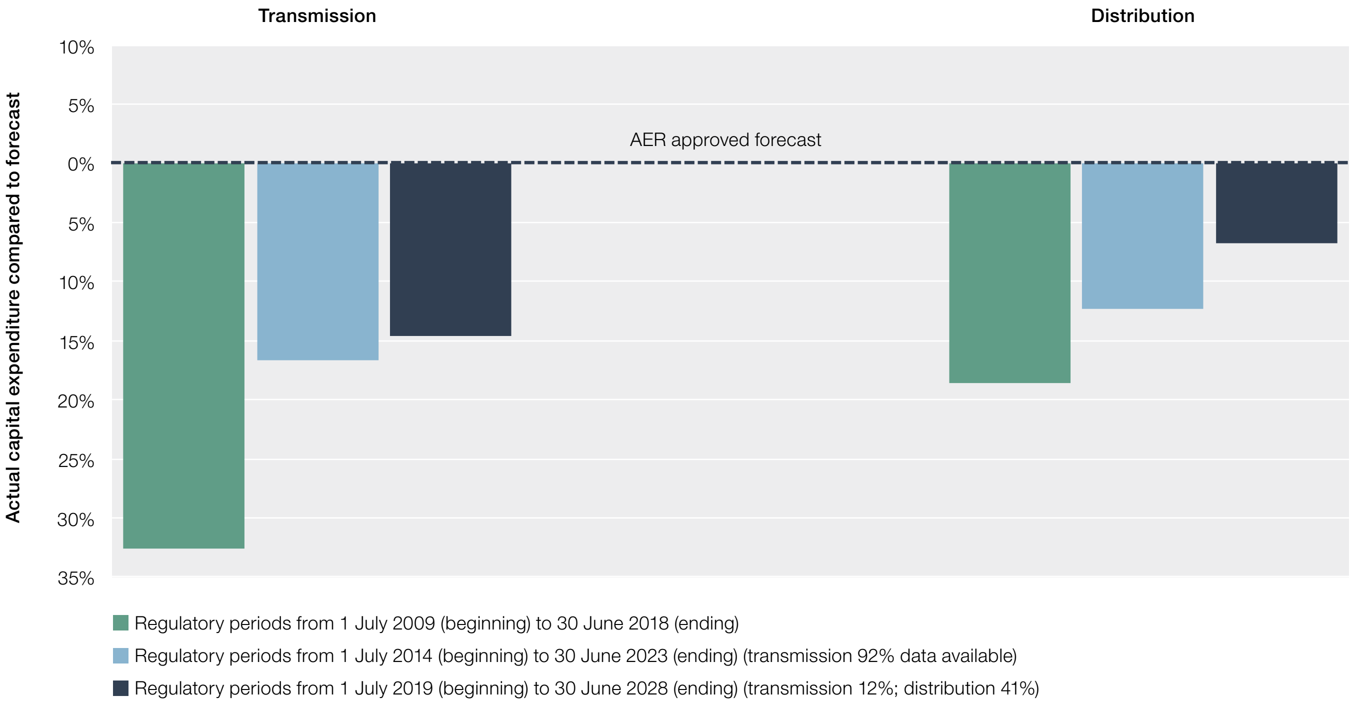
The disparity between forecast and actual investment has eased in recent years. This timing aligns with the AER's reforms to protect consumers from funding inefficient network projects (Figure 4.20).

Over the 5 years from 2013 to 2017, network service providers invested $10.2 billion (25%) less on capital projects than was forecast. In comparison, over the past 5 years (from 2018 to 2022), service providers invested $1.7 billion (6%) less than was forecast. The service providers reporting the most significant underspends over this period were NSW transmission network Transgrid, and the Power and Water (Northern Territory) and United Energy (Victoria) distribution networks, which collectively underspent by 24%.

As previously mentioned, both Transgrid's and ElectraNet's (South Australia) actual capital expenditure was considerably lower than forecast in 2022 primarily due to a reprofiling of expenditure on Project EnergyConnect.

67 Ergon Energy, 2021–22 Annual reporting RIN, 31 October 2022.

Figure 4.20 Capital expenditure against forecast



Source: AER modelling; annual reporting RIN responses.

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, the network service providers are required to undertake a cost-benefit analysis for new investment projects that meet 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, and 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 4.2).

Box 4.2 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 following 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 4.11). 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 remains. 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 4.3) and service quality (Box 4.4). 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 4.16.1).

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 new 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.

4.13.3 Changing composition of investment

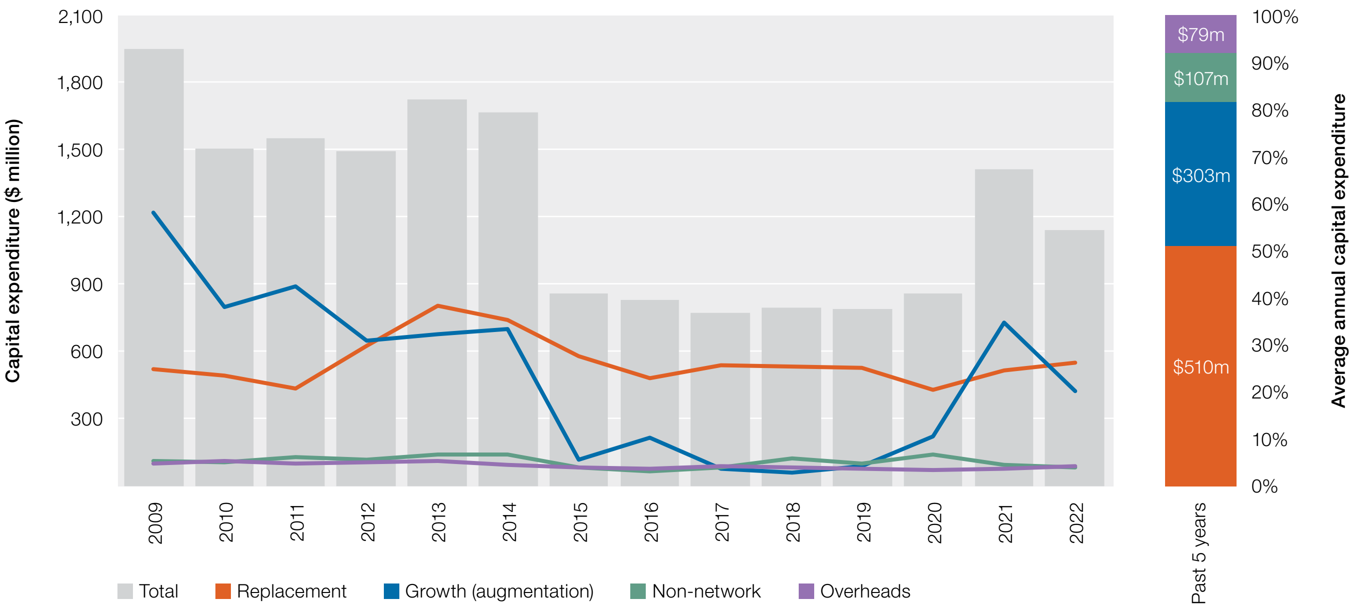
Over the last decade, network investment has been driven by replacement expenditure rather than growth-related expenditure (Figure 4.21 and Figure 4.22). Weaker than forecast demand for electricity, along with less stringent reliability obligations, led many network owners to postpone or abandon growth-related projects.

In 2022, network service providers invested $1.3 billion in growth-related projects, $215 million (14%) less than in the previous year but 30% more than the average spend from 2016 to 2020. The recent increase in growth-related expenditure has primarily been the result of Transgrid's (NSW) substantial investment in Project EnergyConnect, which aims to link up NSW and South Australia by 2024. As at May 2023, construction of ElectraNet's South Australian section of Project EnergyConnect was more than 50% complete and on track to be fully capable by mid-2026.[68]

Transgrid has also forecast substantial investment in developing HumeLink, which aims to connect Snowy 2.0 to the grid by 2026. In May 2023, Snowy Hydro announced it anticipates the timeline for full commercial operation of Snowy 2.0 will be delayed by until December 2028 at the earliest.[69]

Replacing existing assets continues to be the primary driver of capital expenditure for distribution networks, but growth-related expenditure is now also a significant driver for transmission networks.

Figure 4.21 Drivers of capital expenditure – electricity transmission networks (aggregate)



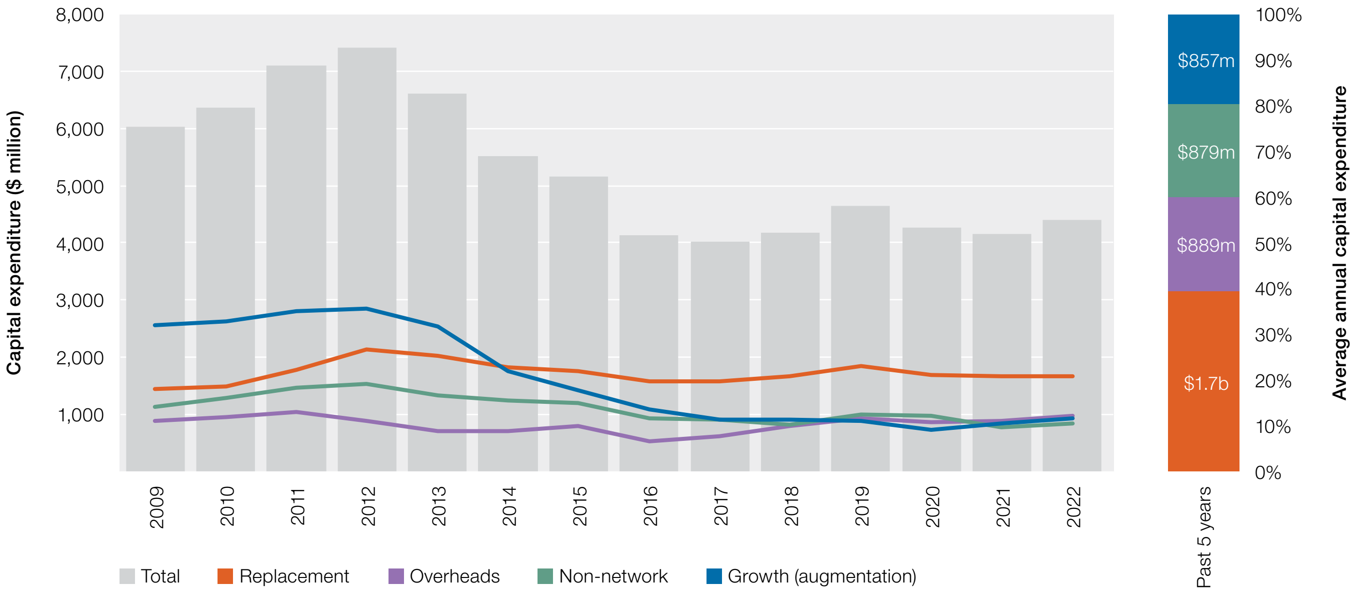
Note: All data are adjusted to June 2022 dollars. The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018). Augmentation of the Victorian transmission network is carried out by AEMO; hence, AusNet Services reports $0 expenditure for augmentation carried out on the transmission network.

Source: Category analysis RIN responses.

68 *pv magazine*, ElectraNet tips interstate transmission link to be online by mid-2026, 8 May 2023.

69 Snowy Hydro, Snowy 2.0 – Project update, media release, Snowy Hydro, 3 May 2023.

Figure 4.22 Drivers of capital expenditure – electricity distribution networks (aggregate)



Note: All data are adjusted to June 2022 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.

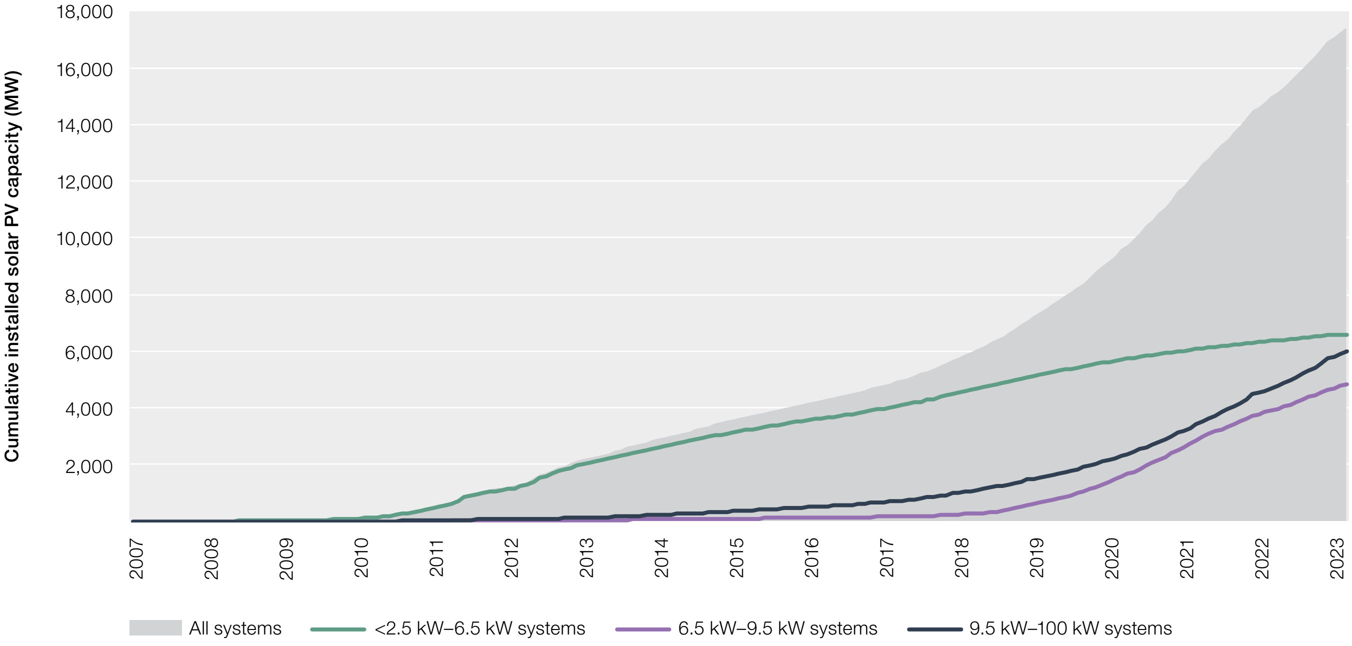
4.13.4 Valuing consumer energy resources

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 (CER) such as solar PV, batteries and electric vehicles now presents a significant, emerging area of 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 1 March 2023, the total installed capacity of smaller solar PV systems with a capacity of up to 6.5 kilowatts increased by 16%, while the total installed capacity of systems with a larger capacity of 6.5 to 100 kilowatts increased by 179% (Figure 4.23).[70]

70 Excludes Western Australia.

Figure 4.23 Cumulative installation of small-scale solar by system size



Note: kW: kilowatts; MW: megawatts; 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 2 June 2023.

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 of consumer energy resources 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.[71] 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.[72]

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 several key respects. 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 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.[73]

71 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.

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

73 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.[74]

4.13.5 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.

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

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).

Until 2017 the regulatory test only applied to growth related investment, which had been the most significant component of network investment until 2014. Replacement expenditure has since overtaken growth investment on most networks (section 4.13.3); as such, the test now also applies to replacement projects. Other revisions were made to the test to ensure it adequately considers system security, emissions reduction goals and low probability events that would have a high impact.

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.[75] The guidelines include a cost-benefit analysis guideline[76], a forecasting best practice guideline and updates to the regulatory investment test for transmission (RIT-T) instrument[77] and application guidelines.[78] The guidelines are part of broader reforms that were led by the Energy Security Board (ESB), with changes made to the National Electricity Rules to streamline the transmission planning process while retaining rigorous cost-benefit analyses.

In August 2023, the AER published a report detailing the outcomes of its transparency review of AEMO's Inputs, Assumptions and Scenarios Report (IASR).[79] The IASR contains the inputs, assumptions and scenarios that AEMO proposes to use in its 2024 ISP. The AER assessed the adequacy of AEMO's explanation of how the inputs, assumptions and scenarios had been derived. The review is not intended to assess the merits of AEMO decisions, rather to form an opinion on the adequacy of AEMO's explanations.

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

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

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

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

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

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

79 AER, Transparency review of AEMO 2023 Inputs, Assumptions and Scenarios Report, Australian Energy Regulator, accessed 31 August 2023.

4.13.6 AEMO's Integrated System Plan

AEMO's ISP provides a coordinated whole-of-system plan for efficient development of the power system in the National Electricity Market (NEM) to ensure needs are met in the long-term interests of consumers.

The ISP 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. AEMO identifies the network investments that are likely to optimise the net market benefits across future NEM development scenarios over the planning horizon as the optimal development path for the NEM.

The optimal development path includes 'actionable' ISP projects and future ISP projects, which can be progressed through the RIT-T process. It also identifies future ISP development opportunities such as distribution assets, storage or demand-side developments.

Significant investment in the transmission network is forecast over the next few years. The modelled cost of actionable ISP projects under the 2022 ISP was around $12.7 billion.[80]

In September 2023, AEMO provided an update to the 2022 ISP cost estimates to reflect supply chain constraints and global competition for electricity infrastructure assets.[81]

AEMO has prepared a new transmission cost forecasting approach for the 2024 ISP, which is due to be published in June 2024. AEMO's new cost forecasting approach has been developed in response to unprecedented cost increases across the sector in recent years. A key change in AEMO's new approach is the application of additional escalation factors for individual cost components – such as commodity prices (oil, aluminium, copper and steel) and land cost – beyond the economy-wide inflation rate.

As a result of AEMO's updated approach, project cost estimates are, depending on scope, approximately 30% higher (in real terms) than in the 2022 ISP.[82] AEMO expects transmission project costs will continue to increase beyond the rate of inflation while the sector adapts to markets pressures driven by the global race to net zero.

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[83] and cost-benefit analysis guidelines.[84] 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.[85]

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.

Figure 4.24 provides a visual summary of AEMO's 2022 ISP along with transmission expansion options that will inform the development of the 2024 ISP. Figure 4.24 also shows several of the smaller ISP projects that have been completed since the 2022 ISP was published, including:

- the QNI Minor interconnection upgrade
- the VNI Minor interconnection
- the Eyre Peninsula link.[86]

80 AEMO, 2022 Integrated System Plan, Australian Energy Market Operator, June 2022, p. 15.

81 AEMO, 2023 Transmission Expansion Options Report, Australian Energy Market Operator, September 2023.

82 AEMO, 2023 Transmission Expansion Options Report, Australian Energy Market Operator, September 2023, pp. 27–28.

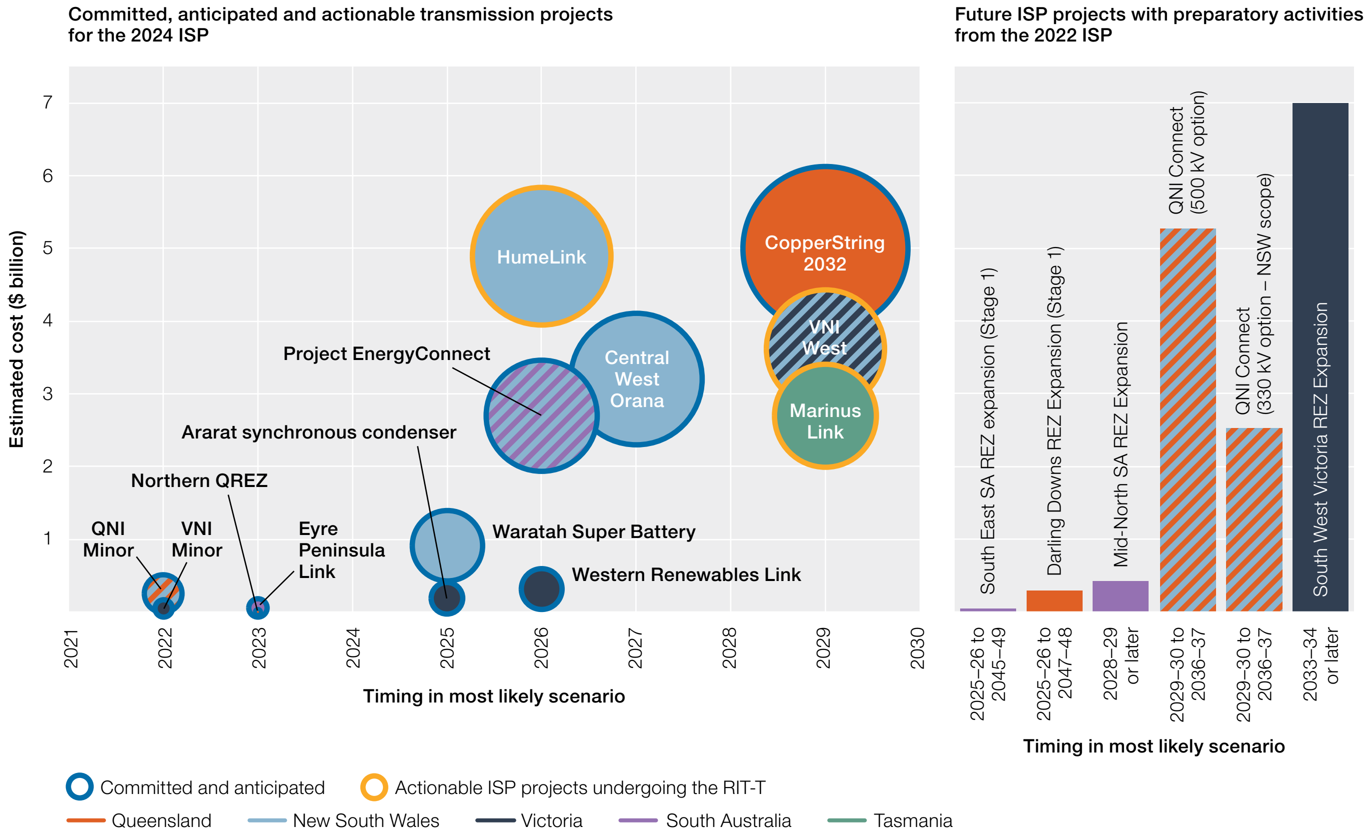
83 AER, Forecasting best practice guidelines, Australian Energy Regulator, August 2020.

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

85 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.

86 Transgrid, Queensland NSW Interconnector, June 2022; Transgrid, Victoria to NSW Interconnector, November 2022; ElectraNet, New transmission line powering the Eyre Peninsula, March 2023.

Figure 4.24 AEMO's integrated system plan



Note: Committed projects meet 5 criteria relating to planning consents, construction commencement, land acquisition, contracts for supply and construction of equipment and necessary financing arrangements. Anticipated projects are in the process of meeting at least 3 of the criteria. Data used to show the estimate costs of future ISP projects with preparatory activities was provided to AEMO by the transmission network service providers. Preparatory activities are intended to improve the conceptual design, lead time, location and cost estimates for transmission projects. The ISP may require preparatory activities for some future ISP projects. Future ISP projects are projects which address an identified need, form part of the optimal development path, and may be actionable ISP projects in the future.

Source: AER analysis, AEMO integrated system plan, June 2022, AEMO Transmission Expansion Options Report, September 2023.

4.13.7 Regulatory tests – recent activity

As at September 2023, 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.[87]

In May 2023, AVP and Transgrid published the project assessment conclusions report for VNI West. The project assessment conclusions report is a major milestone in the RIT-T process, representing the final stage in the RIT-T consultation process.[88]

87 Victorian Government, VNI West and Western Renewables Link Ministerial Order, Victorian Government Gazette, 20 February 2023

88 AER, AEMO Victoria Planning and Transgrid: VNI West PACR, Australian Energy Regulator, 21 June 2023.

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 September 2023, the Tasmanian and Australian governments made a number of amendments to the existing Marinus Link agreement including:[89]

- focusing on delivering one cable initially, with subsequent consideration of a second cable to be considered at a later date
- working towards a delivery time frame as close as possible to 2028
- increasing the Australian Government's share of the funding to 49%, Tasmania's share decreasing to approximately 18% and Victoria's share remaining at 33%.

HumeLink

Transgrid (NSW) completed a RIT-T for HumeLink, a proposed 500 kilovolt transmission upgrade connecting Project EnergyConnect and Snowy 2.0 to Bannaby in southern NSW.

On 17 August 2022, the AER accepted Transgrid's HumeLink first part of stage 1 contingent project application of $71.5 million in revenue, paid by energy consumers, to deliver proposed early works for the HumeLink project.[90]

On 23 May 2023, Transgrid submitted the second part of its stage 1 contingent project application to seek $226.7 million in revenue for the procurement of equipment. Transgrid will submit a second stage contingent project application to the AER by the end of 2023, seeking to recover revenue for project implementation costs once the project has been committed to and a final cost estimate is available.

The AER's role is to review the reasonableness of the proposed costs within the stage 1 part 2 application to ensure consumers pay no more than necessary.

New England REZ Transmission Link and Sydney Ring

The 2 remaining actionable projects identified under the 2022 ISP are the NSW New England REZ Transmission Link and the Sydney Ring project.[91] These 2 projects will progress under the *Electricity Infrastructure Investment Act 2020* (NSW) rather than the ISP framework, so RIT-T processes are not expected for these projects.

4.13.8 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.[92] This results in network service providers providing data on geographic constraints to assist third parties in offering non-network solutions and to inform connection decisions at the transmission level.[93]

4.13.9 Demand management

Network service providers have options to manage demand on their networks to reduce, delay or avoid the need to install or upgrade expensive network assets. Managing demand in this way can minimise network charges. It can also increase the reliability of supply and reduce wholesale electricity costs.

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89 Australian Government and Tasmanian Government, Joint media release, Investing in the future of Tasmanian energy with Marinus Link, 5 September 2023.

90 AER, Transgrid – HumeLink contingent project – Stage 1 part 2, Australian Energy Regulator, 23 May 2023.

91 AEMO, 2022 Integrated System plan, Australian Energy Market Operator, June 2022.

92 AER, Final decision: Distribution annual planning report template v.1, Australian Energy Regulator, June 2017; AER, Final decision: Transmission annual planning report guidelines, Australian Energy Regulator, December 2018.

93 For an example of the constraint data available, see the datasheets under Ausgrid, Distribution and transmission annual planning report and data map, accessed 28 July 2022.

The AER offers incentives for distribution 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 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 distribution network 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.

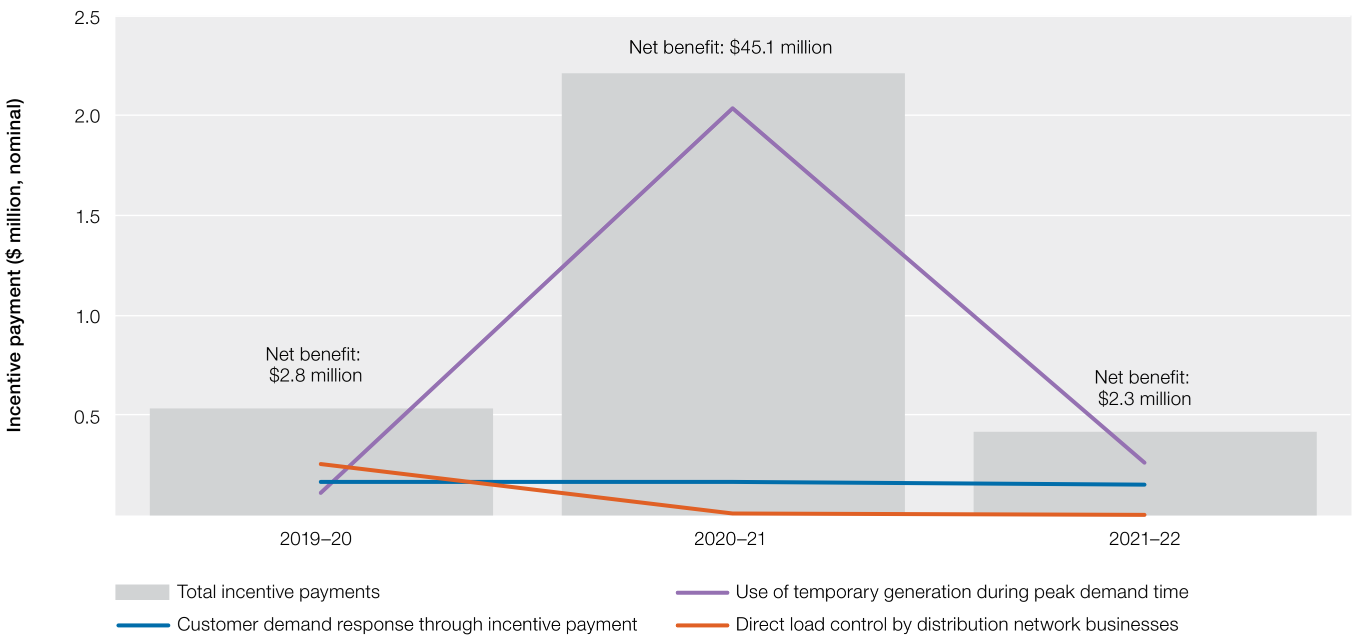
To receive an incentive payment, the network service provider must first submit a claim for its eligible projects[94] to the AER and provide information on how it is using demand management to deliver value to their customers. The AER uses the information provided to determine if the network service provider is eligible to receive an incentive payment.

Complementing this scheme, the AER operates a demand management innovation allowance mechanism (DMIAM).[95] [96] The DMIAM provides funding for network service providers to undertake research and development works to help them to develop innovative ways to deliver ongoing reductions in demand or peak demand for network services. A key 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 $50 million in benefits to consumers (at a cost of $3.2 million) by encouraging distribution service providers to defer replacement or augmentation capital expenditure in favour of pursuing demand management activities (Figure 4.25).[97]

Figure 4.25 Funding of demand management innovations – electricity distribution networks



Source: AER, Demand management incentive scheme (DMIS) assessment 2020–21 and 2021–22.

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

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

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

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

4.14 Operating costs

Network service providers incur operating and maintenance costs that account for around 35% of their annual revenue (Figure 4.5). As part of its 5-year regulatory review, 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 is guided by the forecasts in each network service provider's regulatory proposal. However, if the AER considers the proposed forecasts to be unreasonable then it may replace them with its own forecasts.

Alongside this assessment, the AER's efficiency benefit sharing scheme (EBSS) encourages network service providers to explore opportunities to lower their operating costs (Box 4.3).

Box 4.3 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. Efficiency gains occur if a network service provider spends less on operating and maintenance than forecast in its regulatory determination. Conversely, an efficiency loss occurs if the service provider spends more than forecast.

The regulatory framework allows a network service provider to keep the benefit (or incur the cost) if its actual operating expenditure is lower (higher) than forecast in each year of a regulatory period. The EBSS then allows a network service provider to keep those benefits (or incur those costs) for an additional period. 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 (Box 4.2). The EBSS incentives also balance against those of the service target performance incentive scheme (Box 4.4) to encourage network service providers to make efficient holistic choices between capital and operating expenditure in meeting reliability 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. In retrospect, customers have received closer to 80% of the benefits, due in large part to the impact the changes in rate of return parameters have had on network service providers.

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 2023.

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

4.14.1 Operating expenditure in 2022

In 2022, network service providers spent $3.7 billion on operating costs, $46 million (1.2%) less than in the previous year.

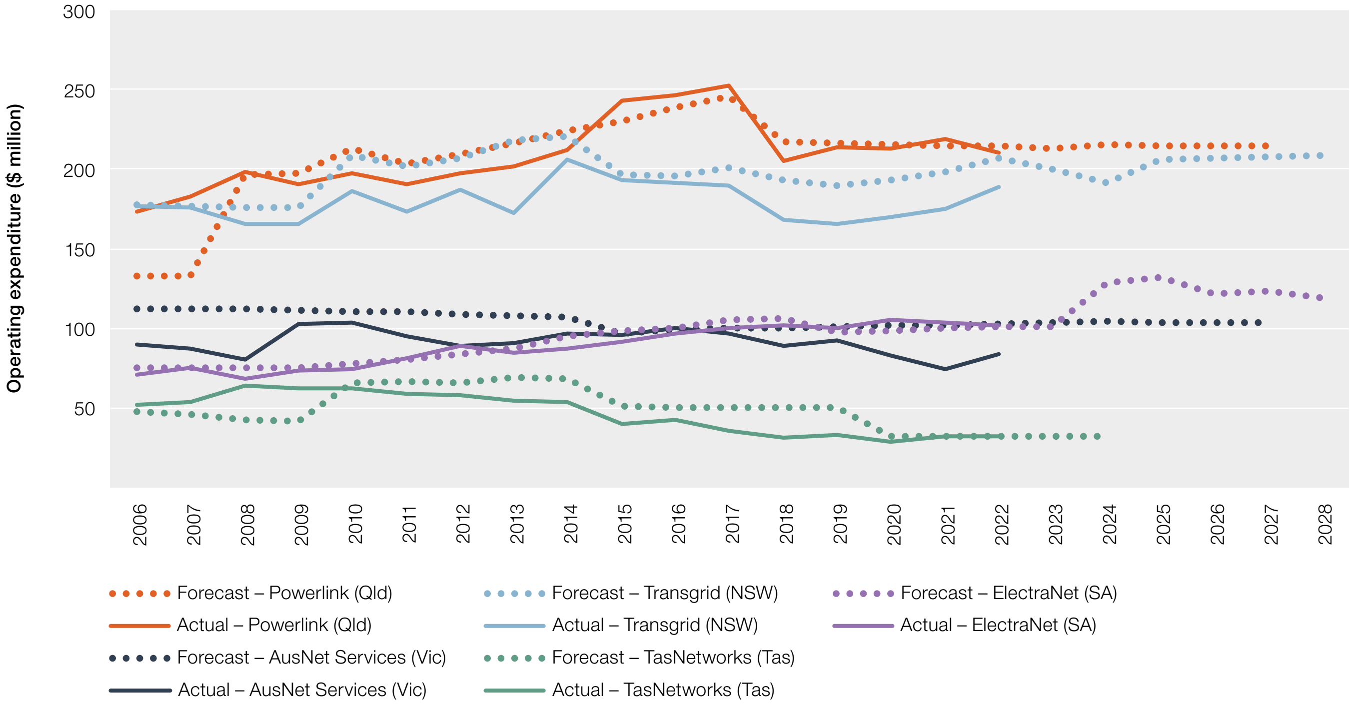
Table 4.6, Figure 4.26 and Figure 4.27 provide a summary of the operating expenditure outlaid in 2022 and how this compared with previous years' expenditure and forecasts.

Table 4.6 Operating expenditure in 2022 – key outcomes

Service type	Operating expenditure (2022)	Operating expenditure (compared with 2021)	Operating expenditure (compared with peak)
Transmission	$617m (▼6% than forecast)	▲$12m (▲2%)	▼$60m (▼9%) (2016)
Distribution	$3.0b (▼10% than forecast)	▼$58m (▼1.9%)	▼$836m (▼22%) (2012)
Total	$3.7b (▼9% than forecast)	▼$46m (▼1.2%)	▼$840m (▼19%) (2012)

Note: Excludes AER determinations on transmission interconnectors.

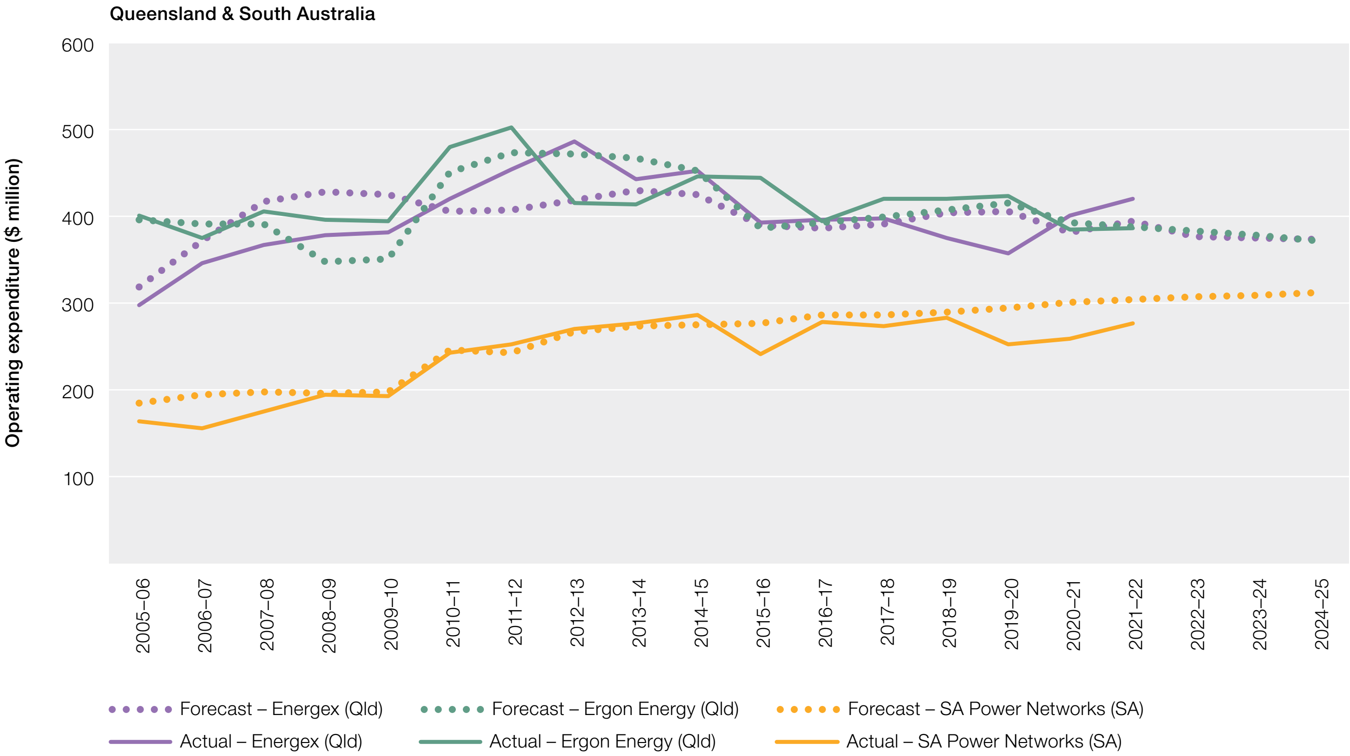
Figure 4.26 Operating expenditure – electricity transmission networks

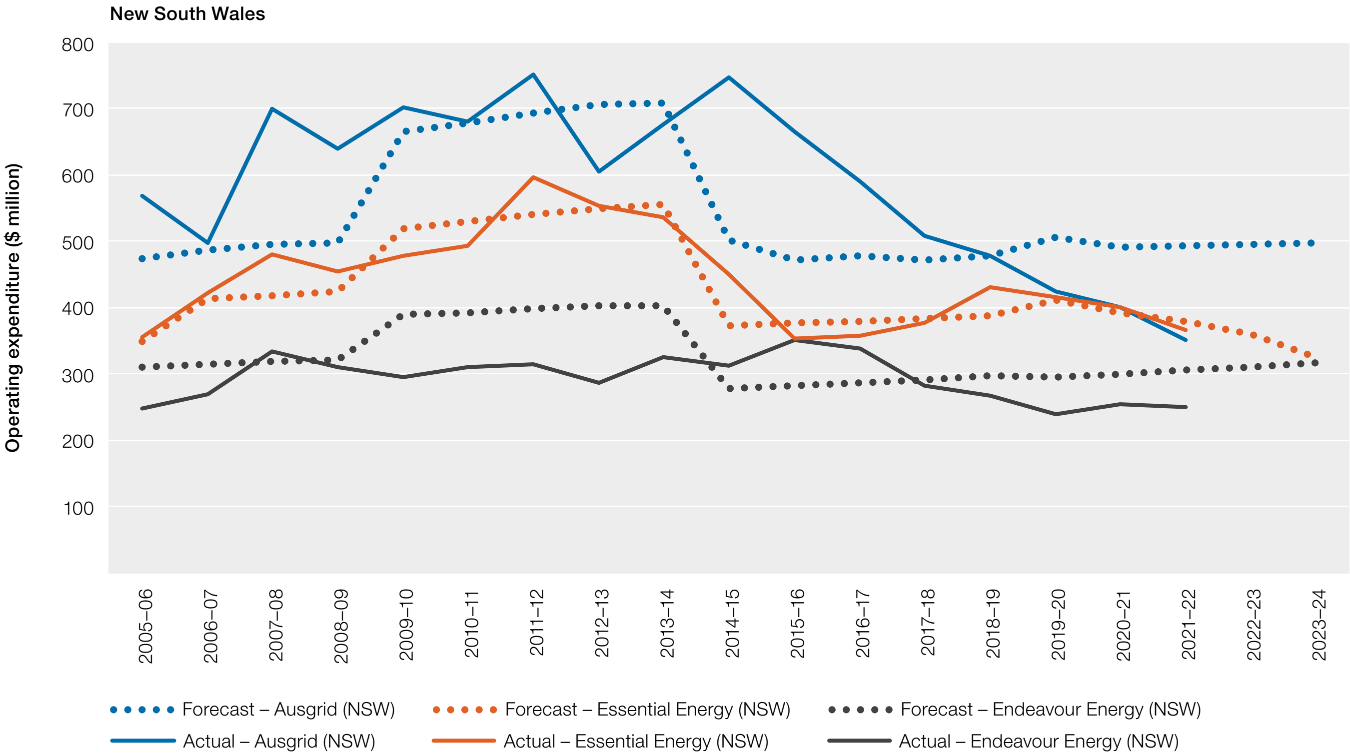


Note: All data are adjusted to June 2022 dollars. The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018). Assumptions are set out in the Figure 4.7 notes.

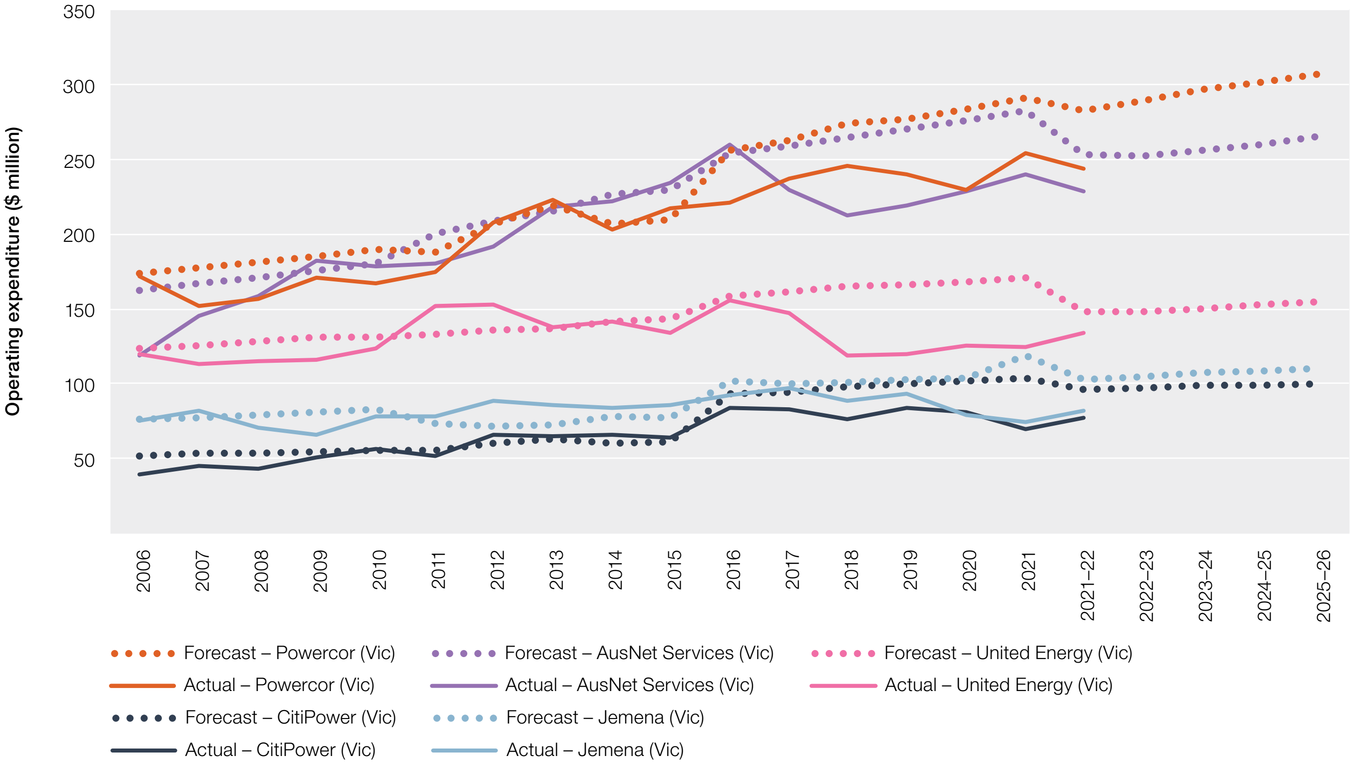
Source: AER modelling; annual reporting RIN responses.

Figure 4.27 Operating expenditure – electricity distribution networks

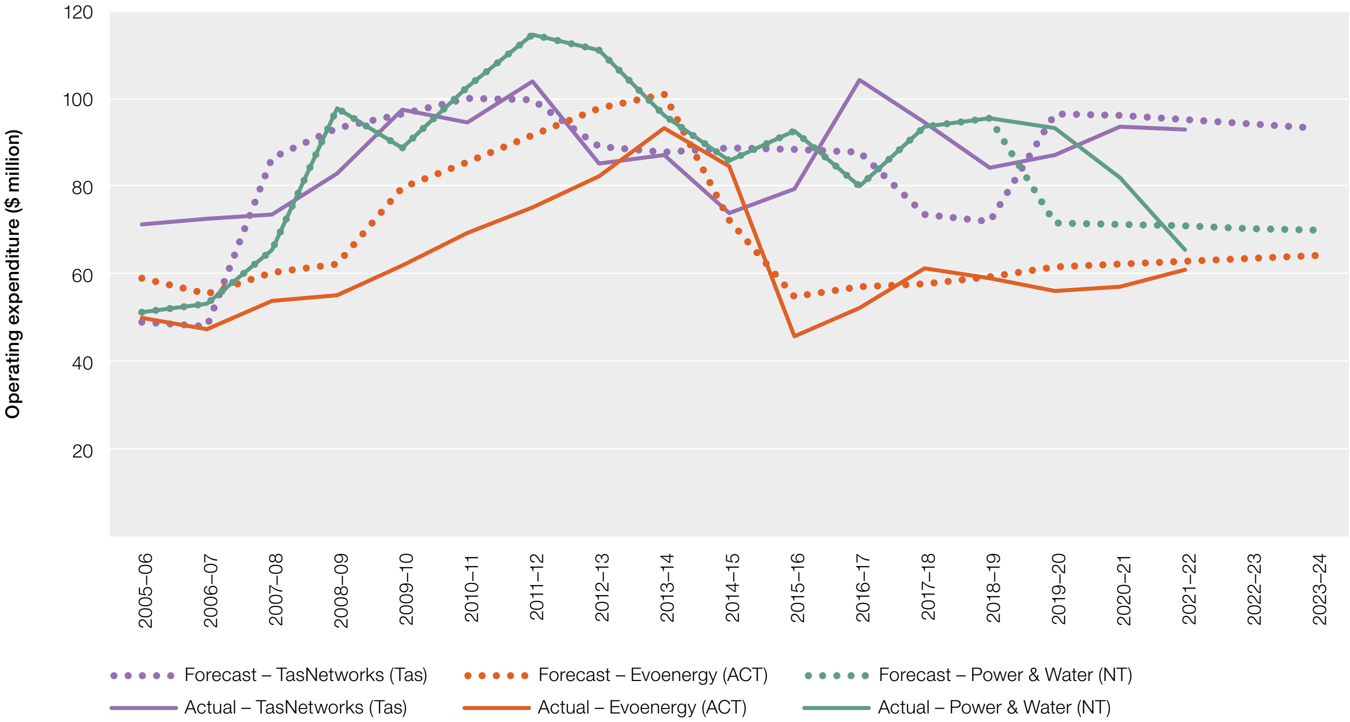




Victoria



Tasmania, ACT & Northern Territory



Note: All data are adjusted to June 2022 dollars. In July 2021, Victorian distribution network service providers transitioned from reporting on a calendar year basis to a financial year basis. Assumptions are set out in the Figure 4.9 notes.

Source: AER modelling; annual reporting RIN responses.

4.14.2 Operating cost trends

Total operating costs for the electricity networks increased by an average of 5% per year from 2006 until 2012, before peaking at $4.5 billion (Figure 4.7 and Figure 4.9).

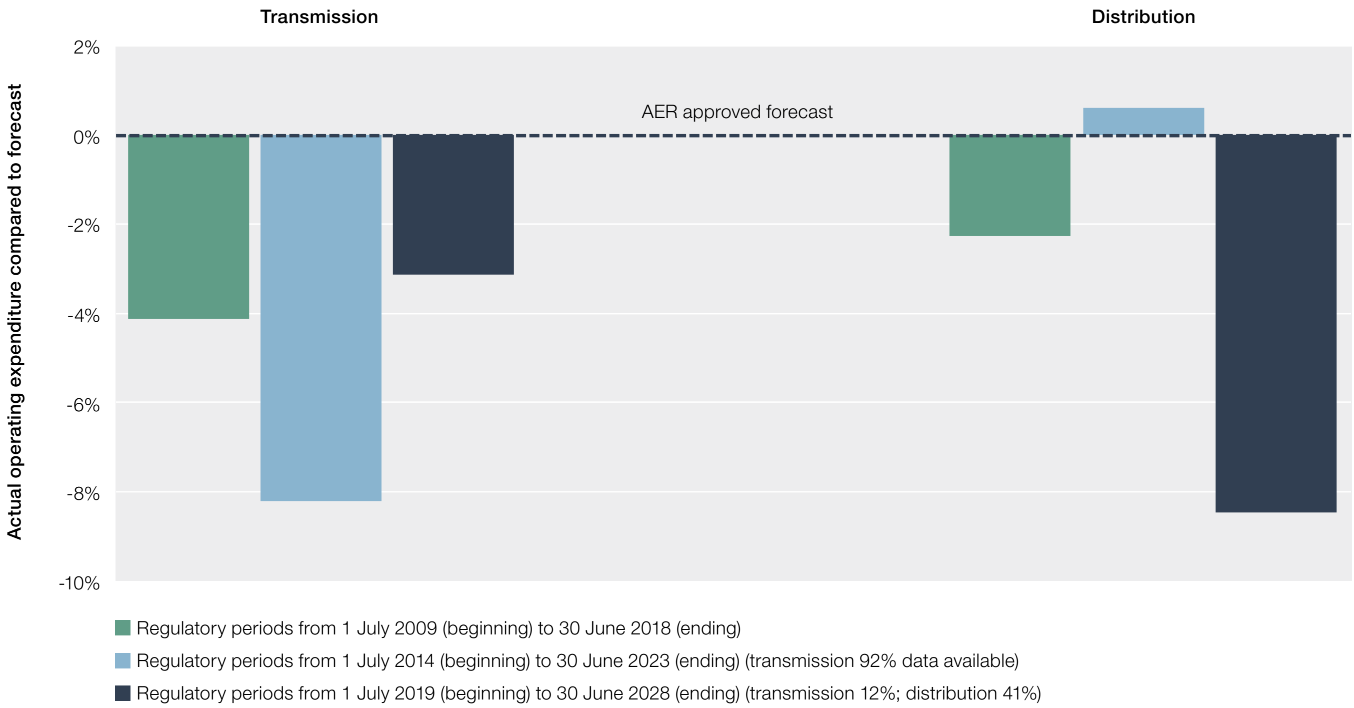
In recent years operating costs have decreased, largely due to network service providers implementing more efficient operating practices. However, the decrease in operating expenditure has been less marked than it has been for capital expenditure.

A number of network service providers implemented efficiencies in managing their operating costs 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 costs – such as marketing, payroll, insurance, inspection and maintenance, vegetation management, emergency response, and funds allocated for research and development – are largely recurrent and predictable. As such, actual operating expenditure against forecast has been far more stable over the past few regulatory periods than it has been for capital expenditure (Figure 4.28).

However, other factors such as reporting obligations, changes to connections charging arrangements, pricing reforms and greater use of non-network options (section 4.8) can also impact costs.

Figure 4.28 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 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.

4.15 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.[98]

The AER uses a forecast productivity growth rate when reviewing the operating expenditure forecasts of distribution network service providers. This growth rate – which has been applied in all regulatory determinations since March 2019 – 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.

4.15.1 Productivity trends

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

- rising capital investment (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[99] decreased by 0.3% during 2021, primarily due to an increase in the capital input for overhead line capacity. The increase was largely driven by a winter peak in 2021 for some of Transgrid's (NSW) existing overhead line assets, rather than any additional network investment or an increase in the overhead line length.[100]

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 15 years since 2006. Capital partial factor productivity – output per unit of capital expenditure – has declined at an average rate of 1.5% per year compared with average operating expenditure efficiency growth – output per unit of operating expenditure – of 0.7% per year over the same period.

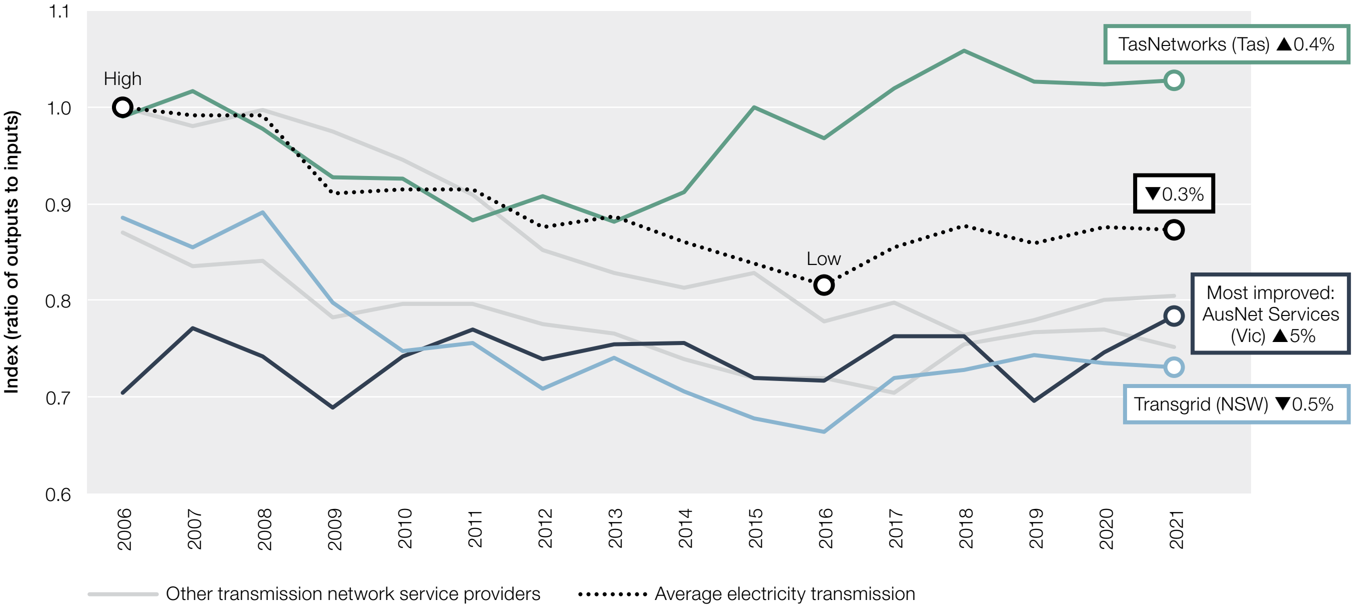
In 2021, 3 of the 5 electricity transmission network service providers in the NEM improved their productivity (Figure 4.29).

98 AER, Annual benchmarking report, electricity distribution network service providers, Australian Energy Regulator, November 2021, pp. 45–52.

99 As measured by total factor productivity (TFP).

100 AER, Annual benchmarking report - Electricity transmission network service providers, Australian Energy Regulator, 30 November 2022.

Figure 4.29 Productivity – electricity transmission networks



Note: Index of multilateral total factor productivity relative to the 2006 performance of ElectraNet (South Australia). The transmission and distribution indexes cannot be directly compared. 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 transmission networks.

Distribution network productivity

Productivity for distribution network service providers[101] increased by 1.5% over 2021, primarily due to increases in reliability. The annual productivity growth rate for distribution network service providers was higher over the past 5 years (2017 to 2021) (0.6%) than it was over the preceding 5 years (2012 to 2016) (0.0%).[102]

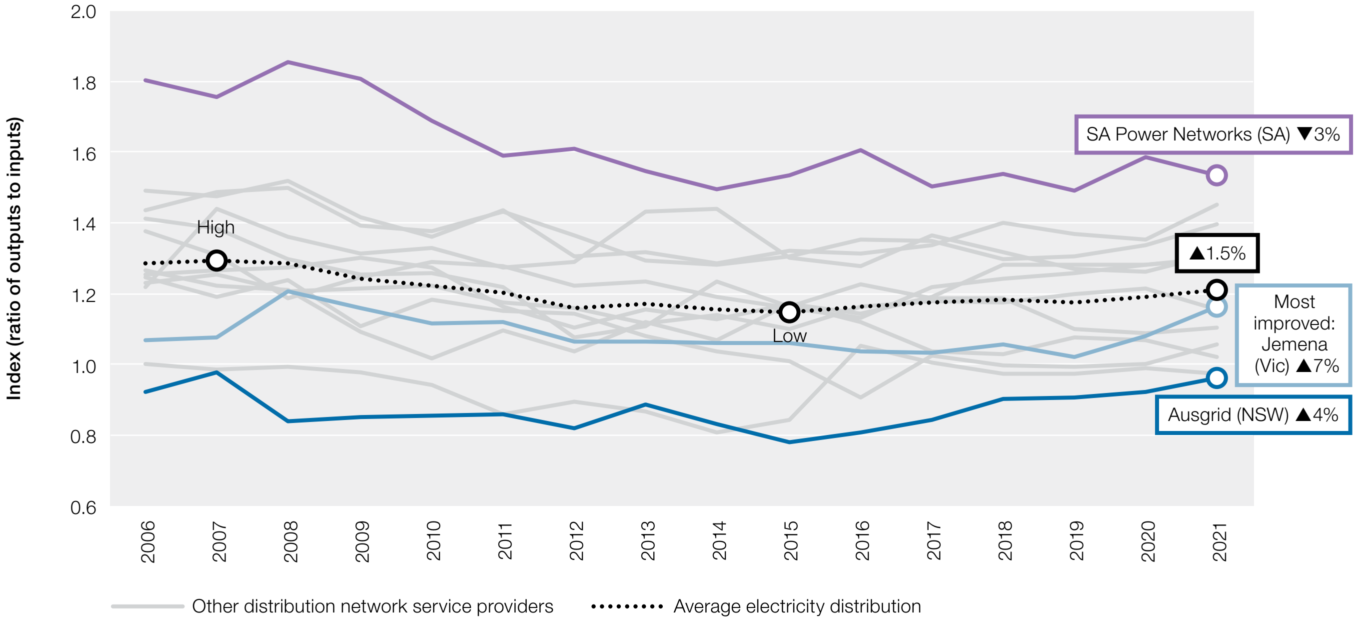
In 2021, 9 of the 13 distribution network service providers in the NEM improved their productivity. The time series data shown in Figure 4.30 highlights the variability in annual productivity for individual distribution network service providers. This variability emphasises the importance of considering single year changes in productivity, be it 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 4.30).

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

102 AER, Annual benchmarking report - Electricity distribution network service providers, Australian Energy Regulator, 30 November 2022.

Figure 4.30 Productivity – electricity distribution networks



Note: Index of multilateral total factor productivity relative to the 2006 performance of Evoenergy (ACT). The transmission and distribution indexes cannot be directly compared. 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.

4.15.2 Network utilisation

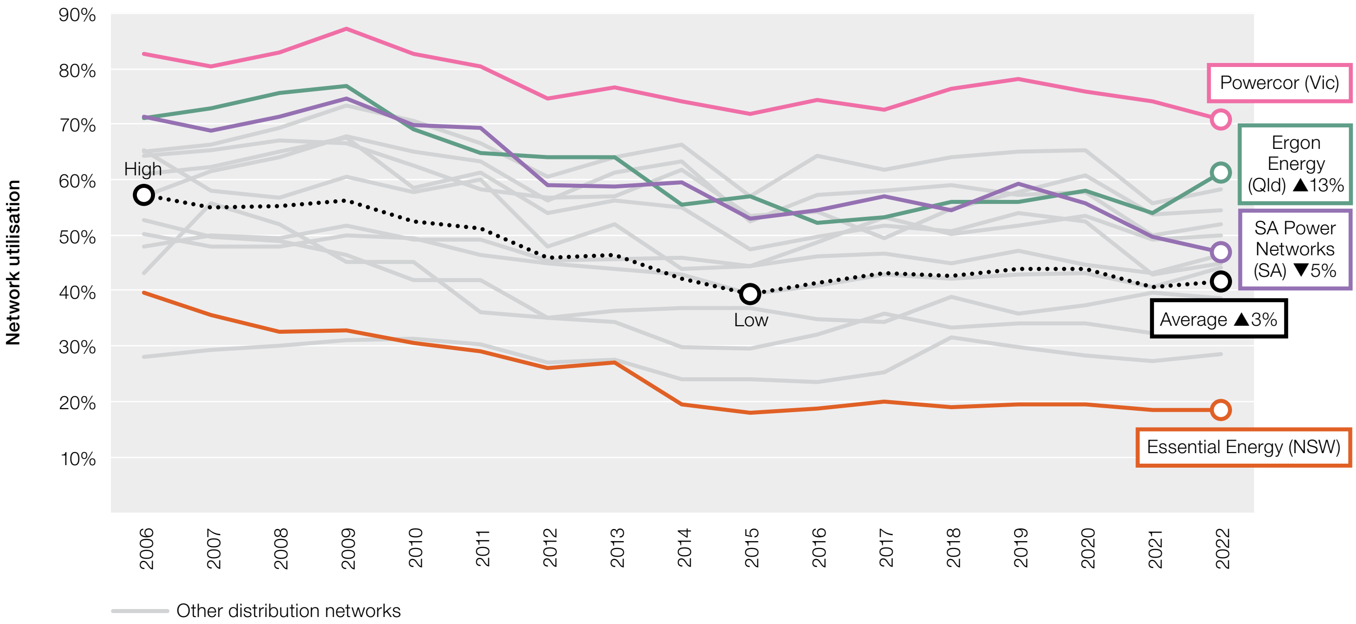
A network's utilisation rate indicates the extent to which a network service provider's assets are being used to meet the needs of customers at times of maximum demand. The utilisation rate can be improved through efficiencies such as using demand response (instead of new investment in assets) to meet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

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.[103] This followed significant investment by many network service providers at a time of weakening electricity maximum demand.

In 2022, maximum demand across the distribution networks increased by an average of 3% over the previous year, the largest proportional increase since 2017. As a result, overall network utilisation increased by 1.1 percentage points to 42% (Figure 4.31).

103 The available data does not extend back beyond 2006.

Figure 4.31 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.
Source: Economic benchmarking RIN responses.

In 2022:

- privately owned distribution network service providers utilised 53% of network capacity
- fully or partly government-owned networks utilised only 35% of network capacity[104]
- 8 of the 9 most highly utilised distribution networks were privately owned.

Under-utilised assets raise the risk of asset stranding – whereby assets are no longer useful – unless network service providers respond to changing conditions. This risk may become more acute as the uptake of consumer energy resources (such as batteries) transforms the industry. The National Electricity Rules do not allow for RAB adjustments to remove historical investment in stranded assets. If network charges become inflated because of asset stranding, then electricity consumers – who pay for those assets – may look for opportunities to bypass the grid altogether.[105]

In August 2023, Energy Consumers Australia wrote that numerous factors indicate electricity demand is likely to increase over the coming years. 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 through additional network investment, will see distribution charges to customers decrease.[106]

4.15.3 Investment disconnect

The level of network productivity depends on how effectively a network service provider uses inputs[107] to deliver a range of outputs[108]. Capital expenditure is largely driven by the need to meet the maximum level of demand on the network. While average demand has declined since 2006 (driven in part by improved energy efficiency and increased self-consumption of solar PV), 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.

104 Section 4.4 provides information on network ownership.

105 T Wood, D Blowers, K Griffiths, Down to the wire – a sustainable electricity network for Australia, Grattan Institute, March 2018.

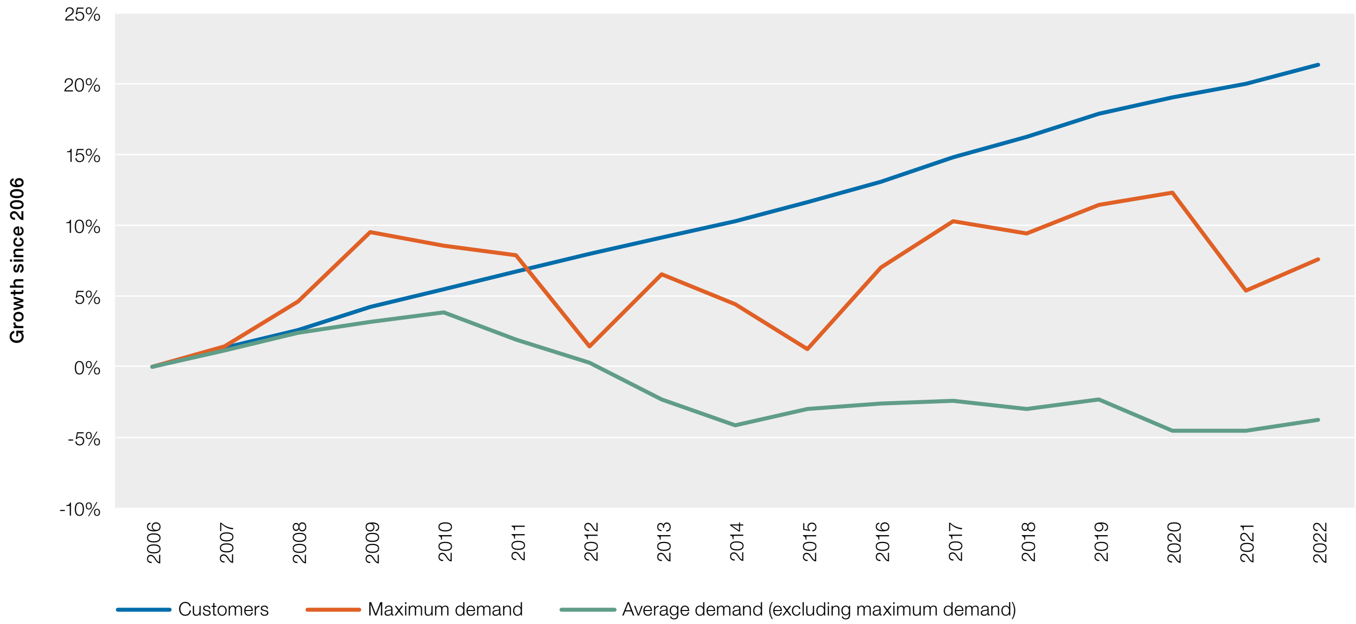
106 Energy Consumers Australia, The bECAuse Blog, 2 August 2023, accessed 6 August 2023.

107 Types of physical capital assets transmission networks invest in to replace, upgrade or expand their networks are transformers and other capital, overhead lines, and underground cables. Operating expenditure is an example of an intangible input.

108 Outputs include circuit line length, ratcheted maximum demand, energy delivered, customer numbers and network reliability.

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 productivity. The number of customers connected to the distribution network has steadily increased by 1.5% per year since 2006 and has outpaced growth in both maximum and average 'non-maximum' demand (Figure 4.32).

Figure 4.32 Growth in customers and demand – electricity distribution networks

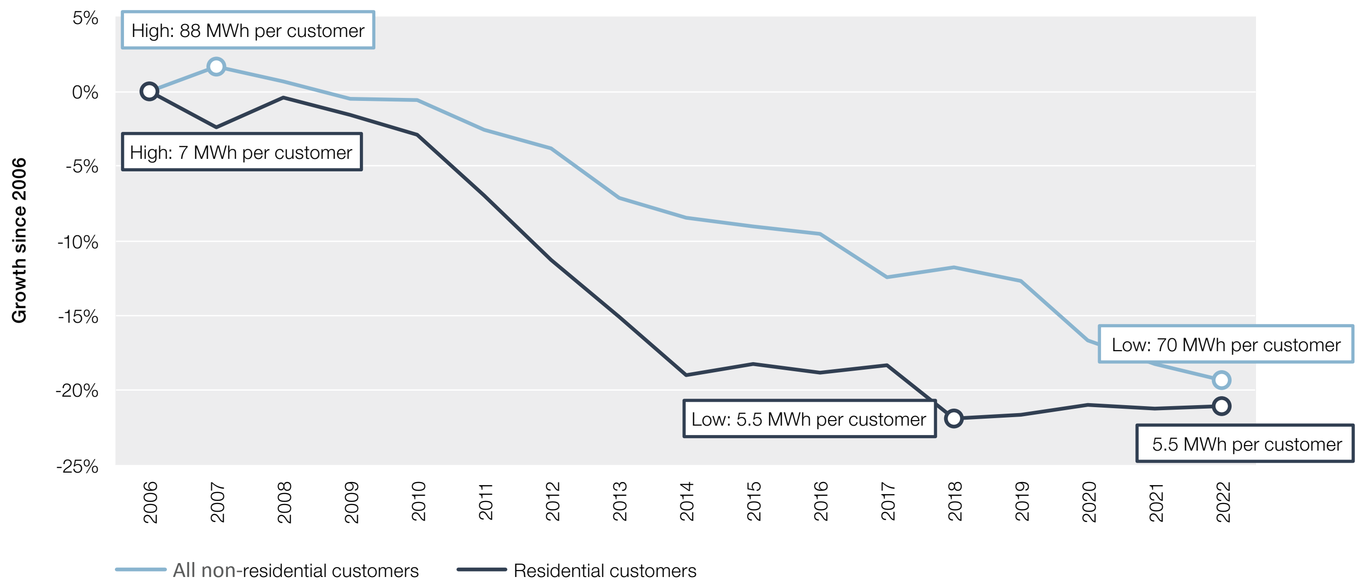


Note: Maximum demand is the network sum of non-coincident, summated raw system maximum demand (megawatts). Non-maximum demand is the total energy delivered (gigawatt hours) for the year, excluding the energy delivered at the time of maximum demand divided by hours in the year minus one. The data show 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 2022 the average residential customer consumed around 5.5 megawatt hours (MWh) from the distribution network, 21% less than it consumed in 2006. Over the same period the average usage per non-residential customer – including low voltage and high voltage customers – has decreased 19% (Figure 4.33).

Figure 4.33 Growth in 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.

4.16 Reliability and service performance

In this section, the term 'reliability' refers to the continuity of electricity supply to customers.[109] 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).

A significant network failure might require the power system operator to disconnect some customers (known as load shedding).

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 widespread. For example, South Australia's catastrophic network failures in September 2016 caused a state-wide blackout.[110]

Electricity outages impose costs on consumers. These costs include both economic losses resulting from lost productivity and business revenues and non-economic 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.

In September 2022, Energy Networks Australia (ENA) awarded Endeavour Energy (NSW) the Industry Innovation Award for its 'Using a Network Digital Twin for Digital Emergency Response and Resilience' initiative which was used to improve public safety and restoration response times to several floods in the Hawkesbury region over 2021–22.[111]

4.16.1 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 4.13.5) that assess network investment proposals

109 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.

110 AER, Investigation report into South Australia's 2016 state-wide blackout, Australian Energy Regulator, accessed 17 July 2023.

111 Endeavour Energy, Endeavour Energy pioneers Neara digital twin in transition to modern grid, 13 December 2021, accessed 14 April 2023.

- assessing bonuses and penalties in the service target performance incentive scheme (Box 4.4)
- setting transmission and distribution reliability standards and targets
- informing market settings, such as wholesale price caps.

In December 2022, the AER updated the VCR based on a consumer price index (CPI) of 7.27%. 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.[112]

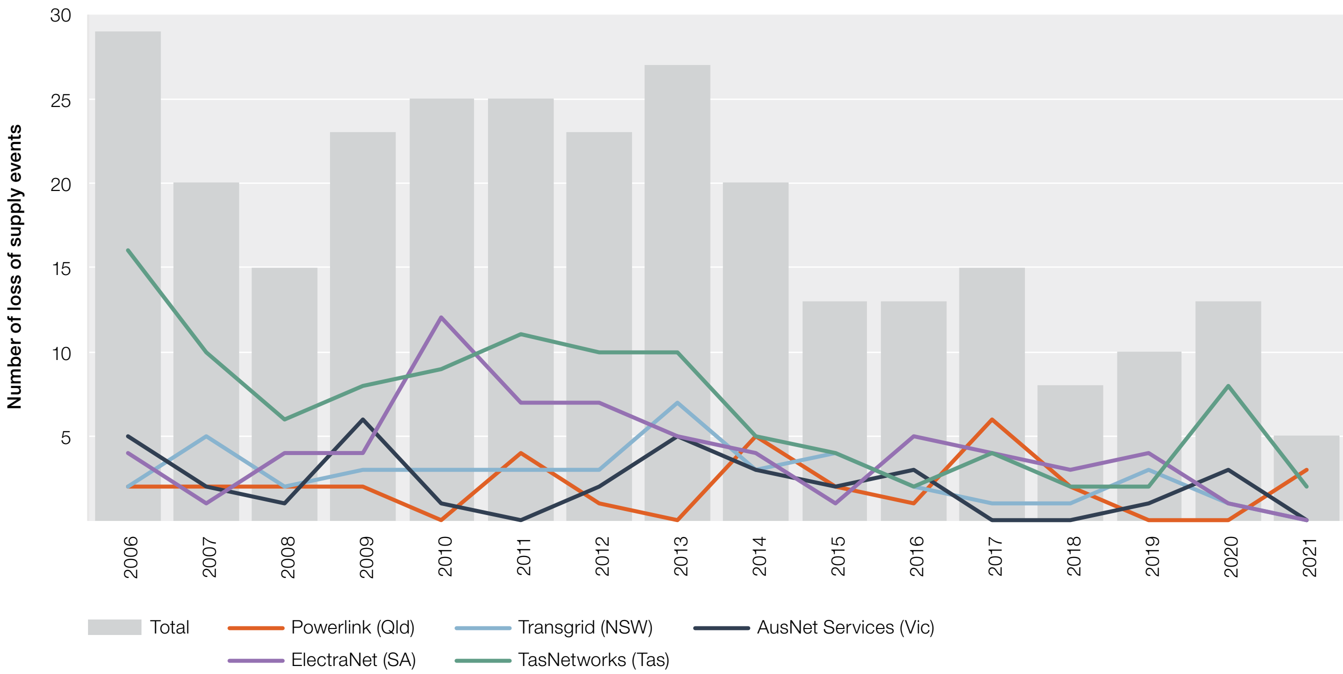
The AER will undertake its next review of the VCR in 2024.

4.16.2 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 2021 the NEM experienced 5 loss of supply events due to transmission failures, the fewest events in any year dating back to at least 2006 (Figure 4.34).

Figure 4.34 Network reliability loss of supply events – electricity transmission networks



Note: Loss of supply events are the times when energy is not available to transmission network customers for longer than a specified duration. The threshold varies across businesses, from 0.05 to 1.0 system minutes as published in AER decisions on the service target performance incentive scheme (STPIS). The thresholds may also vary between regulatory periods for each network. 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 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.

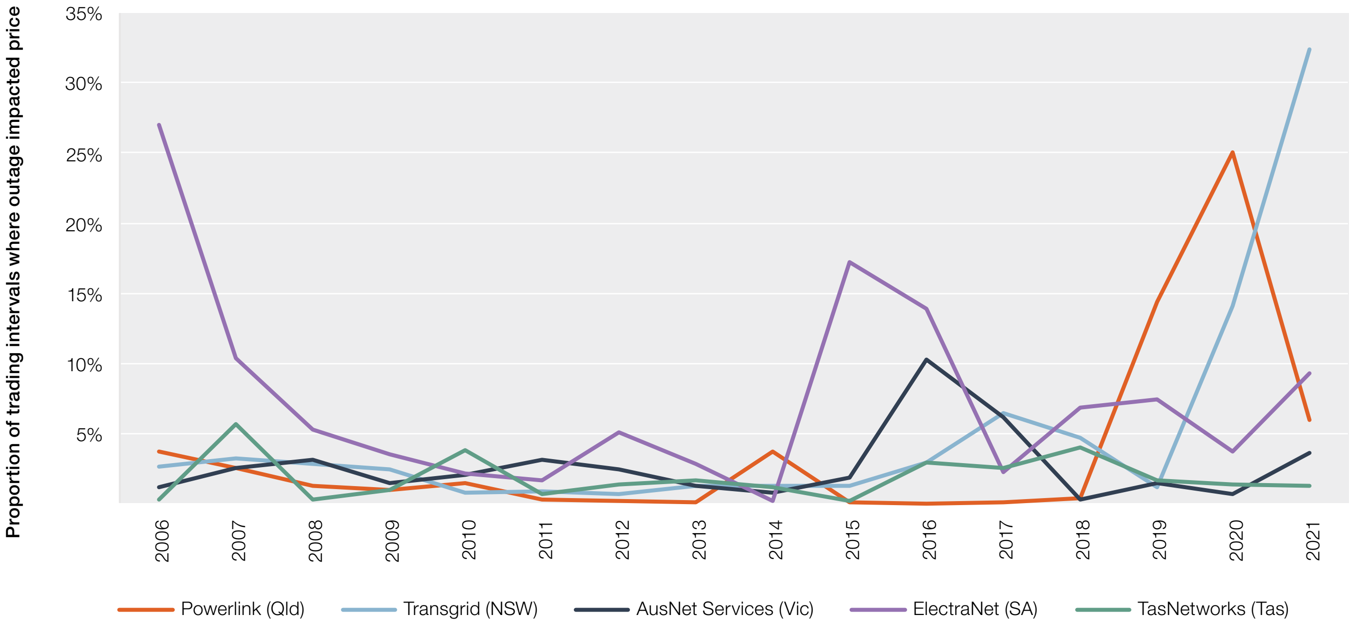
112 AER, Values of customer reliability, Australian Energy Regulator, accessed 23 March 2023.

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.

Issues with network congestion re-emerged from 2015, in part due to outages associated with network upgrades in Queensland and cross-border interconnectors linking Victoria with South Australia and NSW. The level of congestion dropped in South Australia in 2017 following completion of an interconnector upgrade.

In 2021, the number of dispatch intervals impacted by the Transgrid (NSW) network increased significantly as a result of upgrades to the Victoria – NSW and Queensland – NSW interconnectors being undertaken (Figure 4.35).

Figure 4.35 Market impact of loss of supply events – electricity transmission networks



Note: Proportion of dispatch intervals each year when transmission network congestion impacted the National Electricity Market spot price by more than $10 per megawatt hour. The data exclude outages caused by force majeure events and other specific exclusions.

Source: Economic benchmarking RIN responses.

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. For this reason, the AER offers incentives for service providers to reduce the market impact of congestion.

4.16.3 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.[113] 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 outages – 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.

113 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 driving up power bills led to a different approach to setting distribution reliability targets.[114] This 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 4.16.1). While the Queensland and NSW governments began to relax reliability standards from 2014, the assets built to meet the previously high standards remain and customers continue to pay for them.[115]

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 duration – or minutes off supply – the average customer experienced.[116]

The SAIFI and SAIDI metrics have generally been used to focus on the impact of unplanned outages. However, the impact of planned outages 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 recent regulatory determinations through the customer service incentive scheme (CSIS) (Box 4.5). Both the frequency and duration of planned interruptions to supply varies considerably among the distribution networks.

The specific characteristics of a distribution network can have a significant impact on the service provider's reliability performance. In particular, customer densities and environmental conditions differ across networks, which can materially impact the number of customers affected by an outage as well as a network service providers' response time. Levels of historical investment also affect reliability outcomes.

Central business district (CBD) and urban network areas have higher load and customer connection density. 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.

For these reasons, care must be taken when comparing network reliability outcomes between distribution network service providers.

4.16.4 Distribution network reliability in 2021–22

In 2021–22 the average customer in the NEM experienced 1.55 interruptions to supply, a new record low and 1.2% fewer than in the previous year (Figure 4.36). This comprised:

- 1 unplanned (normalised for STPIS) interruption to supply – 3% more than the record low set in the previous year
- 0.25 unplanned (STPIS excluded) interruptions to supply – 5% fewer than in the previous year
- 0.30 planned interruptions to supply – 10% fewer than in the previous year.

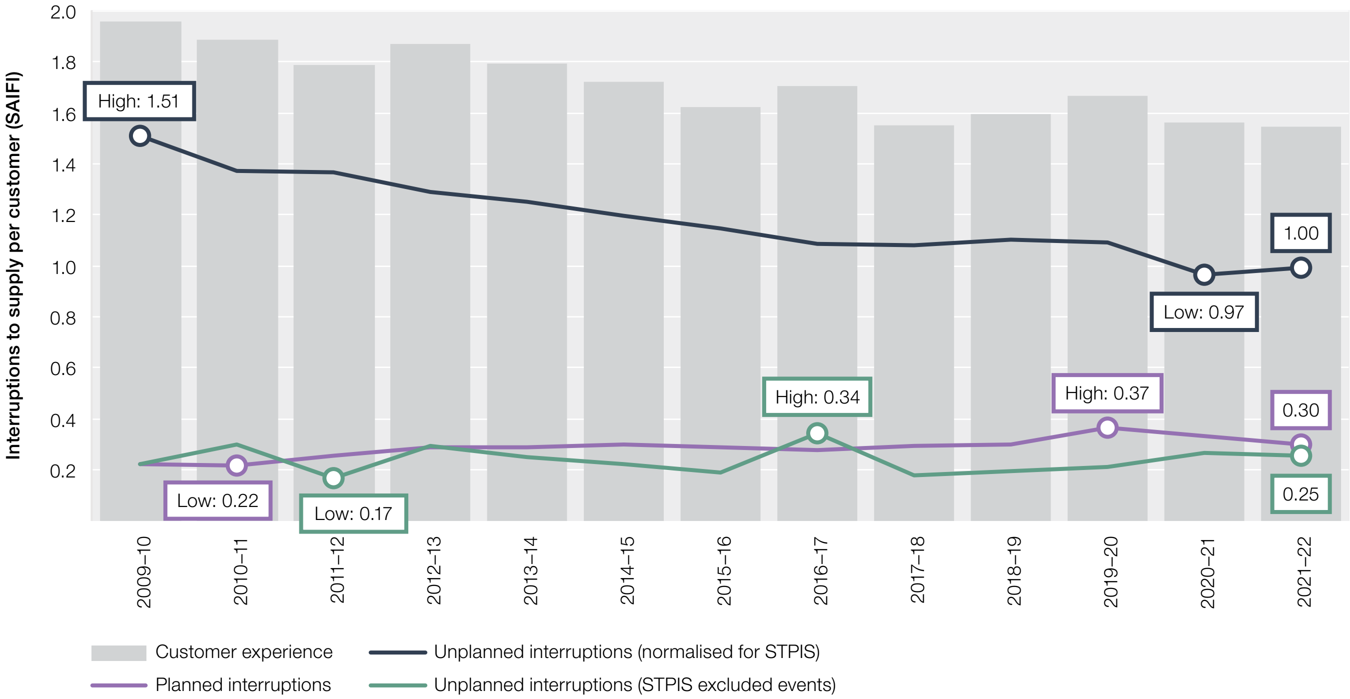
Despite the decrease in in total interruptions, 2021–22 marked only the second year in the available data series when customers experienced more unplanned interruptions (normalised for STPIS) to supply than in the previous year.

114 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.

115 ACCC, Retail Electricity Pricing Inquiry final report, Australian Competition and Consumer Commission, 11 July 2018, p. 109.

116 Unplanned SAIDI excludes momentary interruptions (3 minutes or less).

Figure 4.36 Interruptions to supply (SAIFI) – electricity distribution networks



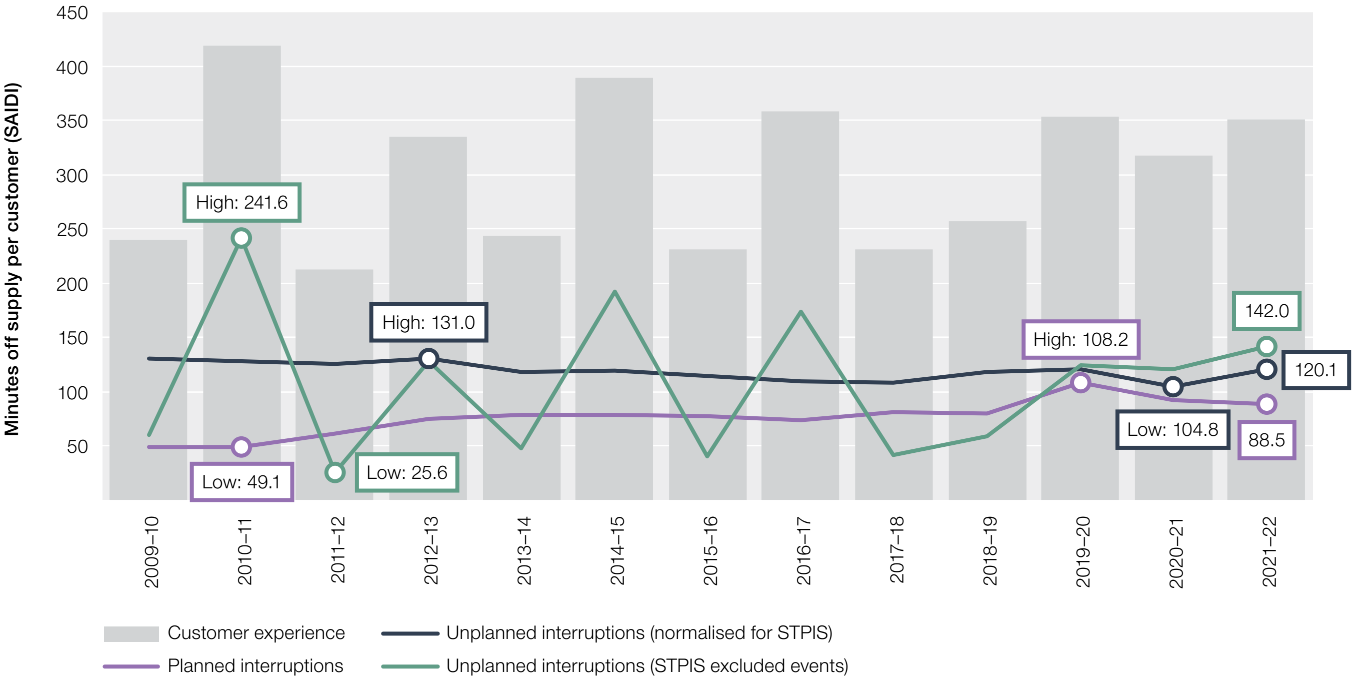
Note: SAIFI: system average interruption frequency index.
Data in Figure 4.36 shows interruptions to supply that lasted longer than 3 minutes. This is consistent with the definition of a sustained interruption in the AER's current service target performance incentive scheme (STPIS) (version 2.0, November 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.

In 2021–22 the average customer in the NEM experienced 350.6 minutes off supply – 10% more than in the previous year (Figure 4.37). This comprised:

- 120.1 unplanned (normalised for STPIS) minutes off supply – 15% more than the record low set in the previous year
- 142.0 unplanned (STPIS excluded) minutes off supply – 18% more than in the previous year
- 88.5 planned minutes off supply – 4% less than in the previous year.

Figure 4.37 Minutes off supply (SAIDI) – electricity distribution networks



Note: SAIDI: system average interruption duration index.

Data in Figure 4.37 shows minutes off supply for interruptions 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.

Over the 12-month period to 30 June 2022 asset failure was the most frequently reported reason for unplanned outages, accounting for 25% of all unplanned outages and 16% of all unplanned minutes off supply across the NEM. Over the same period weather events accounted for fewer (17%) unplanned outages, but a greater number of unplanned minutes off supply (31%). This demonstrates the destructive nature of weather events on the electricity network.

Several severe weather events resulted in significant unplanned minutes off supply during this period, including:

- 28 and 29 October 2021 – Victoria – thunderstorms and extreme wind[117]
- 27 February 2022 – Energex (Queensland) – severe storm and flooding[118]
- 28 February 2022 – Essential Energy (NSW) and Energex (Queensland) – severe storm and flooding.[119]

A third key cause of interruptions to supply is vegetation-related incidents. In the 12-month period to 30 June 2022 vegetation-related interruptions to supply were as frequent as those caused by weather events but resulted in 31% fewer minutes off supply (Figure 4.38).

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. Prior to 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 the 12-month period to 30 June 2023, ESV issued 21 fines to network service providers – 10 to Powercor, 6 to United Energy and 5 to AusNet Services – for failing to keep trees clear of powerlines.[120]

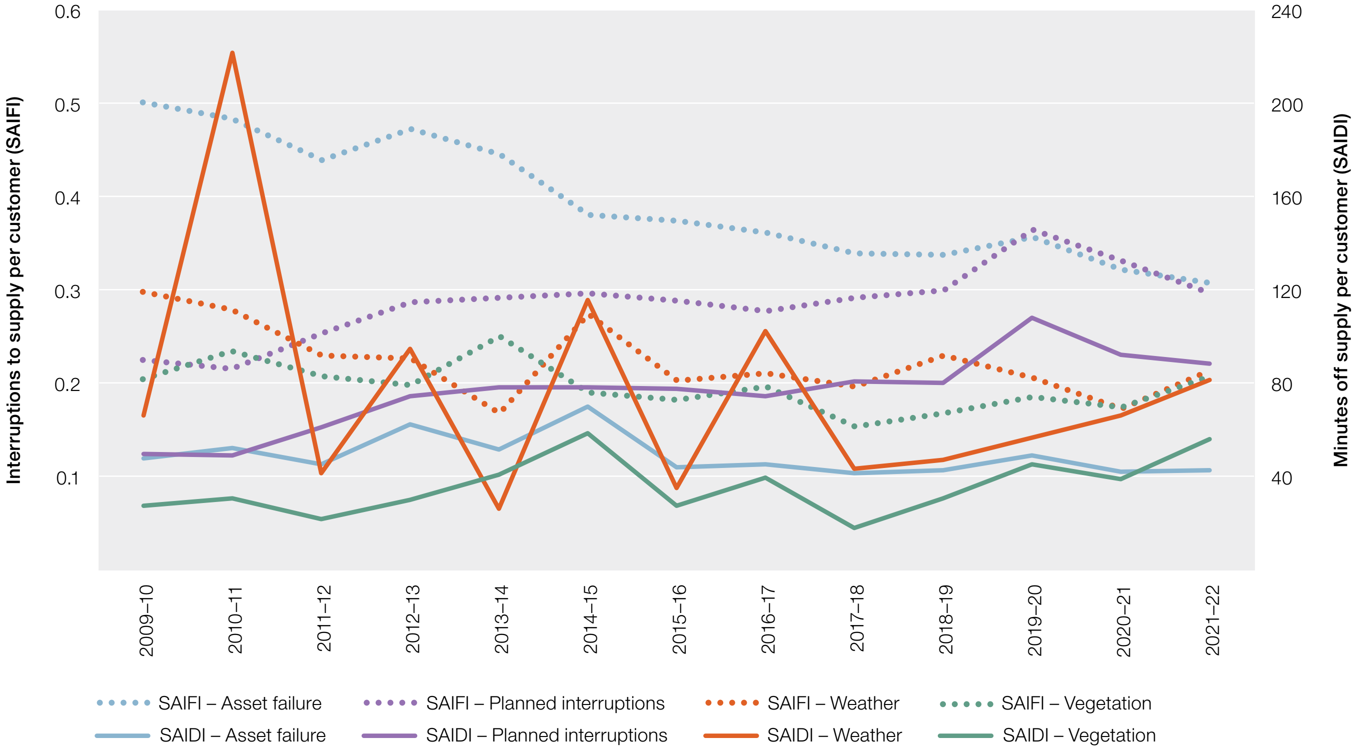
117 The Age, Thousands of properties without power as storm clean-up continues, 29 October 2021, accessed 20 March 2023.

118 ABC News, South-east Queensland battered by severe weather, floods as system lingers over Brisbane, 27 February 2022, accessed 20 March 2023.

119 ABC News, Lismore flood emergency sees people stranded on roofs, evacuation warning issued for entire NSW Northern Rivers, 28 February 2022, accessed 20 March 2023.

120 Electrical Connection, Energy safe fines stack with line clearance powers, 5 July 2023, accessed 21 July 2023.

Figure 4.38 Key drivers of interruptions to supply – electricity distribution networks



Note: SAIDI: system average interruption duration index. SAIFI: system average interruption frequency index.

Data in Figure 4.38 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 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.

In 2019–20 the average customer experienced significantly more frequent and longer planned interruptions to supply than in the past. This was driven by Ausgrid's (NSW) decision to temporarily pause all live work on its network for safety reasons.[121]

4.16.5 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.[122]

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 outages experienced by customers at the end of rural feeders.

121 Ausgrid, Live Work Project, accessed 5 May 2022.

122 AER, Amendment to the service target performance incentive scheme (STPIS) / Establishing a new Distribution Reliability Measures Guideline (DRMG), Australian Energy Regulator, November 2018.

Box 4.4 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 4.2) and efficiency benefit sharing scheme (EBSS) (Box 4.3) 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 outages 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 or penalties are available for exceeding/failing to meet performance targets under the scheme.

Following its 2023 review of incentive schemes[a] the AER decided to amend the market impact component (MIC) of the transmission STPIS in light of increasing transmission congestion. The review of the MIC is expected to commence in late 2023, which will allow any revisions to be picked up in time for the next Queensland and South Australian transmission reset processes. Because the Network Capability Incentive Parameter Action Plan (NCIPAP) is closely linked to the MIC, the AER will review the NCIPAP scheme alongside the MIC review.

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

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.

4.16.6 Incentives to avoid fire starts

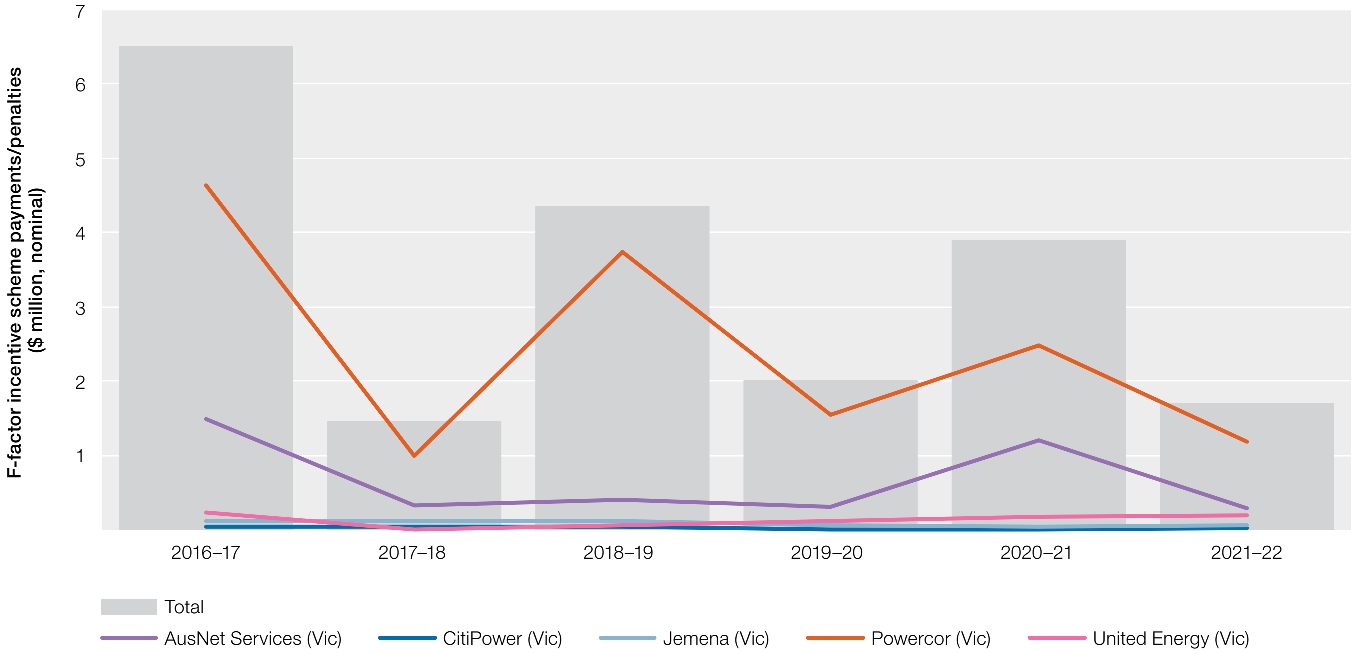
The AER administers the Victorian Government's f-factor scheme, an initiative that provides financial incentives to Victorian distribution service providers to minimise the number of fire starts within their networks in high fire danger zones and times.

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 2021–22 reporting period, incentive payments varied from a $12,000 reward for CitiPower with a totally CBD/urban network, to $1.2 million for Powercor with a predominately rural network. The impact of the incentive payments from 2021–22 will take the form of adjustments to the network businesses' regulated revenues in 2023–24.

Figure 4.39 F-factor incentive payments – Victorian distribution networks



Source: AER, Victorian electricity distributors' fire start reports for the July 2021–June 2022 reporting period.

4.16.7 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.[123] Victoria reports separately on network performance.[124]

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 4.5).[125]

123 AER, Annual retail markets report 2019–20, Australian Energy Regulator, November 2020.

124 ESC, Victorian energy market update, Essential Services Commission, 31 March 2022.

125 AER, Final – Customer Service Incentive Scheme, Australian Energy Regulator, 21 July 2020.

Box 4.5 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 2021–22 the outcomes of the CSIS were rewards of:

- $775,100 for AusNet Services
- $1.6 million for CitiPower
- $3.7 million for Powercor
- $2.2 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.