Electricity networks

Australia's electricity network 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 networks regulated by the Australian Energy Regulator (AER), which are located in all Australian states and territories except Western Australia.

3.1 Electricity network snapshot

In 2022, the AER has completed 2 revenue determinations – for Powerlink (Queensland) and AusNet Services (Victoria) transmission – setting target revenue controls for those networks through to 2027.

Across all electricity networks, reporting over the 12-month period to 30 June 2021:

- Revenue earned by network businesses was 5% lower than in the previous year (the fourth consecutive year of decreased revenue) (section 3.9).
- Expenditure on investment projects was the highest since 2015; 8% higher than in the previous year and 12% higher than the average investment expenditure over the previous 5 years (section 3.13).
- Asset bases continued to grow, driven by investment projects on the Transgrid (NSW) and ElectraNet (South Australia) transmission networks. Asset bases are forecast to grow at an accelerated rate as several major transmission projects progress (sections 3.11 and 3.13.6).
- Expenditure on operating costs was at its lowest since 2017; 0.8% lower than in the previous year and 7% lower than the average operating expenditure over the previous 5 years (section 3.14).
- Customers experienced fewer and shorter (normalised) network outages than in any time in the past. Despite this, major weather events continued to have an impact on the overall customer experience (section 3.16).

3.2 Electricity network characteristics

Transmission networks provide the link between power generators and customers 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 customers. Distribution networks consist of poles and wires, substations, transformers, switching equipment, and monitoring and signalling equipment.

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

Electricity networks have traditionally provided a one-way delivery service to customers. However, the role of electricity networks is evolving as new technologies change how electricity is generated and used. Many small-scale generators such as rooftop solar systems are now embedded within distribution networks, resulting in 2-way electricity flows along the networks. Energy users with rooftop solar systems can now 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.[65]

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. The revenues of embedded networks are not regulated.

65 Australian Renewable Energy Agency, 'Battery costs falling fast, wind and solar still cheapest new electricity', ARENAWIRE, 17 June 2021, accessed 29 March 2022.

3.3 Geography

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

The transmission grid connects with 13 distribution networks.[66] Customers in Queensland, NSW and Victoria are serviced by multiple distribution networks, each of which owns and operates its network within a defined geographic region. South Australia, Tasmania and the ACT are serviced by single distribution networks operating within each jurisdiction (Figure 3.1 and Figure 3.3).

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

The combined value of the regulatory asset bases (RABs) for the electricity networks regulated by the AER is around $105 billion.[67] This comprises 7 transmission networks valued at $22.8 billion and 14 distribution networks valued at $82.6 billion. In total, the networks operate almost 800,000 kilometres of lines and deliver electricity to more than 10.6 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 Western Australian 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.[68]

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

67 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.

68 For further information, see the Department of Treasury (http://www.treasury.wa.gov.au) and ERA (http://www.era.wa.gov.au) websites.

Figure 3.1 Electricity networks regulated by the AER – distribution

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

Figure 3.2 Electricity networks regulated by the AER – transmission

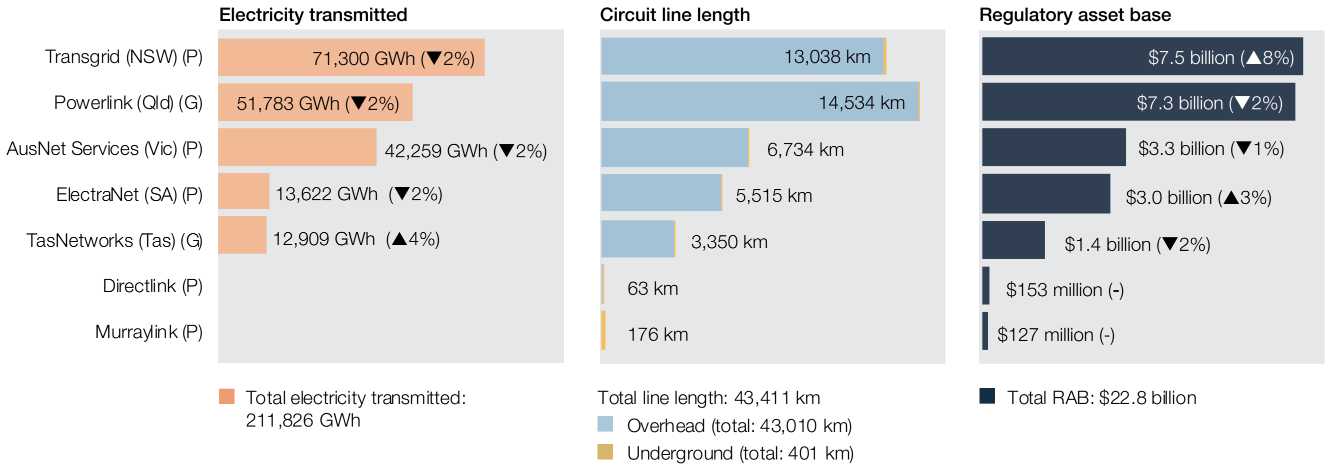
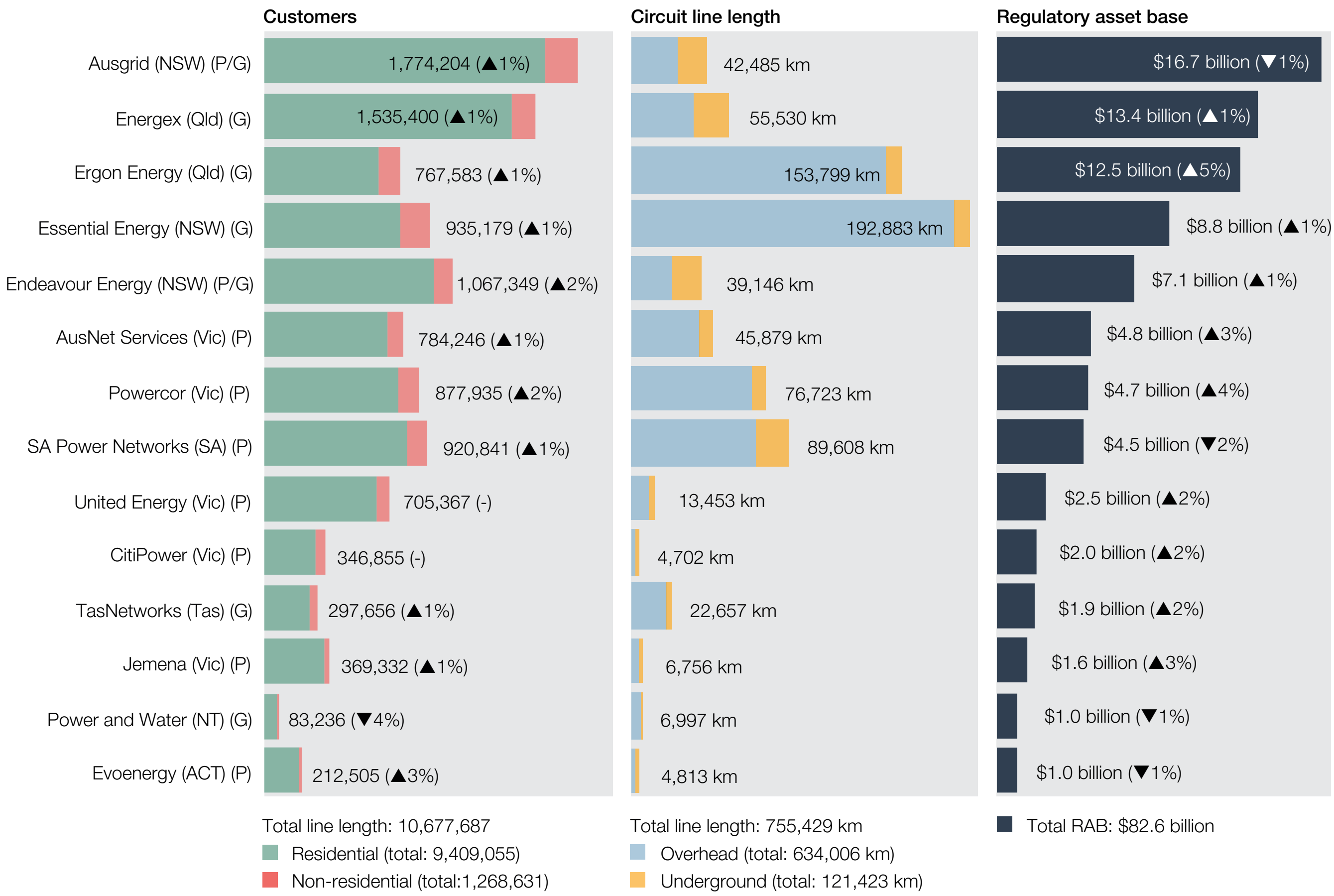


Figure 3.3 Electricity networks regulated by the AER – distribution



(G): state government owned; (P): privately owned; GWh: gigawatt hours; km: kilometres; % values represent change from previous year.

Note: Regulatory asset base is adjusted to June 2022 dollars based on forecasts of CPI. Line length and asset base are as at 30 June 2021 (31 March 2021 for AusNet Services transmission). Electricity transmitted is for the year to 30 June 2021 (year to 31 March 2021 for AusNet Services). Customer numbers, line length and asset base are as at 30 June 2021 for the distribution networks. For regulatory purposes, Northern Territory transmission assets are treated as part of the distribution system.

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

3.4 Network ownership

Australia's electricity networks were originally government owned, but many jurisdictions have now 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 (section 5.2).

Electricity networks in Queensland, Tasmania, the Northern Territory and Western Australia remain wholly government owned. In 2016 the Queensland Government merged state-owned electricity distributors Energex and Ergon Energy under a new 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 businesses do not use revenue from regulated services to cross-subsidise their unregulated products (section 3.8.2). For example, Queensland's state-owned Ergon Energy provides both distribution and retail services in regions outside south-east Queensland.

3.5 How network prices are set

Electricity networks are capital intensive and require significant investment in order to install and operate the required infrastructure. This gives rise to a natural monopoly industry structure, where it is more efficient to have a single network provider than to have 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 serious risks to consumers, given network charges currently make up around 50% of a residential electricity bill (Figure 6.2 in chapter 6). To counter these risks, the role of the AER as economic regulator is to replicate the incentives that network businesses would face in a competitive market (that is, to control costs, invest efficiently and not overcharge consumers).

3.5.1 Regulatory objective and approach

One of the AER's key objectives is to deliver efficient regulation of monopoly infrastructure while incentivising networks to become platforms for energy services.[69]

The National Electricity Law and the National Electricity Rules set the framework for regulating electricity networks and the AER applies that framework. 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, and the reliability, safety and security of the national electricity system.

The AER's regulatory toolkit to pursue this objective is wide ranging (Box 3.1), but one of its fundamental roles is to set the maximum revenue that a network business can earn from its customers for delivering electricity. The AER fulfils this role via a periodic determination process, in which it assesses the amount of revenue a prudent network business would need to cover its efficient costs. Network revenues are then capped at this level for the regulatory period, which is typically 5 years.[70]

69 ACCC and AER, 'Corporate plan 2021–22', 31 August 2020, accessed 29 March 2022.

70 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 3.1 The AER's role in electricity network regulation

Every 5 years the AER sets a cap on the revenue that a network business 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 businesses to improve their performance in ways that customers value
- assessing whether any additional costs not anticipated at the time of our final decision should be passed on to customers
- publishing information on the performance of network businesses, including benchmarking and profitability analyses
- monitoring whether network businesses 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 3.7)
- 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 3.12).

The AER has also been appointed as regulator of the NSW Renewable Energy Zones (REZs). The AER will make revenue determinations for network infrastructure projects authorised by the independent Consumer Trustee for each REZ. The AER's determinations will include calculating the prudent, efficient and reasonable capital costs of each NSW REZ project, as well as:

- determining annual contributions from NSW electricity distribution businesses to fund the framework
- approving a risk management framework developed by the Consumer Trustee
- reviewing tender rules regarding long-term energy service agreements.

As part of the determination process, a network business submits a proposal to the AER setting out the amount of revenue it will need to earn 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 network business's forecasts and the efficiency of its proposed expenditure. If the AER determines the proposal is likely to be unreasonably costly, it may ask for more detailed information or a clearer business case. Subsequently, the AER may amend the amount of revenue proposed by a network business to ensure the approved cost forecasts are efficient.

To form a view on a network business's capital expenditure forecast, the AER assesses the drivers of the proposed expenditure. The AER does not determine the capital programs or projects for a network business. Once the AER determines a capital expenditure forecast, it is up to the network business to prioritise its investment program.

Unlike capital expenditure, a network business's operating costs are largely recurrent and predictable. As such, the AER begins its review by assessing 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 changes in prices, productivity and the outputs the business is required to deliver.

The AER publishes guidelines on its approach to assessing capital and operating expenditure and applying incentives.[71]

Sections 3.10, 3.14 and 3.16 examine the incentive schemes in more detail. Past AER *Electricity network performance reports* have focussed on the impact incentive schemes have had on network businesses' behaviour.[72]

71 AER, 'Guidelines, schemes, models & reviews', AER website, accessed 1 February 2022.

72 AER, 'Electricity network performance report', September 2020, accessed 5 April 2022.

In conducting its review of a network business'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 the earliest stage of the process, including before the network business lodges a formal proposal.

Electricity network businesses continue to significantly improve how they engage with consumers. The regulatory process increasingly focuses on how network businesses engage with their customers in shaping regulatory proposals. In December 2021, the AER published its *Better Resets Handbook*.

The objective of this process is to contribute to high-quality regulatory proposals based on genuine engagement with consumers. Where network proposals are developed in line with these expectations, the AER will be able to undertake a targeted review of the proposal rather than the standard more detailed approach.

The AER previously trialled the 'New Reg' process with Victorian electricity distributor AusNet Services in developing its regulatory proposal for the 5-year period ending 31 June 2026. The New Reg process offers an enhanced, more open approach to how network businesses 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 input on issues of importance to consumers. It advises the AER on:

- whether the revenue proposals submitted by network businesses are in the long-term interests of consumers
- the effectiveness of network businesses' engagement with their customers
- how consumer views are reflected in the development of network businesses' proposals.[73]

3.5.2 Building blocks of network revenue

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

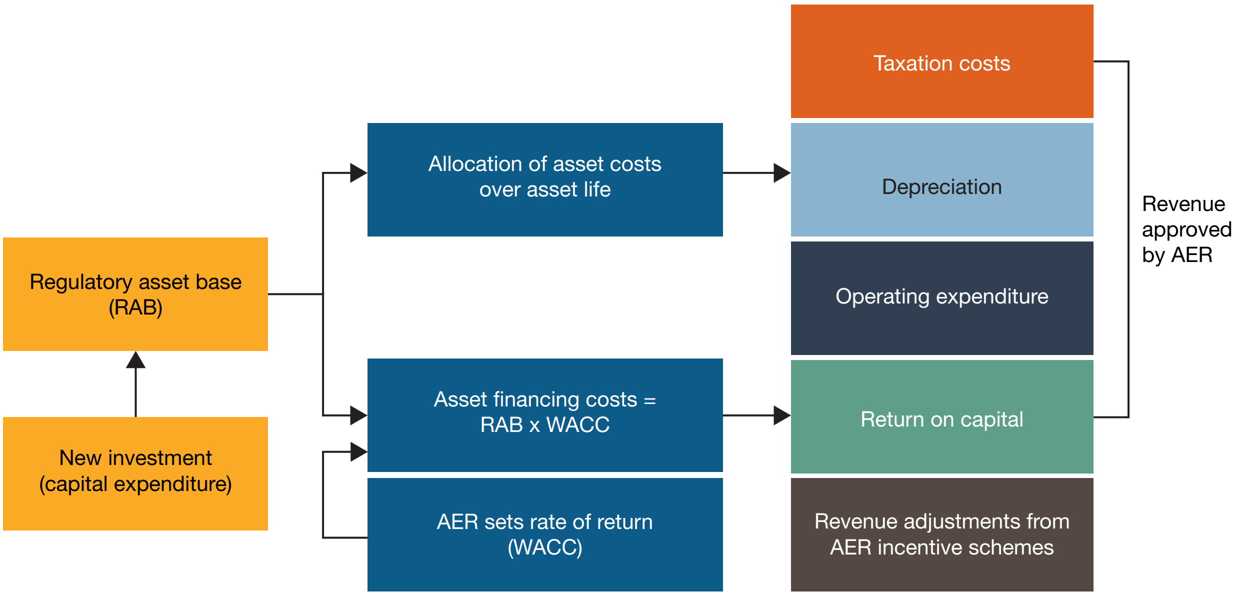
- a commercial return to investors that funds the network's assets and operations
- efficient operating and maintenance costs
- asset depreciation costs
- taxation costs.

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 businesses 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 during the year. Network assets have a long life and investment costs are recovered over the economic life of the assets, which may run to several decades. The amount recovered each year is called depreciation and it reflects the lost value of network assets each year through wear and tear and technical obsolescence (Figure 3.4).

73 AER, 'Consumer Challenge Panel', AER website, accessed 2 February 2022.

Figure 3.4 Forecasting electricity network revenues



AER: Australian Energy Regulator; RAB: regulatory asset base; WACC: weighted average cost of capital.

Note: Revenue adjustments from incentive schemes encourage network businesses to efficiently manage their operating and capital expenditure, improve services provision to customers and adopt demand management schemes that avoid or delay unnecessary investment.

Source: AER.

Additionally, the shareholders and lenders that fund these assets 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)). The size of this return depends on:

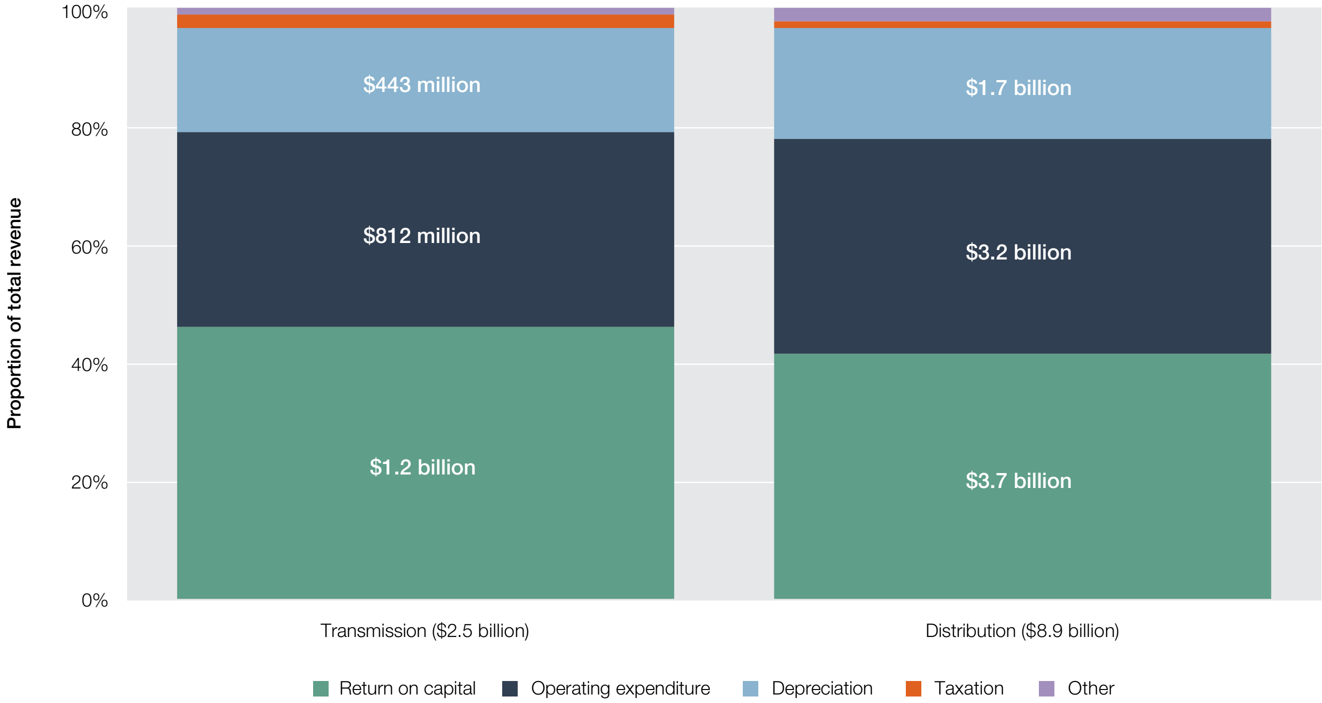
- the value of the network's RAB
- the rate of return that the AER allows based on the forecast cost of funding those assets through equity and debt.[74]

Overall, the return on capital takes up the largest share of network revenue, accounting for 43% of total revenue across all networks (Figure 3.5).

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

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

Figure 3.5 Composition of average annual electricity network revenue



Note: Composition of average annual electricity network revenue – current periods as at June 2022. Consumer price index (CPI) adjusted to June 2022 dollars.

Source: Post-tax revenue modelling used in AER determination process.

3.6 Recent AER revenue decisions

In 2022 the AER published its final revenue decisions for Victorian transmission network AusNet Services for the 5-year period ending 31 March 2027 and Queensland transmission network Powerlink for the 5-year period ending 30 June 2027 (Figure 3.6).

Figure 3.6 Recent AER electricity network revenue decisions

	Revenue	Capital Expenditure	Operating Expenditure	Annual impact on residential bill
Powerlink (QLD)	$3.5b (▼19%)	$892m (▼3%)	$1.1b (▼0.5%)	▲0.1%
AusNet Services (Vic)	$2.6b (▼8%)	$819m (▲4%)	$513m (▲0.9%)	▲0.1%

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 decision.

Source: AER estimates.

The key driver of the lower forecast revenues for AusNet Services and Powerlink is the allowed rate of return, which is lower than the rate applied in the previous period.[75] This reflects a decrease in interest rates compared with those in the previous period, meaning the networks businesses can obtain the capital needed to run their businesses more cheaply. Forecast revenues were also affected by a decrease in tax allowance – predominately as a result of lower return on equity, higher gamma and the new regulatory tax approach applied following our 2018 tax review.[76]

75 The rate of return is a nominal rate of return unless stated otherwise. The real rate of return has also decreased but by a smaller amount. The 4.7% is applied to the first year of the 2021 to 2026 regulatory period. A different rate of return will apply for the remaining regulatory years of the period.

76 AER, 'Regulatory tax approach review 2018', AER website, accessed 25 April 2022.

The AER's decisions for the previous period challenged network businesses to deliver services more efficiently through prudent choices about operating and capital expenditure, without compromising network safety and reliability. The AER's setting of lower forecast revenue allowances for the current period acknowledged that network businesses are rationalising their operations and will continue to build on operational efficiencies. Lower revenue allowances benefit customers by locking in efficiency gains.

3.7 Refining the regulatory approach

The regulatory framework is not static. In December 2021 the AER published its *Better Resets Handbook*, which aims to incentivise network businesses to develop high-quality proposals driven by genuine engagement with consumers.[77]

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 decision stage, creating a more efficient regulatory process for all stakeholders.

The handbook should also lead to many other benefits, including improved relationships and understanding between networks and consumers, greater trust between all parties in regulatory processes, and the generation of new ideas and regulatory approaches that benefit both customers and networks.

3.7.1 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 business's proposal reflects their interests. In recent processes, the AER and network businesses have trialled 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 businesses are experimenting with early engagement models to better reflect consumer interests 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 businesses and consumers. Effective consumer consultation, along with agreement with its customers, can lay the foundations for the AER to accept major elements of a network business's revenue proposals.

Network businesses 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 2021 Powerlink (Queensland) was awarded the ENA/ECA Consumer Engagement Award for its 2022–27 revenue determination engagement process. Powerlink received the award for its outstanding engagement practice which, according to ECA, demonstrated a new standard for customer consultation.

ECA was particularly impressed with Powerlink's willingness to undertake a genuine co-design process together with consumers, market bodies and executive teams within the business. ENA recognised the importance of integrating consumer engagement into energy networks' business planning.[78] Ergon Energy (Queensland) was also shortlisted as a finalist for the award for its consumer-developed load control tariffs.

3.7.2 Changes to revenue setting approaches

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

In January 2022 the AER published a report detailing the outcomes of its transparency review of AEMO's draft 2022 integrated system plan (ISP).[79] The ISP is a whole-of-system plan for eastern Australia's power system (section 3.13.6). The AER concluded that AEMO had adequately explained most of its inputs and assumptions and how they contribute to the draft ISP outcomes. The National Electricity Rules require the AER to finalise a transparency review of AEMO's draft ISP one month following its publication. Transparency in understanding AEMO's approach

77 AER, 'Better Resets Handbook – Towards consumer centric network proposals', AER website, 9 December 2021.

78 Powerlink, 'Powerlink wins 2021 Consumer Engagement award', Powerlink website, 4 November 2021, accessed 20 March 2022.

79 AER, 'AER completes transparency review of draft 2022 Integrated System Plan', AER website, 7 January 2022, accessed 3 February 2022.

is important because it promotes stakeholder understanding of key outcomes in the draft 2022 ISP, which in turn promotes confidence in the ISP. The ISP and RIT-Ts are discussed in section 3.13.

The 2022 ISP also brought into effect guidelines the AER published in August 2020 to make the ISP actionable. The guidelines include a cost-benefit analysis guideline, a forecasting best practice guideline and updates to the regulatory investment test for transmission (RIT-T) instrument and application guidelines.[80] The guidelines are part of broader reforms 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 late 2022 the AER will publish its new Rate of Return Instrument, which will apply to all regulatory determinations made in the subsequent 4 years. As a milestone in that process, the AER published a Draft Instrument in June 2022. The Instrument sets out the AER's approach for estimating the rate of return and comprises the return on debt and the return on equity, as well as the value of imputation credits.

In December 2021, the AER commenced a review of the incentive schemes and guidelines that apply to regulated electricity networks to ensure they remain relevant and fit for purpose.[81] This 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.

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.

In addition, the AER has developed new models for forecasting capital expenditure, which standardise and streamline presentation of information about capital projects and programs. These models map forecast capital expenditure into a format consistent with the post-tax revenue model (PTRM), which is used to calculate the annual revenue requirement for each year of a regulatory period. The new model streamlines the resources and consultation required and increases consistency across regulatory proposals.[82]

3.8 Power of Choice

Innovations in network and communication technology – including 'smart' meters, interactive household devices and energy management and trading platforms – are driving 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 to these off-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.

'Power of Choice' reforms are being progressively rolled out to unlock the potential benefits of these innovations. The reforms include a market-led rollout of smart meters, supported by more cost-reflective network pricing (section 3.8.1), and incentives for demand management as a lower cost alternative to network investment (section 3.13.9).

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. Projects include ActewAGL Retail (ACT) demonstrating that a fleet of EVs can provide similar services to grid-scale batteries and virtual power plants. The EVs used in the trial can be charged from mains power or rooftop solar but can also send electricity back to the grid.[83] A separate trial, led by Jemena (Victoria) with the collaboration of AusNet Services, Evoenergy, TasNetworks and United Energy, is exploring using hardware-based smart charging to dynamically manage residential electric vehicles.[84]

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

80 AER, 'Guidelines to make the integrated system plan actionable', AER website, August 2020, accessed 29 March 2022.

81 AER, 'Review of incentive schemes for regulated networks', AER website, 4 August 2022.

82 AER, 'Standardised model for standard control services capital expenditure (standardised SCS capex model)', AER website, 16 December 2021, accessed 19 April 2022

83 ARENA, '"Batteries on wheels" roll in for Canberra storage trial', ARENAWIRE, 8 July 2020.

84 ARENA, 'Electricity networks gear up to manage electric vehicle demands on the grid', [media release], 5 February 2021.

resources, including benefits from access and pricing reforms.[85] 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 Australian Energy Market Commission (AEMC) proposed rule changes to enable distributors to supply their customers using standalone power systems where it is cheaper than maintaining a connection to the grid.[86] The AEMC identified additional benefits of these systems, including improved reliability and reduced bushfire risks.[87] Following a series of changes in the national electricity and retail laws over 2021, these changes were made to the rules in February 2022.[88]

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.

3.8.1 Tariff structure reforms

Traditionally, households and small businesses have been charged the same electricity tariff for their use of 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 true costs of using the network. This means some consumers, such as those who use electricity at 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.

Distribution network businesses do not charge network tariffs directly to end customers. Rather, distributors charge retailers, who then package network tariffs together with other costs (such as the cost of wholesale energy) in their retail price offers to end customers. It is up to the end customer to choose a retail offer that suits their needs.

The National Electricity Rules require distributors to make network tariffs more cost-reflective, to signal to retailers the true cost of their customers’ use of the network.[89] The AER supports and encourages the reform to more cost-reflective tariffs and tariff reform 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). More 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 customers to encourage the use of solar energy in the middle of the day to avoid excess solar (minimum demand) on the network.

Distributors are required to submit their tariff structure statements to the AER every 5 years, as part of the wider distribution revenue determination process. With each tariff structure statement, distributors progressively move towards more cost-reflective tariffs. Distributors are now moving into their third round of tariff structure statements.

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

- simplifying tariffs and modifying peak windows to provide clear, consistent signals
- designing tariffs that more closely reflect network costs
- applying an ‘opt-out’ or mandatory assignment policy that increases the number of end customers whose retailers will face these more cost-reflective tariffs
- integrating network pricing with areas such as network planning, demand management and direct procurement of network services; and trialing alternative approaches.

85 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.

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

87 AEMC, ‘Final report – updating the regulatory frameworks for distributor-led stand-alone power systems’, May 2020.

88 AEMC, New rules allow distributors to roll out stand-alone power systems in the NEM, February 2022.

89 AEMC, ‘National Electricity Amendment (Distribution Network Pricing Arrangements) Rule 2014, rule determination’, November 2014.

To better manage minimum demand issues, support effective consumer energy resources integration, and enable future market designs, the AEMC made a rule change in August 2021 to remove a prohibition on distributors charging for exports and to expand the definition of 'network services' to include exports of consumer energy resources.[90] Distributors may now signal the cost of serving energy export as well as energy consumption, where provision of the export service imposes a cost on the network (also called 2-way pricing). This rule change required the AER to publish Export Tariff Guidelines for the implementation of any 2-way pricing that may be introduced in the distributors' next round of tariff structure statements.[91]

Under the National Electricity Rules, subject to revenue recovery limits, distributors can trial alternative tariff structures (sub-threshold tariffs) during the regulatory period to support the introduction of innovative tariff structures. Distributors have responded with a broad range of trials to explore innovative approaches, covering solar sponges, critical peak pricing and 2-way pricing. Examples of trials include:

- Ausgrid (NSW): a community battery tariff trial with critical peak pricing, a residential 2-way tariff trial with export rewards and charges and a residential flexible load tariff trial aimed at electric vehicle users.
- Essential Energy (NSW): an export tariff trial with rebates (rewards for customers) for exporting between 5 pm and 8 pm, an export tariff trial for batteries, a weekly demand tariff trial aimed at peaky load large customers and an education only trial to determine whether education alone can shift customer behaviour.
- CitiPower (Victoria): a daytime saver trial aimed at customers with pool pumps and EVs to incentivise customers to use more electricity around midday, and community battery tariff trials (aimed at both distributor-owned and non-distributer-owned batteries).
- Evoenergy (ACT): a residential battery tariff trial aimed at residential customers with batteries and EVs, and a highly cost-reflective large-scale battery tariff trial.[92]

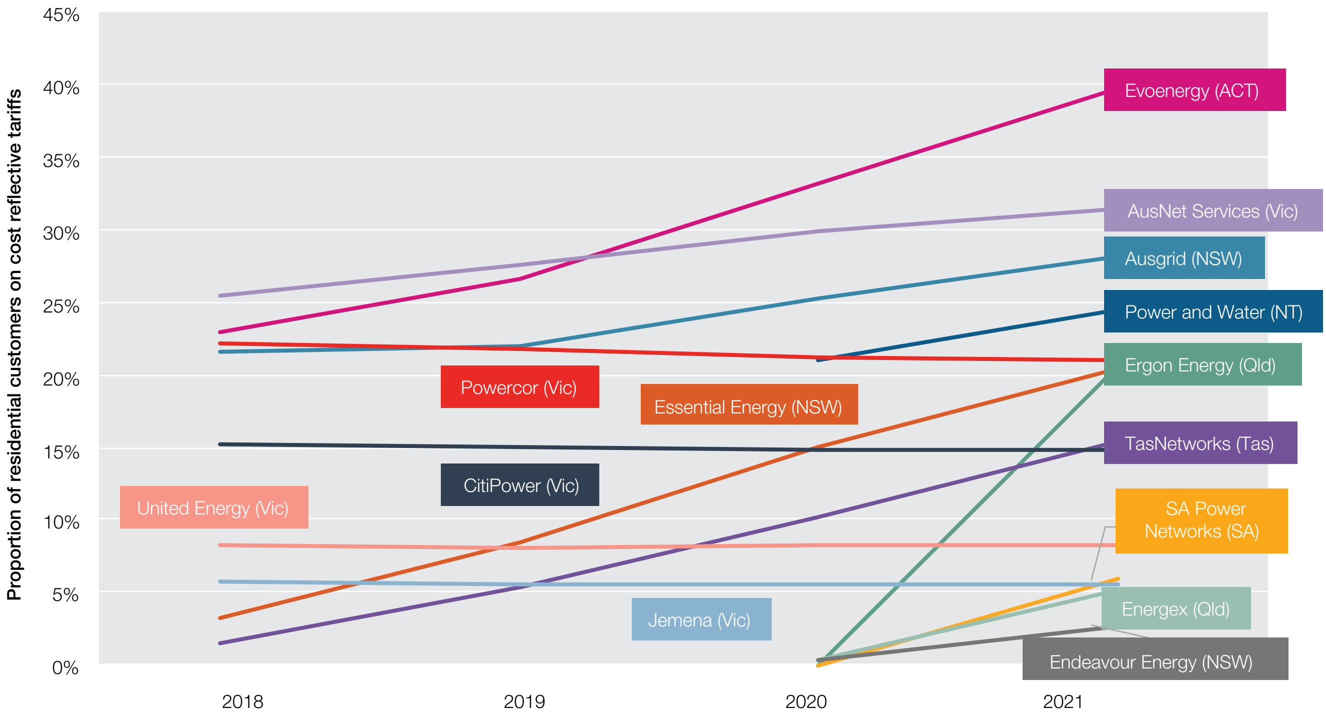
As an example of progress to cost reflectivity, in 2020 the AER approved SA Power Networks' use of a 'solar sponge' tariff for its residential customers. This network tariff offers a lower charge during the middle of the day, when solar output is highest, to encourage customers to use more electricity when it is plentiful and less costly. Raising demand for grid-supplied electricity in the middle of 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. This provides a clear example of the progress that has been made around tariff structures.

90 AEMC, 'Final determination – Access, pricing and incentive and incentive arrangements for distributed energy resources', 12 August 2021, accessed 20 January 2022.

91 AER, Export Tariff Guidelines, 19 May 2022.

92 All current tariff trial notifications are available on the AER website: https://www.aer.gov.au/networks-pipelines/network-tariff-reform/tariff-trials.

Figure 3.7 Residential customers on cost-reflective tariffs



Source: Annual RIN responses.

Although distributors are moving towards more cost-reflective tariffs, the limited uptake of smart meters for residential and small business consumers outside Victoria has been a barrier to 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 2021, around 53% of residential customers in the NEM had metering capable of supporting cost-reflective tariffs (including smart meters and manually readable interval meters). Outside Victoria, the penetration of smart or interval meters ranged from as low as 23% in Queensland to 36% in Tasmania.

Changes to the National Electricity Rules in 2017 transferred responsibility for metering from distributors to retailers. Additionally, from February 2019 retailers are 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.[93]

In December 2020 the AEMC announced a review of the regulatory framework for metering. As at June 2022, the AEMC was working with stakeholders to develop a package of measures to fast-track the deployment of smart meters in the NEM. The AEMC indicated the measures will include a target, which may be based on a range of geography, age and other factors.[94]

3.8.2 Ring-fencing

When a network business offers services in a contestable market, robust ring-fencing arrangements must be in place to ensure the business 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.[95] Effective ring-fencing arrangements are an important mechanism for promoting increased choice for consumers and more competitive outcomes in markets for energy services.

93 AEMC, 'National Energy Retail Amendment (Metering Installation Timeframes) Rule 2018', rule determination, December 2018, accessed 14 February 2022.

94 AEMC, 'Review of the regulatory framework for metering services', December 2020, accessed 26 April 2022.

95 The 2015 Power of Choice reforms (section 3.8) required the AER to develop the distribution ring-fencing guideline.

Ring-fencing aims to prevent network businesses from using revenue from regulated services to cross-subsidise their unregulated products, and/or discriminate in favour of affiliated businesses.

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

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

On 3 November 2021 the AER published an updated ring-fencing guideline for electricity distribution networks.[96] A key change in the updated guideline is inclusion of a provision for ring-fencing interactions with standalone power systems and energy storage devices. Distribution network businesses have been required to comply with this version of the guideline since 3 February 2022.

In July 2022 the AER released its final interim draft ring-fencing guideline for electricity transmission networks.[97] The interim guideline contains minor changes made to reflect amendments to the NER since publication of the prevailing Guideline and remains substantively the same.

3.9 Revenue

Network businesses earn revenue for providing services to consumers. While some services are regulated, others are provided through competitive markets. For transmission network businesses, we focus exclusively on components of their revenue associated with delivering prescribed transmission services. For distribution network businesses, we focus exclusively on revenues associated with providing core distribution services – standard control services.[98]

Figure 3.8 to Figure 3.12 provide a breakdown of the revenue network businesses earned in 2021 and how this compared with previous years and targets.

Figure 3.8 Revenue in 2021 – key outcomes

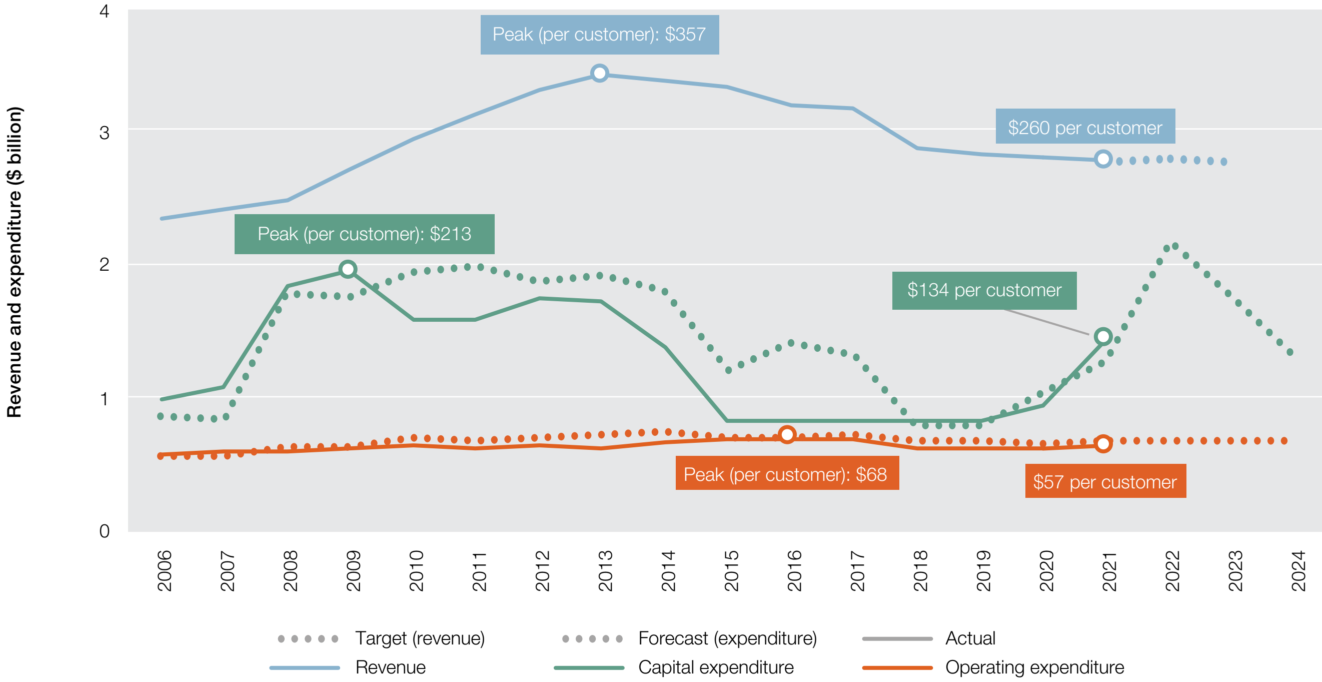
	2021 (actual)	Compared to 2020	Compared to peak (year)
Transmission	$2.8b	▼$38m (▼1.3%)	▼19% (2013)
Distribution	$9.6b	▼$631m (▼6%)	▼29% (2015)
Total	$12.3b	▼$669m (▼5%)	▼27% (2015)

96 AER, 'Ring-fencing guideline – electricity distribution – version 3', AER website, November 2021, accessed 5 April 2022.

97 AER, 'Ring-fencing guideline – electricity transmission – interim', AER website, accessed 5 April 2022.

98 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.

Figure 3.9 Revenue and key drivers – electricity transmission networks

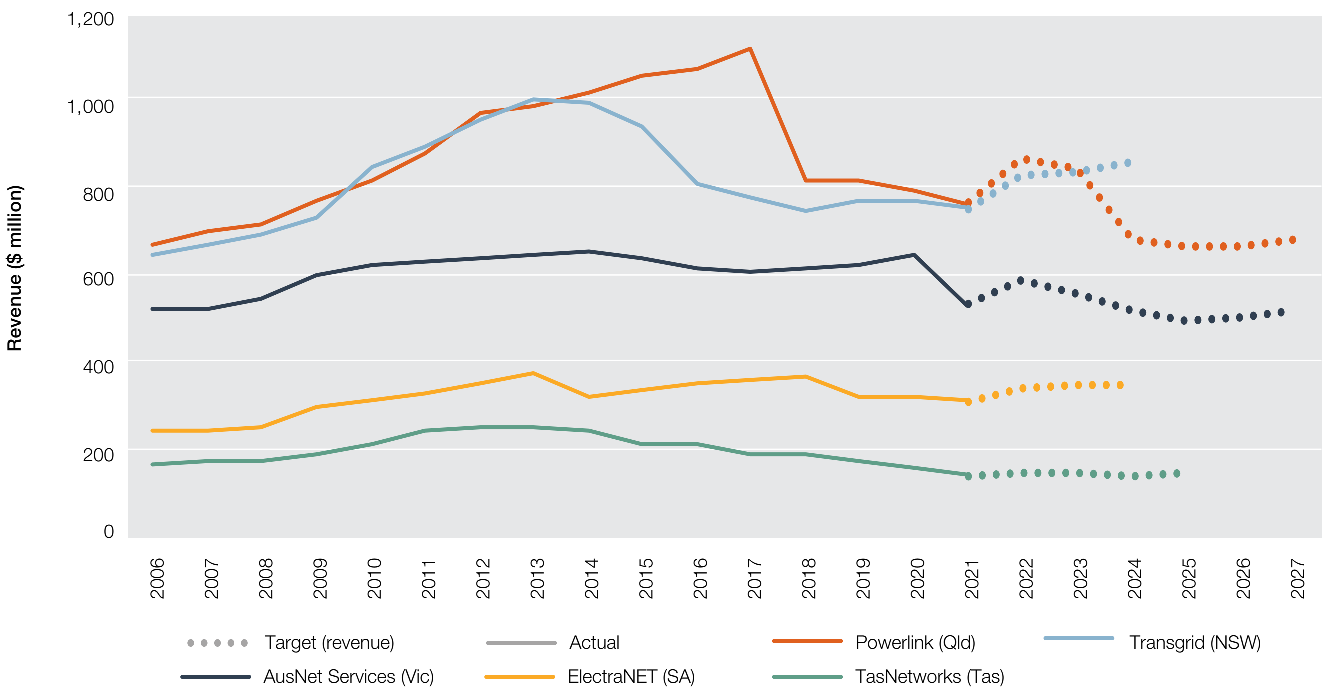


Note: All data are adjusted to June 2022 dollars, based on forecasts of CPI. Most network businesses report on a 1 July – 30 June basis. The exception is AusNet Services (Victoria), which reports on a 1 April – 31 March basis. The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018). Target revenue is derived from regulatory decisions 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.

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.

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

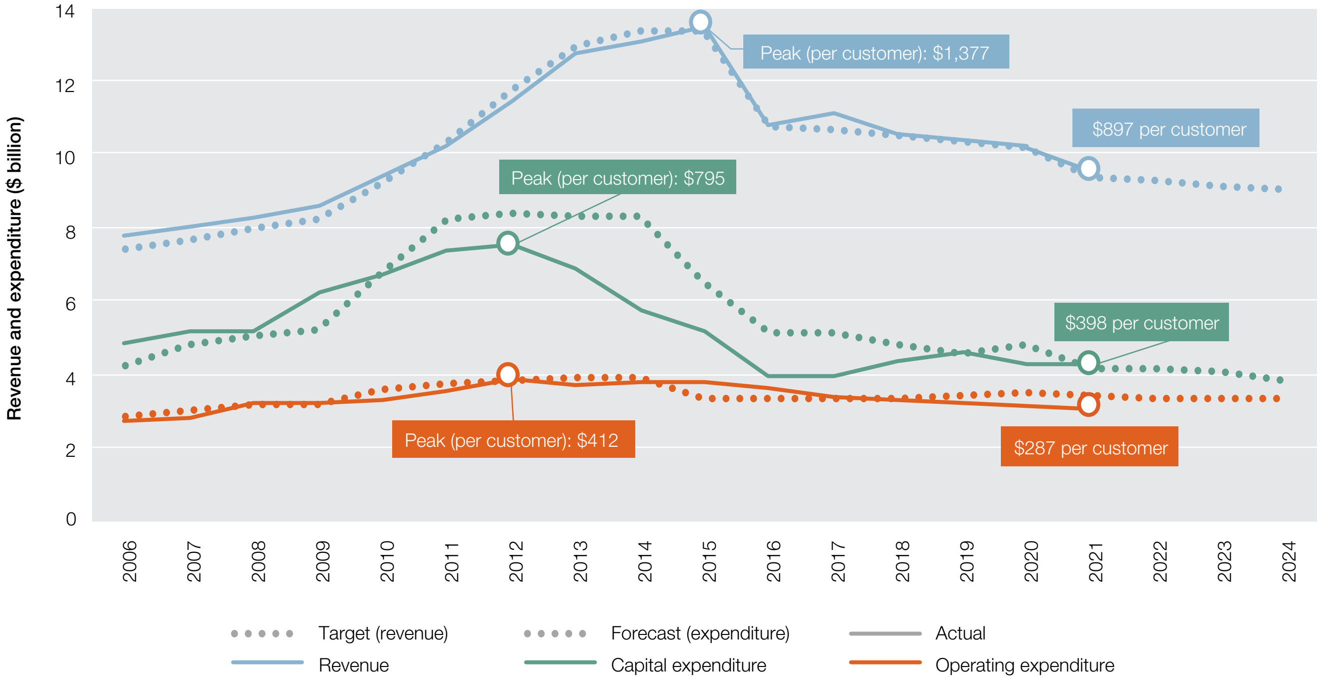
Figure 3.10 Revenue – electricity transmission networks



Note: All data are adjusted to June 2022 dollars, based on forecasts of CPI. 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 Figure 3.9 notes.

Source: AER modelling; annual reporting RIN responses.

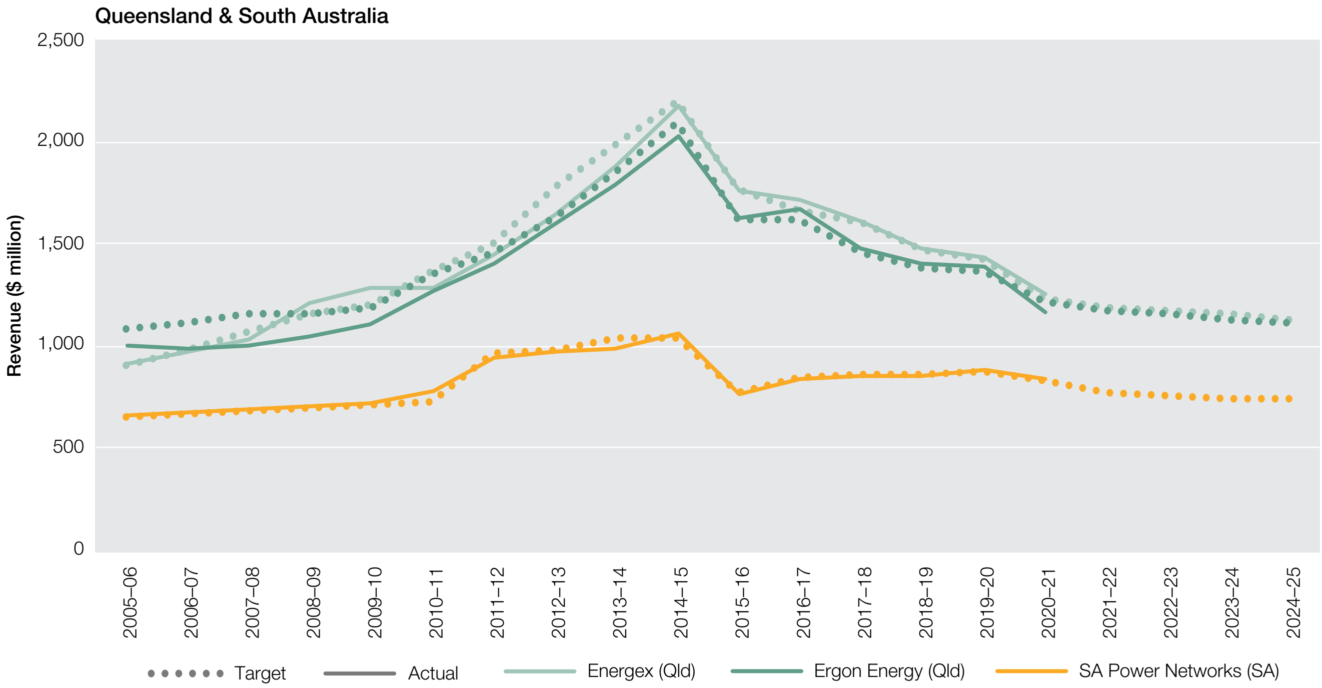
Figure 3.11 Revenue and key drivers – electricity distribution networks

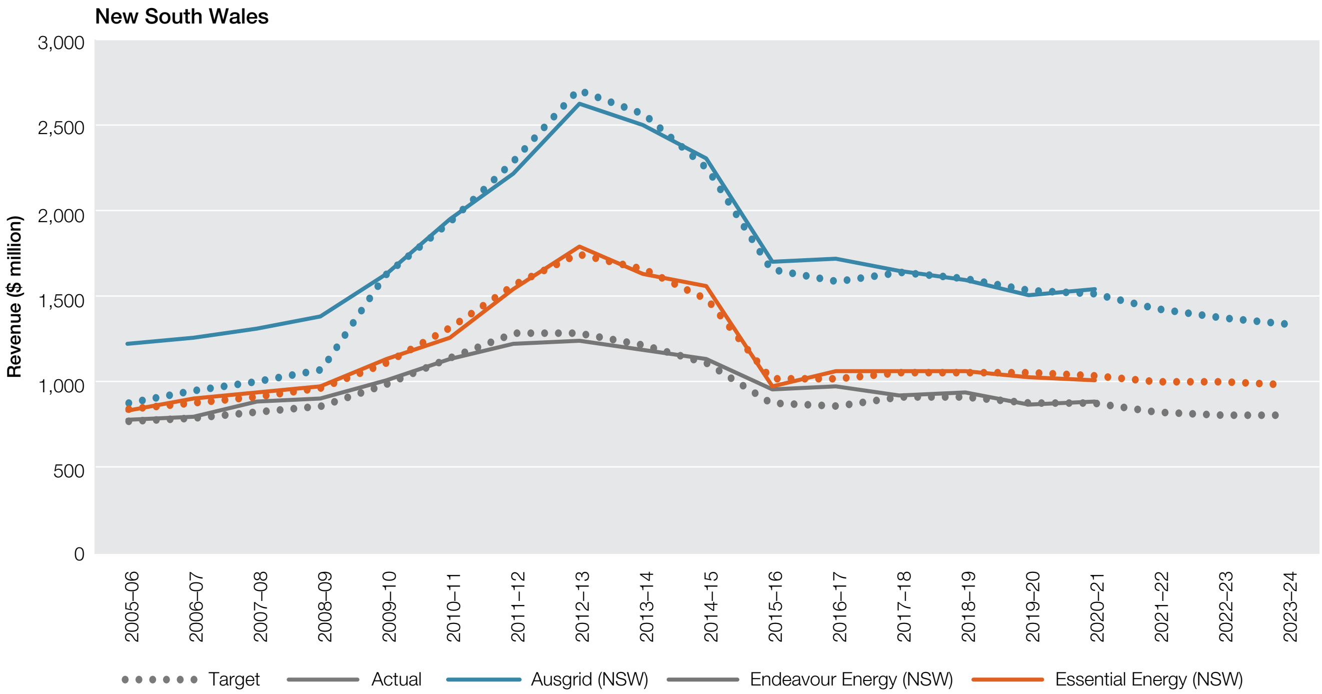


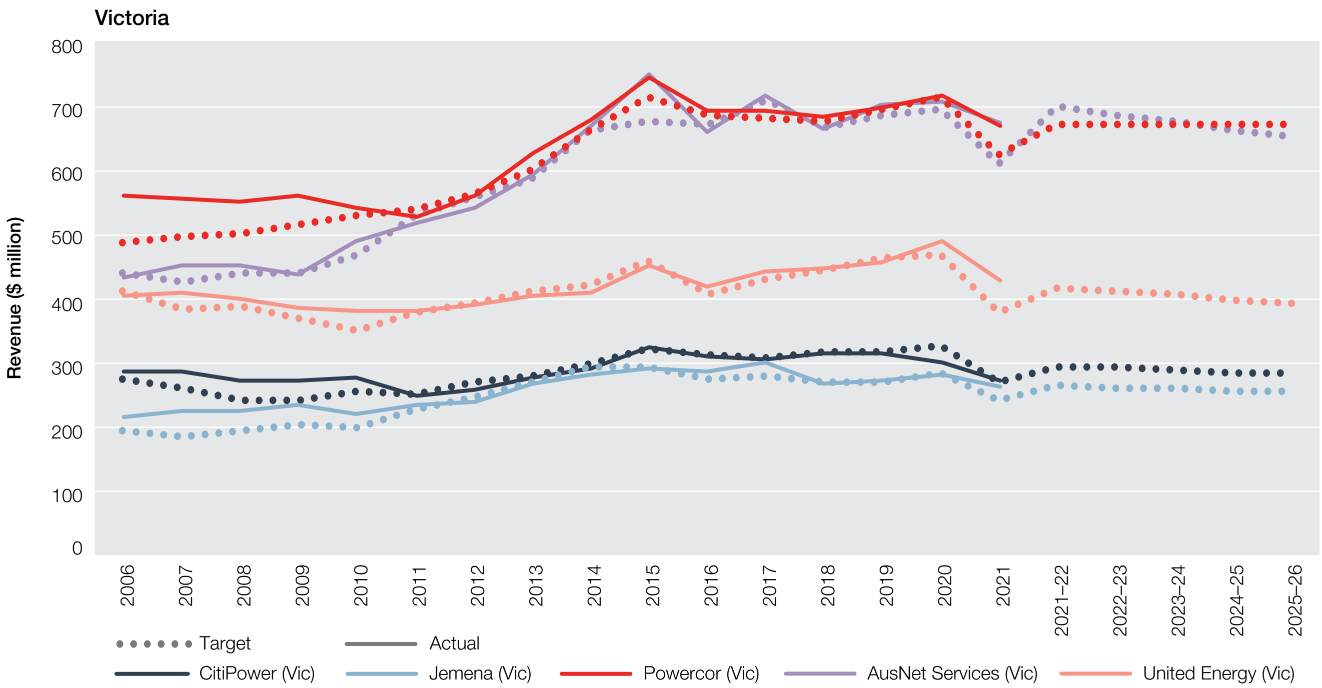
Note: All data are adjusted to June 2022 dollars, based on forecasts of CPI. The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018). Target revenue is derived from regulatory decisions but adjusted to present it on a comparable basis 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 – 30 June 2021). To enable reporting on equivalent terms these values have been doubled.

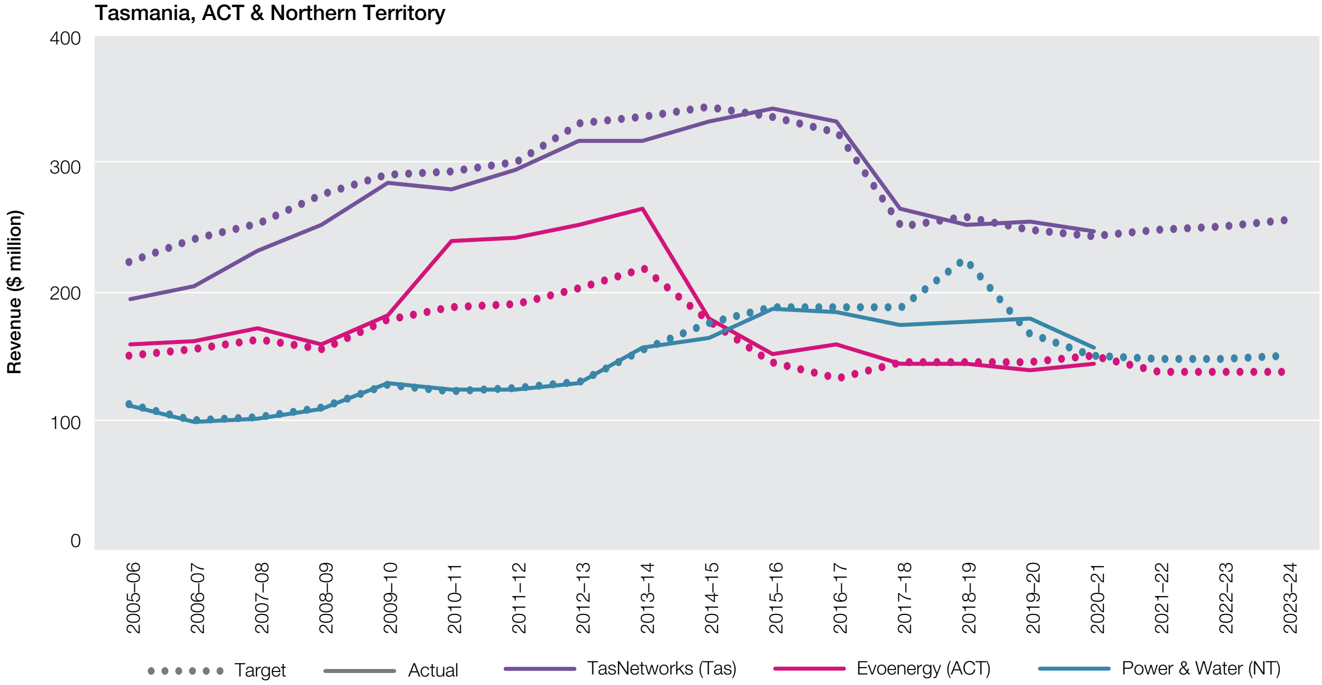
Source: Revenue: economic benchmarking RIN responses; capital expenditure: AER modelling, category analysis RIN responses; operating expenditure: AER modelling, economic benchmarking RIN responses.

Figure 3.12 Revenue – electricity distribution networks




New South Wales
Revenue ($ million)
3,000
2,500
2,000
1,500
1,000
500
0
2005–06
2006–07
2007–08
2008–09
2009–10
2010–11
2011–12
2012–13
2013–14
2014–15
2015–16
2016–17
2017–18
2018–19
2019–20
2020–21
2021–22
2022–23
2023–24
Target
Actual
Ausgrid (NSW)
Endeavour Energy (NSW)
Essential Energy (NSW)


Victoria
Revenue ($ million)
800
700
600
500
400
300
200
100
0
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2021–22
2022–23
2023–24
2024–25
2025–26
Target
Actual
CitiPower (Vic)
Jemena (Vic)
Powercor (Vic)
AusNet Services (Vic)
United Energy (Vic)



Note: All data are adjusted to June 2022 dollars, based on forecasts of CPI. Most network businesses report on a 1 July – 30 June basis. The exception is the Victorian networks which have reported on a 1 January – 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 – 30 June 2021). To enable reporting on equivalent terms these values have been doubled.

Source: AER modelling; annual reporting RIN responses.

Actual network revenues increased by around 7% per year from 2006 to 2015, when network charges accounted for around 43% of retail electricity bills. This significant growth in network revenues led to an increase in retail electricity bills over the period. From 2015 revenues decreased, driven by a 22% reduction in target revenue for the NSW networks in 2015 and an 11% reduction for the Queensland networks in 2016.

A 68% increase in the value of the total transmission and distribution RAB from 2006 to 2014 was a key contributor to the increase in revenue. The increase in RAB was driven by increased investment, in part caused by more strict jurisdictional reliability standards.

Since 2014 the level of investment has decreased, but the impact of past overinvestment remains in the asset base (section 3.11). The inflating RAB increased financing costs and depreciation charges, resulting in higher revenue allowances to cover these costs. Rising interest rates due to the global financial crisis compounded the impact on revenue. Operating expenditure also increased by an average of 6% per year from 2006 to 2012. Further, many AER decisions faced legal challenges over this period, often resulting in court decisions that increased network revenue.

Revenue rose higher in Queensland and NSW than it did elsewhere. In Queensland, it grew by 11% per year from 2006 to 2015; in NSW, it rose by 13% from 2006 to 2013. A key cost driver was the stricter reliability standards imposed by state governments, which required new investment and operating expenditure to meet the new standards. Revenue growth was less pronounced in Victoria, increasing by a relatively stable 4% per year from 2006 to 2015.

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 businesses 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 businesses fell to around 4.6% in 2022 (section 3.12).

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

A combination of these factors reduced the revenue needs of network businesses. Decreasing investment and rates of return gradually often lowered network businesses' revenue as they entered a new 5-year regulatory cycle. 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. The Grattan Institute called for the asset bases of some networks to be written down, so consumers do not pay for that overinvestment.[99] The Australian Competition and Consumer Commission (ACCC) supported this position, particularly for government-owned networks in Queensland, NSW and Tasmania.[100]

Consumer groups and some industry observers remain concerned that the regulatory framework enables network businesses to earn excessive profits. In response to calls for greater transparency around the actual returns earned by the network businesses, in 2018 the AER began publishing information on the businesses' profitability. The AER also releases its *Annual electricity network performance report*, which provides detailed analyses of key operational and financial trends and key profitability measures. The AER's report enables stakeholders to make more informed assessments of the returns earned by each network business.

Operating, maintenance and other costs correlate less closely with market conditions than do other revenue drivers and show relatively stable trends. In 2009 operating costs were about one-third that of asset investment. However, by 2015 weakening investment led to the expenditure on capital projects dropping to a comparable level with operating costs. Operating expenditure later eased as network businesses (especially distributors) implemented efficiency programs (section 3.14).

Figure 3.13 provides a summary of key financial indicators for electricity networks on a per customer basis, which allows for greater comparability across networks.[101] [102] The data in Figure 3.13 reports actual network revenue and expenditure over the past 5 years, which covers a full regulatory period and also reduces the potential for single year bias.

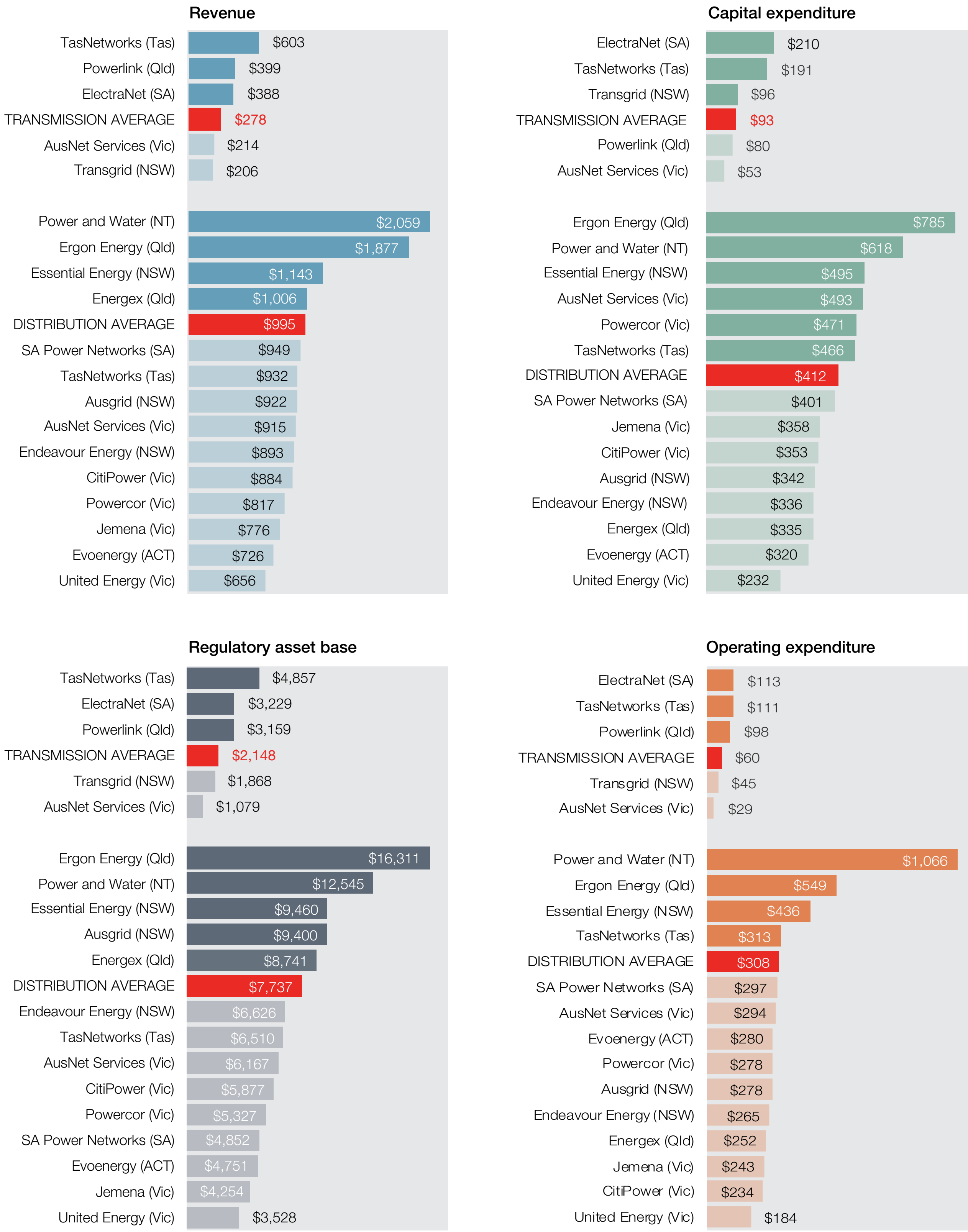
99 T Wood, D Blowers, K Griffiths, 'Down to the wire – a sustainable electricity network for Australia', Grattan Institute, March 2018.

100 ACCC, 'Retail Electricity Pricing Inquiry – final report', 11 July 2018.

101 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.

102 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.

Figure 3.13 Per customer financial metrics – electricity networks



Note: All data are adjusted to June 2022 dollars, based on forecasts of CPI. In 2021 residential customers (a customer who purchases energy principally for personal, household, or domestic use) accounted for 88% of total customers on the distribution network. Of the remaining customers, 10% were non-residential and 1.4% were unmetered or 'other'. While these proportions differed across network businesses – for example, 91% residential for Energex (Qld) and 83% 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 2021. RAB is the actual closing RAB at 30 June 2021. For regulatory purposes, Northern Territory transmission assets are treated as part of the distribution system.

Source: AER revenue decisions and economic benchmarking RINs.

Figure 3.14 provides a snapshot of the key forecasts from the AER's revenue decisions for the current regulatory periods and how they compare with the forecasts from the previous period.

Figure 3.14 AER electricity network revenue decisions – current regulatory period

	Revenue	Capital expenditure	Operating expenditure	Annual impact on residential bill
Transmission	$12.6b (▼5%)	$7b (▲61%)	$3.2b (▼3%)	▲0.3%
Distribution	$46.3b (▼14%)	$19.9b (▼19%)	$16.9b (▲0.6%)	▼0.4%
Total	$58.9b (▼12%)	$26.9b (▼7%)	$20.2b (▲0.04%)	▼0.2%

Note: The current regulatory period is the period in place at 1 July 2022. 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 decision.

Source: AER estimates.

Revenue for transmission businesses is locked in at the beginning of the regulatory period. Businesses are then incentivised to provide services at the lowest possible cost because their returns are determined by their actual costs of providing services. If the transmission networks reduce their costs to below the estimate of efficient costs, the savings are shared with consumers in future regulatory periods.

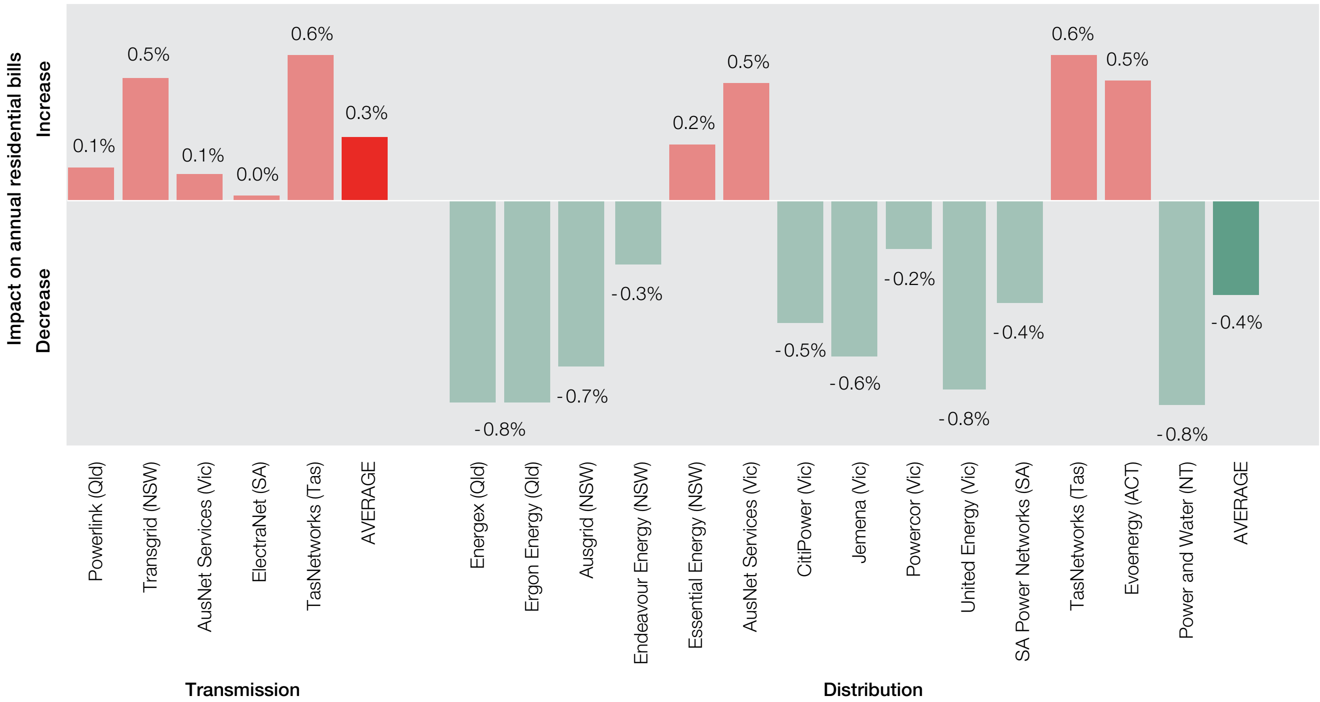
The key driver behind lower revenues for most of the transmission and distribution networks is the change in the return on capital. The rate of return has decreased between regulatory periods; this has been driven by the decrease in interest rates. This means network businesses can now obtain the capital they need to run their businesses more cheaply.

3.10 Network charges and retail bills

Electricity network charges made up 40% to 50% of a residential customer's energy bill in 2021 (section 6.6.1 in chapter 6). Distribution networks account for most of the costs (73% to 78%), and transmission network costs (up to 21%) and metering costs make up the balance.

Declining network revenue since 2015, combined with rising customer numbers, has translated into lower network charges in retail energy bills for most customers (Figure 3.15). This lowering of network charges helped to mitigate some of the pressure (caused by higher wholesale electricity costs) on retail energy bills between 2017 and 2019.

Figure 3.15 Impact of AER revenue decisions on residential customer electricity bills



Note: Estimated impact of latest AER decision 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 decision.

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 decisions; additional AER modelling.

The AER's most recent revenue decisions decreased residential energy bills by an average of 0.2% per year across all states and territories. This is the culmination of an average 0.3% increase in transmission and an average 0.4% decrease in distribution. Changes to network charges mostly arise in the first year of a regulatory period and range from a 9% reduction for Power and Water (Northern Territory) to a 1.6% increase for AusNet Services (Victoria). Initial changes are generally followed by stable prices or modest increases in later years.

Electricity distributors 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 distributor's approved revenues but can account for additional costs associated with transmission and jurisdictional schemes.

Amongst other factors, those annual processes update prices for changes in the consumer price index (CPI). Since June 2021, CPI has increased significantly. For example, over the twelve months to June 2022, CPI increased by 6.1%. The RBA forecasts CPI growth will continue to be high through the end of 2022 and into 2023.[103] As these inflation results feed into annual pricing over coming years they will put upward pressure on prices.

3.11 Regulatory asset base

The RAB for a network business represents the total economic value of assets that provide network services to customers.[104] The value of the RAB substantially impacts a network business's revenue requirement, and the total costs a network's consumers ultimately pay. Given some network assets have a life of up to 50 years, network investment will impact retail energy bills long after the investment is made.

As part of the revenue determination process, the AER forecasts a network business's efficient investment requirements over the forthcoming regulatory period. Efficient investment approved by the AER gets added to the RAB on which the business earns returns, while depreciation on existing assets gets deducted. As such, the value of a network'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.

103 RBA, Statement of Monetary Policy, Forecast table, August 2022.

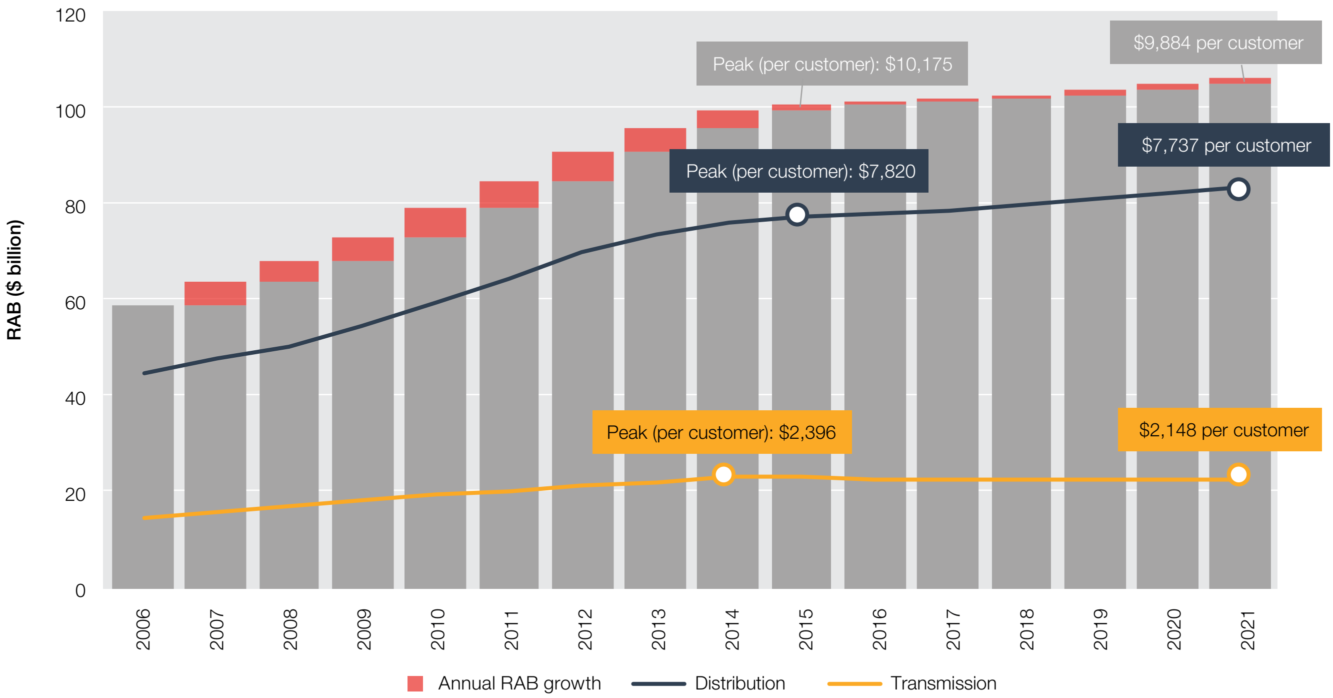
104 To the extent that they are used to provide such services.

Escalating investment inflated the value of the total network RAB from $58.8 billion in 2006 to $98.5 billion in 2014 – an increase of around 8% per year. Since 2014 network investment has steadied, as has the growth in the value of the total network RAB. From 2014 to 2021 the value of the total network RAB continued to grow but at a considerably slower rate of around 1% per year. While the value of the total network RAB continues to grow, the recent trend has differed between transmission and distribution networks.

3.11.1 Regulatory asset base in 2021

As at 30 June 2021 the value of the RAB for electricity network businesses was $105.4 billion, an increase of $1.4 billion (1.3%) from the previous year (Figure 3.16).

Figure 3.16 Value of electricity network assets (regulatory asset base)



Note: All data are adjusted to June 2022 dollars, based on forecasts of CPI. 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 businesses 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 energy rules enabled significant overinvestment in network assets, which partly drove the sharp rise in network revenue from 2006 to 2015 (section 3.9). Under reforms introduced in 2015 the AER may remove inefficient investment from a network's asset base if the network overspent its allowance, to ensure customers do not pay for it.

3.11.2 Overhead support structures

The value of a network business's RAB includes 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 35%) of the total network RAB. This is not surprising given the network spans almost 800,000 kilometres of line, 85% of which is above ground (Figure 3.2 and Figure 3.3).

Transmission towers and distribution poles are installed by network businesses to support overhead powerlines. Transmission towers are predominately made of steel, but distribution poles can be made of wood, concrete, steel or composites like fiberglass. The differing environmental conditions faced by each network business 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.[105]

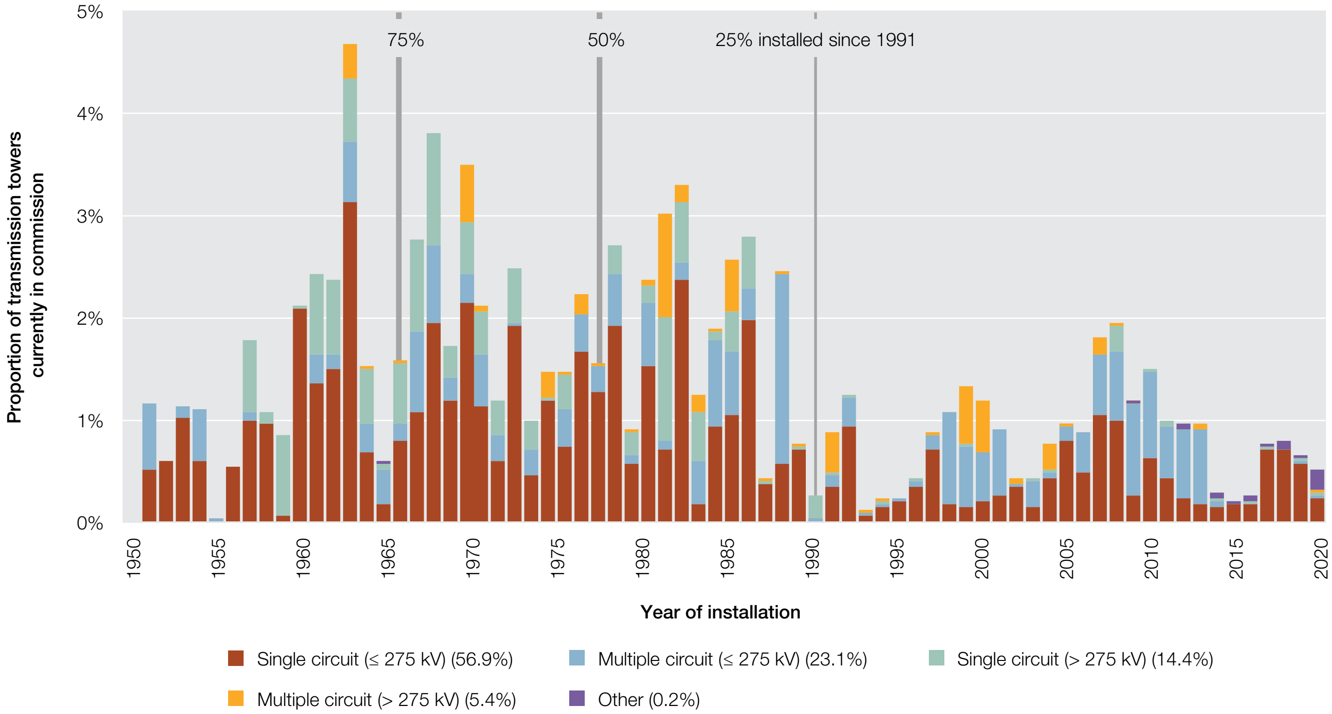
SA Power Networks' distribution network consists of more than 70,000 kilometres of overhead powerlines. However, overhead network assets only make up around 18% of the value of SA Power Networks' RAB. This relatively low representation of overhead assets in SA Power Networks' RAB is uncommon among network businesses given the considerably large size of the network's service area.

Due to the hard-wearing and near-indestructible nature of the distribution poles used in South Australia, SA Power Networks' poles in commission are significantly older than the poles in commission in any other network in the NEM. As such, 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 networks, 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 predominately urban environments.

The transmission tower and distribution pole age profiles shown in Figure 3.17 and Figure 3.18 provide an overview of the total towers and poles currently in commission. However, we note the asset age and tower/pole types differ considerably between the network businesses.

Figure 3.17 Overhead support structures – electricity transmission towers

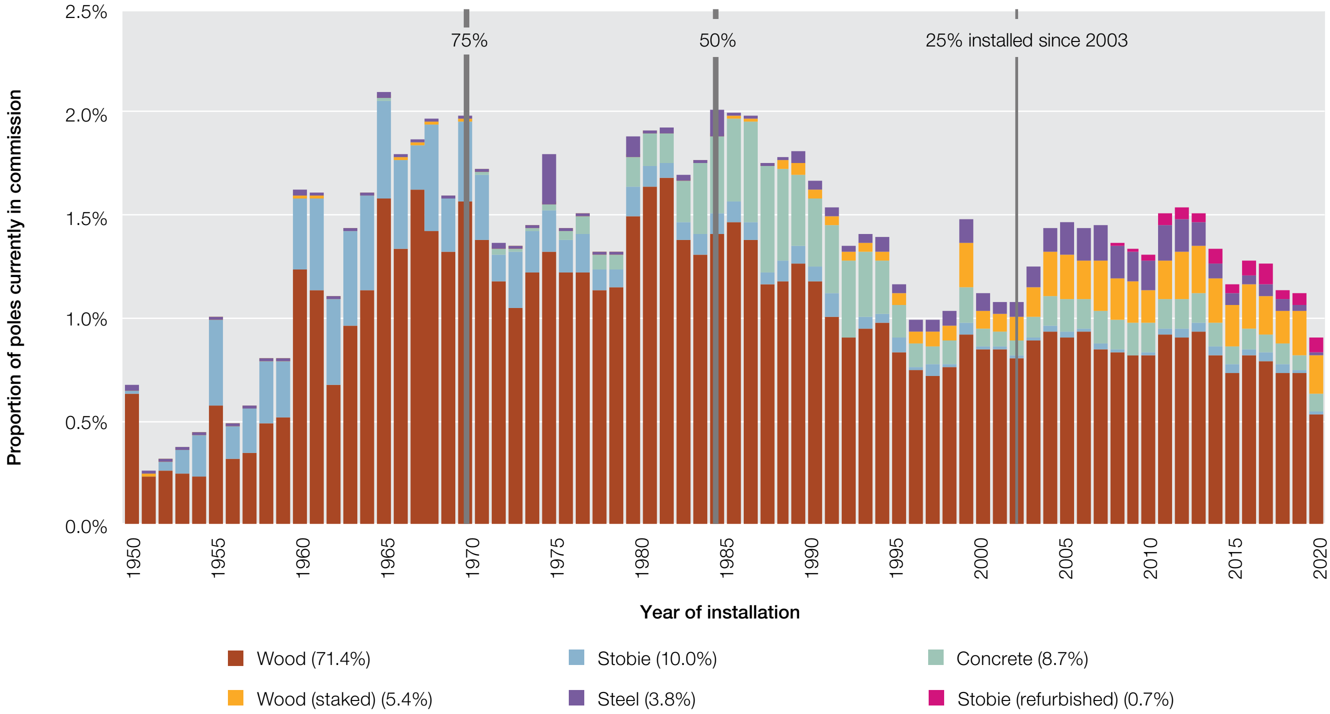


kV: kilovolt.

Source: Category analysis RIN responses.

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

Figure 3.18 Overhead support structures – electricity distribution 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.

3.12 Rates of return

The shareholders and lenders that finance a network business expect a commercial return on their investment. The rate of return estimates the financial returns that a network business's financiers require to justify investing in the business. It is a weighted average of the return needed to attract both equity and debt funding. Equity funding is the dividends paid to a network business's shareholders and debt funding relates to interest paid on borrowings from banks and other lenders. 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, but a network's actual returns can vary from the allowed rate. The difference can be due to several factors, such as the impact of incentive schemes, forecasting errors, 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 by the allowed rate of return.[106]

If the AER sets the allowed rate of return too low, then a network business may not be able to attract sufficient funds to invest in assets needed for a reliable power supply. If the rate is set too high, then the network businesses have a greater incentive to overinvest, and consumers will pay for a 'gold-plated' network that they do not need.

Because electricity networks are capital intensive, returns to investors typically make up 30% to 50% of a network'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.

A one percentage point increase in the allowed WACC will increase revenues by around 8%, which would increase average household bills by around 4%.[107] For this reason, prior to the abolition of limited merits review and the introduction of the binding rate of return instrument, the allowed rate of return was often the most contentious part of the AER's individual revenue decisions.

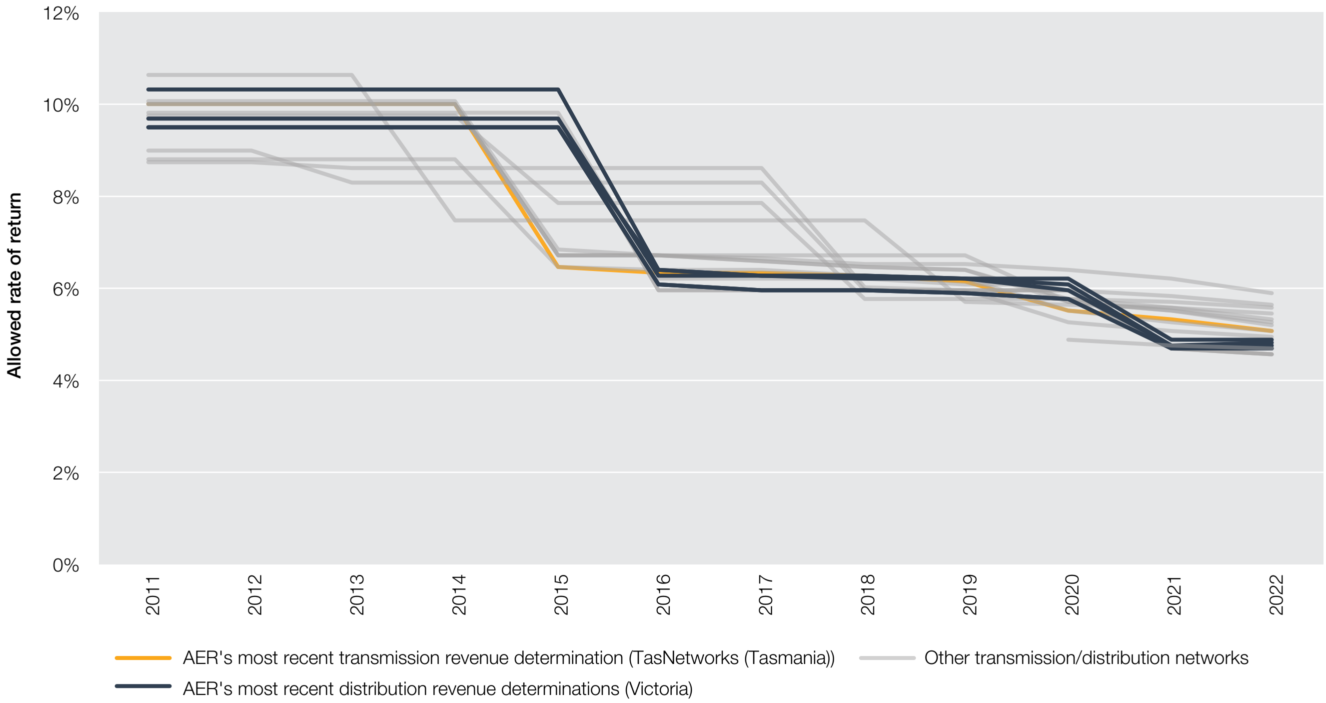
Conditions in financial markets are a key determinant of the allowed rate of return. The AER's revenue decisions from 2009 to 2012 took place against a backdrop of the global financial crisis, an uncertain period associated with reduced liquidity in debt markets and high-risk perceptions. In revenue decisions made during this period the allowed rate

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

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

of return was more than 10%, reflecting the conditions in financial markets (Figure 3.19). The Australian Competition Tribunal increased some allowed rates of return following appeals by the network businesses.

Figure 3.19 Allowed rate of return



Note: Rate of return is the nominal vanilla WACC.

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

Since 2015 the AER has updated the allowed return on capital annually to reflect changes in debt costs. More stable financial market conditions resulted in allowed rates of return averaging around 6% from 2016. These lower allowed rates became a key driver of lower network revenues and charges over the past few years (Figure 3.9 and Figure 3.11).

In recent months, 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 2022 to the end of August have averaged roughly 3%. Similarly, annual yields on 5-year CGSs were as low as 0.25% in November 2020 but over 2022 to the end of August have averaged roughly 2.7%.[108] If risk-free rates, or other key inputs, remain at levels above lower recent rates, this will put upward pressure on network revenue over coming years.

In recent years the AER has estimated network businesses' actual returns for comparison against network businesses' allowed returns. This analysis suggests that actual returns have often exceeded the AER's allowed returns. This is not unexpected given that the premise of a revealed efficient cost framework is to encourage network businesses to become more efficient, allowing for short-term profits to be earned above the allowed rate.[109]

3.13 Investment

Electricity network businesses invest in capital equipment such as towers, poles, wires and other infrastructure needed to transport electricity to customers. Investment drivers vary among networks and depend on a network's age and technology, load characteristics, the demand for new connections, and reliability and safety requirements. Substantial investment is needed to replace old equipment when 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.

108 RBA, Capital Market Yields – Government Bonds – Daily – F2, accessed 6 September 2022.

109 AER, 'Electricity network performance report', September 2021, investigates network profitability and provides a more thorough analysis of actual returns as opposed to allowed/forecast returns.

Figure 3.20 to Figure 3.22 break down the amount of investment network businesses undertook in 2021 and how this compared with previous years' expenditure and forecasts.

Figure 3.20 Capital expenditure in 2021 – key outcomes

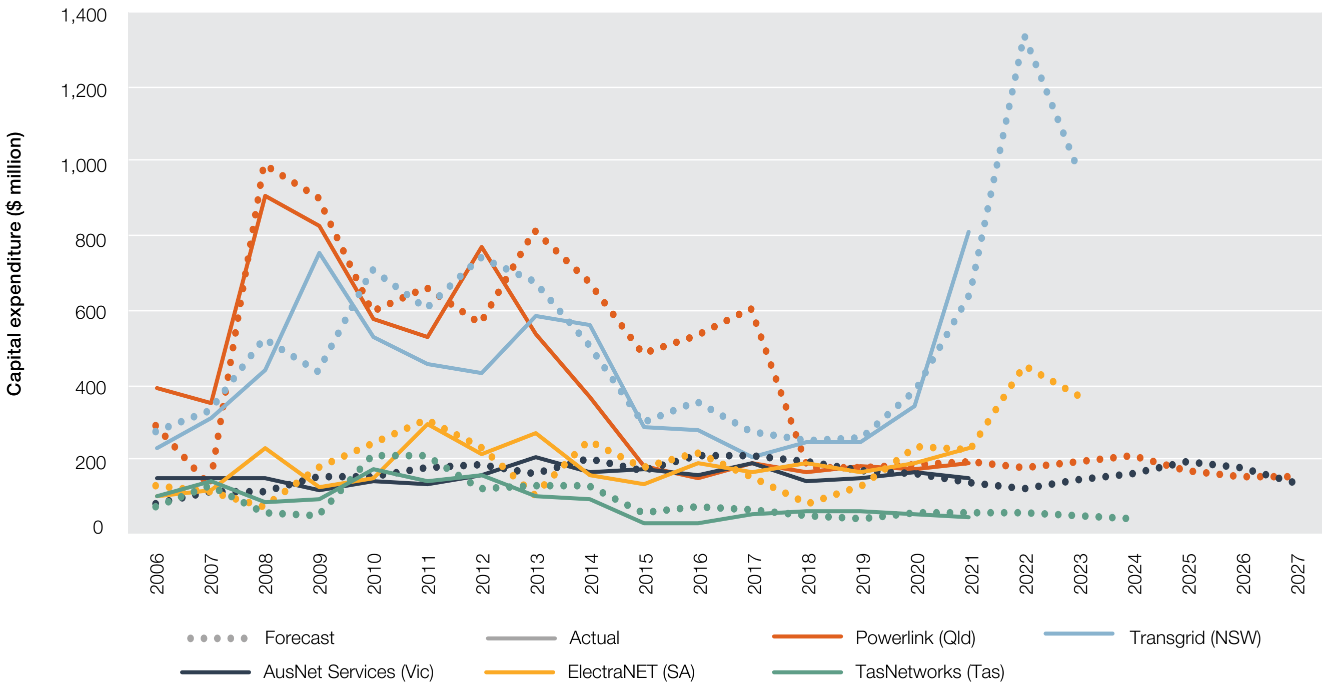
	2021 (actual)	Compared to 2020	Compared to forecast	Compared to peak (year)
Transmission	$1.4b	▲$494m (▲53%)	▲$157m (▲12%)	▼26% (2009)
Distribution	$4.2b	▼$56m (▼1.3%)	▲$96m (▲2%)	▼44% (2012)
Total	$5.7b	▲$438m (▲8%)	▲$253m (▲5%)	▼39% (2012)

Note: Excludes AER decisions on transmission interconnectors.

Significant investment in the transmission network is forecast to continue over the next few years (Figure 3.21). Between 2022 and 2026 the modelled cost of actionable ISP projects under the 2020 ISP – specifically Project EnergyConnect (Transgrid and ElectraNet) and the Queensland–NSW interconnector (QNI) project (Transgrid) – is around $12.8 billion (Figure 3.27).[110]

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.[111]

Figure 3.21 Capital expenditure – electricity transmission networks



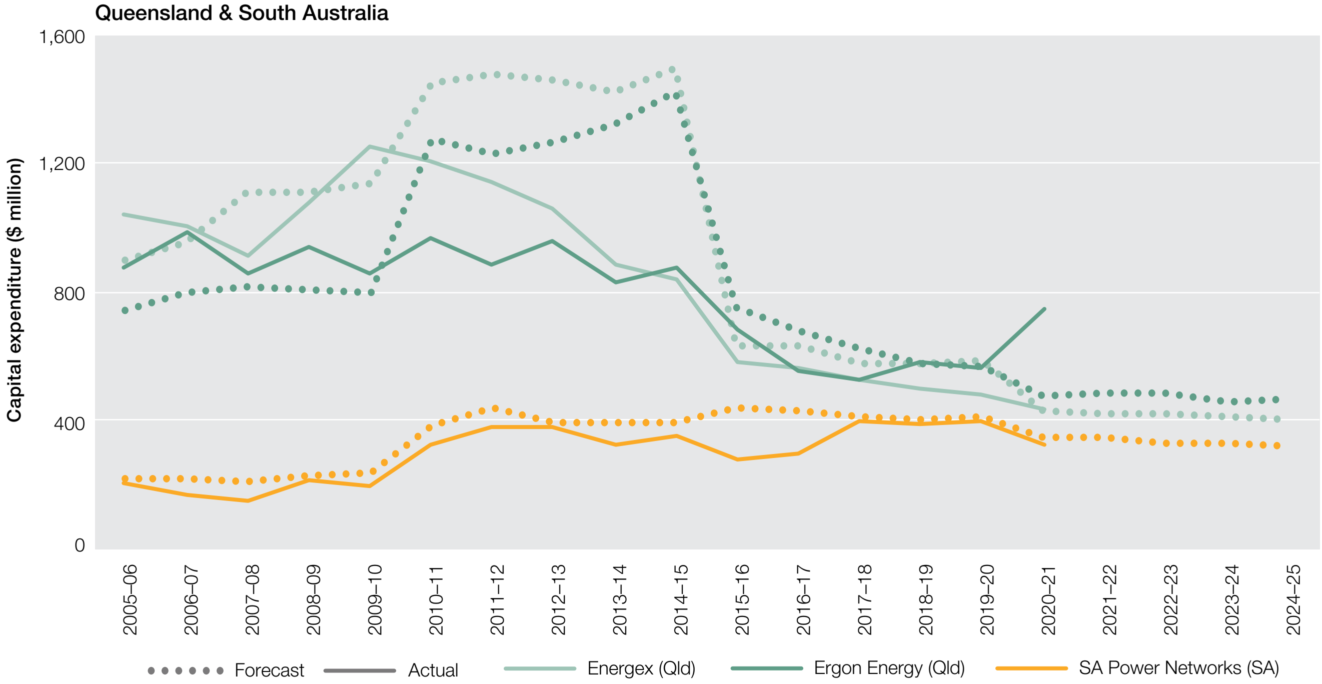
Note: Actual outcomes, CPI adjusted to June 2022 dollars. The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018). Assumptions are set out in Figure 3.9 notes.

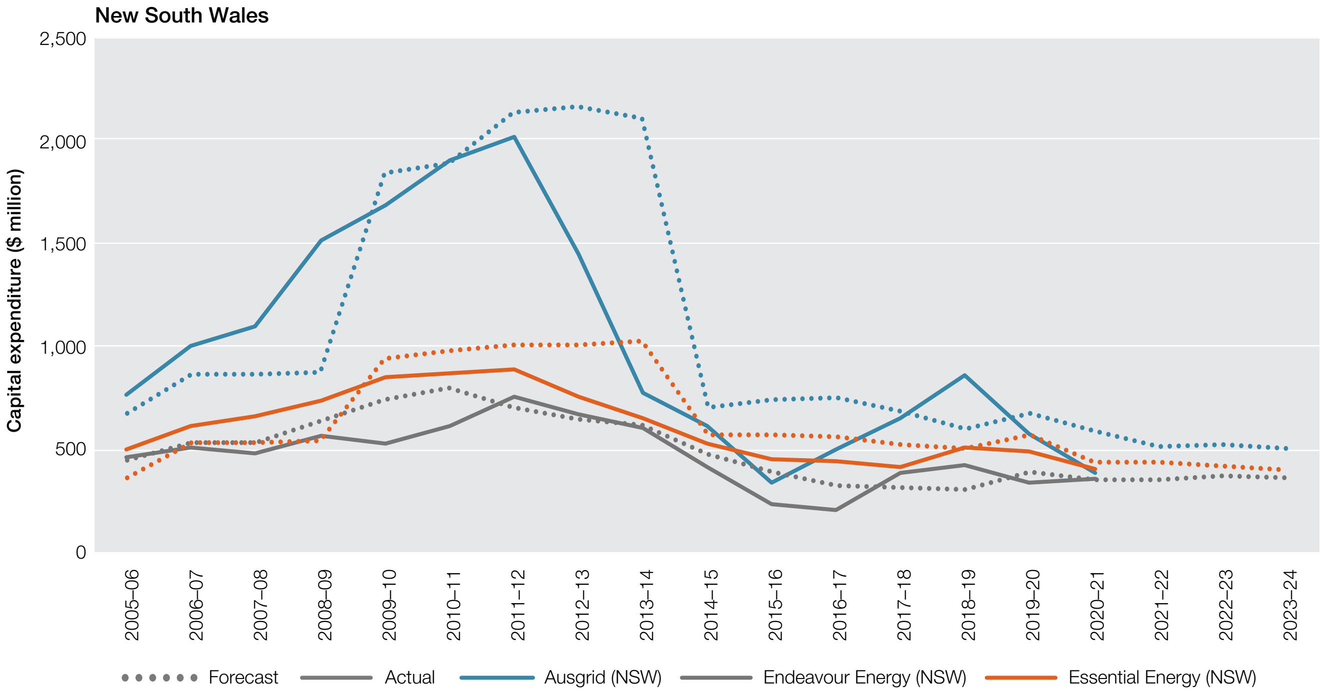
Source: AER modelling; annual reporting RIN responses.

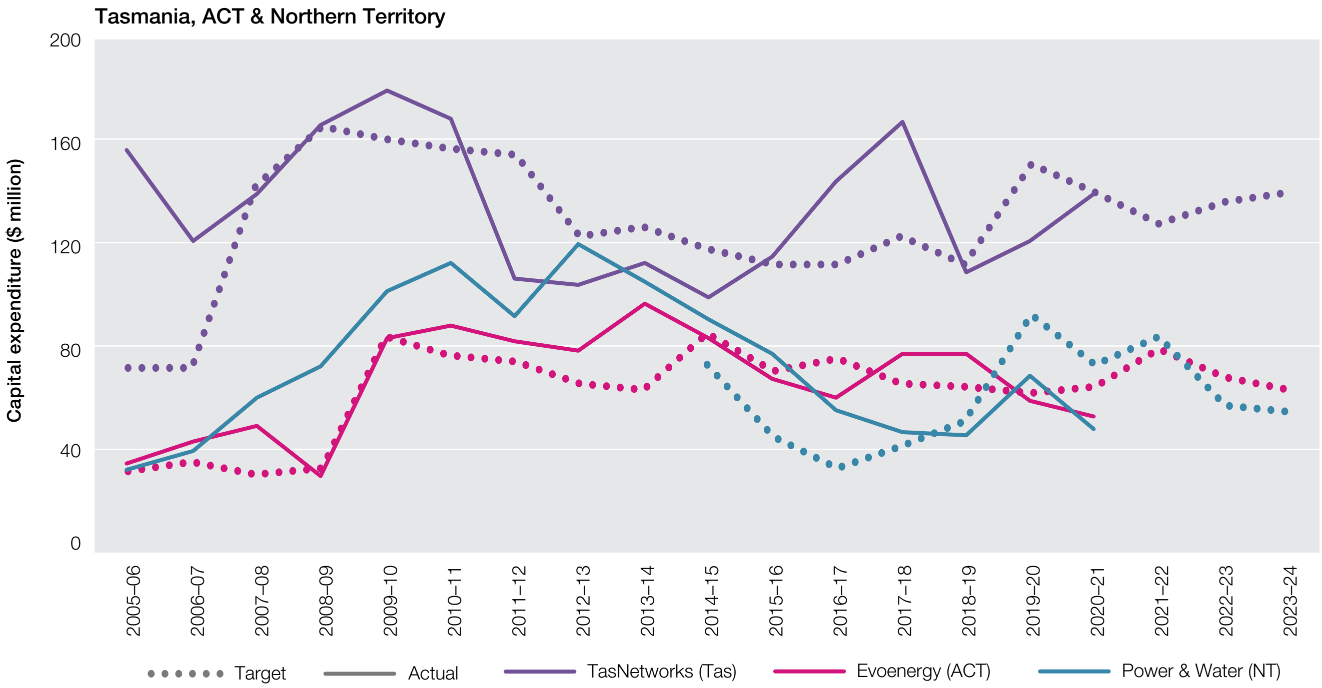
110 AEMO, '2022 Integrated System Plan' June 2022, p. 15

111 Transgrid, 'HumeLink – fact sheet', accessed 30 March 2022

Figure 3.22 Capital expenditure – electricity distribution networks







Note: Actual outcomes, CPI adjusted to June 2022 dollars. Assumptions are set out in Figure 3.11 notes.

Source: AER modelling; annual reporting RIN responses.

3.13.1 Investment trends

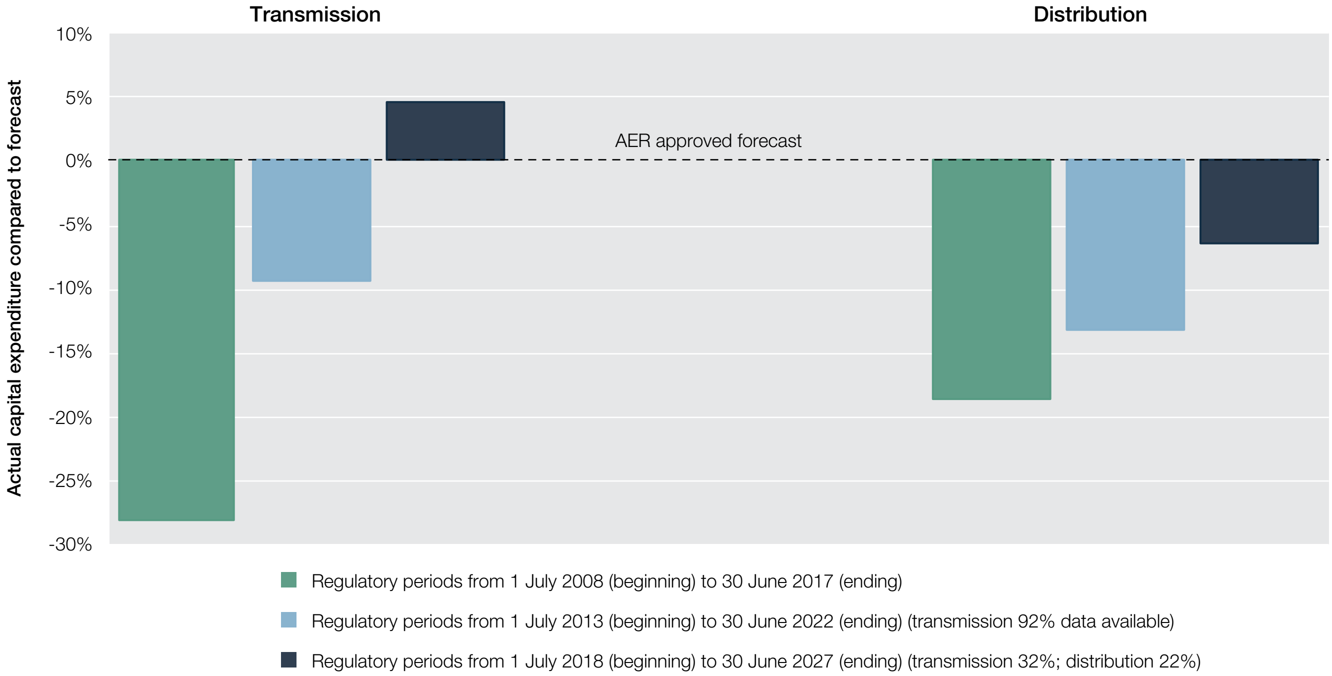
Total investment in the electricity networks increased by an average of 7% per year from 2006 to 2013, when it peaked at $9.3 billion (Figure 3.9 and Figure 3.11).

Network businesses underspent heavily against the forecast over the regulatory periods from July 2008 to June 2017. Network businesses in Queensland were the most significant contributors to the underspend, with Powerlink (transmission) underspending by 54%, Ergon Energy underspending by 31% and Energex (distribution) underspending by 30%. Network businesses in NSW also contributed, with Transgrid (transmission) underspending by 21%, Ausgrid by 23% and Essential Energy (distribution) by 19%.

Investment levels eased in the following regulatory periods[112], when AER reforms to protect consumers from funding inefficient network projects began. Although the trend in underspending continued, it did so at a lesser rate. The Victorian distribution networks were most responsible, led by CitiPower (31% underspend), Jemena (22%) and United Energy (22%).

Network business are still collectively in the early stages of their respective current regulatory periods, but the gap between actual and forecast capital expenditure is continuing to narrow (Figure 3.23).

Figure 3.23 Capital expenditure against forecast



Data availability (%) refers to the proportion of actual capital expenditure data available at the time of publication.

Note: Data used in Figure 3.23 includes actual expenditure for the regulatory year 2021. The timing of regulatory periods differs among network businesses. For example, while 2020–21 reflects the third year of ElectraNet's (transmission) current regulatory period, it reflects the fourth year of Powerlink's (transmission) previous regulatory period. This explains why a proportion of data is available for the current regulatory period even though the dataset from the last regulatory period is not yet complete.

Source: AER modelling; annual reporting RIN responses.

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

In the AER's most recent revenue decisions 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 offered financial incentives for network businesses to avoid investment above forecast levels (Box 3.2).

112 Which ranged from 1 July 2013 – 30 June 2018 for ElectraNet (South Australia) to 1 July 2012 – 30 June 2022 for several network businesses.

Box 3.2 Capital expenditure sharing scheme

The AER's capital expenditure sharing scheme (CESS) creates an incentive for network businesses to keep new investment within forecast levels approved in their regulatory determination. The CESS rewards efficiency savings (spending below forecast) and penalises efficiency losses (spending above forecast).

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

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

The scheme poses risks that network businesses 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 business to earn bonuses by deferring critical investment needed to maintain network safety and reliability. To manage this risk, the CESS is balanced by separate incentives that focus on efficient operating expenditure (Box 3.3) and service quality (Box 3.4). This balancing of schemes encourages network businesses to make efficient decisions on their mix of expenditure to provide reliable services in ways that customers value (section 3.16.1).

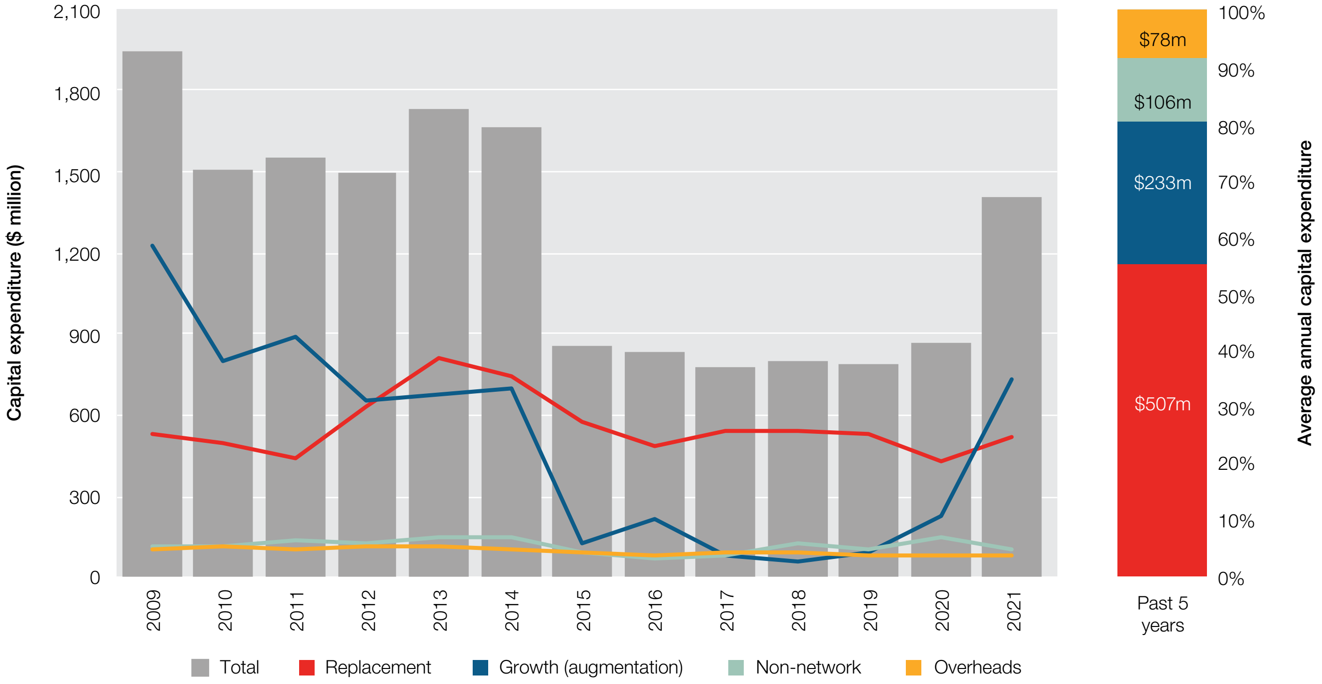
3.13.2 Changing composition of investment

For the last decade, network investment has been driven by replacement expenditure rather than growth-related expenditure (Figure 3.24 and Figure 3.25). Weaker than forecast demand for electricity, along with less stringent reliability obligations, led many network owners to postpone or abandon growth-related projects.

However, in 2021, electricity networks invested $1.6 billion in growth-related projects, an increase of $590 million (59%) over the previous year. This significant increase was not spread evenly across the networks. It was primarily the result of Transgrid (NSW) investing $619 million – driven by Project EnergyConnect – an increase of $535 million (632%) over Transgrid's growth-related expenditure in the previous year.

Despite the significant increase in growth-related expenditure in 2021, the replacement of existing assets continues to be the primary driver of capital expenditure.

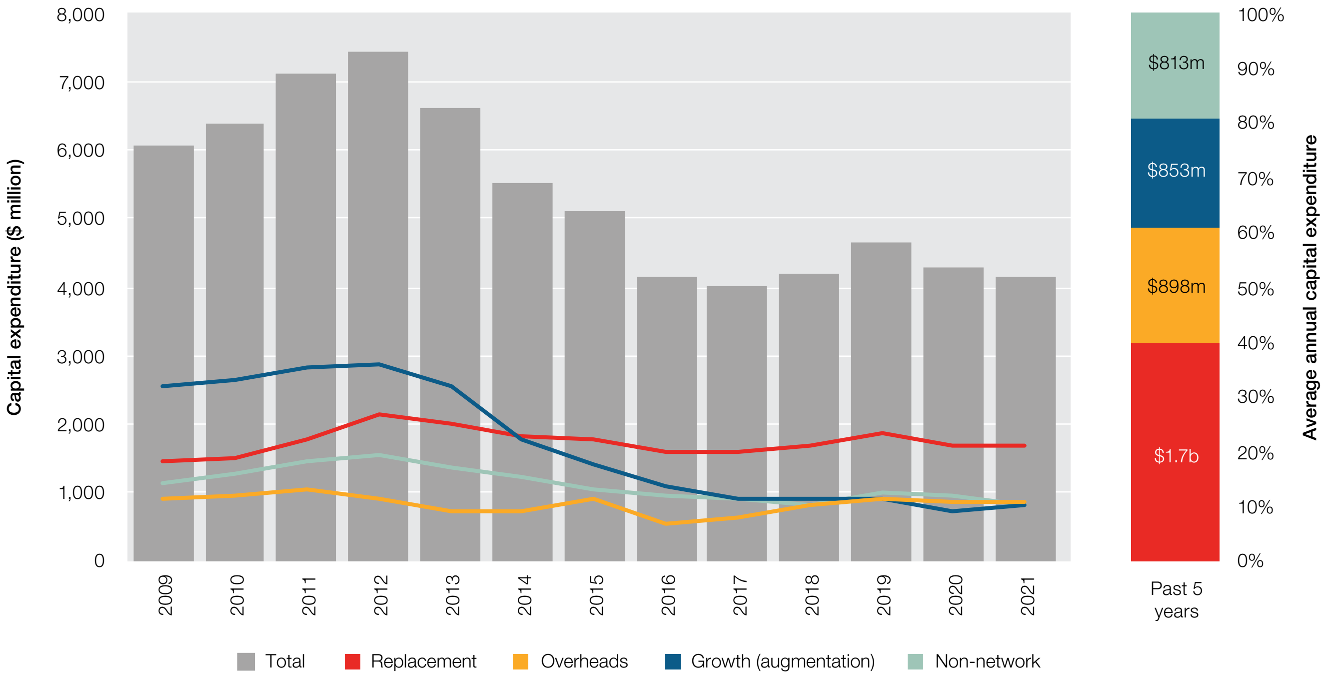
Figure 3.24 Drivers of capital expenditure – electricity transmission networks



Note: All data are adjusted to June 2022 dollars, based on forecasts of CPI. 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.

Figure 3.25 Drivers of capital expenditure – electricity distribution networks



Note: All data are adjusted to June 2022 dollars, based on forecasts of CPI. 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.

3.13.3 Pass through events – natural disasters

In November 2020 Transgrid (NSW) submitted a cost pass through application to the AER, seeking to recover $55.5 million in costs over a 2-year period in relation to the 2019–20 bushfires. The bushfires impacted 9% of the length of Transgrid's transmission line and 2,681 of its transmission structures.

The AER determined some of the costs proposed by Transgrid should not be included and that the pass through amount should be recovered over a longer time frame. The AER approved a pass through amount of $49.8 million to be recovered by Transgrid over the 3 regulatory years to 30 June 2025.[113]

In September 2021 Essential Energy (NSW) submitted a cost pass through application to the AER, seeking to recover costs in relation to the 2019–20 bushfires. The bushfires burnt more than 3.4 million hectares in Essential Energy's network area or over 60% of the total fireground in NSW, resulting in power outages to over 104,000 customers.

The AER determined that, in this case, the 2019–20 bushfires did not constitute a single natural disaster event, but 2 separate natural disaster events (northern NSW and southern NSW). The AER approved a positive pass through amount of $11.1 million for the northern NSW bushfire and $20.2 million for the southern NSW bushfire to be recovered by Essential Energy over the 2 regulatory years to 30 June 2024.[114]

In November 2021 AusNet Services (Victoria) submitted a cost pass through application to the AER, seeking to recover costs in relation to storms that occurred on 9 and 10 June 2021. The storms caused extensive damage to AusNet Services' electricity distribution network and interrupted supply to over 230,000 customers.

The AER was satisfied that the June 2021 storms met the definition of a natural disaster pass through event and that the damage sustained was material. The AER approved a positive pass through amount of $39.1 million to be recovered by AusNet Services over the 4 regulatory years to 30 June 2026.[115]

In March 2022 AusNet Services (Victoria) submitted a cost pass through application to the AER, seeking to recover costs in relation to the storm that occurred on 29 October 2021. This severe storm event caused extensive damage to AusNet Services' electricity distribution network and interrupted supply to over 230,000 customers.[116]

The AER was satisfied the October 2021 storm met the definition of a natural disaster pass through event and that the damaged sustained was material. The AER approved a positive pass through amount of $6.2 million to be recovered by AusNet Services over the 3 regulatory years to 30 June 2026.[117]

3.13.4 Valuing distributed energy resources

The uptake of rooftop solar systems has grown exponentially over the past decade (Figure 3.26). As a result of this rapid growth, integration of consumer energy resources now presents a significant, emerging area of expenditure.

113 AER, 'Decision – cost pass through Transgrid's 2019–20 bushfire natural disaster event', 4 May 2021, accessed 4 April 2022.

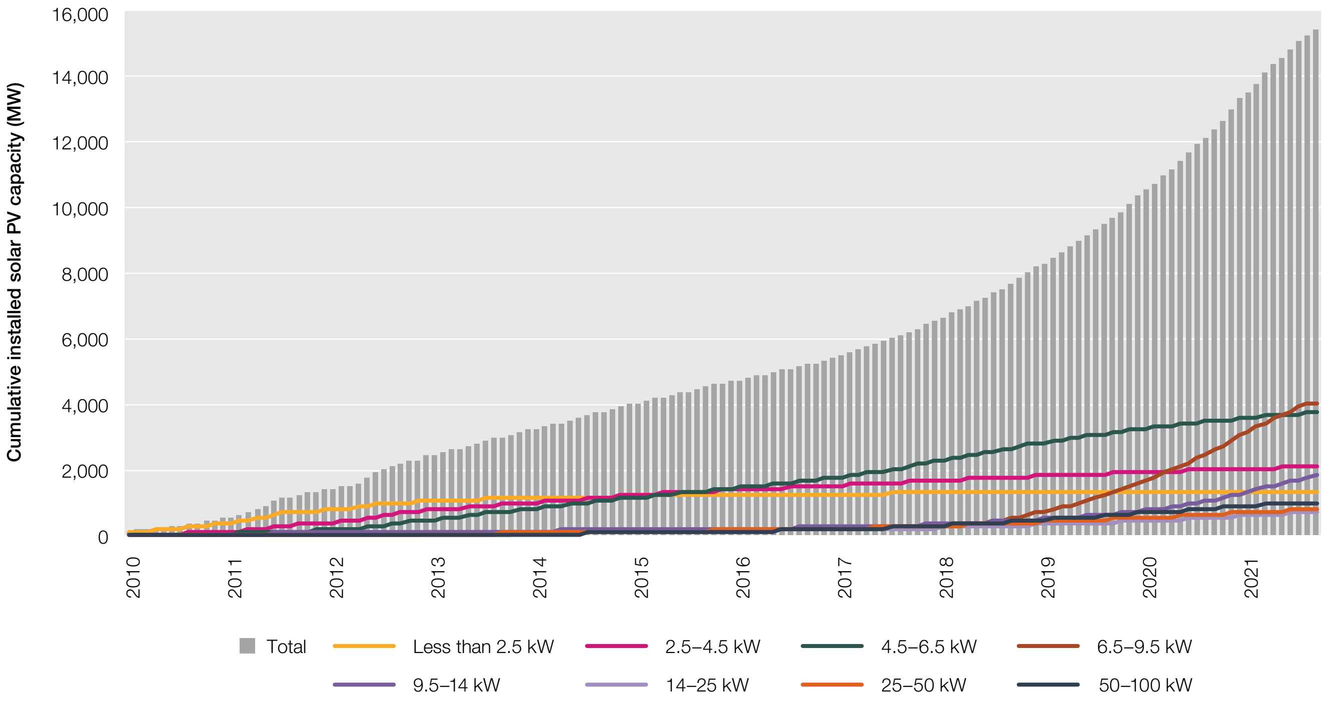
114 AER, 'Determination cost pass through Essential Energy's 2019–20 bushfire natural disaster events', 21 March 2022, accessed 4 April 2022.

115 AER, 'Determination June 2021 storms cost pass through – AusNet Services', 16 March 2022, accessed 4 April 2022.

116 AusNet Services, 'Cost pass through application', 10 March 2022, accessed 4 April 2022.

117 AER, 'AusNet Services – Cost pass through – October 2021 storm', 22 June 2022, accessed 26 June 2022.

Figure 3.26 Cumulative installed small-scale solar capacity



kW; kilowatts; MW: megawatts; PV: photovoltaic

Note: Includes installations of PV systems up to 100 kW in size. Data covers all of Australia.

Source: AER analysis of postcode data from the Australian PV Institute, collected on 6 February 2022.

In November 2019 the AER began developing guidance around assessing proposed integration of expenditure for consumer energy resources. As part of this process, the AER sought stakeholder views on the current and predicted effects consumer energy resources are having on 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 Cutler Merz) on potential methodologies for determining the value of consumer energy resources.[118] 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.[119]

The AEMC, in its *Electricity network economic regulatory framework review (2020)*, 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 distributors could change.

An environment with high levels of consumer energy resources could mean that distributors 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.[120]

118 CSIRO and CutlerMerz, 'Value of distributed energy resources: methodology study – final report', October 2020. Note: Consumer energy resources and distributed energy resources are used interchangeably.

119 AER, 'Draft DER integration expenditure guidance note', AER website, 6 July 2021.

120 AEMC, 'Electricity network economic regulatory framework 2020 review', 1 October 2020.

3.13.5 Regulatory tests for efficient investment

The AER assesses a network business's 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 business to apply the RIT for transmission projects that have an estimated capital cost of greater than $7 million and distribution projects that have an estimated capital cost of greater than $6 million.

A network business must evaluate credible alternatives to network investment (such as generation investment or demand response) that might address the identified need at lower cost. The business 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 businesses' compliance with the tests. It also resolves disputes over whether a network business has properly applied a test. Civil penalties including fines apply to network businesses that do not comply with some of the RIT requirements (including the required consultation procedures).

Until 2017 the regulatory tests only applied to growth investment, which was the biggest component of network investment until 2014. Replacement expenditure has since overtaken growth investment on most networks (section 3.13.2), so 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 August 2020 the AER published its *Cost benefit analysis guidelines* (for transmission projects initiated by AEMO's integrated system plan (ISP)) and updated the RIT-T application guidelines (for other projects).[121] [122] The guidelines are part of a broader reform to streamline the transmission planning process while retaining rigorous cost benefit analysis. The new rules were effective from 1 July 2020, but the new guidelines came into effect through the 2022 ISP.[123]

3.13.6 AEMO's integrated system plan

The ISP provides a coordinated whole-of-system plan for efficient development of the power system to ensure power system needs are met in the long-term interests of consumers. The ISP 'actions' key projects by triggering RIT-T applications (section 3.12.6).

Significant investment in the transmission network is forecast over the next few years. Between 2022 and 2026 the modelled cost of actionable ISP projects under the 2020 ISP is around $12.8 billion.[124]

Under new rules, the ISP is subject to additional governance arrangements through binding cost benefit analysis guidelines and forecasting best practice guidelines. The RIT-T instrument and associated application guidelines have also been updated to be consistent with the new planning process. In line with the new rules, the guidelines seek to provide AEMO with flexibility in how it identifies the optimal pathway for the NEM when developing the ISP.

The AER's cost-benefit analysis guidelines are to be used by AEMO in identifying an optimal development path that promotes the efficient development of the power system, 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.[125]

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.

121 AER, 'Cost benefit analysis guidelines', AER website, August 2020.

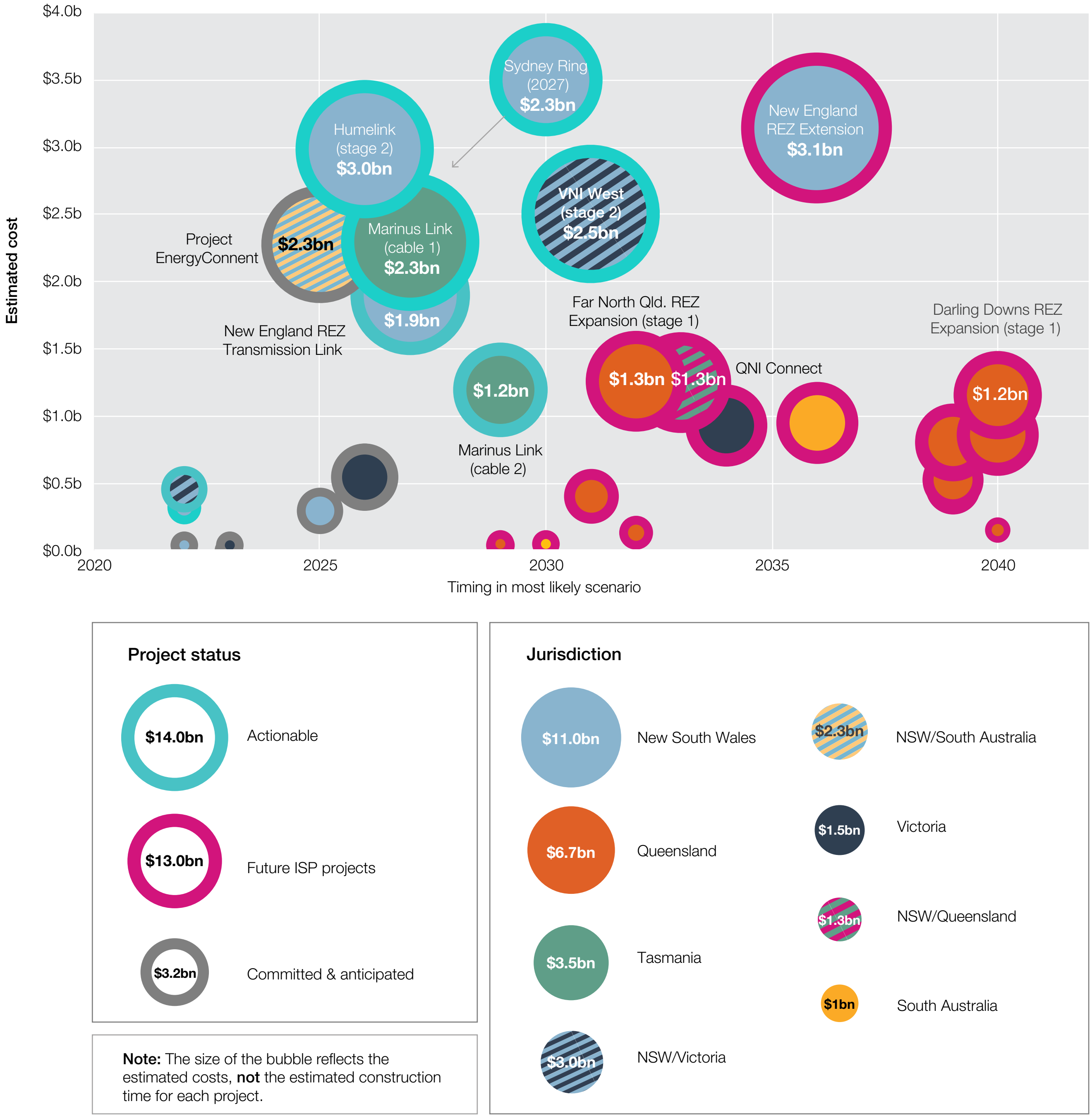
122 AER, 'Application guidelines – regulatory investment test for transmission', AER website, August 2020.

123 AER, 'Final decision – guidelines to make the Integrated System Plan actionable', AER website, August 2020.

124 AEMO, '2022 Integrated System Plan' June 2022, p 15.

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

Figure 3.27 AEMO's integrated system plan



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

Source: AER analysis, AEMO integrated system plan, June 2022

3.13.7 Recent activity – regulatory tests

In August 2022, Energy Ministers announced the establishment of the National Energy Transformation Partnership (the Partnership). Amongst the initial priorities identified under the Partnership, Ministers have committed to identify and declare transmission of national significance (including the actionable projects in the ISP – Marinus, VNI West (via Kerang), and Humelink) to accelerate the timely delivery of these critical projects and ensure better community consultation.

There are numerous ongoing RIT-T processes across the transmission networks. This section highlights major developments amongst actionable ISP projects.

VNI West is a proposed new high capacity 500 kilovolt double-circuit overhead transmission line between Victoria and NSW. AEMO and Transgrid published the project assessment draft report (PADR) for VNI West in July 2022.[126] The PADR is a major milestone in the RIT-T process, in which the proponents identify a preferred option for consultation and feedback. VNI West was identified as the preferred option, with an estimated market benefit of $687 million in present value.

TasNetworks has completed a RIT-T for Project Marinus, which is a proposed undersea electricity connection between Tasmania and Victoria (Marinus Link) and supported by transmission network developments in north-west Tasmania. In June 2021, TasNetworks published the Project Assessment Conclusions Report, identifying a preferred option made up of 2,750 MW undersea cables, staged over 2029 and 2031, supported by AC network upgrades. This concludes the RIT-T process.

In August 2022, the AER approved Transgrid's proposed contingent project costs of $321.9 million to undertake early works for HumeLink.[127] HumeLink is a transmission upgrade connecting the Snowy Mountains Hydroelectric Scheme to Bannaby in NSW, expanding transmission capacity in southern NSW. The range of early work activities to be delivered by 2024 include project design, stakeholder engagement, land-use planning and approvals and acquisition, procurement activities, and project management to reinforce the transmission network in southern NSW.[128] This follows completion of the RIT-T process in December 2021 following resolution of a dispute on the RIT-T.[129]

The 2 remaining actionable projects identified under the 2022 ISP are the NSW REZ transmission link and the Sydney Ring project.[130] These 2 projects will progress under the Electricity Infrastructure Investment Act 2020 (NSW) rather than the ISP framework, so we do not expect RIT-T processes for these projects.

3.13.8 Annual planning reports

Network businesses must publish annual planning reports identifying new investment 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 help non-network providers identify and propose solutions to address network needs.

The AER publishes guidelines and templates to ensure the reports provide practical and consistent information to stakeholders.[131] This results in network businesses providing data on geographic constraints to assist third parties in offering non-network solutions and to inform connection decisions at the transmission level.[132]

3.13.9 Demand management

Distribution network businesses 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.

126 AEMO and Transgrid, Victoria to New South Wales Interconnector West: Project Assessment Draft Report, 29 July 2021.

127 AER, Determination: Humelink Early Works Contingent Project, August 2022.

128 TransGrid, 'Reinforcing the NSW Southern Shared Network to increase transfer capacity to demand centres (HumeLink) – Project assessment conclusions report', 29 July 2021.

129 AER, Humelink: Decision on RIT-T Dispute, November 2021.

130 AEMO, 2022 Integrated System plan, June 2022.

131 AER, 'Final decision: Distribution annual planning report template v1.0', June 2017; AER, 'Final decision: Transmission annual planning report guidelines', December 2018.

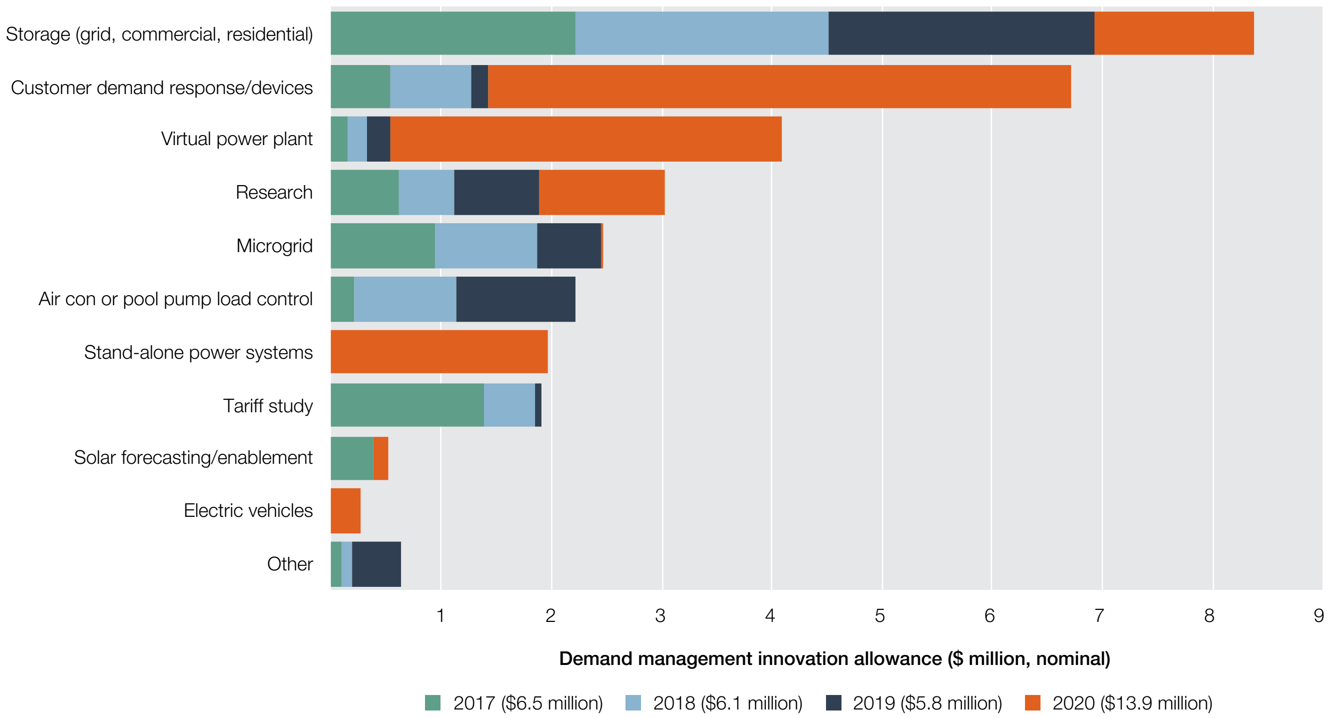
132 For an example of the constraint data available, see the datasheets under Ausgrid, 'Distribution and transmission annual planning report' and data map, accessed 28 July 2022.

The AER offers incentives for distributors 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 distributors 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 distributors an incentive of up to 50% of their expected demand management costs for projects that bring a net benefit across the electricity market.

Complementing this scheme, the AER operates a demand management innovation allowance mechanism (DMIAM). The DMIAM provides funding for distributors 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. An objective of the innovation allowance is to enhance industry knowledge of practical approaches to demand management. Network businesses publish annual activity reports setting out the details of projects they have undertaken. The AER assesses expenditure claims to ensure distribution businesses appropriately use their funding. Any underspent or unapproved spending is returned to customers through revenue adjustments.

Over the 2 years to June 2021 almost $20 million of innovation allowance funding was approved (Figure 3.28).[133]

Figure 3.28 Funding of demand management innovations – 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: AER, Approval of demand management innovation allowance (DMIA) expenditure reports.

3.14 Operating costs

Electricity network businesses incur operating and maintenance costs that absorb around 35% of their annual revenue (Figure 3.5). As part of its 5-year regulatory review for each network business, the AER sets an allowance for businesses 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 business's regulatory proposal but if the AER considers those forecasts are unreasonable then it may replace them with its own forecasts.

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

133 For further information on demand management allowances see the biannual reports published by the AER. AER, 'Demand management innovation allowance (DMIA) compliance reporting', AER website.

Box 3.3 Efficiency benefit sharing scheme

The AER runs an efficiency benefit sharing scheme (EBSS), which aims to share the benefits of efficiency gains in operating expenditure between network businesses and their customers. Efficiency gains occur if a network business spends less on operating and maintenance than forecast in its regulatory determination. Conversely, an efficiency loss occurs if the business spends more than forecast.

The EBSS allows a network business 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. It effectively allows a network business to retain efficiency gains (or bear the cost of efficiency losses) for the duration of the existing regulatory period, which may be up to 5 years. In the longer term, network businesses can retain 30% of efficiency savings but must pass on the remaining 70% (as lower network charges) to customers.

The EBSS provides network businesses with the same reward for underspending (or penalty for overspending) in each year of the regulatory period. Its incentives align with those in the capital expenditure sharing scheme (Box 3.2) – that is, the 30:70 split between the network business and its customers applies in both schemes. The EBSS incentives also balance against those of the service target performance incentive scheme (Box 3.4) to encourage network businesses to make efficient holistic choices between capital and operating expenditure in meeting reliability and other targets.

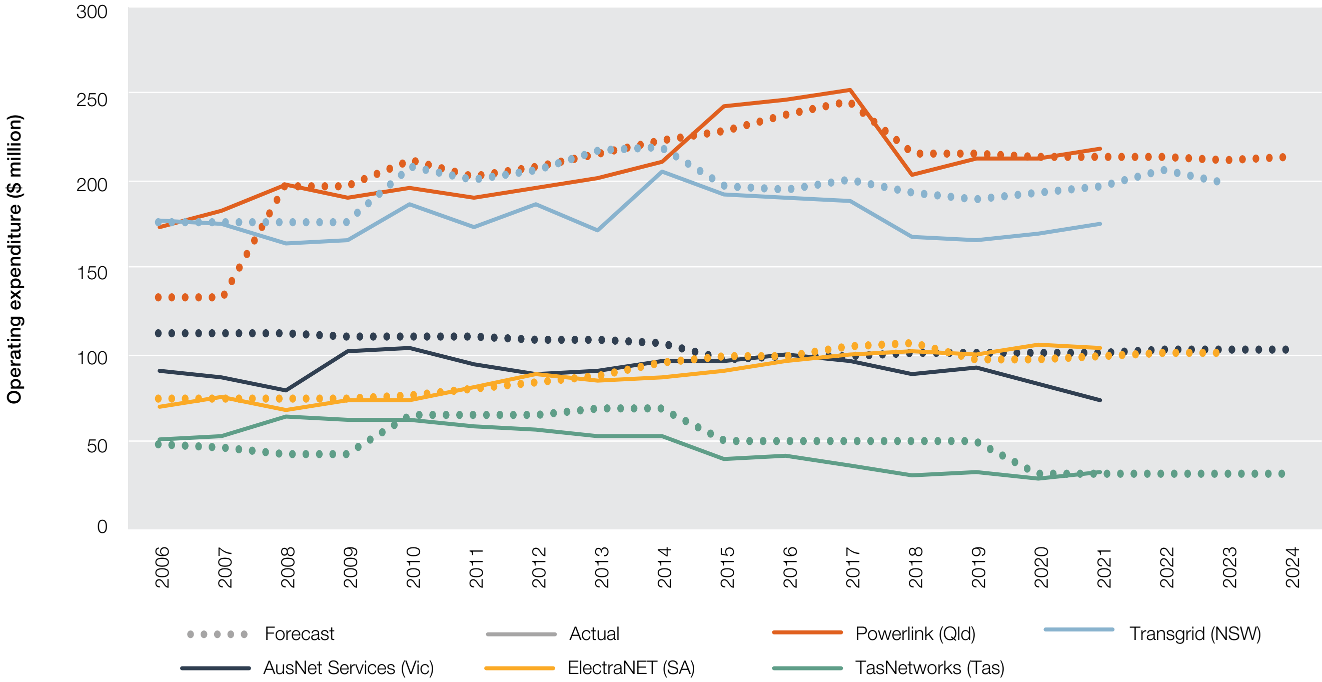
Figure 3.29 to Figure 3.31 provide a breakdown of network businesses' operating costs in 2021 and how this compared with previous years' expenditure and forecasts.

Figure 3.29 Operating expenditure in 2021

	2021 (actual)	Compared to 2020	Compared to forecast	Compared to peak (year)
Transmission	$604m	▲$4m (▲0.7%)	▼$43m (▼7%)	▼11% (2016)
Distribution	$3.1b	▼$34m (▼1.1%)	▼$376m (▼11%)	▼22% (2012)
Total	$3.7b	▼$30m (▼0.8%)	▼$419m (▼10%)	▼19% (2012)

Note: Excludes AER decisions on transmission interconnectors.

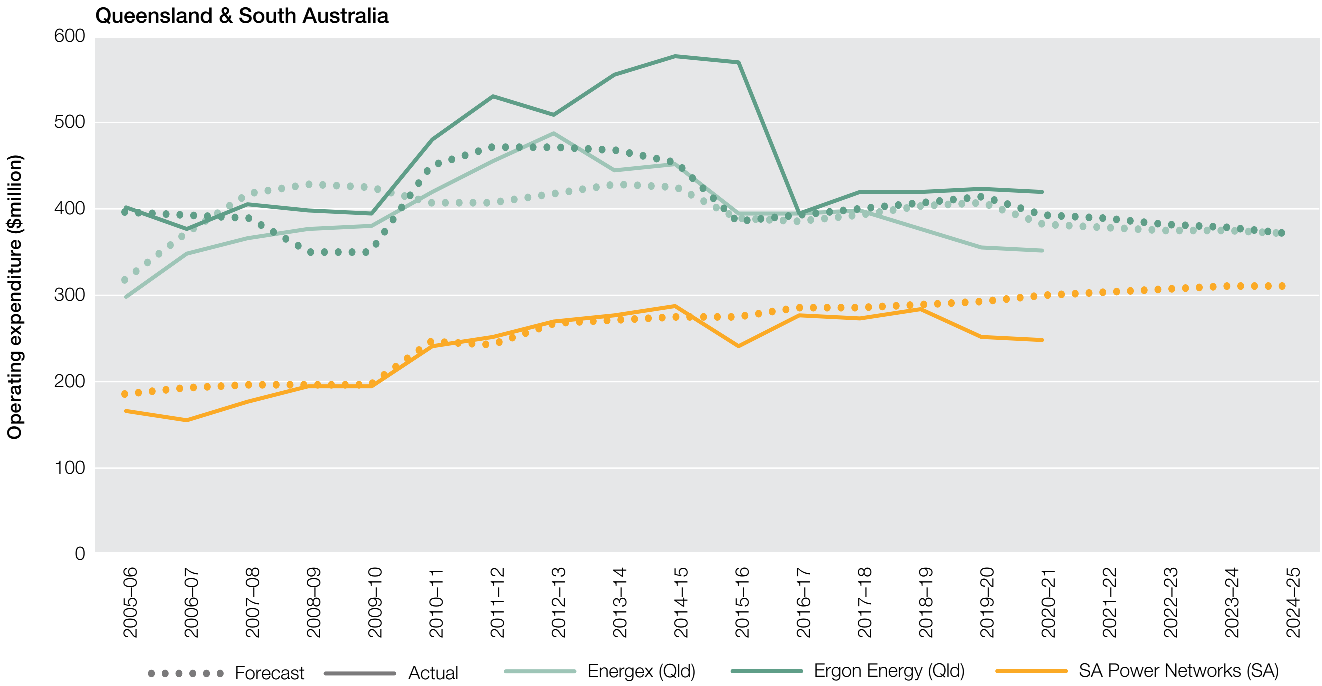
Figure 3.30 Operating expenditure – electricity transmission networks

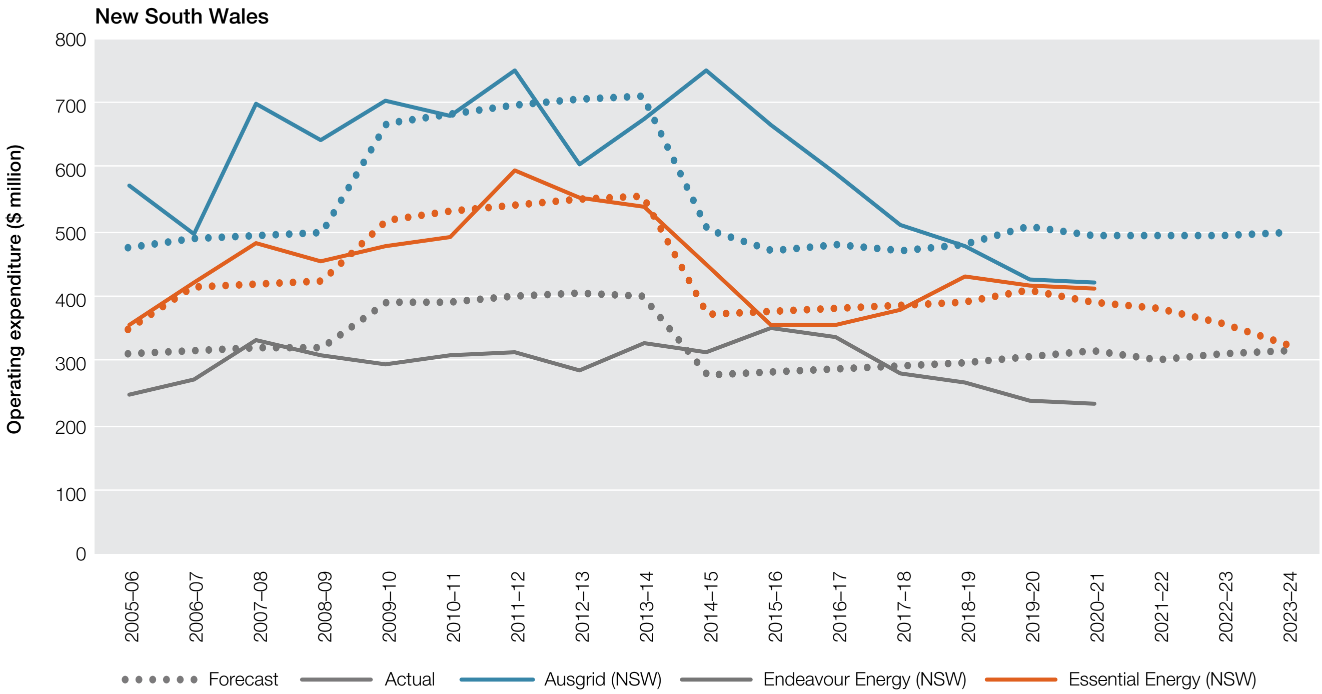


Note: Actual outcomes, CPI adjusted to June 2022 dollars. The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018). Assumptions are set out in Figure 3.9 notes.

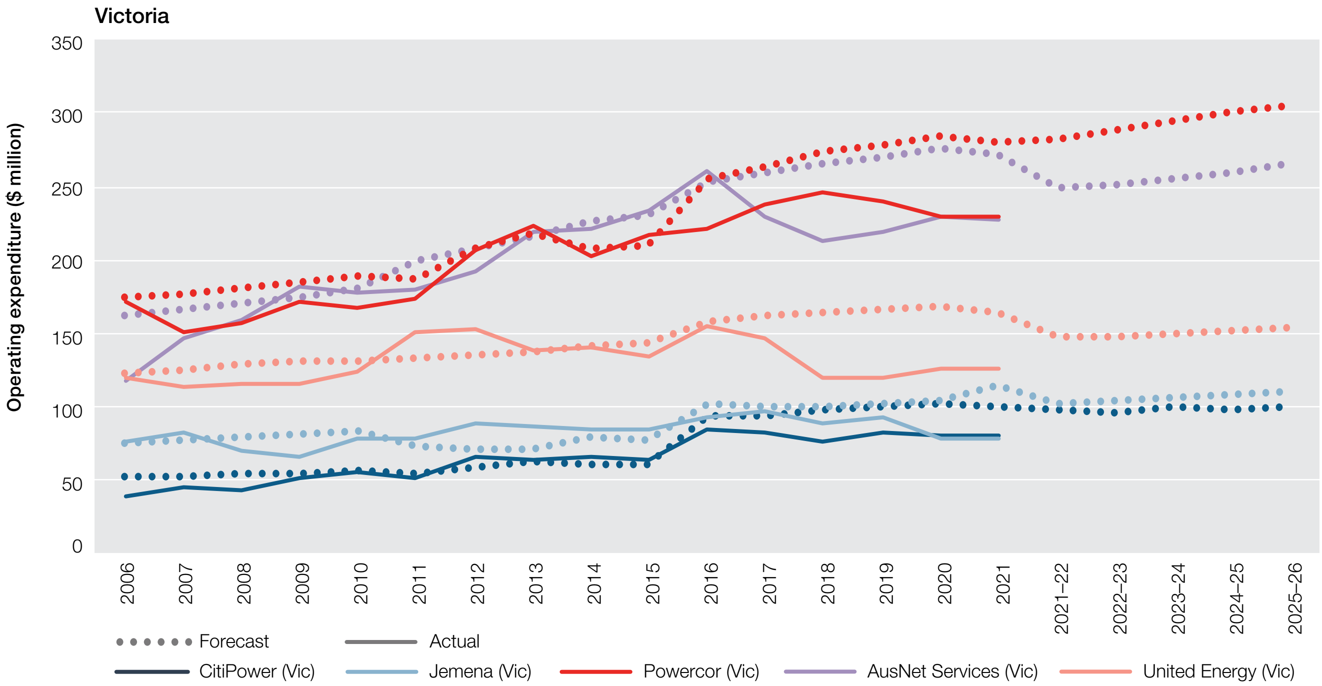
Source: AER modelling; annual reporting RIN responses.

Figure 3.31 Operating expenditure – electricity distribution networks

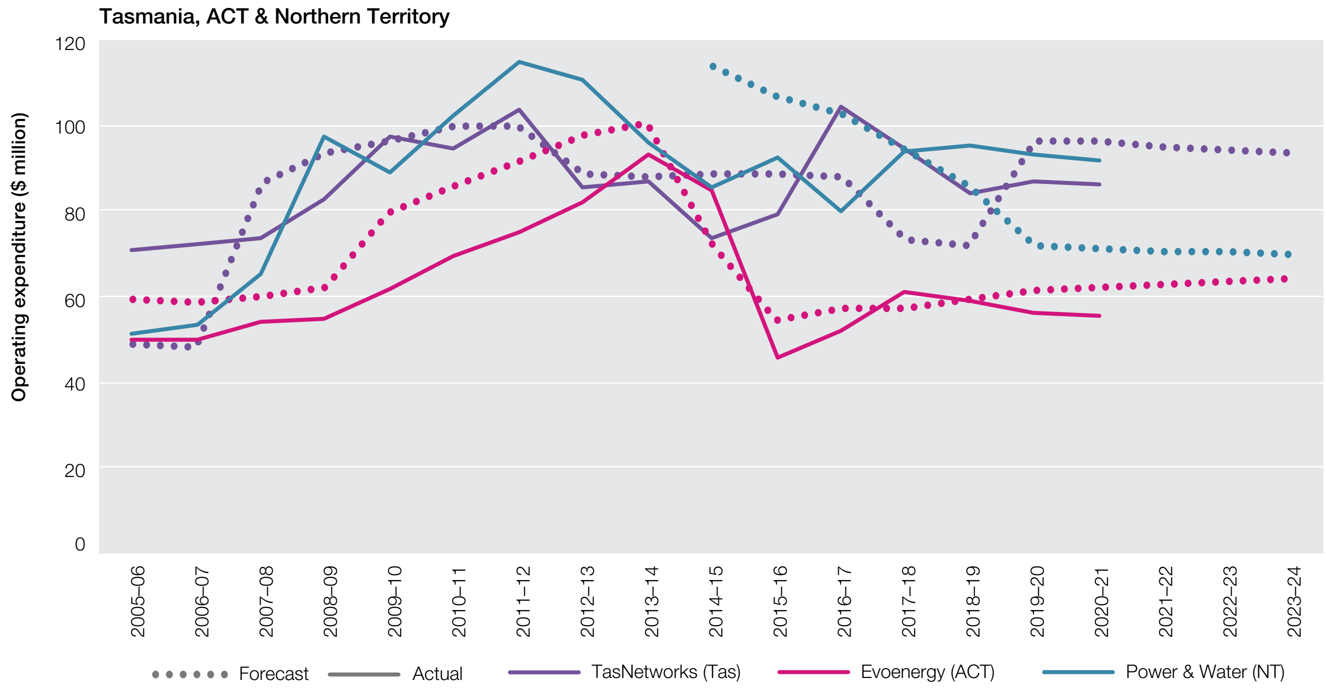




New South Wales
Operating expenditure ($ million)
0
100
200
300
400
500
600
700
800
2005–06
2006–07
2007–08
2008–09
2009–10
2010–11
2011–12
2012–13
2013–14
2014–15
2015–16
2016–17
2017–18
2018–19
2019–20
2020–21
2021–22
2022–23
2023–24
Forecast
Actual
Ausgrid (NSW)
Endeavour Energy (NSW)
Essential Energy (NSW)



Victoria
Operating expenditure ($ million)
0
50
100
150
200
250
300
350
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2021–22
2022–23
2023–24
2024–25
2025–26
Forecast
Actual
CitiPower (Vic)
Jemena (Vic)
Powercor (Vic)
AusNet Services (Vic)
United Energy (Vic)



Note: All data are adjusted to June 2022 dollars, based on forecasts of CPI. Assumptions are set out in Figure 3.11 notes.

Source: AER modelling; annual reporting RIN responses.

3.14.1 Operating cost trends

Total operating costs for the electricity network businesses increased by an average of 6% per year from 2006 until 2012, when it peaked at $4.5 billion (Figure 3.9 and Figure 3.11).

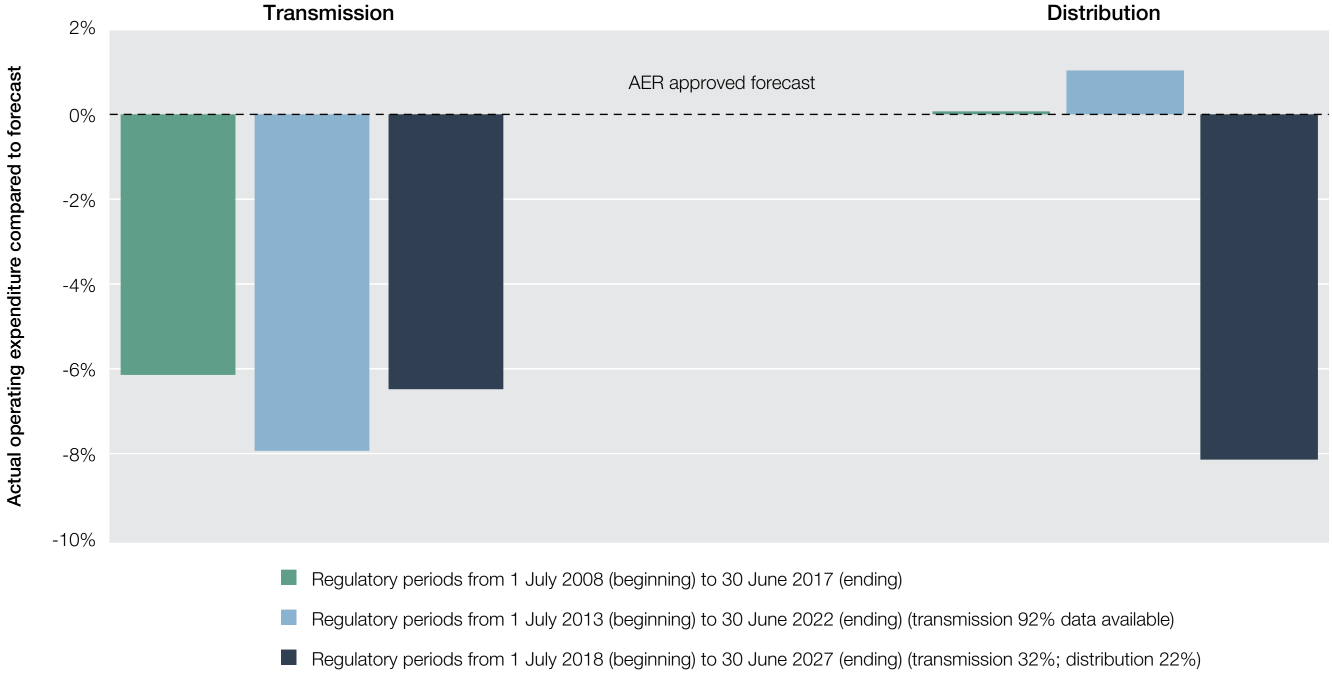
In recent years operating costs have decreased largely due to network businesses implementing more efficient operating practices. However, the decrease in operating costs has been less marked than it was for capital expenditure. Operating and maintenance costs are largely driven by the number of customers that the network business is supplying and the length of line.

A number of network businesses implemented efficiencies in managing their operating costs from 2015, when the AER widened its use of benchmarking to identify operating inefficiencies in some networks. The AER also introduced incentives for network businesses to spend efficiently.

Unlike capital expenditure, a network business's operating costs – such as rent, equipment, marketing, payroll, insurance, step costs and funds allocated for research and development –are largely recurrent and predictable. However, other factors such as reporting obligations, changes to connections charging arrangements, pricing reforms, and greater use of non-network options (section 3.8) can also impact costs.

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 3.32).

Figure 3.32 Operating expenditure against forecast



Note: Data availability (%) refers to proportion of actual operating expenditure data available at time of publication. Data used in igure 3.32 includes actual expenditure for the regulatory year 2021. The timing of regulatory periods differs among network businesses. For example, while 2020–21 reflects the third year of ElectraNet's (transmission) current regulatory period, it also reflects the fourth year of Powerlink's (transmission) previous regulatory period. This explains why a proportion of data is available for the current regulatory period even though the dataset from the last regulatory period is not yet complete.

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 businesses in Queensland and NSW. Those savings – for example, from the uptake of technology solutions and from changes to management practices – are now locked in for customers.

3.15 Productivity

The AER benchmarks the relative efficiency of electricity network businesses to enable comparisons over time. This benchmarking assesses how effectively each network business 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).[134] Productivity will rise if the network's outputs rise faster than the resources used to maintain, replace and augment energy networks. Benchmarking provides a useful tool for comparing network performance, but some productivity drivers – for example, adhering to reliability standards set by government bodies – are beyond the control of network businesses. More generally, benchmarking may not fully account for differences in operating environment, such as legislative or regulatory obligations, climate and geography.[135]

When forecasting a network's efficient operating costs, the AER estimates the productivity improvements that an efficient network should be able to make in providing services. In March 2019 the AER published its decision to apply an annual operating expenditure productivity growth rate of 0.5% when reviewing the operating expenditure forecasts of distribution network businesses.

This productivity growth rate has been applied in all regulatory determinations since March 2019 for electricity distribution businesses.[136]

134 The AER applies a multilateral total factor productivity approach to benchmark network businesses.

135 AER, 'Annual benchmarking report, electricity distribution network service providers', November 2021, pp 45–52.

136 AER, 'Forecasting productivity growth for electricity distributors', 8 March 2019.

3.15.1 Network productivity trends

Productivity for most networks in the NEM declined from 2006 to 2015, especially in the distribution sector. This decline in productivity 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 networks)
- rising expenditure on the distribution networks to meet stricter reliability standards in Queensland and NSW, and regulatory changes following bushfires in Victoria.

However, the privately operated networks in South Australia and Victoria consistently recorded higher productivity scores over this period than those of government-owned or recently privatised networks in other regions.

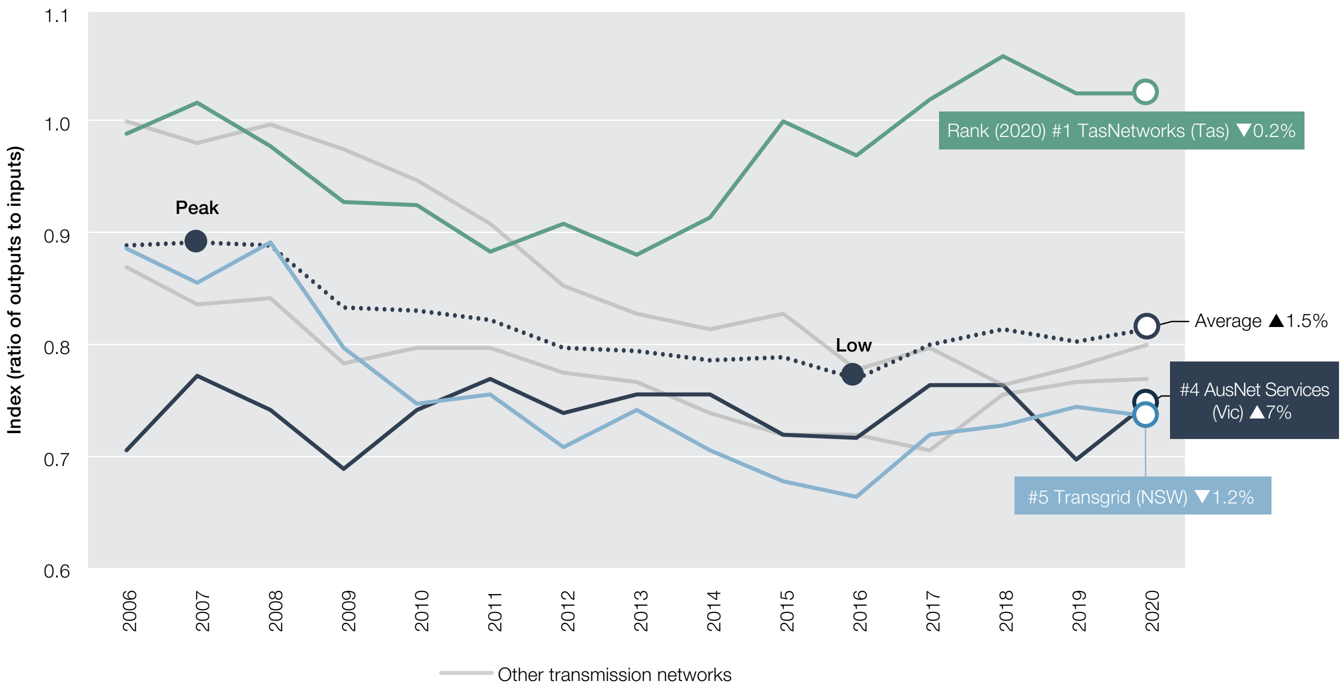
Electricity transmission and distribution productivity increased over 2020, in contrast to declining productivity in the overall Australian economy (down 1%) and the utilities sector (down 4%) over the same period.

3.15.2 Transmission network productivity

Electricity transmission productivity increased by 1.7% over 2020, following a 1.8% decline in 2019. Improved network reliability, combined with a reduction in operating expenditure and overhead line capacity, were the main drivers of the productivity increase.[137]

Viewed over a longer time frame, the productivity of transmission networks has declined at an average rate of 0.9% per year in the 14 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 0.8% per year over the same period (Figure 3.33).

Figure 3.33 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.

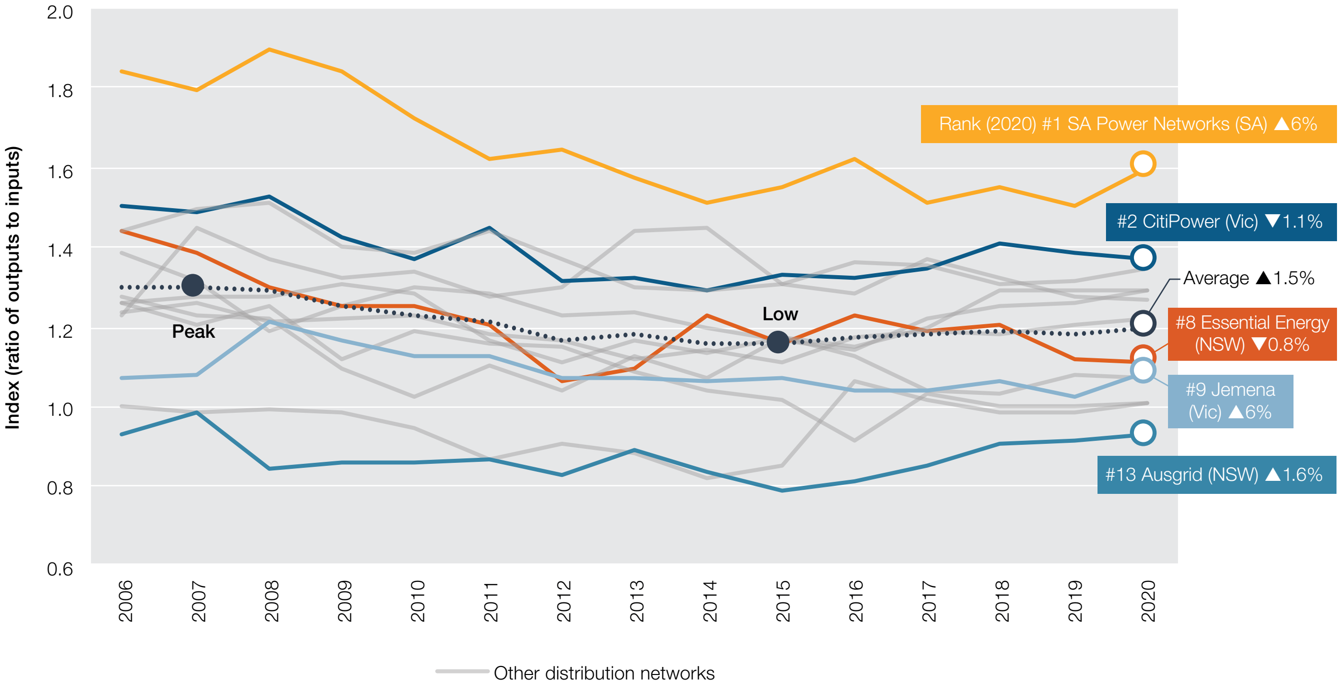
137 As measured by total factor productivity (TFP).

3.15.3 Distribution network productivity

Electricity distribution productivity increased by 1.2% in 2020, following a 1% decrease in 2019.[138] The increase in 2020 was largely driven by ongoing and significant reductions in operating expenditure, with no other individual input or output having a notable impact.

Since 2006 there has been some convergence in the productivity levels of highest and lowest performing distributors. Generally speaking, less productive distributors have improved their productivity since 2012. This has been most evident for United Energy (Victoria), Ausgrid (NSW) and Evoenergy (ACT), which increased their overall productivity, largely because of improvements in operating efficiency. Several middle-ranked distributors, such as Endeavour Energy (NSW), Energex (Queensland), and Essential Energy (NSW), have also improved their productivity and are now closer to the top-ranked distributors. Powercor (Victoria), SA Power Networks (South Australia) and CitiPower (Victoria) have consistently been the most productive distributors in the NEM, but they have experienced a gradual decline in productivity. As a result, their productivity is now much more closely aligned with the middle-ranked distributors (Figure 3.34).

Figure 3.34 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.

3.15.4 Network utilisation

A network's utilisation rate indicates the extent to which a network business'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.

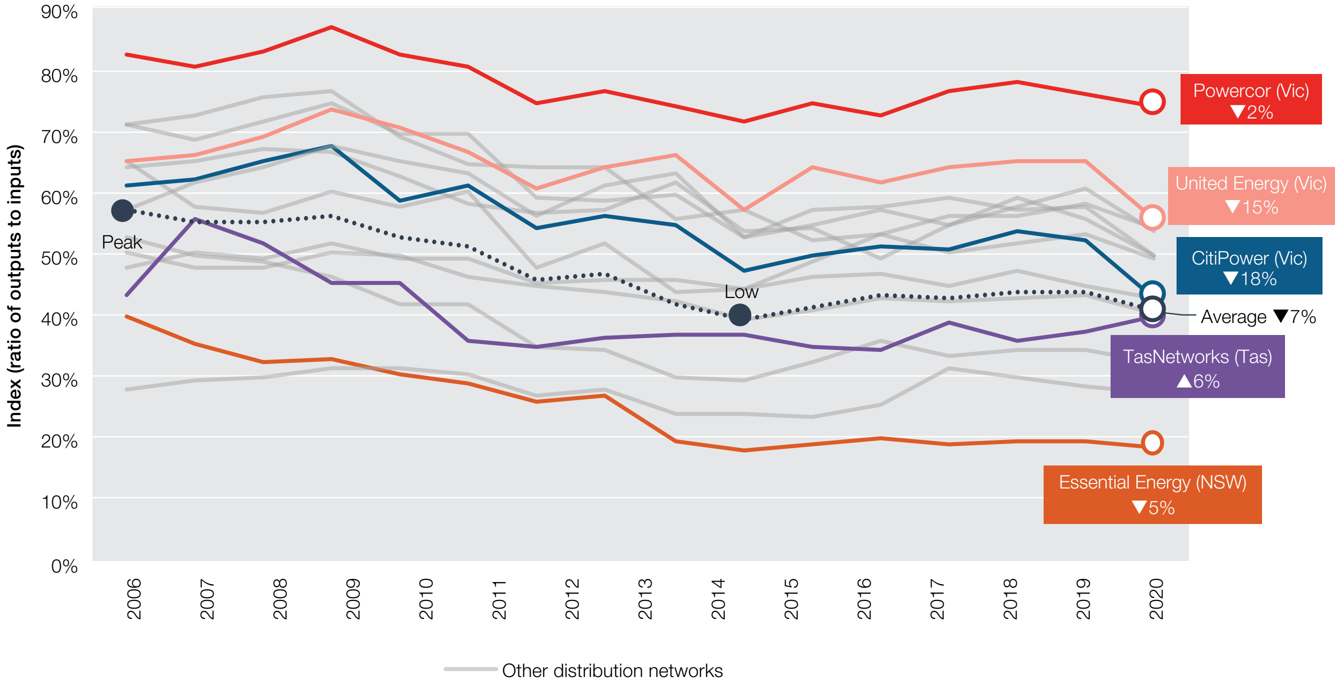
The average level of network utilisation among all distribution networks declined from a high of 57% in 2006 to a low of 39% in 2015.[139] This followed significant investment by many network businesses at a time of weakening electricity maximum demand.

In 2021 maximum demand across the distribution networks dropped by more than 7%, the largest single year decline in demand since 2012. As a result, overall network utilisation dropped by 3 percentage points to 41%, the lowest utilisation rate since 2015 (Figure 3.35).

138 As measured by multilateral total factor productivity (MTFP)

139 The available data does not extend back beyond 2006.

Figure 3.35 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 2021:

- privately owned distributors utilised 54% of network capacity, whereas fully or partly government-owned distributors utilised 36% [140]
- 7 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 businesses 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 to opportunities to bypass the grid altogether.[141]

3.15.5 Investment disconnect

The level of network productivity depends on how effectively a network business uses inputs[142] to deliver a range of outputs.[143] 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.

Since 2006 growth in maximum demand has been somewhat erratic, while the level of average (non-maximum) demand has declined.

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 demand (Figure 3.36).

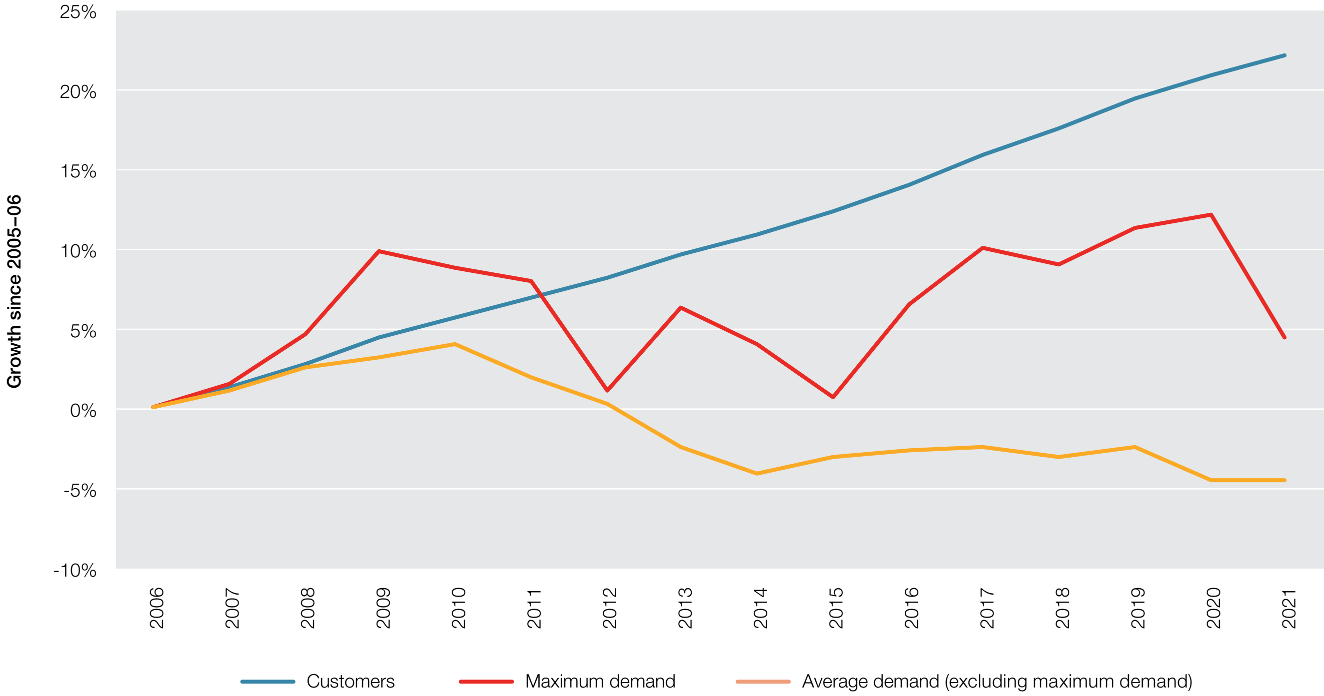
140 Section 3.4 provides information on network ownership.

141 T Wood, D Blowers, K Griffiths, 'Down to the wire – a sustainable electricity network for Australia', Grattan Institute, March 2018.

142 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.

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

Figure 3.36 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).

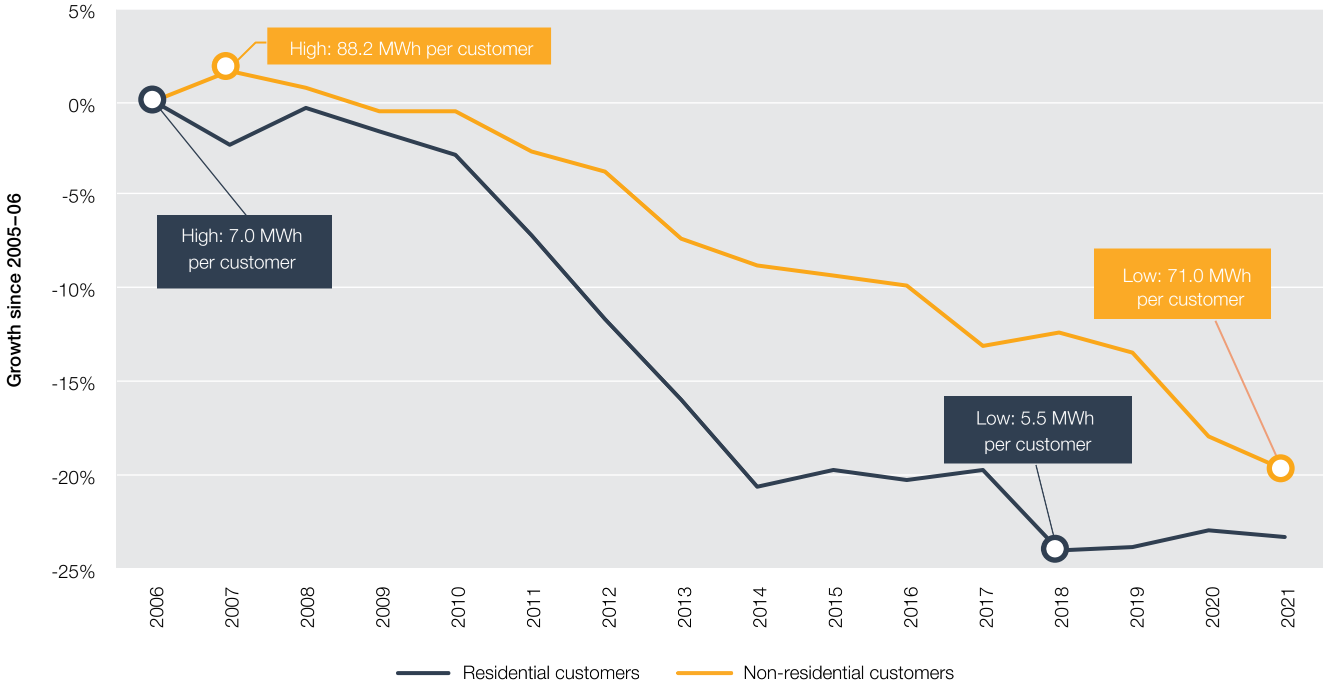
Source: Economic benchmarking RIN responses.

In 2021 the average residential customer consumed 23% less energy from the distribution network than in 2006. Declining energy use by residential customers is evident among all distributors, with 11 of the 14 distributors reporting declines of more than 17% since 2006. Average consumption by business customers has also fallen over that period but to a lesser extent.

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 (Figure 3.37).

Figure 3.37 Growth in average energy 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.

3.16 Reliability and service performance

In this section, 'reliability' refers to the continuity of electricity supply to customers.[144] 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 occur is widespread. For example, South Australia's catastrophic network failures in September 2016 caused a state-wide blackout.

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.

Household 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 reliability levels 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 recently 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.

144 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', August 2021.

3.16.1 Valuing reliability

Understanding the value that customers 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 every 5 years and updates these values annually. The values have a wide application, including as an input for:

- cost–benefit assessments, such as those applied in regulatory tests (section 3.13.5) that assess network investment proposals
- assessing bonuses and penalties in the service target performance incentive scheme (Box 3.4)
- setting transmission and distribution reliability standards and targets
- informing market settings, such as wholesale price caps.

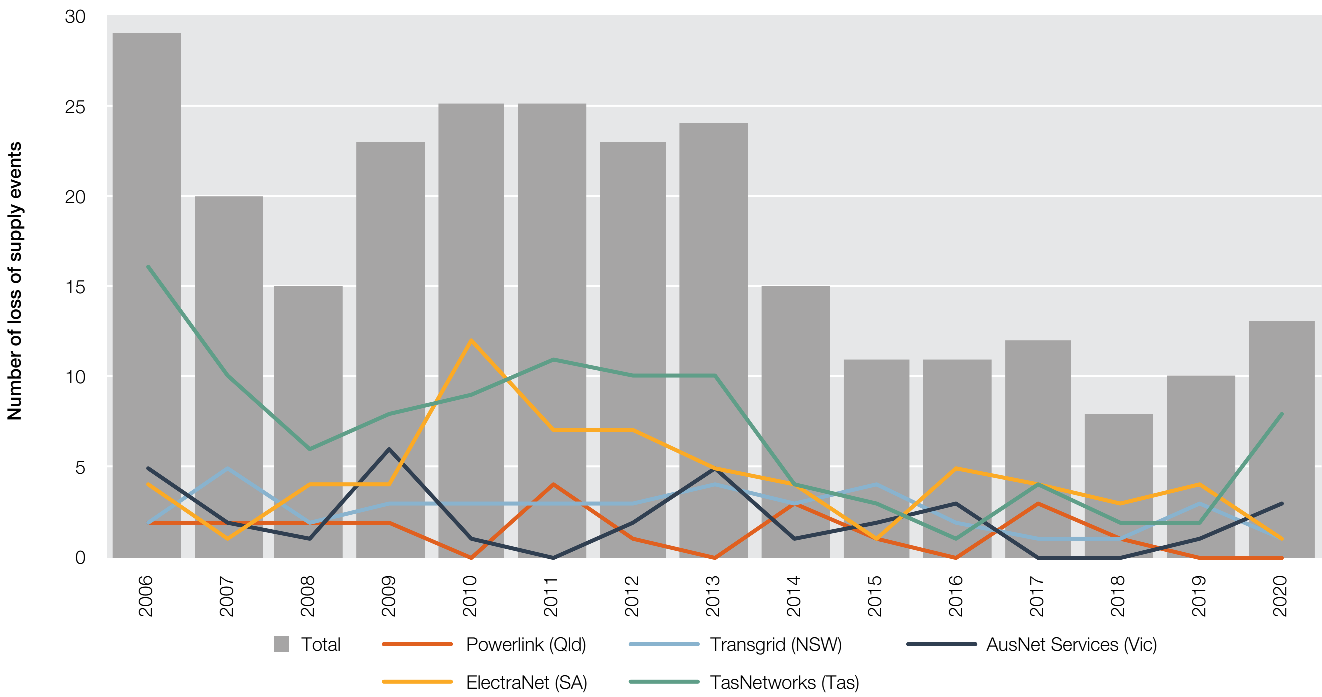
3.16.2 Transmission network performance

Electricity transmission networks are engineered and operated to be extremely reliable, because a single interruption can lead to 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 2020 the NEM experienced 13 loss of supply events due to transmission failures, the most events in any year since 2014. The main driver behind the increase was TasNetworks (Tasmania), which experienced 6 of its 8 events in August 2020. The events were due to a combination of design and operational error, environmental causes and windborne vegetation.[145]

Over the past 5 years, Powerlink (Queensland) has experienced the fewest loss of supply events among the transmission networks (Figure 3.8).

Figure 3.38 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 0.05–1.0 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.

145 TasNetworks, 'Annual Planning Report 2021', accessed 4 April 2022, p 82.

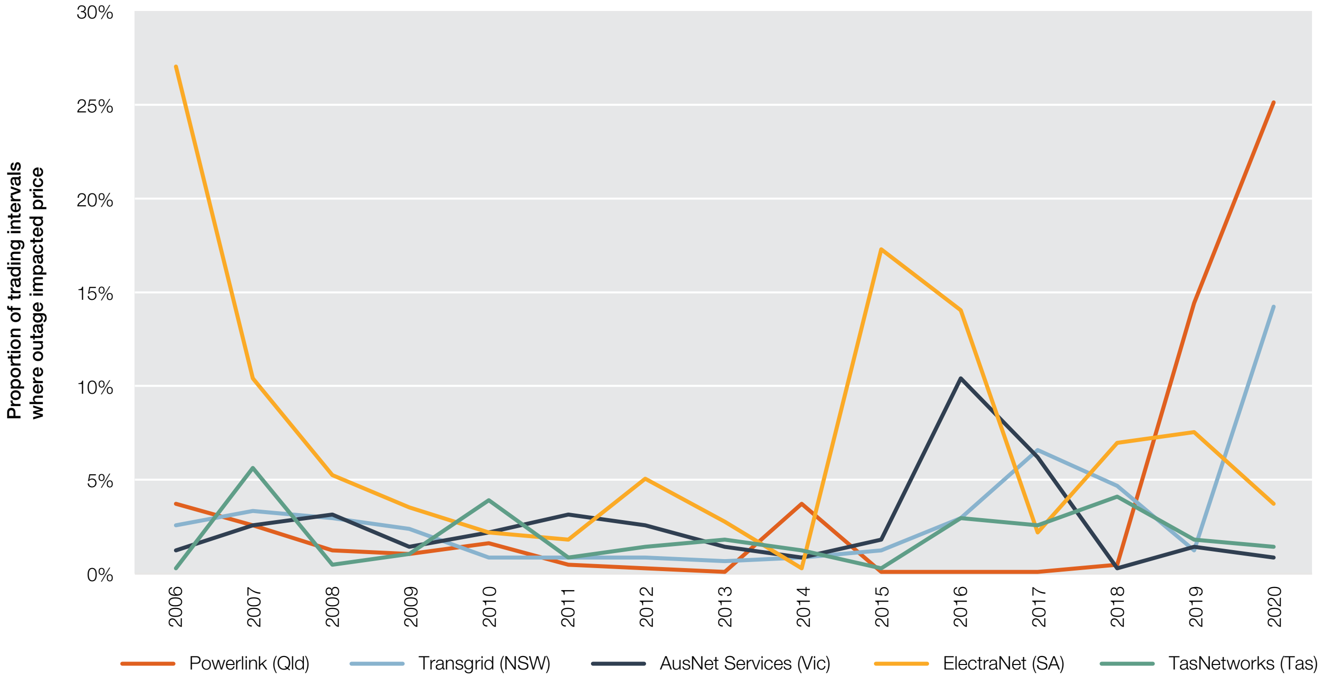
In addition to system reliability, congestion management is another indicator of transmission network performance. All networks are constrained by capability limits, and congestion arises when electricity flows on a network threaten to overload the system. As an example, a surge in electricity demand to meet air conditioning loads on a hot day may push a network close to 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.

Transmission congestion 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 (Figure 3.39).

Figure 3.39 Market impact of loss of supply events – electricity transmission networks



Note: Percentage of trading 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 businesses can help minimise congestion costs by scheduling planned outages and maintenance to avoid peak periods. For this reason, the AER offers incentives for network businesses to reduce the market impact of congestion.

3.16.3 Distribution network reliability

For distribution networks, the reliability of supply – that is, how effectively the network delivers power to its customers – is the main focus of network performance. Around 95% of the interruptions to supply experienced by electricity customers are due to issues in the local distribution network.[146] The capital-intensive nature of the networks makes it prohibitively expensive to invest in sufficient capacity to avoid all interruptions.

Planned interruptions – when a distributor needs to disconnect supply to undertake maintenance or construction works – can be scheduled for minimal impact, and the network business 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.

Jurisdictional reliability standards were historically set at higher 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.[147] This alternative approach considers the likelihood of an interruption occurring and the value that customers place on removing or reducing the impact of an interruption (section 3.16.1). While the Queensland and NSW governments began to relax reliability standards from 2014, the assets built to meet the previously high standards remain and customers continue to pay for them.[148]

Interruptions to supply can also be caused by vegetation-related incidents. In the 12-month period to 30 June 2021 vegetation was the third most significant reason for unplanned outages, behind weather events and asset failure. From 1 July 2022, Energy Safe Victoria (ESV) has the power to issue fines to electricity companies 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.

More than 1,100 power outages are caused by trees touching powerlines in Victoria each year, affecting 400,000 residences and businesses.[149]

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.[150]

The SAIFI and SAIDI metrics have generally been used to focus on the impact of unplanned outages. However, the impact planned outages have on a customer must also be considered when assessing 'customer experience'. The AER has acknowledged this and has incorporated the impact of planned outages into its recent regulatory determinations through the customer service incentive scheme (CSIS) (Box 3.5). Both the relative 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 its reliability performance. In particular, customer densities and numerous environmental conditions differ across networks. These differences can materially impact the number of customers affected by an outage as well as a network business's 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 distributors operating in urban areas than in rural areas.

146 AEMC, 'Final report – 2019 annual market performance review', 12 March 2020, p 51.

147 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.

148 ACCC, 'Retail Electricity Pricing Inquiry final report', 11 July 2018, p 109.

149 Energy Safe Victoria, 'ESV gets new powers to fine for powerline clearance breaches', 30 June 2022 media release.

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

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, comparing network reliability metrices between different distribution networks should be done with care.

3.16.4 Distribution reliability trends

The AER does not determine a distributor's operating and capital expenditure forecasts to eliminate all supply interruptions. This is evident in the AER's service target performance incentive scheme (STPIS) (Box 3.4), in which the AER sets 'normalised' reliability targets that do not penalise a network for interruptions considered to be beyond its control.

Across the distribution sector, 'normalised' levels of reliability have improved over the past decade, delivering fewer unplanned interruptions (SAIFI) and fewer unplanned minutes off supply (SAIDI). This improvement has occurred despite distribution networks investing $10.4 billion (14%) less than forecast on capital projects from 2010 to 2021 (Figure 3.11).

While the levels of unplanned 'normalised' reliability continue to either improve (SAIFI) or plateau (SAIDI), the absolute level of network reliability (that is, the customer experience) has been less consistent. This is predominately due to annual fluctuations in the impact of unplanned (excluded) events, such as outages caused by major weather events. Figure 3.41 demonstrates the impact and unpredictability of major weather events on network reliability.

Normalising the data (that is, removing the impact of extreme events) provides a more reasonable measure of a distributor's controllable outputs. Figure 3.40 and Figure 3.41 summarise SAIDI and SAIFI outcomes across the NEM, as well as weighted network reliability targets that the AER applies through the STPIS.

3.16.5 Distribution network reliability in 2020–21

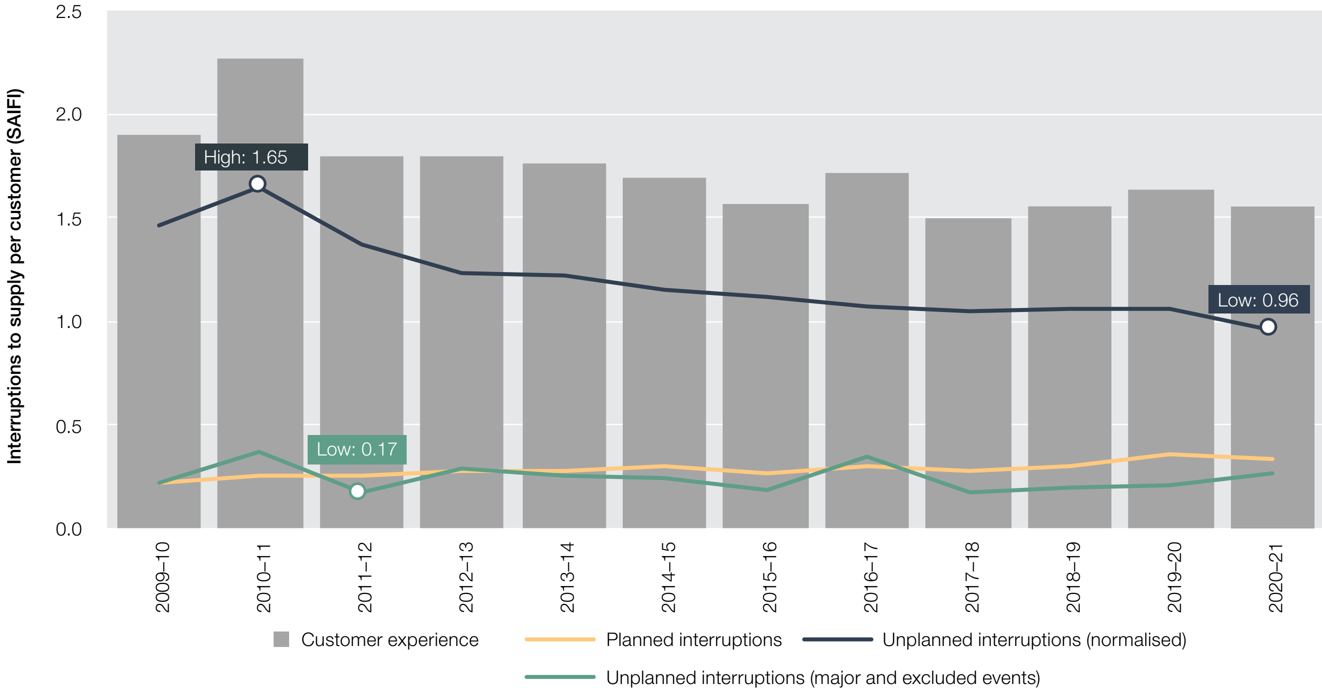
In 2020–21 the average electricity customer experienced 1.56 total interruptions to supply – 9% fewer than in the previous year. This comprised:

- 0.96 unplanned (normalised) interruptions to supply – a new record low and 8% fewer than the previous low in 2017–18
- 0.26 unplanned (excluded) interruptions to supply – 26% more than in the previous year
- 0.33 planned interruptions to supply – 9% less than in the record high set in the previous year.

In 2020–21 the average electricity customer experienced 325.9 total minutes off supply – 8% less than in the previous year. This comprised:

- 105.0 unplanned (normalised) minutes off supply – a new record low and 1.9% fewer than the previous low in 2017–18
- 128.6 unplanned (excluded) minutes off supply – 3% more than in the previous year
- 92.3 planned minutes off supply – 15% less than in the record high set in the previous year.

Figure 3.40 Interruptions to supply (SAIFI) – electricity distribution networks

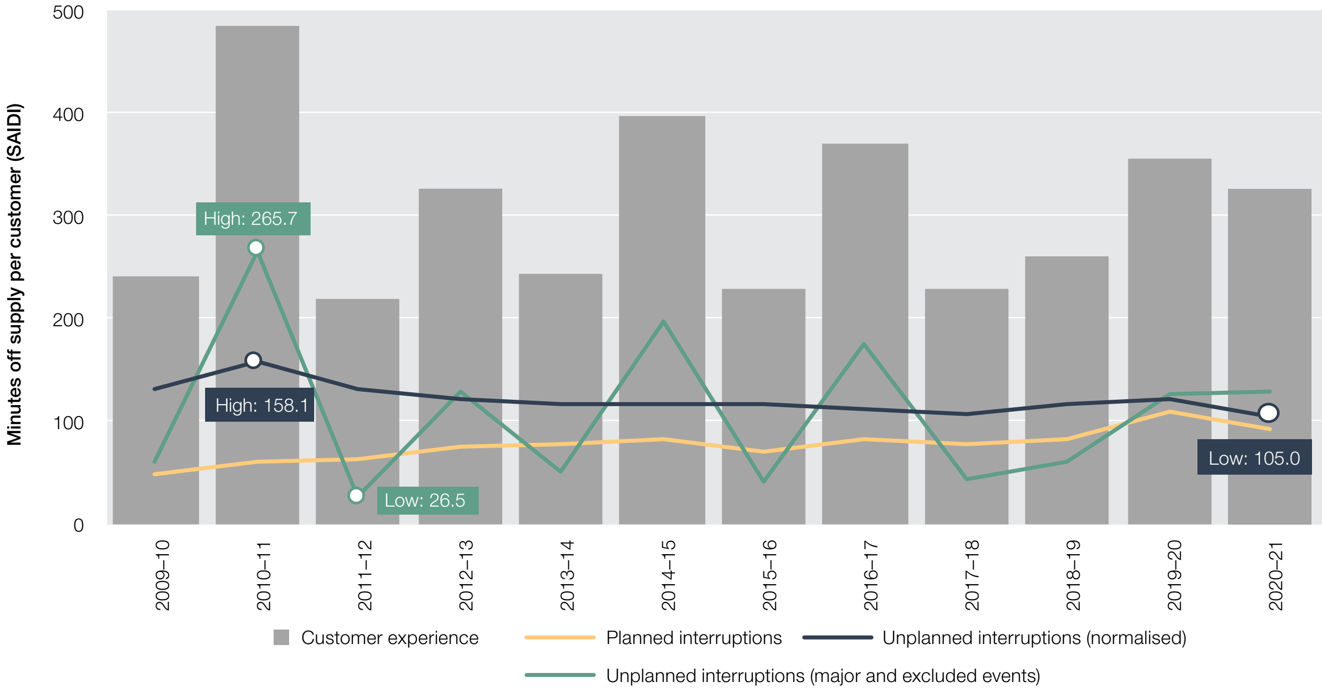


SAIFI: system average interruption frequency index.

Note: Data in Figure 3.40 and Figure 3.39 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 – 30 June.

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

Figure 3.41 Minutes off supply (SAIDI) – electricity distribution networks



SAIDI: system average interruption duration index

Note: Data in Figure 3.41 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 – 30 June.

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

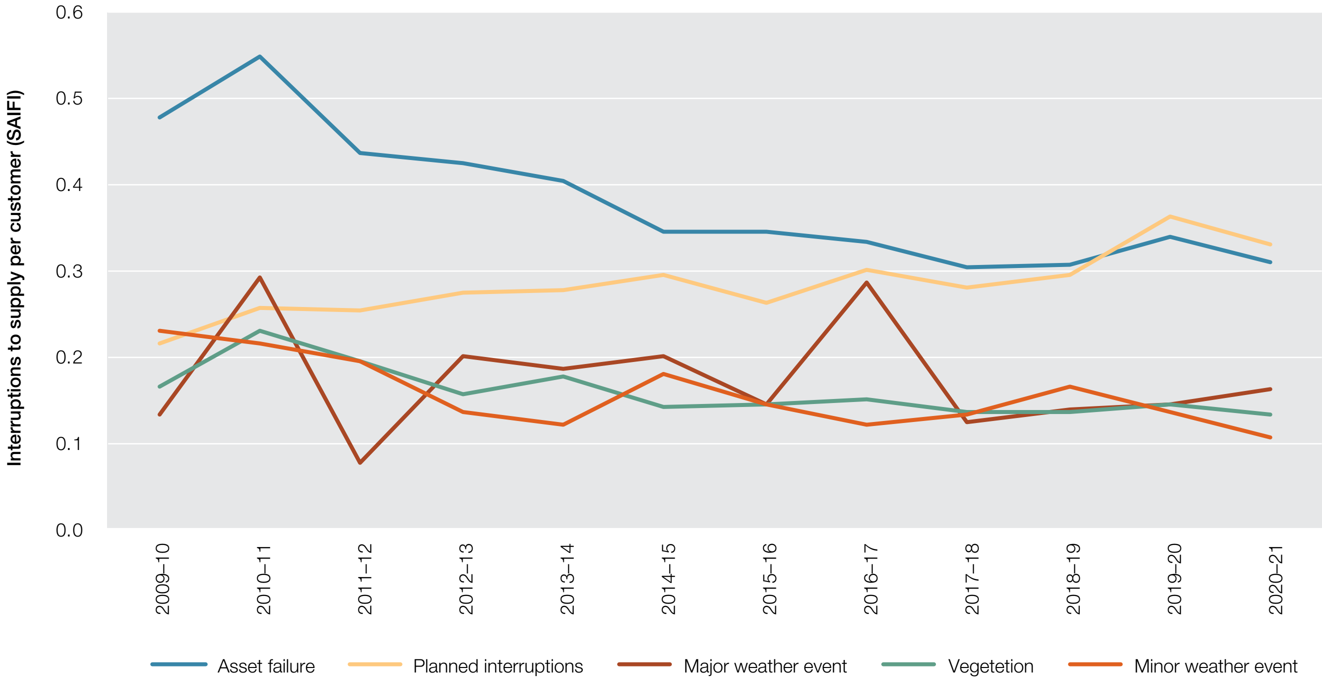
The AER also collects data from networks on the causes of outages. Over the 12-month period to 30 June 2021 asset failure was the most frequently reported reason for unplanned outages, accounting for 25% of all unplanned outages and 16% of all unplanned minutes off supply across the NEM. Over the same period weather events accounted for fewer (22%) unplanned outages, but a greater number of unplanned minutes off supply (59%). 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:

- 31 October 2020 – Energex (Queensland) – thunderstorms and extreme wind[151]
- 1 March 2021 – Ergon Energy (Queensland) – severe storm and flooding[152]
- 9–10 June 2021 – AusNet Services (Victoria), Powercor (Victoria) and United Energy (Victoria) – severe storm and flooding.[153]

The June 2021 storm in Victoria was the most disruptive event in the NEM – in terms of minutes off supply – since Tropical Cyclone Yasi caused extensive outages to customers in northern Queensland in early 2011 (Figure 3.42 and Figure 3.43).

Figure 3.42 Key drivers of interruptions to supply (SAIFI) – electricity distribution networks



SAIFI: system average interruption frequency index

Note: Data in Figure 3.42 and Figure 3.39 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 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 – 30 June.

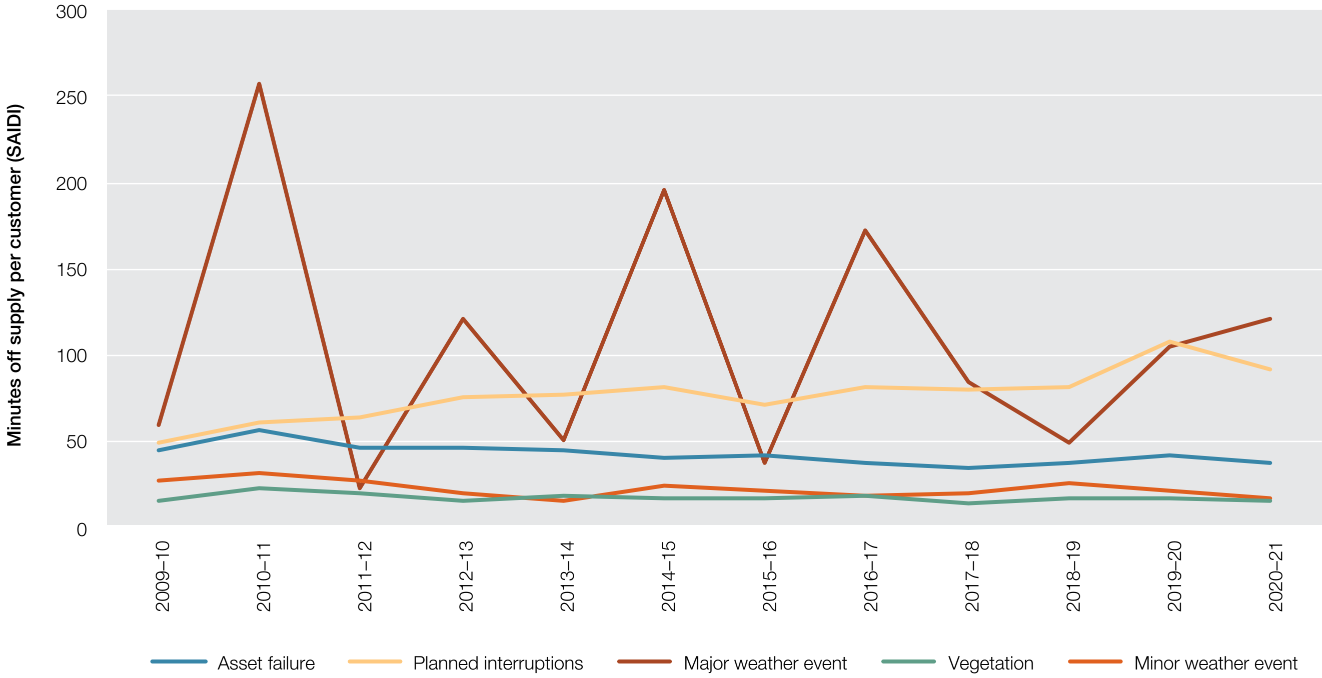
Source: AER modelling; category analysis regulatory information (RIN) responses.

151 ABC News, 'South-east Queensland hit by very dangerous thunderstorms as hail up to 14cm pummels the region', 31 October 2020, accessed 18 December 2021.

152 ABC News, 'Storms swirl across south-east Queensland, cutting power and causing flash flooding', 2 March 2021, accessed 29 June 2022.

153 ABC News, 'Victorians count the cost after violent storm sends trees crashing through homes', 10 June 2021, accessed 18 December 2021.

Figure 3.43 Key drivers of minutes off supply (SAIDI) – electricity distribution networks



SAIDI: system average interruption duration index.

Note: Data in Figure 3.43 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 – 30 June.

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

Over the past 2 years customers have experienced significantly more frequent, and longer planned interruptions to supply than in the past. This has been driven by Ausgrid's (NSW) decision to temporarily pause all live work on its network for safety reasons. However, since September 2020 appropriately trained and authorised Ausgrid employees have been able to perform selected live work tasks.[154]

3.16.6 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.[155]

More generally, the AER reviewed the STPIS to align with the AEMC's recommendations – for example, it amended the scheme to encourage distributors to reduce the impact of long outages experienced by customers at the end of rural feeders.

154 Ausgrid, 'Live Work Project', Ausgrid website, accessed 5 May 2022.

155 AER, 'Amendment to the service target performance incentive scheme (STPIS)/Establishing a new Distribution Reliability Measures Guideline (DRMG)', AER website, November 2018.

Box 3.4 Service target performance incentive scheme

The AER applies a service target performance incentive scheme (STPIS) to regulated network businesses. The STPIS offers incentives for network businesses to improve their service performance to levels valued by their customers. It provides a counterbalance to the capital expenditure sharing scheme (CESS) (Box 3.2) and efficiency benefit sharing scheme (EBSS) (Box 3.3) by ensuring network businesses do not reduce expenditure at the expense of service quality. A separate STPIS applies to distribution and transmission network businesses.

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 of up to +4% of revenue, or penalties of up to –1% of revenue, are available for exceeding/failing to meet performance targets under the scheme.

Distribution

A distributor's allowed revenue is increased (or decreased) based on its service performance. The bonus for exceeding (or penalty for failing to meet) performance targets can range to ±5% of a distributor'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.[a]

The reliability component sets targets based on a network's average performance over the previous 5 years. Performance measures are 'normalised' to remove the impact of supply interruptions deemed to be beyond the distributor's reasonable control. While the reliability performance of each network fluctuates from year to year, network businesses have generally performed better than their STPIS targets.

a Since April 2021, the AER has applied the CSIS instead of the STPIS telephone answering parameter to distribution networks whose customers support the change in customer service measurement.

3.16.7 Incentives to avoid fire starts

The AER administers the Victorian Government's f-factor scheme, an initiative that provides financial incentives to Victorian electricity distribution businesses 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 distributor is required to pay a penalty. Likewise, if the number of fire starts decreases the distributor may receive an incentive payment. Payments and penalties are incorporated into distributors' 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.

In 2020 the outcomes varied from a $1.5 million payment for Powercor to a $6,600 penalty for CitiPower. Overall, Victorian electricity distribution businesses received 54% less in total incentive payments under the f-factor scheme in 2020 than in the previous year.

The impact of the incentive payments from 2020 will take the form of adjustments to the distributors' regulated revenues in 2023.

3.16.8 Customer service

While reliability is the key service consideration for most energy customers, a distribution network's service performance also relates to the 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.

Individual jurisdictions set different standards for these performance indicators. Some jurisdictions apply a guaranteed service level (GSL) scheme that requires network businesses 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 NSW, Queensland, South Australia, Tasmania and the ACT.[156] Victoria reports separately on network performance.[157]

In July 2020 the AER released its new CSIS, which provides incentives for distributors to provide measurable levels of customer service that align with their customers' preferences (Box 3.5).[158]

Box 3.5 Customer service incentive scheme

The AER's customer service incentive scheme (CSIS) is designed to encourage electricity distributors to engage with their customers and provide a level of service which corresponds with their customers' preferences. The AER sets customer service performance targets for network businesses as part of the 5-year revenue determination process. Under the CSIS, distributors 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 distributor'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 distributor 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.

The first application of the CSIS was for Victorian distributors AusNet Services, CitiPower, Powercor and United Energy for the current period (1 July 2021 – 30 June 2026).

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.

156 AER, 'Annual retail markets report 2019–20', November 2020.

157 ESC, 'Victorian energy market update', 31 March 2022.

158 AER, 'Final – Customer Service Incentive Scheme', 21 July 2020.

The AER also oversees the rules protecting energy customers who rely on life support equipment. In June 2022 Endeavour Energy (NSW) paid 7 infringement notices totalling $474,600 for alleged breaches of life support obligations under the National Energy Retail Rules. The breaches included:

- failing to record that there were life support needs at the customer's premises
- not sending information packs
- not notifying the retailer of customers' life support requirements
- not giving the required 4-day notice of planned interruptions.

The AER accepted a court enforceable undertaking from Endeavour Energy, committing to implement new IT systems and to engage an independent expert to conduct an end-to-end review of its life support processes, controls and systems.