

## 3 Electricity networks

Australia's electricity infrastructure consists of transmission and distribution networks, as well as smaller standalone regional systems. Together, these networks have traditionally transported electricity from generators to residential, commercial and industrial customers. However, Australia's energy system is rapidly changing and affecting how electricity networks are used. Technological developments and consumer preferences are leading us away from a supply-side orientated system to one that needs to support two-way flows of electricity, and away from centralised generation to distributed generation.

This chapter covers the 21 electricity network service providers regulated by the Australian Energy Regulator (AER). These service providers are located in all Australian states and territories except Western Australia.

### 3.1 Snapshot

In April 2025, the AER finalised revenue determinations for distribution network service providers Energex (Queensland), Ergon Energy (Queensland) and SA Power Networks (South Australia) as well as the Directlink interconnector.<sup>83</sup> These determinations set target revenue controls through to 30 June 2030.

Across all electricity network service providers, over the 12-month period to 30 June 2024:

- \$12.7 billion in revenue was collected for delivering core regulated services,<sup>84</sup> \$270 million (2.1%) less than in the previous year (section 3.9.1).
- \$7.4 billion was invested in capital projects, \$545 million (8%) more than in the previous year and the most since 2014 (section 3.13.1).
- Regulated asset bases increased by \$2.4 billion (2%), driven by investment on Transgrid's (NSW) transmission network and Powercor's (Victoria) and Jemena's (Victoria) distribution networks.
- \$4.6 billion was spent on operating costs, \$307 million (7%) more than in the previous year and the most since 2016 (section 3.14.1).

83 Directlink is an electricity transmission interconnector between Queensland and NSW.

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

- The average customer experienced 1.26 unplanned interruptions to supply, 15% more than in the previous year (section 3.16.5).<sup>85</sup>
- The average customer experienced 294.5 unplanned minutes off supply, 82% more than in the previous year (section 3.16.5).<sup>86</sup>
- Increases in the number of unplanned interruptions to supply and the duration of unplanned minutes off supply were driven by the impact of several severe storm events across Queensland and Victoria, compared with the relatively low number of severe weather events in the previous year (section 3.16.5).

## 3.2 Electricity network characteristics

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

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

Electricity networks traditionally provided a one-way transportation service to consumers. However, the role of electricity networks has evolved, and technology continues to change how and where electricity is generated and used. Consumers are adopting innovative ways to reduce and manage demand from the grid, investing in what the industry collectively refers to as consumer energy resources. Many small-scale generators such as rooftop solar systems are now embedded within distribution networks, resulting in two-way electricity flows along the networks. Consumers with rooftop solar systems can source electricity from the distribution network when they need it and sell the surplus electricity they generate at other times (section 3.13.4). Electricity generated using rooftop solar systems is also increasingly being stored using battery storage systems. Due to the versatility and falling cost of battery technology, and the need to make use of excess solar generation for use later in the day, the use of batteries is expected to continue to grow. Installing storage options closer to the locations where excess solar is generated could reduce electricity transport costs and make better use of existing infrastructure.

### Box 3.1 Cheaper Home Batteries Program

Since 1 July 2025, the Australian Government's Cheaper Home Batteries Program – applicable to customers with existing solar or those wanting to invest in a new solar-plus-battery set-up – has offered a 30% discount on batteries for households, businesses and community facilities such as sports centres or town halls.

The Cheaper Home Batteries Program can be used in conjunction with jurisdictional battery incentives and is directly funded by the Australian Government to ensure no extra costs are passed on to consumers.<sup>87</sup> This means customers could be eligible for support under multiple schemes.

<sup>85</sup> After removing the impact of interruptions to supply deemed to be beyond the control of the network service providers.

<sup>86</sup> After removing the impact of interruptions to supply deemed to be beyond the control of the network service providers.

<sup>87</sup> Depending on the conditions established by state and territory governments.

### 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<sup>88</sup> are linked by cross-border interconnectors. Three interconnectors (Queensland–NSW, Heywood (Victoria–South Australia) and Victoria to NSW) are owned by the state governments and 3 interconnectors (Directlink, Murraylink and Basslink) are privately owned (Figure 3.2). The transmission network also directly supplies electricity to large industrial customers, such as rail companies, mines and mineral processing facilities.

The transmission grid connects with 13 distribution networks.<sup>89</sup> Consumers in Queensland, NSW and Victoria are served by multiple distribution network service providers, each of which owns and operates its network within a defined geographic region. Consumers in South Australia, Tasmania and the ACT are served by single distribution network service providers operating within each jurisdiction (Figure 3.1 and Figure 3.3).

The Northern Territory has 3 separate distribution networks – the Darwin–Katherine, Alice Springs and Tennant Creek systems – all owned by 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.<sup>90</sup> The AER regulates all major network service providers in the NEM as well as the Northern Territory's distribution network.

## Electricity networks in Queensland, New South Wales, Victoria, South Australia, Tasmania and the Australian Capital Territory create an interconnected grid forming the National Electricity Market.

In June 2025, the AER accepted APA Group's application to convert the Basslink interconnector – a high-voltage cable linking Victoria and Tasmania's electricity grids – from a market network service to a prescribed transmission service. The AER determined that converting Basslink to a regulated transmission service is more likely to promote efficient investment in, and efficient operation and use of, electricity services for the long-term interests of consumers. A fully regulated Basslink will ensure that the interconnector operates as an open link, enabling the market and consumers to benefit from generation in both the Tasmanian and mainland regions of the NEM.<sup>91</sup>

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

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

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88 Transgrid operates the high voltage transmission network in both NSW and the ACT.

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

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

91 AER, [Basslink – Determination 2025–30, Final decision: Basslink conversion](#), Australian Energy Regulator, 26 June 2025.

Permission to transmit or distribute electricity must be granted by the relevant jurisdictional regulator. In September 2024, distribution network service provider Powercor was granted a licence by the Essential Services Commission (Victoria) to plan, design and build transmission infrastructure within its current distribution footprint across western, central and northern parts of Victoria. Powercor can now deliver transmission infrastructure, including new terminal stations and 220 kilovolt powerlines, to connect customer-related projects to the grid.<sup>92</sup>

In February 2025, the Essential Services Commission (Victoria) granted Transmission Company Victoria (TCV) a licence to operate transmission infrastructure and transmit electricity in Victoria. As a licensee, TCV – a wholly owned subsidiary of the Australian Energy Market Operator (AEMO) created to progress VNI West<sup>93</sup> – must comply with all legal requirements of the licence. Any breaches will be subject to the Essential Services Commission’s compliance and enforcement powers, including breaches of the Land Access Code of Practice.<sup>94</sup>

## The aggregated value of the regulatory asset bases for the electricity networks regulated by the AER is around \$123.2 billion.

In May 2025, AusNet Infrastructure No. 2 Pty Ltd<sup>95</sup> applied to the Essential Services Commission (Victoria) for a licence to transmit electricity through the connection and extension assets associated with a new 220kV electrical transmission station in northern Victoria.<sup>96</sup> The decision to grant, or not grant, the licence had not been made at time this report was published.

The aggregated value of the regulatory asset bases (RABs) for the electricity networks regulated by the AER is around \$123.2 billion.<sup>97</sup> This comprises 7 transmission networks valued at \$28.3 billion and 14 distribution networks valued at \$94.9 billion. In total, the networks consist of more than 800,000 kilometres of line and deliver electricity to more than 11 million customers.

The AER does not regulate electricity networks in Western Australia, where the Economic Regulation Authority (ERA) administers state-based arrangements. Western Power (owned by the WA Government) is the state’s principal network, covering the populated south-west region, including Perth. Another state-owned corporation – Horizon Power – services Western Australia’s regional and remote areas.<sup>98</sup>

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92 Powercor, [New transmission provider to deliver more choice and better service to Victoria](#), media release, 25 September 2024, accessed 24 April 2025.

93 A project to build a new transmission line between Victoria and NSW.

94 The Land Access Code of Practice introduced enforceable rules that TCV must comply with, including how and when it provides information to landowners and when it engages with them. The Land Access Code of Practice also requires transmission companies to be open, honest and respectful in their communication with landowners.

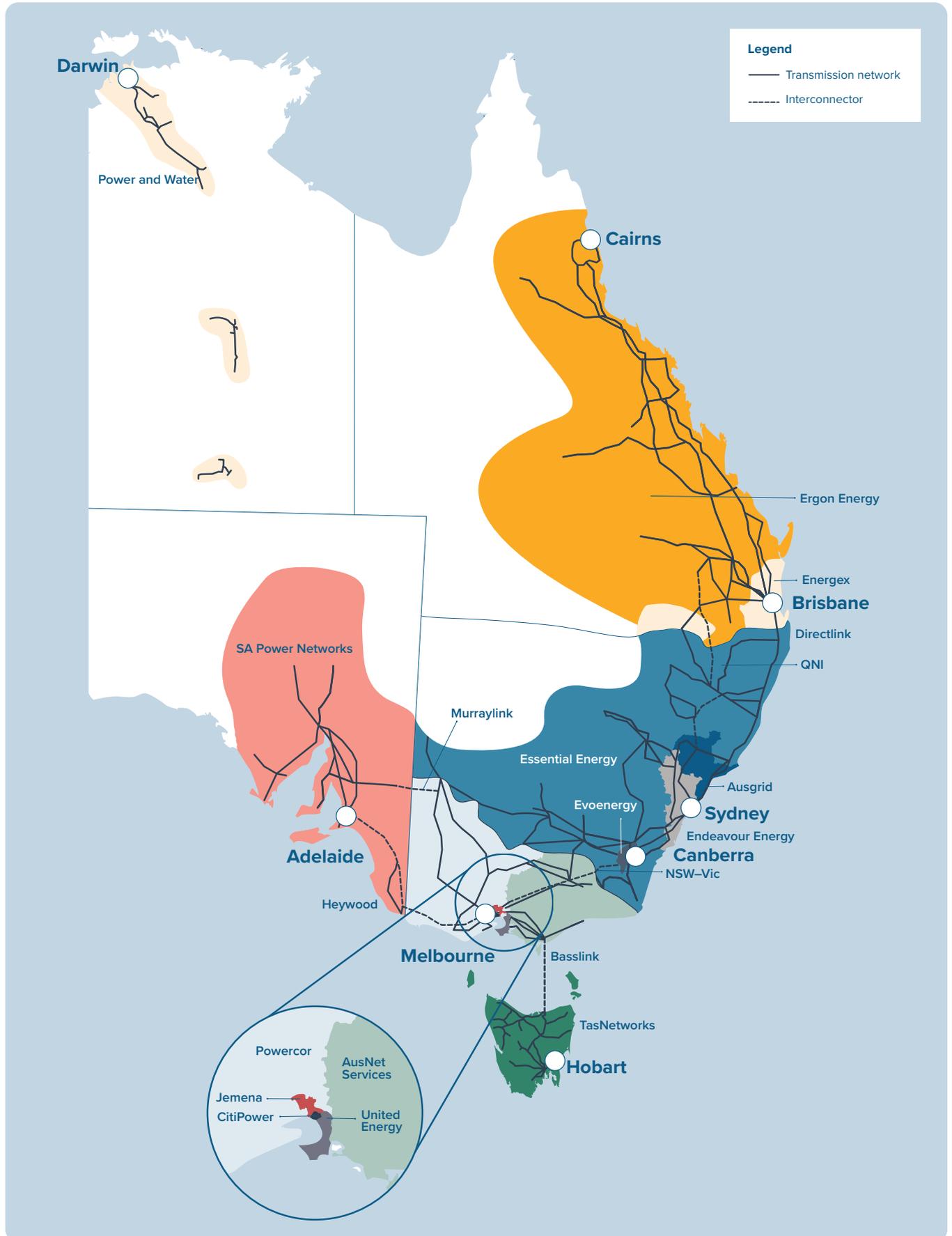
95 As trustee for the AusNet Infrastructure No. 2 Trust.

96 ESC, [AusNet Infrastructure No. 2 Pty Ltd as trustee for the AusNet Infrastructure No. 2 Trust – Application for electricity transmission licence](#), Essential Services Commission (Victoria), 1 May 2025, accessed 2 May 2025.

97 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.

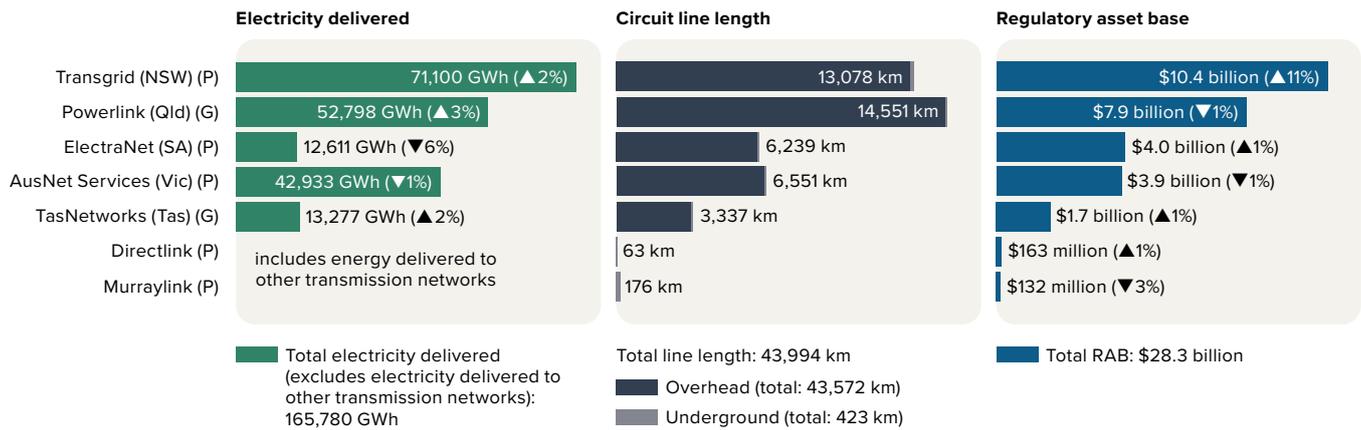
98 For further information, see the [WA Department of Treasury](#) and [ERA](#) websites.

Figure 3.1 Electricity networks regulated by the AER

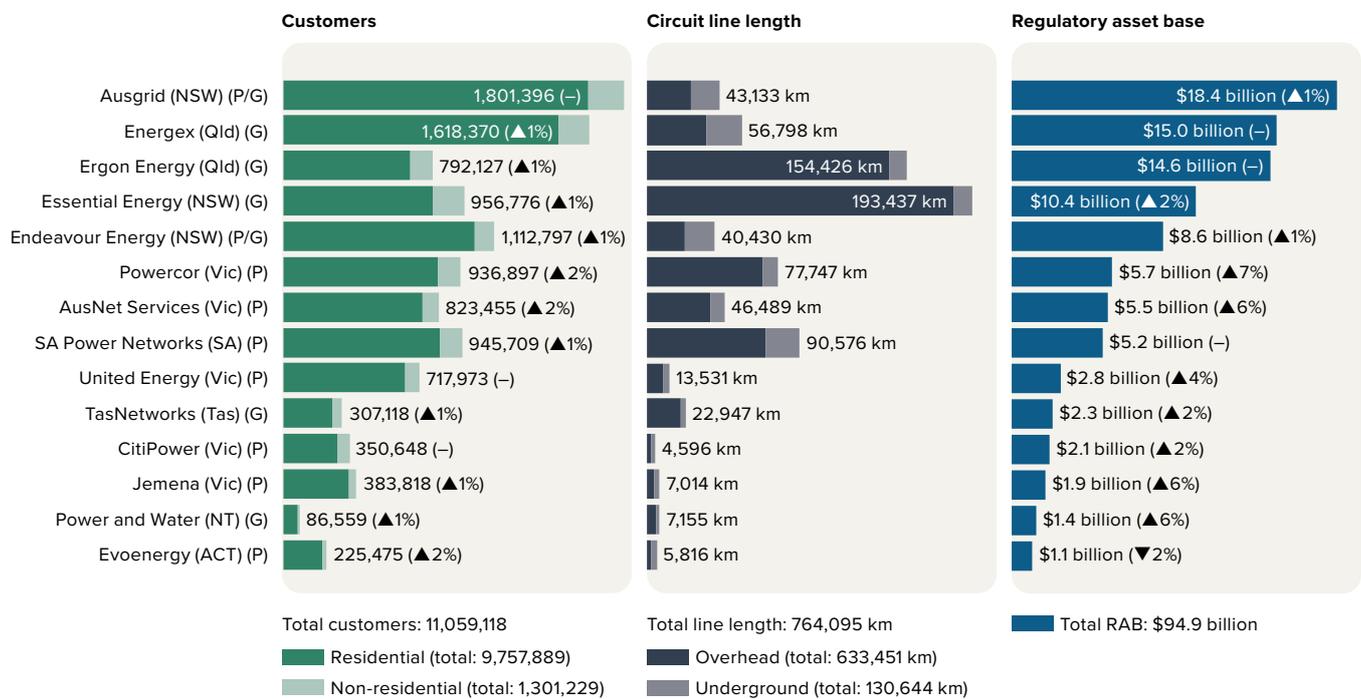


Note: QNI is the Queensland–NSW Interconnector.  
 Source: AER.

**Figure 3.2 Electricity networks regulated by the AER – transmission**



**Figure 3.3 Electricity networks regulated by the AER – distribution**



**Note:** (G): state government owned. (P): privately owned. GWh: gigawatt hours. km: kilometres. % values represent change from previous year. Regulatory asset base is adjusted to June 2024 dollars. Line length and regulatory asset base are as at 30 June 2024 (31 March 2024 for AusNet Services transmission). Electricity delivered is for the 12-month period to 30 June 2024 (year to 31 March 2024 for AusNet Services transmission). Electricity delivered is a measure of total energy transported through the transmission networks. The information reported includes electricity transmitted to distribution networks, pumping stations and directly connected end users. Electricity delivered to other transmission networks is included in the data for individual transmission networks but has been excluded from the total. Customer numbers, line length and asset base are as at 30 June 2024 for the distribution networks. For regulatory purposes, Northern Territory transmission assets are treated as part of the distribution system.

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

## 3.4 Network ownership

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

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

In May 2025, transmission network service provider Transgrid (NSW) underwent its third ownership change since the beginning of the year with Australia's Future Fund agreeing to buy a 10% stake from Canadian pension fund OMERS.<sup>99</sup> Transgrid owns and operates the largest electricity transmission network in the NEM, with a regulated asset base of more than \$10 billion (Figure 3.2). This is forecast to more than double over the next 5 years. Transgrid continues to play a crucial part in facilitating Australia's energy transition and is responsible for delivering several key projects by 2030 (section 3.13.6).

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

## 3.5 How network prices are set

Electricity networks are capital intensive and require significant investment to build and operate the necessary infrastructure. This gives rise to a natural monopoly industry structure, where having a single network service provider is more efficient than having multiple providers offering the same service. Because monopolies face no competitive pressure, they have opportunities and incentives to charge higher prices than they could charge in a competitive market. This monopolistic environment poses risks to consumers, given network charges currently make up as much as 46% of a residential electricity bill (Figure 6.2 in chapter 6). To counter these risks, the role of the AER as the economic regulator is to administer the regulatory framework effectively by replicating the incentives that network service providers would face in a competitive market (that is, to control costs, invest prudently and efficiently and not overcharge consumers).

### 3.5.1 Regulatory objective and approach

One of the AER's key objectives is to deliver efficient regulation of monopoly electricity and gas infrastructure while incentivising networks to become platforms for energy services (section 3.13.4).<sup>100</sup> This objective relates to the transformation of traditional power grids into open systems that facilitate a variety of energy services beyond just delivering electricity to retail customers. The transformation enables interactions between multiple energy producers, consumers and third parties such as retailers or other service providers. Examples of open systems include consumer energy resources (integrating rooftop solar and battery storage), demand response programs, peer-to-peer energy trading and electric vehicle charging solutions. Open systems allow for more flexible, decentralised energy services.

In February 2025, the AER signalled a new approach to testing and trialling new ideas in the energy market with the introduction of policy-led sandboxing. Innovation is crucial to accelerating access, deployment and orchestration of distributed energy resources (including consumer energy resources) and delivering a least-cost energy system to all consumers.<sup>101</sup>

99 Future Fund, [Future Fund and OMERS complete transaction for 9.995% of Transgrid](#), media release, 20 May 2025, accessed 3 July 2025.

100 AER, [AER Strategic Plan 2020-2025](#), Australian Energy Regulator, 14 December 2020, accessed 21 May 2025.

101 AER, [Innovative trials welcomed as AER introduces policy-led sandboxing approach](#), Australian Energy Regulator, 13 February 2025, accessed 5 June 2025.

The National Electricity Law and the National Electricity Rules set out the framework that the AER administers when regulating electricity networks.

In May 2023, Energy Ministers agreed to amend the national energy laws to incorporate an emissions reduction into the National Electricity Objective.<sup>102</sup> The amended National Electricity Objective seeks to promote efficient investment in, and efficient operation and use of, electricity services for the long-term interests of consumers of electricity with respect to:

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

In February 2024, the National Electricity Rules were amended to include ‘changes in Australia’s greenhouse gas emissions’ as a class of market benefit to be considered as part of the Integrated System Plan (ISP) (section 3.13.6) and the regulatory investment tests for transmission (RIT-T) and distribution (RIT-D) (section 3.13.5).<sup>103</sup>

The amended National Electricity Rules also enable electricity network service providers to include expenditure that contributes to achieving emissions reduction targets in their revenue proposals. Together, these amendments to the National Electricity Law and National Electricity Rules provide greater clarity to Australia’s energy market bodies<sup>104</sup> with regards to transitioning Australia’s energy system to net zero by 2050.

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The AER uses a wide range of tools to meet its objectives under the regulatory framework (Box 3.2). One of the AER’s main roles is to set the maximum revenue that a network service provider can collect from customers for delivering a safe, reliable and secure electricity service. The AER fulfils this role via a periodic revenue determination process, in which it assesses the amount of revenue a prudent network service provider would need to cover its efficient costs and address emerging issues such as network cybersecurity, climate resilience, integration of consumer energy resources, and digitalisation. Network revenues are capped at the determined level for the duration of the regulatory period, which is typically 5 years.<sup>105</sup>

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

103 AEMC, [Harmonising the national energy rules with the updated national energy objectives \(electricity\)](#), Australian Energy Market Commission, 1 February 2024, accessed 12 July 2025.

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

105 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.

As part of the determination process, a network service provider submits a proposal to the AER setting out the amount of revenue it considers necessary to cover the costs of providing a safe and reliable supply of electricity. The National Electricity Rules set out specific requirements to ensure the AER assesses expenditure proposals and makes draft and final determinations in accordance with the National Electricity Law. When assessing a network service provider's proposal, the AER must decide if the proposed capital expenditure and operating expenditure forecasts reasonably reflect:

- the efficient costs of achieving the expenditure objectives
- the costs that a prudent operator would require to achieve the expenditure objectives
- a realistic expectation of the demand forecast, and cost inputs, and other relevant inputs required to achieve the expenditure objectives.

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

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

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

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

The AER publishes guidelines on its approach to assessing capital and operating expenditure and applying incentives.<sup>106</sup>

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<sup>106</sup> AER, [Networks guidelines, schemes, models and reviews](#), Australian Energy Regulator, accessed 12 July 2025.

### Box 3.2 The AER's role in electricity network regulation

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

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

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

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

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

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

### 3.5.2 Building blocks of network revenue

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

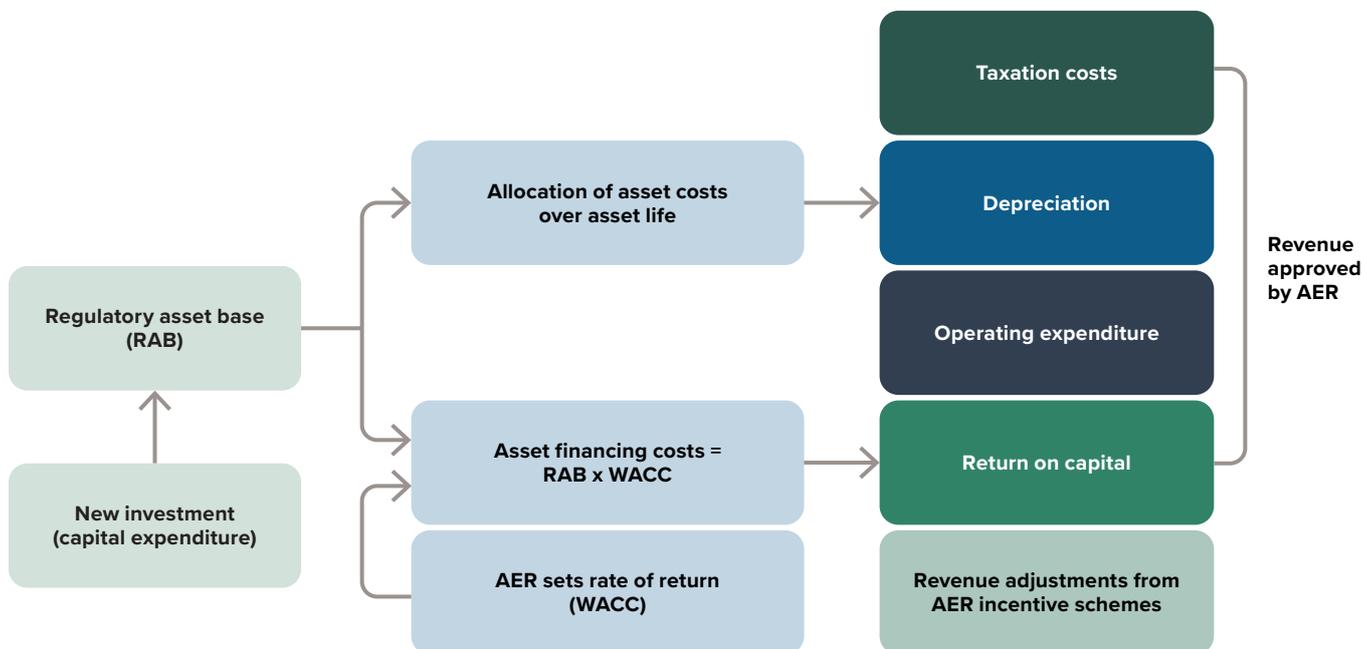
- a return to the investors that fund its assets and operations
- efficient operating and maintenance costs
- asset depreciation costs
- taxation costs.

The AER also makes revenue adjustments for rewards or penalties earned through any applicable incentive schemes.

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

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

Figure 3.4 Forecasting electricity network revenues



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

Source: AER.

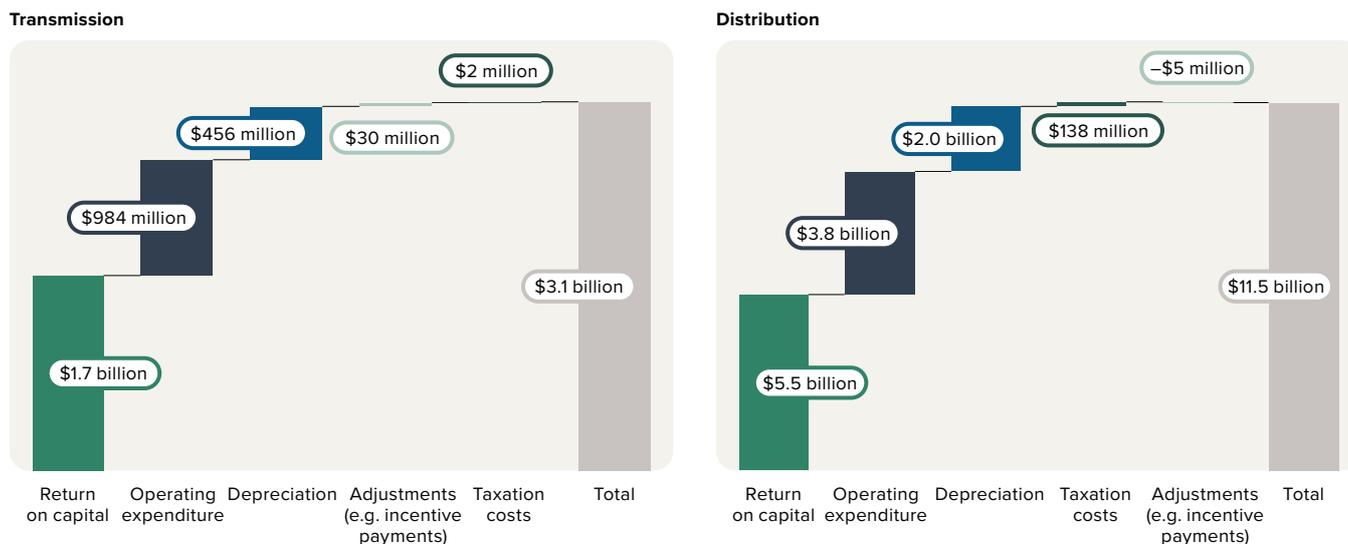
Additionally, the shareholders and lenders that fund these assets require a return on their investment. The AER sets the allowed rate of return (also called the weighted average cost of capital [WACC]) (section 3.12). The size of this return depends on:

- the value of the network service provider’s RAB
- the allowed rate of return that the AER allows based on the forecast cost that a benchmark efficient entity would incur in funding those assets through equity and debt.<sup>107</sup>

Overall, the return on capital takes up the largest share of network revenue, accounting for around 49% of total revenue across all networks (Figure 3.5). Sections 3.11 to 3.14 examine major cost components in more detail.

107 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 1 July 2025. All data are adjusted to June 2024 dollars.  
 Source: Post-tax revenue modelling used in AER determination process.

### 3.6 Recent AER revenue determinations

In April 2025, the AER finalised revenue determinations for distribution network service providers Energex (Queensland),<sup>108</sup> Ergon Energy (Queensland)<sup>109</sup> and SA Power Networks (South Australia)<sup>110</sup> and the Directlink interconnector.<sup>111</sup>

The determinations set target revenue controls for the 5-year period through to 30 June 2030 and seek to balance affordability and efficient and prudent investment that delivers a safe and reliable network to meet the long-term needs of consumers. In making the determinations, the AER addressed emerging issues such as network cybersecurity, mitigating the risks of the increasing frequency of extreme weather events and the integration of consumer energy resources. The AER also recognised that electricity networks must adhere to safety regulations and technical standards and supported the network service providers to efficiently improve network resilience and maintain safety standards.

Network costs are increasing due to economy-wide factors of higher interest rates and a higher inflationary environment. For example, Energex and Ergon Energy’s cost of capital increased from 4.73% to 6.09% and SA Power Networks’ cost of capital increased from 4.75% to 6.12% in the 5 years since the AER’s 2020–25 revenue determinations (section 3.12). Over the same period, inflation increased from 2.27% to 2.72%. This effectively means the cost for network service providers to obtain the capital needed to make the required investments and operate their businesses has increased.<sup>112</sup>

108 AER, [Energex - Determination 2025–30](#), Australian Energy Regulator, 30 April 2025.  
 109 AER, [Ergon Energy - Determination 2025–30](#), Australian Energy Regulator, 30 April 2025.  
 110 AER, [SA Power Networks - Determination 2025–30](#), Australian Energy Regulator, 30 April 2025.  
 111 AER, [Directlink - Determination 2025–30](#), Australian Energy Regulator, 30 April 2025.  
 112 The rate of return is a nominal rate of return unless stated otherwise.

These were all key inputs in the AER's regulatory determinations, which are summarised in Table 3.1.

**Table 3.1 Recent AER electricity network revenue determinations**

Network service provider	Revenue (forecast)	Capital expenditure (forecast)	Operating expenditure (forecast)
Energex (Queensland)	\$7.7 billion (▲16%)	\$3.1 billion (▲30%)	\$2.4 billion (▲12%)
Ergon Energy (Queensland)	\$7.3 billion (▲13%)	\$4.3 billion (▲62%)	\$2.3 billion (▲6%)
SA Power Networks (South Australia)	\$4.4 billion (▲6%)	\$2.2 billion (▲11%)	\$2.0 billion (▲19%)

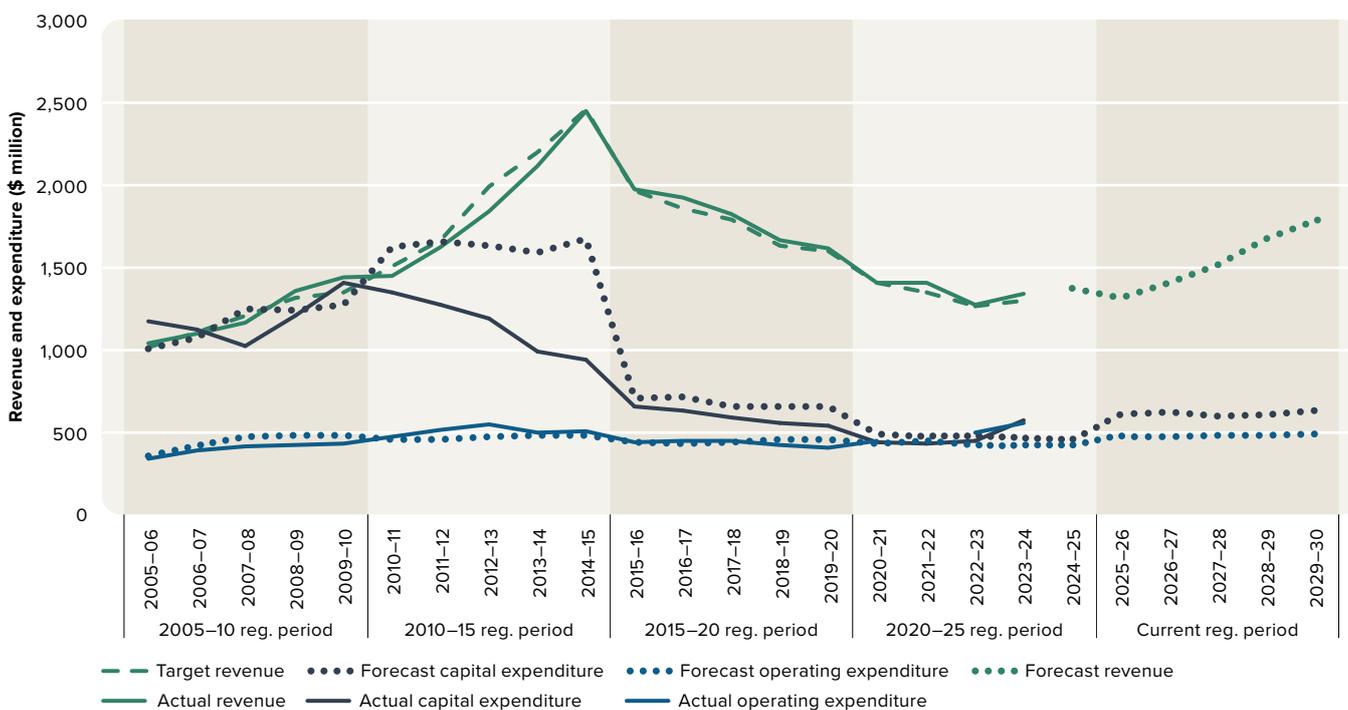
Note: All revenue and expenditure data are adjusted to June 2024 dollars. Changes in revenue and expenditure are in relation to forecasts from the previous regulatory periods.

Source: AER estimates.

### 3.6.1 Energex (Queensland)

The AER's final determination was that Energex can collect \$7.7 billion in revenue from its customers over the 2025–30 regulatory period, \$1.0 billion (16%) more than the revenue forecast for the previous regulatory period (2020–25). The AER estimates that approximately 55% of the increase was driven by higher capital and operating expenditure, with the other 45% driven by higher inflation and interest rates (Figure 3.6).

**Figure 3.6 Revenue and key drivers – Energex (Queensland)**



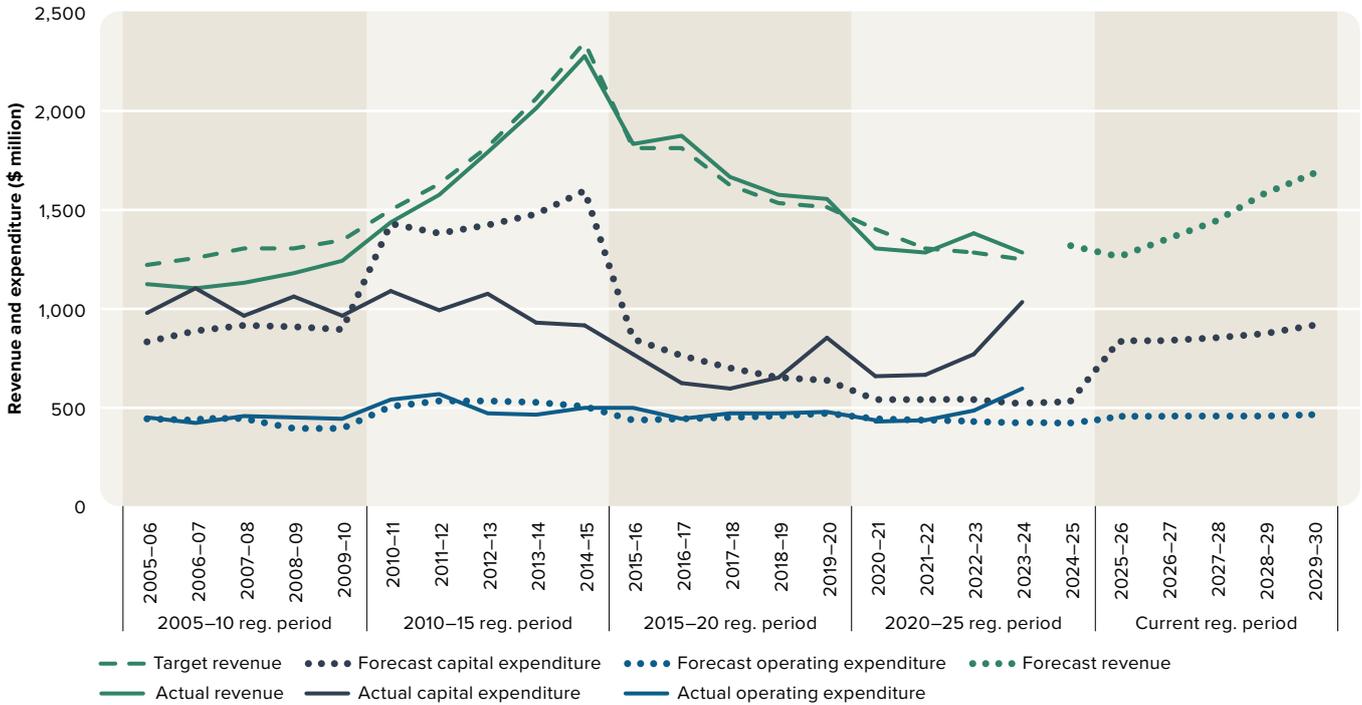
Note: All data are adjusted to June 2024 dollars.

Source: AER modelling; annual reporting RIN responses.

### 3.6.2 Ergon Energy (Queensland)

The AER’s final determination was that Ergon Energy can collect \$7.3 billion in revenue from its customers over the 2025–30 regulatory period, \$832 million (13%) more than the revenue forecast for the previous regulatory period. The AER estimates that approximately 57% of the increase was driven by higher inflation and interest rates, with the other 43% driven by higher capital and operating expenditure (Figure 3.7).

Figure 3.7 Revenue and key drivers – Ergon Energy (Queensland)

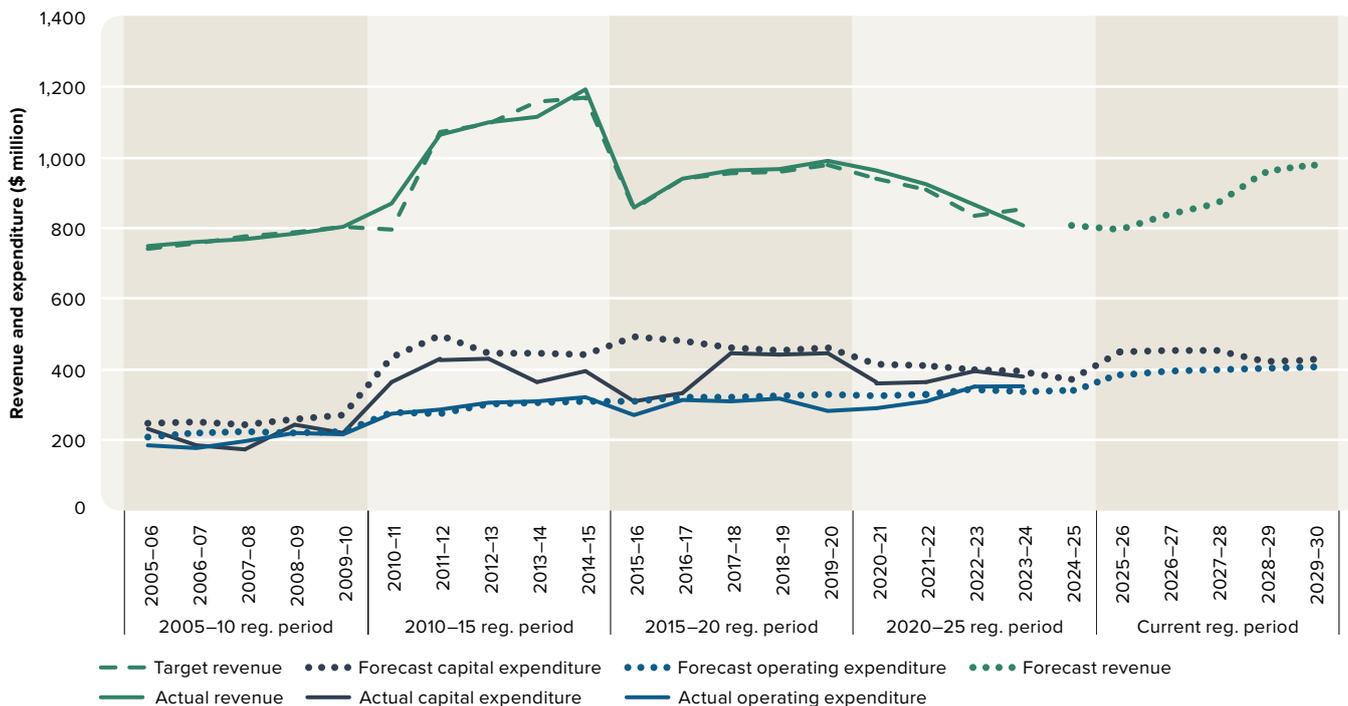


Note: All data are adjusted to June 2024 dollars.  
 Source: AER modelling; annual reporting RIN responses.

### 3.6.3 SA Power Networks (South Australia)

The AER’s final determination was that SA Power Networks can collect \$4.4 billion in revenue from its customers over the 2025–30 regulatory period, \$259 million (6%) more than the revenue forecast for the previous regulatory period. The AER estimates that approximately 54% of the increase was driven by higher capital and operating expenditure, with the other 46% driven by higher inflation and interest rates (Figure 3.8).

Figure 3.8 Revenue and key drivers – SA Power Networks (South Australia)



Note: All data are adjusted to June 2024 dollars.  
 Source: AER modelling; annual reporting RIN responses.

For Energex (Queensland) and Ergon Energy (Queensland) the drivers of higher forecast revenues were partially offset by negative revenue adjustments, mainly due to the impacts of large efficiency benefit sharing scheme (EBSS) (Box 3.4) and capital expenditure sharing scheme (CESS) (Box 3.3) penalties applied in the final determinations.

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

In 2024, Ergon Energy materially overspent against forecast capital expenditure for the fifth consecutive year. Ergon Energy submitted that overspends were driven by the need to address priority network safety programs, including defect rectifications and remediation works.<sup>113</sup>

In its draft determination, the AER recommended a 50% reduction in the amount of capital expenditure<sup>114</sup> to be included in Ergon Energy’s opening RAB at 1 July 2025.<sup>115</sup> The AER found that Ergon Energy did not provide sufficient supporting material to demonstrate prudent and efficient decision-making for some of its capital expenditure. Instead, there were information gaps and reliance on poor-quality data. In its final determination, the AER reiterated its concerns made in the draft determination regarding Ergon Energy’s asset management practices, particularly its practice of retrospectively applying new standards to existing assets and its approach to opportunistically replacing pole top structures and service lines when replacing poles.<sup>116</sup>

Ergon Energy acknowledged its increasing operating costs over the previous regulatory period (2020–25) and identified key drivers including flood and storm costs in 2023–24, increasing vegetation management costs resulting from newly negotiated contracts, a general increase in costs driven by the COVID-19 pandemic and an increase in labour and overhead costs associated with growth in its capital program.<sup>117</sup>

113 Ergon Energy, *2021-22, 2022-23 and 2023-24 Annual reporting RINs*, 31 October 2022, 2023 and 2024.

114 Outlaid by Ergon Energy over the 5-year period from 2018 to 2023.

115 AER, *Ergon Energy - Draft determination 2025–30*, Australian Energy Regulator, 23 September 2024.

116 AER, *Ergon Energy - Determination 2025–30*, Australian Energy Regulator, 30 April 2025.

117 Ergon Energy, *Response to AER Information request, IR#047 – actual base year opex, Q.1 and workbook*, 12 July 2024.

## 3.7 Refining the regulatory approach

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

In May 2024, the AER published an update to its *Better Resets Handbook – Towards consumer-centric network proposals* (the Handbook) as part of reflecting the addition of the emissions reduction objective to the existing National Energy Objectives (section 3.5.1).<sup>118</sup>

Regulatory proposals that are developed through genuine engagement with consumers and meet the AER's expectations for forecast expenditure, depreciation and tariff structure statements are more likely to be largely or wholly accepted at the draft determination stage, creating a more efficient regulatory process for all stakeholders.

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

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

- whether the revenue proposals submitted by network service providers are in the long-term interests of consumers
- the effectiveness of network service providers' engagement with their customers
- how consumer views are reflected in the development of network service providers' proposals.<sup>119</sup>

The AER was satisfied that both Energex's (Queensland) and Ergon Energy's (Queensland) stakeholder engagement plans for the 2025–30 revenue determination process were well targeted and provided meaningful input into their revised proposals. Both Energex and Ergon Energy engaged with their Voice of Customer Panel, Customer and Community Council and Network Pricing Working Group to obtain consumer views on the AER's draft determinations on capital investment, network tariffs and the customer service incentive scheme (CSIS) (Box 3.6), and to gain support for the direction of their revised proposals.<sup>120</sup>

However, Energex and Ergon Energy presented an unbalanced picture to consumers about the AER's draft determinations on capital expenditure and some tariff elements. Both Energex and Ergon Energy suggested the AER's draft determination on capital expenditure would lead to worsening reliability and compromise safety goals. Energex and Ergon Energy also implied their two-way tariff proposals were rejected by the AER and encouraged consumers to support postponing its implementation.

The AER was satisfied that SA Power Networks' (South Australia) stakeholder engagement following the 2025–30 draft determination was effective in gathering feedback for the revised proposal. SA Power Networks held targeted engagement with its consumer groups to address issues raised by the AER in the draft determination and held information sessions to provide an overview of their proposed response, and the expected revenue and bill impacts of their revised proposal. SA Power Networks' collaborative approach to refine the innovation fund with consumers was a standout in its post-draft determination engagement process.<sup>121</sup>

The AER noted that Energex, Ergon Energy and SA Power Networks all failed to fully address the issue of affordability in their revised proposals despite the issue being raised by several stakeholders.

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118 AER, [Better Resets Handbook – Towards consumer centric network proposals](#), Australian Energy Regulator, 30 July 2024.

119 AER, [Consumer Challenge Panel](#), Australian Energy Regulator, accessed 3 February 2025.

120 AER, [Energex – Determination 2025–30 – Final decision](#) and [Ergon Energy – Determination 2025–30 – Final decision](#), Australian Energy Regulator, 30 April 2025.

121 AER, [SA Power Networks – Determination 2025–30 – Final decision](#), Australian Energy Regulator, 30 April 2025.

### 3.7.1 Changes to revenue setting approaches

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

In February 2023, the AER released its latest rate of return instrument (the 2022 Instrument). The rate of return is a key component used to determine the amount of revenue network service providers can recover from customers. The AER sets the rate of return to cover the cost of capital of an efficient service provider.

In March 2024, the AER released an updated version of the February 2023 Instrument, which binds all access arrangements from 25 February 2023 until the next revision of the Instrument.<sup>122</sup> The instrument sets out the approach by which the AER will estimate the rate of return and comprises the return on debt and the return on equity, as well as the value of imputation credits (section 3.12).

In March 2025, as a first step toward making the 2026 Rate of Return Instrument, the AER published a paper setting out the high-level review process it will undertake to produce the Instrument.<sup>123</sup>

The AER also continues to review and incrementally refine elements of its benchmarking methodology and data. The aim of this work is to continually improve the reliability of the benchmarking results it publishes and uses in its network revenue determinations (section 3.15).

## 3.8 Electricity pricing for a renewable future

The amount of electricity generated by consumer-owned or controlled devices continues to grow. This growth in consumer energy resources – such as rooftop solar panels, home batteries, electric vehicles and smart devices that can interact with the grid – presents both opportunities and challenges as technological advances constantly shifts the way in which electricity is supplied, stored and used.

As we transition to a renewable future – in particular, the increase in consumer energy resources – it is important that individual consumers can make informed choices about their electricity usage to avoid increasing costs for all consumers. Sending signals via network prices is one way to incentivise consumers to use electricity in ways that minimises the need for future network investment.

Distribution network service providers set network tariffs to recover the costs of owning and operating the electricity network. Cost-reflective network tariffs – which means charging different prices for different periods of the day – send broad and consistent signals to energy retailers that sourcing electricity from the grid during periods of peak demand, or exporting it during periods of minimum demand, contributes to network costs in the long run. As such, cost-reflective network tariffs can incentivise retailers to encourage customers to consume energy when there are fewer constraints on the grid and electricity is cheaper to distribute.

Conversely, ‘static’ or ‘flat’ network tariffs see distribution network service providers charge retailers the same price per unit of electricity regardless of when the electricity is used. These types of network tariffs do not reflect that consuming electricity during periods of peak or minimum demand can contribute to network costs.

Network assets generally have a long life span and are paid for by customers. Distribution network service providers are best placed to develop network tariffs that signal the impact demand will have on network costs. Managing network demand and supply imbalances to increase capacity utilisation (section 3.15.2) could mitigate future costs by reducing the need for network augmentation, thereby lowering future network bills for all consumers. When network service providers pass broad and consistent price signals to retailers, it incentivises retailers to then facilitate alternative ways to align consumers’ energy use with efficient use of network infrastructure through innovative energy services and retail tariffs.

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122 AER, [Rate of Return Instrument 2022](#), Australian Energy Regulator, accessed 20 March 2025.

123 AER, [Rate of Return Instrument – 2026 review process paper](#), Australian Energy Regulator, 28 March 2025.

### 3.8.1 Smart meters, new technologies and network pricing

Smart meters are advanced digital electricity meters that provide accurate real-time information about electricity usage. Smart meters measure and record electricity usage every 30 minutes and automatically sends the data to the customer's distribution network service provider. This enables distribution network service providers to develop cost-reflective network tariffs, and for retailers to pass on these tariffs (via the retail contract), to customers who are willing and able to respond to time-variable tariffs and make informed decisions in managing both their electricity usage and exports.

Smart meters play an essential role in supporting the energy transition. The provision of accurate real-time usage data is vital to the development and implementation of demand management strategies and enables distribution network service providers to better balance the variable supply of renewable electricity. For example, facilitating time-varying retail pricing and supporting the orchestration of consumer energy resources can reward customers for using electricity when there is ample network capacity.

The penetration of smart meters has increased over the past decade. However, the proportion of network customers outside of Victoria with access to smart meters remains relatively low. Outside of Victoria, most households still have accumulation meters that need to be manually read. As such, most households still only have access to flat retail offers. Accelerating the deployment of smart meters means that customers and the broader energy system can get faster access to the benefits offered by these devices.

In August 2023, the Australian Energy Market Commission (AEMC) released its final report supporting the accelerated rollout of smart meters.<sup>124</sup> The report set out several recommendations and options to achieve universal penetration of smart meters across the NEM by 2030. Following this, the AEMC published a final determination and final rule seeking to efficiently accelerate the deployment of smart meters to all customers, commencing December 2025.<sup>125</sup>

The AER demonstrated its support of the AEMC's proposed acceleration of the rollout by approving the cost recovery of old network-delivered meters in the quickest, lowest cost way to all customers.<sup>126</sup> The AER has signalled through its recent revenue determinations that the transitioning of legacy meters may require it to consider different classifications and/or price/revenue control settings for distribution network service providers.<sup>127</sup> While the AER will look to maintain a consistent approach in assessing legacy metering services, consideration of the individual circumstances of each distribution network service provider will be required to ensure it provides outcomes that are in the long-term interests of consumers.

The AEMC's *Accelerating smart meter deployment* final rule determination includes customer protections prohibiting up-front costs and requiring retailers to obtain a customer's explicit informed consent before moving them to a new (cost-reflective) retail tariff for the 2-year period after the installation of a smart meter. This reflects the risk that some customers could be worse off under time-varying or demand tariffs.<sup>128</sup> The AEMC determination also enables jurisdictions to implement a requirement that designated retailers continue to offer flat retail tariffs. To date, Queensland is the only jurisdiction to require designated retailers to offer a flat standing offer as an alternative tariff to customers with smart meters.<sup>129</sup>

The AEMC is currently consulting on a rule change, initiated by Energy Consumers Australia (ECA), to enable consumers to access real-time data from their smart meters.<sup>130</sup> Having access to real-time energy usage data has the potential to enhance the consumer's benefits of having a smart meter. Currently, consumers and third parties seeking access to real-time energy usage data need to install separate digital meter readers or current transformers, with consumers paying to gain the additional access.

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124 AEMC, [Final report – Review of the regulatory framework for metering services](#), Australian Energy Market Commission, 30 August 2023.

125 AEMC, [Final rule determination – Accelerating smart meter deployment](#), Australian Energy Market Commission, 28 November 2024.

126 AER, [Final revenue decisions balance affordability and required investment](#), media release, Australian Energy Regulator, 30 April 2024.

127 AER, [Final Decision – Endeavour Energy electricity distribution determination 2024 to 2029 – Overview](#), Australian Energy Regulator, 30 April 2024, p. 27.

128 A demand tariff is a network tariff that includes a charge based on the customer's maximum power usage during a specified period, typically a 30-minute interval within a defined peak period.

129 *National Energy Retail Law (Queensland) Amendment Regulation (No. 2) 2024*.

130 AEMC, [Directions paper – Real time data for consumers rule 2025](#), Australian Energy Market Commission, 30 January 2025.

### 3.8.2 Regulatory reforms that support changing energy flows

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

#### Tariff structure statement process

The AER's role is to approve, or not approve, network tariffs proposed by distribution network service providers based on whether they comply with the network pricing principles of the National Electricity Rules and contribute to the achievement of the Network Pricing Objective and the National Electricity Objective. With each subsequent tariff structure statement, distribution network service providers are required under the National Electricity Rules to progressively move towards more cost-reflective network tariffs.<sup>131</sup>

The AER makes its decisions on tariff structure statements by assessing whether network tariff design is progressing towards cost reflectivity.<sup>132</sup> This includes considering the impact network tariffs have on customers, retailers' ability to incorporate tariffs in their retail offers and whether customers will understand their network tariffs. This has been an important consideration for the AER in assessing the default network tariffs that distribution network service providers assign to customers.<sup>133</sup>

**The AER's role is to approve, or not approve, network tariffs proposed by distribution network service providers based on whether they comply with the network pricing principles of the National Electricity Rules and contribute to the achievement of the Network Pricing Objective and the National Electricity Objective.**

Distribution network service providers are required to submit tariff structure statements to the AER every 5 years as part of the wider revenue determination process. Tariff structure statements set out proposed network tariff structures for the forthcoming 5-year period, policies on how network tariffs are assigned and information on how network tariffs are set. The 5-year tariff structure cycle was imposed to place weight on certainty for electricity retailers and consumers, because distribution network service providers cannot modify approved network tariffs within a 5-year period unless exceptional circumstances have been met. Given the pace of the energy transition, a 5-year cycle may no longer be fit for purpose. Increased flexibility in the tariff structure statement process is being considered as part of the AEMC's *Electricity pricing for a consumer-driven future* review.<sup>134</sup>

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131 Most distribution network service providers have completed their third round of tariff structure statements. The AER will make a final determination on the Victorian distribution network service providers' third round of tariff structure statements in April 2026.

132 To signal to energy retailers, then to customers via their energy retail, periods of network capacity and periods of network congestion.

133 The 'default network tariff' is the initial tariff a customer is assigned to, unless the customer's retailer chooses an alternative tariff made available by the distribution network service provider.

134 AEMC, [The pricing review: Electricity pricing for a consumer-driven future](#), Australian Energy Market Commission, accessed 5 June 2025.

## Increasing network utilisation through tariffs

Distribution network service providers reward customers for behaving in ways that better utilise the existing network, potentially reducing the need for future network investment. Some innovative approaches include:

- designing tariffs that more closely reflect network costs, including introducing ‘solar soak’ periods – tariffs that have low charges during the day to encourage consumers to use electricity in this time (most distribution network service providers have or will soon include these tariffs)
- introducing export rewards or two-way tariffs in recognition of the need to manage the significant levels of electricity now being exported back into the grid from consumer energy resources, such as small-scale solar and batteries.

The introduction of two-way tariffs is one example of tariff reform and follows a rule change made by the AEMC in August 2021 to integrate consumer energy resources more efficiently into the electricity grid.<sup>135</sup> Export reward tariffs – which offer rewards to customers for exporting electricity at times when it is most needed (in addition to retailers’ solar feed-in tariff payments) and apply charges for exporting large amounts of solar into the grid at times when it is not needed – better reflect the costs and benefits to the network from solar-exporting customers and incentivise behaviours that benefit all customers. Export reward tariffs are intended to help customers who generate solar decide when to consume the solar electricity themselves and when to export it.<sup>136</sup>

The AER first approved the use of export reward tariffs in April 2024. Export reward tariffs were introduced by distribution network service providers in NSW on 1 July 2024, followed by South Australia on 1 July 2025. Network service providers are not required to introduce export reward tariffs and any proposed export reward tariff is subject to the AER’s approval as part of the tariff structure statement process.

Some distribution network service providers have also introduced flexible export limits, a connection that allows the service provider to limit solar exports when needed to protect local power supply. This allows customers to export more than the static (fixed) limit at other times. For example, Endeavour Energy (NSW) announced a flexible exports service that will allow eligible customers to increase the amount of energy they can export to the grid from 5 kilowatts (kW) up to 10 kW for 95% of the year. Endeavour Energy will only limit exports if grid stability is at risk.<sup>137</sup>

As at 30 June 2024, approximately 37% of residential consumers in the NEM were assigned to a cost reflective network tariff that was charged to their retailer (Figure 3.9). This proportion will likely increase in response to the accelerated rollout of smart meters. However, it is important to recognise that the direct impact on a customer’s electricity bill from any network tariff, two-way or otherwise, will still depend on how it is passed on by the retailer in a customer’s retail contract.

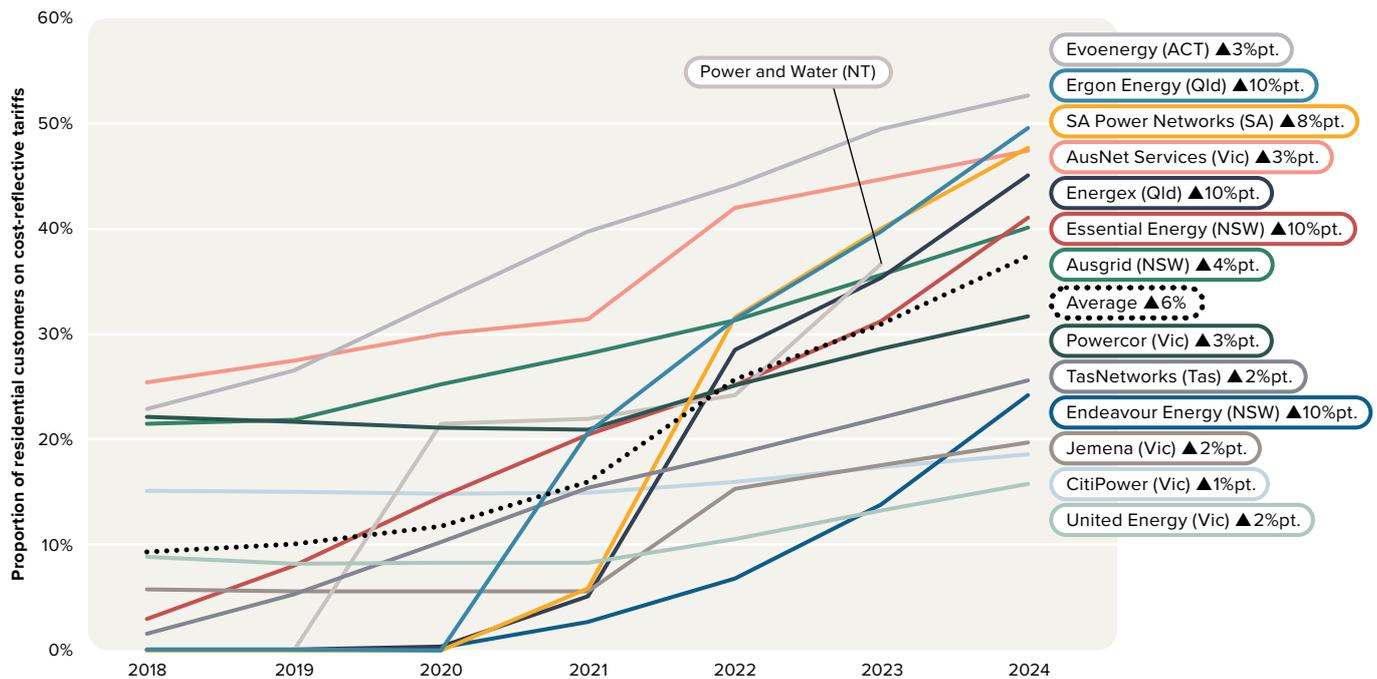
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135 AEMC, [Access, pricing and incentive arrangements for distributed energy services](#), Australian Energy Market Commission, 12 August 2021, accessed 2 June 2025.

136 AER, [Export reward tariffs and you](#), Australian Energy Regulator, April 2024.

137 Endeavour Energy, [World-leading AI technology to unlock electricity bill savings and double rooftop solar](#), media release, 25 February 2025, accessed 25 February 2025.

Figure 3.9 Residential customers on cost-reflective tariffs



Note: 2024 data for Power and Water (NT) was not available.  
 Source: Annual RIN responses.

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

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

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

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

With the need for innovative solutions to support changes in consumers’ energy use more urgent than ever, the AER may look for rule amendments around sub-threshold tariffs to be less restrictive as part of the AEMC’s *Electricity pricing for a consumer-driven future*.<sup>138</sup>

138 AEMC, [The pricing review: Electricity pricing for a consumer-driven future](#), Australian Energy Market Commission, accessed 5 June 2025.

## Network tariffs for EV users and EV charging point operators

The network tariff reform program, administered by the AER, is a long-term micro-economic reform program aimed at reducing future network costs through more efficient use of the network. This is particularly important for the emerging electric vehicle (EV) load on the network. Most distribution network service providers now have default cost-reflective tariffs that signal to retailers when there is abundant network capacity, making it cheaper for consumers to charge their EVs. This generally occurs in the middle of the day when solar generation is high and overnight when fewer customers are using appliances. Customers with EVs with vehicle-to-grid capability may also benefit from export reward tariffs and be rewarded for exporting electricity into the grid when it is needed.

Trials have demonstrated that consumers have responded well to EV load price signals, with even greater benefits from blending price signals with external control over a consumer's EV chargers. For example:

- AGL's Electric Vehicle Orchestration Trial found that EV customers on time-of-use retail offers (that reflect cost-reflective network tariffs) respond strongly to price signals and move EV charging to off-peak periods.<sup>139</sup>
- Origin Energy's trial demonstrated that providing incentives to participants through time-varying offers reduced charging consumption at peak times by 20%.<sup>140</sup>

There has also been an emergence of non-tariff mechanisms employed by distribution network service providers to help manage EV-related demand. For example, customers in Queensland can install equipment that allows their distribution network service provider to dynamically control an EV fast charger, limiting electricity supply in close to real-time when the network is congested.<sup>141</sup> Together, cost-reflective tariffs, external control and smart devices could increase network capacity utilisation and mitigate potential adverse network efficiency outcomes as Australia's road transport electrifies.

The AER supports a consistent approach to network tariffs for EV charge point operators – the entities responsible for building, operating and maintaining EV charging infrastructure – across the NEM to facilitate the expansion of Australia's EV charge point network. Following the AER's 2025–30 revenue determinations for Energex (Queensland), Ergon Energy (Queensland)<sup>142</sup> and SA Power Networks (South Australia),<sup>143</sup> customers with 'peaky load profiles' (relatively high demand but low utilisation) – such as new/small charge point operators – will be able to opt in to either a 'time-of-use' or 'demand' tariff in all distribution networks in the NEM.<sup>144</sup>

The AER considers the access to similar network tariff structures for EV charge point operators NEM-wide could further support uptake and use of EVs, consistent with the Australian Government's National Electric Vehicle Strategy, to 'make it easy to charge EVs across Australia' and 'reduce road transport emissions'.<sup>145</sup>

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139 Australian Government, [AGL Electric Vehicle Orchestration Trial](#), Australian Renewable Energy Agency, May 2023, accessed 5 July 2025.

140 Australian Government, [Origin Energy Electric Vehicles Smart Charging Trial Lessons Learnt 2](#), Australian Renewable Energy Agency, May 2022, accessed 5 July 2025.

141 Energex, [EV charging & connections](#), accessed 6 June 2025.

142 AER, [Final Decision Attachment 19 – Tariff structure statement – Ergon Energy and Energex – 2025-30 Distribution determination revenue proposal](#), Australian Energy Regulator, 30 April 2025.

143 AER, [Final Decision Overview – SA Power Networks – 2025-30 Distribution determination revenue proposal](#), Australian Energy Regulator, 30 April 2025.

144 Prior to the Energex/Ergon Energy/SA Power Networks determinations, consistency had already been achieved in other NEM jurisdictions. Across NSW, Victoria, Tasmania and the ACT, EV charge point operators could already access time-of-use tariffs while consumption is less than 160 MWh.

145 Australian Government, [The National Electric Vehicle Strategy](#), Department of Climate Change, Energy, the Environment and Water, accessed 2 June 2025.

### 3.8.3 Ring-fencing

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

The objective of ring-fencing is to provide a regulatory framework that promotes the development of competitive markets. It does so by creating a level playing field between natural monopoly and third-party service providers in new and existing markets for contestable services.<sup>146</sup> Effective ring-fencing arrangements are important for promoting an increased choice of service providers for consumers and more competitive outcomes in markets for electricity services without losing the cost efficiencies of natural monopolies.

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

The AER has developed separate ring-fencing guidelines for transmission and distribution networks. Under the guidelines, network service providers must identify and separate the costs and business activities attributed to the provision of regulated network services from those attributed to the delivery of services in competitive markets. Network service providers are required to report to the AER any breaches of the guidelines within 15 business days of becoming aware of the breach. In addition, network service providers must annually report to the AER on their compliance with the guidelines. When breaches have occurred, network service providers have generally communicated promptly with the AER, acted quickly to remediate any potential harms and put plans in place to prevent breaches from recurring. The introduction of civil penalties for ring-fencing breaches has further encouraged improved compliance.

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

In the 12-month period to 30 December 2024, 2 transmission and 6 distribution network service providers reported breaches related to the protection of ring-fenced information. The AER did not consider these breaches had a material impact on competition within contestable markets.

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

On 27 February 2025, the AER amended the ring-fencing guidelines for distribution network service providers to remove the maximum length of waivers and provide the AER with discretion to determine the duration of waivers.<sup>147</sup>

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<sup>146</sup> The 2015 Power of Choice reforms required the AER to develop the distribution ring-fencing guideline.

<sup>147</sup> AER, [Ring-fencing guideline \(electricity distribution, version 4\)](#), Australian Energy Regulator, 27 February 2025.

Table 3.2 provides a summary of the waivers granted by the AER in the 12-month period to 30 June 2025. In addition, the AER has previously granted waivers – some of which specifically target new and innovative services – for distribution network service providers to install and operate community-scale batteries to further test and trial how locally based storage can benefit consumers.

**Table 3.2 Recent AER waiver approvals**

Network service provider	Waiver description	Waiver commencement date	Waiver end date
Ergon Energy (Qld)	Allows Ergon Energy to continue to use a similar brand name and branding as Ergon Energy Retail.	27 June 2025	30 June 2035
Ergon Energy (Qld)	Allows Ergon Energy to continue to classify the Mareeba and Charters Towers depots as regional offices for the purposes of ring-fencing.	10 June 2025	30 June 2045
Ergon Energy (Qld)	Allows Ergon Energy to continue to provide connection from its mainland network to Hayman Island via undersea cable.	21 May 2025	30 June 2040
Ergon Energy (Qld)	Allows Ergon Energy to continue to provide other services to and on behalf of transmission network service provider Powerlink (Qld).	2 April 2025	30 June 2040
Ergon Energy (Qld)	Allows Ergon Energy to act as the metering coordinator for 3 communities in regional Queensland.	19 September 2024	31 December 2027
Ergon Energy (Qld)	Allows Ergon Energy to provide generation services in Queensland's isolated networks using behind-the-meter generation assets.	22 August 2024	30 June 2030
Transgrid (NSW)	Allows Transgrid to continue to provide telecommunication services not associated with the transmission network to one customer.	17 April 2025	12 April 2026
AusNet Services (Vic)	Allows AusNet Services to install, own and operate 10 pole-top batteries.	19 November 2024	31 December 2035
Power and Water (NT)	Allows Power and Water to address an inconsistency between the ring-fencing guidelines and the NER (Northern Territory) about the publishing of registers.	1 July 2024	30 June 2034

Note: The waivers listed in Table 3.2 refer to those granted by the AER in the 12-month period to 30 June 2025. As at 30 June 2025, the AER was assessing a number of ongoing ring-fencing waiver applications, including a ring-fencing waiver application by CitiPower (Victoria), Powercor (Victoria) and United Energy (Victoria) to install and maintain kerbside electric vehicle charging infrastructure in their collective distribution areas.

## 3.9 Revenue

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

For transmission network service providers, 'regulated services' include revenues associated with delivering prescribed transmission services. For distribution network service providers, it includes revenues associated with providing standard control services.<sup>148</sup>

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

<sup>148</sup> Regulated services include electricity transportation, connections and metering services and represent most of a network service provider's revenue. For transmission network service providers, 'regulated services' includes revenues associated with delivering prescribed transmission services. For distribution network service providers, it includes revenues associated with providing standard control services.

The AER updates the revenue targets each year to account for actual inflation, changes in network service providers' allowed returns on debt, cost pass-throughs (section 3.9.3) and other factors. Interest rates and inflation are factors outside both network service providers' and the AER's control.<sup>149</sup>

### 3.9.1 Revenue in 2024

Over the 12-month period to 30 June 2024, network service providers earned \$12.7 billion for delivering core regulated services,<sup>150</sup> \$270 million (2.1%) less than in the previous year.

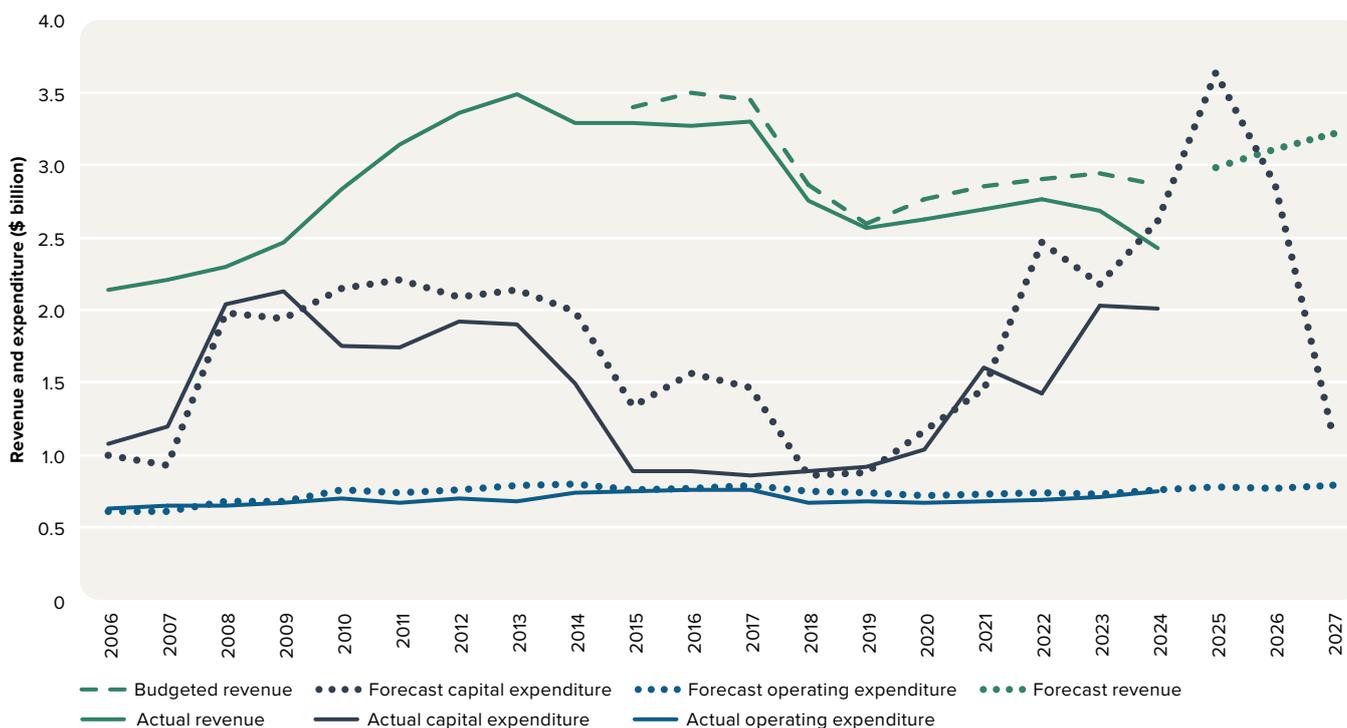
Table 3.3, Figure 3.10 and Figure 3.11 provide a summary of the revenue that network service providers collected for serving customers in 2024 and how it compared with previous years' targets and actuals.

**Table 3.3 Revenue in 2024 – key outcomes**

Service type	Revenue (actual) (2024)	Revenue (actual) (compared with 2023)	Revenue (actual) (compared with peak)
Transmission	\$2.4 billion	▼\$256 million (▼10%)	▼\$1.1 billion (▼31%) (2013)
Distribution	\$10.3 billion	▼\$14 million (▼0.1%)	▼\$4.9 billion (▼32%) (2015)
Total	\$12.7 billion	▼\$270 million (▼2.1%)	▼\$5.7 billion (▼31%) (2015)

Note: All data are adjusted to June 2024 dollars.  
Source: AER estimates.

**Figure 3.10 Revenue and key drivers – electricity transmission networks (aggregate)**



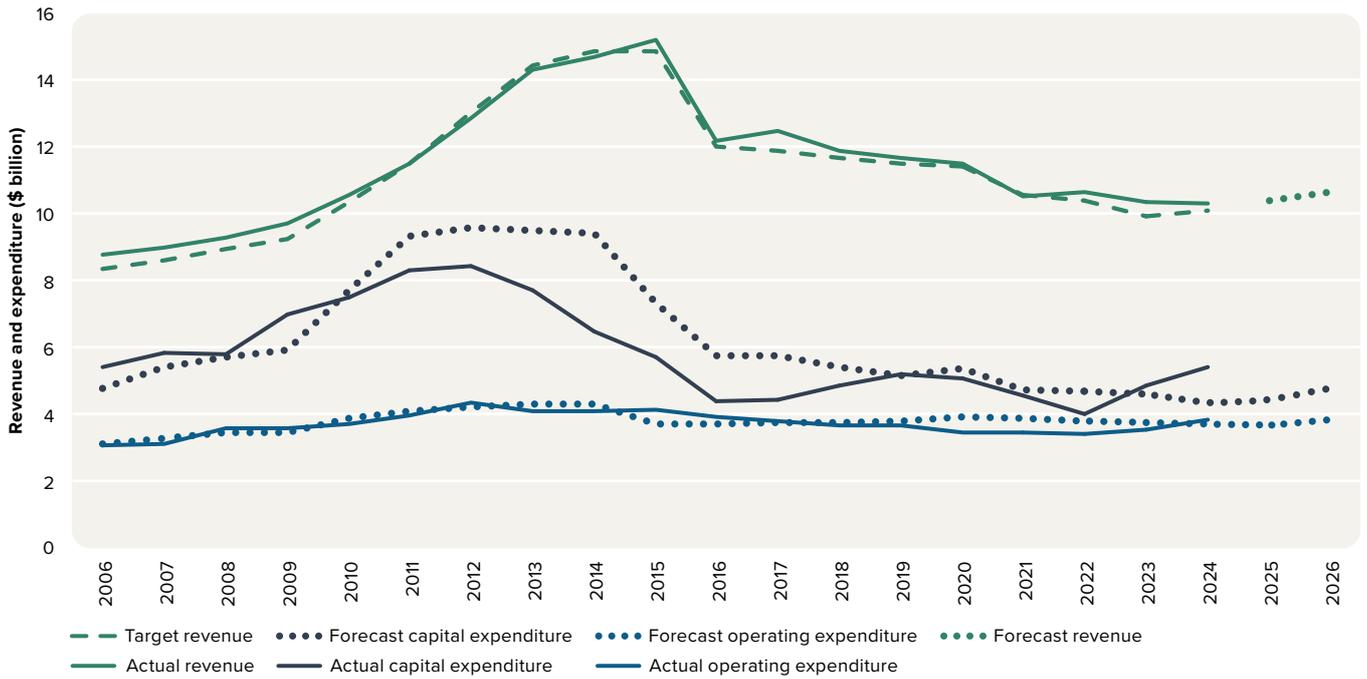
Note: All data are adjusted to June 2024 dollars. Most network service providers report on a 1 July to 30 June basis. The exception is AusNet Services (Victoria), which reports on a 1 April to 31 March basis. The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018). Transmission network service providers earn revenues for delivering prescribed transmission services, some of which comes directly from customers and some from sources such as inter-regional and intra-regional settlements residues or inter-regional settlements auction proceeds. Budgeted revenue reflects the revenues transmission network service providers budgeted to be collected from customers.

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

149 AER, [Rate of return – overview for consumers](#), Australian Energy Regulator, February 2023.

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

Figure 3.11 Revenue and key drivers – electricity distribution networks (aggregate)



Note: All data are adjusted to June 2024 dollars. The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018). The exception is the Victorian networks, which until year end 2020 reported on a 1 January to 31 December basis. Target revenue for the Victorian distribution networks for the 2021 year has been derived from the transitional year (1 January to 30 June 2021). To enable reporting on equivalent terms, these values have been doubled. The adjustments include rewards and penalties from incentive schemes, cost pass-throughs and other factors that are considered in determining the target revenues used to set prices each year.

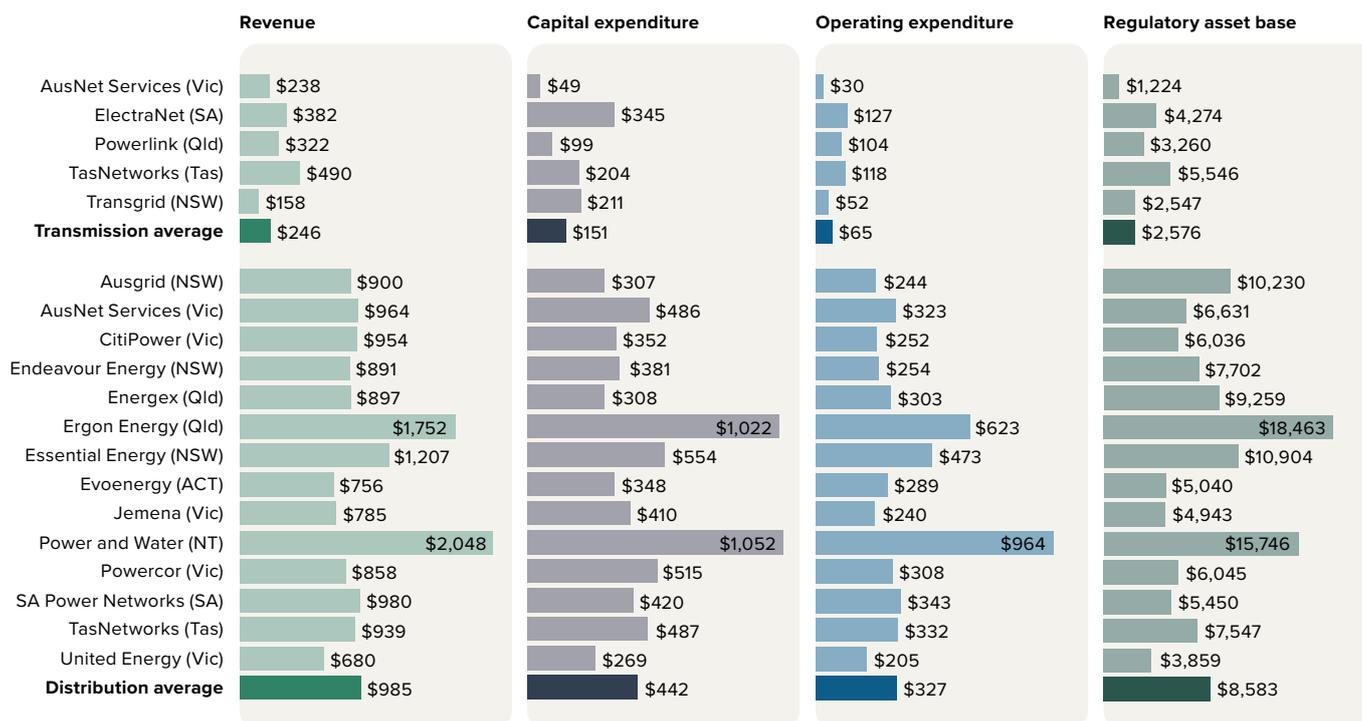
Source: Revenue: economic benchmarking RIN responses; capital expenditure: AER modelling, category analysis RIN responses; operating expenditure: AER modelling, economic benchmarking RIN responses.

When assessing financial indicators for network service providers, it is often more useful to view the outputs on a ‘per customer’ basis. This allows for easier comparison between networks of different sizes and structures. However, multiple factors other than customer numbers – such as line length and terrain – can impact these outputs.

Figure 3.12 summarises key ‘per customer’ financial indicators related to the delivery of core regulated services.<sup>151</sup>

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

Figure 3.12 Average per customer metrics – 2020 to 2024 (5 years)



Note: All data are adjusted to June 2024 dollars. In 2024, residential customers (a customer who purchases electricity principally for personal, household or domestic use) accounted for 88% of total customers on the distribution network. While the proportion differed across network service providers – for example, 91% residential for Endeavour Energy (NSW) and 83% for CitiPower (Victoria) – the differences do not materially affect the ‘per customer’ metric. Revenue, capital expenditure and operating expenditure are the annual averages over the 5 years to 30 June 2024. RAB is the actual closing regulatory asset base at 30 June 2024. For regulatory purposes, Northern Territory transmission assets are treated as part of the distribution system.

Source: AER revenue determinations and economic benchmarking RINs.

We note the ‘revenue per customer’ output for Ergon Energy (Queensland) shown in Figure 3.12 does not reflect the amount Ergon Energy’s network customers actually paid. The Queensland Government supports customers in regional Queensland (served by Ergon Energy) by ensuring they pay similar prices for their electricity to customers in South East Queensland (served by Energex). This is done by subsidising – through the Community Service Obligation payment – additional costs involved in supplying electricity to regional Queenslanders through payments to Ergon Energy Retail.<sup>152</sup>

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

152 Queensland Government, [Electricity prices](#), Business Queensland, accessed 5 June 2025.

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

**Table 3.4 AER electricity network revenue determinations – current regulatory periods**

Service type	Revenue (forecast)	Capital expenditure (forecast)	Operating expenditure (forecast)
Transmission	\$15.4 billion (▲4%)	\$11.1 billion (▲36%)	\$3.9 billion (▲7%)
Distribution	\$55.7 billion (▲7%)	\$25.0 billion (▲4%)	\$19.2 billion (▲1.8%)
Total	\$66.8 billion (▲7%)	\$36.1 billion (▲12%)	\$23.1 billion (▲2.6%)

Note: The current regulatory period is the period in place at 1 July 2025. All revenue and expenditure data are adjusted to June 2024 dollars. Changes in revenue and expenditure are in relation to forecasts from the previous regulatory periods.

Source: AER estimates.

The key drivers behind increased revenues for most of the network service providers have been changes in the return on capital, regulatory depreciation and operating expenditure building blocks (section 3.5.2).

In the most recent round of regulatory determinations,<sup>153</sup> the allowed rate of return increased from the rate applied in the previous period due to the increase in interest rates. This created significant upward pressure on network revenue. However, some of the regulatory determinations currently in place were made before 2024, when lower interest rates saw the allowed rate of return decrease from the previous regulatory period, which led to downward pressure on revenue for some network service providers.

In 2019, the AER reviewed how it calculates the cost of corporate tax and made changes to its approach to align with the rulings of the Australian Taxation Office. The impact of the changes generally resulted in the cost of corporate tax for regulatory periods beginning between 2020 and 2024 being lower than it was in the past. In contrast, the network service providers that took part in the most recent round of regulatory determinations saw an increase in the estimated cost of corporate income tax, primarily due to a higher return on equity determined in the current regulatory period (2025–30) compared with the 2020–25 period.

### 3.9.2 Trends in network revenue

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

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

These increases were more pronounced in Queensland and NSW than in other jurisdictions. Cost pressures began to ease when demand for electricity from the grid plateaued, causing new investment to be scaled back from 2013. The changing demand outlook coincided with government moves to allow network service providers greater flexibility in meeting reliability requirements. The financial environment also improved after 2012, easing borrowing and equity costs. After peaking at more than 10% between 2009 and 2013, allowed rates of return for some network service providers fell to around 4.9% in 2023 (section 3.12).

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

A combination of these factors reduced the revenue needs of network service providers. Decreasing investment and rates of return lowered revenue requirements as network service providers entered a new 5-year regulatory cycle. However, consumers will continue to pay for the relatively high investment in network assets from 2006 to 2013 for the remainder of the economic lives of those assets, which in some cases may be up to 50 years.

<sup>153</sup> In April 2025, the AER finalised revenue determinations for distribution network service providers Energex (Queensland), Ergon Energy (Queensland) and SA Power Networks (South Australia) and the Directlink interconnector. These determinations set target revenue controls through to 30 June 2030.

Since 2017 network revenues have generally decreased, driven by a 22% reduction in target revenue for the NSW-based networks in the 2015–19 regulatory period, followed by an 11% reduction for the Queensland based networks in the 2016–20 regulatory period.

Consumer groups and some industry observers remain concerned that the regulatory framework enables network service providers to earn excessive profits. In response to calls for greater transparency around the actual returns earned by network service providers, the AER now publishes information on network profitability in an annual network performance report. The AER’s network performance report provides detailed analyses of key operational and financial trends as well as key profitability measures.<sup>154</sup> The network performance report provides key insights to enable stakeholders to make more informed assessments of the returns earned by each network service provider.

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

### 3.9.3 Pass-through events

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

Table 3.5 summarises the cost pass-through applications approved by the AER in the 12-month period to 30 June 2025.<sup>155</sup> The number of cost pass-through applications assessed by the AER in recent years has grown, largely due to more frequent severe natural disaster events causing damage to network assets, as well as the accelerating pace of regulatory change associated with the energy transition.

**Table 3.5 Cost pass-throughs**

Network service provider	Pass-through event	AER approved (\$ nominal)	Recovery period
Powerlink (Qld)	Network support	\$0.9 million	2025–26
Energex (Qld)	Natural disaster (storm)	\$11.5 million	2025–27
Ergon Energy (Qld)	Natural disaster (storm)	\$24.6 million	2025–27
Ergon Energy (Qld)	Natural disaster (storm)	\$15.3 million	2025–27
AusNet Services (Vic)	Easement land tax	\$61.3 million	2025–26
AusNet Services (Vic)	Natural disaster (storm)	\$12.9 million	2025–27
AusNet Services (Vic)	Natural disaster (storm)	\$30.1 million	2025–28
AusNet Services (Vic)	Victorian Emergency Backstop Mechanism (VEBM)	\$17.2 million	2025–26
Jemena (Vic)	Victorian Emergency Backstop Mechanism (VEBM)	\$8.3 million	2025–28
Powercor (Vic)	Victorian Emergency Backstop Mechanism (VEBM)	\$11.5 million	2025–26
United Energy (Vic)	Victorian Emergency Backstop Mechanism (VEBM)	\$6.5 million	2025–26
ElectraNet (SA)	Network support	–\$7.2 million	2025–26
TasNetworks (Tas)	Network support	\$0.4 million	2025–26

Note: Approved under clauses 6.6.1, 6A.7.2, 6A.7.3 or 11.6.21 of the National Electricity Rules.

Source: AER, [Cost pass throughs](#).

<sup>154</sup> AER, [Networks performance reporting](#), Australian Energy Regulator, accessed 13 July 2025.

<sup>155</sup> AER, [Cost pass throughs](#), Australian Energy Regulator, accessed 4 July 2025.

## 3.10 Network charges and retail bills

Electricity network charges made up as much as 46% of a residential customer's electricity bill in 2024 (Figure 6.2 in chapter 6). Distribution network services accounted for most of the costs (63% to 92%), with transmission network service costs (up to 27%), jurisdictional scheme costs<sup>156</sup> (up to 15%) and metering costs (up to 8%) making up the balance.

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

The AER's revenue determinations for the current regulatory periods are estimated to increase residential electricity bills by an average of 0.7% per year across all states and territories (Figure 3.13). The estimated bill impact is based on average annual electricity usage for a residential customer. As such, customers with different usage will experience different changes in their bills. In the past, the most significant changes to network charges generally arose in the first year of a regulatory period. However, in the most recent revenue determinations, the most significant changes (increases) often occur later in the period. For example, residential customers on Energex's (Queensland) and Ergon Energy's (Queensland) distribution networks have been allocated an estimated 3.2% increase in the fourth year of the current regulatory period, compared with an estimated average 2.2% increase per year over the whole period.

### The AER's revenue determinations for the current regulatory periods are estimated to increase residential electricity bills by an average of 0.7% per year across all states and territories.

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

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

The transition from a network service providers' initial revenue proposal to the AER's final determination, which happens over a 15-month period, is illustrated in Figure 3.13. In the most recent round of revenue determinations, the AER approved higher revenues in than were indicated in the draft decisions. This was primarily driven by a lower-than-expected inflation rate, which increases the value of regulatory depreciation and a higher rate of return, increasing the return on capital.

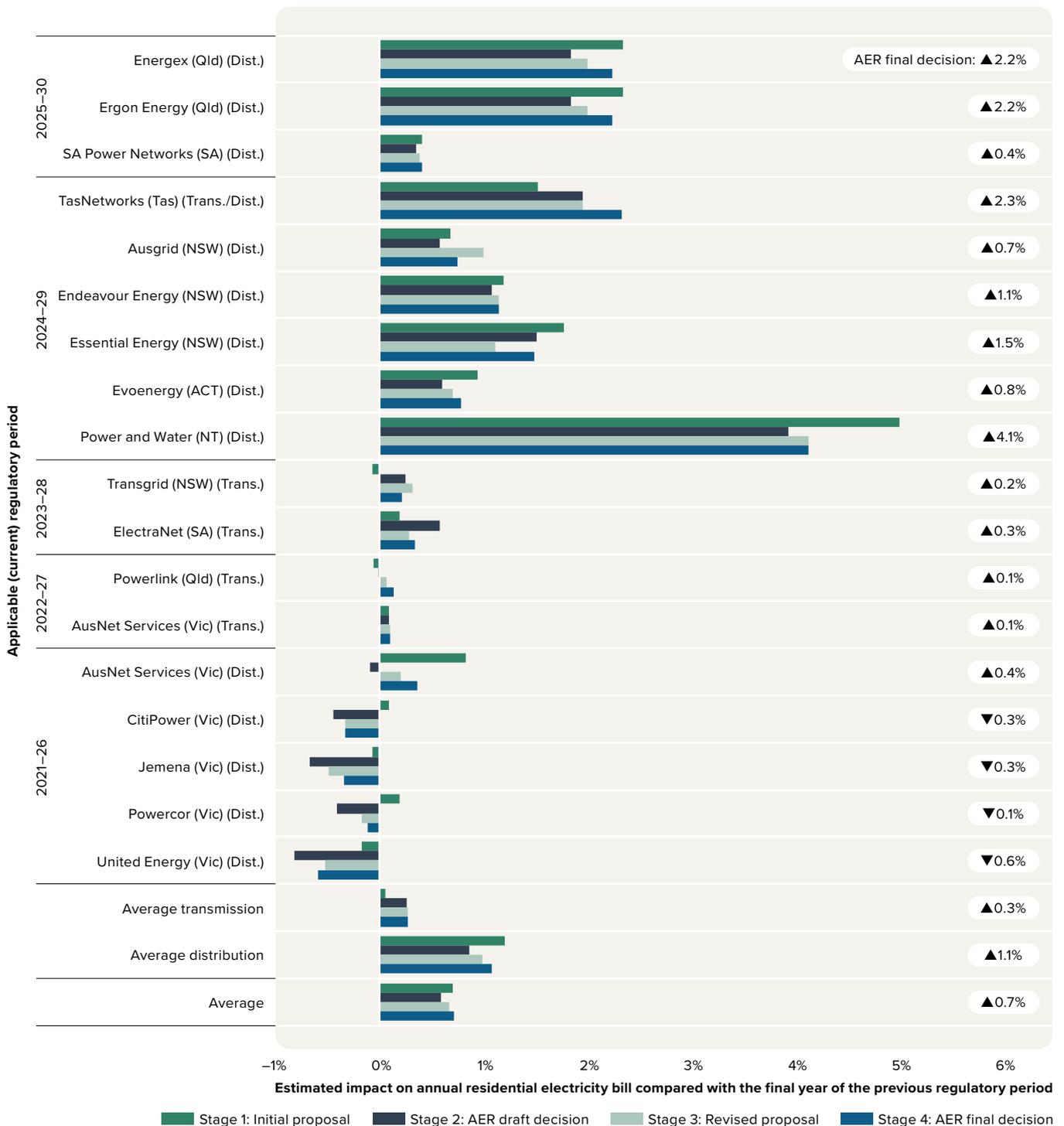
Among other factors, the annual process updates prices for changes in the consumer price index (CPI). Over the 12 months to December 2024, applying to network prices over 2025–26, CPI increased by 2.4%. In May 2025, the Reserve Bank of Australia announced that inflation had eased and was now within its target range (2–3%). While the unemployment rate was low, the global outlook had worsened and was more unpredictable than usual.<sup>157</sup>

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<sup>156</sup> Jurisdictional scheme costs are costs related to jurisdictional regulatory obligations that are passed through to customers by distribution network service providers. These schemes generally relate to historical premium feed-in tariff schemes, as well as emerging renewable energy zones, such as the NSW Electricity Infrastructure Roadmap.

<sup>157</sup> RBA, [Statement of Monetary Policy](#), Reserve Bank of Australia, May 2025.

Figure 3.13 Impact of AER revenue determinations on residential customer electricity bills



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

Source: AER revenue determinations; additional AER modelling.

## 3.11 Regulatory asset base

The regulatory asset base (RAB) represents the total economic value of the assets that provide network services to customers.<sup>158</sup> The value of the RAB substantially impacts a network service provider's revenue requirement and the total cost a customer ultimately pays. Given some network assets have a life of up to 50 years, network investment will impact electricity bills long after the investment is made.

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

### The AER may remove inefficient investment from a network service provider's RAB if the service provider overspent its capital allowance, to ensure customers do not pay for it.

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

Escalating investment inflated the value of the total electricity network RAB from \$65.8 billion in 2006 to \$109.4 billion in 2013 – an increase of around 8% per year. Since then, network investment has steadied, as has the growth in the value of the total network RAB. Since 2014, the value of the total network RAB has continued to grow but at a considerably slower rate of around 1% per year.

#### 3.11.1 Regulatory asset base in 2024

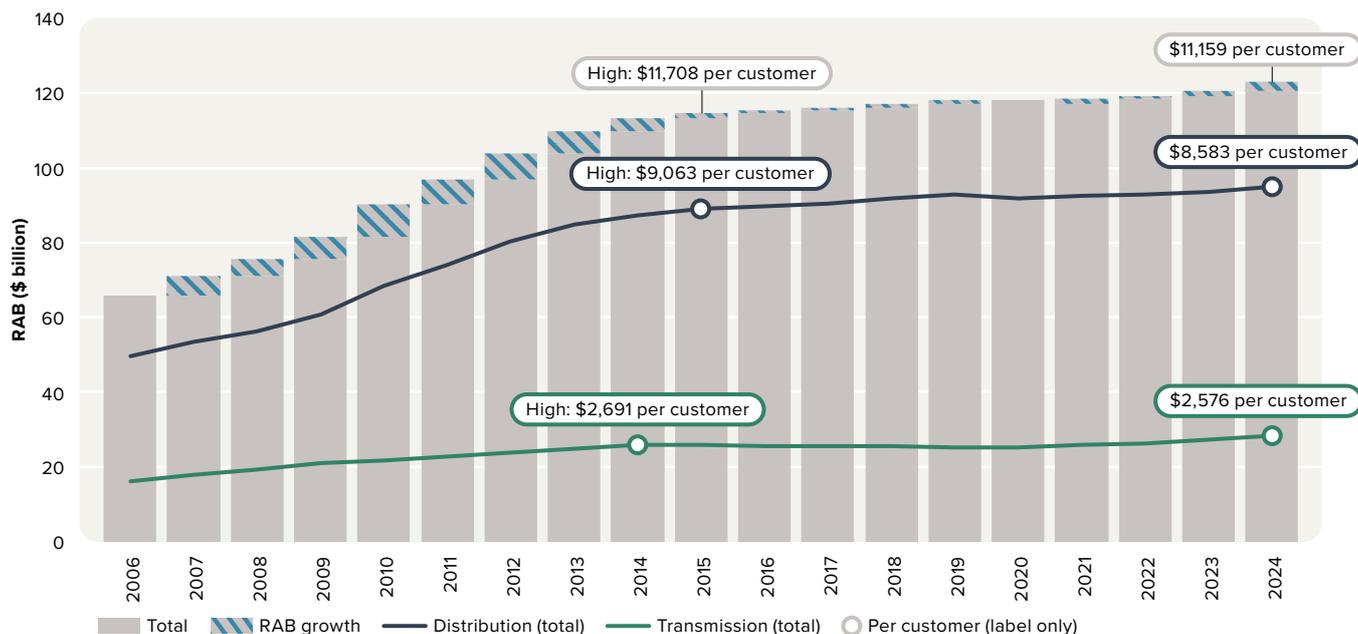
As at 30 June 2024, the aggregated value of the RABs for the electricity networks regulated by the AER was around \$123.2 billion, an increase of \$2.4 billion (2%) from the previous year (Figure 3.14).<sup>159</sup> This comprises 7 transmission networks valued at \$28.3 billion and 14 distribution networks valued at \$94.9 billion.

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<sup>158</sup> To the extent that they are used to provide such services.

<sup>159</sup> 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.

Figure 3.14 Value of electricity network assets (regulatory asset base)



Note: All data are adjusted to June 2024 dollars. The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018). This figure includes the RAB values for the Directlink and Murraylink transmission interconnectors. The Directlink and Murraylink RABs are immaterial and have not been used in the 'per transmission customer' calculation.

Source: AER modelling; economic benchmarking RIN responses.

Recent RAB growth has been most pronounced for the Transgrid (NSW) and ElectraNet (South Australia) transmission service providers. Several major capital project investments in the previous period (2018–23) – Project EnergyConnect, HumeLink, Queensland–NSW Interconnector and Victoria–NSW Interconnector Minor – have driven the increase in Transgrid’s RAB. Current period investment in these projects has already been scrutinised through contingent project assessments.<sup>160</sup>

Transgrid’s RAB growth is expected to slow over the current regulatory period (2023–28). However, it is possible that investment projects, such as those relating to AEMO’s ISP (section 3.13.6) and triggered contingent projects, could significantly increase Transgrid’s RAB over the period.<sup>161</sup>

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

Increases in the value of the RABs of Australia’s electricity grid are expected to continue as more major transmission network projects enter development. These projects are necessary to enable the reliable supply of low carbon energy as part of Australia’s energy transition (section 3.13.6).

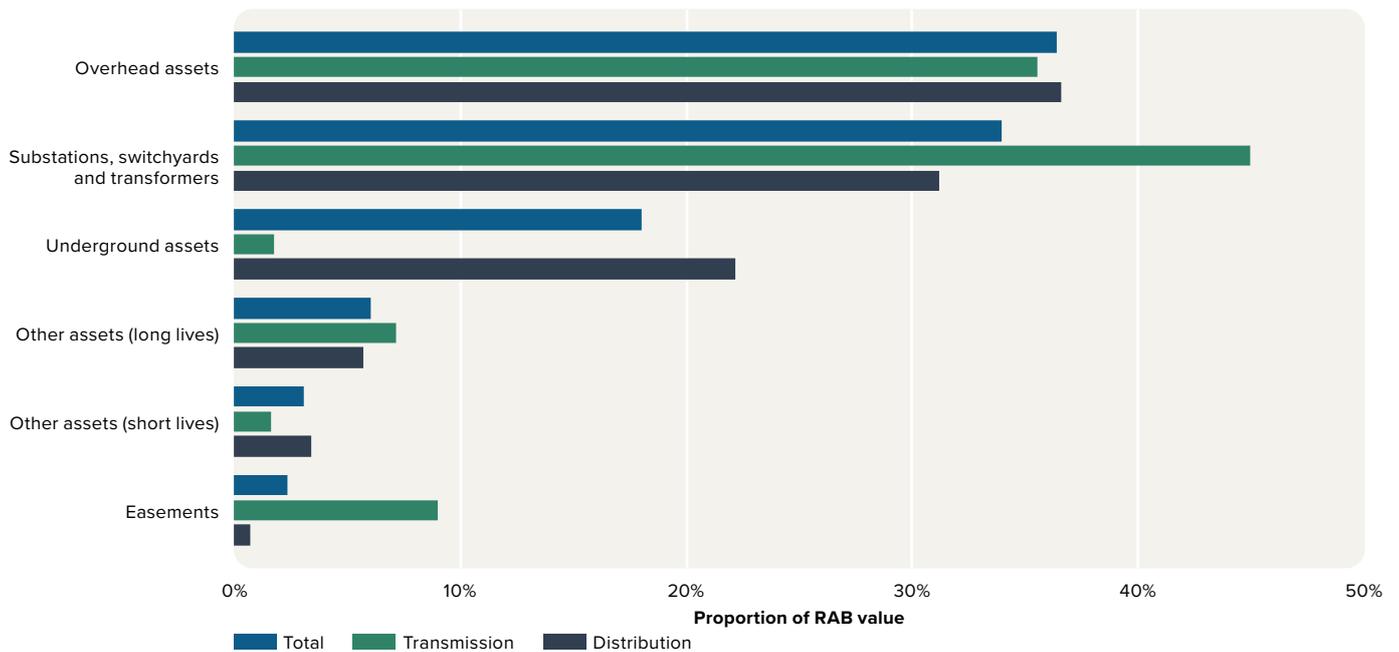
### 3.11.2 Overhead support structures

A network service provider’s RAB is made up of many assets, which can be broken down into several categories. Overhead network assets represent the most observable component of electricity network infrastructure and account for the greatest proportion (around 36%) of the total aggregated network RAB. This is not surprising given the combined transmission and distribution networks include more than 800,000 kilometres of line, 84% of which is above ground (Figure 3.15).

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

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

Figure 3.15 Disaggregated value of electricity network assets (regulatory asset base)



Source: Economic benchmarking RIN responses.

Network service providers install transmission towers and distribution poles to support overhead powerlines. Transmission towers are predominately made of steel, whereas distribution poles are made of wood, concrete, steel or composites like fibreglass. The differing environmental conditions faced by each network service provider can influence their choice of material. For example, in some parts of Australia, wooden poles are more quickly destroyed by termites, so metal poles are used instead. In its 2024–29 draft determination, the AER acknowledged Essential Energy’s (NSW) proposed use of composite poles (made from resin and fibreglass) to replace wooden poles as part of its ‘at-risk’ poles program.<sup>162</sup>

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 more than a century ago – came about as an engineering solution to South Australia’s lack of tall, termite-resistant hardwood for poles to carry powerlines and telephone wires.<sup>163</sup> SA Power Networks manufactures about 4,500 Stobie poles every year, which are used to replace poles when they have reached the end of their working life or when new overhead powerlines are being installed.<sup>164</sup>

SA Power Networks’ distribution network consists of more than 70,000 kilometres of overhead powerlines.<sup>165</sup> However, overhead network assets only make up around 19% of the value of SA Power Networks’ RAB. This relatively low proportion of overhead assets in SA Power Networks’ RAB is uncommon among network service providers, especially given the extensive size of the network service area.

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

162 AER, [Draft decision – Attachment 5 – Capital expenditure – Essential Energy 2024 to 2029](#), Australian Energy Regulator, September 2023.

163 P Sumerling and W Prest, [Stobie Poles](#), SA History Hub, History Trust of South Australia, accessed 13 July 2025.

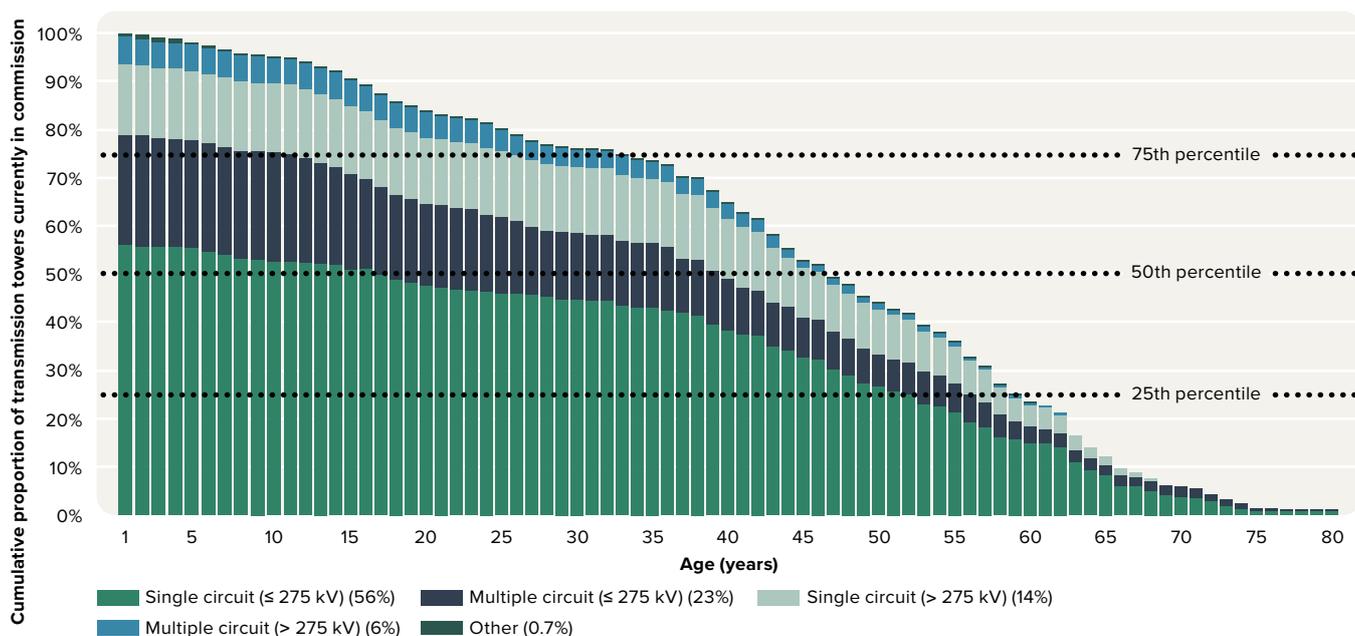
164 ABC News, [Stobie poles are a South Australian icon, but how did they come about?](#), 31 March 2023, accessed 13 July 2025.

165 Third only to Essential Energy (NSW) with 182,708 kilometres and Ergon Energy (Queensland) with 144,583 kilometres.

Some service providers, such as Essential Energy (NSW) and Ergon Energy (Queensland), operate larger, rural distribution networks that are almost entirely above ground. Conversely, CitiPower (Victoria) and Evoenergy (ACT) operate smaller, urban distribution networks that are predominately underground. Unsurprisingly, predominately rural networks are more reliant on overhead poles than the networks operating in more urban environments.

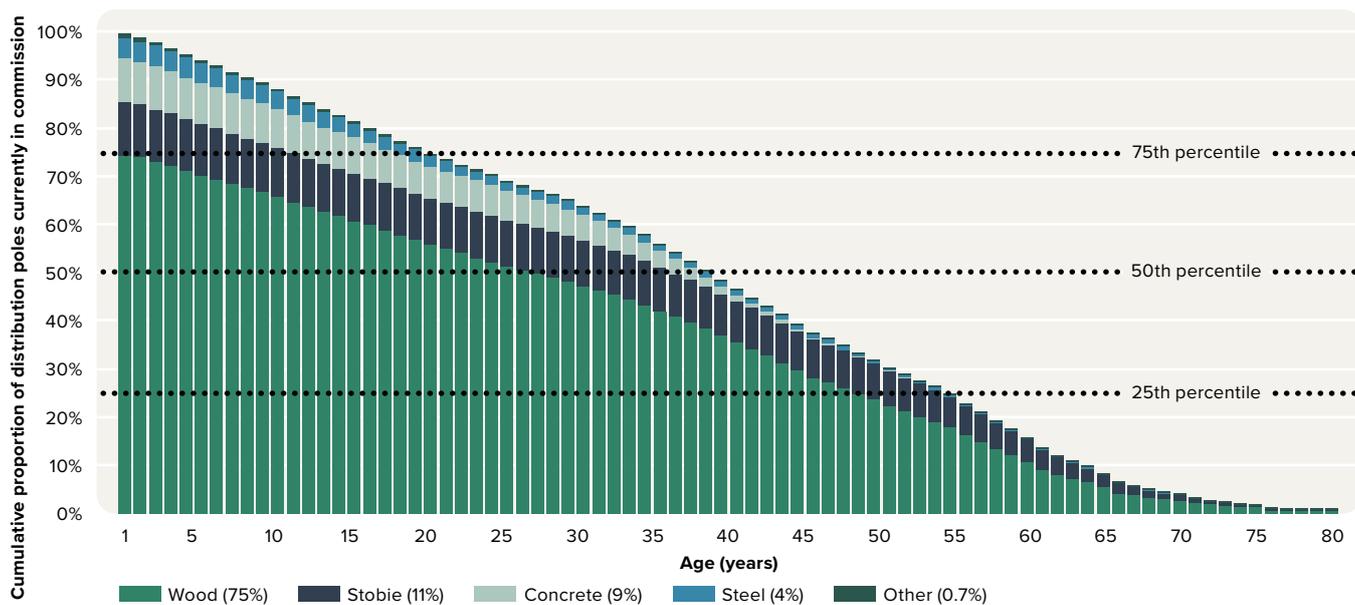
The asset age profiles shown in Figure 3.16 and Figure 3.17 provide an overview of the age of the towers and poles currently in commission across the collective electricity networks. However, we note the asset age, and the types of towers and poles, vary considerably between each network.

**Figure 3.16 Overhead support structures – electricity transmission network towers**



Note: kV: kilovolt.  
Source: Category analysis RIN responses.

**Figure 3.17 Overhead support structures – electricity distribution network poles**



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

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

The increase in demand for the materials needed to construct energy infrastructure has been driven by the rollout of thousands of kilometres of new transmission lines to cater for the transition away from coal-fired energy.<sup>166</sup>

In May 2025, AEMO published its *Draft 2025 Electricity Network Options Report*<sup>167</sup> to gather feedback on the electricity network options to inform the development of the 2026 ISP (section 3.13.6). In the report, AEMO states that transmission costs have risen, particularly for overhead lines, and that the Australian energy sector continues to be subject to ongoing supply chain issues associated with the delivery of materials and equipment, as well as workforce and skills shortages.

## 3.12 Rates of return

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

The AER sets an allowed rate of return based on a benchmark efficient entity, but a network service provider's actual returns can vary from the allowed rate. The difference can be due to several factors, such as the impact of incentive schemes, efficiency improvements, forecasting errors or the network service provider adopting a different debt or tax structure to the benchmark efficient entity. Some differences may be temporary if caused by revenue over- or under-recovery under a revenue cap or the revenue smoothing process. The AER calculates allowed returns each year by multiplying the RAB (section 3.11) by the allowed rate of return.<sup>168</sup>

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

Because electricity networks are capital intensive, returns to investors currently make up around 49% (53% for transmission, 48% for distribution) of a network service provider's total revenue allowance. As such, a small change in the allowed rate of return can have a significant impact on both a network service provider's revenue and customers' electricity bills.

As an estimate, a one percentage point increase in the allowed WACC will increase revenues by around 8%, which would increase average household bills by around 4%.<sup>169</sup> For this reason, before limited merits review was abolished and the binding rate of return instrument was introduced, the allowed rate of return was often the most contentious part of the AER's individual revenue determinations.

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

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166 Herald Sun, [Buying local has limitations, says Transgrid chief](#), 8 May 2024 (purchased article).

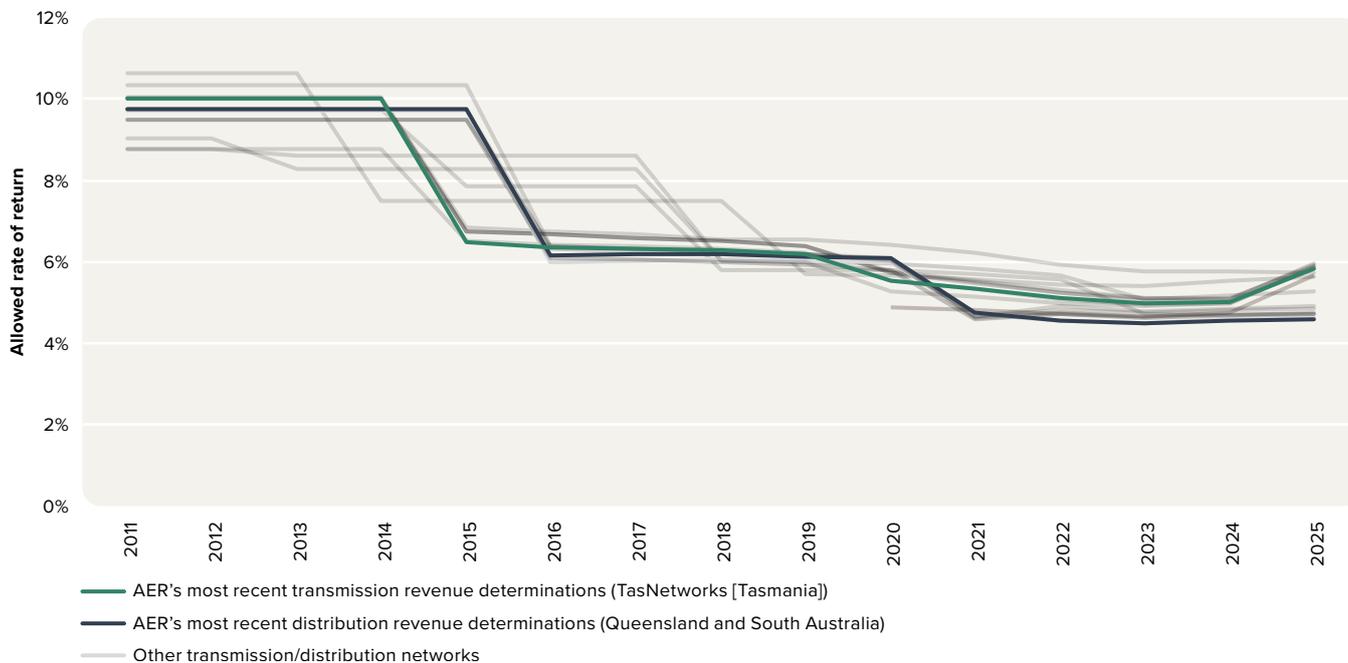
167 AEMO, [Draft 2025 electricity network options report](#), Australian Energy Market Operator, 22 May 2025, accessed 28 May 2025.

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

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

Since 2015 the AER has updated the allowed rate of return annually to reflect changes in debt costs. More stable financial market conditions resulted in allowed rates of return averaging around 6% from 2016. These lower allowed rates became a key driver of lower network revenues and charges over the past few years (Figure 3.18).

**Figure 3.18 Allowed rate of return**



Note: Allowed rate of return is the nominal vanilla weighted average cost of capital (WACC).  
 Source: AER determinations on electricity network revenue proposals; AER determinations following remittals by the Australian Competition Tribunal or full Federal Court.

Recently, a key input into rates of return has increased. The risk-free rate is an important driver of allowed returns on equity and is estimated using required returns on Commonwealth Government Securities (CGSs), also known as Australian Government bonds. Since January 2020, annual yields on 10-year CGSs have ranged from 0.61% (March 2020) to 4.94% (November 2023). Over the 12-month period to 30 June 2025, annual yields on 10-year CGSs averaged around 4.29%.<sup>170</sup> If the risk-free rate continues to increase it will put upward pressure on network revenue over coming years.

In recent years the AER has estimated network service providers' actual returns to provide a comparison against their allowed returns. The outcomes suggest that actual returns often exceed the AER's allowed returns. This is not unexpected given that the premise of a revealed efficient cost framework is to encourage network service providers to become more efficient, allowing for short-term profits to be earned above the allowed rate.<sup>171</sup>

In March 2024, the 2022 Rate of Return Instrument was superseded by 'version 1.2'. This updated version binds all regulatory determinations from 25 February 2023 until the next revision of the Instrument.<sup>172</sup> In March 2025, as a first step toward making the 2026 Rate of Return Instrument, the AER published a paper setting out the high-level review process it will undertake to produce the Instrument.<sup>173</sup>

170 RBA, [Capital Market Yields – Government Bonds – Daily – F2](#), Reserve Bank of Australia, accessed 6 July 2025.  
 171 The AER's [Electricity network performance reports](#) investigate network profitability and provide a more thorough analysis of actual returns than allowed/forecast returns.  
 172 AER, [Rate of Return Instrument 2022](#), Australian Energy Regulator, accessed 13 July 2025.  
 173 AER, [Rate of Return Instrument – 2026 review process paper](#), Australian Energy Regulator, 28 March 2025.

## 3.13 Capital expenditure

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

### 3.13.1 Capital expenditure in 2024

Over the 12-month period to 30 June 2024, network service providers invested \$7.4 billion in capital projects, \$545 million (8%) more than in the previous year and \$455 million (7%) more than was forecast.

Table 3.6 provides a summary of the capital expenditure outlaid in 2024 and how this compared with previous years’ expenditure and forecasts.

**Table 3.6 Capital expenditure in 2024 – key outcomes**

Service type	Capital expenditure (2024)	Capital expenditure (compared with 2023)	Capital expenditure (compared with peak)
Transmission	\$2.0 billion (▼23% than forecast)	▼\$11 million (▼0.5%)	▼\$113 million (▼5%) (2009)
Distribution	\$5.4 billion (▲24% than forecast)	▲\$556 million (▲11%)	▼\$3.0 billion (▼36%) (2012)
Total	\$7.4 billion (▲7% than forecast)	▲\$545 million (▲8%)	▼\$2.9 billion (▼28%) (2012)

Note: All data are adjusted to June 2024 dollars. Excludes AER determinations on transmission interconnectors. Numbers may not sum due to rounding.  
Source: AER modelling; RIN responses.

Forecast capital expenditure increased for Transgrid (NSW) in 2024 primarily due to the forecast costs associated with Project EnergyConnect. Transgrid’s actual capital expenditure from 2022 to 2024 was significantly lower than forecast due in large part to its reprofiling of expenditure on Project EnergyConnect (Figure 3.19).

In January 2025, Transgrid revised the net cost of Project EnergyConnect from \$2.1 billion to \$3.6 billion. It attributed the increase to several ‘unforeseeable factors such as COVID-related global supply chain impacts on key equipment and materials, critical labour shortages, record inflation, the impacts of the war in Ukraine, flooding and the insolvency of [construction group] Clough’.<sup>174</sup>

Investment in the transmission network is forecast to continue over the next few years. Although the estimated cost of actionable ISP projects under the 2024 ISP is around \$27.8 billion<sup>175</sup> (Figure 3.24), most of this estimated cost does not yet fall within the AER’s approved forecast expenditure window. Further, AEMO has indicated that since the publication of its 2024 ISP, costs have risen by 25% to 55% for overhead transmission line projects and 10% to 35% for transmission substation projects.<sup>176</sup>

HumeLink, a proposed 500 kilovolt transmission line that will connect Wagga Wagga, Bannaby and Maragle and expand Transgrid’s transmission network in NSW, was identified as a staged actionable ISP project in AEMO’s 2020<sup>177</sup> and 2022<sup>178</sup> ISPs and was confirmed to be actionable in AEMO’s 2024 ISP.<sup>179</sup>

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

<sup>174</sup> Transgrid, [EnergyConnect update](#), media release, 8 January 2025.

<sup>175</sup> AEMO, [2024 Integrated System Plan](#), Australian Energy Market Operator, June 2024, pp. 61–63.

<sup>176</sup> AEMO, [Draft 2025 electricity network options report](#), Australian Energy Market Operator, 22 May 2025, accessed 28 May 2025.

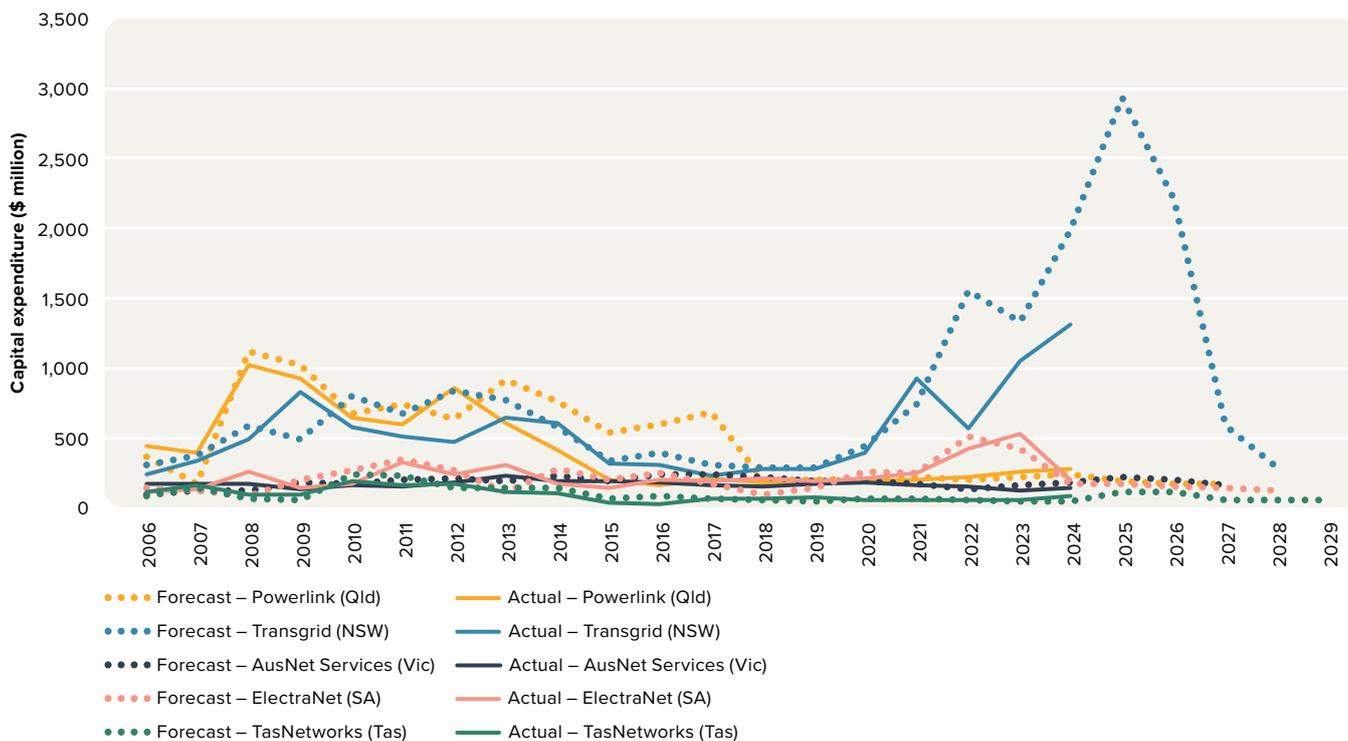
<sup>177</sup> AEMO, [2020 Integrated System Plan](#), Australian Energy Market Operator, July 2020.

<sup>178</sup> AEMO, [2022 Integrated System Plan](#), Australian Energy Market Operator, June 2022.

<sup>179</sup> AER, [Transgrid HumeLink contingent project stage 2](#), Australian Energy Regulator, 2 August 2024.

In August 2024, the AER approved \$4.0 billion (\$2023) in forecast capital expenditure for stage 2 of Transgrid’s HumeLink project. The AER’s role in the process was to assess Transgrid’s contingent project application to determine the incremental revenues that are to be added to its revenue allowance. The AER did not accept Transgrid’s proposed expenditure of \$4.3 billion (\$2023) because it did not consider the proposed amount reflected prudent and efficient capital expenditure required to deliver the project. Subject to a financial investment decision by the proponent, HumeLink is likely to be completed by 2026–27.

**Figure 3.19 Capital expenditure – electricity transmission networks**



Note: All data are adjusted to June 2024 dollars. The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018). Assumptions are set out in the Figure 3.10 notes.

Source: AER modelling; annual reporting RIN responses.

### 3.13.2 Trends in capital expenditure

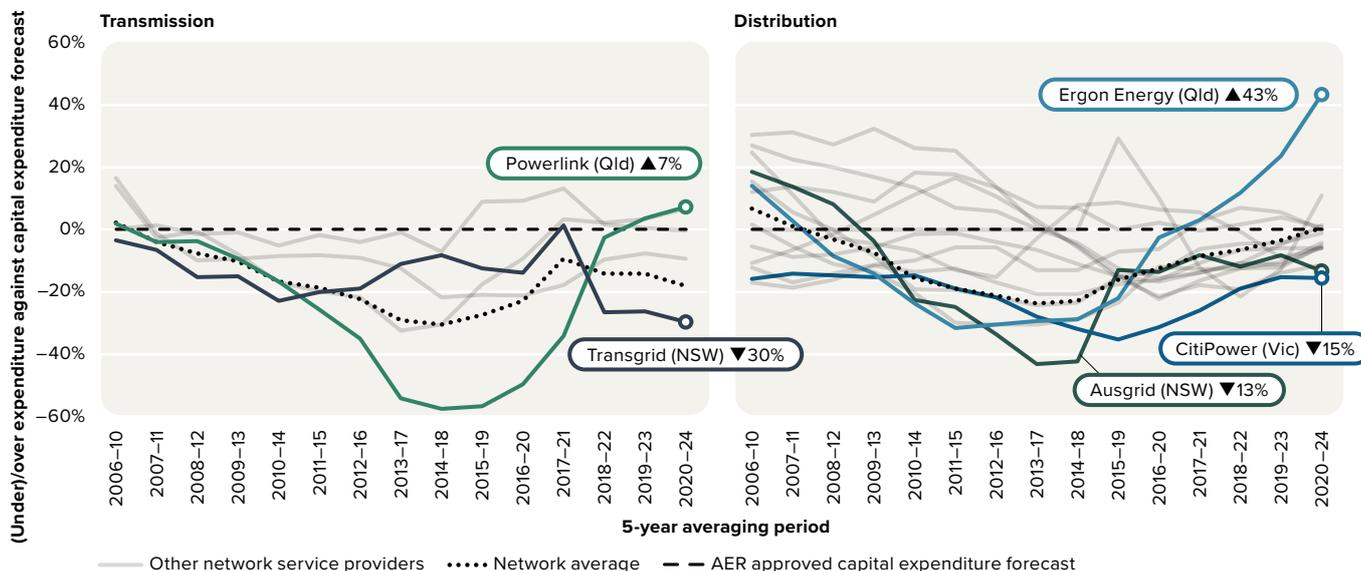
In 2006, governments and the AEMC changed the rules to incentivise greater investment to address concerns that network investment was not keeping pace with projected growth in electricity demand. More stringent reliability standards imposed by the NSW and Queensland governments also contributed to further growth by requiring new investment to meet the stricter targets.

Investment in electricity networks increased by an average of 8% per year in the 6-year period from 2006 before peaking at around \$10.4 billion in 2012 (Figure 3.10 and Figure 3.11).

Over the 4-year period from 2006 to 2009, network service providers invested \$2.8 billion (10%) more on capital projects than was forecast. However, the trend of overspending was soon to be reversed, with network service providers underspending by \$17.5 billion (16%) against forecast over the following 13 years (from 2010 to 2022). Over this time, many investment projects were either postponed or abandoned when it became clear that earlier projections of sustained demand growth would not eventuate. Further, a shift in government policy towards less stringent reliability obligations made some projects redundant, leading to several proposed projects being scaled back or deferred.

The disparity between forecast and actual investment has eased in recent years.<sup>180</sup> The timing of this change in behaviour aligns with the AER’s reforms to protect consumers from funding inefficient network projects (Figure 3.20).

Figure 3.20 Capital expenditure against AER approved forecast



Note: All data are adjusted to June 2024 dollars.  
 Source: AER modelling; annual reporting RIN responses.

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

In the AER’s most recent revenue determinations,<sup>181</sup> the most significant driver of forecast investment expenditure was the replacement of assets that are reaching the end of their life, along with infrastructure that supports the delivery of electricity transmission services.

In 2015 the AER introduced the capital expenditure sharing scheme (CESS), which offers financial incentives for network service providers to avoid undertaking investment above forecast levels (Box 3.3).

180 Transmission network service provider Transgrid’s (NSW) actual capital expenditure in 2022 was significantly lower than forecast due in large part to its reprofiling of expenditure on Project EnergyConnect.

181 In April 2025, the AER finalised revenue determinations for distribution network service providers Energex (Queensland), Ergon Energy (Queensland) and SA Power Networks (South Australia) and the Directlink interconnector. These determinations set target revenue controls through to 30 June 2030.

### Box 3.3 Capital expenditure sharing scheme

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

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

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

Following our 2023 review of incentive schemes,<sup>182</sup> we elected to amend the CESS and implement the Bright-Line Tiered Test to apply:

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

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

To manage this risk, the CESS is balanced by separate incentives that focus on efficient operating expenditure (Box 3.4) and service quality (Box 3.5). This balancing of schemes encourages network service providers to make efficient decisions on their mix of expenditure to provide reliable services in ways that customers value (section 3.16.1).

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

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

In February 2025, we published a consultation paper on proposed amendments to the CESS Guideline. The consultation paper initiated our review of the Guideline to accommodate the AEMC's amended rule on managing ISP project uncertainty through targeted ex-post reviews published in August 2024. This requires us to update our Guideline to enable us to carry out separate targeted ex-post review for ISP projects and non-ISP projects.<sup>183</sup> Our draft amendments to the CESS Guideline were published on 16 May 2025.<sup>184</sup>

182 AER, [Review of incentive schemes for regulated networks](#), Australian Energy Regulator, April 2023, accessed 13 July 2025.

183 AER, [Consultation opens on the Capital Expenditure Incentive Guideline amendments](#), Australian Energy Regulator, 21 February 2025.

184 AER, [Capital Expenditure Guideline Review 2025](#), Australian Energy Regulator, 16 May 2025.

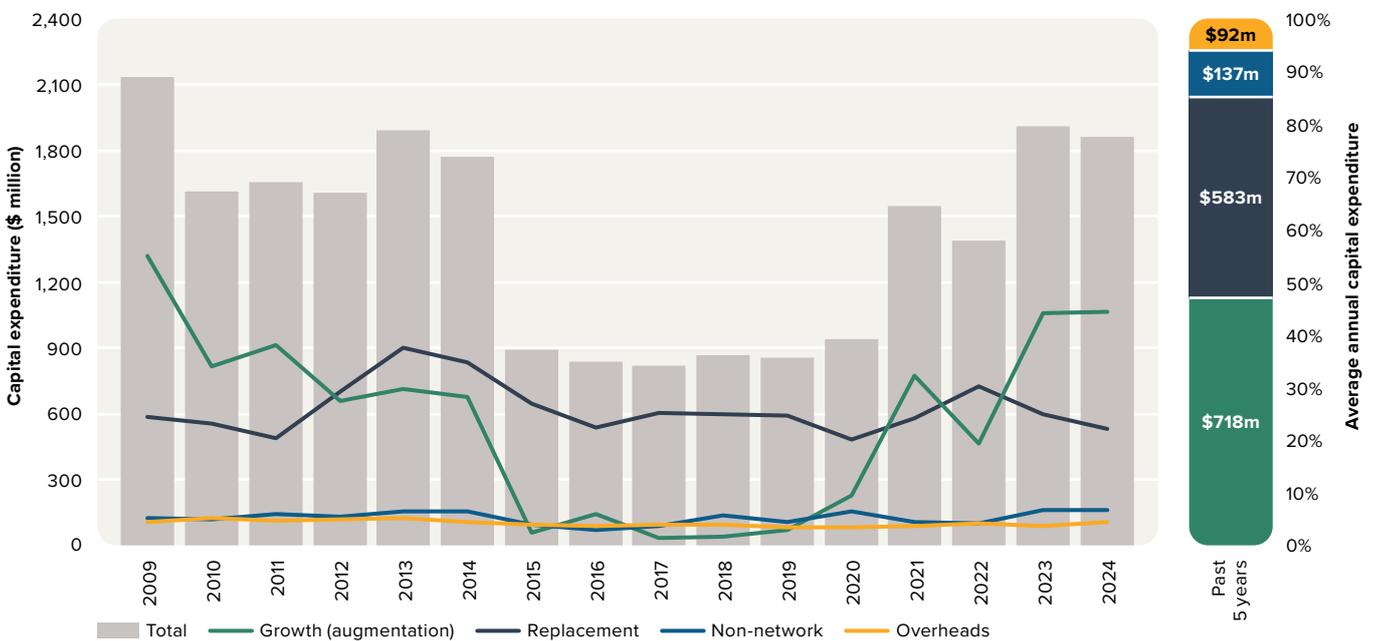
### 3.13.3 Changing composition of investment

Over the 12-month period to 30 June 2024, network service providers invested \$2.8 billion on replacing existing infrastructure on their respective networks (Figure 3.21 and Figure 3.22).

Over the same period, network service providers spent \$1.9 billion on growth-related projects, \$215 million (10%) less than in the previous year but still more than any other year since 2014. The recent increase in growth-related expenditure has been driven by Transgrid’s (NSW) substantial investment in Project EnergyConnect.

Transgrid has also forecast substantial investment in developing HumeLink (section 3.13.1), which, among other roles, aims to connect Snowy 2.0 to the grid by 2026. In May 2024, Snowy Hydro stated that despite ‘challenging’ conditions the project is on schedule and is expected to be operational by December 2028.<sup>185</sup>

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

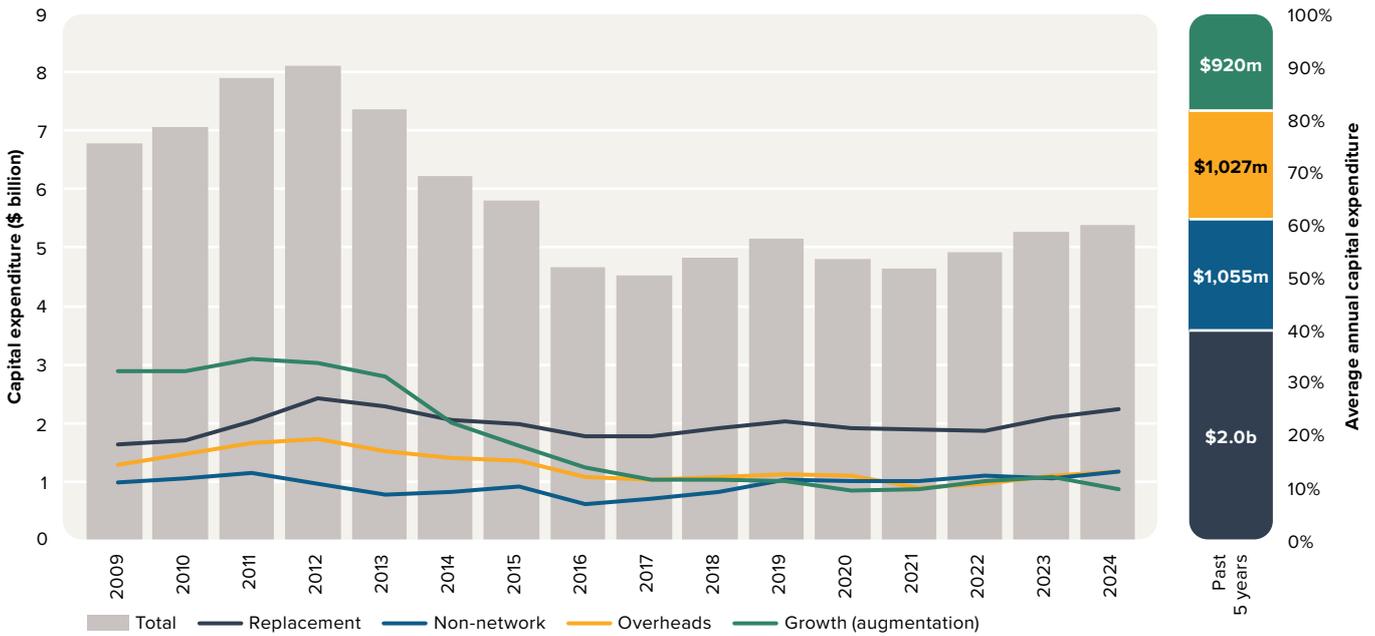


Note: All data are adjusted to June 2024 dollars. The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018). Augmentation of the Victorian transmission network is carried out by AEMO; hence, AusNet Services reports \$0 expenditure for augmentation carried out on the transmission network.

Source: Category analysis RIN responses.

185 ABC News, [Snowy Hydro boss doubles down on project timeline despite slow progress and budget blow-out](#), 9 May 2024, accessed 8 August 2024.

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



Note: All data are adjusted to June 2024 dollars. The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018).

Source: Category analysis RIN responses.

### 3.13.4 Valuing consumer energy resources

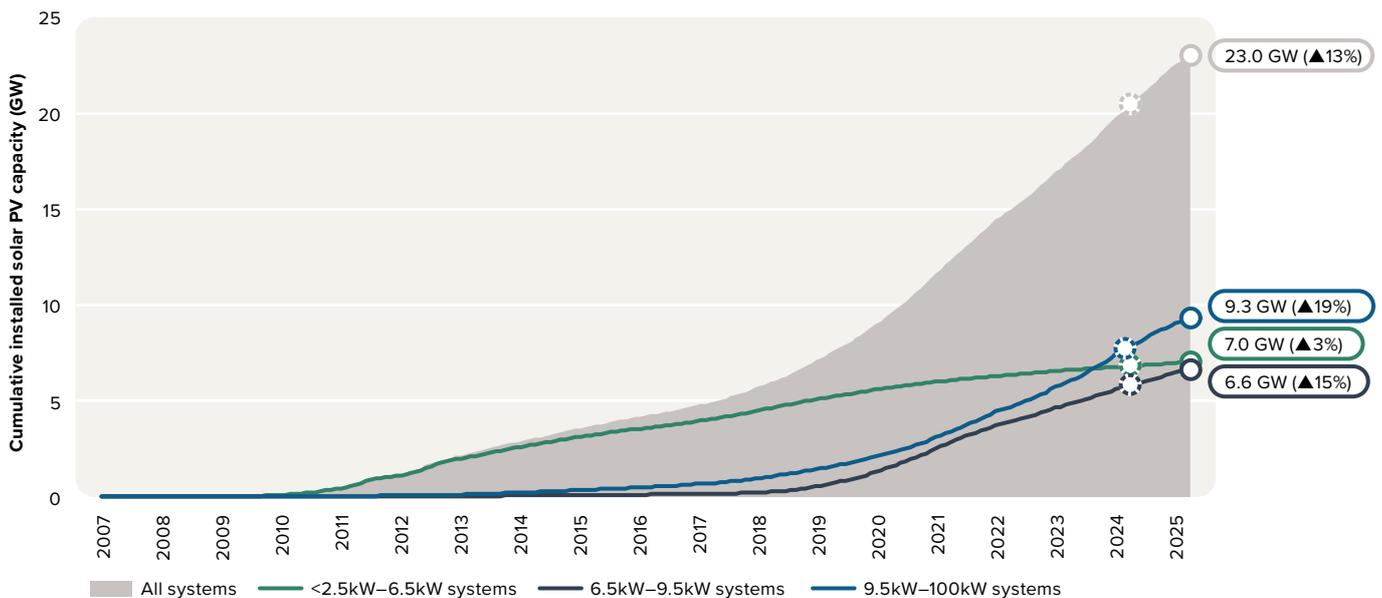
AEMO’s 2024 ISP notes that effective integration of consumer energy resources has the potential to significantly reduce future grid-scale investment needed to support increases in electricity consumption. For example, recent analysis by the Institute for Energy Economics and Financial Analysis indicates that consumer energy resources (across the full range of possible sources) have the potential to deliver \$11 billion in avoided network costs if well integrated.<sup>186</sup>

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

As at 1 March 2025, the total installed capacity of small-scale solar PV systems – systems with a capacity of up to 100 kilowatts measured around 23 gigawatts, a 13% increase from the previous year (Figure 3.23).

186 Australian Government, [National consumer energy resources roadmap – Powering decarbonised homes and communities](#), Department of Climate Change, Energy, the Environment and Water, 19 July 2024, accessed 13 July 2025, p. 9.

Figure 3.23 Cumulative installation of small-scale solar



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

Source: AER analysis of postcode data from the Australian PV Institute, collected on 19 June 2025.

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

In 2020, the AER released a report (by the CSIRO and CutlerMerz) on potential methodologies for determining the value of consumer energy resources.<sup>187</sup> 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.<sup>188</sup>

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

187 CSIRO and CutlerMerz, [Value of distributed energy resources: methodology study – final report](#), October 2020. The labels ‘consumer energy resources’ and ‘distributed energy resources’ are used interchangeably.

188 AER, [Draft DER integration expenditure guidance note](#), Australian Energy Regulator, 6 July 2021.

An environment that consists of increasing levels of consumer energy resources means that distribution network service providers need to alter aspects of their operation – facilitating electricity flows in multiple directions and enabling efficient access to markets for consumer energy resources so that they can provide the greatest benefits to the system as a whole.<sup>189</sup> In April 2023, the AER released its consumer energy resources strategy, which communicates the regulators goal of enabling consumers to own and use energy resources to consume, store and trade energy as they choose in support of the broader long-term interest of all energy consumers.<sup>190</sup>

AEMO, in its 2024 ISP, stated that ‘renewable energy connected by transmission and distribution, firmed with storage and backed up by gas-powered generation is the lowest-cost way to supply electricity to homes and businesses as Australia transitions to a net zero economy’.<sup>191</sup> New transmission networks and more modern distribution networks are needed to connect these diverse low-cost resources to homes, businesses and industry. Transmission networks will continue to transport electricity to where it is needed, when it is needed, and improve the power system’s resilience. Modernised distribution networks then facilitate the flow of electricity in multiple directions, delivering electricity to homes and businesses and taking back any surplus from consumers’ own assets, thereby enabling efficient access to markets for consumer energy resources and providing benefits to the system as a whole.

This is a monumental change from the traditional role of distribution networks, wherein the assets have been traditionally used to distribute energy received from transmission networks to end users. The transition to a modernised distribution network is already underway. In 2024, more than 14 million megawatt hours (10%)<sup>192</sup> of the total energy delivered came from export customers with smart meters.<sup>193</sup>

### 3.13.5 Regulatory tests for efficient investment

The AER assesses network service providers’ efficient investment requirements every 5 years as part of the regulatory process, but it does not approve individual projects. Instead, it administers a cost-benefit test called the regulatory investment test (RIT). The National Electricity Rules require a network service provider to apply the RIT for transmission projects that have an estimated capital cost of greater than \$8 million and for distribution projects that have an estimated capital cost of greater than \$7 million.<sup>194</sup>

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

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

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189 AEMC, [Electricity network economic regulatory framework 2020 review](#), Australian Energy Market Commission, 1 October 2020.

190 AER, [Consumer energy resources strategy](#), Australian Energy Regulator, 3 April 2023.

191 AEMO, [2024 Integrated System Plan](#), Australian Energy Market Operator, June 2024, p. 55.

192 Data only captures energy exporting customers with smart meters. As 25% of exporting customers do not have smart meters, both the ‘14 million megawatt hours’ and ‘10%’ of the total energy delivered understate the true volume and proportion of energy exported by network customers.

193 AER, [Insights into Australia’s growing two-way energy system – Export services network performance report 2024](#), Australian Energy Regulator, 18 December 2024.

194 AER, [2024 cost thresholds review for the regulatory investment test – Final determination](#), Australian Energy Regulator, 12 November 2024.

In 2020, the AER published guidelines that prescribe the cost-benefit analysis framework, consultation processes and forecasting practices that AEMO must apply when developing its ISP. AEMO's 2022 ISP brought into effect the AER's guidelines to make the ISP actionable.<sup>195</sup> The guidelines include a cost benefit analysis guideline,<sup>196</sup> a forecasting best practice guideline and updates to the regulatory investment test for transmission (RIT-T) instrument<sup>197</sup> and application guidelines.<sup>198</sup> The guidelines are part of broader reforms that were led by the Energy Security Board,<sup>199</sup> with changes made to the National Electricity Rules to streamline the transmission planning process while retaining rigorous cost-benefit analyses.

In November 2024, the AER amended the cost benefit analysis guidelines, the RIT instruments and accompanying application guidelines to account for recent changes to the National Electricity Rules and changes raised in the AER's *Directions paper – Social licence for electricity transmission projects*. The amendments provide additional guidance on:

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

In January 2024, the AER published a report detailing the outcomes of its transparency review of AEMO's Draft 2024 ISP.<sup>200</sup> The AER assessed the adequacy of AEMO's explanation of how key inputs and assumptions had been derived and how those inputs and assumptions contributed to the outcomes in the Draft 2024 ISP. The review was not intended to assess the merits of AEMO decisions; rather, it is to form an opinion on the adequacy of AEMO's explanations.

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

### 3.13.6 AEMO's Integrated System Plan

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

The 2024 ISP appeals for urgent investment in generation, storage and transmission to deliver secure, reliable and affordable electricity through the energy transition. The ISP's optimal development path sets out the needed generation, firming and transmission to transition to net zero by 2050 through current policy settings. The optimal development path includes 'actionable projects', which should be delivered urgently, and 'future ISP projects', which may require transmission network service providers to undertake preparatory activities. It also states that distribution networks will play a major role in the transition by hosting consumer energy resources and some utility-scale renewable and storage projects – facilitating coordinated two-way flow of electricity between grids.<sup>201</sup>

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195 AER, [Final decision – guidelines to make the Integrated System Plan actionable](#), Australian Energy Regulator, August 2020.

196 AER, [Cost benefit analysis guidelines](#), Australian Energy Regulator, August 2020.

197 AER, [Application guidelines – regulatory investment test for transmission](#), Australian Energy Regulator, August 2020.

198 AER, [Guidelines to make the integrated system plan actionable](#), Australian Energy Regulator, August 2020, accessed 29 March 2022.

199 The Energy Security Board has since been dissolved. Since 1 July 2023, the Energy Advisory Panel co-ordinates market body advice to governments on security, reliability and affordability of Australia's east coast energy system.

200 AER, [Transparency review of AEMO draft 2024 Integrated Systems Plan](#), Australian Energy Regulator, accessed 9 August 2024.

201 AEMO, [2024 Integrated System Plan](#), Australian Energy Market Operator, June 2024.

Significant investment in the transmission network is forecast over the next decade. The modelled cost of actionable ISP projects under the 2024 ISP is around \$27.8 billion<sup>202</sup> (Figure 3.24). However, AEMO has since indicated that transmission costs have risen by as much as 55% for overhead transmission line projects and 35% for transmission substation projects compared with the modelled costs used in the 2024 ISP.<sup>203</sup> Transmission network service providers and other jurisdictional planning bodies have advised AEMO that the recently observed cost increases in tendering processes and project delivery are primarily driven by:

- sustained supply chain pressures on materials, equipment and workforce
- market competition driven by a high number of concurrent projects under development in the NEM
- project complexity, including an increased number of projects planned for remote areas
- social licence and additional community and landholder engagement along proposed transmission line routes
- additional contracting costs to account for risk allocation in engineering, procurement and construction contracts in response to pressures in the current market.

When preparing the 2026 ISP, AEMO will revisit transmission network projects previously identified as needing to proceed, with the exception of projects that have advanced to anticipated or committed status.

In December 2024, in response to a request from the Minister for Climate Change and Energy,<sup>204</sup> the AEMC made rule changes requiring AEMO to consider how distribution network investments impact the development of consumer energy resources and other distributed resources, as well as the impact that both have on the optimal development path identified in the ISP.<sup>205</sup>

The ISP will now include greater consideration of the broad range of demand-side factors that influence the identification of the optimal development pathway, including the uptake and orchestration of consumer energy resources and distributed resources, demand flexibility, electrification and energy efficiency. The ISP will also provide more insight into AEMO's assumptions about distribution network development opportunities, where these are consistent with the efficient development of the power system.

## The ISP will now include greater consideration of the broad range of demand-side factors that influence the identification of the optimal development pathway, including the uptake and orchestration of consumer energy resources and distributed resources, demand flexibility, electrification and energy efficiency.

The AER provides oversight of the ISP by ensuring that AEMO's processes are robust, credible and transparent. The requirements and considerations that are expected of AEMO's forecasting processes are specified in the AER's forecasting best practice guidelines<sup>206</sup> and cost benefit analysis guidelines.<sup>207</sup> The guidelines seek to provide AEMO with flexibility in how it identifies the optimal pathway for the NEM when developing the ISP based on a quantitative assessment of the costs and benefits of various options across a range of scenarios. The guidelines also apply to RIT-Ts for actionable ISP projects.<sup>208</sup>

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202 2023 dollars (\$2023).

203 AEMO, [Draft 2025 electricity network options report](#), Australian Energy Market Operator, 22 May 2025, accessed 28 May 2025.

204 Australian Government, [Rule change request](#), Department of Climate Change, Energy, the Environment and Water, May 2024, accessed 2 June 2025.

205 AEMC, [Improving consideration of demand-side factors in the ISP](#), Australian Energy Market Commission, 19 December 2024, accessed 2 June 2025.

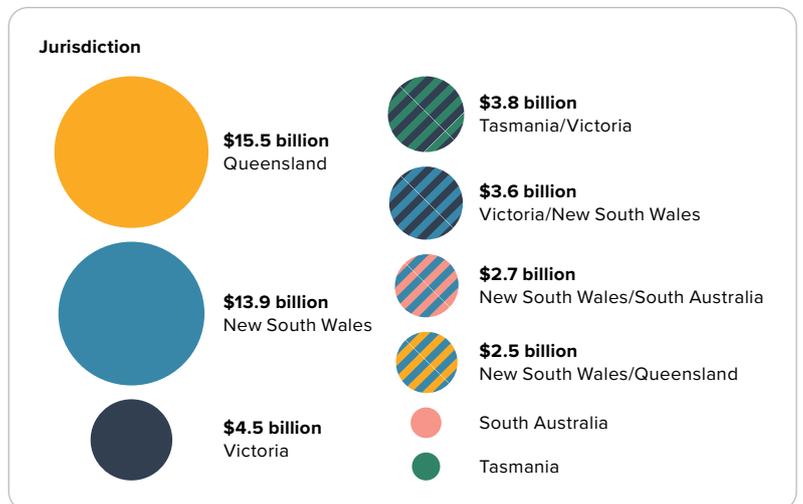
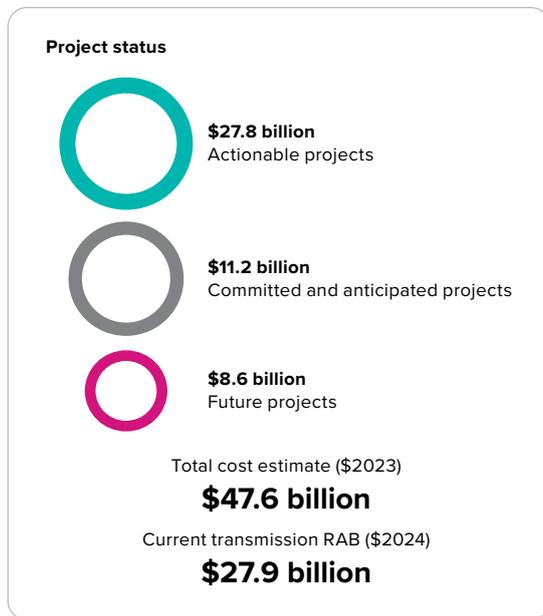
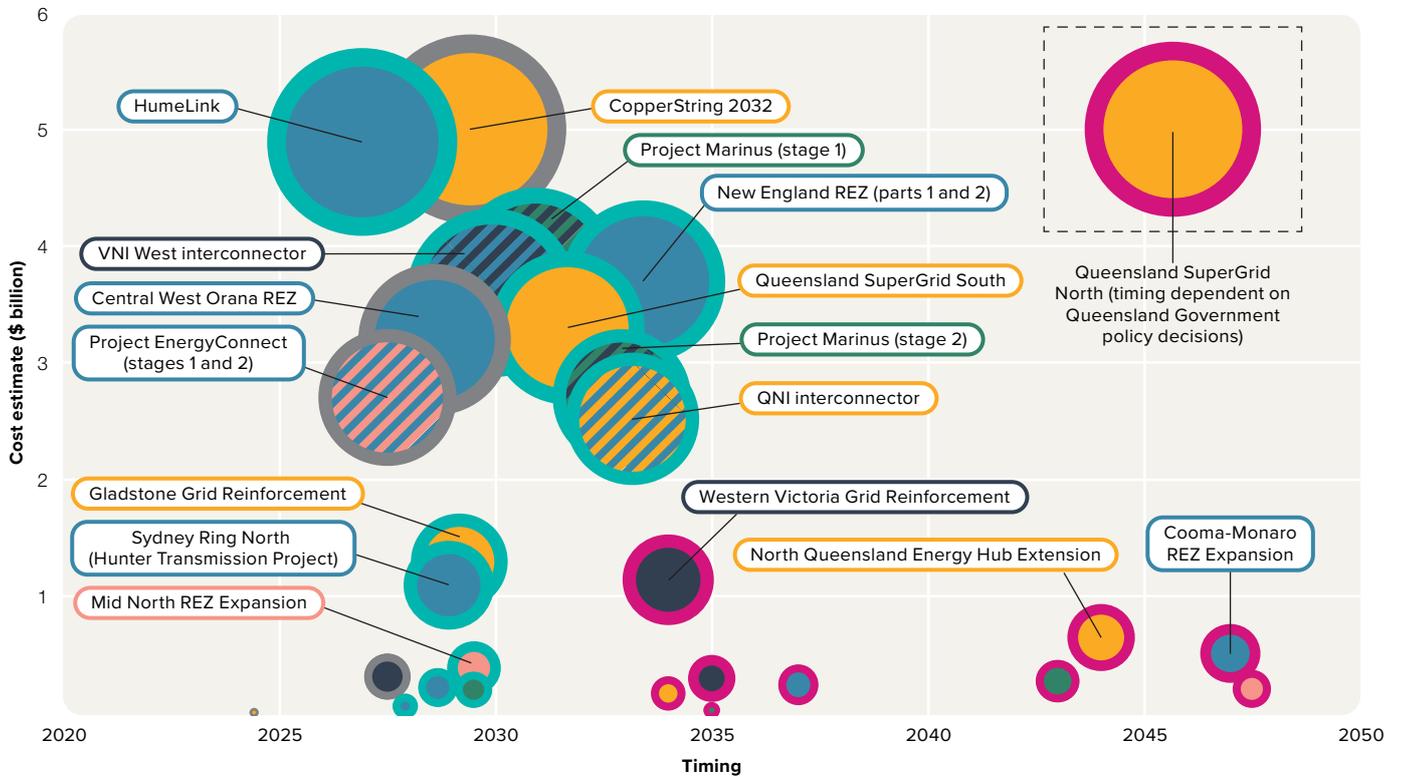
206 AER, [Forecasting best practice guidelines](#), Australian Energy Regulator, August 2020.

207 AER, [Cost benefit analysis guidelines](#), Australian Energy Regulator, August 2020.

208 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.

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

Figure 3.24 AEMO’s 2024 Integrated System Plan



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

Note: All data are adjusted to 2023 dollars unless otherwise stated. The ISP cost estimates in Figure 3.24 were published almost 12 months prior to AEMO’s *Draft 2025 electricity network options report (May 2025)* wherein the costs are estimated to be approximately 25% to 55% higher for overhead transmission line projects and 10% to 35% higher for transmission substation projects (section 3.11.2).

Source: AER analysis; AEMO Integrated System Plan, June 2024.

### 3.13.7 Regulatory investment tests – recent activity

As at August 2025, several RIT-T processes were ongoing across the transmission networks. This section highlights major developments among actionable ISP projects.

#### Victoria to NSW Interconnector West (VNI West)

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

In February 2023, the Victorian Minister for Energy published a Ministerial Order under the *National Electricity (Victoria) Act 2005* to confer functions on AVP, which included assessing alternative additional options to the preferred options (as identified through the RIT-T) that would expedite the development and delivery of VNI West or otherwise better meet a crucial national electricity system need in Victoria.<sup>209</sup>

In May 2023, AVP and Transgrid published the project assessment conclusions report for VNI West. The project assessment conclusions report is a major milestone in the RIT-T process, representing the final stage in the RIT-T consultation process.<sup>210</sup>

In May 2024, the AER published its determination to approve Transgrid's contingent project application for capital expenditure to undertake early works related to the NSW portion of the project.<sup>211</sup> Early works will enable Transgrid to refine the project scope, identify and manage project risks, and progress pre-construction activities and community engagement.

#### Marinus Link

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

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

In June 2023, the AER published its decision to commence a revenue determination process for Marinus Link. This decision allowed Marinus Link to progress the project and submit a regulatory proposal for costs associated with stage 1 early works and construction costs. The AER approved the proposed costs for early works in December 2023.<sup>212</sup> The costs for early works and the construction of stage 1 will not be recovered from consumers until the Marinus Link Interconnector is commissioned.<sup>213</sup>

Marinus Link Pty Ltd has shortlisted 2 engineering and construction consortiums – TasVic Greenlink and Empower – to complete the balance of works, covering onshore civil and installation works. This tender is the final major tender for stage 1 of Marinus Link.<sup>214</sup>

In May 2025, the AER published its initial draft decision on Marinus Link's Stage 1, Part B (construction costs) revenue proposal.<sup>215</sup> The AER is taking a two-step approach in making its determination for this proposal, to support consumer engagement and the timely delivery of Project Marinus. This includes an initial draft decision limited to 2 market tested work programs, with the remaining cost elements assessed in a supplementary draft decision.

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209 Victorian Government, [VNI West and Western Renewables Link Ministerial Order](#), Victorian Government Gazette, 20 February 2023.

210 AER, [AEMO Victoria Planning and Transgrid: VNI West PACR](#), Australian Energy Regulator, 21 June 2023.

211 AER, [Transgrid VNI West stage 1 early works contingent project](#), Australian Energy Regulator, 6 May 2024.

212 AER, [AER Determination – Marinus Link Stage 1 Part A \(Early works\)](#), Australian Energy Regulator, 19 December 2023.

213 AER, [Marinus Link – Intending transmission network application](#), Australian Energy Regulator, 1 June 2023.

214 Marinus Link Pty Ltd, [Victorian Community Update – Major construction contractors shortlisted](#), 1 April 2025.

215 AER, [Marinus Link – Intending transmission network application – Draft decision](#), Australian Energy Regulator, 16 May 2025.

The AER's initial draft decision is to accept Marinus Link Pty Ltd.'s forecast capital expenditure of \$1.6 billion (\$2023) for the 2 market tested work programs. This comprises converter station design and equipment supply of \$737 million (\$2023) and the high voltage direct current cable system of \$895 million (\$2023). The 2 market tested work programs account for 46% of the total proposed capital expenditure for the construction of the first Marinus Link cable. The AER expects to make its final decision on Stage 1, Part B (constructions cost) in December 2025.

### Actionable ISP projects proceeding under RIT-T framework

There were 4 actionable projects – Sydney Ring South, Waddamana to Palmerston transfer capability upgrade, Mid North South Australia REZ Expansion and QNI Connect – identified in the 2024 ISP. AEMO has stated that these projects will proceed under the RIT-T framework.<sup>216</sup> The RIT-T proponent responsible for each of these actionable projects will be required to initiate its RIT-T process by publishing a project assessment draft report by the relevant date specified in the 2024 ISP.

### Actionable ISP projects not proceeding under RIT-T framework

The 2024 ISP identified 5 actionable projects that AEMO has stated will progress under NSW or Queensland frameworks.<sup>217</sup> These projects will not complete a RIT-T but will instead be subject to the requirements of their respective frameworks.

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

The other 3 actionable projects identified in the 2024 ISP that are outside of the RIT-T framework are Gladstone Grid Reinforcement, Queensland SuperGrid South and HunterCentral Coast REZ Network Infrastructure Project.

The Energy Corporation of NSW (EnergyCo) and Transgrid (NSW) have signed a commitment deed confirming Transgrid as the preferred network service provider to deliver the Hunter Transmission Project (Sydney Ring North).<sup>218</sup> Separately, EnergyCo has appointed Ausgrid (NSW) as the preferred distribution network service provider for the Hunter-Central Coast REZ Network Infrastructure Project.<sup>219</sup>

In March 2025, EnergyCo commenced the competitive tender process for parties interested in becoming the network operator for the New England REZ Network Infrastructure Project. This tender process will run through 2025 with a formal request for proposal in late 2025.<sup>220</sup>

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<sup>216</sup> AEMO, [2024 Integrated System Plan](#), Australian Energy Market Operator, June 2024, p. 14.

<sup>217</sup> *Electricity Infrastructure ACT 2020* (NSW) or *Energy (Renewable Transformation and Jobs) Act 2024* (Queensland).

<sup>218</sup> NSW Government, [NSW Government partners with Transgrid to advance the Hunter Transmission Project](#), 29 January 2025, accessed 30 April 2025.

<sup>219</sup> NSW Government, [Hunter-Central Coast Renewable Energy Zones power ahead](#), media release, 31 January 2025, accessed 17 June 2025.

<sup>220</sup> NSW Government, [EnergyCo seeks partner to deliver and operate New England Renewable Energy Zone](#), 17 March 2025, accessed 30 April 2025.

Table 3.7 shows the 12 network projects classified as actionable in AEMO’s 2024 ISP.

**Table 3.7 Network projects in the 2024 ISP optimal development path**

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

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

Source: AEMO Integrated System Plan, June 2024, p. 14.

The Australian Government has collaborated with states and territories to create the National Renewable Energy Priority List, which will provide coordinated support for regulatory planning and environmental approval processes for identified priority renewable energy projects across Australia. The Priority List adopts a ‘faster to yes, faster to no’ approach. Identified projects will receive additional support and facilitation through regulatory and environmental processes. They will still have the same scrutiny applied as any other project and continue to be required to meet all statutory requirements.<sup>221</sup>

The ISP-listed Powerlink-led CopperString 2032 project is also on the Priority List. In April 2025, the Queensland Government revealed the full cost of the project – an 840 kilometre new double-circuit line to connect Queensland’s North-West Minerals Province to the NEM near Townsville – to be almost \$14 billion, nearly \$12 billion more than originally announced.<sup>222 223</sup> The Queensland Government stated it will leverage the infrastructure expertise of Queensland Investment Corporation – an Australian investment manager and sovereign investor – to deliver CopperString 2032, the biggest energy project in North Queensland’s history.

CopperString 2032 will be built and owned by the Queensland Government, under the Queensland Energy and Jobs Plan commitment to public ownership of the state’s transmission assets. It was not actioned through the ISP framework.<sup>224</sup>

221 Australian Government, [National Renewable Energy Priority List](#), Department of Climate Change, Energy, the Environment and Water, accessed 9 May 2025.

222 Queensland Government, [Crisafulli Government saves CopperString](#), media release, 8 April 2025.

223 ABC News, [Queensland Premier Anastacia Palaszczuk announces more support for outback mega-power line](#), 7 October 2020, accessed 8 April 2025.

224 AEMO, [2024 Integrated System Plan](#), Australian Energy Market Operator, June 2024, p. 60.

### 3.13.8 Annual planning reports

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

The AER publishes guidelines and templates to ensure the annual planning reports provide practical and consistent information to stakeholders.<sup>225</sup> This results in network service providers providing data on network constraints to assist third parties in offering non-network solutions and to inform connection decisions at the transmission level.<sup>226</sup>

The NSW Government is conducting a review into transmission planning arrangements in the state. The Transmission Planning Review, which was a recommendation of the *Electricity Supply and Reliability Check Up* report, will consider transmission planning arrangements in NSW to reduce duplication and ensure coordination between relevant entities, and make recommendations for reform. The review is set to conclude by September 2025.<sup>227</sup>

On 22 January 2025, Energy Consumers Australia (ECA) submitted a request to the AEMC to amend the National Electricity Rules to improve the existing distribution system planning processes.<sup>228</sup> ECA noted that the existing distribution annual planning reports are not required to include an analysis of consumer energy resources hosting capacity, and that the analysis undertaken every 5 years through the existing expenditure proposal process is insufficient to ensure distribution network service providers can account for large shifts in the uptake of consumer energy resources. ECA has requested a rule change, which will require distribution network service providers to make appropriate use of the data they have, develop a roadmap towards collecting more data at greater granularity, and increase the comprehensiveness and forward-looking timeframe of their planning. Additionally, the rule change will require distribution network service providers to make public the data, methodology, calculations and outputs (such as consumer energy resources hosting capacity maps) that are central to their plans.

ECA considers the impact of the proposed changes will help achieve the National Electricity Objective and result in a host of benefits for consumers and distribution network service providers. These benefits include generating more value from the existing network infrastructure and already available data, particularly from smart meters, proactive network planning to right-size investment in consumer energy resources, improved network utilisation, improved oversight on network planning and costs, and better guiding of investment in consumer energy resources and distributed energy resources. Most importantly, better distribution system planning should reduce network costs, thereby reducing consumer electricity bills.

### 3.13.9 Demand management

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

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

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225 AER, [Final decision: Distribution annual planning report template v1.0](#), Australian Energy Regulator, June 2017; AER, [Final decision: Transmission annual planning report guidelines](#), Australian Energy Regulator, December 2018.

226 An example of the available constraint data can be found in the datasheets under Ausgrid's [Distribution and transmission annual planning report](#), accessed 11 July 2024.

227 NSW Government, [NSW Transmission Planning Review 2025](#), 14 February 2025, accessed 21 February 2025.

228 AEMC, [Integrated distribution system planning](#), Australian Energy Market Commission, 22 January 2025, accessed 20 March 2025.

To receive an incentive payment, a network service provider must first submit a claim for its eligible projects<sup>229</sup> to the AER and provide information on how it is using demand management to deliver value to its customers. The AER uses the information provided to determine if the network service provider is eligible to receive an incentive payment.

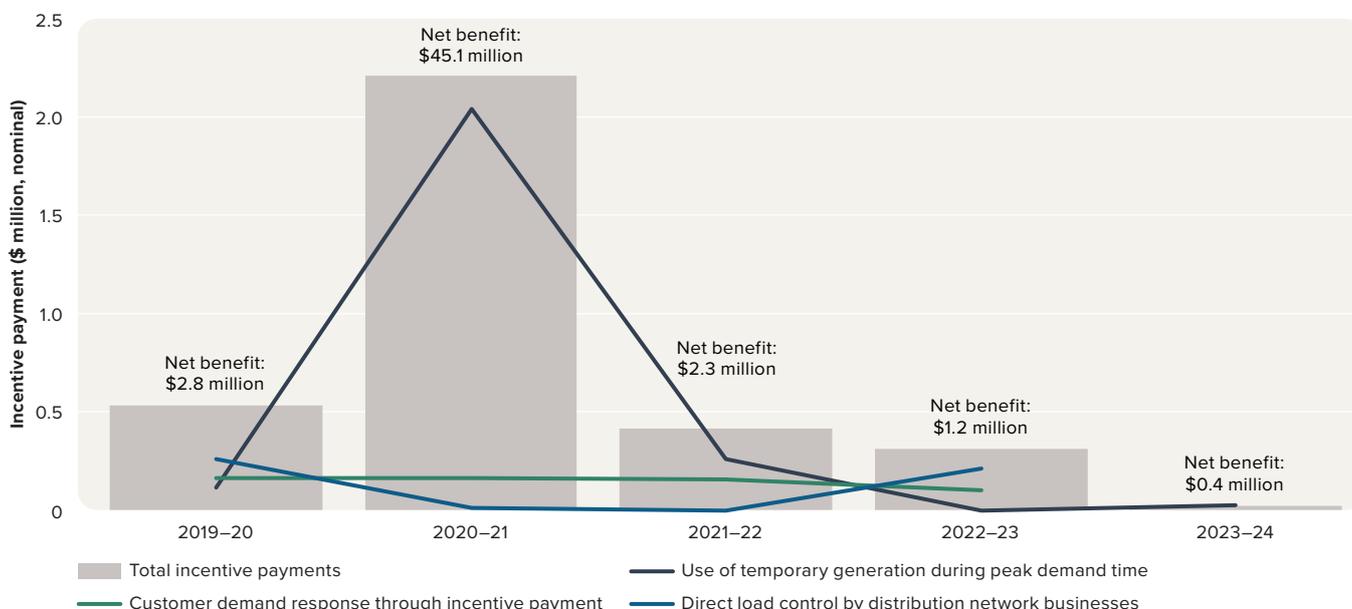
## The DMIS has delivered an estimated \$52 million in benefits to consumers (at a cost of \$3.5 million) by encouraging distribution network service providers to defer replacement or augmentation capital expenditure in favour of pursuing demand management activities.

Complementing this scheme, the AER operates a demand management innovation allowance mechanism (DMIAM).<sup>230 231</sup> The DMIAM provides funding for network service providers to undertake research and development works to help them develop innovative ways to deliver ongoing reductions in demand or peak demand for network services. An objective of the innovation allowance is to enhance industry knowledge of practical approaches to demand management. Network service providers publish annual activity reports setting out the details of projects they have undertaken.

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

To date, the DMIS has delivered an estimated \$52 million in benefits to consumers (at a cost of \$3.5 million) by encouraging distribution network service providers to defer replacement or augmentation capital expenditure in favour of pursuing demand management activities (Figure 3.25).<sup>232</sup>

**Figure 3.25 Funding of demand management innovations – electricity distribution networks**



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

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

230 AER, [Demand management incentive scheme and innovation allowance mechanism](#), Australian Energy Regulator, 14 December 2017.

231 AER, [Demand management innovation allowance mechanism \(transmission\)](#), Australian Energy Regulator, 27 May 2021.

232 For further information on the demand management incentive scheme see the reports published by the AER. AER, [Demand management incentive scheme \(DMIS\)](#), Australian Energy Regulator.

## 3.14 Operating expenditure

Network service providers incur operating and maintenance costs that account for around 33% of their annual revenue (Figure 3.5). As part of its 5-year revenue determination processes, the AER sets an allowance for each network service provider to recover the efficient operating costs of supplying electricity to customers. The allowance accounts for forecasts of electricity demand, productivity improvements, changes in input prices and changes in the regulatory environment. The AER reviews the operating expenditure forecasts in each network service provider's regulatory proposal. If the AER is not satisfied the network service provider's proposal is in the long-term interests of consumers, it will request further information or a clearer business case. Subsequently, the AER may amend the proposed operating expenditure to ensure the approved cost forecasts are prudent and efficient.

Alongside this assessment, the AER's efficiency benefit sharing scheme (EBSS) encourages network service providers to explore opportunities to lower their operating costs (Box 3.4).

### Box 3.4 Efficiency benefit sharing scheme

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

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

The EBSS provides network service providers with the same reward for underspending (or penalty for overspending) in each year of the regulatory period. Its incentives are designed to align with those in the capital expenditure sharing scheme (CESS) (Box 3.3). The EBSS incentives also balance against those of the service target performance incentive scheme (STPIS) (Box 3.5) to encourage network service providers to make efficient holistic choices between capital and operating expenditure in meeting reliability and other targets.

When we released our expenditure incentives guideline in 2013,<sup>233</sup> we estimated around 70% of the benefits from the EBSS would go to customers. Since then, changes in rate of return parameters have increased the share of benefits going to customers. We estimate that customers are now receiving around 80% of the benefits.

Following our 2023 review of incentive schemes,<sup>234</sup> we decided to retain the EBSS in its current format. Our analysis showed that the EBSS has contributed to improved efficiency and lower prices, and that the scheme is working as intended. The benefits to consumers are up to 4 times the benefits to network service providers.

<sup>233</sup> AER, [Expenditure incentives guideline](#), Australian Energy Regulator, accessed 30 May 2024.

<sup>234</sup> AER, [Review of incentive schemes for regulated networks](#), Australian Energy Regulator, accessed 5 May 2024.

### 3.14.1 Operating expenditure in 2024

Over the 12-month period to 30 June 2024, network service providers outlaid \$4.6 billion on operating expenses, \$307 million (7%) more than in the previous year and \$75 million (1.7%) more than was forecast.

Table 3.8 summarises the operating expenditure outlaid in 2024 and how this compared with previous years' expenditure and forecasts.

**Table 3.8 Operating expenditure in 2024 – key outcomes**

Service type	Operating expenditure (2024)	Operating expenditure (compared with 2023)	Operating expenditure (compared with peak)
Transmission	\$746 million (▼1.2% than forecast)	▲\$41 million (▲6%)	▼\$14 million (▼1.9%) (2016)
Distribution	\$3.8 billion (▲2.3% than forecast)	▲\$266 million (▲7%)	▼\$528 million (▼12%) (2012)
Total	\$4.6 billion (▲1.7% than forecast)	▲\$307 million (▲7%)	▼\$479 million (▼9%) (2012)

Note: All data are adjusted to June 2024 dollars. Excludes AER determinations on transmission interconnectors. Numbers may not sum due to rounding.  
Source: AER modelling; RIN responses.

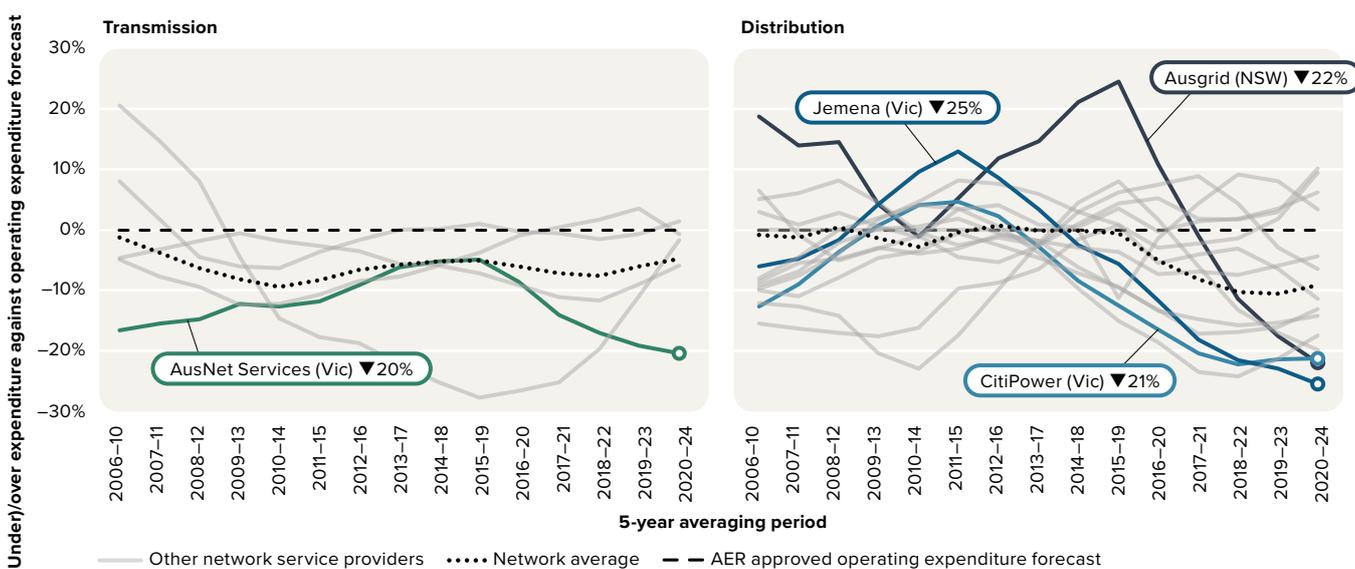
### 3.14.2 Trends in operating expenditure

The total aggregated operating expenditure outlaid by electricity network service providers increased by an average of 5% per year in the 6-year period from 2006, before peaking at \$5.0 billion in 2012.

Several network service providers implemented efficiencies in managing their operating expenditure from 2015, when the AER widened its use of benchmarking to identify operating inefficiencies in some networks. Other factors, such as reporting obligations, pricing reforms and greater use of non-network options (section 3.8), may have also impacted costs.

Unlike capital expenditure, a network service provider's operating expenditure – such as inspection and maintenance, vegetation management, emergency response, payroll, insurance and any funds allocated for research and development – is largely recurrent and predictable. As such, actual operating expenditure against forecast has consistently been more stable than it has been for capital expenditure (Figure 3.26).

**Figure 3.26 Operating expenditure against AER approved forecast**



Note: All data are adjusted to June 2024 dollars.  
Source: AER modelling; annual reporting RIN responses.

## 3.15 Productivity

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

Although benchmarking provides a useful tool for comparing network performance, some productivity drivers – for example, adhering to reliability standards set by government bodies – are beyond the control of network service providers. More generally, benchmarking may not fully account for differences in operating environment, such as legislative or regulatory obligations, climate and geography.<sup>235</sup>

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

### 3.15.1 Productivity trends

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

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

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

#### Transmission network productivity

Since 2006 there has been convergence in the level of productivity of all transmission network service providers, with the exception of TasNetworks (Tasmania). Since 2013, TasNetworks' productivity has improved significantly, which likely reflects efficiencies gained through the merger of Transend's electricity transmission network with Aurora's electricity distribution network in July 2014.<sup>236</sup> In contrast, over the same period the level of productivity of Powerlink (Queensland), Transgrid (NSW) and ElectraNet (South Australia) has deteriorated, largely due to decreases in capital multilateral partial factor productivity – output per unit of capital stock – reflecting increases in capital inputs.

Productivity for the electricity transmission industry decreased by 1.0% in 2023<sup>237</sup>, primarily due to an increase in operating expenditure<sup>238</sup> driven by higher maintenance costs across the sector. Growth in the capital inputs<sup>239</sup> for transformers and overhead lines also had a negative impact on productivity. However, these negative impacts were partly offset by increases in circuit length and improved reliability<sup>240</sup> compared with the previous year.

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235 AER, [Annual benchmarking report, electricity distribution network service providers](#), Australian Energy Regulator, November 2023, pp. 66–74.

236 ENA, [TasNetworks](#), Energy Networks Australia, accessed 11 February 2025.

237 As measured by total factor productivity (TFP).

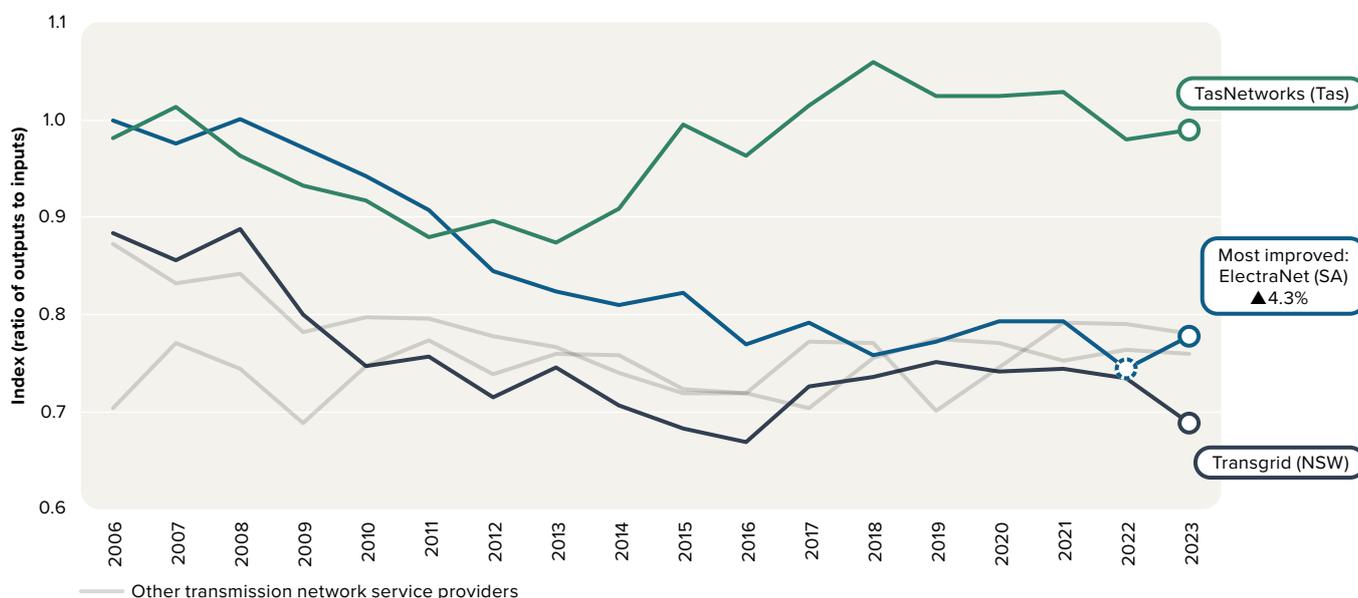
238 The operating expenditure input reflects the costs associated with the labour, materials and services that are purchased each year.

239 The capital inputs (transformers, overhead lines and underground cables) measure the physical quantity of the assets.

240 Reliability (energy not supplied) measures the extent to which network services providers can maintain a continuous supply of electricity.

ElectraNet’s (South Australia) productivity increased in 2023, primarily driven by increases in circuit length and reliability. The significant positive contribution of circuit length was due to the high output weight attributed to circuit length<sup>241</sup> and the installation of new circuit lines as part of ElectraNet’s Eyre Peninsula Link project. ElectraNet also reported 78% less ‘energy not supplied’ than in the previous year (Figure 3.27).

Figure 3.27 Productivity – electricity transmission networks



Note: Index of multilateral total factor productivity relative to the 2006 performance of ElectraNet (South Australia). The ‘most improved’ label refers to the relative change in multilateral total factor productivity over the previous year. The transmission index shown in Figure 3.27 cannot be directly compared with the distribution index shown in Figure 3.28. The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018).

Source: AER annual benchmarking report for electricity transmission networks, 2024.

### Distribution network productivity

Productivity for the electricity distribution industry<sup>242</sup> decreased by 2.5% in 2023. This marked the largest year-on-year decrease since 2012 and was primarily due to an increase in operating expenditure<sup>243</sup> driven by higher maintenance costs across the sector. Intensified vegetation management arising from bushfire risk related regulatory obligations, higher emergency response costs due to storm and flood events, and the clearing of maintenance backlogs after the COVID-19 pandemic were among the many drivers listed by distribution network service providers.

In 2023, 3 of the 13 distribution network service providers in the NEM improved their productivity over the previous year. Evoenergy (ACT) – the most improved network service provider – increased its productivity by 10%, driven primarily by a reduction in its operating expenditure input.<sup>244</sup>

Since 2006, there has been some convergence in the productivity levels of distribution network service providers. SA Power Networks (South Australia), CitiPower (Victoria) and Powercor (Victoria) have consistently been the most productive<sup>245</sup> distribution network service providers in the NEM. However, both SA Power Networks and Powercor recorded large decreases in productivity in 2023 (Figure 3.28).

241 Quantonomics, [Economic Benchmarking Results for the Australian Energy Regulator’s 2024 TNSP Benchmarking Report](#), 26 July 2024, p. 63.

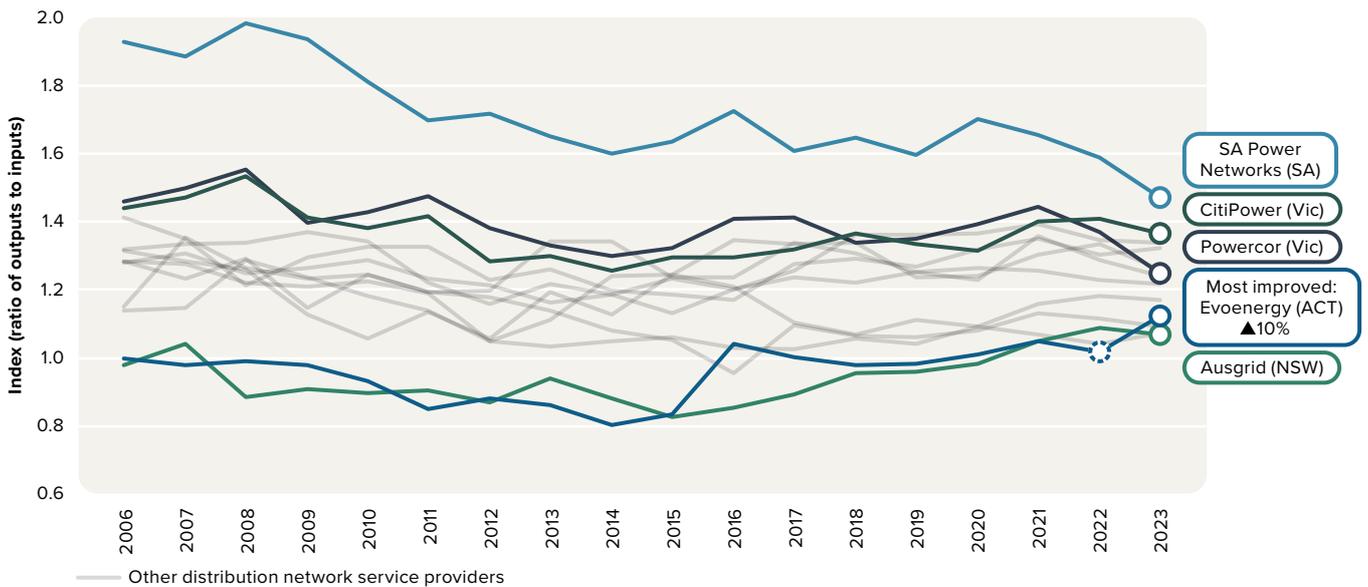
242 As measured by total factor productivity (TFP).

243 The operating expenditure input reflects the costs associated with the labour, materials and services that are purchased each year.

244 In contrast, the operating expenditure input increased by 7.0% across the distribution industry.

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

Figure 3.28 Productivity – electricity distribution networks



Note: Index of multilateral total factor productivity relative to the 2006 performance of Evoenergy (ACT). The ‘most improved’ label refers to the relative change in multilateral total factor productivity over the previous year. The distribution index shown in Figure 3.28 cannot be directly compared with the transmission index shown in Figure 3.27. 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, 2024.

The time series shown in Figure 3.27 and Figure 3.28 demonstrates the variability in year-on-year productivity for individual network service providers. This variability emphasises the importance of considering single-year changes in productivity, be they negative or positive, in the context of longer-term trends.

### 3.15.2 Network utilisation

Our measure of network utilisation gauges how well each distribution network service provider’s assets have been used to meet the needs of consumers at times of maximum demand. The proportion of network capacity being used to serve customers will fluctuate as networks’ capacity and/or demand for electricity fluctuates.

Distribution networks are put under greater pressure at times of maximum demand, which generally occurs when most consumers are at home using electricity-intensive appliances, such as air conditioning, ovens and televisions.

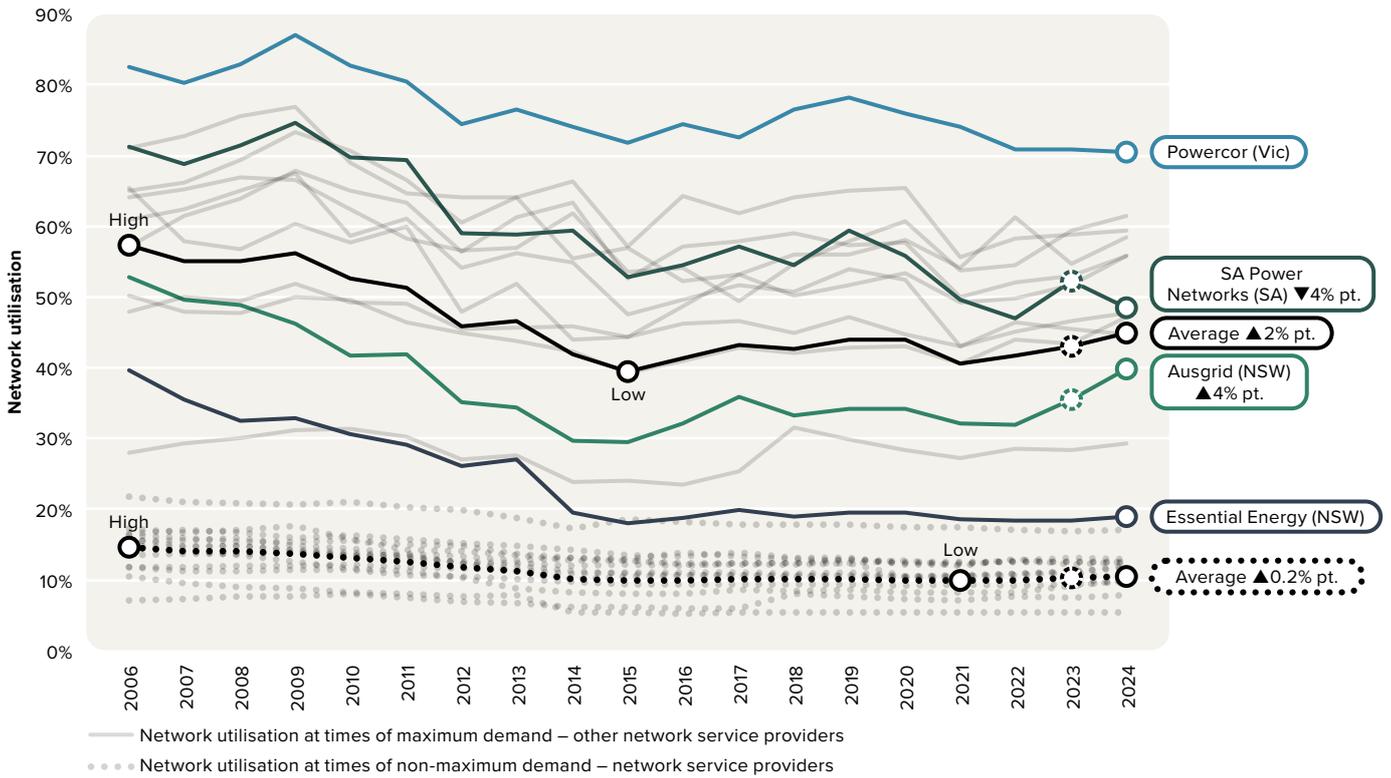
In the 12-month period to 30 June 2024:

- a 4% increase in maximum demand, coupled with a slight decrease in network capacity, saw the overall network utilisation increase to 45%, the highest since 2013 (47%)
- privately owned distribution network service providers utilised 56% of network capacity
- fully or partly government-owned networks utilised 41% of network capacity<sup>246 247</sup>
- 4 of the 5 most highly utilised distribution networks are privately owned (Figure 3.29).

246 Section 3.4 provides information on network ownership.

247 TasNetworks (Tasmania) has been excluded from the network utilisation metrics/commentary. The maximum demand input (at the zone substation level) does not capture all of TasNetworks’ customers as not all customers on its network are connected through a zone substation (for example, there are no zone substations in the north or north-west of Tasmania).

Figure 3.29 Network utilisation – electricity distribution networks



Note: Network utilisation at times of maximum demand is calculated using non-coincident, summated raw system annual maximum demand divided by total zone substation transformer capacity. Network utilisation at times of non-maximum demand is the average energy delivered over the year less the energy delivered during the maximum 30-minute interval divided by total zone substation transformer capacity. TasNetworks (Tasmania) has been excluded because maximum demand input (at the zone substation level) does not capture all of TasNetworks' customers. The changes identified in the labels refer to the relative change in utilisation in percentage points over the previous year.

Source: Economic benchmarking RIN responses.

The average level of network utilisation at times of maximum demand across all distribution networks decreased from a high of 57% in 2006 to a low of 39% in 2015.<sup>248</sup> The decrease in network utilisation followed significant investment by many network service providers during a time of declining maximum demand.

The level of network utilisation outside of the 30-minute maximum demand window<sup>249</sup> is considerably lower than it is during the peak period. This is not unexpected, given the 'non-maximum demand window' captures network demand over 99.99% of the year,<sup>250</sup> including times when demand is consistently low, such as overnight or on weekends.

Network utilisation is an informative, yet incomplete, measure of a network's ability to respond to increases in maximum demand on the network. A lower utilisation rate (that is, higher spare capacity) indicates a network can service large increases in maximum demand and may also mean customers are paying for network assets they rarely use. Measuring network utilisation is further complicated by the different de-rating factors that networks may apply to their reported substation transformer capacities.

248 Data prior to 2006 is not available.

249 The 30-minute maximum demand window refers to the 30-minute period when the highest amount of electricity was consumed on any given day within the period.

250 Or the entire year less the demand reported in the highest 30-minute interval in the year (i.e. 0.01% of the year).

The method of measuring network utilisation shown in Figure 3.29 does not account for two-way network flows and may not show localised constraints from exports from solar PV systems. These constraints are increasing as more consumers continue to install solar PV systems, leading to curtailment of export capabilities.<sup>251</sup>

Electricity pricing during periods of maximum demand operate on a 'time-of-use' tariff structure, meaning consumers are billed more for accessing electricity from the networks during peak times. Network service providers charge these higher rates to account for the greater strain placed on their networks. To change the behaviour of network customers, network service providers offer lower rates during quieter 'off-peak' periods to incentivise consumers to shift their energy use away from busier 'peak' periods.

Consumers can benefit in several ways by shifting their usage from 'peak' to 'off-peak' times. The most obvious and immediate benefit for consumers who can shift their usage is the lowering of electricity bills by taking advantage of the lower 'off-peak' rates. Further to this, spreading demand more evenly across the day reduces strain on the network, which is not only beneficial for grid stability but can also reduce or delay the need for costly network augmentation, thereby reducing future network expenditure being passed on to consumers.

If the volume of energy delivered increases at a faster rate than the total cost of delivering it, the average cost per unit of energy falls, thereby lowering distribution charges per unit for customers.

The AER continues to encourage network service providers to, where possible, increase the rates of network utilisation by utilising existing capacity before investing in new assets. Opportunities to increase electricity network utilisation at times of both 'maximum' and 'non-maximum' demand may also be found through electrification of vehicles and buildings, load shifting and generation management.

In its 2024 ISP, AEMO forecasts households to draw about as much electricity from the grid in 2050 as they do now.

'Their electric vehicles and appliances will drive up underlying consumption and be offset by their investments in rooftop solar and energy efficiency. Individual households will differ in how they rely on the grid. Many will continue to be without rooftop solar and draw electricity from the grid, while those with solar may export excess energy during the day and import from the grid overnight.'<sup>252</sup>

In August 2023, Energy Consumers Australia (ECA) wrote that numerous factors indicate that electricity demand is likely to increase over the coming years. In February 2024, the University of Technology Sydney's Institute for Sustainable Futures secured a grant from ECA to undertake a research project aimed at revolutionising network utilisation metrics. The core focus of the project is to enhance network productivity to reduce the overall cost of energy, especially as customers increasingly adopt solar and move towards electrifying their homes and vehicles.<sup>253</sup>

Given the current utilisation rates, distribution networks may be well placed to accommodate increases in demand without the need for major investment. Responding to increasing demand through actions like demand response, as opposed to additional network investment, will see distribution charges to customers decrease.<sup>254</sup>

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251 Curtailment can take many forms, such as static limits (setting a fixed maximum limit on the amount of electricity that can be exported from a solar PV system); voltage rise (networks indirectly limiting exports by not better managing voltages on their network and the inverter trips itself off or down); or flexible export limits (networks actively managing and occasionally limiting exports).

252 AEMO, [2024 Integrated System Plan](#), Australian Energy Market Operator, June 2024, p. 26.

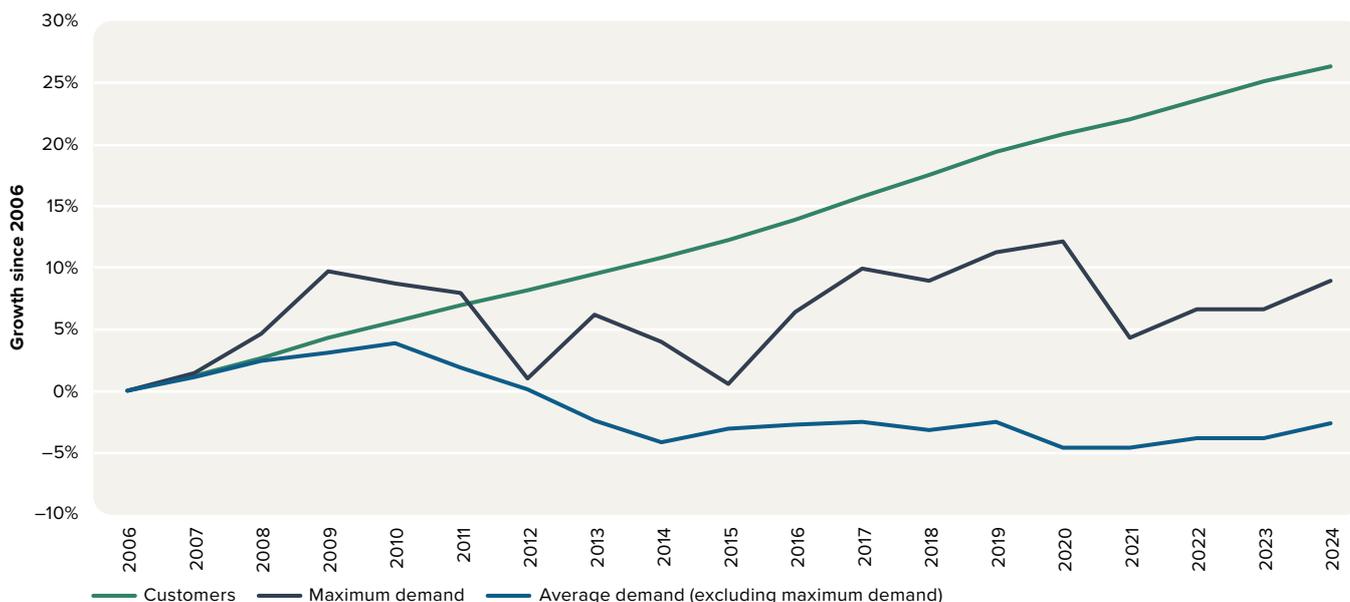
253 University of Technology Sydney, [Empowering tomorrow's energy by redefining network utilisation](#), 8 February 2024, accessed 13 July 2025.

254 Energy Consumers Australia, [The bECAuse Blog](#), 2 August 2023, accessed 13 July 2025.

Capital expenditure is largely driven by the need to meet the maximum level of demand on the network. Average demand has declined since 2006 (driven in part by improved energy efficiency and increased self-consumption of solar PV), whereas maximum demand has become more variable. While maximum demand has always varied with the weather, the increased use of air conditioners and solar PV has exacerbated this effect.

As network demand becomes ‘peakier’, assets installed to meet maximum demand – which occurs 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 decreases utilisation. The number of customers connected to the distribution network has steadily increased by around 1.5% per year since 2006 and has outpaced growth in both maximum and average ‘non-maximum’ demand (Figure 3.30).

**Figure 3.30 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).

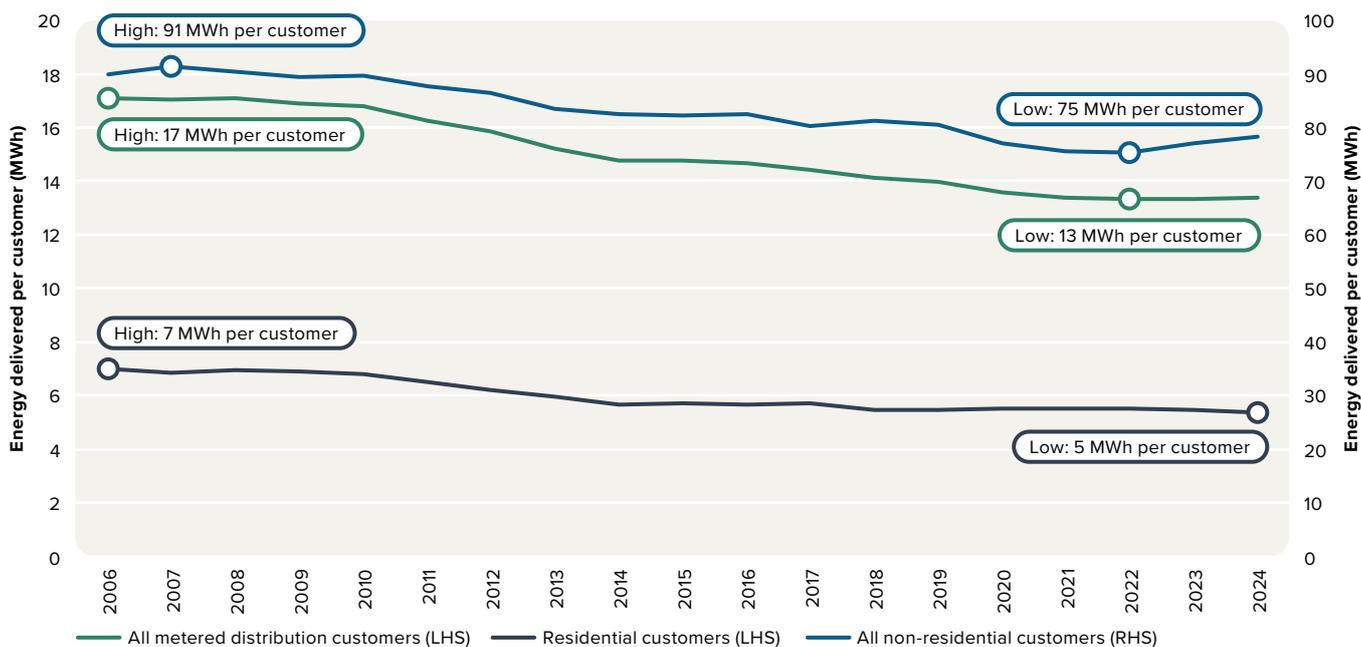
Source: Economic benchmarking RIN responses.

In 2024, the average residential customer<sup>255</sup> consumed around 5 megawatt hours (MWh) of electricity from the grid, 23% less than in 2006. Over the same period the average non-residential customer – which includes low voltage, high voltage and ‘other’ customers – decreased their annual usage from the grid by around 13%.

Non-residential ‘per customer’ grid usage in 2024 increased slightly, driven by a 1.8% decrease in the number of non-residential customers not on demand tariffs, which was only partially offset by a 0.1% decrease in the amount of energy consumed by the remaining customers in that category (Figure 3.31).

255 A customer who purchases energy principally for personal, household or domestic use at premises.

Figure 3.31 Average grid usage per customer – electricity distribution networks



Note: MWh: megawatt hours. 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, the term ‘reliability’ refers to the continuity of electricity supply to customers.<sup>256</sup>

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). Load shedding is the managed reduction of electricity supply to selected areas during extreme events to protect the electricity network from damage and more widespread consumer outages. Used as a last resort, load shedding assists in balancing supply and demand to maintain power system security.<sup>257</sup>

AEMO identifies the amount and duration of electricity shortfalls, but it does not decide which areas have their power turned off. The transmission and distribution network service providers determine how manual load shedding is done at a local level to meet the shortfall. Where load shedding is required for longer periods – such as more than 2 hours – distribution network service providers generally seek to spread the disruption across their network on a rotational basis to minimise the impact to the community, particularly health facilities, emergency services and public transport.<sup>258</sup>

256 The continuity of electricity supply from customers that export energy into the grid (for example, energy generated from rooftop solar PV) is also an element of service performance for networks. Reforms to treat export services as distribution services have been completed. See AEMC, Rule determination: [Access, pricing and incentive arrangements for distributed energy resources](#), Australian Energy Market Commission, 12 August 2021.

257 AEMO, [Fact sheet: Load Shedding](#), Australian Energy Market Operator, 28 November 2023, accessed 16 May 2025.

258 AEMO, [Fact sheet: Load Shedding](#), Australian Energy Market Operator, 28 November 2023, accessed 16 May 2025.

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 (such as possums or birds). High demand during extreme weather can also overload parts of a distribution network. Transmission network issues rarely cause consumers to lose power, but the impact when they do is often widespread. For example:

- in September 2016, South Australia's catastrophic network failures caused a state-wide blackout<sup>259</sup>
- in February 2024, a significant thunderstorm crossed Victoria causing 6 high voltage transmission towers to collapse, resulting in 2,210 megawatts of generation to be disconnected and 90,000 customers having their supply switched off (load shedding).<sup>260</sup>

Electricity outages cause financial loss for consumers, such as lost productivity and business revenues. Consumers also experience less tangible losses such as reduced convenience, comfort, safety and amenity.

Residential and business consumers expect 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 in their electricity bills. Therefore, there is a trade-off between electricity reliability and affordability. Reliability standards and incentive schemes need to strike the right balance by targeting levels of reliability that customers are willing to pay for.

To help achieve this, state and territory governments set reliability standards for electricity networks that seek to efficiently balance the costs and benefits of a reliable power supply. Although approaches to setting standards have varied across jurisdictions, governments have now moved to a more consistent national approach to reliability standards.<sup>261</sup> This approach factors in the value that consumers place on having a reliable power supply.

### 3.16.1 Valuing network reliability

Understanding the value that consumers place on reliability is important when conducting cost benefit analyses for proposed network expenditure, setting reliability standards or determining 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.

In 2019, the AER developed the values of customer reliability (VCR) methodology for standard outages (up to 12 hours), following extensive consultation and quality assurance. In December 2024, the AER updated the VCR following an extensive review of the 2019 VCR methodology. Throughout the course of the review the AER engaged with market bodies, governments, network service providers, customer and industry representatives, and customers themselves.<sup>262</sup>

The AER reviews its VCR methodology and updates the values at least once every 5 years. The published VCR is adjusted on an annual basis between reviews. The values have a wide application, including as an input for:

- undertaking cost-benefit assessments, such as those applied in regulatory tests (section 3.13.5) that assess network investment proposals
- assessing bonuses and penalties in the service target performance incentive schemes (Box 3.5)
- setting transmission and distribution reliability standards and targets
- informing market settings, such as wholesale price caps.

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259 AER, [Investigation report into South Australia's 2016 state-wide blackout](#), Australian Energy Regulator, accessed 13 July 2025.

260 Engage Victoria, [Final report – Network outage review 2024](#), Department of Energy, Environment and Climate Action, September 2024, accessed 13 July 2025.

261 For example, under clause 3.9.3D of the National Electricity Rules, AEMO provides a reliability framework that network service providers are required to operate within. See AEMO, [Reliability Standard Implementation Guidelines](#), Australian Energy Market Operator, 24 April 2023.

262 AER, [Values of Customer Reliability 2024 – Final report](#), Australian Energy Regulator, 30 August 2024.

### 3.16.2 Valuing network resilience

In September 2024, the AER published its final decision on its review of the value of network resilience (VNR) for outages lasting longer than 12 hours (i.e. 'prolonged' outages). The VNR will help inform network service providers and stakeholders about making appropriate investments to enhance network resilience against extreme weather events, considering both the ability to withstand and recover from such events. The AER's VNR review was conducted simultaneously to the VCR review and provides an estimate of the value customers place on network resilience during prolonged outages.<sup>263</sup>

In May 2025, the AEMC made a rule change to help make the electricity grid more resilient to extreme weather events.<sup>264</sup> The AEMC noted that storms, flooding and bushfires are becoming more frequent and intense, adding further strain to the electricity distribution network, leaving customers exposed to power outages.

Distribution network resilience will now be explicitly recognised in the National Electricity Rules, establishing a formal framework that includes:

- new resilience expenditure factors that distribution network service providers and the AER must consider when developing and assessing expenditure proposals
- a requirement for the AER to develop, publish and maintain formal network resilience guidelines
- new annual planning and reporting requirements (section 3.13.8) to improve the transparency and accountability of distribution network service providers' performance, and outcomes for consumers, in severe weather events.

The new framework encourages distribution network service providers to plan for extreme weather and invest in measures to reduce the risk of power outages, while encouraging prioritisation of the needs of vulnerable consumers and those most at risk from power outages.

Investments could include adaptation measures such as strengthening poles and wires in high-risk communities, relocating infrastructure in flood prone areas or increasing the number of mobile generators and substations that can keep the lights on when the power supply is disrupted. Distribution network service providers can also propose resilience spending on programs to manage bushfire and flood risks.

Victorian distribution network service providers will be able to factor resilience expenditure into their revised regulatory proposals from 2 October 2025. The AER must consider these new factors in its final distribution determinations for 2026–31. Transitional rules will require:

- the AER to develop and publish formal network resilience guidelines by 1 December 2026
- distribution network service providers to comply with new annual planning and reporting requirements in their annual planning reports from 2028.

The rule is part of a broader program of work aiming to reduce the impacts of climate change on the electricity grid.

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<sup>263</sup> AER, [Value of network resilience 2024](#), Australian Energy Regulator, 30 September 2024.

<sup>264</sup> AEMC, [Including distribution network resilience in the National Electricity Rules](#), Australian Energy Market Commission, 8 May 2025.

### 3.16.3 Transmission network reliability

Transmission networks are engineered and operated to be extremely reliable because a single interruption can lead to high impacts or widespread power outages. To minimise the risk of outages occurring, transmission networks are engineered with capacity to act as a buffer against credible unplanned interruptions.

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

Network congestion may require AEMO to change the generator dispatch order. A low-cost generator may be constrained from running to avoid overloading an affected transmission line and a higher cost generator may be dispatched instead, raising electricity prices. At times, congestion can cause perverse trade flows, such as a lower priced NEM region importing electricity from a region with much higher prices.

Congestion on the transmission network caused significant market disruption in 2006 when rising electricity demand placed strain on the networks. But increased network investment from 2006 to 2014 – including upgrades to congested lines – eliminated much of the problem. A decline in energy demand reinforced the trend and for several years when network congestion affected less than 10% of NEM spot prices. But ultimately, consumers have paid for the substantial costs of network investment.

Not all congestion is inefficient and augmenting transmission networks to reduce congestion is an expensive solution. Eliminating congestion is efficient only to the extent that the market benefits outweigh the costs of new investment.

Network service providers can help minimise congestion costs by scheduling planned outages and maintenance to avoid peak periods. The AER incentivises service providers to reduce the market impact of congestion under the service target performance incentive scheme (STPIS) (Box 3.5).<sup>265</sup>

### 3.16.4 Distribution network reliability

For distribution networks, the reliability of supply – that is, how effectively the network delivers power to its customers – is the focus of network performance. Around 95% of the interruptions to supply experienced by electricity customers are due to issues in the local distribution network.<sup>266</sup> The capital-intensive nature of electricity networks makes it prohibitively expensive to invest in sufficient capacity to avoid all interruptions.

Planned interruptions – when a network service provider needs to disconnect supply to undertake maintenance or construction works – can be scheduled for minimal impact and the service provider must provide timely notice to customers of its intention to interrupt supply. Unplanned interruptions to supply – such as those resulting from asset overload or damage caused by extreme weather – are more disruptive and provide no warning to customers, so they cannot prepare for the impact of an interruption.

Jurisdictional reliability standards were historically set at more stringent levels to protect customers from the cost and inconvenience of supply interruptions. Following power outages in 2004, the Queensland and NSW governments 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.

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<sup>265</sup> AER, [Service target performance incentive scheme V6](#), Australian Energy Regulator, 17 April 2025.

<sup>266</sup> AEMC, [Final report – 2019 annual market performance review](#), Australian Energy Market Commission, 12 March 2020, p. 51.

Concerns that reliability-driven investment was putting upwards pressure on electricity bills led to governments adopting an alternative approach to setting distribution reliability targets.<sup>267</sup> The alternative approach considers both the likelihood of an interruption occurring and the value that customers place on removing or reducing the impact of an interruption (section 3.16.1). While the Queensland and NSW governments began to relax reliability standards from 2014, the assets built to meet the previously high standards remain in the RAB and customers continue to pay for them.<sup>268</sup>

Two widely applied measures of distribution network reliability are the system average interruption frequency index (SAIFI) and the system average interruption duration index (SAIDI). SAIFI measures the frequency – or number – of interruptions to supply the average customer experienced each year, while SAIDI measures the total time the average customer was without power.<sup>269</sup>

The SAIFI and SAIDI metrics have generally been used to focus on the impact of unplanned interruptions to supply. However, the impact of planned interruptions must also be considered when assessing the overall customer experience. The AER has acknowledged this and has incorporated the impact of planned outages into some of its regulatory determinations through the customer service incentive scheme (CSIS) (Box 3.6).

## Maintaining or improving reliability may require expensive investment in network assets, which is a cost passed on to electricity customers in their electricity bills. Therefore, there is a trade-off between electricity reliability and affordability.

Both the frequency and duration of planned and unplanned interruptions to supply varies considerably among the distribution networks. The specific features of each distribution network can have a significant impact on the service provider's reliability performance. Customer densities, geographical characteristics and environmental conditions differ across networks, which can materially impact the number of customers affected by an outage as well as a network service provider's response time. Levels of historical investment also affect reliability outcomes.

Central business district (CBD) and urban network areas have higher load and customer connection densities. Distribution lines supplying urban areas are generally significantly shorter than those supplying rural areas. CBD and urban areas also tend to have a higher proportion of underground cables (which are protected from pollution, storms, trees, bird life, vandalism, equipment failure and vehicle collisions) and more interconnections with other urban lines. Restoration times following interruptions to supply are usually quicker for network service providers operating in urban areas than in rural areas.

Conversely, rural areas generally have lower load and lower customer connection densities and often include customers living in smaller population centres remote from supply points. Distribution lines supplying customers in rural areas tend to cover wider geographic areas. This increases exposure to external influences, such as storm damage, trees and branches and lightning. Further, rural lines are generally radial in nature, with limited ability to interconnect with nearby lines. These characteristics tend to result in more frequent and longer interruptions.

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

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<sup>267</sup> 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.

<sup>268</sup> ACCC, *Retail Electricity Pricing Inquiry final report*, Australian Competition and Consumer Commission, 11 July 2018, p. 109.

<sup>269</sup> Unplanned SAIDI excludes momentary interruptions (3 minutes or less).

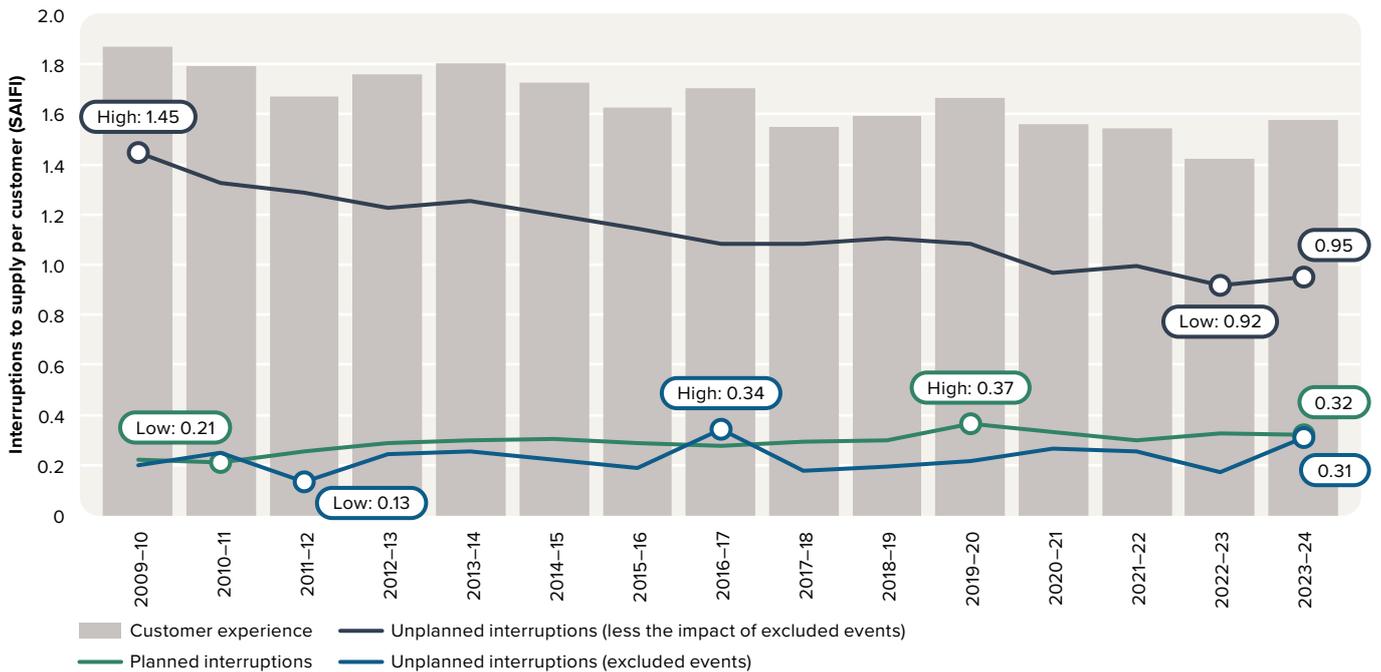
### 3.16.5 Distribution network reliability in 2023–24

Over the 12-month period to 30 June 2024, the average customer in the NEM experienced 1.58 interruptions to supply, 11% more than the record low set in 2022–23 (Figure 3.32).

The 1.58 interruptions to supply comprised of:

- 0.95 unplanned interruptions to supply (normalised for STPIS) – 3% more than the record low set in the previous year
- 0.31 unplanned interruptions to supply (STPIS excluded events) – 77% more than in the previous year and the most since 2016–17
- 0.32 planned interruptions to supply – 3% less than in the previous year.

Figure 3.32 Interruptions to supply (SAIFI) – electricity distribution networks



Note: SAIFI: system average interruption frequency index. Data show interruptions to supply that lasted longer than 3 minutes. This is consistent with the definition of a sustained interruption in the AER’s current service target performance incentive scheme (STPIS) (version 2.0, November 2018). The previous version of the STPIS (May 2009) defined sustained interruptions as those that lasted longer than one minute. Reporting historical SAIFI using a consistent definition allows for greater comparability over time. As such, the values shown above may not reflect outcomes reported in the past. Years reflect 1 July to 30 June. The unplanned interruptions (STPIS excluded events) cannot be directly calculated at a whole of NEM level because the major event day calculation must be made at a network level. For example, 22 November 2022 was classed as a major event (STPIS excluded event) for AusNet Services (Victoria) but did not qualify as a major event day for any of the other 12 distribution network service providers in the NEM. As such, the unplanned interruptions (STPIS excluded events) and unplanned interruptions (normalised measures) are calculated based on each individual network service provider’s outputs and subsequently weighted to show a ‘whole of NEM’ measure.

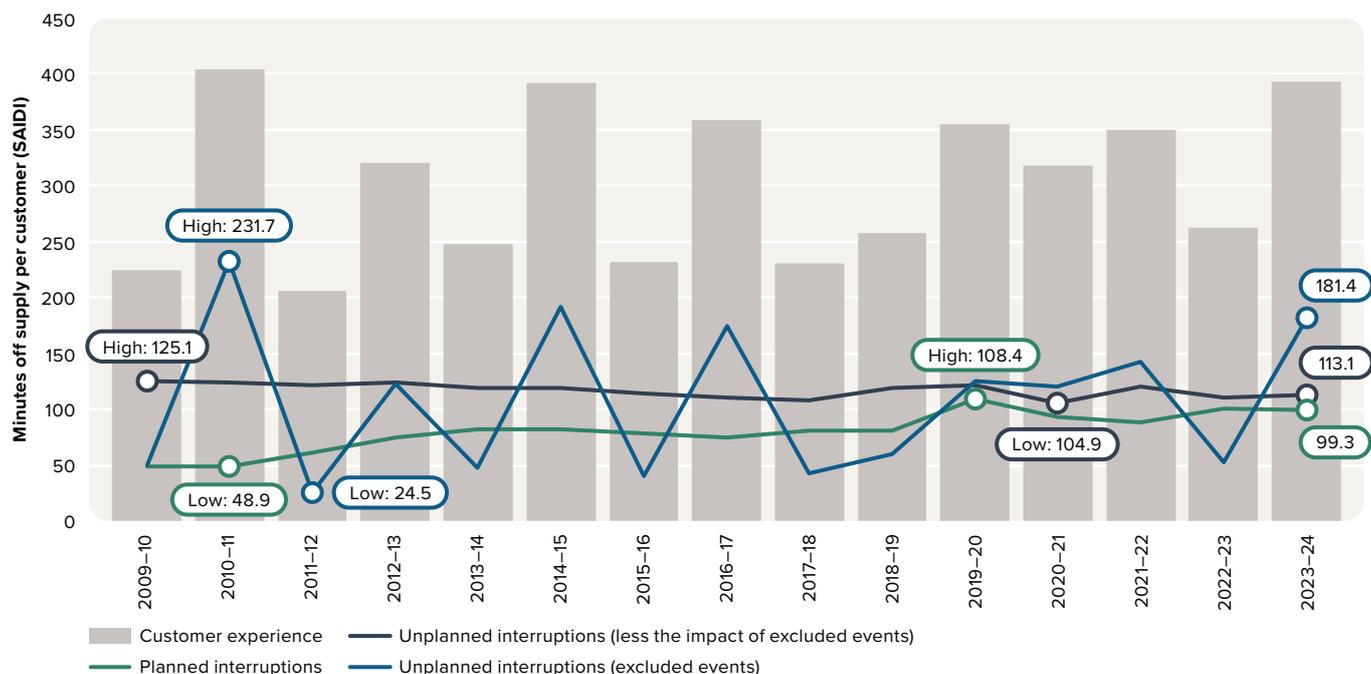
Source: AER modelling; category analysis regulatory information (RIN) responses.

Over the 12-month period to 30 June 2024, the average customer in the NEM experienced 393.8 minutes off supply – 50% more than in the previous year and the most since 2010–11 (Figure 3.33).

The 393.8 minutes off supply comprised of:

- 113.1 unplanned minutes off supply (normalised for STPIS) – 3% more than in the previous year
- 181.4 unplanned minutes off supply (STPIS excluded events) – 248% more than in the previous year and the most since 2010–11
- 99.3 planned minutes off supply – 1% less than in the previous year.

Figure 3.33 Minutes off supply (SAIDI) – electricity distribution networks



Note: SAIDI: system average interruption duration index. Data show interruptions to supply that lasted longer than 3 minutes. This is consistent with the definition of a sustained interruption in the AER's current service target performance incentive scheme (STPIS) (version 2.0, November 2018). The previous version of the STPIS (May 2009) defined sustained interruptions as those that lasted longer than one minute. Reporting historical SAIDI using a consistent definition allows for greater comparability over time. As such, the values shown above may not reflect outcomes reported in the past. Years reflect 1 July to 30 June. The unplanned interruptions (STPIS excluded events) cannot be directly calculated at a whole of NEM level because the major event day calculation must be made at a network level. For example, 22 November 2022 was classed as a major event (STPIS excluded event) for AusNet Services (Victoria) but did not qualify as a major event day for any of the other 12 distribution network service providers in the NEM. As such, the unplanned interruptions (STPIS excluded events) and unplanned interruptions (normalised measures) are calculated based on each individual network service provider's outputs and subsequently weighted to show a 'whole of NEM' measure.

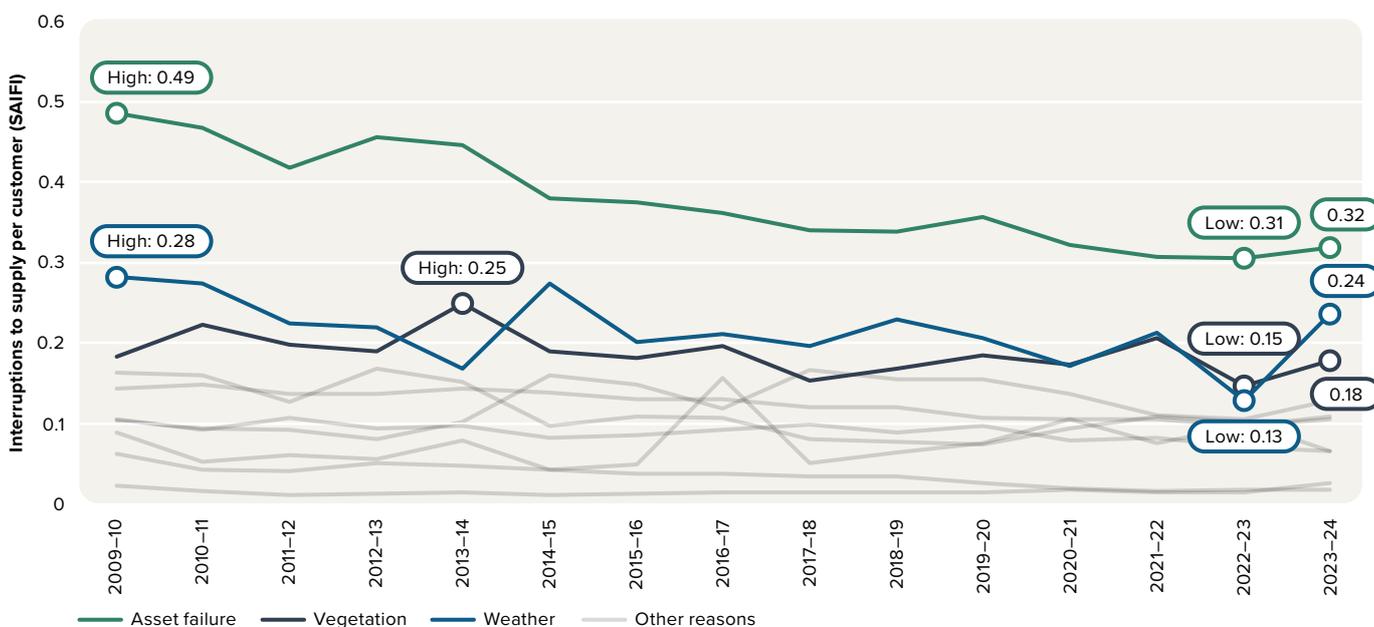
Source: AER modelling; category analysis regulatory information (RIN) responses.

Unplanned interruptions occur for many reasons, including:

- weather events
- vegetation interfering with powerlines
- bushfires
- asset failure and technical faults
- third-party accidents
- animals
- load shedding (reducing or disconnecting load from the power system) to help balance supply and demand during the peak period.

Since 2009–10, asset failure<sup>270</sup> has consistently been the primary cause of interruptions to supply in the NEM (responsible for around 28% of interruptions to supply) (Figure 3.34). However, asset failure is rarely the most disruptive in terms of time off supply (Figure 3.35). Over the same 14-year period, weather events such as lightning, floods, heatwaves or high winds have generally been the secondary cause of interruptions to supply (responsible for around 15% of interruptions to supply) but are often the most disruptive in terms of duration (responsible for 16–60% of time off supply). This clearly demonstrates the destructive nature of weather events on the electricity network.

**Figure 3.34 Reasons for unplanned interruptions to supply (SAIFI) – electricity distribution networks**

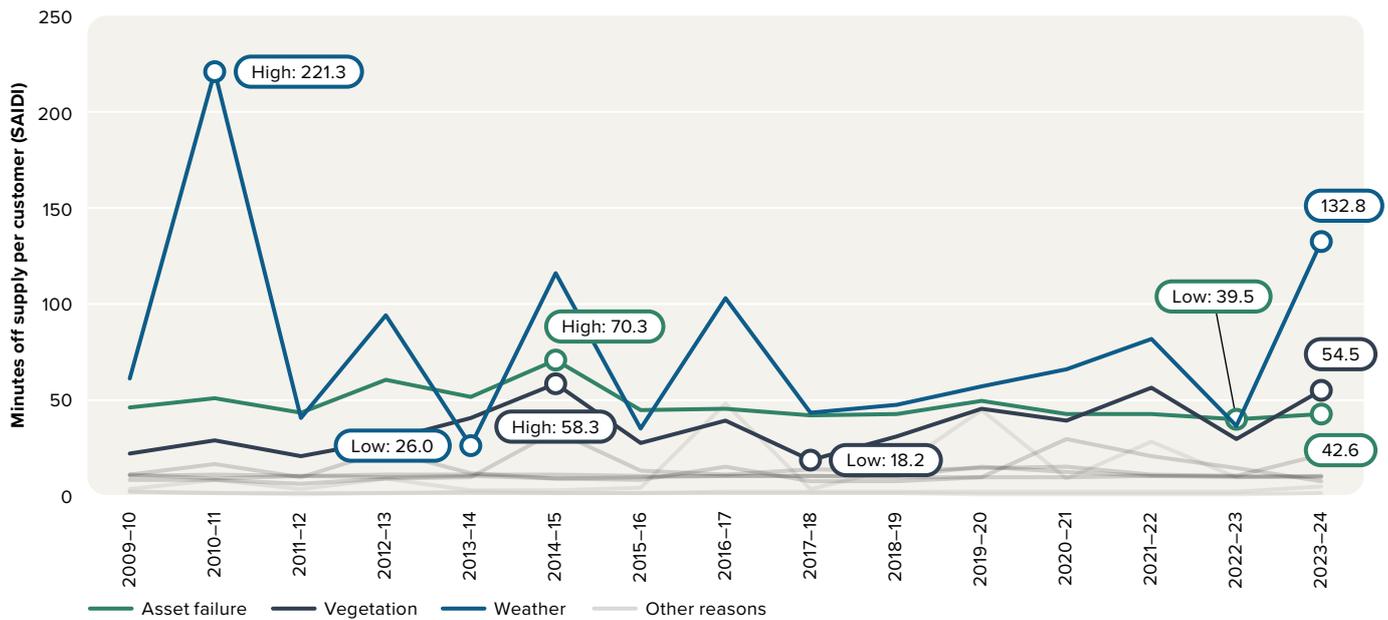


Note: SAIFI: system average interruption frequency index. Data show interruptions to supply that lasted longer than 3 minutes. This is consistent with the definition of a sustained interruption in the AER’s current service target performance incentive scheme (STPIS) (version 2.0, November 2018). The previous version of the STPIS (May 2009) defined sustained interruptions as those that lasted longer than one minute. Reporting historical SAIFI using a consistent definition allows for greater comparability over time. As such, the values shown above may not reflect outcomes reported in the past. Years reflect 1 July to 30 June.

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

270 The failure of an asset to perform its intended function safely and in compliance with jurisdictional regulations, not because of external impacts such as extreme or atypical weather events, third-party interference, wildlife interference or vegetation interference.

Figure 3.35 Reasons for unplanned minutes off supply (SAIDI) – electricity distribution networks



Note: SAIDI: system average interruption duration index. Data show interruptions to supply that lasted longer than 3 minutes. This is consistent with the definition of a sustained interruption in the AER’s current service target performance incentive scheme (STPIS) (version 2.0, November 2018). The previous version of the STPIS (May 2009) defined sustained interruptions as those that lasted longer than one minute. Reporting historical SAIDI using a consistent definition allows for greater comparability over time. As such, the values shown above may not reflect outcomes reported in the past. Years reflect 1 July to 30 June.

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

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

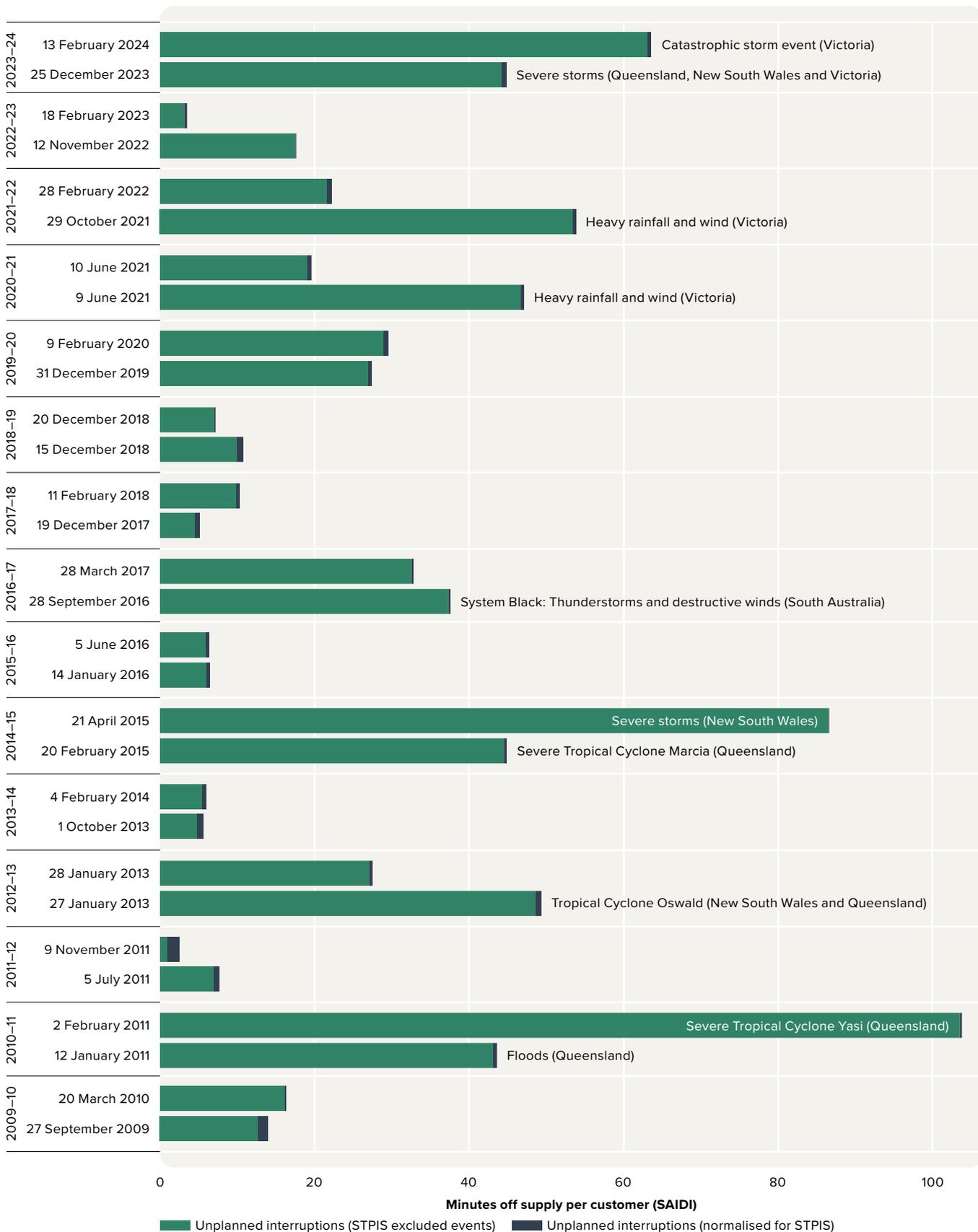
This is best illustrated by the impact of Severe Tropical Cyclone Yasi on Ergon Energy’s distribution network. On 2 February 2011, the average customer on the Ergon Energy network – which operates in regional Queensland – experienced an extraordinary 1,391 minutes off supply. On that same date, the average customer on the neighbouring Energex network experienced only 0.2 minutes off supply.

The relatively high number of minutes off supply experienced by the average NEM customer in 2023–24 was in large part driven by severe storms in Queensland on Christmas Day 2023,<sup>271</sup> and across central and eastern Victoria in mid-February 2024.<sup>272</sup> These disruptive weather events occurred one year after the average NEM customer experienced a relatively low number of minutes off supply 2022–23, partly due to the lack of catastrophic weather events throughout the year (Figure 3.36). This again demonstrates the potentially destructive and unpredictable nature of weather events on the electricity network.

271 ABC News, [Woman killed by fallen tree as wild Christmas storm lashes south-east Queensland](#), 26 December 2023, accessed 29 April 2025.

272 Victorian Government, [February 2024 Victorian storms](#), accessed 29 April 2025.

**Figure 3.36 Unplanned minutes off supply – most disruptive days each year**



Note: SAIDI: system average interruption duration index. Data show interruptions to supply that lasted longer than 3 minutes. This is consistent with the definition of a sustained interruption in the AER’s current STPIS (version 2.0, November 2018). The previous version of the STPIS (May 2009) defined sustained interruptions as those that lasted longer than one minute. Reporting historical SAIDI using a consistent definition allows for greater comparability over time. As such, the values shown above may not reflect outcomes reported in the past. Years reflect 1 July to 30 June.

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

## Reliability and weather events

A significant storm event hit Victoria on 13 February 2024, causing heavy rainfall and damaging winds. The event caused significant damage to Victoria's electricity distribution network, affecting around 12,000 kilometres of distribution lines and more than one million customers.<sup>273</sup> Following this event, the Victorian Government commissioned an independent review into the operational response of electricity network service providers to the February 2024 storms. In September 2024, the Network Outage Review Expert Panel (the Panel) published its final report, which consisted of 19 recommendations and 12 observations focused on delivering a clear pathway of improvements, necessitating a step change in the operational response by transmission and distribution network service providers during prolonged power outage events.

The Panel's recommendations provided a strong focus on achieving change quickly, with certainty and using mechanisms that are within Victoria's control. The final report detailed the importance of better preparedness, coordination and collaboration as well as actions to improve the reliability of the electricity system and support the community by placing people, their needs and safety at the forefront.

In April 2024, independent advisory body Infrastructure Victoria published a report stating that most of Victoria's infrastructure – such as roads, electricity networks and buildings – are not built to perform in an environment with more severe weather and intense rainfall events, and more hot days and bushfires.<sup>274</sup>

Since 1 July 2022, Energy Safe Victoria (ESV) has had the power to issue fines to Victorian network service providers that do not keep trees safely clear of powerlines. Before this, ESV's powers to take enforcement action for line clearance breaches were limited to issuing warnings or notices to take corrective action or prosecution through the court system.

In May 2024, Powercor (Victoria) was fined \$2.1 million for breaching the Electricity Safety Act and contravening electric line clearance regulations. ESV prosecuted Powercor for 105 offences, including failing to inspect almost 5,000 powerlines and failing to clear vegetation from more than 100 other lines, including one span at Glenmore where a destructive fire broke out.<sup>275</sup>

### 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.<sup>276</sup>

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

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<sup>273</sup> Engage Victoria, [Final report – February 2024 storm and power outage event – Independent review of transmission and distribution businesses operational response](#), Department of Energy, Environment and Climate Action, September 2024, accessed 15 October 2024.

<sup>274</sup> Infrastructure Victoria, [Weathering the storm – Adapting Victoria's infrastructure to climate change](#), April 2024, accessed 16 July 2024.

<sup>275</sup> ESV, [Powercor convicted on record number of charges, fined \\$2.1 million](#), media release, Energy Safe Victoria, 8 May 2024, accessed 13 July 2025.

<sup>276</sup> AER, [Amendment to the service target performance incentive scheme \(STPIS\) / Establishing a new Distribution Reliability Measures Guideline \(DRMG\)](#), Australian Energy Regulator, November 2018.

### Box 3.5 Service target performance incentive scheme

We apply a service target performance incentive scheme (STPIS) to most regulated network service providers. The STPIS offers incentives for network service providers to improve their service performance to levels valued by their customers. It provides a counterbalance to the capital expenditure sharing scheme (CESS) (Box 3.3) and efficiency benefit sharing scheme (EBSS) (Box 3.4) by ensuring network service providers do not reduce expenditure at the expense of service quality. A separate STPIS applies to distribution and transmission networks.

#### Transmission

The transmission STPIS covers 3 service components:

- the frequency of supply interruptions, duration of interruptions to supply and the number of unplanned faults on the network
- rewards for operating practices that reduce network congestion
- funding for one-off projects that improve a network's capability, availability or reliability at times when users most value reliability or when wholesale electricity prices are likely to be affected.

Financial bonuses of up to +4% of revenue, or penalties of up to -1% of revenue, are available for exceeding (or failing) to meet performance targets under the scheme. In April 2025 we published our final decision (version 6) on our review of all components (market impact component, network capability component and the service component) of the transmission STPIS.<sup>277</sup>

Our final positions were to:

- suspend the market impact component, and explore developing an effective alternative with AEMO and key stakeholders
- amend the network capability component to make it a more streamlined process
- amend the loss of supply event frequency parameter of the service component.

Version 6 of the STPIS was applied to transmission interconnector Directlink for its 2025–30 regulatory period and will apply to other transmission network service providers at the commencement of their next respective regulatory period<sup>278</sup>.

#### Distribution

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

Currently, the AER applies the distribution STPIS to 2 service elements:

- reliability of supply – unplanned (normalised) system average interruption duration index (SAIDI), unplanned (normalised) system average interruption frequency index (SAIFI) and momentary interruptions to supply (MAIFI)
- customer service – response times for phone calls, streetlight repair, new connections and written enquiries.<sup>279</sup>

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

<sup>277</sup> AER, [Service target performance incentive scheme V6 – Final Decision](#), Australian Energy Regulator, 17 April 2025.

<sup>278</sup> unless a Rule change is introduced to allow the commencement of version 6 before those dates.

<sup>279</sup> Since April 2021, the AER has applied the CSIS instead of the STPIS telephone answering parameter to distribution network service providers whose customers support the change in customer service measurement.

### 3.16.7 Incentives to avoid fire starts

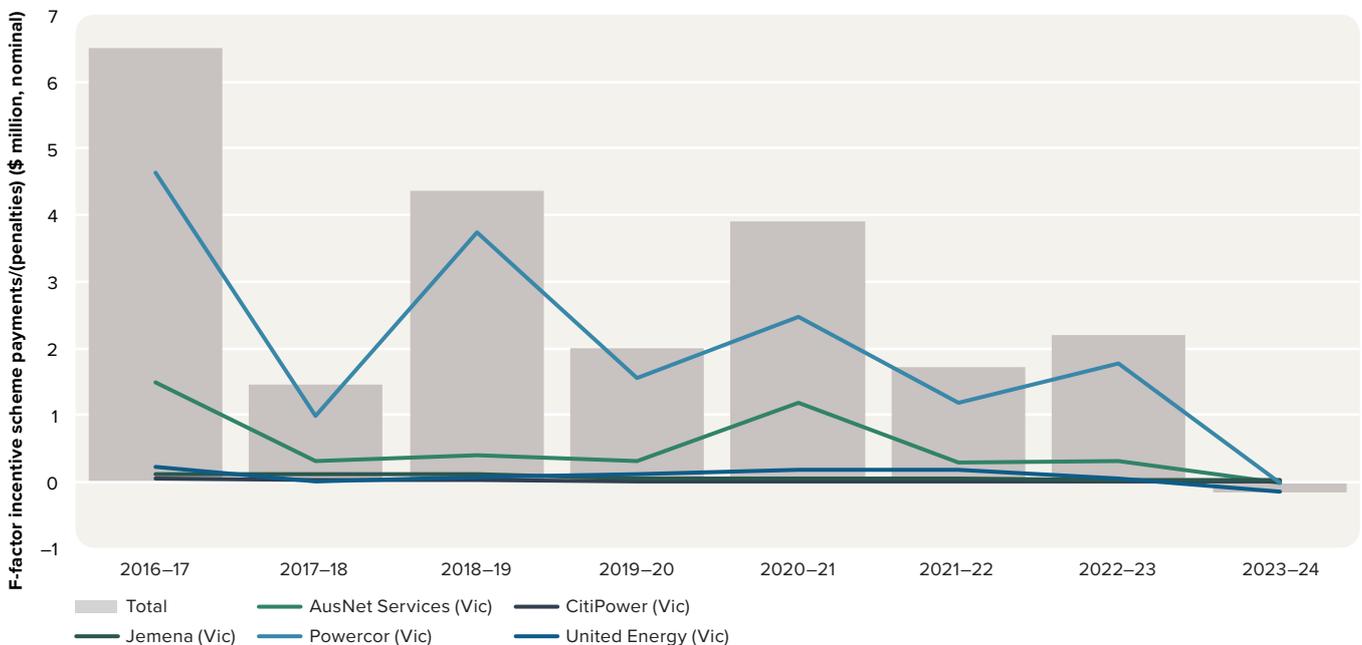
The AER administers the Victorian Government’s f-factor scheme, an initiative that provides financial incentives to Victorian distribution network service providers to minimise the number of fire starts within their networks in high fire danger zones and times.

If the number of fire starts increases, the distribution network service provider is required to pay a penalty. Likewise, if the number of fire starts decreases, the service provider may receive an incentive payment. Payments and penalties are incorporated into network service providers’ allowable revenue each year.

The penalty or reward rates under this scheme range from around \$1.48 million per fire start in high-risk areas on code-red days to \$300 in low-risk areas on a low fire danger day.

For the 2023–24 reporting period, incentive payments varied from a \$21,432 reward for Jemena to a \$153,816 penalty for United Energy. Both networks serve predominately urban customers with smaller components of rural customers. The impact of the incentive payments from 2023–24 will take the form of adjustments to the network service providers’ regulated revenues in 2025–26 (Figure 3.37).

Figure 3.37 F-factor incentive payments – Victorian distribution networks



Source: AER, Victorian electricity distributors’ fire start reports for the July 2023–June 2024 reporting period.

### 3.16.8 Customer service

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

- providing timely notice of planned interruptions
- ensuring the quality of supply, including voltage variations
- avoiding wrongful disconnection (including for life support customers) and ensuring quick timeframes for reconnection
- being on time for appointments
- having a fast response to fault calls
- providing transparent information on network faults.

Each jurisdiction sets its own standards for these performance indicators. Some jurisdictions apply a guaranteed service level scheme that requires network service providers to compensate customers for inadequate performance. Because reporting criteria vary by jurisdiction, performance outcomes are not directly comparable. The AER provides an annual summary of outcomes against some of these measures for networks in Queensland, NSW, South Australia, Tasmania and the ACT.<sup>280</sup> Victoria reports separately on network performance.<sup>281</sup>

In July 2020 the AER released its customer service incentive scheme (CSIS), which provides incentives for distribution network service providers to provide measurable levels of customer service that align with their customers' preferences (Box 3.6).<sup>282</sup>

#### Box 3.6 Customer service incentive scheme

Our customer service incentive scheme (CSIS) is designed to encourage distribution network service providers to engage with their customers and provide a level of service that reflects their customers' preferences. We approve customer service performance targets as part of the 5-year revenue determination process. Under the CSIS, distribution network service providers may be financially rewarded or penalised depending on how well they perform against the designated customer service targets. The revenue at risk under the scheme is capped at  $\pm 0.5\%$ . The CSIS can only be applied if the telephone answering parameter of the STPIS is not applied.

The CSIS is a flexible 'principles-based' scheme that can be tailored to the specific preferences and priorities of a network service provider's customers. This flexibility allows for the evolution of customer engagement and the introduction of new technologies. The CSIS incentives are intended to target areas of service that customers want to see improved.

In subsequent regulatory periods, the targets under the scheme will be adjusted and set in accordance with any improved level of customer service.

Currently, the CSIS is applied to Victorian distribution network service providers AusNet Services, CitiPower, Powercor and United Energy for their current period (1 July 2021 to 30 June 2026) and to Essential Energy (NSW) and TasNetworks (Tasmania) (1 July 2024 to 30 June 2029).

In 2023–24 the outcomes of the CSIS were:

- \$291,423 penalty for AusNet Services
- \$1.7 million reward for CitiPower
- \$4.0 million reward for Powercor
- \$2.2 million reward United Energy.

280 AER, [Annual retail markets report 2023–24](#), Australian Energy Regulator, 2 December 2024.

281 The Essential Services Commission (Victoria) publishes all of its energy reports in one central [Victorian Energy Market Reporting Hub](#).

282 AER, [Final – Customer Service Incentive Scheme](#), Australian Energy Regulator, 21 July 2020.