Image courtesy of TransGrid

3 Electricity networks

Australia's electricity network infrastructure consists of transmission and distribution networks, as well as smaller standalone regional systems. Together these networks transport electricity from generators to residential and industrial customers (infographic 1). This chapter covers the 21 electricity networks regulated by the Australian Energy Regulator (AER), which are located in all Australian states and territories other than Western Australia.

3.1 Electricity network characteristics

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

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

Electricity networks have traditionally provided a one-way delivery service to customers. However, the role of electricity networks is evolving as new technologies change how electricity is generated and used. Many small scale generators such as rooftop solar photovoltaic (PV) systems are now embedded within distribution networks, resulting in 2-way electricity flows along the networks. Energy users with solar PV systems can now source electricity from the distribution network when they need it and sell back the surplus electricity they generate at other times. Electricity generated using solar PV systems is also increasingly being stored using battery storage systems. Due to the versatility and falling cost of battery technology their use is expected to continue to grow over the coming years.[1]

Alongside the major distribution networks, small embedded distribution networks deliver energy to sites such as apartment blocks, retirement villages, caravan parks and shopping centres. Electricity is delivered to a single connection point at these sites, then sold by the embedded network operator to tenants or residents. The revenues of embedded networks are not regulated.

3.2 Geography

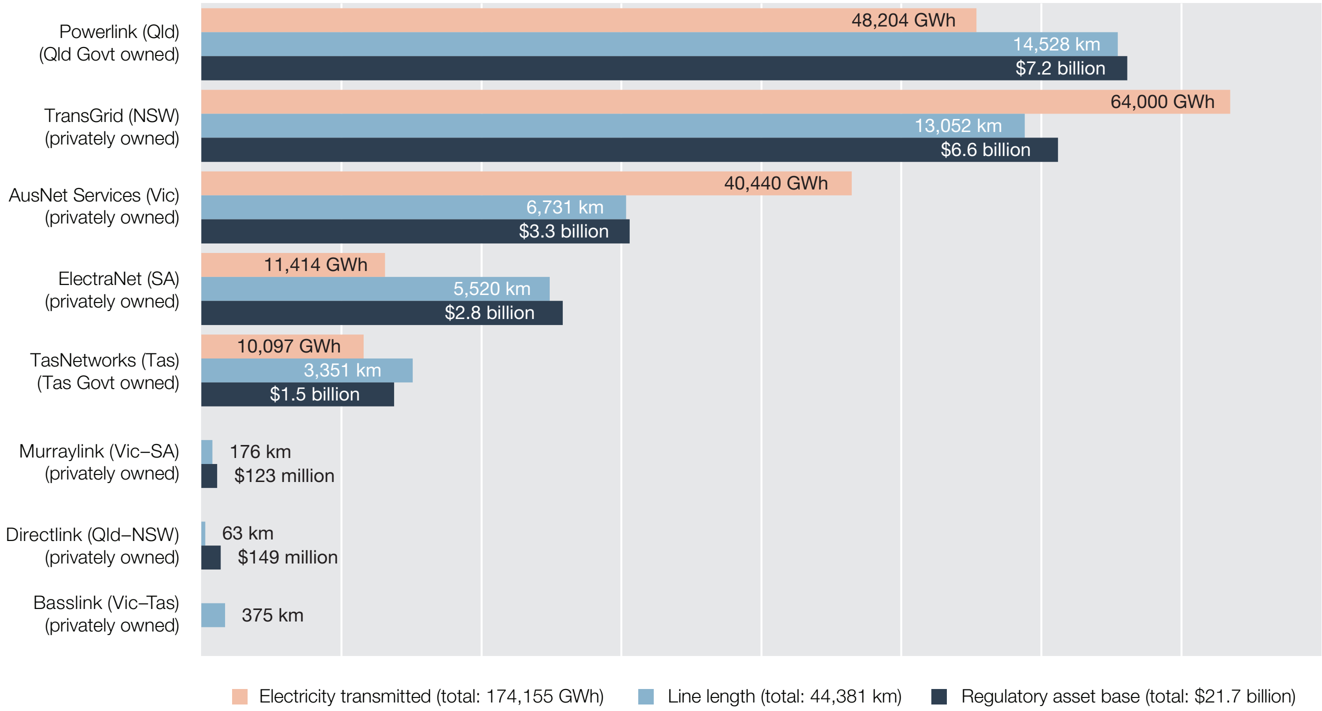
Electricity networks in Queensland, New South Wales (NSW), Victoria, South Australia, Tasmania and the Australian Capital Territory (ACT) create an interconnected grid forming the National Electricity Market (NEM). The NEM transmission grid has a long, thin, low density structure, reflecting the dispersed locations of electricity generators and demand centres. The 5 state-based transmission networks are linked by cross-border interconnectors. Three interconnectors (Queensland–NSW, Heywood, and Victoria–NSW) form part of the state-based networks, while 3 other interconnectors (Directlink, Murraylink and Basslink) are privately owned (figure 3.1). The transmission network also directly supplies energy to large industrial customers such as Alcoa's aluminium smelter in Portland (Victoria).

The transmission grid connects with 13 distribution networks.[2] Consumers in Queensland, NSW and Victoria are serviced by multiple distribution networks, each of which owns and operates its network within a defined geographic region. South Australia, Tasmania and the ACT are serviced by single distribution networks operating within each jurisdiction (figures 3.2 and 3.3).

1 Australian Renewable Energy Agency, *Battery storage*, AREA website, accessed 16 May 2021.

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

Figure 3.1 Electricity networks regulated by the AER – transmission



GWh: gigawatt hours; km: kilometres.

Note: Line length and asset base are as at 30 June 2020 (30 March 2020 for AusNet Services). Figure shows electricity transmitted in 2019–20 (year to March 2020 for AusNet Services). Regulatory asset base is adjusted to June 2021 dollars based on forecasts of the consumer price index (CPI). Northern Territory transmission assets are treated as part of the distribution system for regulatory purposes.

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

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

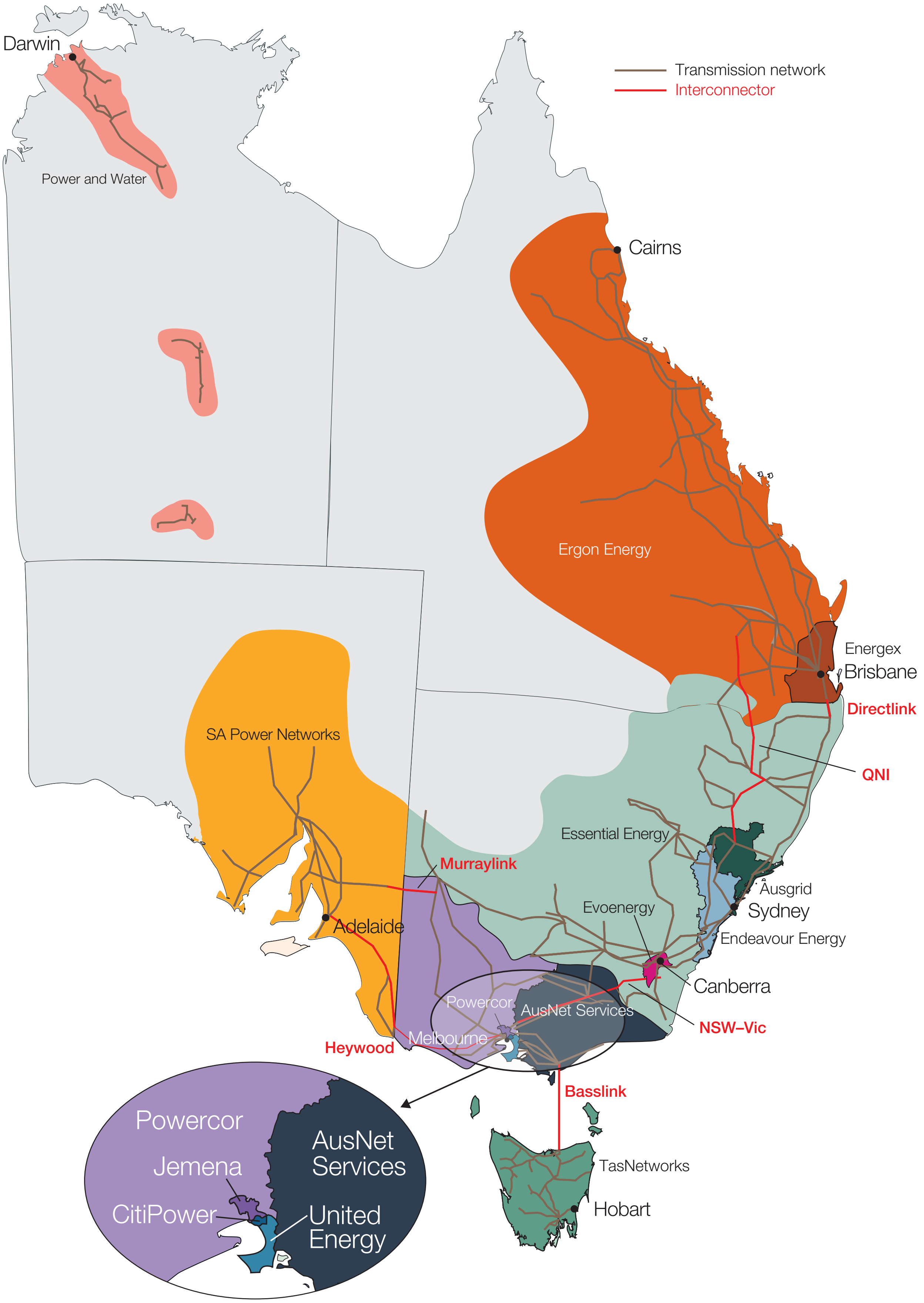
The combined value of the regulatory asset bases (RABs)[3] for the electricity networks regulated by the AER is a little over $100 billion. This comprises 7 transmission networks valued at $21.7 billion and 14 distribution networks valued at $78.8 billion. In total, the networks span almost 790,000 kilometres of line and deliver electricity to more than 10 million customers.

The AER does not regulate electricity networks in Western Australia, where the Economic Regulation Authority (ERA) administers state-based arrangements. Western Power (owned by the Western Australian Government) is the state's principal network, covering the populated south west region, including Perth. Another state-owned corporation – Horizon Power – services Western Australia's regional and remote areas.[4]

3 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.

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

Figure 3.2 Electricity networks regulated by the AER – distribution

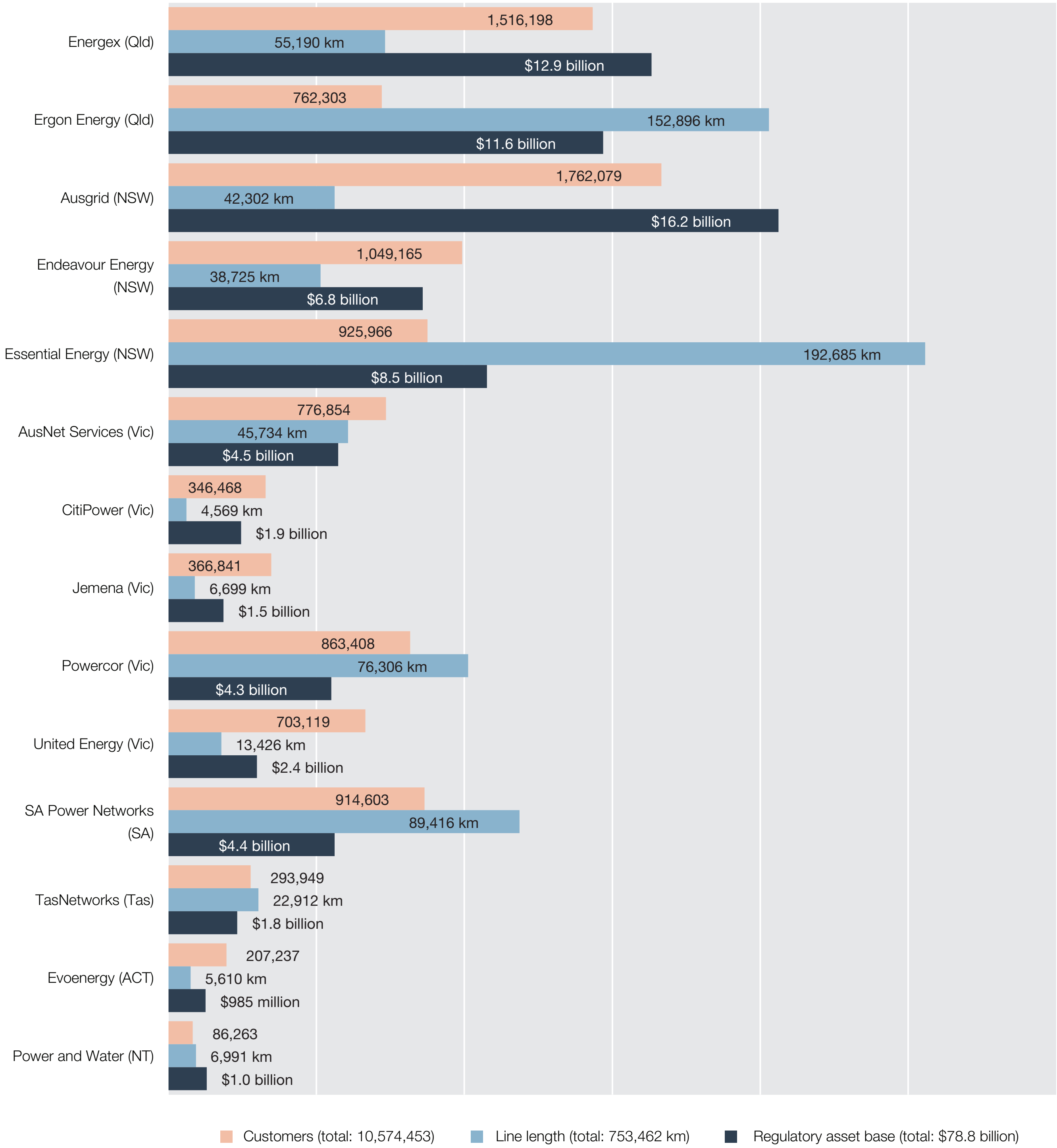


QNI: Queensland–NSW Interconnector.

Note: The AER does not regulate the Basslink Interconnector.

Source: AER.

Figure 3.3 Electricity networks regulated by the AER – distribution



km: kilometres.

Note: Customer numbers, line length and asset base is as at 30 June 2020 (31 December 2020 for Victorian businesses). Regulatory asset base is adjusted to June 2021 dollars based on forecasts of the consumer price index (CPI). For regulatory purposes, Northern Territory transmission assets are treated as part of the distribution system.

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

3.3 Network ownership

Australia's electricity networks were originally government owned, but many jurisdictions have now partly or fully privatised the assets. Privatisation of the electricity networks began in Victoria, which sold its transmission and distribution networks to private entities in the 1990s.[5]

In 2000 the South Australian Government privatised its transmission network and leased its distribution network. In the same year, a joint venture between the ACT Government and private equity holders was established to operate the ACT distribution network.[6]

In November 2015 the NSW Government leased its transmission network (TransGrid) to private interests. It then leased 50.4% of 2 distribution networks – Ausgrid in 2016 and Endeavour Energy in 2017 – to private interests. The predominately rural Essential Energy network remains government owned and operated.

Ownership of the 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. Fund managers such as Spark Infrastructure and Hastings also have substantial equity in the sector. Significant ownership links exist across the electricity and gas network sectors (section 5.2).

Electricity networks in Queensland, Tasmania, the Northern Territory and Western Australia remain wholly government owned. The Queensland Government in 2016 merged state-owned electricity distributors Energex and Ergon Energy under a new parent company, Energy Queensland.

In some jurisdictions, ownership of electricity networks overlaps with other industry segments, with ring-fencing for operational separation. Queensland's state-owned Ergon Energy, for example, provides both distribution and retail services in regions outside south east Queensland.

3.4 How network prices are set

Electricity networks are capital intensive, so their average costs will fall as output rises. This characteristic gives rise to a natural monopoly industry structure, where it is more efficient to have a single network provider than to have multiple providers offering the same service.

Because monopolies face no competitive pressure, they have opportunities and incentives to charge unfair prices. This environment poses serious risks to consumers, given network charges can make up close to 50% of a residential electricity bill (figure 6.8 in chapter 6). To counter these risks, the role of the AER as economic regulator is to mimic the incentives that network businesses would face in a competitive market (that is, to control costs, invest efficiently and not overcharge consumers).

3.4.1 Regulatory objective and approach

The National Electricity Law and the National Electricity Rules set the framework for regulating electricity networks, and the AER applies that framework. The regulatory objective of the National Electricity Law is to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to price, quality, safety and reliability and security of supply of electricity; and the reliability, safety and security of the national electricity system.

The AER seeks to ensure the delivery of a reliable, secure, affordable and low emissions energy supply in an efficient and timely way that meets the expectations of energy consumers and the community. Its regulatory toolkit to pursue this objective is wide ranging (box 3.1), but its central role is to set the maximum revenue that a network business can earn from its customers for delivering electricity. The AER fulfils this role via a periodic determination process, in which it assesses how much revenue a prudent network business would need to cover its efficient costs. Network revenues are then capped at this level for the regulatory period, which is typically 5 years.[7]

5 In Victoria, ownership of the transmission network is separated from planning and investment decision making. AusNet Services owns the state's transmission assets, but the Australian Energy Market Operator (AEMO) plans and directs network augmentation (expansion). AEMO also purchases bulk network services from AusNet Services for sale to customers.

6 The ACT has no transmission assets.

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

Box 3.1 The AER's role in electricity network regulation

The Australian Energy Regulator (AER) sets a cap every 5 years on the revenue that a network business can earn from its customers. Alongside this central role, we undertake broader regulatory functions, including:

- assessing network charges each year to ensure they reflect underlying costs and do not breach revenue limits
- providing incentives for network businesses to improve their performance in ways that customers value
- assessing whether any additional costs not anticipated at the time of our original decision should be passed on to customers
- publishing information on the performance of network businesses, including benchmarking and profitability analyses
- monitoring whether network businesses properly assess the merits of new investment proposals.

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

- Power of Choice reforms empowering customers to make informed choices about their energy use, which ultimately help keep network costs down (sections 3.7 and 1.8)
- adopting a more consumer centric approach to setting network revenues (section 3.6)
- publishing information on network profitability
- reviewing how rates of return and taxation allowances are set for energy networks (section 3.11).

As part of the determination process, a network business submits a proposal to the AER setting out how much revenue it will need to earn to cover the costs of providing a safe and reliable electricity supply. The AER then assesses the reasonableness of the network business's forecasts and the efficiency of expenditure proposals. If the AER concludes a business's proposal is likely to be unreasonably costly, it may ask for more detailed information or a clearer business case. Subsequently, the AER may amend a network's proposal to ensure the approved cost forecasts are efficient.

In forming a view on the prudency of a network business's capital expenditure forecast, the AER assesses capital expenditure drivers for that business. The AER does not determine which capital programs or projects a network business can invest in. Once the AER sets a capital expenditure forecast, it is up to the network business to prioritise its investment program. However, the network business must undertake a cost–benefit analysis (CBA) for new investment projects that meet cost thresholds (section 3.12.7).

As operating cost are largely recurrent and predictable, the AER starts its review process by assessing the actual operating expenditure a business incurred in the (then) current regulatory period. The AER uses its assessment techniques to determine whether this base expenditure is efficient and applies a rate of change to this base to account for changes in prices, productivity and the outputs the business is required to deliver.

The AER publishes guidelines on its approach to assessing capital and operating costs and applying incentives.[8]

Sections 3.9, 3.13 and 3.15 examine the incentive schemes in more detail. The AER's *Electricity network performance report* details the impact incentive schemes have had on network businesses' behaviour.[9]

In conducting its revenue assessment, the AER draws on a range of inputs, including expenditure forecasts, benchmarking and revealed costs from past expenditure. It engages closely with stakeholders from the earliest stage of the process, including before the network businesses lodge a formal proposal.

Electricity network businesses have made, and continue to make, significant improvements to the ways in which they engage with consumers. The regulatory process increasingly focuses on how network businesses engage with their customers in shaping regulatory proposals. As part of this focus, the AER has recently trialled the 'New Reg' process – an enhanced, more open approach to how network businesses incorporate consumer perspectives in developing their regulatory proposals – with Victorian distribution network AusNet Services (box 3.2).

8 AER, Guidelines, schemes & models, AER website, accessed 1 March 2021.

9 AER, *Electricity network performance report,* September 2020.

Additionally, the AER's Consumer Challenge Panel (CCP) – comprising experienced and highly qualified individuals with consumer, regulatory and/or energy expertise – provides input on issues of importance to consumers. It advises the AER on whether the revenue proposals submitted by network businesses are in the long term interests of consumers; the effectiveness of network businesses' engagement with their customers; and how consumer views are reflected in the development of the network businesses' proposals.[10]

Box 3.2 Trialling the New Reg model

The Australian Energy Regulator (AER), along with Energy Consumers Australia and Energy Networks Australia, launched the New Reg initiative in June 2017 to explore ways to improve sector engagement and identify opportunities for regulatory innovation. The vision of the New Reg initiative is to ensure that customers' preferences drive energy network businesses' proposals and regulatory outcomes.

Victorian distributor AusNet Services trialled the New Reg initiative and negotiated parts of its 2021 to 2026 regulatory proposal with a customer forum. The AER engaged Cambridge Economic Policy Associates (CEPA) to conduct an evaluation of AusNet Services' trial of New Reg.

CEPA's interim evaluation concluded that the overall vision for New Reg appeared to have been largely realised. CEPA also identified some learnings for future engagement processes.[11]

CEPA's final evaluation of the New Reg trial will inform the AER's future work in relation to network consumer engagement. As part of the New Reg trial the AER is also considering potential reforms to ensure regulatory outcomes reflect consumer preferences and priorities. These included increasing flexibility to better reflect consumer–network agreed price and service combinations and desired incentives. The AER also identified reforms to support and empower consumers and reward effective engagement.[12]

3.4.2 Building blocks of network revenue

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

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

The AER also makes revenue adjustments for over- or under-recovery of revenue made in the past; and for rewards or penalties earned through any applicable incentive schemes (figure 3.4).

While network businesses are entitled to earn revenue to cover their efficient costs each year, this revenue does not include the full cost of investment in new assets made during the year. Network assets have a long life, so investment costs are recovered over the economic life of the assets, which may run to several decades. The amount recovered each year is called depreciation, and it reflects the lost value of network assets each year through wear and tear and technical obsolescence.

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

- the value of the network's RAB, which captures the total economic value of assets that are providing network services to customers plus positive adjustments for forecast new capital expenditure and negative adjustments for depreciation on existing assets
- the rate of return that the AER allows based on the forecast cost of funding those assets through equity and debt.[13]

10 AER, *Consumer Challenge Panel*, AER website, accessed 1 March 2021.

11 CEPA, *New Reg: AusNet Services trial – interim evaluation report*, 4 December 2020.

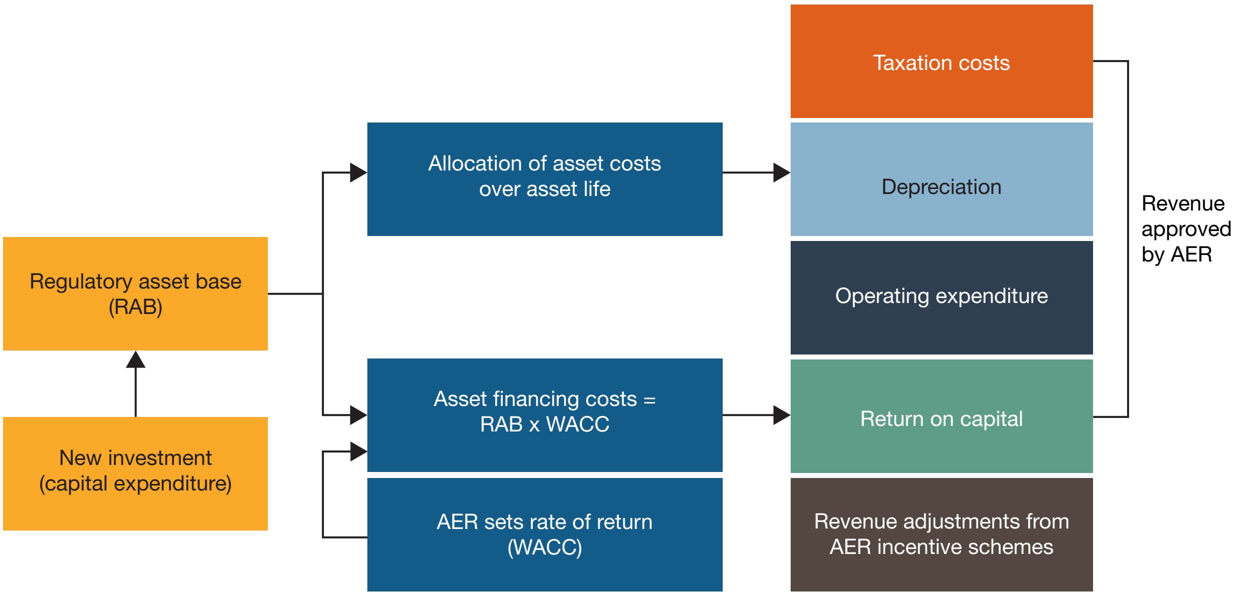
12 AER, ECA, ENA, *Submission to electricity network economic regulatory framework 2020 review*, July 2020.

13 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.

Overall these returns take up the largest share of network revenue, accounting for 43% across all networks (49% for transmission and 42% for distribution) (figure 3.5).

Operating costs – such as maintenance costs and overheads – absorb 35% of revenue across all networks (30% for transmission and 36% for distribution). Depreciation absorbs another 18%, while taxation and other costs account for the remaining 3% of network revenue. Sections 3.10 to 3.13 examine major cost components in more detail.

Figure 3.4 Forecasting electricity network revenues

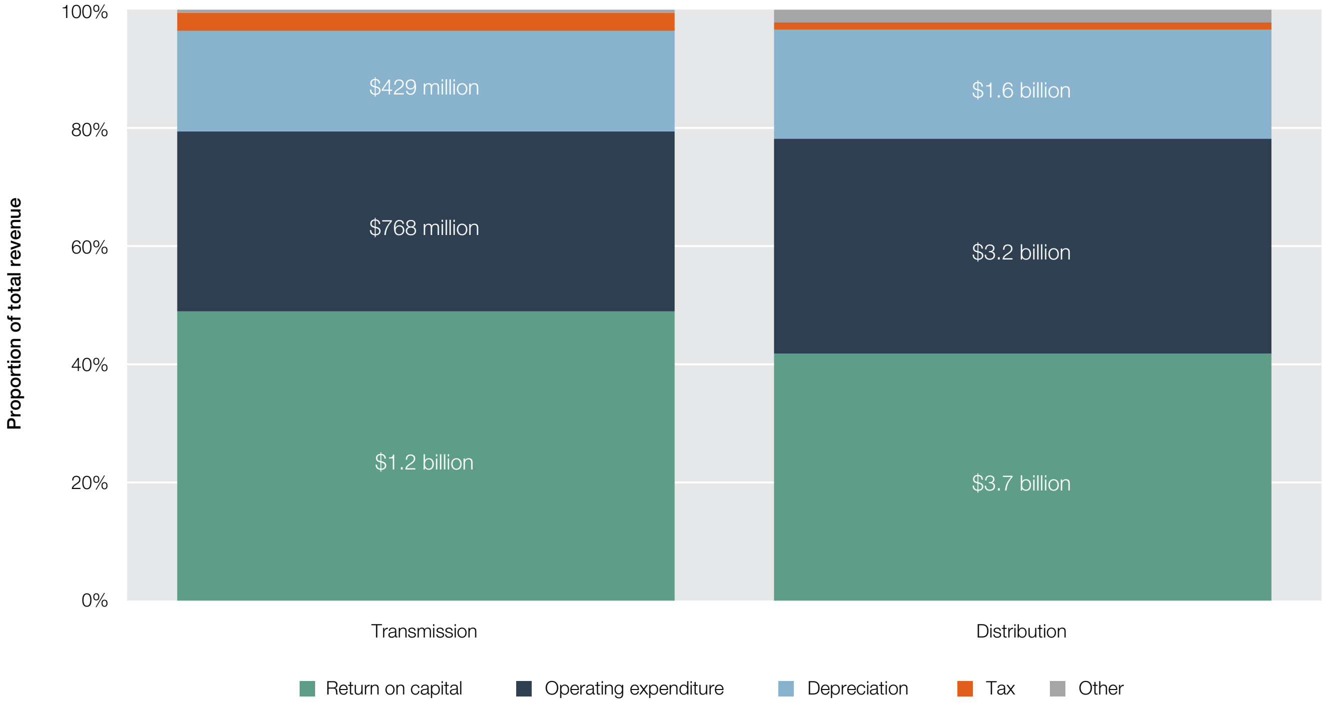


AER: Australian Energy Regulator; RAB: regulatory asset base; WACC: weighted average cost of capital.

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

Source: AER.

Figure 3.5 Composition of average annual electricity network revenue – current periods



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

3.4.3 Timelines and process

The National Electricity Law and the National Electricity Rules set the regulatory framework and process, which is both lengthy and highly consultative. The process begins around 3 years before the beginning of a regulatory period, when the AER works with stakeholders on a review framework and approach. The next step is for a network business to propose the revenue that it considers it needs to earn to cover the efficient costs of meeting its service and reliability obligations. Network businesses engage with their customers in framing the revenue proposal.

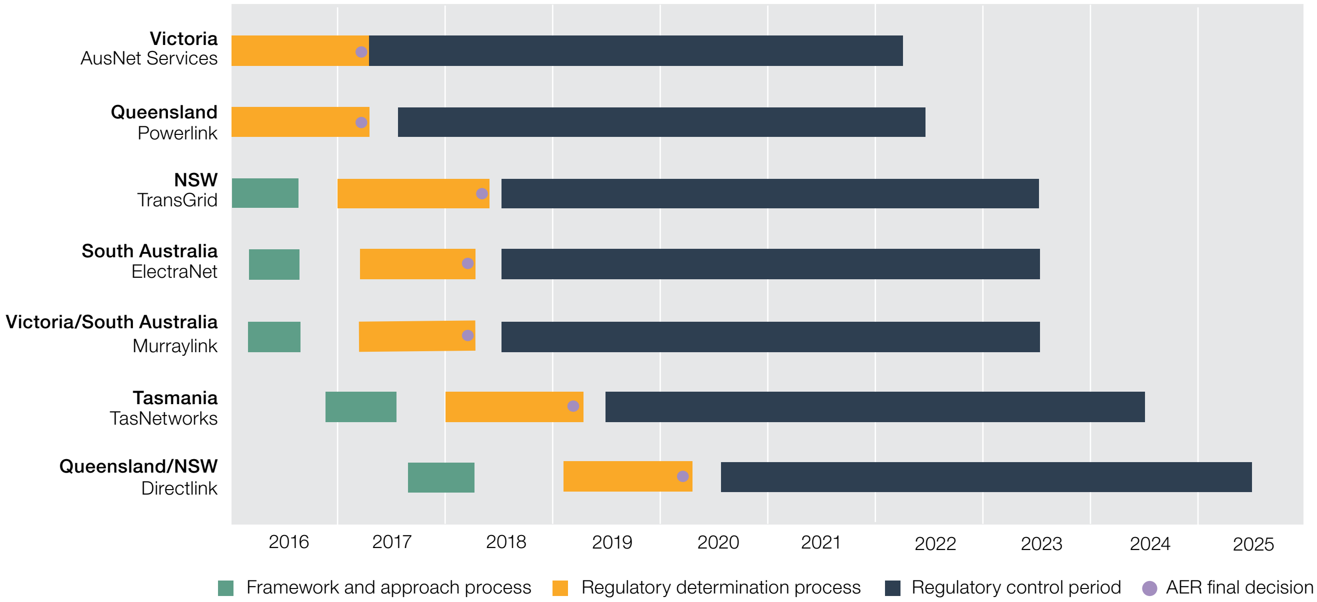
The AER has 15 months to review a revenue proposal before releasing its final decision. It consults widely with energy customers, consumer representatives, government, investment groups, network businesses and other stakeholders. This consultation includes issues papers, draft decisions and public forums. The timing of the AER reviews is staggered to avoid bunching (figures 3.6 and 3.7).

Following its review, the AER makes a final decision setting the maximum amount of revenue that a network business can earn from its customers through network charges.[14]

While the decision sets network revenues rather than prices, the 2 are closely related. Network businesses set prices by spreading their allowed revenue across the customer base.[15]

As part of the regulatory process (section 3.7.1), the AER assesses tariff structure statements that set out a network's pricing policies and annually reviews prices to ensure they are consistent with the revenue decision and reflect efficient costs.

Figure 3.6 AER decision timelines – electricity transmission networks



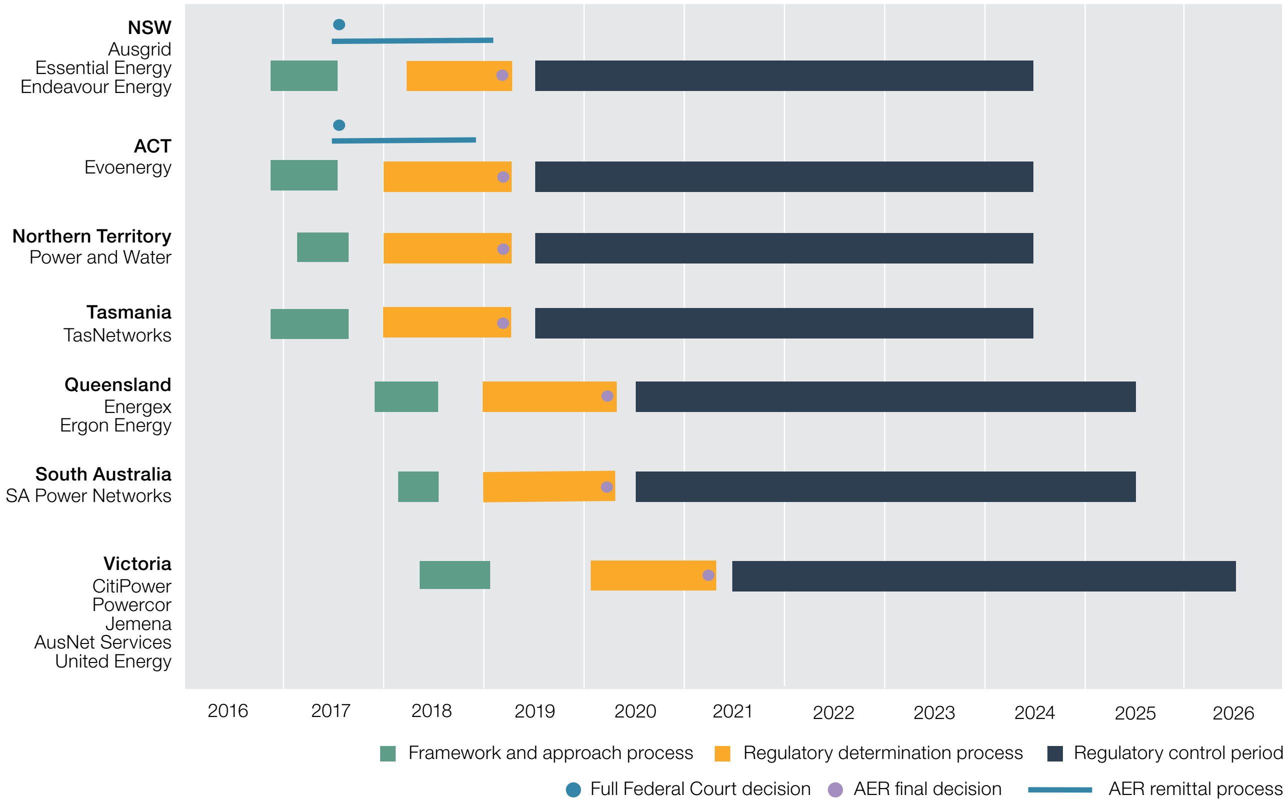
Note: Timelines for AER decisions are effective at 1 July 2021. The latest information is available on the AER website: (https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements).

Source: AER.

14 For transmission networks, the AER determines a cap on the maximum revenue that a network can earn during a regulatory period. For distribution networks, revenue caps apply in all states except the ACT, where an average revenue cap links revenue to volumes of electricity sold.

15 Traditionally, each customer paid a fixed daily charge plus a charge based on actual energy use. These arrangements are evolving under new pricing structures that encourage customers to consider how their energy use impacts network costs. Pricing reforms to address this issue form part of the Power of Choice program (section 3.7).

Figure 3.7 AER decision timelines – electricity distribution networks



Note: Timelines for AER decisions are effective at 1 July 2021. The latest information is available on the AER website: (https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements).

Source: AER.

3.5 Recent AER revenue decisions

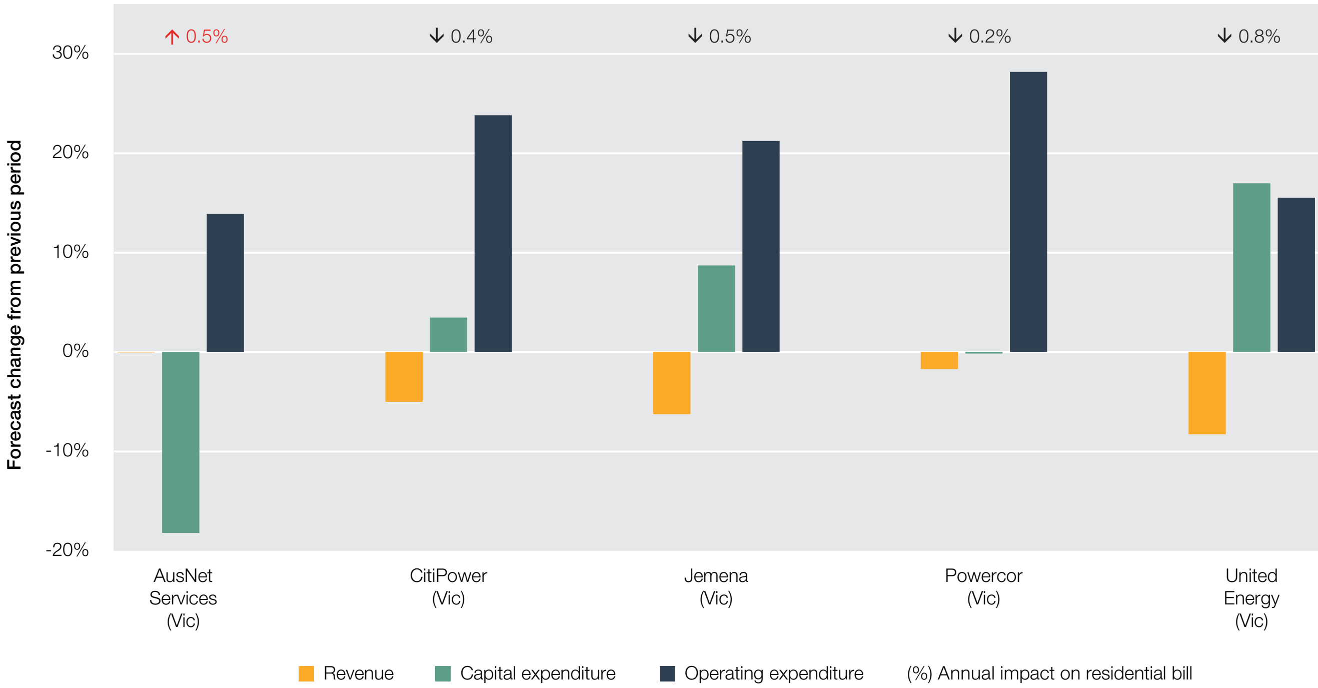
In April 2021 the AER published its final revenue decisions for the 5 electricity distribution networks in Victoria – AusNet Services, CitiPower, Jemena, Powercor, and United Energy. These decisions cover the 5-year period ending 30 June 2026 (figure 3.8).

The 5 Victorian distributors are forecast to earn a combined $11.1 billion in revenue over the current period – $313 million (2.7%) less than they were forecast to earn and $392 million (3.4%) less than they actually earned in the previous period. The key driver of the lower forecast revenue is the allowed rate of return, which decreased from around 6.3% for the previous period to 4.7% for the current period.[16] This reflects a decrease in interest rates, meaning the Victorian distributors can obtain the capital they need to run their businesses more cheaply.

In 4 of the 5 decisions, the AER approved lower forecast revenues in the current period than were forecast in the previous period – the exception being AusNet Services. Distribution network charges for AusNet Services' consumers will increase slightly over the current period due to the increase in forecast revenue, combined with a decrease in forecast demand (which causes network charges – revenue per energy unit ($ per kWh) – to increase).

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

Figure 3.8 Recent AER electricity network revenue decisions – key outcomes



Note: Bill impact is the change in the average annual customer bill compared with the customer bill in the final year of the previous period, adjusted for inflation, assuming retailers pass through outcomes of the decision.

Source: AER estimates.

For the period commencing 1 July 2021 the Victorian distributors are forecast to invest around $5.2 billion in capital projects – $108 million (2%) less than they invested in the previous period. Despite the AER's lower approved capital expenditure allowance the collective value of the Victorian distributors' RABs is forecast to increase by $1.4 billion (10%) by 2026.

The Victorian distributors are forecast to spend around $4.4 billion on operating costs over the current period – $744 million (20%) more than they spent in the previous period.

The AER's decisions for the previous period challenged network businesses to deliver services more efficiently through prudent choices about operating and capital expenditure, without compromising network safety and reliability. In total, the Victorian distributors underspent in the previous period by $1.2 billion (18%) and by $600 million (14%) against their respective approved capital and operating expenditure forecasts. The AER's setting of lower forecast revenue allowances for the current period acknowledged network businesses are rationalising their operations and will continue to build on operational efficiencies. Lower revenue allowances benefit customers by locking in efficiency gains.

3.5.1 Legal reviews of AER decisions

A party can seek judicial review of an AER decision on a network business's revenue. Before October 2017 a party could also apply to the Australian Competition Tribunal (the Tribunal) for a limited merits review of an AER decision.

From 2008 to 2017 network businesses and other parties applied for limited merits review of 33 of the AER's 52 electricity network decisions. Network businesses often succeeded in having their allowed rates of return and revenues increased, whereas consumer representatives and governments were invariably unsuccessful in arguing that network revenues should be decreased.[17] Tribunal decisions added over $3 billion to network revenues.

Following the Australian Government's abolition of limited merits review in October 2017, the AER committed to a more collaborative approach to network regulation, driven by customers' best interests (section 3.6). No appeals for judicial review have since been lodged on any AER decisions on network revenue.

17 AER, *Review of the limited merits review framework, AER submission to Ministerial Forum of Energy Ministers (formerly CoAG Energy Council)*, October 2016.

3.6 Refining the regulatory approach

The regulatory framework is not static. Recent reforms include the AER using benchmarking to assess network costs; offering incentives for network efficiency; and rewarding the network businesses for quality engagement with their customers when they are developing revenue proposals.

The AER continues to review and incrementally refine elements of its benchmarking methodology and data. The aim of this work is to maintain and continually improve the reliability of the benchmarking results it publishes and uses in its network revenue determinations. In 2019, for example, it reviewed alternative approaches to assessing information and communication technology (ICT) expenditure. ICT is increasingly a more integral component of energy services delivery. In its review, the AER assessed whether its existing ICT expenditure assessment tools were fit for purpose.

In 2020 the AER reviewed its treatment of inflation in its regulatory framework. In December 2020 the AER announced that it would adjust its approach to estimate expected inflation from using a 10-year average to a 5-year average of the Reserve Bank of Australia's headline rate to match the 5-year timeframe of a typical regulatory period. The new approach addresses issues highlighted in stakeholder submissions and is more responsive to changing economic circumstances.[18]

In July 2020 the AER released its new Customer Service Incentive Scheme (CSIS), which provides incentives for distributors to provide levels of customer service that align with their customers' preferences (box 3.6).[19] Distributors are encouraged to engage with their customers, identify the customer services they want improved and then set targets to improve those services. The CSIS rewards distributors for improving their customer service and penalises them if service levels deteriorate. The CSIS improves the incentives available for distribution networks to recognise the value of customer service and has been applied to Victorian distributors AusNet Services, CitiPower, Powercor and United Energy in the 2021 to 2026 period.

The AER also implemented changes to regulatory arrangements that sit outside the formal determination process. In June 2020 the AER published its objectives and priorities to be addressed through network service performance reports for regulated electricity and gas network businesses.[20] The AER plans to review these objectives and priorities by 2025 to ensure they remain fit for purpose.

In August 2020 the AER published guidelines to make AEMO's integrated system plan (ISP), a whole-of-system plan for eastern Australia's power system, actionable. The guidelines include a new CBA guideline; a new forecasting best practice guideline; and updates to the regulatory investment test for transmission (RIT-T) instrument and application guidelines.

The guidelines are part of a broader reform led by the Energy Security Board (ESB), with changes made to the National Electricity Rules to streamline the transmission planning process while retaining rigorous CBA. While the new rules were effective from 1 July 2020, the new guidelines will come into effect through the 2022 ISP.[21]

The ISP and RIT-Ts are discussed in section 3.12.

3.6.1 Aligning business and consumer interests

The regulatory process is complex and often adversarial. In this environment, consumers may find it challenging to have their perspectives heard and to assess whether a network business's proposal reflects their interests. In recent processes, the AER and network businesses have trialled new approaches to improve consumer engagement.

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

A number of network businesses are experimenting with early engagement models to better reflect consumer interests and perspectives in framing their regulatory proposals – for example, running 'deep dive' workshops. The AER has trialled a new approach to customer engagement – the New Reg – in partnership with Energy Networks Australia (ENA) and Energy Consumers Australia (ECA) (box 3.2).[22]

18 AER, *Final position – regulatory treatment of inflation*, December 2020.

19 AER, *Final – Customer Service Incentive Scheme*, July 2020.

20 AER, *Objectives and priorities for reporting on regulated electricity and gas network performance – Final*, June 2020.

21 AER, *Final decision – Guidelines to make the Integrated System Plan actionable*, August 2020.

22 AER, ECA and ENA, *New Reg: towards consumer-centric energy network regulation, a joint initiative of the Australian Energy Regulator, Energy Consumers Australia, and Energy Networks Australia, Directions paper*, March 2018.

Early engagement offers the potential to expedite the regulatory process, reducing costs for businesses and consumers. In particular, effective consumer consultation can lay the foundations for the AER to accept major elements of a network business's revenue proposals. If a business and its customers can agree on key areas then the AER will put significant weight on a proposal reflecting that consensus.

Also, network businesses are increasingly looking to maintain open and ongoing dialogue with stakeholders throughout the regulatory period, as opposed to engaging intensively once every 5 years when a proposal is being considered.

In 2019 Jemena (Victoria) was awarded the ENA/ECA Consumer Engagement Award for its Electricity Network People's Panel. Jemena received recognition because it 'met consumers where they were' – tailored its engagement to them, ensured that translators were on hand, made childcare available and provided transport to ensure that no one was left out of the conversation.[23]

SA Power Networks (South Australia) and Powerlink (Queensland) were also shortlisted as finalists for the award – SA Power Networks for its community engagement on its tariff structure statement and Powerlink for enabling consumer advocates to build an engagement process for its 2023 to 2027 revenue determination.

In 2020 Jemena was again nominated for the ENA/ECA Consumer Engagement Award for its community-focused response to the COVID-19 pandemic. Jemena's diverse customer base presented a unique challenge in how to respond to the pandemic. Jemena identified key customer and community challenges using a consultative, evidence-based approach and delivered solutions in collaboration with industry and the community.[24]

AusNet Services (Victoria) was also nominated for the award for participating in the New Reg trial (box 3.2). As part of the trial AusNet Services established an independent customer forum to represent the perspectives of its customers in negotiating and agreeing price and service offerings, supported by the AER. The forum met with numerous members of AusNet Services' staff over a 2-year period and gained detailed information on the network business, its customers and its plans. The forum also met with many of AusNet Services' customers independently. Agreed outcomes were incorporated in AusNet Services' 2021 to 2026 revenue proposal.

3.7 Power of Choice reforms

Innovations in network and communication technology – including 'smart' meters, interactive household devices, and energy management and trading platforms – are driving change in energy markets. These innovations allow consumers to access real-time information about, and make informed decisions in managing, their energy use. If consumers choose to voluntarily reduce their energy use from the grid in peak periods (by shifting energy use or relying on battery storage), it can potentially delay the need for costly network investment.

Power of Choice reforms are being progressively rolled out to unlock the potential benefits of these innovations. The reforms include a market-led rollout of smart meters, supported by more cost-reflective network pricing (section 3.7.1), and incentives for demand management as a lower cost alternative to network investment (section 3.12.10).

The emergence of electric vehicles (EVs) can also help consumers manage their energy needs. The Australian Renewable Energy Agency (ARENA) is funding projects to assess different approaches to optimise the use of EVs. Projects include ActewAGL Retail (ACT) demonstrating that a fleet of EVs can provide similar services to grid-scale batteries and virtual power plants. The EVs used in the trial can be charged from mains power or rooftop solar but can also send electricity back to the grid.[25] A separate trial, led by Jemena (Victoria), is exploring using hardware-based smart charging for dynamic management of residential electric vehicles.[26]

More generally, the Distributed Energy Integration Program (DEIP) – a collaboration of government agencies, market authorities, industry and consumer associations – aims to enhance consumers' benefits from using distributed energy resources (DER), including benefits from access and pricing reforms.[27] The DEIP has also ran a series of task forces to explore issues relating to integrating EVs into the energy system.

23 Energy Networks Australia, *Consumer engagement report*, 2020.

24 Energy Networks Australia, 'Consumer Engagement Award finalists announced' [media release], 6 October 2020.

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

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

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

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

In May 2020 the Australian Energy Market Commission (AEMC) proposed rule changes to enable distributors to supply their customers using stand-alone power systems (SAPS)[28] where it is cheaper than maintaining a connection to the grid. The AEMC identified additional benefits of these systems, including improved reliability and reduced bushfire risks.[29]

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

3.7.1 Tariff structure reforms

Under traditional network tariff (price) structures, households and small businesses are charged the same tariffs regardless of how and when they use energy. Some consumers – such as those with air conditioners or solar PV systems – do not pay their full network costs under these structures, while other consumers pay more than they should. Network tariffs for large consumers are typically more cost-reflective.

Changes to the National Electricity Rules which took effect in 2017 require distributors to make their tariffs more cost-reflective so as to signal to retailers the cost of their customers' use of the network and investment in DER. Retailers are the primary focus of network tariff reform, because they act as the interface with consumers. They package network tariffs with other costs (such as wholesale energy) in their retail price offers and decide how to reflect the charges in those offers. It is up to the consumer to choose a retail offer that suits their needs, whether that be a flat rate retail tariff or a more innovative product.

Tariff reform can encourage more efficient use of networks, delay the need for new investment, and reduce the amount of infrastructure that needs to be maintained in the long term. Initially, reform focused on signalling costs during peak demand periods (which historically drove network investment). More recent reform has involved sending price signals to efficiently integrate DER – such as solar PV, batteries and EVs – into distribution networks.

As an example, the AER in 2020 approved SA Power Networks' (South Australia) use of a 'solar sponge' tariff for its residential consumers. This tariff offers a lower network charge during the middle of the day, when solar output is highest, to encourage shifting of electricity use to those times. Raising demand for grid-supplied electricity in the middle of the day can help manage voltage issues and thermal overloads associated with low demand, while shifting demand away from the evening peak that can put heavy strain on the network. SA Power Networks also introduced a demand tariff that offers discounted time of use rates and a seasonal peak demand component.[30]

Distributors are moving towards fully cost-reflective pricing in their second round of tariff structure statements, which the AER considers as part of the revenue determination process. Progress has included:

- simplifying tariff offerings to provide clear, consistent signals
- designing tariffs that more closely reflect how consumers' use of the network affects costs
- applying an 'opt-out' or mandatory assignment policy that increases the number of consumers whose retailers will face these more cost-reflective tariffs
- integrating network pricing with areas such as network planning, demand management and direct procurement of network services; and trialling alternative approaches.

In March 20201 the AEMC released a draft rule change to remove a prohibition on distributors charging for exports and expanded the definition of 'network services' to include DER exports. The AER expects that the next (third) round of tariff structure statements submitted by the distributors in NSW, Tasmania, the ACT and the Northern Territory will signal the cost of serving both consumption and generation.[31] The AER will continue to use an iterative approach to advancing this reform and will consult with stakeholders to produce a non-binding guideline on how export tariffs will be implemented.

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

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

30 SA Power Networks, *2020–25 regulatory proposal, Attachment 17 – tariff structure statement*, January 2019.

31 The tariff structure statements are due in January 2023 and will take effect from 1 July 2024.

To support the transitional introduction of export tariffs the AEMC modified revenue recovery arrangements to allow distributors to trial alternative tariff structures during the regulatory period.

The limited uptake of smart meters for residential and small business consumers has been a barrier to cost-reflective network tariffs being implemented in distribution networks outside of Victoria. Smart meters, which measure electricity use in half-hour blocks, are essential for cost-reflective network tariffs to be applied. At February 2021 around 39% of customers in the NEM had metering capable of supporting cost-reflective tariffs (including smart meters and manually readable interval meters). Installation rates vary across regions.

Victoria was the first jurisdiction to progress metering reforms, with its electricity distribution businesses rolling out smart meters from 2009 to 2014. Around 98% of small consumers in Victoria have a smart meter.

In other jurisdictions, the rollout of smart meters is occurring on a market-led basis, following changes to the National Electricity Rules which have been applicable since December 2017. All new and replacement meters installed for residential and small businesses consumers must now be smart meters, and other consumers can negotiate for a smart meter as part of their electricity retail offer.

The changes to the rules also transferred responsibility for metering from distributors to retailers. The transition to retailer responsibility coincided with large delays in meter installations in some regions. Participants indicated reasons for the delays included poor coordination and data provision among network businesses, retailers and metering coordinators; inadequate retailer systems, processes and controls; and poor resourcing. But from February 2019 new rules required retailers to provide consumers with electricity meters within 6 business days from a property being connected to the network, or with replacement meters within 15 days.[32] In December 2020 the AEMC announced a review of whether additional changes could help smart meters deliver more consumer benefits.[33]

Outside Victoria, in February 2021 NSW had the highest penetration of smart or interval meters, at around 25% of residential and small business customers. Installation levels in other regions ranged from 15% of customers in Queensland to 23% of customers in the ACT.[34] This share is expected to increase, ranging from 30% for Essential Energy (NSW) to 63% for TasNetworks (Tasmania) by 2025, reflecting the requirement for new meters – including end of life replacements – to be smart meters.

In March 2021 the NSW Government lifted restrictions on remote connection and disconnection of smart meters. Relaxing this restriction gives retailers an increased incentive to roll out more smart meters across NSW, delivering benefits to customers, particularly those in regional NSW who face higher fees for technicians to come out to their property.[35]

Around 24% of residential and small business customers outside of Victoria have moved to cost-reflective retail tariffs. Tasmania and NSW have seen the greatest take-up of these tariffs (at 47% and 41% of customers respectively), followed by the ACT (23% of customers). Customer adoption of cost-reflective tariffs remains low in Queensland (1% of customers) and South Australia (7% of customers). Distributors forecast the proportion of their residential consumers assigned to cost-reflective network tariffs will continue to increase from 2020 (figure 3.9).

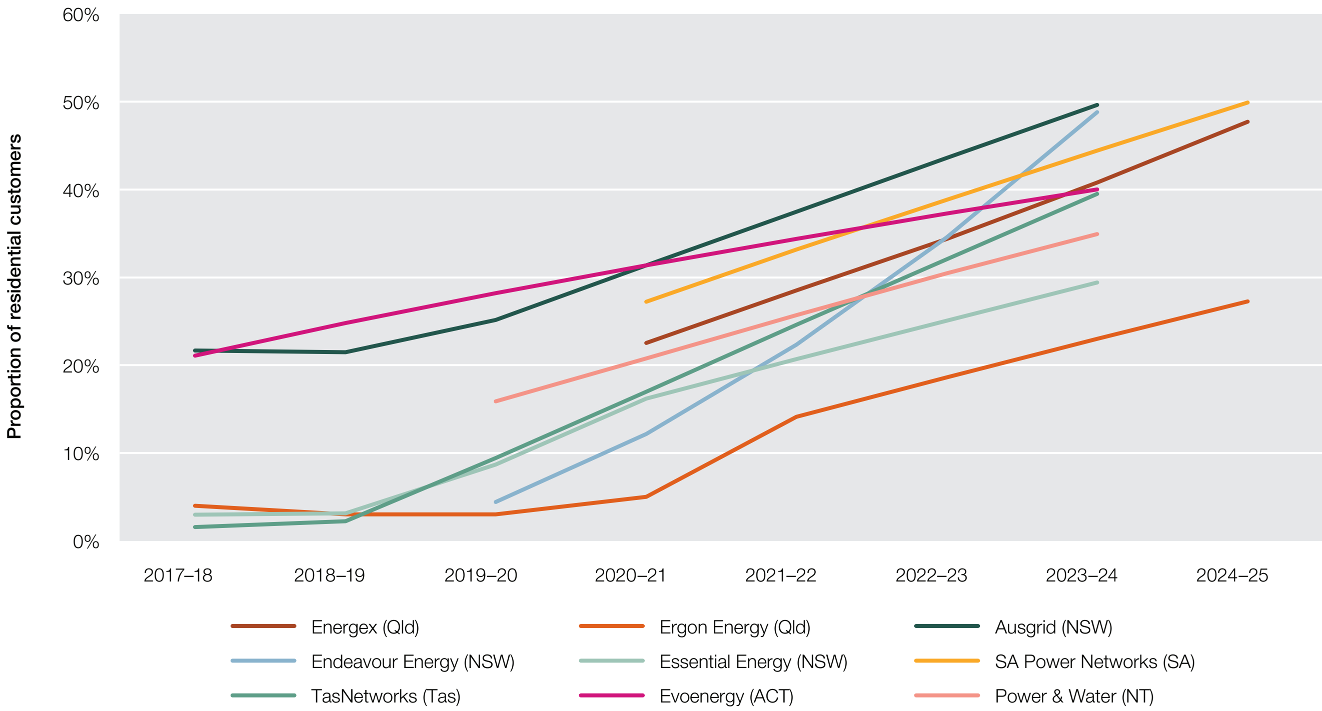
32 AEMC, *National Energy Retail Amendment (Metering Installation Timeframes) Rule 2018, rule determination*, December 2018.

33 AEMC, *Review announced into how electricity smart meters can deliver more customer benefits*, 3 December 2020.

34 Estimates based on AER market intelligence.

35 The National Tribune, 'Cutting red tape for smart meter savings', The National Tribune, 15 March 2021.

Figure 3.9 Projected assignment of cost-reflective tariffs for residential consumers – electricity distribution networks



Source: AER analysis of unpublished forecasts supplied by regulated electricity distribution businesses.

3.7.2 Ring-fencing

When a network business offers metering or other services in a contestable market, robust ring-fencing arrangements must be in place to ensure the business competes fairly with other providers. Ring-fencing aims to ensure network businesses do not use revenue from regulated services to cross-subsidise their unregulated products. It also aims to deter discrimination in favour of affiliated businesses.

The AER administers a ring-fencing guideline that requires distribution network businesses to separate their regulated network services (and the costs and revenues associated with them) from unregulated services, such as metering. Unregulated services must be offered through a separate entity.

All distributors are required to comply with the AER's ring-fencing guideline and annually report on their compliance to the AER. Since 2017–18 the AER has generally observed fewer compliance issues and breaches. However, compliance could still be improved in a number of areas, particularly in relation to protecting confidential information about the network. When breaches have occurred, distributors have generally communicated promptly with the AER, acted quickly to remediate any potential harms, and put a plan in place to prevent breaches from recurring. The introduction of civil penalties in February 2020 will continue to help encourage improved compliance.

In 2019 the AER commenced a review of the current distribution ring-fencing guideline to strengthen some obligations and simplify compliance. The review has since broadened to include consideration of the changing nature of services offered by distribution businesses, including through the use of new technology such as stand-alone power systems and storage devices. The competitive markets for distributor led stand-alone power systems and storage devices are in their infancy and it is unknown how quickly these markets may develop.

Electricity distributors are showing interest in entering these markets to provide contestable services, and to realise efficiencies in using storage devices to provide multiple services. In May 2021, the AER published its draft electricity distribution ring-fencing guideline for stakeholder feedback.[36] The amended guideline is scheduled to be finalised in the third quarter of 2021.

36 AER, *Draft ring-fencing guideline – Electricity distribution – version 3*, May 2021.

3.8 Revenue

Network businesses earn revenue for providing numerous services to consumers. While some of these services are regulated, others are provided through competitive markets. For transmission network businesses we focus on components of their revenue associated with delivering prescribed transmission services. For distribution network businesses we focus on revenues associated with providing core distribution services – standard control services.[37]

Since 2006 the amount of revenue earned by network businesses has seen distinct trends – rapid growth (until around 2013 in transmission and 2015 in distribution), followed by a significant downturn. The downturn in revenue was more gradual for the transmission network businesses than it was for distributors.

3.8.1 Revenue trends

Network revenues increased by around 6% per year from 2006 to 2015. With network charges absorbing around 43% of retail customer bills, this growth led to escalating retail electricity bills over the period.

A 67% increase in the value of the RAB from 2006 to 2014 – caused by surging investment – was a key contributor to the increase in revenue. From 2014 investment weakened, but the impact of past overinvestment remains in the asset base (section 3.10). The ballooning asset base increased financing costs and depreciation charges, resulting in higher revenue allowances to cover these costs. Rising interest rates due to the global financial crisis compounded the impact on revenue. Operating expenditure also increased by an average of 6% per year from 2006 to 2012. Further, many AER decisions faced legal challenges over this period, often resulting in court decisions that increased network revenue.

Revenue rose higher in Queensland and NSW than elsewhere. In Queensland, it grew by 14% per year from 2006 to 2015; in NSW, it rose by 14% from 2006 to 2013. Revenue growth was less dramatic in Victoria, increasing by a relatively stable 4% per year from 2006 to 2015. A key cost driver in Queensland and NSW was the stricter reliability standards imposed by state governments, which required new investment and operating expenditure to meet the new standards.

Cost pressures began to ease when electricity demand from the grid plateaued, causing new investment to be scaled back from 2013. The changing demand outlook coincided with government moves to allow network businesses greater flexibility in meeting reliability requirements. The financial environment also improved after 2012, easing borrowing and equity costs. After peaking at over 10% between 2009 and 2013, rates of return approved for some network businesses were below 5% in 2021 (section 3.11).

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

In combination, these factors reduced the revenue needs of network businesses. But the 5-year regulatory cycle meant lower investment and rates of return often lowered revenue only after a significant lag. More generally, consumers will continue to pay for the overinvestment in network assets from 2006 to 2013 for the remainder of the economic lives of those assets, which may be up to 50 years. The Grattan Institute called for the asset bases of some networks to be written down so consumers do not pay for that overinvestment.[38] The Australian Competition and Consumer Commission (ACCC) supported this position, particularly for government-owned networks in Queensland, NSW and Tasmania.[39]

Consumer groups and some industry observers remain concerned the regulatory framework enables network businesses to earn excessive profits. In response to calls for greater transparency around the actual returns earned by the network businesses, in 2018 the AER began publishing information on the businesses' profitability. In September 2020 the AER released its first *Electricity network performance report*,[40] which provides detailed analyses of key operational and financial trends as well as introducing a number of key profitability measures.[41] The report enables stakeholders to make more informed assessments of the returns earned by each network business.

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

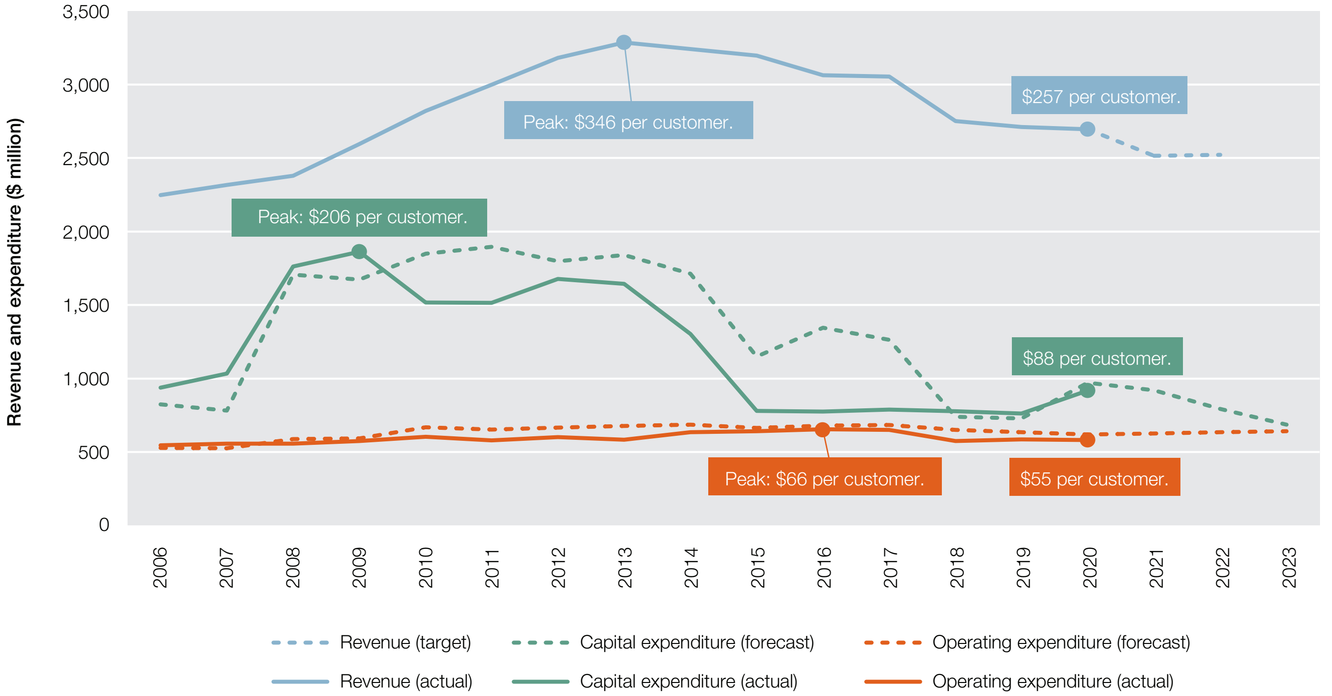
38 Grattan Institute, *Down to the wire – a sustainable electricity network for Australia*, March 2018.

39 ACCC, *Retail Electricity Pricing Inquiry – final report*, June 2018

40 AER, *Electricity network performance report*, September 2020.

41 AER, *Profitability measures for electricity and gas network businesses, final position paper*, December 2019.

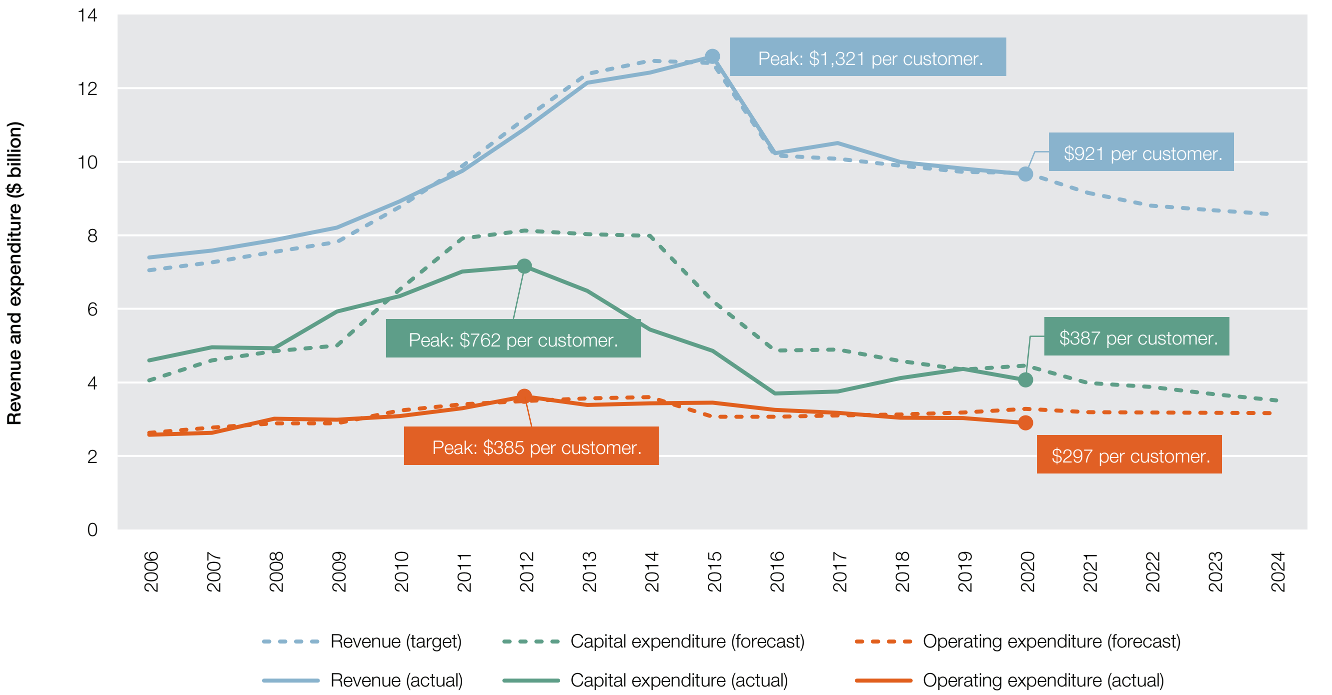
Figure 3.10 Revenue and key drivers – electricity transmission networks



Note: All data are adjusted to June 2021 dollars, based on forecasts of the consumer price index (CPI). Most network businesses report on a 1 July – 30 June basis. The exception is AusNet Services (Victoria), which reports on a 1 April – 31 March basis. The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018). Forecast transmission revenues are subject to adjustments over which the AER has limited visibility. Target revenue is derived from regulatory decisions but adjusted to present it on a comparable basis to actual revenues. The adjustments include rewards and penalties from incentive schemes, cost pass-throughs and other factors that are taken into account in determining the target revenues used to set prices each year.

Source: revenue: economic benchmarking regulatory information notice (RIN) responses; capital expenditure: AER modelling, category analysis RIN responses; operating expenditure: AER modelling, economic benchmarking RIN responses.

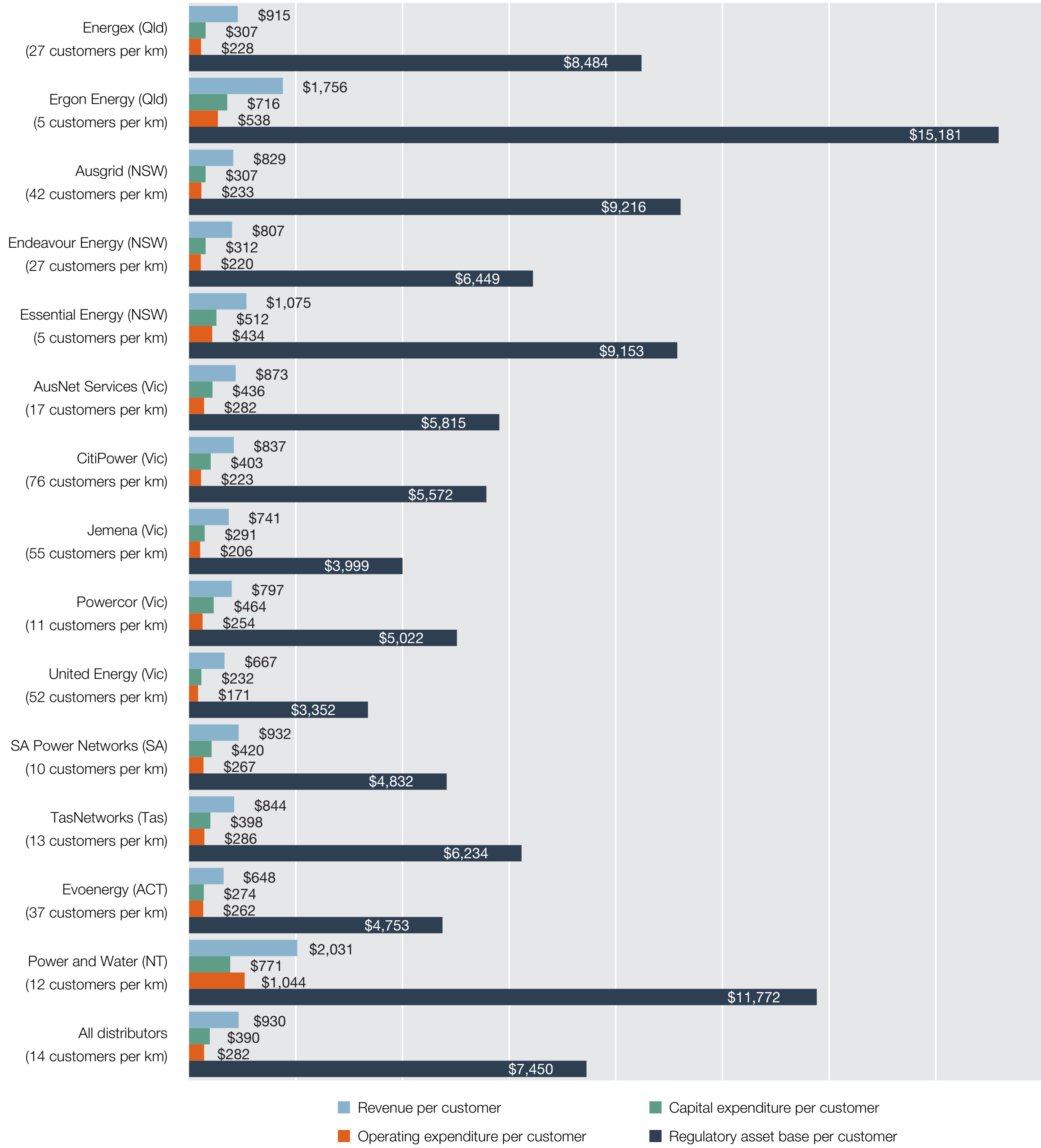
Figure 3.11 Revenue and key drivers – electricity distribution networks



Note: All data are adjusted to June 2021 dollars, based on forecasts of the consumer price index (CPI). Most network businesses report on a 1 July – 30 June basis. The exceptions are the Victorian distribution network businesses, which report on a 1 January – 31 December basis. The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018). Target revenue is derived from regulatory decisions but adjusted to present it on a comparable basis to actual revenues. The adjustments include rewards and penalties from incentive schemes, cost pass-throughs and other factors that are taken into account in determining the target revenues used to set prices each year.

Source: revenue: economic benchmarking regulatory information notice (RIN) responses; capital expenditure: AER modelling, category analysis RIN responses; operating expenditure: AER modelling, economic benchmarking RIN responses.

Figure 3.12 Key financial indicators (2020) – electricity distribution networks



Note: In 2020 residential customers (a customer who purchases energy principally for personal, household or domestic use) accounted for 89% of total customers on the distribution network. Of the remaining customers, 10% were non-residential (including high voltage customers who were connected at higher than 415 volts and low voltage customers who were connected at 240 or 415 volts) and 1% were unmetered or ‘other’. While these proportions differed across network businesses – 92% residential for Evoenergy (ACT) and 83% for CitiPower (Victoria), for example – the differences did not materially affect the ‘per customer’ metric. Revenue, capital expenditure, operating expenditure and asset base are actual outcomes for the regulatory year ending in 2020. For regulatory purposes, Northern Territory transmission assets are treated as part of the distribution system.

Source: AER estimates derived from economic benchmarking regulatory information notice (RIN) responses; AER modelling; AER revenue decisions; Australian Competition Tribunal decisions.

Operating, maintenance and other costs correlate less closely with market conditions than do other revenue drivers and show relatively stable trends. In 2009 operating costs were about one-third that of asset investment. However, by 2015 weakening investment had seen the expenditure on capital projects drop to a comparable level with operating costs. Operating expenditure later eased as network businesses (especially distributors) implemented efficiency programs (section 3.13).

Figure 3.12 provides a summary of key financial indicators from 2020 for distribution networks on a per customer basis. This allows for greater comparability across networks.[42]

3.8.2 Revenue in 2020

In 2020 electricity network businesses earned a total of $12.4 billion in revenue. Of this, transmission network businesses earned $2.7 billion, which was 0.6% less than in the previous year and 18% less than the peak in 2013 (figure 3.10). Distributors earned around $9.7 billion, which was 1.5% less than in the previous year and 25% less than its peak in 2015 (figure 3.11).

Network revenue is forecast to continue to fall over the next few years. Beyond that point investment on the transmission networks is likely to increase the industry RAB, pushing revenue higher.

3.8.3 Current AER revenue decisions

Transmission network businesses are forecast to earn around $13.1 billion in revenue over the current periods – $2.1 billion (14%) less than they were forecast to earn in the previous periods. Distribution network businesses are forecast to earn around $44.8 billion – $7.7 billion (15%) less than they earned in the previous periods (figure 3.11).[43]

Unlike the distribution networks, forecast (or target) transmission revenues cannot be directly compared to actual revenues. Actual revenues are subject to adjustments over which the AER has limited visibility. The adjustments include rewards and penalties from incentive schemes, cost pass-throughs and other factors that are taken into account in determining the target revenues used to set prices each year. Revenue for transmission businesses are locked in at the beginning of the regulatory period. The businesses are then incentivised to provide services at the lowest possible cost because their returns are determined by their actual costs of providing services. If the transmission networks reduce their costs to below the estimate of efficient costs, the savings are shared with consumers in future regulatory periods.

In its most recent revenue decisions the AER approved revenue targets for the Victorian distributors which are $313 million (2.7%) less than they were forecast to earn and $392 million (3.4%) less than they actually earned in the previous period (figure 3.8).

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

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

43 The current regulatory period is the period in place at 1 July 2021.

3.9 Network charges and retail bills

Electricity network charges made up 40–50% of a residential customer's energy bill in 2020–21 (section 6.6.1 in chapter 6). Distribution networks account for the majority of costs (73–78%) with transmission network costs (up to 21%) and metering costs making up the balance.

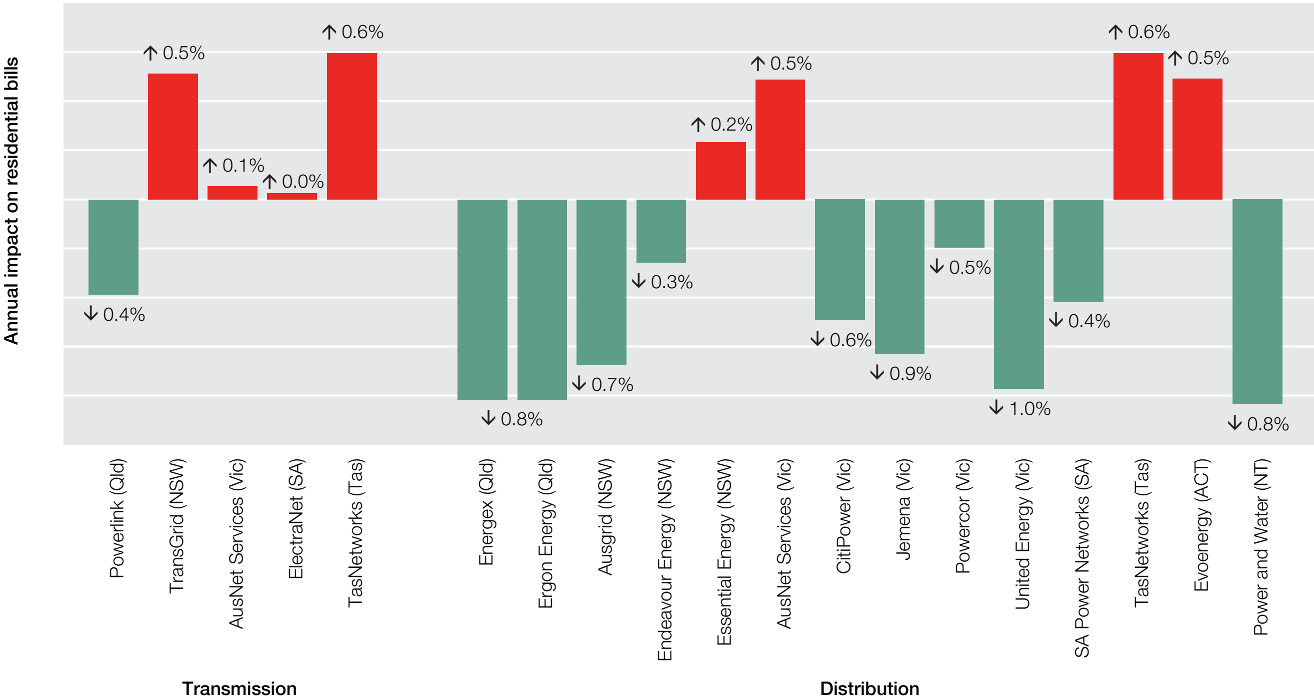
Declining network revenue since 2015, combined with rising customer numbers, has translated into lower network charges in retail energy bills for most customers (figure 3.13). This lowering of network charges helped to mitigate some of the pressure (caused by higher wholesale electricity costs) on retail energy bills between 2017 and 2019.

The AER's most recent revenue decisions decreased residential energy bills by an average of 0.1% per year across all states and territories. This is the culmination of an average 0.2% increase in transmission and an average 0.4% decrease in distribution. Changes to network charges mostly arise in the first year of a regulatory period and range from a 9% reduction for Power and Water (Northern Territory) to a 1.6% increase for AusNet Services (Victoria). Initial changes are generally followed by stable prices or modest increases in later years.

The reduction in network charges reflects factors such as lower finance costs, lower demand for electricity (so less need for new investment), operating efficiencies implemented by network businesses (partly in response to AER incentive schemes), and regulatory refinements such as the AER's wider use of benchmarking to assess efficient costs.

Electricity distributors submit annual pricing proposals to the AER, outlining proposed prices to take effect in the following year. These proposing prices must be consistent with the distributor's approved revenues but are adjusted for factors such as the distributor's performance against incentive schemes and correcting for prior year under- or over-recoveries. The distributors also adjust prices to recover costs from transmission and jurisdictional schemes that are not considered by the AER in setting approved revenues.

Figure 3.13 Impact of AER revenue decisions on annual residential customer electricity bills



Note: Estimated annual impact of latest AER decision on the network component of a residential electricity bill based on AER estimates of retail electricity prices and typical residential consumption in each network. Revenue impacts are nominal and averaged over the life of the current decision.

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

Source: AER revenue decisions; additional AER modelling.

In May 2021 the AER approved Evoenergy's 2021–22 electricity pricing proposal in accordance with its 2019 to 2024 distribution determination. Evoenergy's pricing proposal generated media attention due to its significant proposed price increases. From 1 July 2021 the network tariff component of the typical annual bill for Evoenergy customers is estimated to be $241 higher for households and $1,476 higher for small business compared with the previous year – an increase of 41%.[44] Evoenergy's charges for jurisdictional[45] taxes and renewables policies drove much of this increase, rising 133% from the charges for 2020–21.[46]

3.10 Regulatory asset base

The RAB for a network business represents the total economic value of assets that provide network services to customers.[47] These assets have been accumulated over time and will be at various stages of their economic lives. Some networks may have relatively older/newer assets than others depending on their growth and the phase of the replacement cycle they are in. The value of the RAB substantially impacts a network service providers' revenue requirements and the total costs a network's consumers ultimately pay. Given some network assets have a life of up to 50 years, network investment will impact retail energy bills long after the investment is made.

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

Escalating investment inflated the value of the total network RAB from $56.6 billion in 2006 to $94.9 billion in 2014 – an increase of around 8% per year. Since 2014 the amount network investment has steadied, as has the growth in the value of the total network RAB. From 2014 to 2020 the value of the total network RAB continued to grow but at a considerably slower rate of around 1% per year. While the value of the total network RAB has continued to grow, the trend has not been the same for both transmission and distribution networks.

3.10.1 Regulated asset base in 2020

In 2020 the combined value of the RABs for network businesses was $100.4 billion, which was 1.2% higher than in the previous year. Of this, the value for the transmission networks was $21.7 billion, which was 0.3% lower than in the previous year and 3% lower than at its peak in 2014. In 2020 the combined value of the RAB for distribution networks reached a new high of $78.8 billion, which was 1.6% higher than in the previous year. However, in recent years the growth in the value of the RAB has been offset by greater increases in the number of customers connected to the networks. As such, the $9,498 RAB per customer in 2020 was 3% lower than its peak in 2015 (figure 3.14).

Network businesses receive a guaranteed return on their RAB. For this reason, they have an incentive to overinvest if their allowed rate of return exceeds their actual financing costs. Previous versions of the energy rules enabled significant overinvestment in network assets, which partly drove the sharp rise in network revenue from 2006 to 2015 (section 3.12.2). Under reforms introduced in 2015 the AER can remove inefficient investment from a network's asset base if the network overspent its allowance, to ensure customers do not pay for it.

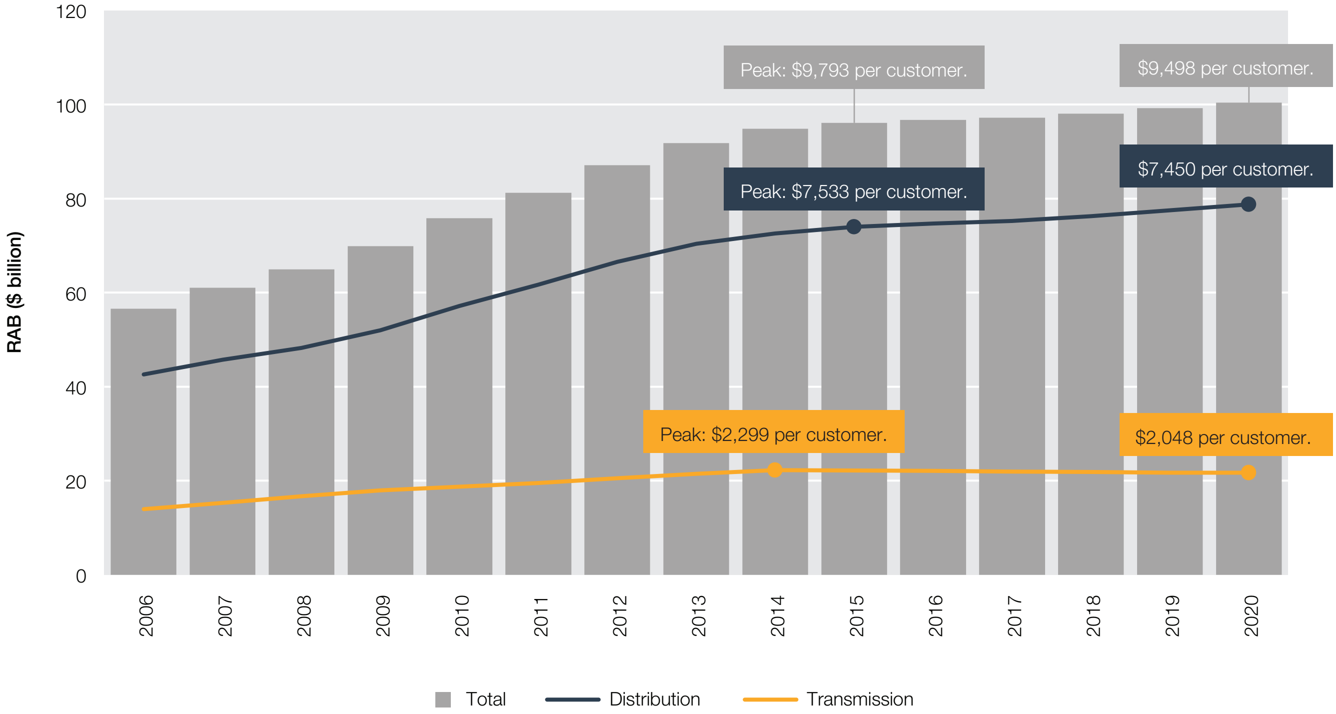
44 AER, *AER approves 2021–22 Evoenergy network tariffs for ACT electricity customers*, AER website, 14 May 2021, accessed 21 May 2021.

45 Jurisdictional schemes are expenses incurred by Evoenergy pursuant to ACT Government requirements, such as the large scale feed-in tariff.

46 Evoenergy, *Network pricing proposal 2021/22*, April 2021.

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

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



Note: Closing regulatory asset bases (RABs) for electricity networks in the NEM, consumer price index (CPI) adjusted to (forecast) June 2021 dollars. Most network businesses report on a 1 July – 30 June basis. The exceptions are Victorian networks: AusNet Services (transmission) reports on a 1 April – 31 March basis; and the Victorian distribution network businesses report on a 1 January – 31 December basis. The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018). Transmission networks do not report customer numbers. Per customer metrics for the transmission network were calculated using the total number of distribution customers.

Source: AER modelling; economic benchmarking regulatory information notice (RIN) responses.

3.10.2 Overhead support structures

The assets that make up a network business's RAB are disaggregated into a number of categories. In 2020 substations, switchyards and transformers were the largest class of assets for transmission businesses (44% of the total transmission network RAB), followed by overhead assets (36%). Overhead network assets were the largest class of assets for distribution businesses (35% of the total distribution network RAB), followed by underground network assets (23%), zone substations and transformers (19%) and distribution substations including transformers (14%).

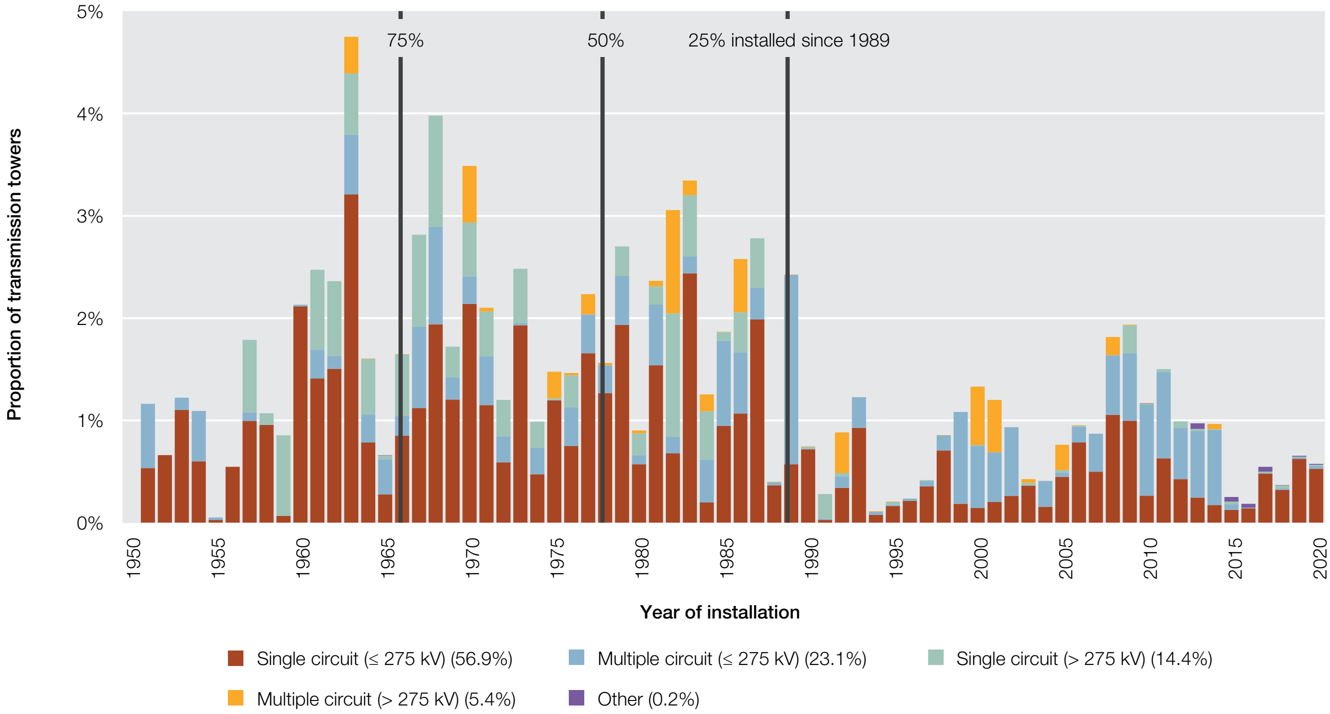
Transmission towers and distribution poles are installed and maintained by network businesses to support overhead power lines. While transmission towers are predominately made of steel, distribution poles are generally made of wood, concrete, steel or composites like fiberglass. Different environmental conditions faced by networks can shape their choice of material. For example, in some parts of Australia, wooden poles are more quickly destroyed by termites, so metal poles must be used instead.

Overhead network assets represent the most observable components of electricity network infrastructure and account for the greatest proportion of the total network RAB (around 35%). This is not surprising given the network spans almost 790,000 kilometres of line, 85% of which is above ground.

There are significant differences in the age and profile of the towers and poles on each network. Some networks, such as Essential Energy (NSW) and Ergon Energy (Queensland) operate larger rural distribution networks that are almost entirely above ground. Conversely, Evoenergy (ACT) and CitiPower (Victoria) operate smaller urban distribution networks that are predominately underground. In these cases the predominately rural networks are more reliant on overhead poles than the networks operating in predominately urban environments.

The overhead network asset age profiles shown in figures 3.15 and 3.16 provide an overview of the different types of towers and poles currently in commission. The individual profiles and characteristics of each network vary significantly from the whole of NEM averages.

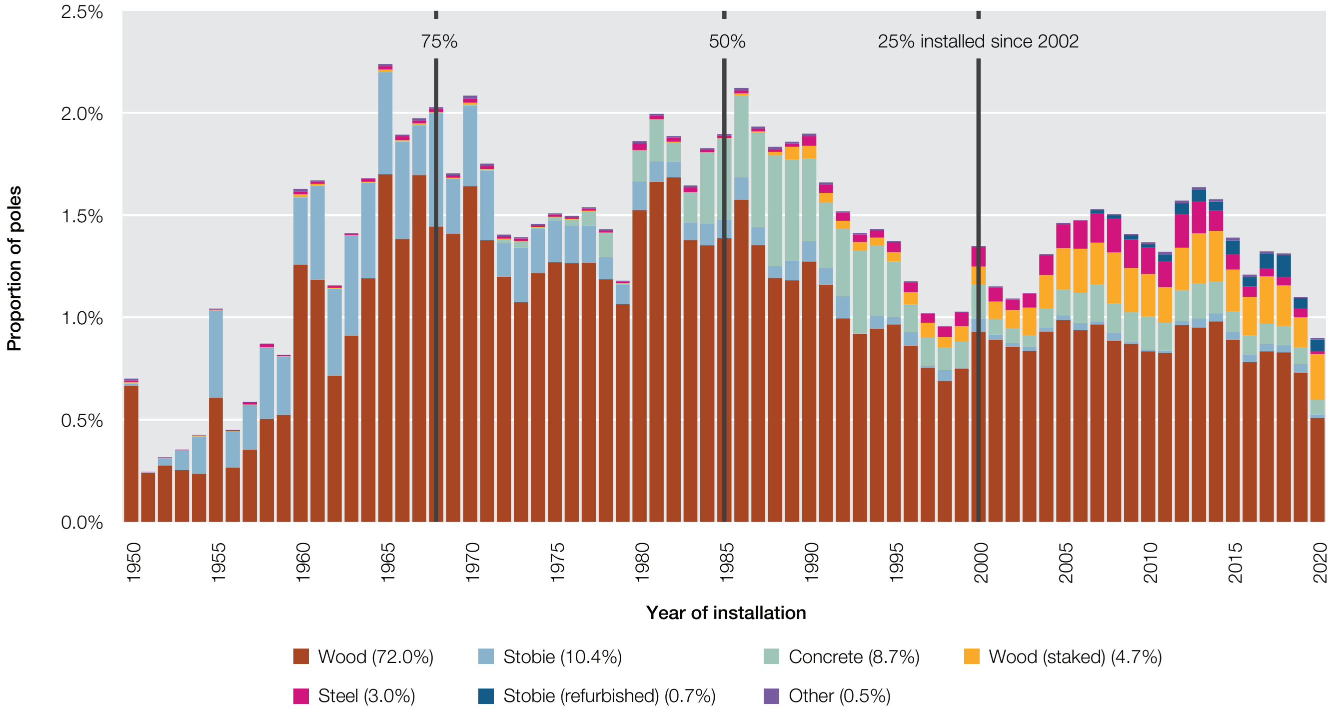
Figure 3.15 Overhead support structures – electricity transmission towers in the National Electricity Market



kV: kilovolt.

Source: Category analysis regulatory information notice (RIN) responses.

Figure 3.16 Overhead support structures – electricity distribution poles in the National Electricity Market



Note: Only includes distributors in the National Electricity Market and does not include Power and Water (Northern Territory). 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 regulatory information notice (RIN) responses.

3.11 Rates of return

The shareholders and lenders that finance a network business expect a commercial return on their investment. The rate of return estimates the cost of funds that a network business's financiers require to justify investing in the business. It is a weighted average of the return needed to attract 2 sources of funding – equity (dividends paid to a network business's shareholders) and debt (interest paid on borrowings from banks and other lenders). Given this weighting approach, the rate of return is sometimes called the weighted average cost of capital (WACC).

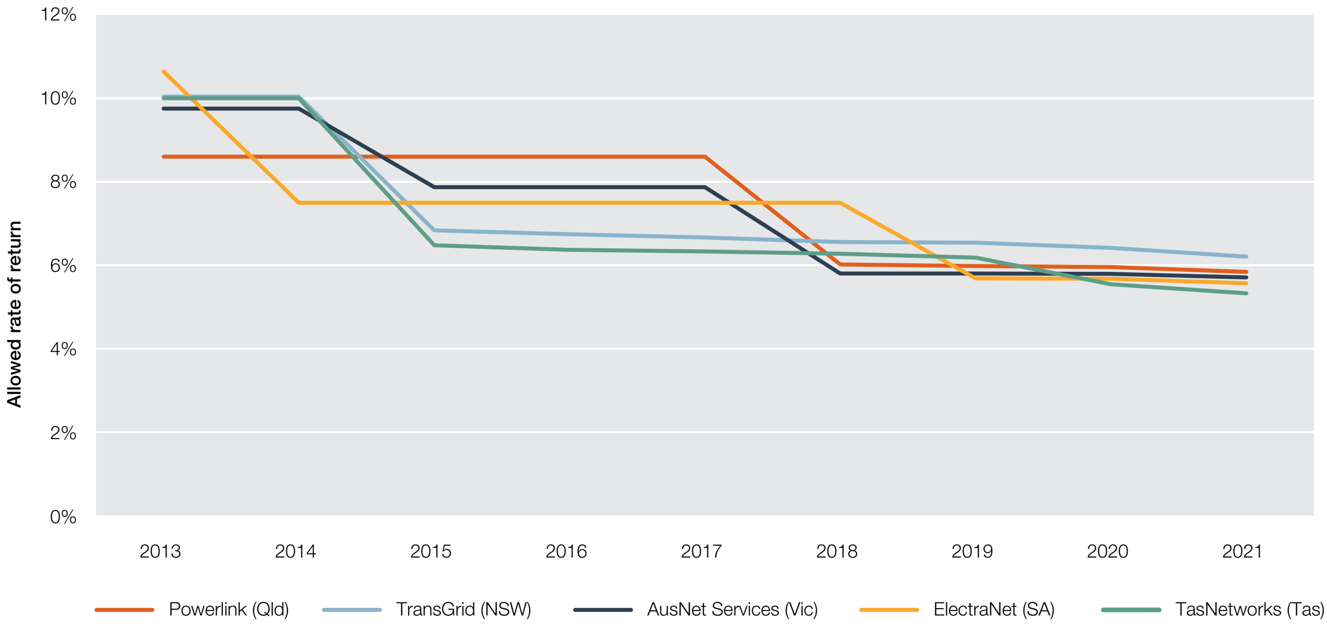
The AER sets an allowed rate of return, but a network's actual returns can vary from the allowed rate. The variance can be due to a number of factors, such as the impact of incentive schemes, forecasting errors, revenue over- or under-recovery under a revenue cap, or the revenue smoothing process. The AER calculates allowed returns each year by multiplying the RAB by the allowed rate of return.[48]

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

As electricity networks are capital intensive, returns to investors typically make up 30–50% of a network's total revenue allowance. A small change in the allowed rate of return can have a significant impact on network revenue and a customer's energy bills. A one percentage point increase in the rate of return for TransGrid (NSW transmission) would increase the business's revenues by around 10%, for example. For this reason, the allowed rate of return is often a contentious part of a revenue decision.

Conditions in financial markets are a key determinant of the allowed rate of return. The AER's revenue decisions from 2009 to 2012 took place against a backdrop of the global financial crisis, an uncertain period associated with reduced liquidity in debt markets, and high risk perceptions. Reflecting conditions in financial markets, the allowed rate of return peaked at over 10% in revenue decisions made during this period (figures 3.17 and 3.18). The Tribunal increased some allowed rates of return following appeals by the network businesses.

Figure 3.17 Allowed rate of return – electricity transmission networks



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

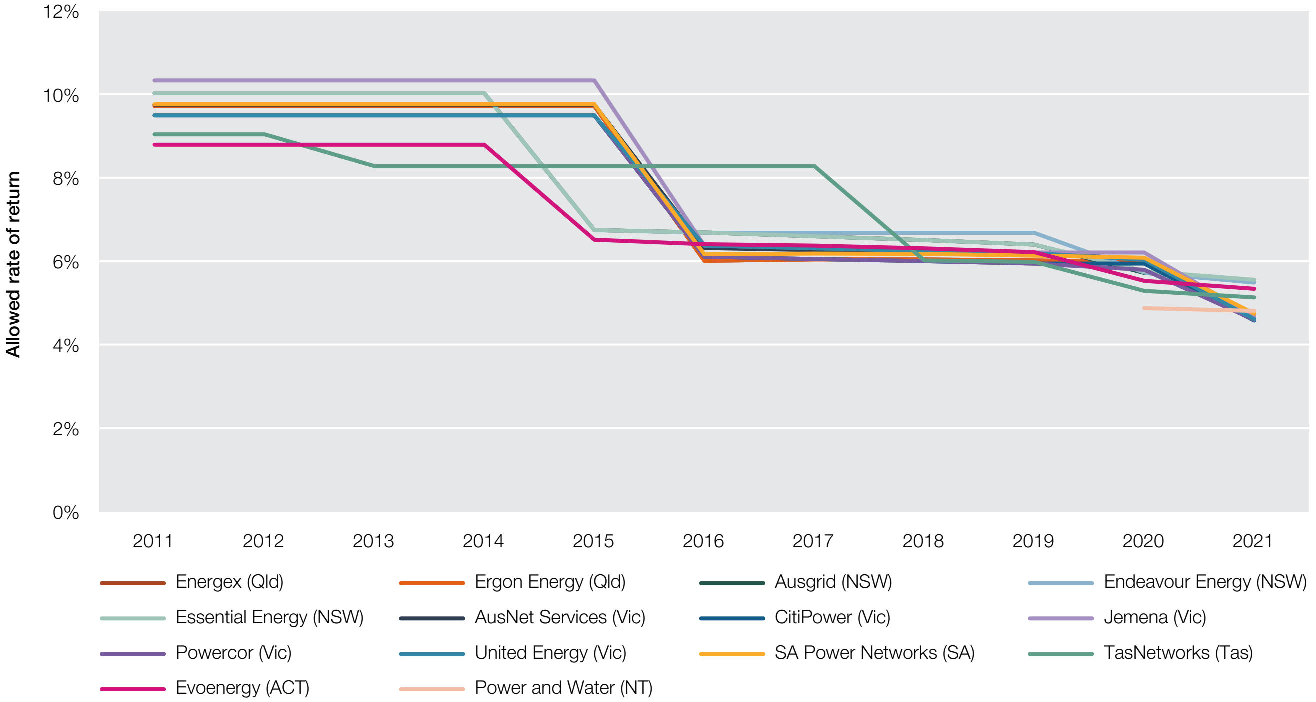
Source: AER decisions on electricity network revenue proposals; AER decisions following remittals by the Australian Competition Tribunal or Full Federal Court.

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

Borrowing and equity costs have since eased. From 2015 the AER has updated the cost of capital annually to reflect changes in debt costs. More stable financial market conditions resulted in allowed rates of return averaging around 6% from 2016. These lower allowed rates became a key driver of lower network revenues and charges over the past few years (figures 3.10 and 3.11).

In recent years the network businesses' actual returns have often exceeded the AER's allowed returns. This is not unexpected given the premise of a revealed efficient cost framework encourages network businesses to become more efficient, allowing network businesses to earn short term profits above the allowed rate.[49]

Figure 3.18 Allowed rate of return – electricity distribution networks



Note: Rate of return is the nominal vanilla weighted average cost of capital (WACC). Victorian data for the 2021 year has been derived from the transitional year (6 months data). To enable reporting on equivalent terms it has been doubled.

Source: Post-tax revenue models (PTRMs) developed as part of final regulatory decisions, as made by the AER or jurisdictional regulators, and amended to take into account any updates made after the final decision.

3.11.1 Reforms to setting the allowed rate of return

Outcomes from to the AER's approach to setting allowed rates of return were often adversarial before 2018, with many network businesses arguing for a different approach with different parameters. Regulatory decisions were often challenged. These legal battles were long and costly and added to uncertainty for network businesses, consumers and investors.

New legislation introduced in 2018 provided for the AER to make binding rate of return determinations that apply to all network businesses. The AER released its first Rate of Return Instrument (RRI) in December 2018, setting out how it determines the allowed rate of return on capital in revenue determinations.[50]

In setting the allowed rate of return, the AER balances the need for efficient and stable investment against the need to ensure consumers pay no more than necessary for safe and reliable energy. The RRI sets out the approach by which the AER will estimate the rate of return, and includes the return on debt and the return on equity, as well as the value of imputation credits. The RRI is expected to reduce consumer bills by around $30 to $40 a year on average, relative to the approach set out in the AER's 2013 rate of return guideline.[51]

The first regulatory determinations under the RRI were completed in April 2019. The AER is required to review and replace the RRI by December 2022.[52]

49 The AER's *Electricity network performance report* (September 2020) investigates network profitability in order to better understand actual returns as opposed to allowed/forecast returns.

50 The 2018 RRI specifies the return on debt as a formula, using the trailing average portfolio approach. Network businesses not already applying this method must transition to it over a 10-year period.

51 AER, 'AER releases final decision on rate of return for regulated energy networks' [media release], 17 December 2018.

52 The AER is required to set the RRI every 4 years.

3.12 Electricity network investment

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

3.12.1 Investment trends

Total investment in the electricity network grew by an average of 8% per year from 2006 until 2012, when it peaked at $14.1 billion (figures 3.10 and 3.11). From 2006 to 2009 network businesses invested 11% more on capital projects than their approved forecasts. This growth was in response to concerns that investment was not keeping pace with the projected growth in electricity demand. More stringent reliability standards imposed by some state governments also spurred higher than forecast investment.

From 2013 lower demand for electricity began to reverse this trend. Many projects were 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 on network businesses made some projects redundant, leading to several proposals being scaled back or deferred.

Investment levels further eased from 2015, when AER reforms that protect consumers from funding inefficient network projects began. Plus, a capital expenditure sharing scheme (CESS) offered financial incentives for network businesses to avoid investment above forecast levels (box 3.3). From 2010 to 2018 network businesses underspent on capital projects (compared with approved AER forecasts) by $13.1 billion (18%).

In 2019 network businesses marginally overspent on capital projects (by 1.2%) compared with approved AER forecasts. However, this proved to be an anomaly, as in 2020 network businesses again underspent on capital projects (by 8%).

Box 3.3 Capital expenditure sharing scheme

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

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

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

The scheme poses risks that network businesses may inflate their original investment forecasts. To manage this risk, the AER assesses whether proposed investments are efficient at the time of each revenue determination. Another risk is that the scheme may incentivise a network business to earn bonuses by deferring critical investment needed to maintain network safety and reliability. To manage this risk, the CESS is balanced by separate incentives that focus on efficient operating expenditure (box 3.4) and service quality (box 3.5). This balancing of schemes encourages network businesses to make efficient decisions on their mix of expenditure so as to provide reliable services in ways that customers value (section 3.15.1).

3.12.2 Network investment in 2020

In 2020 electricity network businesses invested $5 billion on capital equipment, which was 3% less than in the previous year and 44% less than its peak in 2012. Of this, transmission network businesses spent $918 million, which was 20% higher than in the previous year but 51% lower than its peak in 2009 (figure 3.10).[53]

Distribution network businesses spent $4.1 billion, which was 7% less than in the previous year and 43% less than its peak in 2012 (figure 3.11).

Significant investment in the transmission network has been proposed over the next few years. Actionable projects under AEMO's 2020 ISP are expected to cost over $11 billion from 2022 to 2026.[54]

3.12.3 Current AER investment allowances

Transmission networks are forecast to invest around $4.1 billion in capital projects over their current regulatory periods. The approved forecasts are $403 million (9%) less than the transmission networks invested in their previous periods, where they underspent by a combined $1.9 billion (33%) against forecast (figure 3.10).[55]

Distribution networks are forecast to invest around $19.1 billion in capital projects over their current regulatory periods. The approved forecasts are $1.4 billion (7%) less than the distributors invested in their previous periods where they underspent by $3.3 billion (14%) against forecast (figure 3.11).

In its most recent revenue decisions the AER approved a combined $5.2 billion of forecast investment for the Victorian distributors over the current regulatory period. The majority of forecast investment for the Victorian distributors is to replace or refurbish old assets. The approved forecast is $108 million (2%) less than the Victorian distributors invested in the previous period.

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

3.12.4 Changing composition of investment

Over the past decade, the composition of network investment has changed markedly. Until recently, significant network investment occurred in growth (augmentation) to support new connections (such as new substations) and expand capacity to cope with forecast rising demand. In 2009, for example, growth projects accounted for 44% of investment (63% for transmission and 35% for distribution).

But weaker than forecast demand for electricity, along with less stringent reliability obligations, led many network owners to postpone or abandon growth-related projects in the following years. In 2020 growth-related investment accounted for only 7% of investment (26% for transmission and 2% for distribution). Investment on growth-driven projects by transmission networks in 2020 was $965 million (82%) less than at its peak in 2009 (figure 3.19). Likewise, investment on growth-driven projects by distribution networks in 2020 was $1.7 billion (96%) less than at its peak in 2012 (figure 3.20).

Since 2009 expenditure allocated to replacing ageing or degraded assets remained fairly constant at $1.5–2.3 billion. However, as a proportion of decreasing total investment, replacement expenditure has risen considerably. Since 2017 capital (replacement) expenditure has accounted for almost 50% of total network investment (63% for transmission and 46% for distribution).

Since 2017 network investment in augmentation has been lower than investment in replacement projects, overheads and non-network assets (for example, ICT, buildings and property, fleet and plant, minor asset tools and equipment, and motor vehicles).

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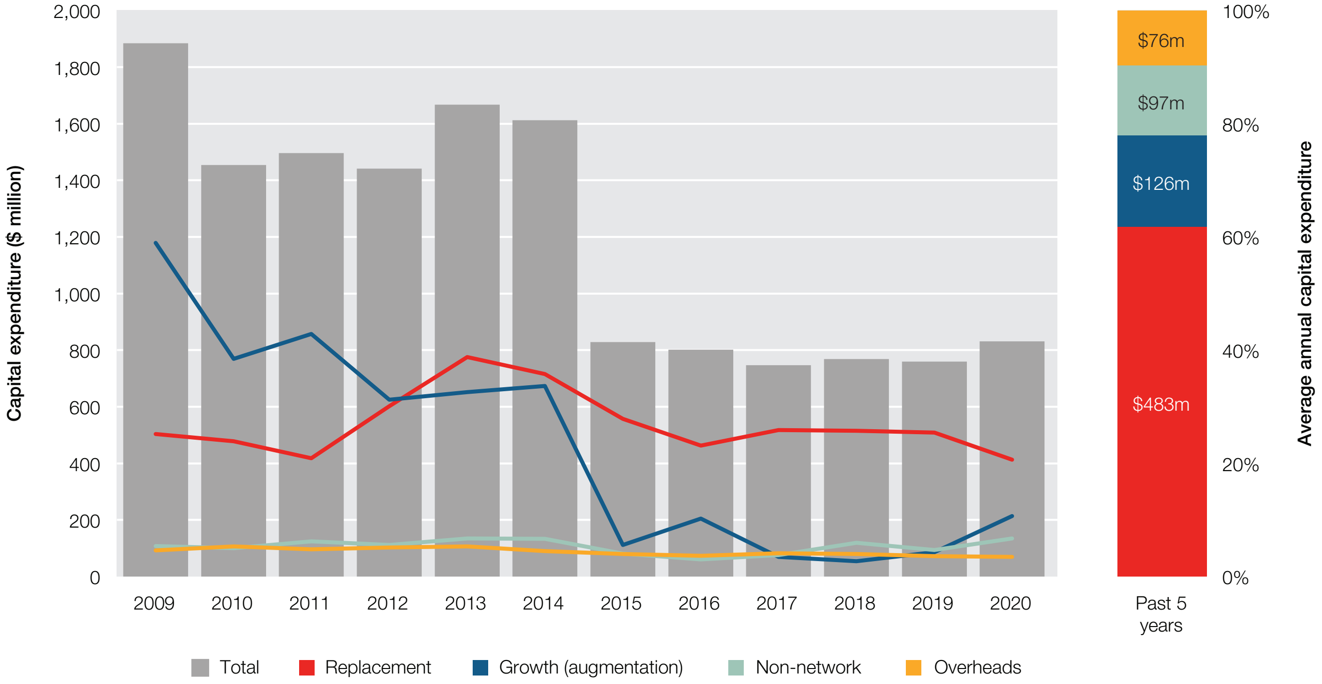
53 Excludes AER decisions on transmission interconnectors.

54 AEMC, *Electricity network economic regulatory framework 2020 review*, 1 October 2020, p 3.

55 The current regulatory period is the period in place at 1 July 2021.

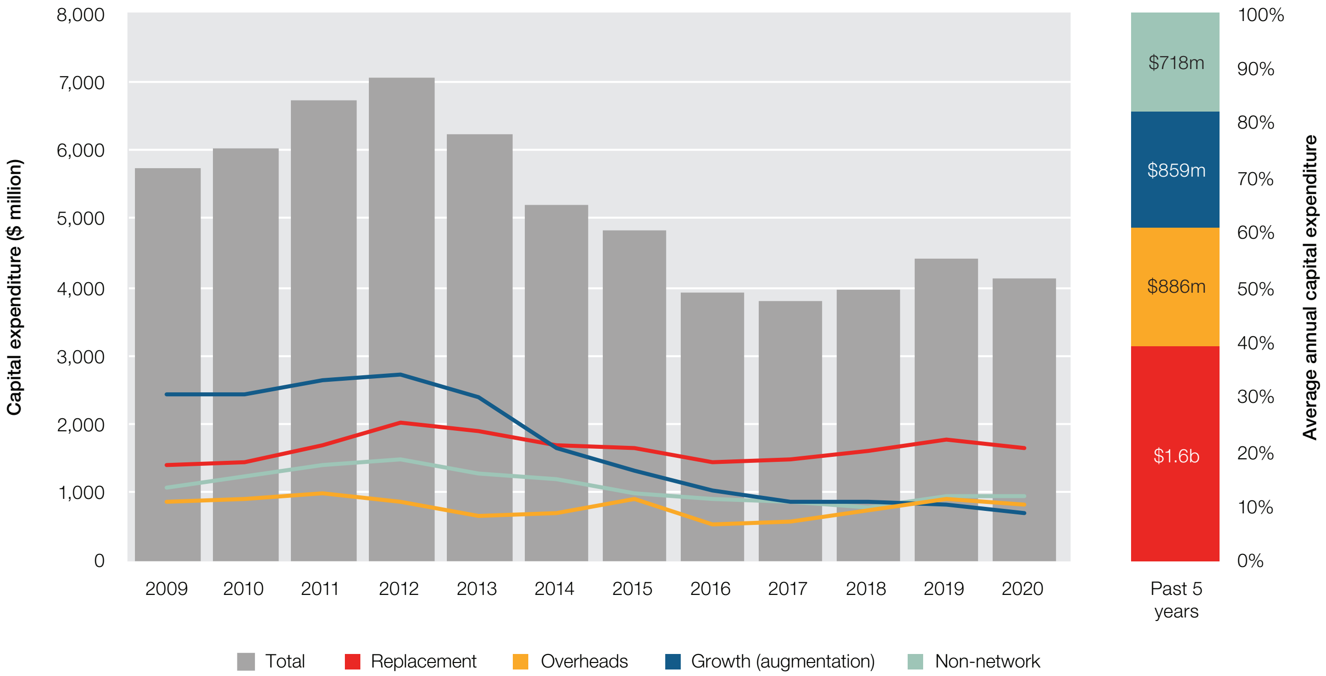
Figure 3.19 Drivers of capital expenditure – electricity transmission networks



Note: Actual outcomes, consumer price index (CPI) adjusted to (forecast) June 2021 dollars. Most network businesses report on a 1 July – 30 June basis. The exception is the Victorian network AusNet Services, which reports on a 1 April – 31 March basis. The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018).

Source: Category analysis regulatory information notice (RIN) responses.

Figure 3.20 Drivers of capital expenditure – electricity distribution networks



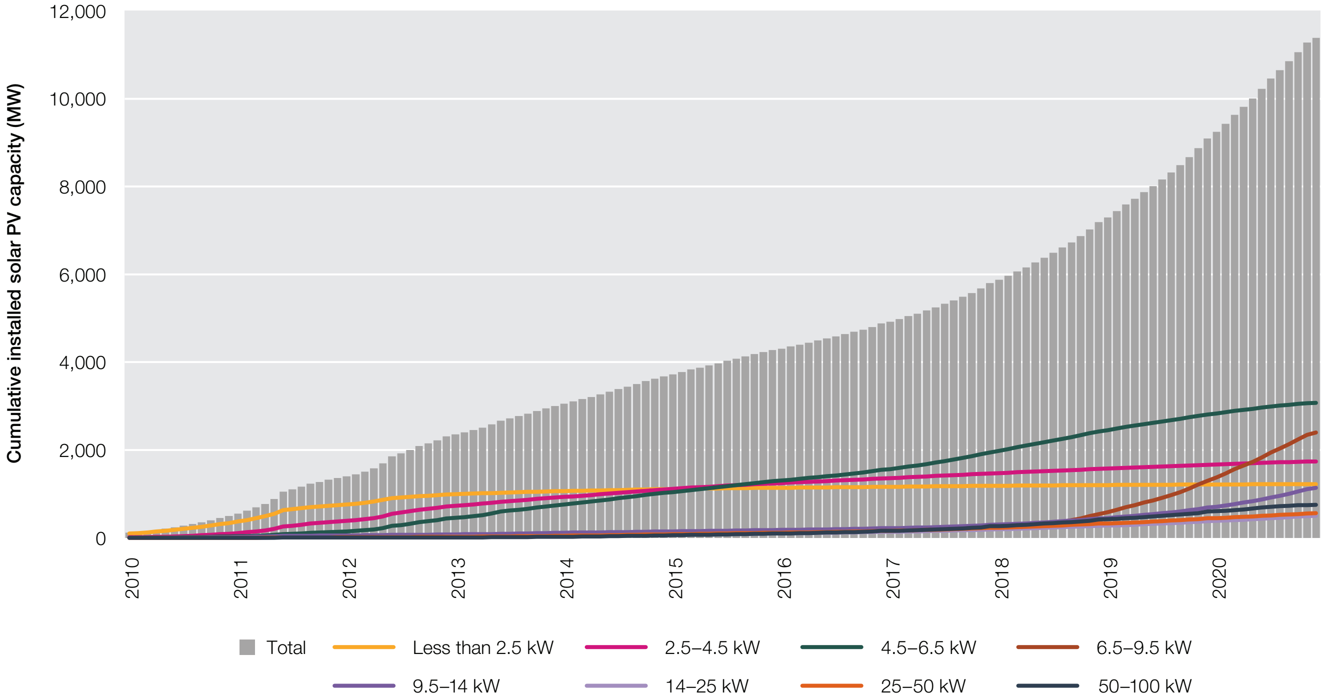
Note: Actual outcomes, consumer price index (CPI) adjusted to (forecast) June 2021 dollars. Most network businesses report on a 1 July – 30 June basis. The exceptions are Victorian networks, which report on a 1 January – 31 December basis. The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018).

Source: Category analysis regulatory information notice (RIN) responses.

3.12.5 Valuing distributed energy resources

The uptake of rooftop solar PV systems has grown exponentially in the past decade (figure 3.19). As a result of this rapid growth, DER integration now presents a significant, emerging area of expenditure.

Figure 3.21 Cumulative installed small scale solar photovoltaic capacity



kW: kilowatts; MW: megawatts; PV: photovoltaic.

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

Source: AER analysis of postcode data from the Australian PV Institute, collected on 24 February 2021.

In November 2109 the AER began developing guidance around assessing proposed DER integration expenditure. As part of this process, the AER sought stakeholder views on the current and predicted effects DER is having on networks and whether its current set of expenditure assessment tools are fit for purpose.

In November 2020 the AER released a report (by the CSIRO and Cutler Merz) on potential methodologies for determining the value of DER (VaDER).[56] 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 DER installed by customers.

The findings and recommendations of the VaDER report will be reviewed and considered as part of the AER's DER integration expenditure guideline, which is expected to be completed in 2021.

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

A high DER environment could mean that distributors need to alter aspects of their operation, from transporting electricity one-way to being platforms for multiple services, facilitating electricity flows in multiple directions and enabling efficient access for DER so that they can provide the greatest benefits to the system as a whole. This change is likely to have implications for some features of the current regulatory framework.[57]

56 CSIRO and CutlerMerz, *Value of distributed energy resources: methodology study – final report*, October 2020.

57 AEMC, *Electricity network economic regulatory framework 2020 review*, 1 October 2020.

3.12.6 Regulatory tests for efficient investment

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

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

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

In August 2020 the AER published its CBA guidelines[58] (for transmission projects initiated by AEMO's ISP) and updated the RIT-T application guidelines (for other projects).[59] The CBA guidelines are to be used by AEMO in identifying an optimal development path that promotes the efficient development of the power system, based on a quantitative assessment of the costs and benefits of various options across a range of scenarios. The CBA guidelines also apply to RIT-Ts for actionable ISP projects.[60]

Until 2017 the regulatory tests applied to only growth investment, which until 2014 was the biggest component of network investment. But, with replacement expenditure overtaking growth investment on most networks (section 3.12.4), the test now applies to replacement projects too. Other revisions were made to the test to ensure it adequately considers system security, emissions reduction goals, and low probability events that would have a high impact.

In August 2020 the AER published guidelines to make AEMO's ISP actionable (section 3.6). The guidelines are part of a broader reform to streamline the transmission planning process while retaining rigorous CBA. While the new rules were effective from 1 July 2020, the new guidelines will come into effect through the 2022 ISP.[61]

Under the new rules, the ISP provides a coordinated whole-of-system plan for the efficient development of the power system that meets power system needs in the long term interests of consumers. The ISP 'actions' key projects by triggering RIT-T applications (section 3.12.7). Under the new rules, the ISP is subject to additional governance arrangements through binding CBA guidelines and forecasting best practice guidelines. The RIT-T instrument and associated application guidelines have also been updated to be consistent with the new planning process. In line with the new rules, the guidelines seek to provide AEMO, in developing the ISP, with flexibility in how it identifies the optimal pathway for the NEM.

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 apply largely unchanged for non-ISP projects, such as asset replacements.

Significant investment in the transmission network is forecast over the next few years. Between 2022 and 2026 the modelled cost of actionable ISP projects under the 2020 ISP is around $4.8 billion, with an additional $6.7 billion worth of projects categorised as actionable ISP projects with decision rules.[62] [63]

58 AER, *Cost benefit analysis guidelines*, August 2020.

59 AER, *Application guidelines – regulatory investment test for transmission*, August 2020.

60 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.

61 AER, *Final decision – guidelines to make the Integrated System Plan actionable*, August 2020.

62 A 'decision rule' refers to a set of conditions or triggers that, if they occurred, may justify a project proceeding.

63 AEMC, *Electricity network economic regulatory framework 2020 review*, 1 October 2020, p 21.

3.12.7 Recent regulatory test activity

TransGrid is undertaking a RIT-T for the HumeLink project to reinforce the transmission network in southern NSW. TransGrid published a project assessment draft report for the project in January 2020[64] and expects to finalise the RIT-T by publishing a project assessment conclusions report in August 2021. If the project is found to have positive net market benefits, TransGrid may then apply to the AER for a contingent project assessment. There are 2 pathways for such an application. The first involves the contingent project trigger events approved in the AER's 2018 to 2023 revenue determination for TransGrid. The second involves the trigger events set out in the National Electricity Rules relating to actionable ISP projects.

TransGrid is also in the final stages of a RIT-T process investigating a new grid-scale storage facility to leverage the significant wind and solar generation around Broken Hill and ensure a more reliable supply. However, as at April 2021 TransGrid had put the project on hold as it sought confirmation from the AER about its approach to estimating non-network option costs.

TasNetworks is undertaking a RIT-T for the Marinus Link project, which is a proposed 1,500 megawatt (MW) capacity undersea electricity connection from Tasmania to Victoria. The increased transmission capacity may be delivered in 2 separate 750 MW developments and will be supported by transmission network developments in north west Tasmania.

In March 2020 the Victorian Government introduced legislation to fast-track priority energy projects such as grid-scale batteries and electricity transmission upgrades. The legislation allows the government – in consultation with AEMO – to bypass elements of the RIT process.[65] In November 2020 the Victorian Government directed AEMO to sign a contract with renewable energy specialist Neoen to build one of the world's largest lithium-ion batteries to boost reliability, drive down electricity prices, and support the state's transition to renewable energy.[66]

3.12.8 Annual planning reports

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

The AER publishes guidelines and templates to ensure the reports provide practical and consistent information to stakeholders.

3.12.9 Demand management

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

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

Complementing this scheme, the AER offers a *demand management innovation allowance* (DMIA). This is a research and development fund to help distributors 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. Published annual activity reports set out details of projects undertaken by each business. The AER assesses expenditure claims to ensure distribution businesses appropriately use their funding. Any underspent or unapproved spending is returned to customers through revenue adjustments. Over the 2 years to 30 June 2020[67] almost $9.5 million of innovation allowance funding was approved (figure 3.22).

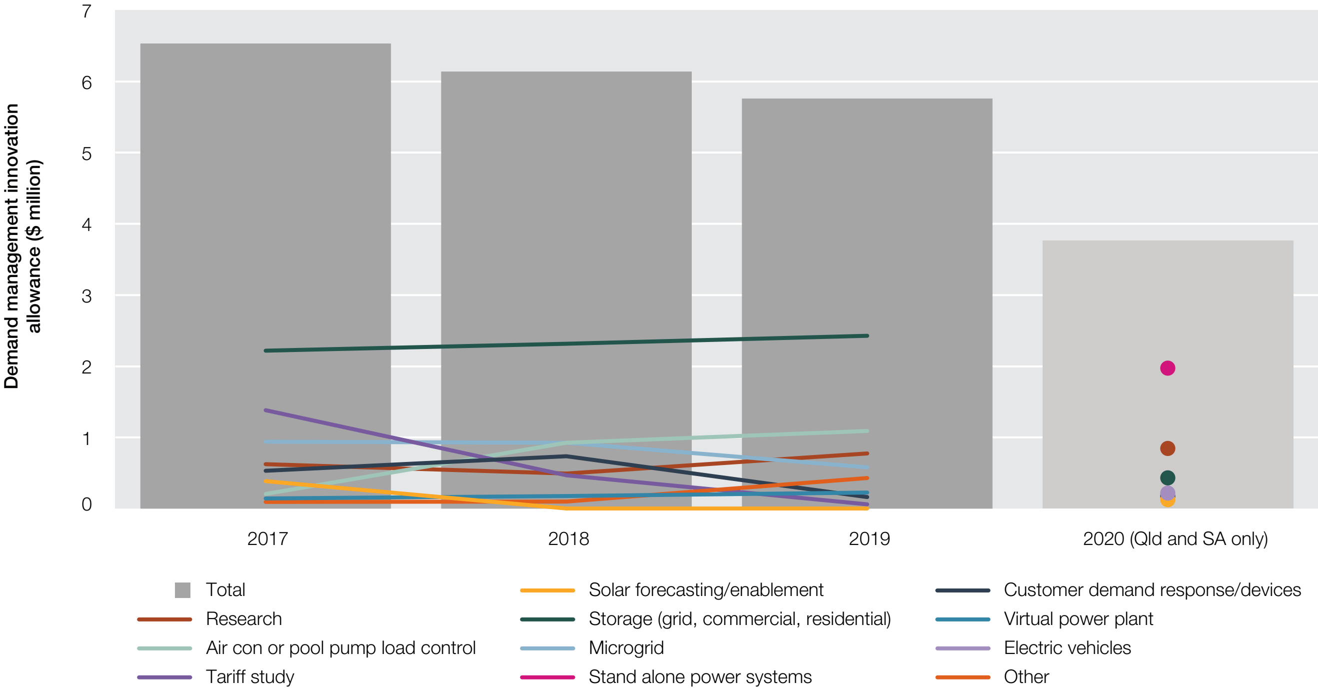
64 TransGrid, *Reinforcing the NSW Southern Shared Network to increase transfer capacity to demand centres (HumeLink)*, 10 January 2020.

65 The Hon Lily D'Ambrosio MP (Victorian Minister for Energy, Environment and Climate Change), 'Victoria acts to secure a more reliable energy system' [media release], 18 February 2020.

66 The Hon Lily D'Ambrosio MP (Victorian Minister for Energy, Environment and Climate Change), 'Victoria to build southern hemisphere's biggest battery' [media release], 5 November 2020.

67 At the time of publishing, the AER had not assessed DMIA claims by Victorian distributors for expenditure incurred in 2020 or claims by the NSW, Tasmanian, ACT, and Northern Territory distributors for 2019–20.

Figure 3.22 Funding of demand management innovations – electricity distribution networks



Note: Victorian distribution network businesses report on a 1 January – 31 December basis. All other distribution network businesses report on a 1 July – 30 June basis. The data show the outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018.

Source: AER, *Approval of demand management innovation allowance (DMIA) expenditures by Victorian electricity distributors in 2019*, November 2020; AER, *Approval of demand management innovation allowance (DMIA) expenditures by distributors*, September 2019; AER, Approval of demand management innovation allowance (DMIA) expenditures by non-Victorian electricity distributors in 2018–19, May 2020.

In 2019–20 the AER approved more than $1.7 million for Ergon Energy's (Queensland) West Leichhardt single-wire earth return project. This project involved the trial of 2 larger scale SAPS as an alternative to grid supply. The outcome of the trial will enable the substitution of costly network components with alternative supply arrangements that provide improved power quality and reliability.

Over 2018 and 2019 the AER approved almost $950,000 for Powercor's (Victoria) Energy Partner program. The demand response program allowed the distributor to directly control its consumers' air conditioners to coordinate the temperature set points for a short time over the 2018–19 and 2019–20 summer periods. Similarly Endeavour Energy claimed around $450,000 over 2017–18 and 2018–19 for its air conditioner control trial using a demand response enabling device.

In 2018–19 the AER approved more than $700,000 for Endeavour Energy's (NSW) Grid Connected Battery Energy Storage System trial. Battery storage can provide several network benefits, primarily peak load lopping, voltage management, load balancing and reliability improvement which may reduce or defer investment decisions. The project allowed Endeavour Energy to identify the functional requirements of the battery energy storage systems (BESS) for connection and operation on its network.

Over 2018 and 2019 the AER approved more than $470,000 for AusNet Services' (Victoria) Mooroolbark Community Mini Grid Trial. The microgrid project was designed to test a future role for AusNet Services' distribution network in an environment of widespread DER that can be coordinated to deliver services and value to both customers and the network. The project encompassed the design, build and operation of an 18-house mini grid in a suburban community that will be monitored and controlled by a cloud-based mini grid control system that can implement distribution system operator control functions and algorithms.

The project also tested the performance of DER systems in providing backup supply to individual customers in case of network outage; and the ability for the mini grid as a whole to operate as an island (grid-separated mode) for short periods of time.

The AER approved almost $400,000 for Energex's (Queensland) Expanded Network Visibility Initiative (ENVI). The purpose of Energex's ENVI research was to build on the work of the Solar Enablement Initiative and LV State Estimation project – former DMIA projects which demonstrated state estimation (use of network data to assess real-time system performance and operational conditions) in operation on Energex's network. ENVI will develop the tools and systems to enable the scale-up of state estimation across Energy and Ergon Energy Network medium and low voltage feeders.

Some successful DMIA trials are being implemented as business as usual activity within their networks. Examples of such projects are:

- AusNet Services' grid energy storage system trial, which was upgraded with various functional enhancements and reliability improvements to enable it to be used to improve power supply reliability in the Mallacoota region
- United Energy's voluntary residential demand response trial (Summer Saver program), which targets network areas with highly utilised distribution transformers and low voltage circuits at high risk of overloading during summer months. Customers participating in the program are offered financial rewards to reduce electricity use when asked by United Energy. The trail period for the program ended in 2019 and United Energy has since implemented it as ongoing expenditure under the new DMIS. United Energy reported in November 2019 that the program had led to the deferral of more than $10 million in capital expenditure.[68]

The AER publishes biannual DMIA reports on its website.[69]

3.13 Electricity network operating costs

Electricity network businesses incur operating and maintenance costs that absorb around 35% of their annual revenue (figure 3.5). As part of its 5-year regulatory review for each network business, the AER sets an allowance for the businesses to recover the efficient costs of supplying power to customers. The allowance accounts for forecasts of electricity demand, productivity improvements, changes in input prices, and changes in the regulatory environment. In the first instance, the AER is guided by the forecasts in each business's regulatory proposal. If the AER considers those forecasts are unreasonable then it may replace them with its own forecasts.

Alongside this assessment, the AER runs an efficiency benefit sharing scheme that encourages network businesses to explore opportunities to lower their operating costs (box 3.4).

Box 3.4 Efficiency benefit sharing scheme

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

The EBSS allows a network business to keep the benefit (or incur the cost) if its actual operating expenditure is lower (higher) than forecast in each year of a regulatory period. It effectively allows a network business to retain efficiency gains (or bear the cost of efficiency losses) for the duration of the existing regulatory period, which may be up to 5 years. In the longer term, network businesses can retain 30% of efficiency savings but must pass on the remaining 70% (as lower network charges) to customers.

The EBSS provides network businesses with the same reward for underspending (or penalty for overspending) in each year of the regulatory period. Its incentives align with those in the capital expenditure sharing scheme (box 3.3) – that is, the 30:70 split between the network business and its customers applies in both schemes. The EBSS incentives also balance against those of the service target performance incentive scheme (box 3.5) to encourage network businesses to make efficient holistic choices between capital and operating expenditure in meeting reliability and other targets.

68 United Energy, *Re: Application for the revised DMIS to start from 1 November 2019*, 7 June 2019.

69 AER, *Demand management innovation allowance (DMIA) assessment 2019–20* (www.aer.gov.au/networks-pipelines/compliance).

3.13.1 Operating cost trends

Total operating costs for the electricity network businesses grew by an average of 5% per year from 2006 until 2012, when it peaked at $4.2 billion (figures 3.10 and 3.11).

Operating costs for transmission networks peaked at $654 million in 2016 but have since fallen by an average of 3% per year. For distribution networks operating costs peaked at $3.6 billion in 2012 and have also since fallen by an average 3% per year. The reduction in operating costs is largely attributed to network businesses implementing more efficient operating practices.

While distribution networks reduced operating expenditure between 2015 and 2019, the reduction was less marked than it was for capital expenditure. Operating and maintenance costs are largely driven by the number of customers that the network business is supplying and the length of line.

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

Not all costs are controllable by network businesses, however. Factors such as reporting obligations, changes to connections charging arrangements and Power of Choice requirements can also impact costs.

3.13.2 Network operating costs in 2020

In 2020 electricity network businesses spent a total of $3.5 billion on operating and maintaining the networks. Of this, transmission network businesses spent $580 million, which was 0.9% less than in the previous year and 11% less than its peak in 2016 (figure 3.10).[70]

Distribution network businesses spent $2.9 billion, which was 5% less than in the previous year and 20% less than its peak in 2012 (figure 3.11).

3.13.3 Current AER operating allowances

Transmission networks are forecast to spend around $3.1 billion and distribution around $16.3 billion on operating costs over their current regulatory periods. The approved forecasts are comparable to the actual operating costs incurred in their previous periods, where transmission networks underspent by $178 million (6%) and the distributors overspent marginally (0.4%) against forecast (figures 3.10 and 3.11).[71]

In its most recent revenue decisions the AER approved a combined $4.4 billion of forecast operating expenditure for the Victorian distributors over the current period. The approved forecast is $744 million (20%) more than the Victorian distributors spent on operating costs in the previous period, where they underspent by $601 million (20%) against forecast (figure 3.8).

Distributors in Victoria, South Australia, Tasmania and the ACT are forecast to increase their operating expenditure in their current periods while those in Queensland, NSW and the Northern Territory are forecast to decrease their operating expenditure.

The increase in operating expenditure allowances for the privately owned Victorian and South Australian distributors was largely because they had implement efficiencies ahead of many of the other network businesses (section 3.13). In doing so, they made their levels of expenditure relatively lean and left less scope for improvement.[72]

A combination of AER incentives and network-driven efficiencies has contributed to significant cost reductions, especially among government-owned (or recently privatised) distribution network businesses in NSW, Queensland and Tasmania.[73] Those savings – from the uptake of technology solutions and from changes to management practices, for example – are now locked in for customers.

70 Excludes AER decisions on transmission interconnectors.

71 The current regulatory period is the period in place at 1 July 2021.

72 AER, *Annual benchmarking report, electricity distribution network service providers*, November 2019.

73 As an example, the AER noted TasNetworks (Tasmania) appears to be responding to incentives in the regulatory framework to better manage its costs.

3.14 Electricity network productivity

The AER benchmarks the relative efficiency of electricity network businesses to enable comparisons over time. This benchmarking assesses how effectively each network business uses its inputs (assets and operating expenditure) to produce outputs (such as meeting maximum electricity demand, electricity delivered, reliability of supply, customer numbers and circuit line length).[74] Productivity will rise if the network's outputs rise faster than the resources used to maintain, replace and augment energy networks. While benchmarking provides a useful tool for comparing network performance, some productivity drivers – for example, reliability standards set by government bodies – are beyond the control of network businesses. More generally, benchmarking may not fully account for differences in operating environment, such as legislative or regulatory obligations, climate and geography.[75]

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

This productivity growth rate has been applied in all regulatory determinations since March 2019 for electricity distribution businesses.[76]

3.14.1 Network productivity

Productivity for most networks in the NEM declined from 2006 to 2015, especially in the distribution sector. This outcome was largely driven by:

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

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

3.14.2 Transmission network productivity

Electricity transmission productivity declined by 1.8% over 2019 following 2 consecutive years of improvement. This result was driven by a significant worsening in productivity in the AusNet Services (Victoria) and TasNetworks (Tasmania). AusNet Services' decline in productivity growth was largely driven by a single outage event that worsened its reliability performance. TasNetworks remained the most productive transmission network in 2019 despite the decline in its productivity (figure 3.23).

The decrease in productivity in 2019 for AusNet Services and TasNetworks was primarily driven by lower network reliability. However, growth in transformer capacity and operating expenditure were also contributing factors. The decline in electricity transmission productivity was consistent with the decline across both the overall economy and the utility sector (electricity, gas, water and waste services) over the same period. The improvement in transmission productivity over the 2 years prior was be linked to reductions in operating expenditure.

Viewed over a longer timeframe, the productivity of transmission networks has declined at an average rate of 1.1% per year over the 14 years to 2019. Capital partial factor productivity[77] declined at an average rate of 1.8% per year compared to average operating expenditure efficiency growth[78] of 0.7% per year over the same period.

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

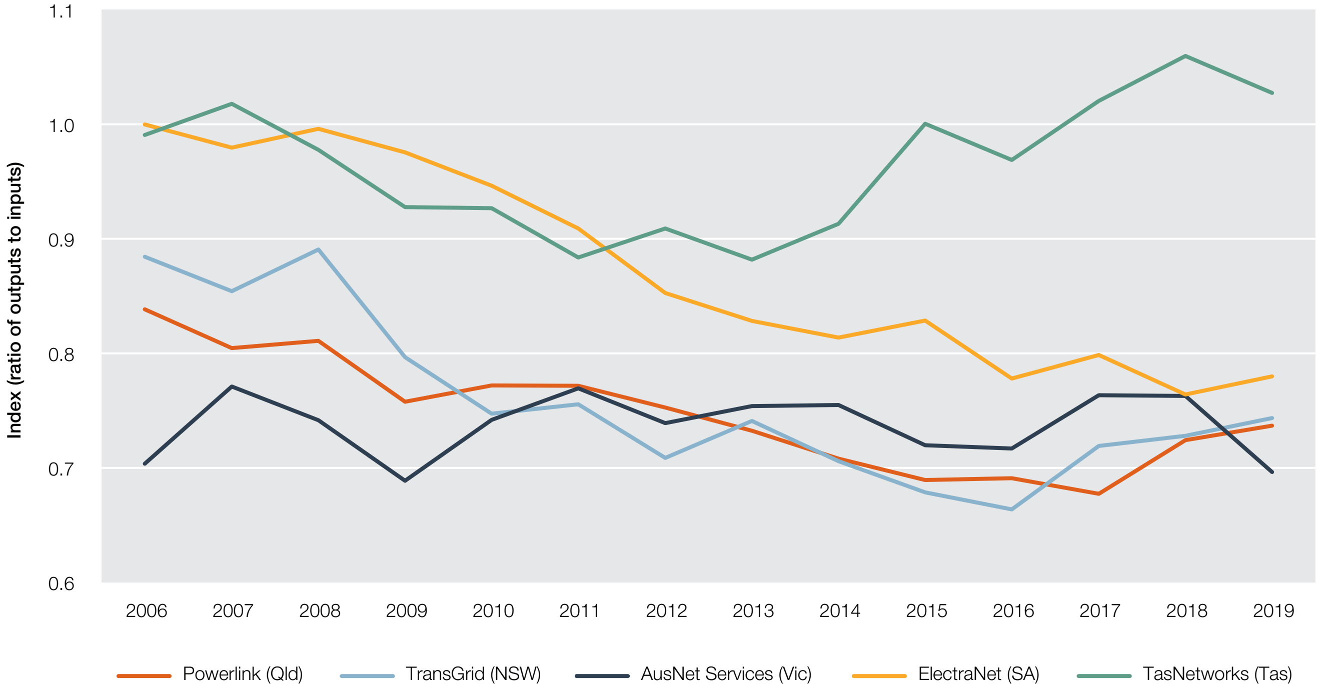
75 AER, *Annual benchmarking report, electricity distribution network service providers*, November 2019, pp 21–27.

76 AER, *Forecasting productivity growth for electricity distributors*, 8 March 2019.

77 Output per unit of capital expenditure.

78 Output per unit of operating expenditure.

Figure 3.23 Productivity – electricity transmission networks



Note: Index of multilateral total factor productivity relative to the 2006 performance of ElectraNet (South Australia). The transmission and distribution indexes cannot be directly compared. Most network businesses report on a 1 July – 30 June basis. The exception is AusNet Services, which reports on a 1 April – 31 March basis. The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018).

Source: AER annual benchmarking reports for electricity transmission networks.

3.14.3 Distribution network productivity

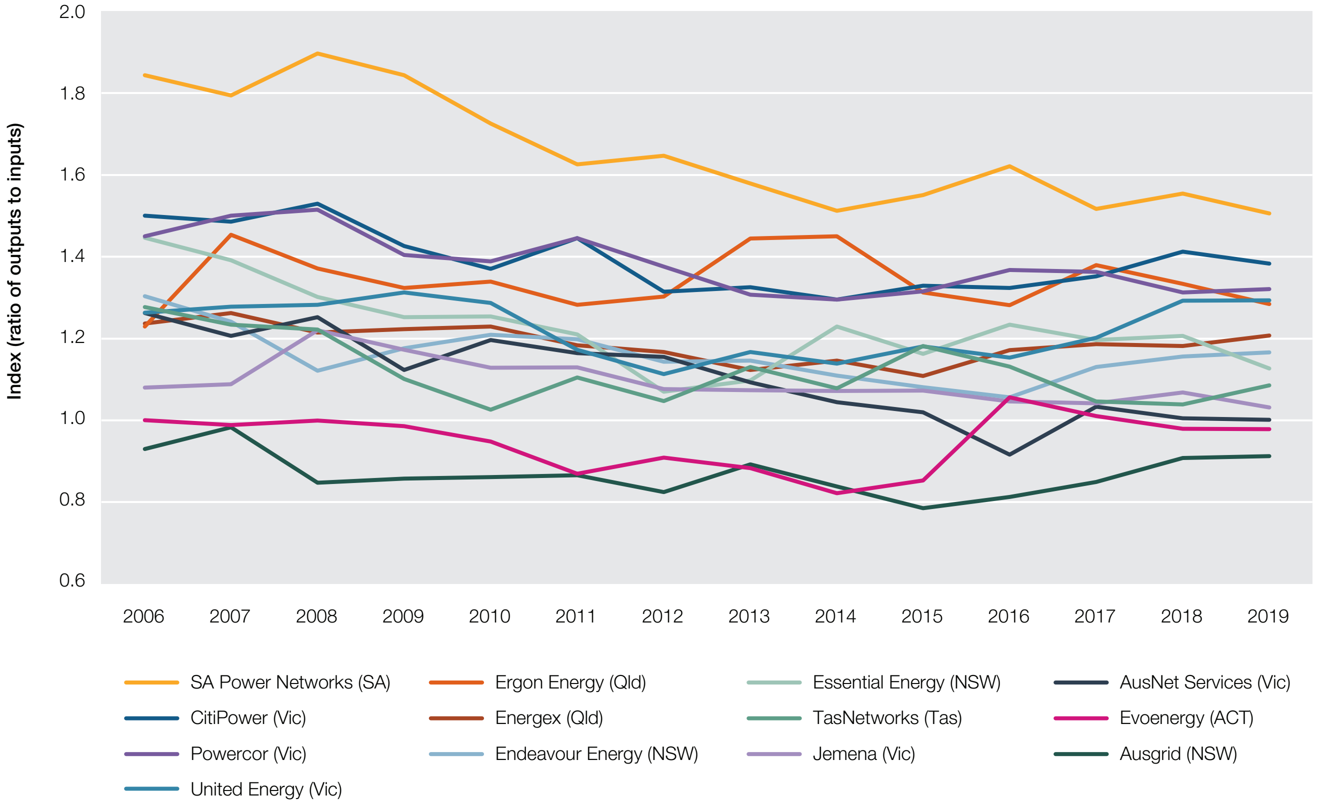
Electricity distribution productivity decreased by 1% in 2019 following 3 years of consecutive improvement. However, productivity outcomes varied across networks. As with the transmission networks the decrease was primarily due to lower network reliability and was consistent with lower productivity growth for the overall economy and the utility sector over the same period.

Across distribution network businesses in 2019:

- 7 distributors were less productive than in the previous year
- Essential Energy (NSW) and Ergon Energy experienced the largest decreases in productivity (6.8% and 3.8% respectively)
- TasNetworks (Tasmania) and Energex (Queensland) showed the most significant increases in productivity (4.4% and 2.1% respectively).

Since 2006 there has been some convergence in the productivity levels of highest and lowest performing distributors (figure 3.24). Generally speaking, less productive distributors have improved their productivity since 2012. In particular, Ausgrid (NSW) and Evoenergy (ACT) have increased their overall productivity, largely as a result of improvements in operating efficiency. Several middle-ranked distributors such as United Energy (Victoria), Endeavour Energy (NSW) and Energex (Queensland), have also improved their productivity and are now closer to the top-ranked distributors. Further, while Powercor (Victoria), SA Power Networks (South Australia) and CitiPower (Victoria) have consistently been the most productive distributors in the NEM they have experienced a gradual decline in productivity. As a result, their productivity is now much more closely aligned with the middle-ranked distributors.

Figure 3.24 Productivity – electricity distribution networks



Note: Index of multilateral total factor productivity relative to the 2006 performance of Evoenergy (ACT). The transmission and distribution indexes cannot be directly compared. Most network businesses report on a 1 July – 30 June basis. The exceptions are the Victorian networks which report on a 1 January – 31 December basis. The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018).

Source: AER annual benchmarking reports for electricity distribution networks.

3.14.4 Investment disconnect

For several years from 2006, a key contributor to poor network productivity was sustained growth in investment at a time when electricity demand was falling (figures 3.25 and 3.26). Network investment rose every year from 2006 to 2012, despite the amount of total electricity delivered peaking in 2009 for transmission and in 2010 for distribution. The earlier decline in total energy delivered by transmission networks was due to the loss of some industrial loads.

Two key factors drove the mismatch between electricity usage and new investment:

- a growing divide between maximum network demand and total electricity generated
- over-forecasting of maximum demand.

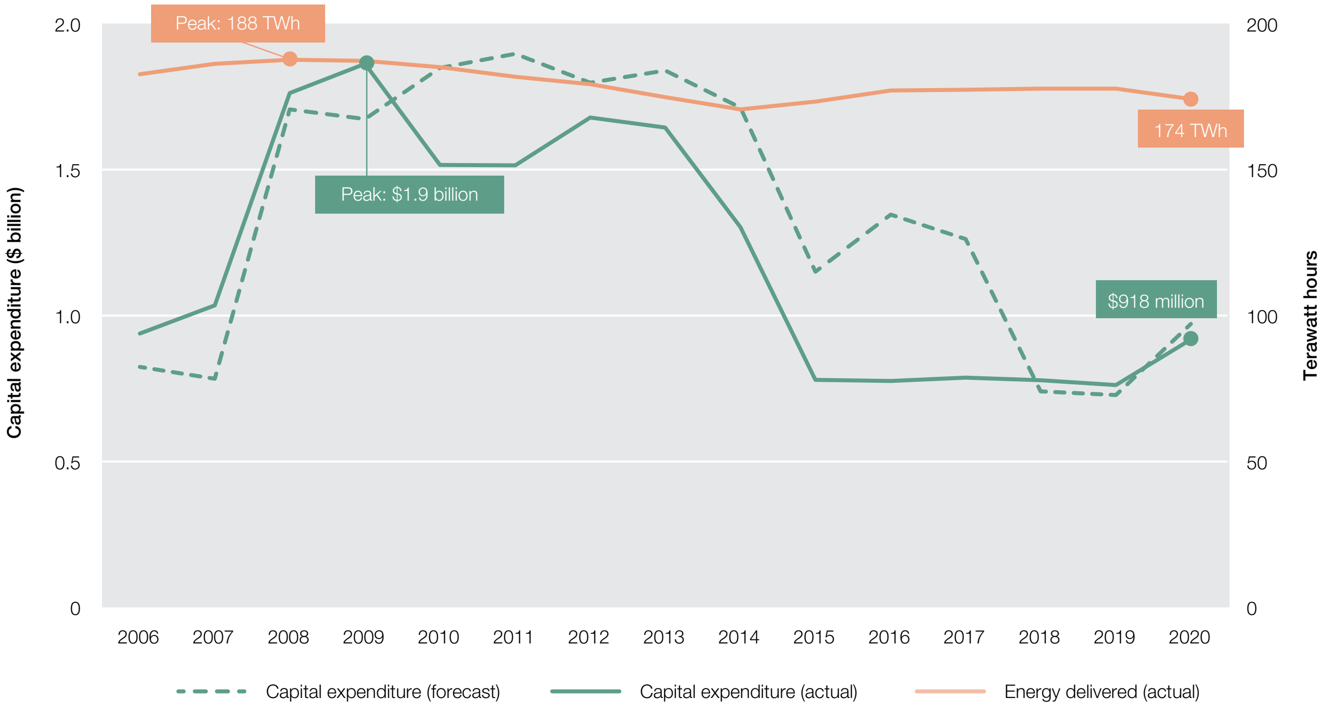
The level of productivity depends on how effectively a network business uses inputs[79] to deliver a range of outputs.[80] Capital expenditure is largely driven by the need to meet the maximum level of demand on the network. But, since 2006, maximum demand has grown, while average (non-maximum) demand has declined (figure 3.27).

As network demand becomes 'peakier', assets installed to meet demand at peak times – which occur for approximately 0.01% of the year – may sit idle (or be underused) for longer periods. This outcome is reflected in poor usage rates, which weaken productivity. The number of customers connected to the distribution network has steadily increased by 1.5% per year since 2006 and has outpaced growth in both maximum and average demand.

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

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

Figure 3.25 Investment and energy delivered – electricity transmission networks

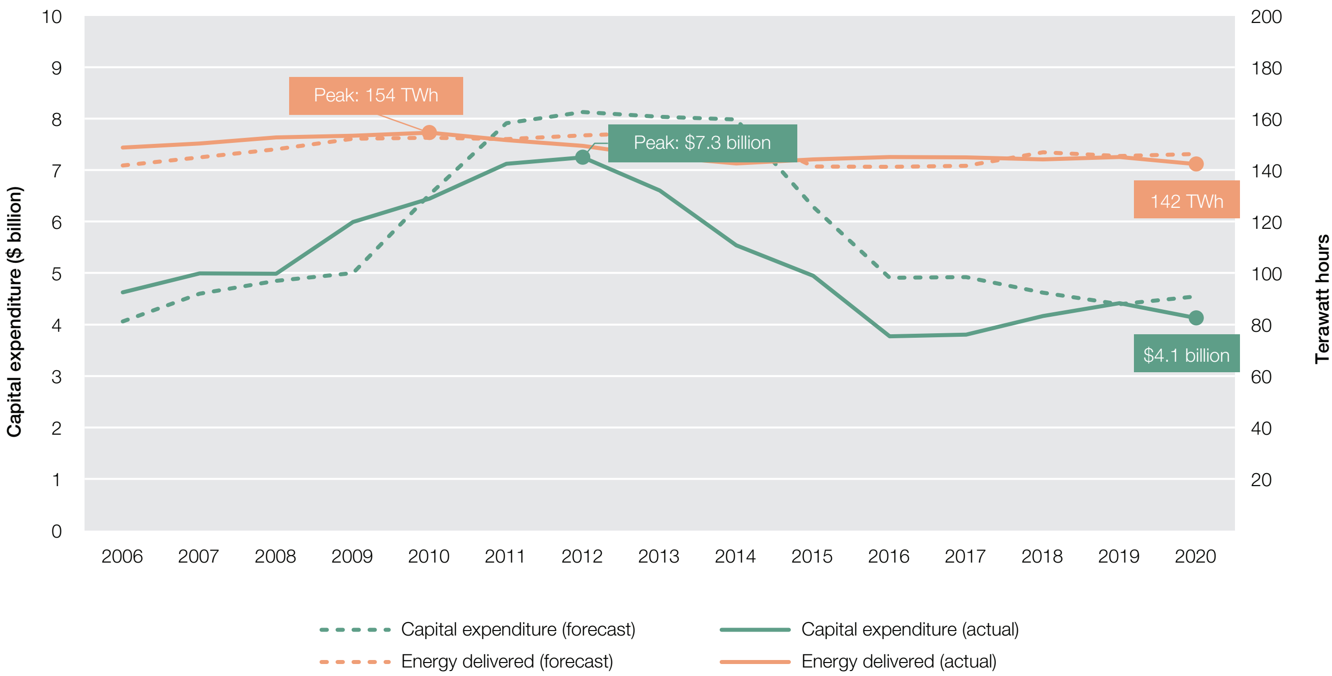


TWh: terawatt hours.

Note: Most network businesses report on a 1 July – 30 June basis. The exceptions are Victorian networks: AusNet Services (transmission) reports on a 1 April – 31 March basis. The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018). Data exclude energy delivered to other transmission networks via interconnectors. Physical losses and deliveries to industrial customers directly from the transmission network account for some differences between transmission and distribution loads.

Source: Annual benchmarking regulatory information notice (RIN) responses.

Figure 3.26 Investment and energy delivered – electricity distribution networks

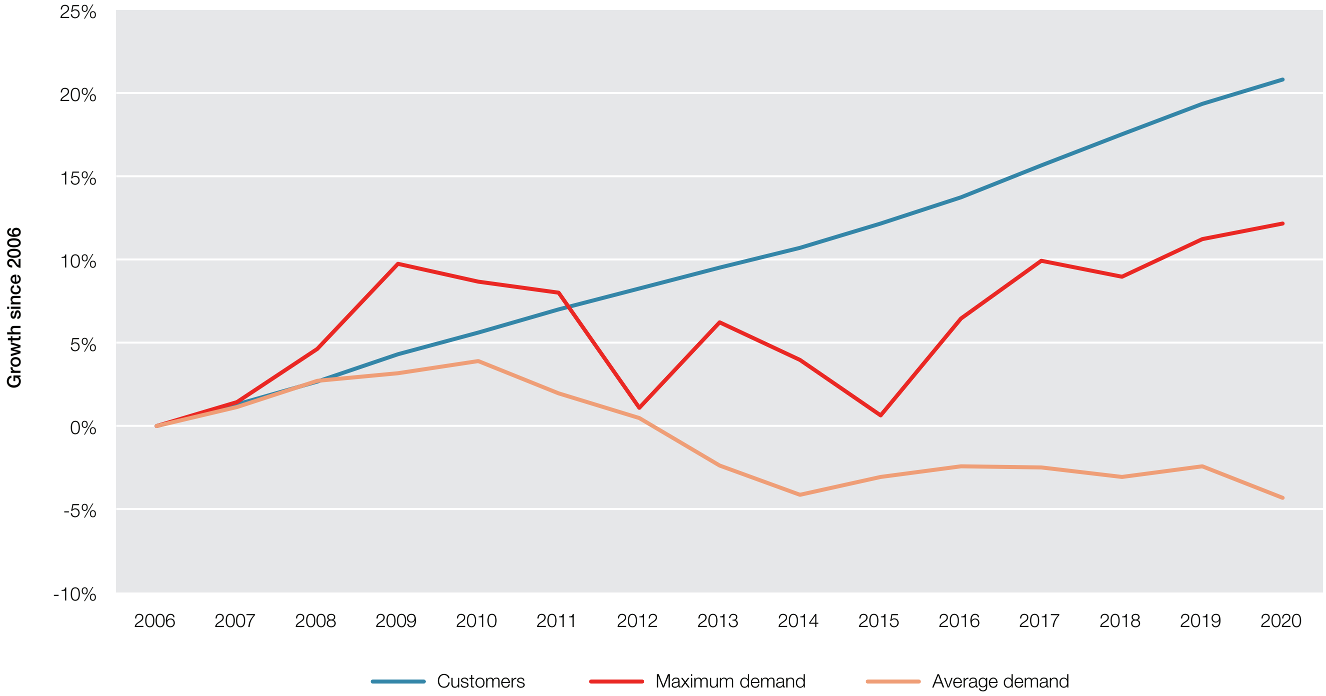


TWh: terawatt hours.

Note: Most network businesses report on a 1 July – 30 June basis. The exceptions are Victorian networks, which report on a 1 January – 31 December basis. The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018). Data exclude energy delivered to other transmission networks via interconnectors. Physical losses and deliveries to industrial customers directly from the transmission network account for some differences between transmission and distribution loads.

Source: Annual benchmarking regulatory information notice (RIN) responses.

Figure 3.27 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.

Source: Economic benchmarking regulatory information notice (RIN) responses.

In 2020 the average residential customer consumed 21% less energy from the distribution network than in 2006. Declining energy use by residential customers is evident among all distributors, with 11 of the 14 distributors reporting declines of more than 15% since 2006. Average consumption by business customers has also fallen over that period but to a lesser extent.

The overall decline in energy consumption from the grid can be attributed to multiple factors, including solar PV replacing some grid sourced electricity; housing and appliances becoming more efficient; consumers reducing their energy use in response to higher prices; reductions in demand from large industrial customers; and in 2020 the impact of COVID-19 on consumer behaviour (figure 3.28).

Forecasts by planning authorities and market participants consistently failed to capture a step decline in electricity use from the grid and a flattening of maximum demand from around 2009. This decline can be attributed to multiple factors, including solar PV replacing some grid sourced electricity; housing and appliances becoming more efficient; and consumers reducing their energy use in response to higher prices. Electricity use also contracted in the manufacturing sector.[81] More recently, networks have explored demand response to meet short term peaks in demand as an alternative to investing in long lived assets (section 3.12.10).

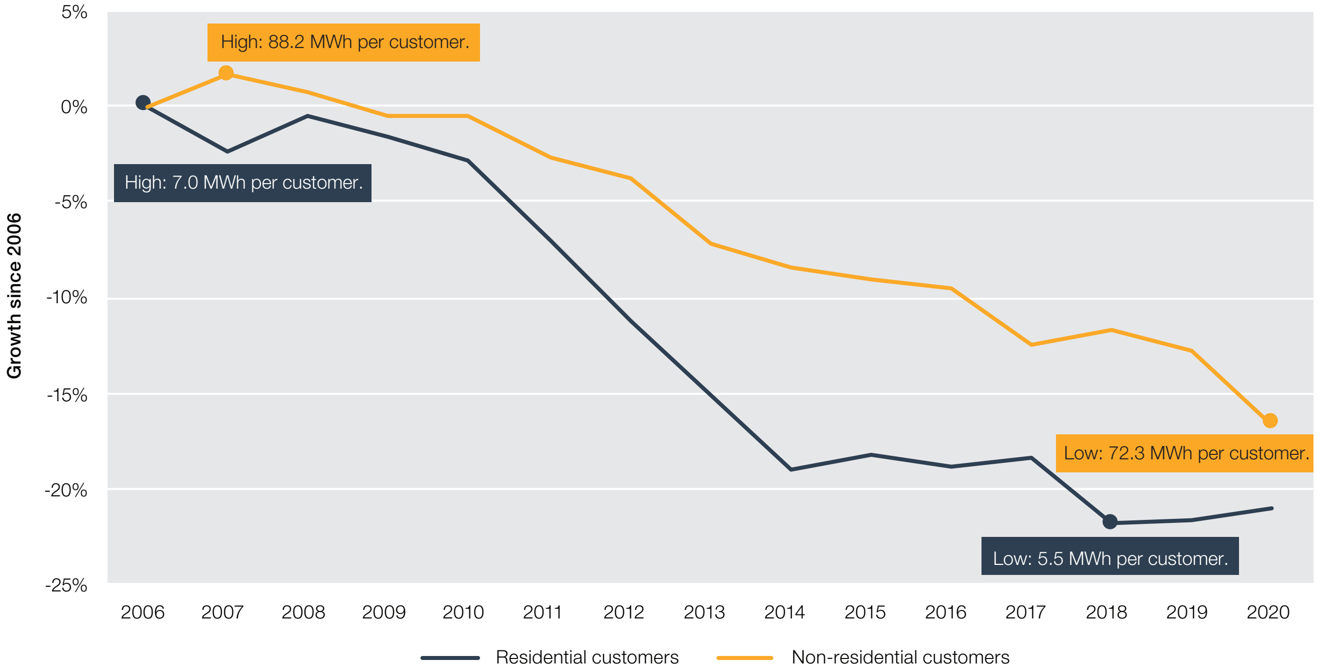
Inaccurate demand forecasts fuelled a wave of investment that inflated the electricity networks' RABs, which increased by 78% from 2006 to 2020. This overinvestment contributed to capital productivity declining for all transmission network businesses since 2006, although since 2013 the rate of decline has slowed.[82]

Overinvestment also drove weaker distribution network productivity but to a lesser extent than did rising operating expenditure. Capital productivity amongst the distribution networks has consistently declined since 2006, with little convergence amongst the individual distribution businesses. All of the distribution networks showed lower capital productivity in 2019 than in 2006, and many were only marginally better than in 2012, when distribution network capital productivity was at its lowest.

81 AEMC, *Electricity network economic regulatory framework review*, 18 July 2017, pp 37–38.

82 AER, *Annual benchmarking report – electricity transmission network service providers,* November 2020, p 22.

Figure 3.28 Change in average energy usage per customer – electricity distribution networks



Note: Most distribution network businesses report on a 1 July – 30 June basis. The exception is the Victorian businesses which report on a 1 January – 31 December basis. The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018).

Source: Economic benchmarking regulatory information notice (RIN) responses.

3.14.5 Adapting to an evolving market

As the market evolves, the regulatory framework needs to encourage network businesses to make efficient choices between capital and operating expenditure. A traditional network solution to meet increasing consumer demand in an area might be to augment a zone substation, for example. But a more efficient solution might be to purchase services from a battery provider, or an aggregator of batteries, to manage peak demand.

Regulatory frameworks need to support emerging technologies and business models that have the potential to benefit consumers. Current frameworks encourage network businesses to favour (relatively expensive) long-lived capital investment (which gets added to the asset base) over cheaper operating expenditure alternatives, especially if a business's regulated rate of return is higher than its actual borrowing costs.

Network businesses are also having to adapt to a new operating environment, in which DER is changing energy flows and creating new pressure points in the system. These challenges require network businesses to develop innovative solutions to keep the network operating efficiently.

In March 2020 the AEMC recommended a package of rule changes aimed at making it easier for network businesses to develop and trial innovative approaches to providing energy services to consumers.[83] The rules would implement 'regulatory sandbox' arrangements in the national electricity and gas markets, where participants can test innovative concepts in the market under relaxed regulatory requirements at a smaller scale, on a time-limited basis and with appropriate safeguards in place.[84]

In October 2020 ElectraNet (South Australia) and TransGrid (NSW) submitted a rule change request to the AEMC seeking an exception to the applicability of the rules in relation to the financeability of its share of actionable ISP projects.

In April 2021 the AEMC rejected the rule change request. The AEMC considered that the regulatory framework does not create a barrier to financing ElectraNet's or TransGrid's actionable ISP projects (currently Project EnergyConnect) and that the proposed rule would not provide the right investment incentives and would likely substantially increase costs to consumers in the near to medium term.[85]

83 AEMC, *Final report – regulatory sandboxes – advice to Ministerial Forum of Energy Ministers (formerly CoAG Energy Council) on rule drafting*, 26 March 2020.

84 The Ministerial Forum of Energy Ministers (formerly CoAG Energy Council) will separately develop law changes and conduct stakeholder consultation before the law changes are submitted to the South Australian Parliament. The AEMC's recommended rule drafting will then be updated to reflect the final form of law changes.

85 AEMC, *Participant derogation – financeability of ISP project (TransGrid), rule determination*, 8 April 2021.

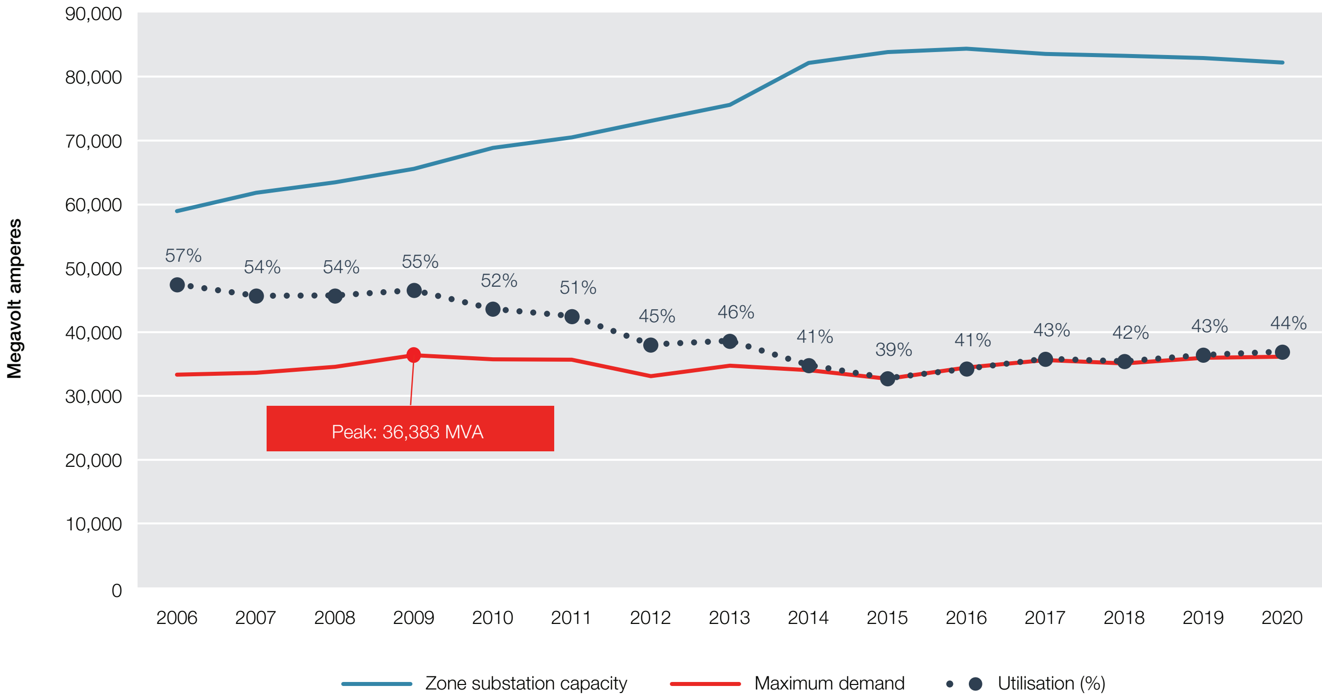
3.14.6 Network utilisation

A network's utilisation rate is a part productivity measure, indicating the extent to which a network business's assets are being used to meet maximum demand. The rate can be improved through efficiencies such as using demand response (instead of new investment in assets) to meet rising maximum demand.

The average network utilisation amongst all distribution networks declined from a high of 56% in 2006[86] to a low of 39% in 2015 following overinvestment by many network businesses at a time of weakening electricity maximum demand. Maximum demand has since increased, rising 11% between 2015 and 2020 (reaching its highest point since 2009). While maximum demand has been increasing, network capacity has been decreasing – down 2% since its peak in 2016. When combined, these events have resulted in the average network utilisation amongst the distribution networks steadily increasing over the past 5 years. In 2020 network utilisation reached 44% – the highest rate since 2013 (figure 3.29).

Network utilisation rates tend to be higher among privately owned distribution networks (62% in 2020) than in fully or partly government owned networks (38% in 2020).[87] In 2020, 5 of the top 6 most highly utilised distribution networks were privately owned, with Ergon Energy (Queensland) being the only exception.

Figure 3.29 Network utilisation – electricity distribution networks



MVA: megavolt amperes.

Note: Network utilisation is the non-coincident, summated raw system annual peak demand divided by total zone substation transformer capacity.

Source: Economic benchmarking regulatory information notice (RIN) responses.

Powercor (Victoria) has operated the most highly utilised distribution network in each year since 2006, followed by United Energy (Victoria) from 2016 to 2020. For the past decade Essential Energy (NSW) has consistently been the most underutilised distribution network, followed by Power and Water (Northern Territory).

Under-utilised assets raise the risk of asset stranding – whereby assets are no longer useful – unless network businesses respond to changing conditions. This risk may become more acute as the uptake of DER (such as batteries) transforms the industry. The National Electricity Rules do not allow for RAB adjustments to remove historical investment in stranded assets. If network charges become inflated as a result of asset stranding then electricity consumers – who pay for those assets – may look to opportunities to bypass the grid altogether.[88]

86 The available data does not extends back beyond 2006.

87 Section 3.16 provides a detailed assessment of network ownership.

88 Grattan Institute, *Down to the wire – a sustainable electricity network for Australia*, March 2018.

3.15 Reliability and service performance

Reliability refers to the continuity of electricity supply to customers. Many factors can interrupt the flow of electricity on a network. Supply interruptions may be planned (for example, due to the scheduled maintenance of equipment) or unplanned (for example, due to equipment failure, bushfires, extreme weather events or the impact of high demand stretching the network's engineering capability).

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

Most interruptions to supply originate in distribution networks. They typically relate to power line damage caused by lightning, car accidents, debris such as falling branches, and animals (including possums and birds). Peak demand during extreme weather can also overload parts of a distribution network. Transmission network issues rarely cause consumers to lose power, but the impact when they occur is widespread; for example, South Australia's catastrophic network failures in September 2016 caused a state-wide blackout.

Electricity outages impose costs on consumers. These costs include both economic losses resulting from lost productivity and business revenues and non-economic costs such as reduced convenience, comfort, safety and amenity.

Household and business consumers desire a reliable electricity supply that minimises these costs. But maintaining or improving reliability may require expensive investment in network assets, which is a cost passed on to electricity customers. There is, therefore, a trade-off between electricity reliability and affordability. Reliability standards and incentive schemes need to strike the right balance by targeting reliability levels that customers are willing to pay for.

State and territory governments set reliability standards for electricity networks that seek to efficiently balance the costs and benefits of a reliable power supply. While approaches to setting standards have varied across jurisdictions, governments recently moved to a more consistent national approach to reliability standards. This approach factors in the value that consumers place on having a reliable power supply.

3.15.1 Valuing reliability

Understanding the value that customers place on reliability is an important consideration when setting reliability standards or network performance targets. This value tends to vary among customer types and across different parts of the network. Considerations include a customer's access to alternative energy sources; their past experience of interruptions to supply; and the duration, frequency and timing of interruptions.

In July 2018 the AER assumed from AEMO responsibility for estimating how much customers are prepared to pay for reliable electricity supply. In December 2019 it published valuations for unplanned widespread outages of up to 12 hours in all jurisdictions. It drew on customer surveys and modelling to determine the values and consulted with governments, energy regulators, industry representatives and customers.[89]

The AER's 2019 estimates were broadly similar to those estimated by AEMO in 2014, but the values varied across sectors. Both reviews found business customers tended to value reliability more highly than residential customers, who were particularly concerned about long outages and outages at peak times. Differences were also apparent across industries, but these differences changed over time: the 2019 estimates were lower than the 2014 estimates for agricultural and commercial customers but higher for industrial customers.

The AER will develop new estimates of customers' reliability valuations every 5 years and update these values annually. The values will have wide application, including as an input for:

- cost–benefit assessments such as those applied in regulatory tests (section 3.12.7) that assess network investment proposals
- assessing bonuses and penalties in the service target incentive scheme (box 3.5)
- setting transmission and distribution reliability standards and targets
- informing market settings such as wholesale price caps.

In March 2020 the AER published a draft model[90] to estimate the costs of widespread and long duration outages (WALDO). As a result of stakeholder feedback the AER decided to discontinue the WALDO model and methodology but is considering avenues for future work, such as research partnerships with universities.

89 AER, *Values of customer reliability, final report on VCR values*, December 2019.

90 Developed with ACIL Allen.

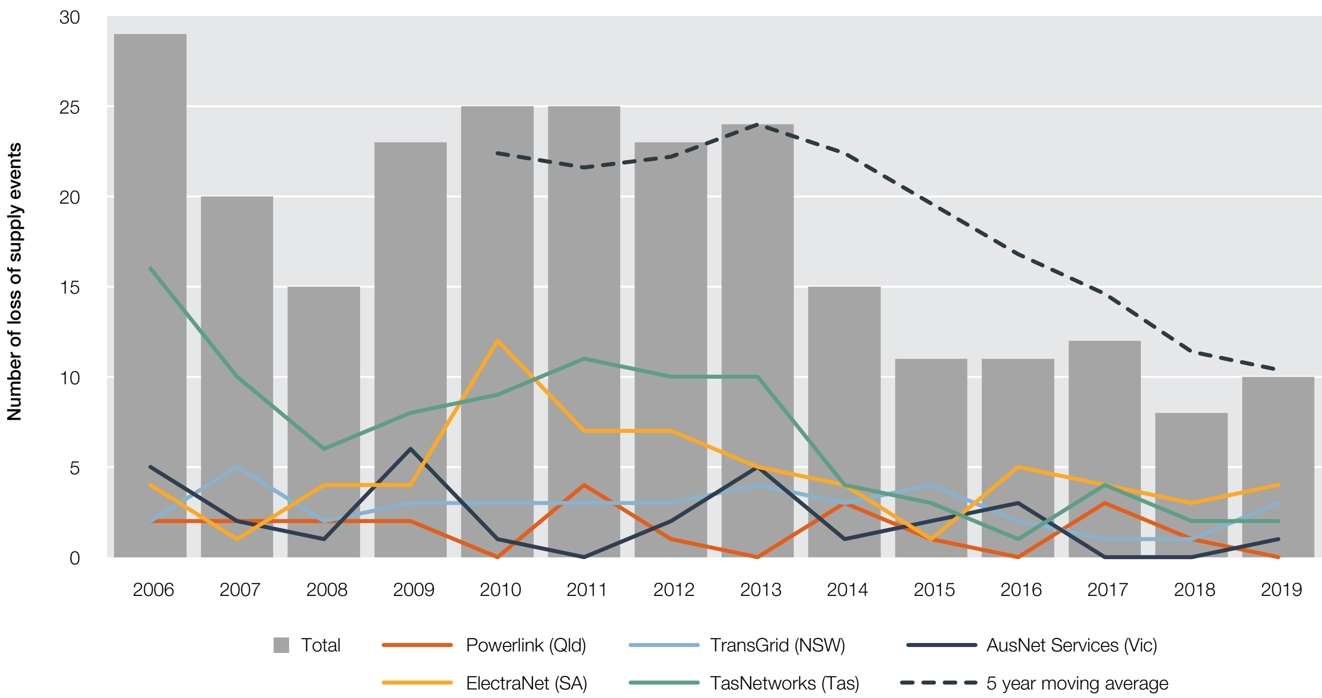
3.15.2 Transmission network performance

Electricity transmission networks are engineered and operated to be extremely reliable, because an interruption can lead to widespread power outages. To avoid this outcome, the transmission networks are engineered with capacity to act as a buffer against credible unplanned interruptions.

Across the NEM, lost supply events due to transmission failures have occurred no more than 25 times in any year since 2006. The 5-year average number of lost supply events due to transmission failures continues to decline, with no network business reporting more than 5 loss of supply events in any year since 2013.

In 2019 the NEM experienced 10 loss of supply events due to transmission failures. Over the past 5 years Powerlink (Queensland) and AusNet Services (Victoria) have consistently experienced the fewest loss of supply events amongst all of the transmission networks in the NEM (figure 3.30).

Figure 3.30 Network reliability loss of supply events – electricity transmission



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

Most transmission network businesses report on a 1 July – 30 June basis. The exception is AusNet Services (Victoria), which reports on a 1 April – 31 March basis. The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018).

Source: Economic benchmarking regulatory information notice (RIN) responses.

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

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

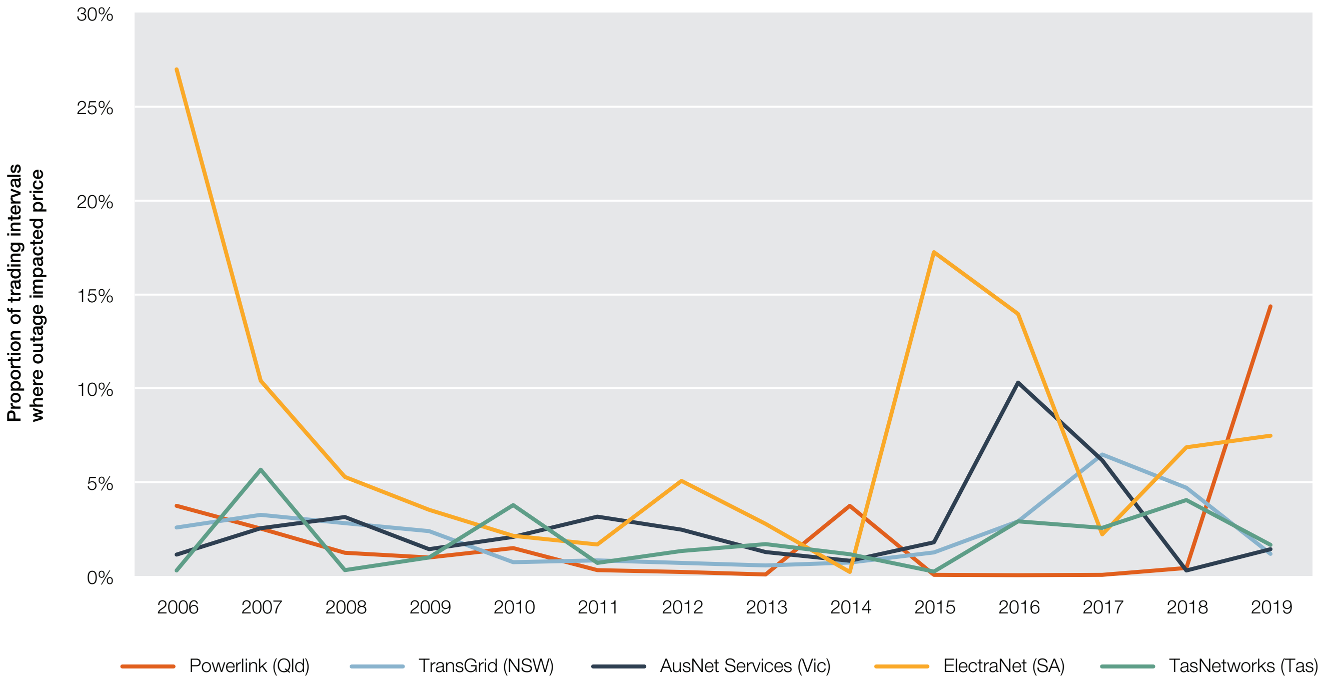
Transmission congestion caused significant market disruption in 2006, when rising electricity demand placed strain on the networks (figure 3.31). But network investment from 2006 to 2014 – including upgrades to congested lines – eliminated much of the problem. Weakening energy demand reinforced the trend, and for several years network congestion affected less than 10% of NEM spot prices. But, ultimately, consumers paid for the substantial costs of the network investment.

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

Not all congestion is inefficient, however. Reducing congestion through investment to augment transmission networks is an expensive solution. Eliminating congestion is efficient only to the extent that the market benefits outweigh the costs of new investment.

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

Figure 3.31 Market impact of loss of supply events – electricity transmission networks



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

Source: Economic benchmarking regulatory information notice (RIN) responses.

3.15.3 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 interruptions to supply that electricity customers experience are due to issues in their local distribution network.[91] The capital intensive nature of the networks makes it prohibitively expensive to invest in sufficient capacity to avoid all interruptions.

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

Jurisdictional reliability standards were historically set at higher levels to protect customers from the cost and inconvenience of supply interruptions. Following power outages in 2004, the Queensland and NSW governments in 2005 tightened reliability standards for distribution networks, requiring significant investment that drove network costs for several years. In contrast, Victoria placed more emphasis on reliability outcomes and the value that customers place on reliability.

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

Concerns that reliability-driven investment was driving up power bills led to a different approach to setting distribution reliability targets.[92] The approach accounts for the likelihood of interruptions and for the value that customers place on reliability (section 3.15.1). While the Queensland and NSW governments began to relax reliability standards from 2014, the assets built to meet the previously high standards remain, and customers continue to pay for them.[93]

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 experienced by the average customer each year, while SAIDI measures the total duration – or minutes – off supply experienced by the average customer.[94]

The characteristics of a distribution network can have a significant impact on its reliability performance. In particular, customer densities (figure 3.12) and environmental conditions differ across networks. This can materially impact the number of customers affected by an outage and a network business's response time.

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

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

For these reasons comparisons across distribution networks should be made with care. Levels of historical investment also affect reliability outcomes.

The SAIFI and SAIDI metrics have generally been used to focus on the impact of unplanned outages. However, the impact planned outages have on a customer must also be considered when assessing 'customer experience'. The AER has acknowledged this and has incorporated the impact of planned outages into its recent regulatory determinations through the CSIS (box 3.6). Both the relative frequency and duration of planned interruptions to supply varies considerably amongst the distribution networks.

Distribution reliability trends

The AER does not determine a distributor's operating and capital expenditure forecasts to eliminate all supply interruptions. This is evident in the AER's service target performance incentive scheme (STPIS) (box 3.5), in which the AER sets 'normalised' reliability targets that do not penalise a network for interruptions considered to be beyond its control.

Across the distribution sector, 'normalised' levels of reliability have improved over the past decade, delivering fewer unplanned interruptions to and fewer unplanned minutes off supply. This improvement has occurred despite distribution networks investing $11 billion (16%) less than forecast on capital projects from 2010 to 2020 (figure 3.11).

Normalising the data removes the impact of extreme events and provides a more reasonable measure of a distributor's controllable outputs. Figures 3.32 and 3.33 summarise SAIDI and SAIFI outcomes across the NEM, as well as weighted network reliability targets that the AER applies through the STPIS.

92 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.

93 ACCC, *Retail Electricity Pricing Inquiry, final report*, June 2018, p 109.

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

While unplanned 'normalised' reliability continues to improve (SAIFI), or plateau (SAIDI), the absolute level of network reliability (that is, 'customer experience') has varied. This is predominately due to year on year fluctuations in the impact of unplanned (excluded) events, such as outages caused by major weather events. Figure 3.33 demonstrates the impact and unpredictability of major weather events on network reliability. For example, the average network customer experienced 87% fewer unplanned (excluded) minutes off supply in 2012 than they did in the previous year, when northern Queensland was lashed by Tropical Cyclone Yasi. Further examples of unplanned (excluded) events include:

- network outages associated with bushfires in Victoria in 2009
- network outages caused by strong winds and torrential rain in NSW in April 2015
- reduced reliability for Queensland customers as a result of cyclones and severe flooding in 2013, 2015 and 2017
- a power outage across almost the whole of South Australia as a result of storm damage to electricity transmission infrastructure in 2016.

Distribution network reliability in 2020

In 2020 the average electricity customer experienced 1.66 total interruptions to supply – 0.7% fewer than in the previous year. This comprised:

- 1.08 unplanned (normalised) interruptions to supply – 3% fewer than in the previous year and a new record low (0.2% fewer than the previous low in 2017)
- 0.21 unplanned (excluded) interruptions to supply – 16% fewer than in the previous year but 36% more than the low recorded in in 2012
- 0.37 planned interruptions to supply – 21% more than in the previous year.
- In 2020 the average electricity customer experienced 350.1 total minutes off supply – 27% more than in the previous year. This comprised:
- 119.5 unplanned (normalised) minutes off supply – 0.7% more than in the previous year and 12% more than the low recorded in 2017
- 124.4 unplanned (excluded) minutes off supply – 64% more than in the previous year and 318% more than the low recorded in in 2012
- 106.2 planned minutes off supply – 32% more than in the previous year.

The average customer experienced significantly more total minutes off supply in 2020 than in the previous year. The increase was largely driven by the impact of the devastating bushfires which burned throughout the spring and summer of 2019–20, destroying thousands of homes and burning over 17 million hectares of land across NSW, Victoria, Queensland, ACT, Western Australia and South Australia.[95]

Customers also experienced a significant increase in the frequency and duration of planned interruptions to supply in 2020. The increase was primarily driven by Ausgrid's decision to temporarily pause all live work on its network for safety reasons.[96]

As distribution networks are so heavily impacted by the occurrence of severe weather events, it is more prudent to assess network performance over a rolling 5-year averaging period than it is on a year by year basis. When using a 5-year rolling average network customers experienced 2% fewer unplanned (normalised) interruptions to supply in 2020 than at any time in the past, while the average unplanned (normalised) minutes off supply were only 0.5% higher than at the record low point in 2018.

On average, in 2020 the distributors performed 17% better than their (weighted) SAIFI targets and 3% better than their (weighted) SAIDI targets.

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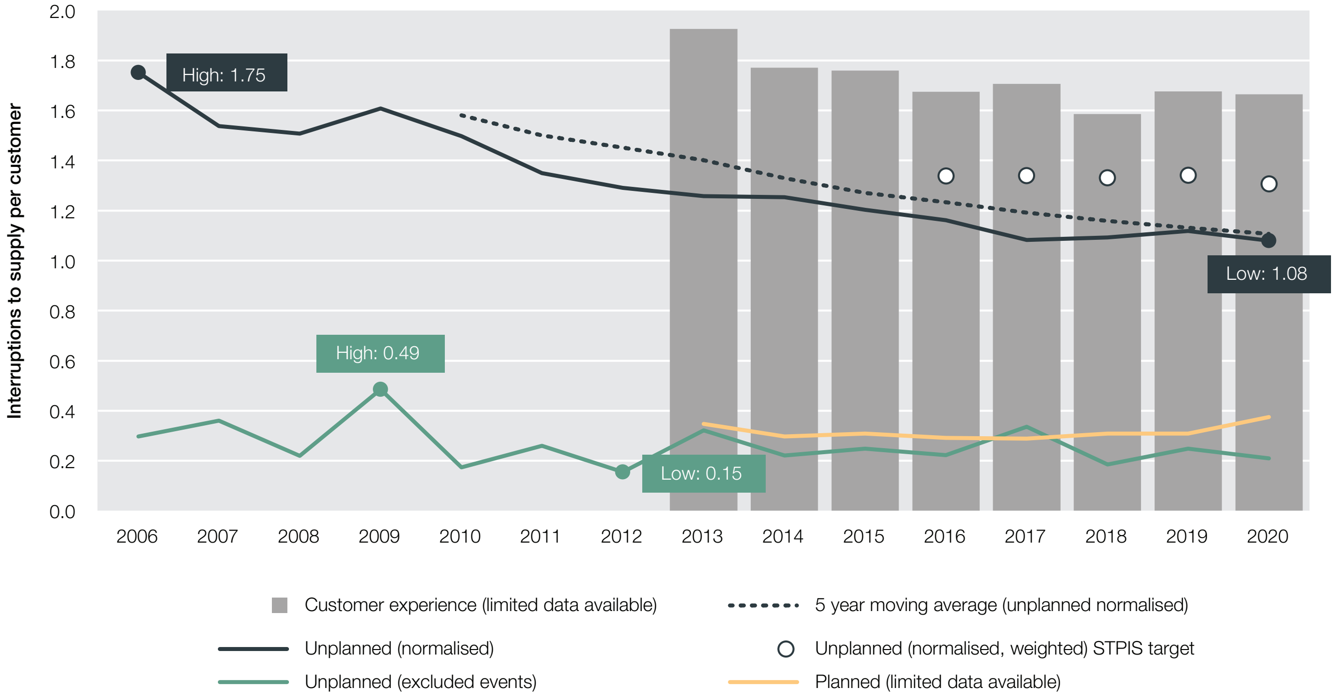
95 Australasian Fire and Emergency Service Authorities Council, 'Cumulative seasonal summary' [tweet], AFESAC, 28 February 2020 (https://twitter.com/AFACnews).

96 Ausgrid, *Live Work Project*, Ausgrid website, accessed 5 May 2021 (www.ausgrid.com.au).

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

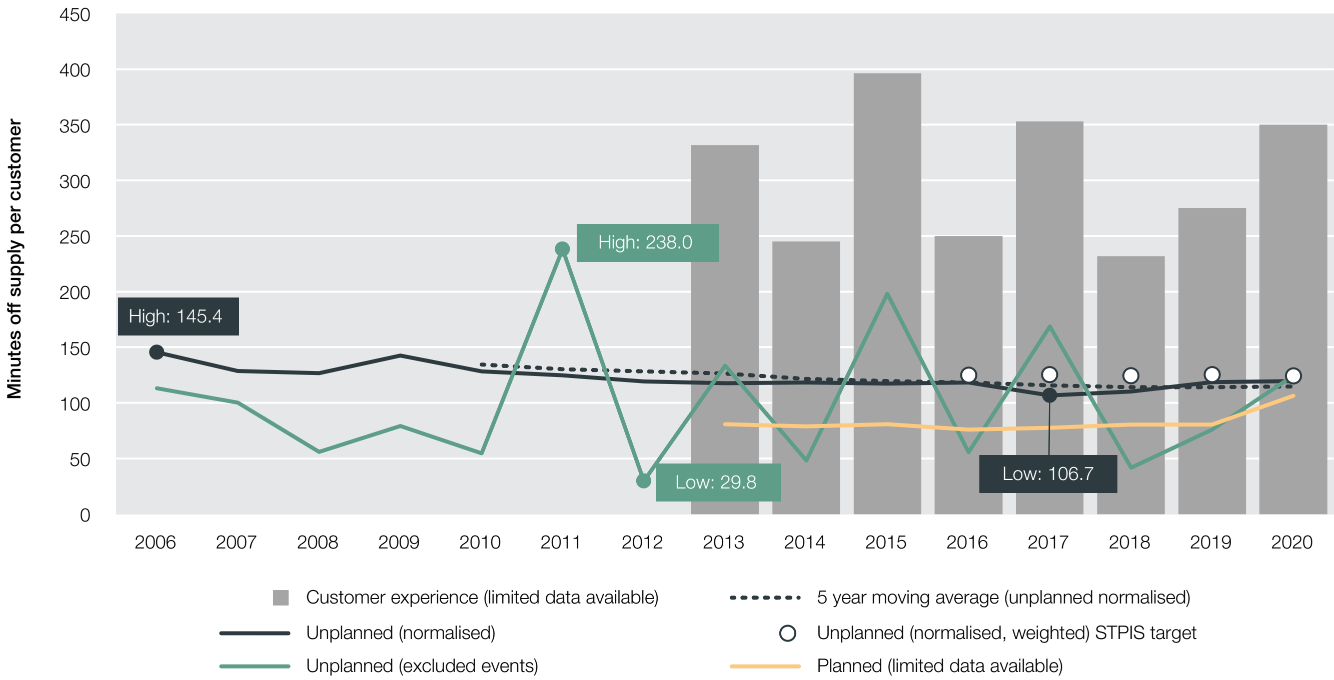


SAIFI: system average interruption frequency index; STPIS: service target performance incentive scheme.

Note: STPIS targets are set at the feeder level. The STPIS targets shown represent weighted network level targets, calculated by multiplying the distributor's feeder level targets by the proportion of its customers on each feeder type. Victorian network businesses report on a 1 January – 31 December basis. All other network businesses report on a 1 July – 30 June basis. The NEM data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018).

Source: AER modelling; economic benchmarking regulatory information (RIN) responses.

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



SAIDI: system average interruption duration index; STPIS: service target performance incentive scheme.

Note: STPIS targets are set at the feeder level. The STPIS targets shown represent weighted network level targets, calculated by multiplying the distributor's feeder level targets by the proportion of its customers on each feeder type. Victorian network businesses report on a 1 January – 31 December basis. All other network businesses report on a 1 July – 30 June basis. The National Electricity Market data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018).

Source: AER modelling; economic benchmarking regulatory information (RIN) responses.

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.[97]

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

Box 3.5 Service target performance incentive scheme

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

Transmission

The transmission STPIS covers 3 service components:

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

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

Distribution

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

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

- reliability of supply – unplanned (normalised) system average interruption duration index (SAIDI), unplanned (normalised) system average interruption frequency index (SAIFI), and momentary interruptions to supply (MAIFI)
- customer service – response times for phone calls, streetlight repair, new connections and written enquiries.[98]

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

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

98 The AER's Customer Service Incentive Scheme (CSIS) (box 3.6) will replace the STPIS telephone answering parameter for regulatory determinations made from 30 April 2021 onwards.

Incentives to avoid fire starts

The AER administers a Victorian Government scheme (f-factor scheme) offering incentives to Victorian distributors to lower the number of fire starts originating from their network, especially in high fire danger zones and at times of heightened fire risk. Available penalties and rewards range from around $1.48 million per fire start in high risk areas on code red days to $300 in low risk areas on low fire danger days.

Incentive payments for 2018–19 ranged from around $62,000 for the mostly urban United Energy network to more than $3.7 million for the predominantly rural Powercor network.[99]

Victorian distributors received almost 3 times more in f-factor rewards in 2018–19 than in the previous year. Rewards were significantly higher for United Energy (up 1,124%), Powercor (up 276%) and AusNet Services (up 28%) due to a lower number of fire starts in the period.

The AER will continue to administer the f-factor scheme to all Victorian distributors in the 2021 to 2026 period. The distributors will continue to receive incentive payments if they make sustained and continuous improvements in fire start performance. Once they make improvements, their benchmark targets are tightened in future years.

3.15.4 Customer service

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

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

Individual jurisdictions set different standards for these performance indicators. Some jurisdictions apply a guaranteed service level (GSL) scheme that requires network businesses to compensate customers for inadequate performance. Because reporting criteria vary by jurisdiction, performance outcomes are not directly comparable. The AER provides an annual summary of outcomes against some of these measures for networks in NSW, Queensland, South Australia, Tasmania and the ACT.[100] Victoria reports separately on network performance.[101]

In July 2020 the AER released its new CSIS, which provides incentives for distributors to provide measurable levels of customer service that align with their customers' preferences (box 3.6).[102]

The AER also oversees the rules protecting energy customers who rely on life support equipment. Between December 2018 and 31 March 2020 the AER issued 7 infringement notices to distribution businesses for failing to provide sufficient notice of outages to life support customers – 3 notices were issued to TasNetworks (Tasmania) and 2 notices were issued to Energex (Queensland) and Evoenergy (ACT).

In the period 31 March 2020 to mid-May 2021 the AER did not issue any infringement notices to distribution businesses for failing to provide sufficient notice of outages to life support customers.

99 AER, *Victoria F-factor scheme results for the 2016–20 period*, 30 June 2020.

100 AER, *Annual retail markets report 2019–20*, November 2020.

101 ESC, *Victorian energy market update*, March 2021.

102 AER, *Final – Customer Service Incentive Scheme*, July 2020.

Box 3.6 Customer Service Incentive Scheme

The Australian Energy Regulator's (AER's) Customer Service Incentive Scheme (CSIS) is designed to encourage electricity distributors to engage with their customers and provide a level of service which corresponds with their customers' preferences. The AER sets customer service performance targets for network businesses as part of the 5-year revenue determination process. Under the CSIS, distributors may be financially rewarded or penalised depending on how well they perform against the designated customer service targets. The revenue at risk under the scheme is capped at ±0.5%.

The CSIS is a flexible 'principles based' scheme that can be tailored to the specific preferences and priorities of a distributor's customers. This flexibility will allow for the evolution of customer engagement and adapt to the introduction of new technologies.

The CSIS provides safeguards to ensure the financial rewards/penalties under the scheme are commensurate with actual improvements/detriments to customer service. The incentives target areas of service that customers want to see improved.

The AER generally sets performance targets under the CSIS at the level of current performance. However, it may adjust the performance targets if the level of current performance is not considered to provide a good outcome for consumers.[103]

The incentive rates are tested with customers to confirm that they align with the value that customers place on the level of performance improvement/decline. This means that, even if a distributor performs exceptionally well against its targets, customers will still benefit. In subsequent regulatory periods, the targets under the scheme will be adjusted and set in accordance with any improved level of customer service.

The AER applies the CSIS through a selection of the following performance parameters:

- communication of unplanned outages
- frequency, duration and/or communication of planned outages
- customer service for new connections (basic and standard)
- customer service in managing complaints.

For each parameter, customer satisfaction is measured using a survey.

The first application of the CSIS is for Victorian distributors AusNet Services, CitiPower, Powercor and United Energy for the 2021 to 2026 period.

103 AusNet Services' historical performance for the complaints parameter was not considered acceptable. In this case using targets based on historical performance would not have the desired effect. As such, the performance target was calculated using industry-leading performance; therefore, AusNet Services will only be rewarded for material improvements to customer service.