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AUSTRALIAN ENERGY REGULATOR

State of the energy market
Network performance report 2026

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Inquiries about this publication should be addressed to:

Australian Energy Regulator
GPO Box 3131
Canberra ACT 2601
Email: aerinquiry@aer.gov.au
Tel: 1300 585 165

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1 Executive summary

Our 2026 Network performance report analyses the key outcomes and performance trends of 25 network service providers (NSPs) that operate in electricity and gas networks across Australia, except for Western Australia. Specifically, this report looks at:

- 14 electricity distribution network service providers (DNSPs),
- 5 electricity transmission network service providers (TNSPs)
- 6 gas DNSPs

Each NSP is regulated by the AER under the National Electricity Objective (NEO) and National Gas Objective (NGO).[1]

Our report covers their operational and financial performance as well as the performance of electricity DNSPs in specifically providing export services to customers who have consumer energy resources (CER), such as rooftop solar and batteries. This annual network performance report provides accessible information that support our role to monitor Australia's electricity and gas networks.

1.1 Network performance in 2025

Australia's energy system is in the midst of a major transformation driven by the decarbonisation and decentralisation of energy services and the addition of new technologies to meet Australia's climate goal of net-zero carbon emissions by 2050.

In 2025, electricity networks and gas distribution networks played contrasting roles in this transition. Investment in electricity network capacity is needed for the growth in new solar, wind generation and battery storage, while electricity distribution networks need to facilitate the co-ordination of more CER into the electricity grid.

Conversely, while residential customers electrify their household gas appliances, there will be a decline in the gas delivered by gas distributors and the number of customers connected to their networks.

In recent gas regulatory access arrangement decisions,[2] the AER has allowed accelerated depreciation as a way to mitigate against stranding gas assets associated with past capital investments. However, this will not resolve the broader policy question involving consumers, network businesses and governments as to who should pay for the costs of the stranding asset risk, or when, and how this could occur.

This contrast in the trajectory of electricity networks and gas distribution networks is evident in our network performance data in 2025.

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1 This report does not include any operational or financial data on the TNSPs we report on. This data (and infographic) will be published in the second half of the year.

2 AER, Jemena Gas Networks (NSW) – Access arrangement 2025-30 Final decision, May 2025. AER, Australian Gas Networks (SA) – Access arrangement 2026-31 Final decision, May 2026. AER, Evoenergy – Access arrangement 2026-31 Final decision, May 2026.

Electricity networks are growing, as networks are investing more capital expenditure (capex) to support the growth in renewable energy and electrification, including the electrification of transport. Alternatively, while there are some differences between jurisdictions, gas distribution networks are declining and there has been an increase in customers disconnecting from the gas distribution networks.[3]

This report also shows the evolution of the electricity grid into a two-way energy system. The growth in rooftop solar generation and home battery storage has increased the number of electricity distribution network customers exporting surplus generation. In 2025, this growth has led to 28% of all electricity distribution customers including residential and non-residential low-voltage customers using the network to export electricity. Further growth is expected next year from the continued installation of household batteries as part of the government's Cheaper Home Batteries Program.

In 2025, total network revenues increased compared with the previous year for both electricity networks and gas distribution networks. However, these revenues remain significantly below their respective peaks in 2015.[4]

There was a notable increase in expenditures by electricity networks in 2025, which was primarily due to overspends by Ergon Energy, Jemena, AusNet Services (distribution) and Energex. In aggregate, this has resulted in significant overspends of the total operating expenditure (opex) and (capex) allowances of electricity distribution networks. For gas distribution networks there was an aggregate increase in capex and opex spends from the prior year, however the expenditures were below the total capex and opex allowances.

Financial performance differed across networks in 2025. In aggregate, electricity networks and gas distribution networks return on assets (RoA) increased. However, for electricity networks the returns were below their allowed rate of return. For the return on regulated equity (RoRE), lower inflation, declines in expenditure efficiency and lower outperformance from the debt allowance led to lower returns for both electricity networks and gas distribution networks. The gap between allowed and actual RoRE returns was closed, largely due to the changes in the interest rate and inflation environment flowing through.

In relation to service levels, for electricity distribution networks there was an increase in the total electricity delivered and aggregate maximum demand, which led to network utilisation continuing its upwards trajectory. For gas distribution networks there was a decrease in gas demand, due to milder temperatures, improved appliance efficiency and customers reduced consumption in response to cost-of-living pressures.

Although the frequency and duration of electricity outages increased slightly compared with the previous year, overall reliability remained high with outage levels still below earlier peaks. Gas distribution networks continued to record very low pipeline outages and had a slight improvement in "unaccounted for gas (UAFG)" loss rate, which measures the gap between gas entering the network and gas delivered to customers.

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[3] AER, Regulating gas pipelines under uncertainty - Information paper, November 2021.

[4] The 2015 peak was $18.7b for electricity networks and $1.9b for gas distribution network revenues.

1.2 Summary of 2025

Key finding	Electricity networks	Gas distribution networks
Revenue	• Electricity network revenues increased by 6% to $14.5b (real terms). This resulted in a $62 increase in annual costs per customer. This was due to an increase of 6% in both distribution and transmission revenues respectively. • Despite this increase, electricity network revenues remain significantly below (25%) their 2015 peak. On a revenue per customer basis, 2025 revenues were $658 lower than the 2015 peak.	• Gas distribution network revenues increased by 4.0% to $1.7b (real terms), or a $10 increase on a per customer basis compared to the previous year. • Despite this increase, gas distribution network revenues remain 17% below their 2015 peak. On a revenue per customer basis, 2025 revenues were $157 lower than the 2015 peak.
Incentive schemes	• Electricity networks earned $506m in incentive revenues in 2025, an increase of 28% from the previous year. • The increase in 2025 was driven by an increase of EBSS ($83m) and STPIS ($58m) rewards, which was offset by a decrease of CESS rewards ($25m).	• Gas distribution networks paid $9m in relation to incentive scheme penalties in 2025. This represented less than 1% of total distribution network revenues.
Capex	• Electricity networks capex increased by 14% to $8.6b, in real terms and they collectively overspent their capex allowance for the second consecutive year. In 2025, their collective allowance was exceeded by 3%. • Similar to 2024, this overspend was primarily driven by electricity distribution networks, with Ergon Energy individually accounting for more than half of this overspend. • Electricity transmission networks collectively invested $2.9b in 2025, an increase of 42% from the prior year. Most capex was on integrated system plan (ISP) projects, with over $2b invested in 2025. • The capex to provide export services increased by 59% to $111m, representing 2% of the total capex investment by electricity distribution networks.	• Gas distribution networks capex increased by 10% to $628m in real terms in 2025. • Gas distribution networks' capex predominantly relates to the new connections made on the gas distribution networks and the replacement of cast iron pipelines with pipelines using polyethene or polyamide materials. • This capex enables gas distribution networks to connect new customers and install new polyethylene or polyamide pipelines where necessary to provide a safe and reliable supply of gas to customers.

Key finding	Electricity networks	Gas distribution networks
Opex	• Opex was $5.1b for electricity networks, an increase of 10% in real terms. Overall, electricity networks overspent their opex allowance in 2025 by 13%. • The opex incurred to provide export services was $32m, an increase of 66% from the previous year. This represented 0.7% of the total opex spend by electricity distribution networks.	• Opex was $614m for gas distribution networks, an increase of 2%. Despite this increase, gas distribution networks collectively underspent their opex allowance by 12%, the eighth consecutive underspend since 2018.
Asset bases	• There was a 2.8% increase in real terms in the regulated asset base (RAB) values for electricity networks in 2025. When disaggregated, electricity distribution network RABs increased by 1.9% and electricity transmission network RABs increased by 5.7%. • Electricity RAB per MWh electricity delivered was $866, an increase of $12 from the prior year.	• Capital asset base (CAB) values increased by 1.4% in real terms for gas distribution networks in 2025, resulting in a CAB per customer of $2,709, an increase of $8 from the prior year. • The CAB per GJ delivered for gas distribution networks was $47, which was a slight increase of $2 from the prior year. Since 2011, this CAB per GJ delivered has increased by 49% or $15.
Energy delivered and utilisation	• Electricity delivered by electricity distribution networks was 148.8 thousand GWh in 2025, an increase of 1.4% and the fourth consecutive annual increase. • There was 16.3 thousand GWh of electricity exported, an increase of 17% from the prior year. This represented 11.0% of the total electricity delivered by electricity distribution networks. • At the conclusion of 2025, the total capacity of the solar PV and batteries owned by export service customers was 21 thousand MVA, a 13% increase from the prior year. • Distribution network utilisation continued its upwards trajectory in 2025 to 46%, the highest level since 2013. This was driven by higher maximum demand for Victorian electricity distribution networks.	• There was 261 thousand TJs of gas delivered by gas distribution networks in 2025, a decrease of 3% from the prior year. • There was a decrease in the gas delivered for each gas distribution network except Jemena Gas Networks, which had a 1.3% increase from the prior year. • Going forward there is uncertainty in relation to the pace of decline in gas demand from the electrification of household appliances and other policy developments in the energy transition to net zero emissions.

Key finding	Electricity networks	Gas distribution networks
Customer numbers	• There was a 5.1% increase in export service customers. At the conclusion of 2025, 28% of customers were using export services provided by electricity distribution networks. • There were 180,000 export service customers with a battery in 2025, representing 5.8% of export service customers. This is expected to increase exponentially in 2026, following the rebates offered to current or new export service customers for the Cheaper Home Batteries Program.	• There was a 1% increase in customers connected to the gas distribution networks in 2025, and 1.5% increase in residential connections. AGN Victoria had the largest increase in residential customer base (3%), whilst Evoenergy's customer base decreased by 1.1%. • The number of residential connections were equal to the prior year, whilst the disconnections increased by 5%.
Network reliability and export limits	• The overall reliability across electricity distribution networks remained high because outage levels were still below earlier peaks, although the frequency and duration of electricity outages increased slightly compared with the previous year. • The average non-zero static export limit — the fixed maximum amount of electricity a customer is allowed to export above zero — decreased slightly in 2025 to 5.3 kVA. There were around 20,000 export service customers which had flexible export limits in 2025, a 448% increase from the prior year. Over 90% of these customers were connected to SA Power Networks.	• Network reliability across gas distribution networks remained high in 2025. UAFG improved slightly and outages continued at the same low levels as 2024.
Financial performance	• Electricity networks return on assets (RoA) increased by 0.4 percentage points (p.p.), however as allowed returns also increased, their aggregate returns were 0.2 p.p. below their allowed rates of return. This is the second consecutive year that aggregate actual returns were below the allowed returns. • The return on regulated equity (RoRE) decreased by 2.7 p.p. in 2025, for the second consecutive year and closed the gap between actual and allowed returns.	• Gas distribution networks aggregate RoA increased by 0.6 p.p., the first increase since 2021. This resulted in aggregate RoA returns 0.7 p.p. above allowed returns. • In aggregate, the RoRE decreased by 2.4 p.p. in 2025, primarily due to falling inflation. This resulted in returns which were 1.6 p.p. above the allowed returns.

2 Background

The 25 NSPs included in this report are located in every state and territory in Australia except Western Australia. [5]

Figure 2-1 Electricity NSPs and gas DNSPs regulated by the AER

2.1 Our objectives and stakeholder engagement

Through the history of our network performance reports and the accompanying datasets, we have advanced the following network performance reporting objectives,[6] determined with the input of our stakeholders:[7]

- Provide an accessible information resource - We prepare our network performance reports with the aim of making them informative and accessible to a wide variety of stakeholders.
- Improve transparency - In publishing our reports and accompanying data, our goal is to illustrate the impacts and interactions of network performance under different regulatory tools or settings.
- Improve accountability - This report focuses on the overall effectiveness of network regulation and the performance of NSPs.
- Inform consideration of the effectiveness of the regulatory regime in achieving the National Energy Objectives - Provides us and stakeholders with insights into the

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5 The report is published in accordance with rules 6.27 (a) and (c), and 6A.31 (a) and (c) of the National Electricity Rules (NER), and division 5, section 64 of the National Gas Law (NGL). Further, in accordance with 6.27A(a) of the NER, the report includes electricity DNSP performance in relation to export capacity, battery penetration, export limits and curtailment.

6 AER, Network performance reporting for regulated electricity and gas networks - Final position on objectives and priorities for network performance reporting, December 2025.

7 Stakeholder engagement is discussed further in section 2.1.1 of this report.

regulatory framework, our decisions under the framework and network performance under those decisions.

- Encourage improved performance - We expect these reports will contribute to improved performance by encouraging NSPs to adopt more efficient processes and promote technologies applied successfully by better performing NSPs.
- Improve network data resources - Through our network performance reports, we have sought to investigate and utilise a wide range of our network data sources and identify and manage differences in reporting which impede comparability of NSPs.

We have been publishing electricity reports since 2020 and gas reports since 2021. The effectiveness of our future reporting is dependent on stakeholders' feedback on both the report and our datasets so that we can improve their usefulness over time.

2.1.1 Stakeholder engagement for this report

In developing this report, we:

- sought a review of the draft report from NSPs and consumer representatives for factual accuracy, and
- provided NSPs with a copy of the supporting datasets to check for errors or omissions.[8]

2.2 Data used in this report

Data in this report is sourced from annual information orders (AIOs), regulatory information notices (RINs), post-tax revenue models (PTRMs) and roll-forward models (RFMs), submitted to the AER by networks and published on the AER website. Data for the 2025 regulatory year was submitted by most networks to the AER in November 2025. The length of the data series in this report and our datasets varies across the energy sectors and data types.

- operational data for electricity NSPs begins in 2006 and for gas NSPs in 2011
- financial performance data for both electricity NSPs and gas NSPs begins in 2014
- export service data for electricity DNSPs begins in 2021[9]

The NER and NGR specify that we may not publish NSP data that is considered confidential. Confidential data may include data that is identifiable to a third party or data that if disclosed may have a substantial adverse effect on the interests of that business.[10] Confidentiality claims over inputs for financial performance measures prevent us from publishing detailed input data, although we are still able to publish the resulting financial performance measures.

Given stakeholder interest, we have again included the methodology we use to calculate the financial performance measures in Appendix B, C and D.

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8 We completed this consultation in compliance with 8.7.4 (a), (b), & (c) of the NER and 140 of the NGR.

9 Export services network performance data was previously (2021 to 2024) reported by electricity DNSPs through voluntary information requests. For the 2025 regulatory year and going forward, this information will be reported by electricity DNSPs in the AIOs.

10 ACCC/AER, Information policy, June 2014, p 9.

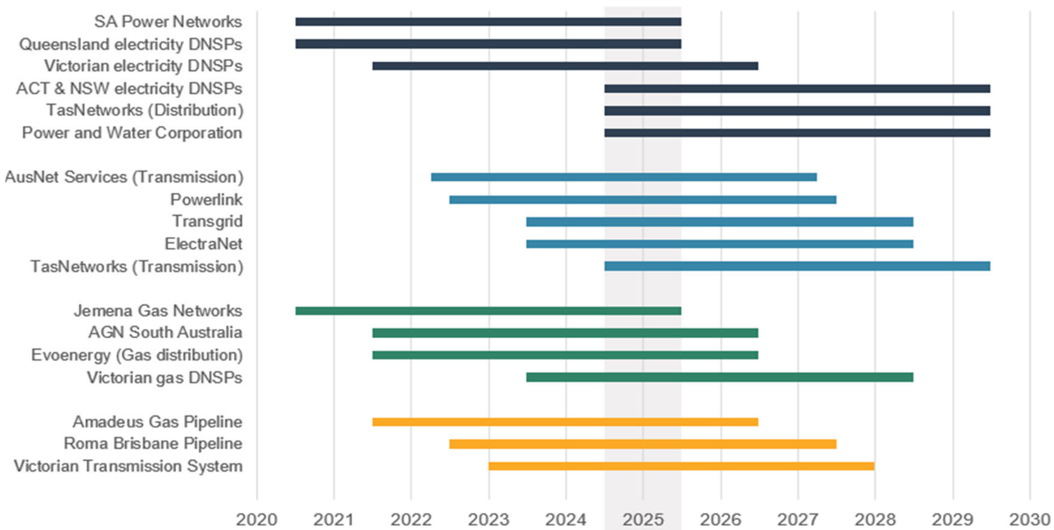
The accompanying datasets underpinning this report are provided in the operational and financial performance Microsoft Excel workbooks published alongside this report.

2.2.1 The 2025 regulatory year differed across networks

In this report the 2025 regulatory year for NSPs is the period 1 July 2024 to 30 June 2025. The exception is AusNet Services (transmission) which had a regulatory year from 1 April 2024 to 31 March 2025, and the Victorian Transmission System which had a regulatory year from 1 January 2025 to 31 December 2025.

Our regulatory periods and access arrangements typically apply over 5-year periods. We make these decisions for electricity and gas NSPs in a staggered cycle (Figure 2-2).

Figure 2-2 Electricity and gas NSP regulatory determination periods



Source: AER analysis of regulatory determination periods available on AER website.

The regulatory cycle is generally considered to commence with the determination of the electricity DNSPs in the ACT, NSW, Tasmania and the NT. This is based on these regulatory determinations being the first to have periodically implemented substantial changes in regulatory settings (e.g., 2013 Better Regulation; 2018 Rate of Return Instrument). The 2025 regulatory year is the first year of the regulatory cycle.

3 Electricity network operational performance

This chapter focuses on the performance of electricity NSPs in the 2025 regulatory year.[11] References to NSPs in this chapter relate to electricity DNSPs and TNSPs.

3.1 Network costs increased in 2025

3.1.1 Electricity network revenue increase in 2025

NSPs are monopoly businesses that provide essential services to customers. The AER is required under the NER to regulate the revenue NSPs are allowed to collect. We set the allowed revenue, based on our assessment of forecast efficient costs, which enables NSPs to fund their operations and receive a market rate of return on their capital investments. These costs are set in a manner which incentivises NSPs to make efficiency gains through reducing costs, whilst improving services for customers. Most customers pay network costs through network tariffs that are passed on to them through their electricity retailer.

Electricity NSPs are regulated under a ‘revenue cap’ regulatory framework. This means they annually set prices to earn the maximum revenue allowed under the revenue cap. We set the maximum allowed revenue (MAR) so NSPs can recover the costs an efficient network would incur in providing core regulated services. Gas DNSPs are regulated under a weighted average ‘price cap’ and hybrid tariff variation mechanism which is detailed in section 4.2.

Distribution and transmission revenue relates to revenue collected for core regulated services: standard control services for DNSPs and prescribed transmission services for TNSPs, as defined by the NER. These services include most energy transportation, connections and metering and represent the majority of an NSP’s revenue.

In 2025, network customers paid an average of $1,309 in revenues to NSPs. Of this, $1,010 was paid to DNSPs and $299 to TNSPs.[12] This is an increase of $62 in real terms compared to 2024. In total, NSPs recovered $14.5b from customers, 6% higher than the previous year.

Despite the increase in 2025, electricity network costs remain significantly below the peak in 2015. When compared to the peak, total electricity network costs are down 25% and network customers are paying $658 less in real terms.

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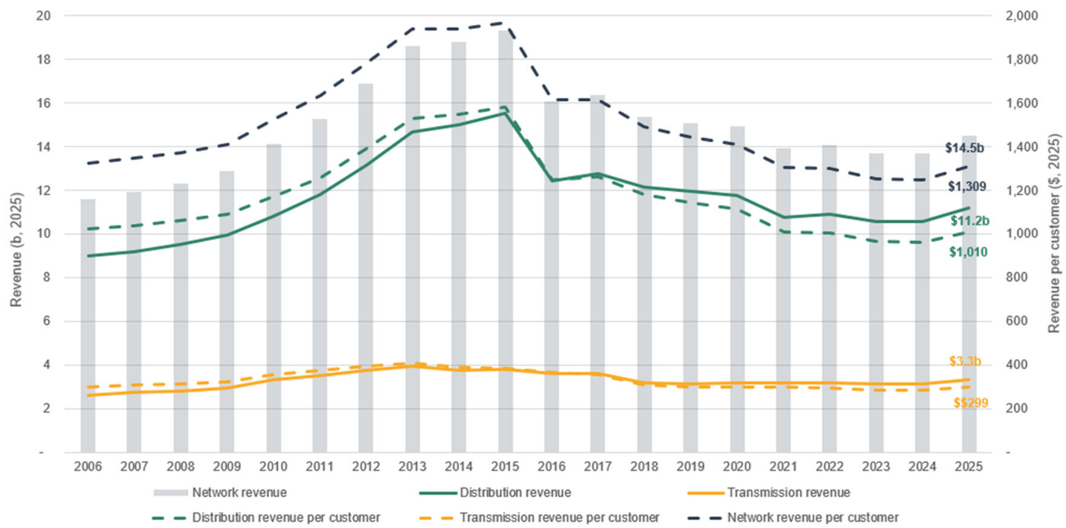
11 Refer to section 2.2.1 for details of each NSP’s regulatory year.

12 Transmission revenue includes transmission revenue ‘from customers’ ($3.0b) and transmission revenue from ‘other sources’ ($354m). This is discussed further in section 3.1.6.

Figure 3-1 Network revenue - NSPs - $ real 2025



Source: Network revenue: Annual RIN and Annual Information Order (AIO) table 8.1.1.1, 'Revenue - standard control services' for DNSPs. For TNSPs or where annual RIN data is not available for DNSPs, data is from economic benchmarking (EB) RIN and AIO Table 3.1.1, 'Revenue grouping by chargeable quantity'. Network revenue per customer: Revenue provided above. Customer number data is from EB RIN and AIO table 3.4.2, 'Distribution customer numbers by customer type or class.' Note: AER calculation to convert to $ June 2025 terms. Network revenue is the sum of distribution revenue and transmission revenue. DNSP revenue per customer calculated by dividing DNSP's revenue by DNSP's customer numbers. TNSP revenue per customer calculated by dividing TNSP's revenue by the sum of distribution customers located in the same region as the TNSP.

3.1.2 Networks have higher incentive schemes revenues in 2025

The regulatory framework incentivises NSPs to improve customer outcomes by increasing their efficiency, reducing costs, and improving service performance. This is achieved through incentive schemes which provide a monetary benefit for meeting performance targets or imposing a penalty for falling short of performance targets in relation to expenditure efficiency, reliability or other regulatory targets.[13]

Incentive schemes are designed to motivate NSPs to take actions that benefit customers. The goal of incentive schemes is to ensure that the overall benefit to customers outweighs the incentive revenue provided to the NSP. These schemes effectively align NSPs' interests with those of their customers.

During 2025, NSPs earned $506m in incentive revenues, an increase of 28% from the previous year. This has been primarily driven by an increase of EBSS ($83m) and STPIS ($58m) rewards, which was offset by a decrease of CESS rewards ($25m). These rewards are balanced against consumers receiving benefits from higher reliability and reduced capex and opex allowances in future years.

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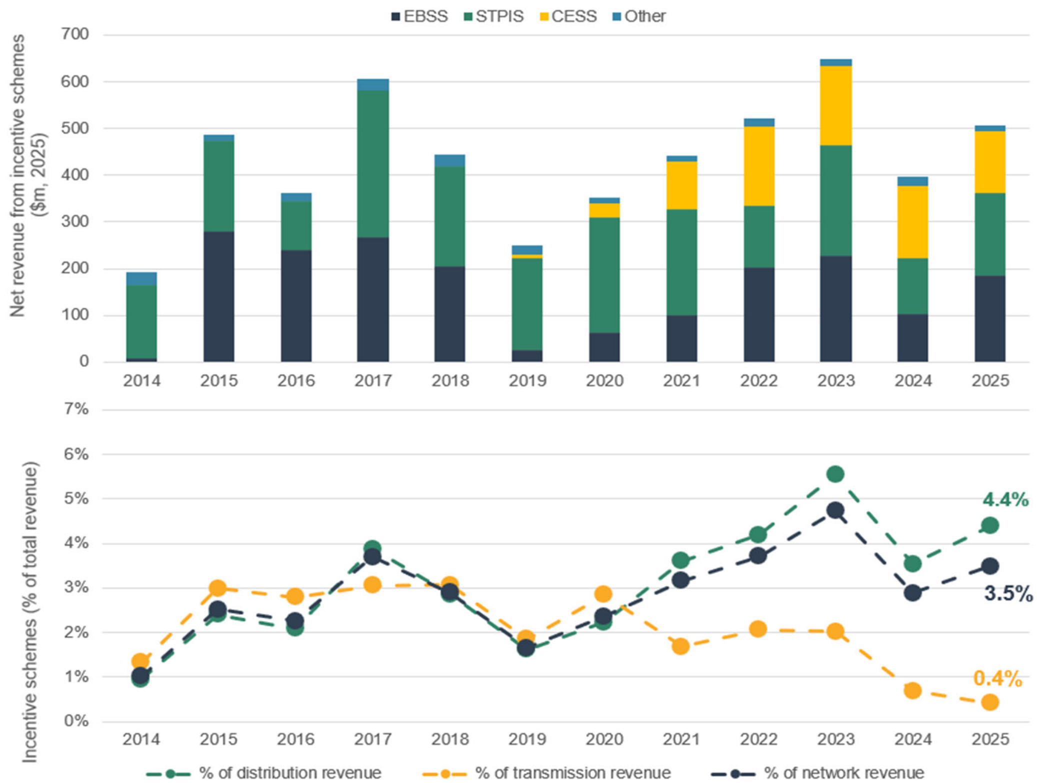
13 A list of the applicable incentive schemes is provided in Table 3-1 of the [2025 Electricity and gas network performance report](#).

Figure 3-2 Revenue from incentive schemes - NSPs - $ real 2025



Incentive scheme revenues/payments from EB RIN and AIO table 3.1.3, ‘Revenue (penalties) allowed (deducted) through incentive schemes.’ Where not available, data is from respective NSP’s PTRM, ‘Revenue adjustments.’ Distribution revenue: Refer to Figure 3-1. Transmission revenue: Refer to Figure 3-1. Notes: AER calculation to convert to $ June 2025 terms. Incentive schemes as percentage of distribution, transmission and network revenue are calculated by dividing incentive schemes by total distribution, transmission and network revenues.

Since 2020, whilst DNSPs rewards have increased to 4.4% of total distribution revenue, the incentive scheme rewards for TNSPs have decreased to their lowest level in our dataset, being 0.4% of the total transmission revenues. The decrease in TNSP incentive schemes when compared to DNSPs is due to:

- TNSPs having $16m of EBSS rewards in 2025, which contrasts to $170m of rewards for DNSPs.
- TNSPs earning $2m of STPIS rewards in 2025, which is $66m below the rewards earned in 2018. These lower rewards may be impacted by the penalties for TNSPs from market impact component (MIC) events in recent years. In April 2025, we suspended the MIC in the TNSP STPIS and stated we would explore developing an effective alternative with AEMO and key stakeholders.[14]
- TNSPs cumulatively earning $36m of CESS rewards in the period 2019 to 2025, with an overall $6m CESS penalty in 2025. In contrast, DNSPs in the period 2020 to 2025 earned $732m in CESS rewards, with overall rewards of $138m in 2025. These CESS rewards relate to the performance of NSPs in prior regulatory periods.

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[14] AER, Explanatory Statement - Electricity TNSPs - STPIS - Final Amendments, April 2025, p 2.

3.1.3 NSPs earn higher returns from incentive schemes

The monetary benefits from incentive schemes also enable NSPs to earn higher returns than allowed in their regulatory determinations. Conversely, if a NSP failed to meet the performance targets in relation to expenditure efficiency, reliability or other regulatory targets, they will earn returns lower than allowed

Over the past seven regulatory years, the rewards from incentive schemes resulted in NSPs on a weighted average basis having returns which were 0.8 p.p. higher than allowed. These returns differed across the NSPs and the regulatory periods.

Figure 3-3 Contributions of incentive schemes to RoRE

Source: Electricity financial performance models (confidential versions). Note: Financial performance numbers are nominal for the respective regulatory year.

3.1.4 Cost pass through events increased electricity network costs

The NER allow NSPs to recover costs associated with unforeseen events that are outside of an NSP's control and are not captured in existing approved expenditure allowances.[15] Costs must be material and may be passed through to customers only if they exceed 1% of an NSP's annual revenue allowance.

Cost pass throughs are more frequently positive (increasing allowed revenue) and less frequently negative (decreasing allowed revenue). Cost pass throughs may either directly increase the revenue allowed to be collected by an NSP, or they may increase revenue in future years by increasing the NSP's capex allowance, which flows through to increase the NSP's RAB.[16]

In 2025, NSPs recovered an additional $156m from pass through revenues - approximately 1.1% of the total electricity network revenues. As with prior years, the main driver of cost pass throughs in 2025 were natural disasters, which increased allowed revenues by $76m,

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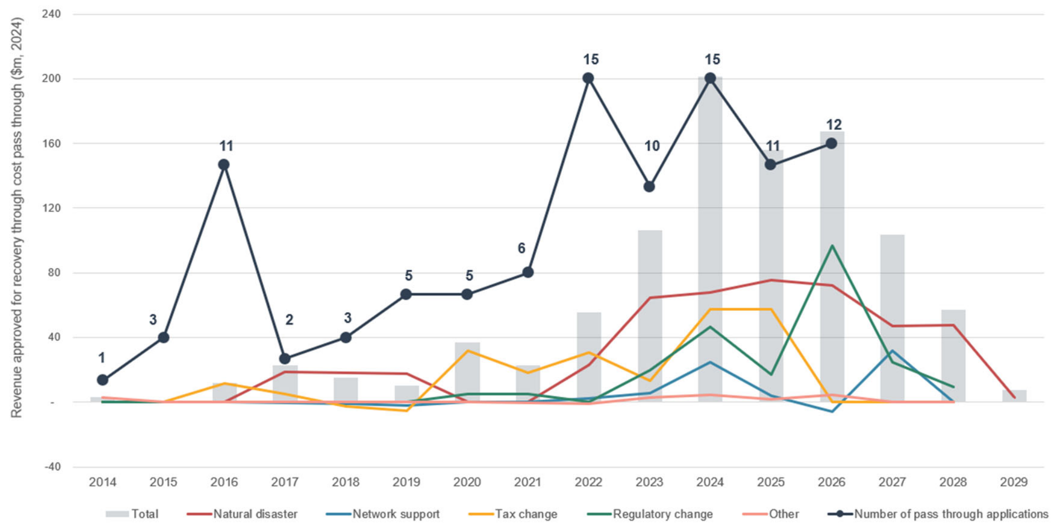
15 Under NER cl 6.6.1 for DNSPs and NER cl 6A.7.3 for TNSPs.

16 This is through additional returns from the return of capital and return on capital building blocks.

followed by tax ($57m) and regulatory requirements changes ($17m). These related to cost pass throughs that were lodged by NSPs in the period 2021 to 2025 and determined predominantly before the start of the 2025 regulatory period.

Figure 3-4 Revenue from cost pass throughs - NSPs - $ real 2025



Source: AER analysis of decisions under AER, Cost pass-throughs, accessed March 2026. Note: Calculation to convert values to $ June 2025 terms. Includes approved cost pass-through applications lodged to March 2026. Excludes jurisdictional scheme and feed in tariff cost pass throughs.

In 2025, we received 10 pass-through applications and made decisions on 15, six of which were lodged in 2024 and nine of which were lodged in 2025. These pass throughs primarily increased allowed revenues in 2025 and 2026.

3.1.5 Changes in network costs differs across networks

Total network revenues are calculated using the distribution revenue of 14 DNSPs and the transmission revenues of 5 TNSPs. Due to a range of factors, including changes to allowed rate of returns, revenue smoothing (x factors), under/over recoveries, incentive schemes and cost pass throughs, the annual movement in network costs can differ across the networks.

In last year's report, we noted that higher inflation and interest rates in the period following 2022, have subsequently led to higher allowed rates of return for electricity NSPs. For DNSPs with a 2024-29 regulatory period,[17] the recent regulatory decision involved an increase in return on equity component of their allowed rate of return, to reflect changes in financial markets for an investment of similar risk. This has led to an increase in these DNSPs' return on capital and the maximum revenue they were allowed to earn under the revenue cap.

In 2025, in real terms, there was an increase in network revenues, however the total network revenues and the annual increase from the prior year differed across the electricity NSPs.

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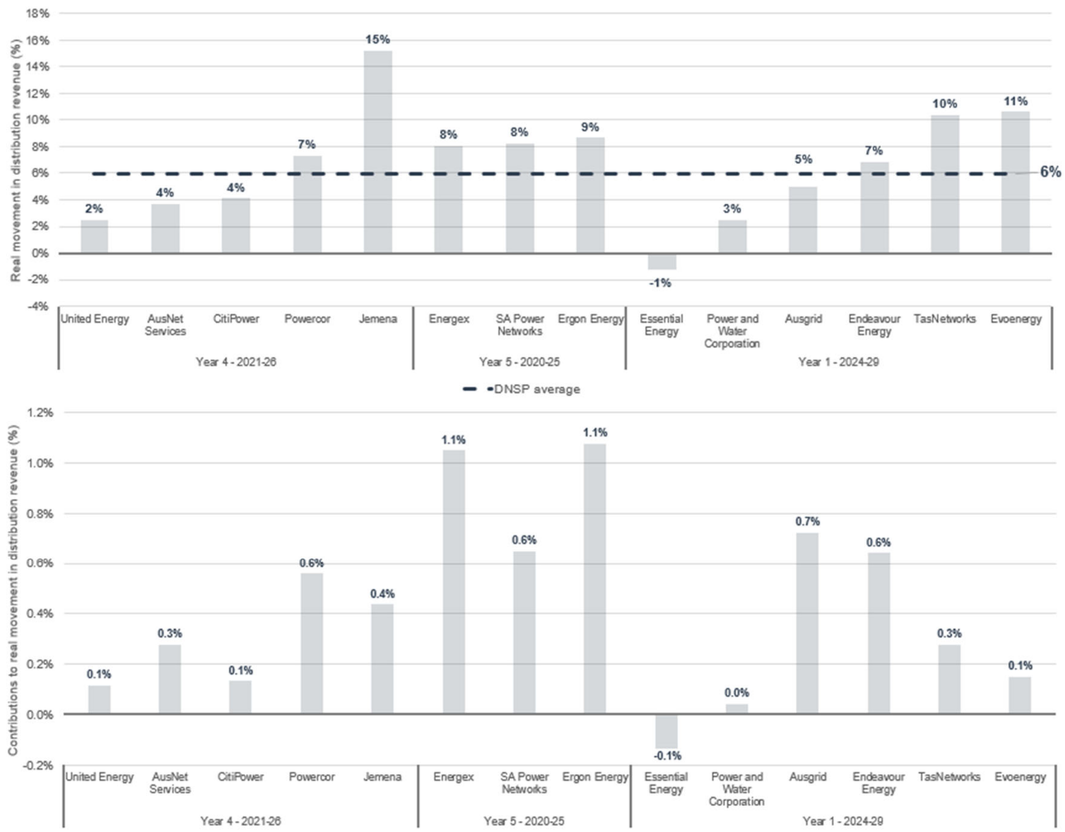
17 Ausgrid, Evoenergy, Endeavour Energy, Essential Energy, Power and Water Corporation and TasNetworks (distribution).

Figure 3-5 Annual movement in distribution revenue – 2024 to 2025 - $ real 2025



Source: Network revenue: Annual RIN and Annual Information Order (AIO) table 8.1.1.1, 'Revenue - standard control services' for DNSPs. Note: AER calculation to convert to $ June 2025 terms. Annual movements calculated by dividing the variance between DNSP's 2024 and 2025 revenue, by the DNSP's 2024 revenue.

Despite higher returns on equity in their allowed rate of return, DNSPs commencing their 2024-29 regulatory period did not predominantly cause the 6% aggregate annual increase in distribution revenues. As noted above, approximately half the 6% increase was attributable to Energex, Ergon Energy and SA Power Networks who were in year 5 of their regulatory period.

This indicates, in addition to the higher returns on equity, other pricing factors such as revenue smoothing, true ups of previous under recovery of revenue, incentive schemes rewards and cost pass throughs led to an increase in distribution revenue in 2025.

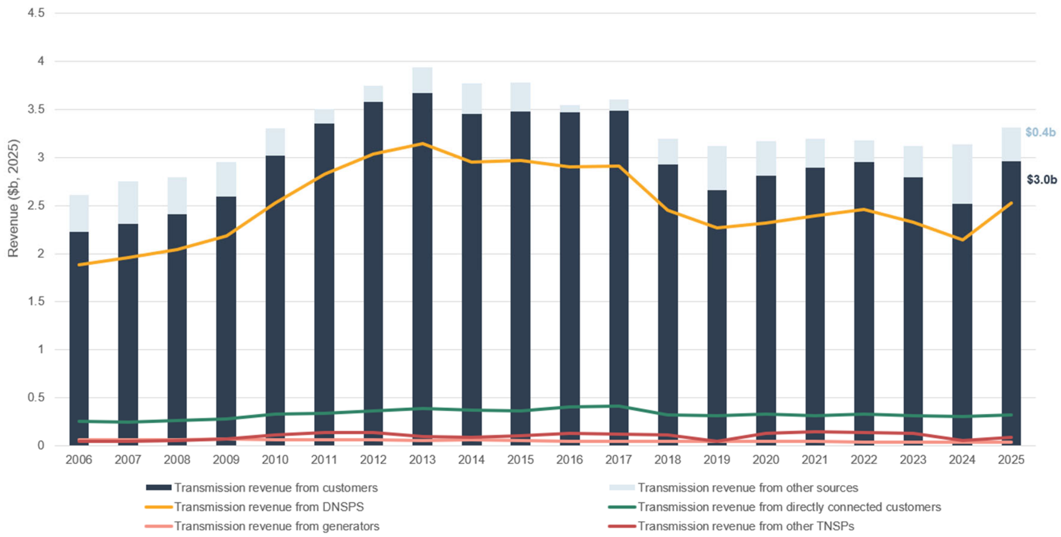
3.1.6 TNSPs recover more revenue from customers in 2025

Unlike DNSPs, which recover distribution revenue by charging retailers, TNSPs recover transmission revenue from several sources. The main source is DNSPs, but TNSPs also collect revenue from other customers, including directly connected users, generators and other transmission networks. This revenue is known as 'transmission revenue from customers.'

In addition to this 'transmission revenue from customers', TNSPs receive revenue from AEMO related inter-regional settlement residues (including proceeds from auctions) and intra-regional settlements residues, which are reported as revenue from 'other sources.' The MAR or AER approved revenue for a TNSP includes both 'transmission revenue from customers' and revenue from 'other sources.' This total revenue is used for our financial performance measures to assess a TNSP's returns against their allowed returns.

In 2025, transmission revenue from customers (dark blue in Figure 3-6) increased by 17% to $3.0b, due to an increase in revenue from distribution networks, as a higher proportion of the MAR was recovered from customers. On an individual TNSP basis, notable annual increases were observed for Transgrid (42%), Powerlink (17%) and AEMO/AusNet Services (13%).

Figure 3-6 Transmission revenue from customers and other sources



Source: Transmission revenue: (EB) RIN and AIO Table 3.1.1.' Note: AER calculation to convert to $ June 2025 terms.

When including revenue from 'other sources,' (light blue in Figure 3-6), total transmission revenues increased by 6% to $3.3b, with "other sources" revenue decreasing from $615m to $354m in 2025.

On average, revenue from 'other sources' has been approximately 10% of the TNSPs' MAR, with the highest proportion noted in 2024, where 20% ($615m) of MAR was collected from 'other sources.' In 2025, the revenue from 'other sources' reverted back to average, with the $354m representing 11% of the TNSPs' MAR.

3.1.7 DNSP jurisdictional scheme charges increase in 2025

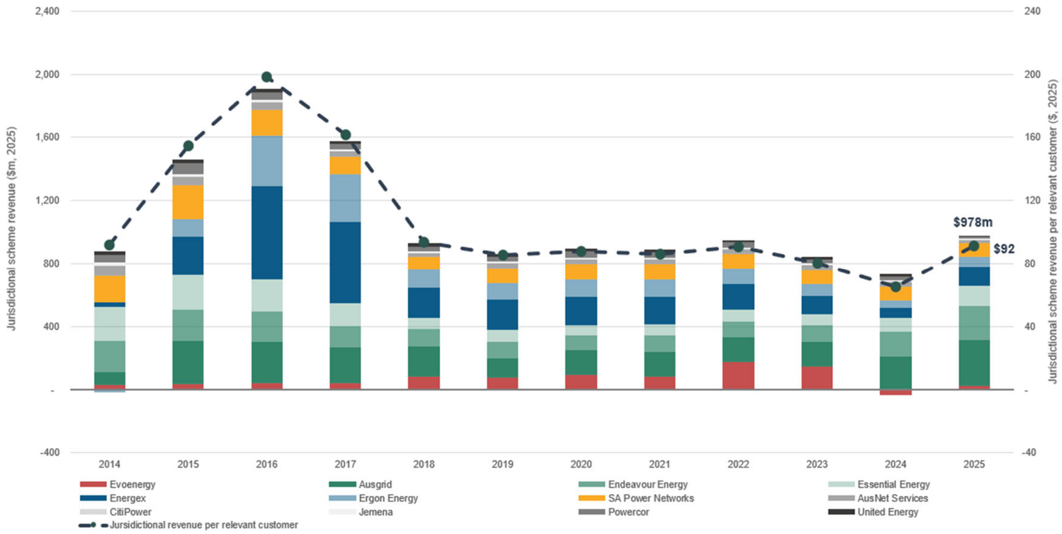
In addition to distribution and transmission charges, a DNSP's network tariffs also recover costs associated with pass-through of jurisdictional scheme charges, which the DNSP is required to pay pursuant to its jurisdictional scheme obligations ("jurisdictional schemes").

Jurisdictional scheme charges are dependent on a DNSP's jurisdiction. These charges are submitted to use by the DNSPs based on their forecast jurisdictional payments in the annual pricing process, taking into account any over or under recoveries in previous years. In 2025, relevant DNSP customers[18] paid $92 for jurisdictional schemes, an increase of $27 from the

[18] This does not include customers from TasNetworks (distribution) and Power and Water Corporation as these DNSPs do not have any jurisdictional scheme network tariffs in their approved network tariffs.

prior year. In total, $978m was collected from relevant customers for jurisdictional schemes, an increase of 41% from the prior year.

Figure 3-7 Jurisdictional scheme revenues - NSPs - $ real 2025



Source: Jurisdictional scheme revenue: Annual RIN and AIO table 8.1.1.1, ‘Revenue - standard control services.’ Note: AER calculation to convert to $ June 2025 terms. Jurisdictional scheme revenue per relevant customer calculated by dividing the jurisdictional scheme by the relevant customer numbers.

The increase in 2025 is primarily driven by

- the NSW Electricity Infrastructure Roadmap costs recovered from Ausgrid, Endeavour Energy and Essential Energy customers increasing by $201m to $345m,[19]
- an increase in jurisdictional scheme revenues for Energex ($51m) and Ergon Energy ($17m).

3.2 Expenditures increased as networks in aggregate overspent their allowance

An NSP’s total expenditure is the sum of opex and capex. Opex comprises day-to-day business expenses while capex is spent on longer term investments, most notably in network infrastructure. The regulatory framework is designed so that NSPs recover revenue for opex within the 5-year regulatory period through the opex allowance building block, while capex is added to the RAB (see below) and recovered over the life of the asset in the return of capital building block.

We set forecasts for opex and capex in a manner that incentivises NSPs to reduce costs. Opex efficiency against an NSP’s allowance leads to lower forecast expenditures in future years, ultimately leading to lower network costs for customers. Financial benefits from capex efficiency are reflected through incentive schemes and shared with customers via lower network costs in the subsequent regulatory period. Further, capex allowances are set as a

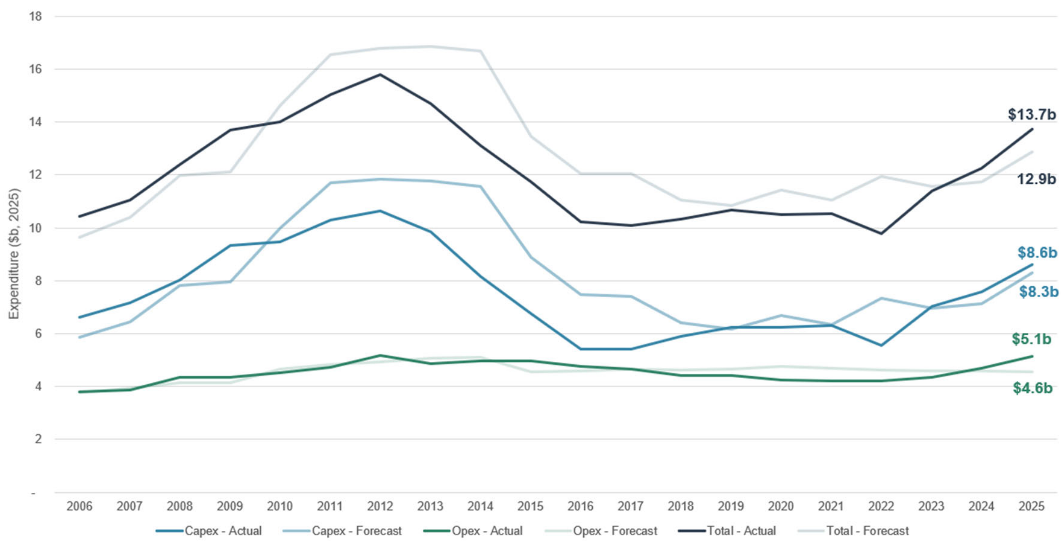
19 The contributions have been converted into $ June 2025 terms. We have been tasked with making annual contribution determinations that set out the costs of implementing the NSW Electricity Infrastructure Roadmap. These determinations are published on our website.

total on a five-year basis, and while NSPs may overspend or underspend relative to annual allowances in individual years, an overspend in a single year does not necessarily indicate an overspend over the regulatory period as a whole. These fluctuations can be due to a number of factors, some of which may be capex incentives, financial or otherwise, which vary through the course of the regulatory period.

When compared to the previous year, NSP actual expenditure in 2025 increased by 12% to $13.7m, exceeding their aggregate forecast expenditure by 8%. However, not all NSPs exceeded their forecasts; this variance is primarily driven by Energex and Ergon Energy (see Figure 3-11 below). This is the second consecutive year that NSPs in aggregate have overspent on their combined expenditure allowance.

This involved NSPs investing $8.5b of capex into their networks, an increase of 14% from the previous year (an overspend of their capex allowance by 3%). In addition, NSPs spent $5.1b on opex in 2025, an increase of 10% from the prior year (an overspend of their opex allowance by 13%).

Figure 3-8 Total expenditure - NSPs - $ real 2025

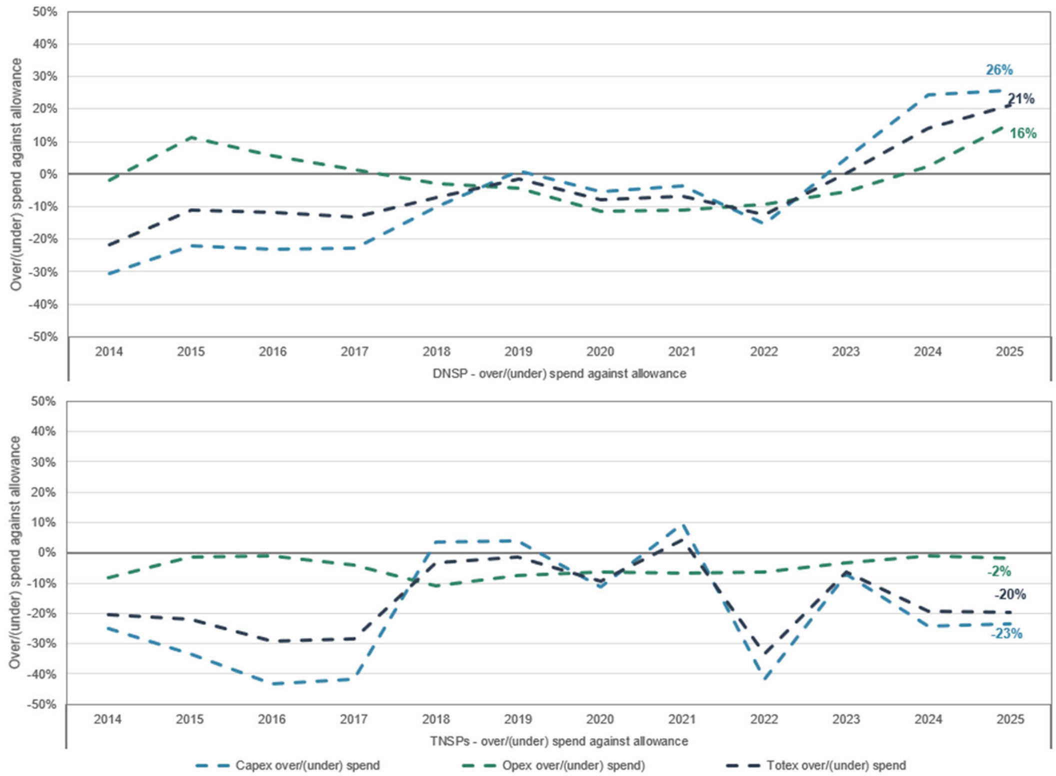


Source: Actual capex: RFM input - 'Actual capex,' 'Actual asset disposal,' 'Actual capital contributions.' Where RFM not available for TNSPs, use category analysis (CA) RIN and AIO: 2.1 Expenditure Summary, (ii) for DNSPs, use annual RINs and AIO: Table 8.2.4 'Capex by asset class,' Table 8.2.5 'Capital contributions by asset class,' Table 8.2.6 Disposals by asset class. Actual opex: EB RIN - Table 3.2.2 'Opex'. Forecast capex: PTRM Input - 'Forecast net capex.' Forecast opex: PTRM Input - 'Forecast operating and maintenance expenditure.'
Note: AER calculation to convert values into $ June 2025 terms. Net capex is gross capex less capital contributions and disposals.

3.2.1 DNSPs overspend their allowances, whilst TNSPs underspend their allowances

In 2025, the total expenditure (totex) spends against allowances differed between DNSPs and TNSPs, with DNSPs collectively overspending their allowance by 21%, and TNSPs underspending their allowance by 20%.

Figure 3-9 Expenditure over/(under) spend against allowance - NSPs - $ real 2025



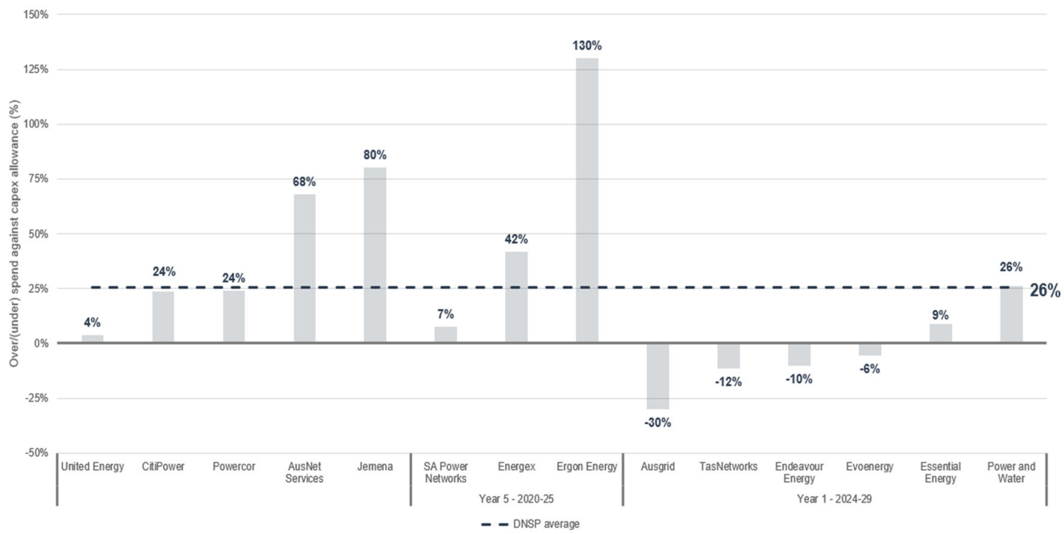
Source: Refer to actual and forecast capex and opex from Figure 3-8. Note: AER calculation to convert values into $ June 2025 terms. Over/under capex, opex and totex calculated by comparing total actual capex, opex and totex against total forecast capex, opex and totex for regulatory year.

The capex and opex overspends by DNSPs in the last two regulatory years have been driven by replacement expenditure, and to some extent capex related to the energy transition and the increased uptake of CER. This followed an extended period in which DNSPs predominantly underspent their expenditure allowances. The contrasting significant underspends for TNSPs in the last two regulatory years, is due to lower capex expenditure from delays in major ISP projects; Project EnergyConnect (PEC) and Humelink, which are discussed further below.

Capex investment differed across DNSPs in 2025, with the majority overspending their capex allowance. Similar to previous years,[20] Ergon Energy had the largest overspend (130%), followed by Jemena (80%) AusNet Services (68%) and Energex (42%). In contrast in the first year of their 2024-29 regulatory period, Ausgrid significantly underspent their capex allowance.

[20] Further discussion on Ergon Energy's previous capex overspends and the ex- post review of Ergon Energy's capex from 2018 to 2023 were detailed in our 2025 Electricity and gas network performance report.

Figure 3-10 Capex over/(under) against allowance – DNSPs - $ real 2025



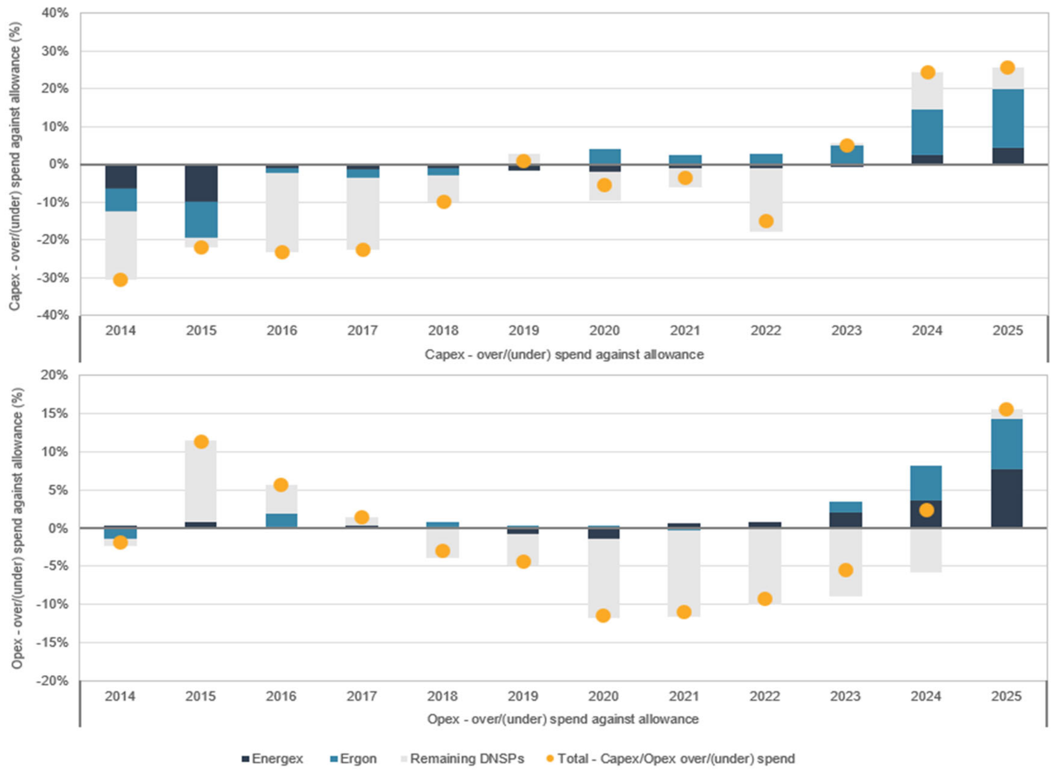
Source: Refer to actual and forecast capex and opex from Figure 3-8. Note: Refer to Figure 3-9.

3.2.2 Energex and Ergon Energy lead overspends for second consecutive year

The capex overspends by Energex and Ergon Energy contributed significantly to the aggregate capex overspends by DNSPs in 2025. In addition, the two DNSPs' opex overspends were also the primary cause for the aggregate opex overspends in 2025 (58% and 68% higher respectively than their allowances).

This is the second consecutive year that expenditure overspends by Energex and Ergon Energy have been the main contributor to the collective capex and opex overspends by DNSPs.

Figure 3-11 Contributions to DNSP over/(under) spend against allowance - $ real 2025



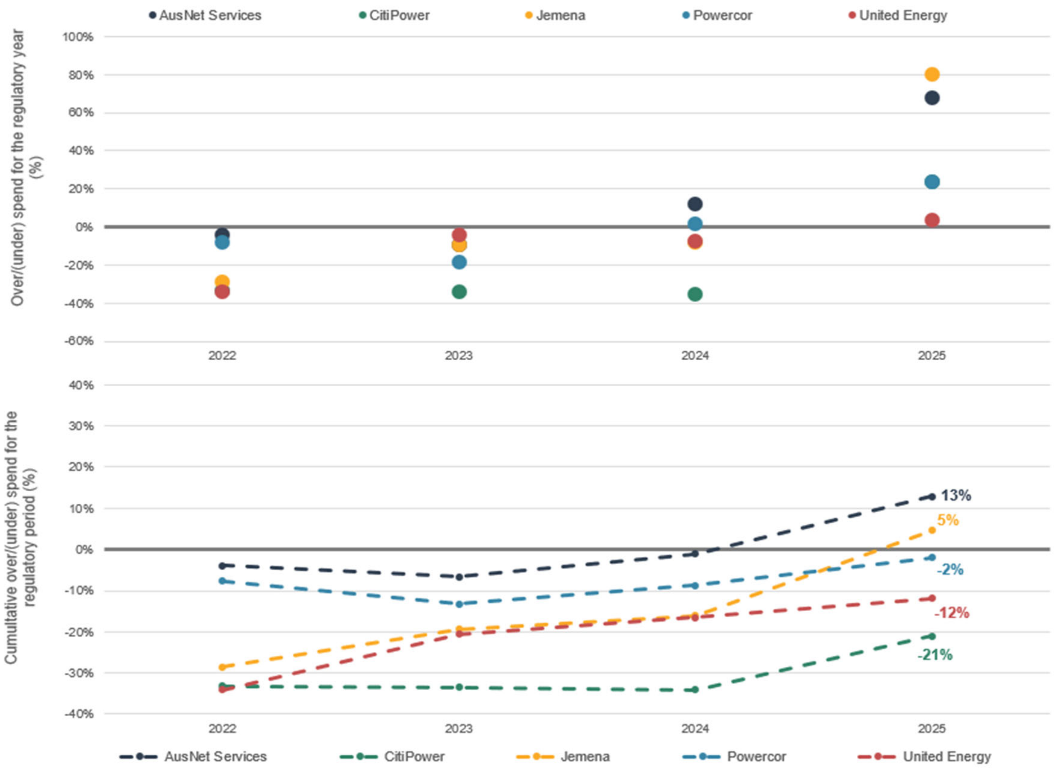
Source: Refer to actual and forecast capex and opex from Figure 3-8. Note: AER calculation to convert values into $ June 2025 terms. For over/under capex and opex refer to Figure 3-9. Contributions to total over/under spend calculated by comparing Energex's, Ergon Energy's and the remaining DNSPs' respective over/under spends to the DNSP total over/under spend.

3.2.3 AusNet Services and Jemena overspend for regulatory year and cumulatively for the regulatory period to date

We set capex allowances as a total over a five-year basis and expect capex patterns of NSPs to fluctuate between underspend and overspend against their annual allowance. There are different factors that can determine patterns of capex, which relates to capex incentives, financial or otherwise, which vary through the course of the regulatory period.

In 2025, the fourth year of their 2021-26 regulatory period, all Victorian DNSPs overspent their respective capex allowance. However, when comparing total capex spends against the capex allowance for the regulatory period, only AusNet Services and Jemena have cumulatively overspent on their allowance for the regulatory period. This overspend is a result of both DNSPs overspending their 2025 regulatory capex allowance significantly.

Figure 3-12 Over/under spend of capex allowance for current regulatory period - Victorian DNSPs - $ real 2025



Source: Refer to actual and forecast capex for DNSPs from Figure 3-8. Note: AER calculation to convert values into $ June 2025 terms. Net capex is gross capex less capital contributions and disposals. Capex over/under calculated by comparing total actual capex against total forecast capex for regulatory year and regulatory period.

Victorian DNSPs will conclude their current 2021-26 regulatory period in the 2026 regulatory year. We will assess any potential capex overspends by AusNet Services and Jemena and/or any other Victorian DNSP as part of the 2021-26 regulatory determinations. This involves considering whether any capex overspends by NSPs from the last two years of their previous regulatory period and the first three years of their current regulatory period are to be included in the opening balance of the RAB for their next regulatory period.[21]

3.2.4 Export service expenditure remains low for DNSPs

DNSPs will incur opex and make capex investments to provide export services to export customers by accepting and distributing the electricity generated within its distribution network.

Export service expenditure is required to be prudent and efficient, with expenditure to prevent or rectify emerging or actual constraints being justified by the calculated benefits of alleviating the constraints.

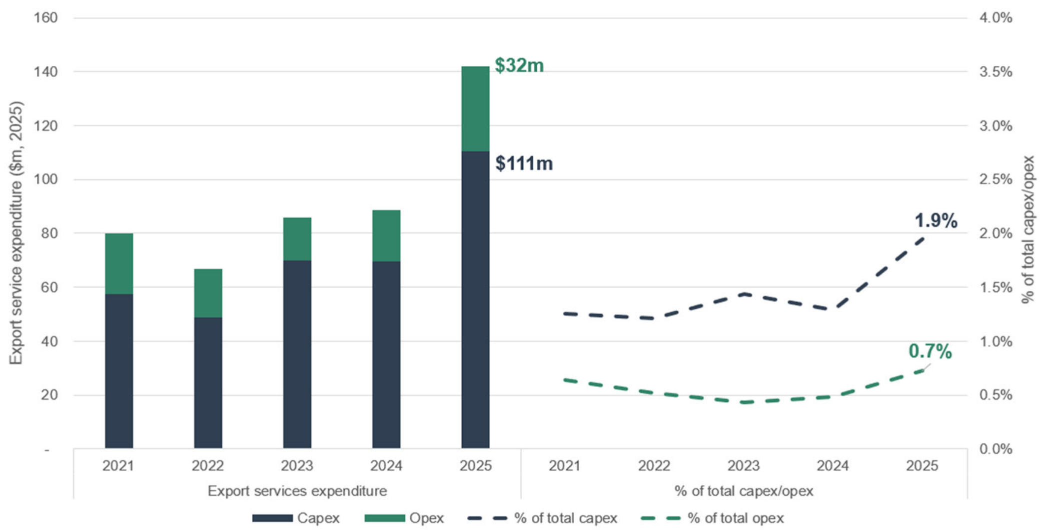
These expenditures are guided by customer export curtailment values (CECV) to determine the efficient level of network expenditure to enable export services, with the CECV also used

21 Further details on our considerations on NSP capex overspends in regulatory determinations were detailed in our 2025 Electricity and gas network performance report.

as an input into network planning, investment and incentive arrangements for export services.[22] In accordance with the NER,[23] in the second half of the year we will review the methodology to determine the CECV.

In 2025, there was an increase in DNSPs' export services expenditure, with capex increasing by 59% to $111m and opex increasing by 66% to $32m. Despite this increase, export service expenditure remains low, reflecting less than 2% of the total respective opex and capex spends by DNSPs. This reflects export service expenditure is required to be incremental to address potential issues in relation to congestion, constraints and curtailment from export service customers exporting to the grid.

Figure 3-13 Export services expenditure - DNSPs - $ real 2025



Source: Export service capex: DNSP information request and AIO Table 3.9.10. Export service opex: DNSP information request and AIO Table 3.9.10. Capex and opex totals refer to Figure 3-8. Note: AER calculation to convert values into $ June 2025 terms. Export services as percentage of capex and opex year calculated by dividing capex and opex export services expenditure by the total capex and opex for regulatory year.

3.2.5 TNSPs increase investment in ISP projects

While underspending their capex allowance, due to delays in major ISP projects, TNSPs collectively invested $2.9b in 2025, an increase of 37% from the prior year.

As highlighted in last year's report,[24] since 2019, TNSPs have been investing in a number of ISP projects. Over this 7-year period, the ISP related capex for TNSPs has gradually increased, with over $2b invested in ISP projects in 2025.

There are currently 8 projects which have been completed or are being undertaken in relation to the ISP. AEMO's ISP provides a coordinated whole-of-system plan for efficient

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22 AER, Explanatory statement: Final Customer export curtailment value methodology, June 2022.

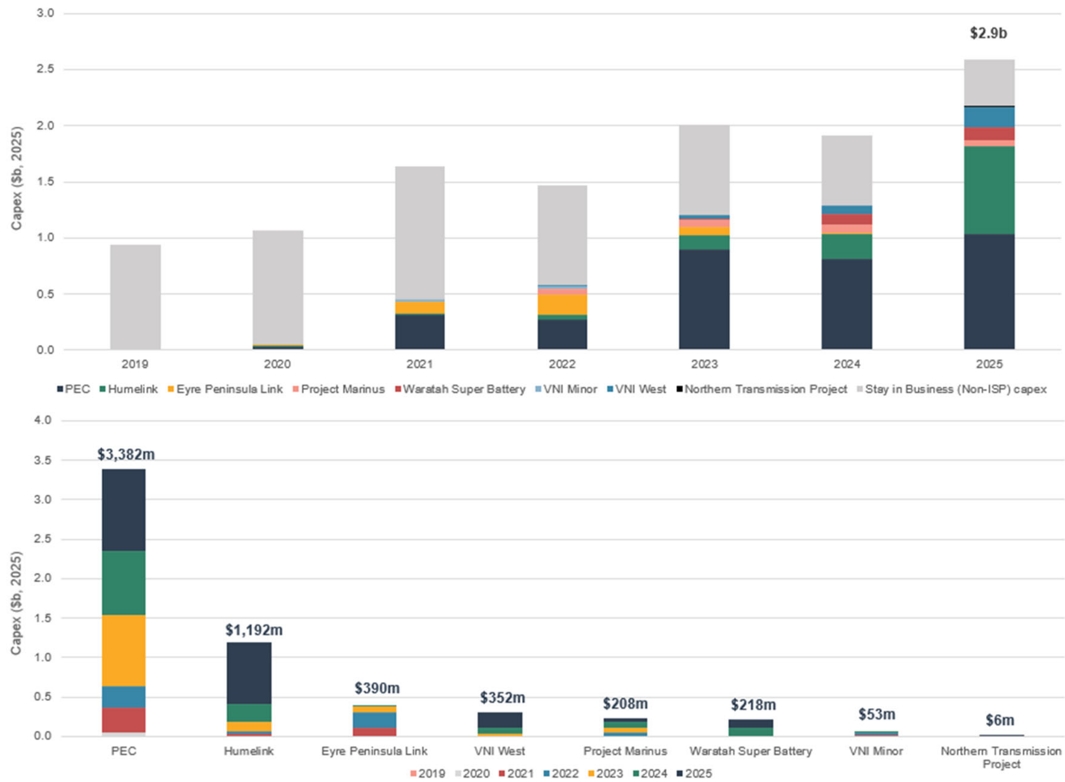
23 NER rule 8.13(f).

24 AER, 2025 Electricity and gas networks performance report, December 2025, p 25.

development of the power system in the NEM that achieves power system needs for a planning horizon of at least 20 years to contribute to achieving the NEO.

In 2025, Transgrid made over 95% of the total TNSP investment into ISP projects, with significant capex spends for PEC and Humelink.

Figure 3-14 Capex and ISP Capex - TNSPs - $ real 2025



Source: Actual capex: Refer to Figure 3-8. ISP capex sourced from AIO 7.5 Large projects and information requests. Note: Refer to Figure 3-8. This figure includes capex for Waratah Super Battery which operates under NSW Infrastructure Investment Act 2020 and not under Chapter 6A of the NER. The capex amounts for Waratah Super Battery are capitalised under a separate RAB from Transgrid's prescribed transmission services RAB.

In 2025, ElectraNet and TasNetworks respectively made initial capex investments into the Northern Transmission Project (NTx) and North West Transmission Developments (NWTD) portion of Project Marinus. This capex relates to approved contingent projects for early works on both ISP projects.[25]

3.2.5.1 RIT-T and RIT-D guidelines consider community engagement and emissions reduction

In August 2020 we published guidelines to make the ISP actionable.[26] This comprised the cost benefit analysis guidelines that describe the analysis that AEMO must apply in the ISP

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[25] AER, AER Determination - ElectraNet Mid North South Australia REZ Expansion Stage 1a Early Works Contingent Project Application, June 2025; AER, AER Determination - TasNetworks' NWTD Stage 1 – Early Works Contingent Project Application, March 2025.

[26] AER, Final decision - Guidelines to make the ISP actionable, August 2020

and TNSPs must apply in their Regulatory investment test for transmission (RIT-T) in an optimal development path, that sets out the needed generation, firming and transmission.[27]

We maintain guidelines on the correct application of the RIT-T and distribution (RIT-D) guidelines, to provide procedural guidance, requirements and clarity to RIT proponents on the correct interpretation of the relevant requirements in the NER.[28]

In November 2024, we published an update to our guidelines, which includes requirements for NSPs to consider the need for community engagement and inclusion of changes to Australia's greenhouse gas emissions as a market benefit class in their RIT analysis.[29]

The update to the guidelines for community engagement ensures there is consultation and engagement if a project is expected to or may have an impact on the community. This requires impacted communities to be informed by the RIT proponents, and their concerns considered in a meaningful and transparent manner.

In addition, the inclusion Australia's greenhouse gas emission changes as a market benefit class in a NSP's RIT analysis, will require NSPs to compare the emission changes between the credible options in the RIT-T and RIT-D and the base case. This ensures that the greenhouse gas emission reduction requirements in the NEO are considered by AEMO and RIT proponents in the ISP and RIT-T/RIT-D respectively.

3.3 Increased capex investment results in RAB growth

The RAB represents the total economic value of network assets that NSPs use to provide regulated network services. RAB values substantially impact the total network costs customers pay, both now and in the future, through the return on capital (a return to the investors that fund its assets and operations) and return of capital (asset depreciation costs) building blocks.

The average economic life of network assets varies across the NSPs, and the RAB is constantly changing as new assets replace aging and depreciated assets. This means some NSPs require significant capital investment for growth or replacement of their network assets, while others require less investment.

Network assets generally have a long-life span, with gradual recovery in the return of capital building as the network assets are depreciated. This reduces the short-term dollar impact on network costs of immediate RAB growth; however, consumers will pay for the investment over the long-term life of the asset.

27 The RIT-T instrument is a binding AER regulatory instrument published (originally in 2010) in accordance with NER clause 5.16.1(a). RIT-T proponents (usually TNSPs) must apply the RIT-T to all proposed transmission investments, except in the circumstances described in NER clause 5.16.3(a).

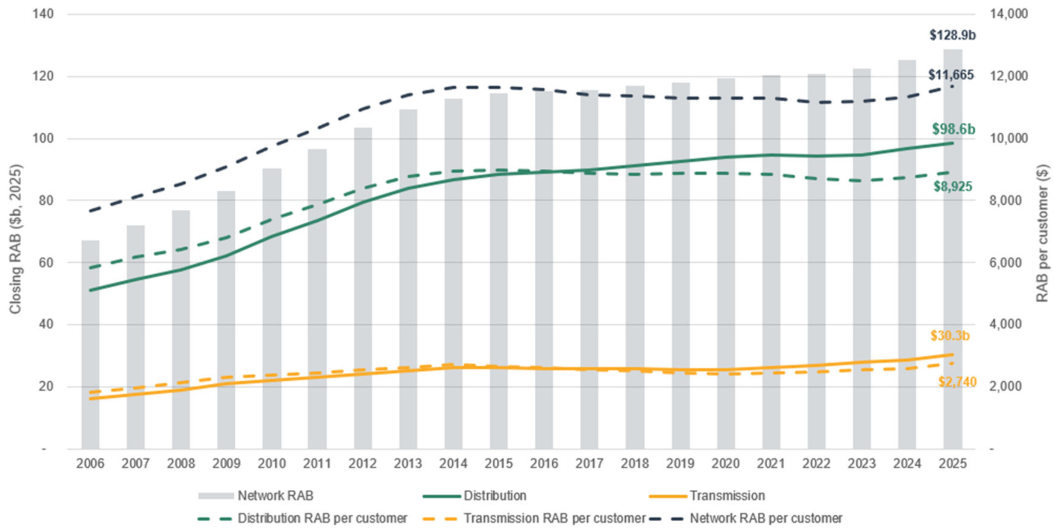
28 AER, Regulatory Investment Test for Transmission application guidelines, November 2024, AER, Regulatory Investment Test for Distribution application guidelines, November 2024.

29 AER, Regulatory Investment Test for Transmission application guidelines, November 2024, p 67 and 40, AER, Regulatory Investment Test for Distribution application guidelines, November 2024, p 63 and 38.

In 2025, there was a 2.8% increase in NSPs RAB in real terms, with a combined value of $128.9b. Disaggregated there was:

- a 1.9% increase in real terms in the RABs of DNSPs for a combined value of $98.6b
- a 5.7% increase in real terms in the RABs of TNSPs for a combined value of $30.3b.

Figure 3-15 RAB - NSPs - $ real 2025



Source: Closing RAB: RFM, 'RAB roll-forward' and AER analysis. Customer numbers data is from EB RIN and AIO table 3.4.2, 'Distribution customer numbers by customer type or class.' Note: AER calculation to convert to $ June 2025 terms. Network RAB is the sum of distribution and transmission revenue. DNSP RAB per customer calculated by dividing DNSP's RAB by DNSP's customer numbers. TNSP RAB per customer calculated by dividing TNSP's RAB by the sum of distribution customers located in the same region as the TNSP. Network RAB per customer calculate by dividing the Network RAB by the total number of network customers.

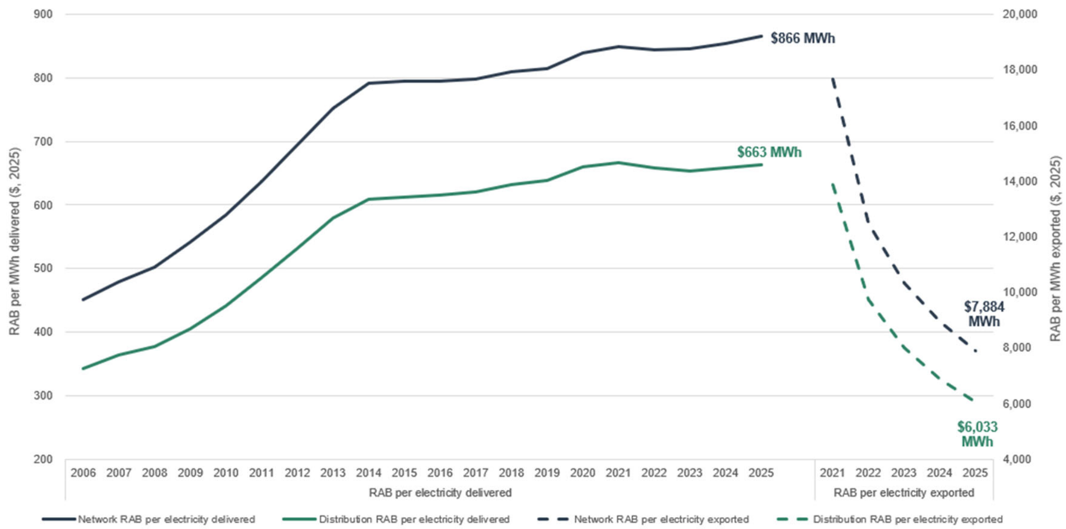
The capex invested by NSPs in section 3.2, has led to a RAB per customer in 2025 of $8,925 for DNSPs (an increase of 2.1% in real terms) and $2,740 for TNSPs (an increase of 5.9% in real terms). Overall, in 2025 there was an increase of $331 in the network RAB per customer in real terms (an increase of 2.9%).

3.3.1 CER self-consumption leads to increase in RAB per electricity consumed

The efficiency of networks using their network assets to deliver electricity to consumers can be measured through the RAB per MWh delivered. Going forward (as discussed below), we expect electricity consumption by consumers to increase, which could lead to lower unit costs for the electricity consumed, and a lower total network costs for consumers.

Although the RAB per electricity delivered has gradually increased since 2014, the average annual growth in the measure since 2014 has been below 1%. This highlights that there has been a correlation between the growth in NSPs' total RAB and the total electricity delivered over the period to the 2025 regulatory year.

Figure 3-16 RAB per electricity delivered/exported – NSPs - $ real 2025

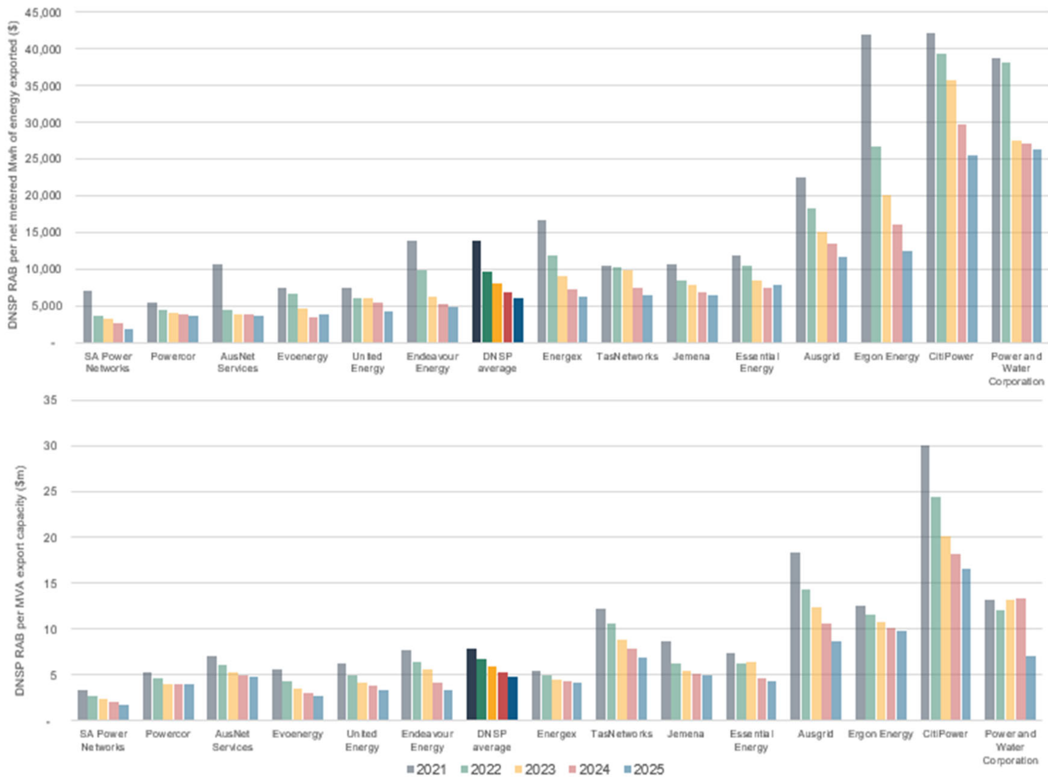


Source: Network and Distribution RAB: Refer to Figure 3-15. Electricity delivered data is from EB RIN and AIO table 3.4.1, 'Energy delivered by type or class'. Electricity exported from AER analysis using net metered volume of energy exported from DNSP information request and AIO table 3.9.1. Note: RAB per electricity delivered and exported calculated by dividing the total Network RAB and Distribution RAB by the total electricity delivered and electricity exported.

One of the factors for the modest increase in electricity delivered in recent years, is export service customers self-consuming the electricity generated from their solar PV systems and batteries, which is 'behind the meter' and not included in the electricity delivered by DNSPs.

Since 2021 there has been a decrease in the DNSP and network RAB per electricity exported, decreasing by over 56% and 55% respectively over the five-year period. This has been driven by the growth in the export capacity and amount of electricity exported by export service customers, which has differed across the DNSPs.

Figure 3-17 RAB per electricity exported and export capacity – DNSPs - $ real 2025



Source: RAB: Refer to Figure 3-15. Electricity export data calculated from AER analysis using net metered volume of energy exported from DNSP information request and AIO table 3.9.1. Export capacity calculated from AER analysis using export capacity and AIO table 3.9.4. Note: RAB per electricity exported calculated by dividing the total DNSP RAB by the total electricity exported. RAB per export capacity by dividing the total DNSP RAB by the total export capacity.

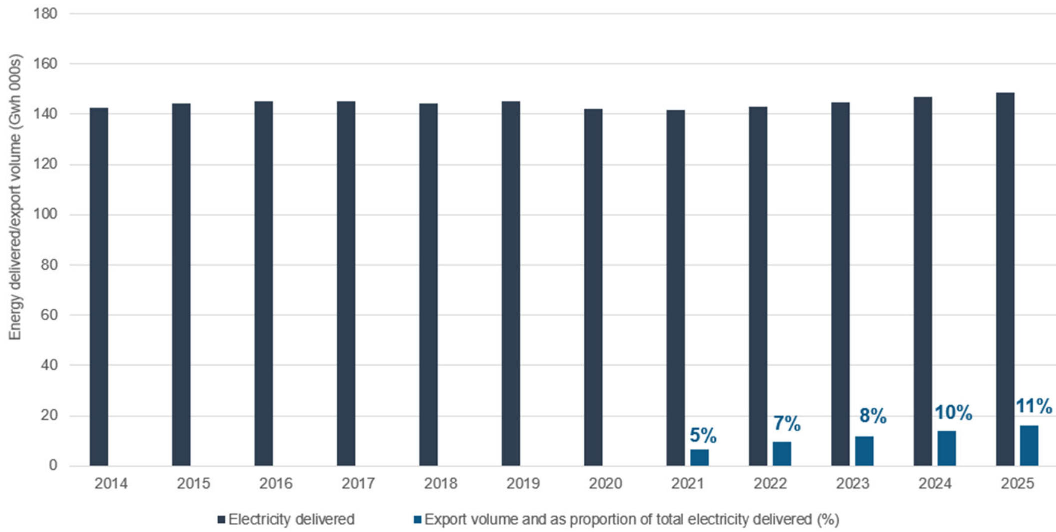
In the past five years, the RAB cost for exported electricity and installed export capacity has decreased for all DNSPs, with most DNSPs having a lower annual RAB cost for each measure across the five-year period. This indicates that the electricity exported and installed capacity is growing across all DNSPs at a faster rate than growth in the economic value of their network assets, as export service customers are using existing network assets to export into the grid.

When comparing across the DNSPs, SA Power Networks has the lowest RAB cost across both measures, due to the higher number of export service consumers in South Australia and penetration of CER assets relative to the cost of their network asset. In contrast, the lower number of export service consumers in CitiPower's higher density distribution network has led to the largest RAB cost across the DNSPs per electricity exported and export capacity.

3.4 Increase in electricity delivered and exported

The electricity delivered and electricity exported differs across DNSPs, based on the composition and size of their customer base and number of export service customers. Overall, DNSPs delivered 149 thousand GWh of electricity in 2025 and export service customers exported 16.3 thousand GWh of electricity,[30] an increase of 1.4% and 17% respectively from the prior year. Overall, 11% of the total electricity delivered came from electricity exported by export service customers.

Figure 3-18 Electricity delivered and electricity exported - DNSPs



Source: Electricity delivered refer to Figure 3-16. Electricity export data refer to Figure 3-17. Note: Export volume as percentage of electricity delivered calculated by dividing the electricity exported by the total electricity delivered.

As noted above, one of the factors for the modest increase in electricity delivered, is export service customers self-consuming the electricity generated from their solar PV systems and batteries, which is 'behind the meter' and not included in the electricity delivered by DNSPs.

Going forward, we expect electricity delivered and self-consumption from CER assets to increase from a growing customer base and the electrification of household gas appliances and consumers using household electric vehicle (EV) charging infrastructure to charge their EVs. Over the medium to long term, as the number of export service customer increases and more export service customers install residential batteries, there is uncertainty regarding the extent to which increased consumption will be supplied by DNSPs versus self-consumed by export service customers.

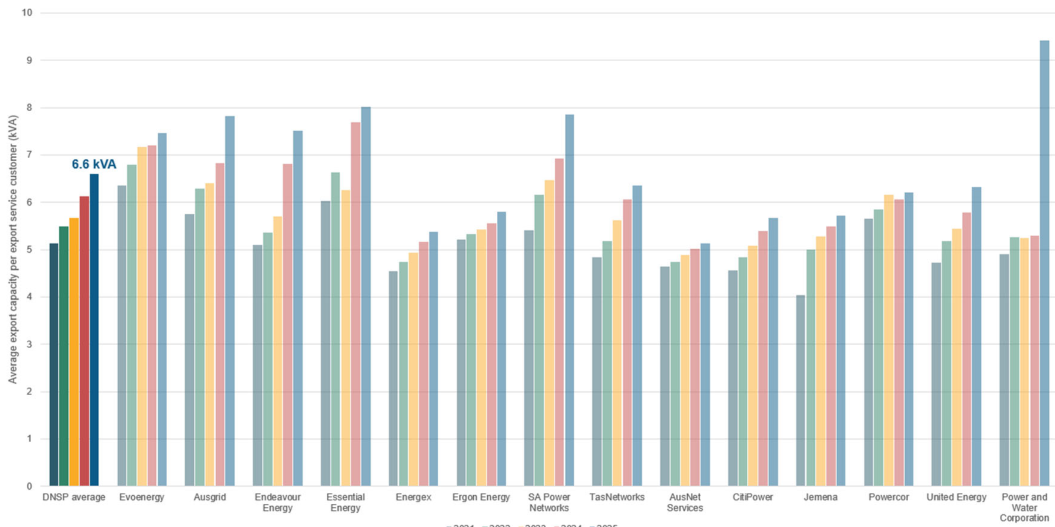
3.4.1 Export capacity increases in 2025

The export capacity for export service customers can differ across DNSPs. This can be due to a number of factors, including higher or lower export limits by DNSPs, reduction in the costs of CER installations encouraging export service customers to install larger capacity and changes in the cost of electricity import or export tariffs by retailers which may incentivise larger or smaller CER installations.

The average export capacity for export service customers increased across all DNSPs in 2025, with the overall DNSP average increasing to 6.6 kVA, from 6.1 kVA in the prior year.

[30] This is a 149 million MWh of electricity delivered, and 16.3 million MWh of electricity exported.

Figure 3-19 Export capacity per export service customer - DNSPs



Source: Export capacity: Refer to Figure 3-17. Export service customers calculated from AER analysis using net metered volume of energy exported from DNSP information request and AIO table 3.9.5. Note: Export capacity per export service customer calculated by dividing total export capacity by number of export service customers.

Following a significant increase in the export capacity of their non-residential LV consumers, Power and Water Corporation had the highest average export capacity per export service customers at 9.6 kVA. Conversely, AusNet Services has the lowest export capacity, despite a small increase in its export capacity to 5.1 kVA per export service customer.

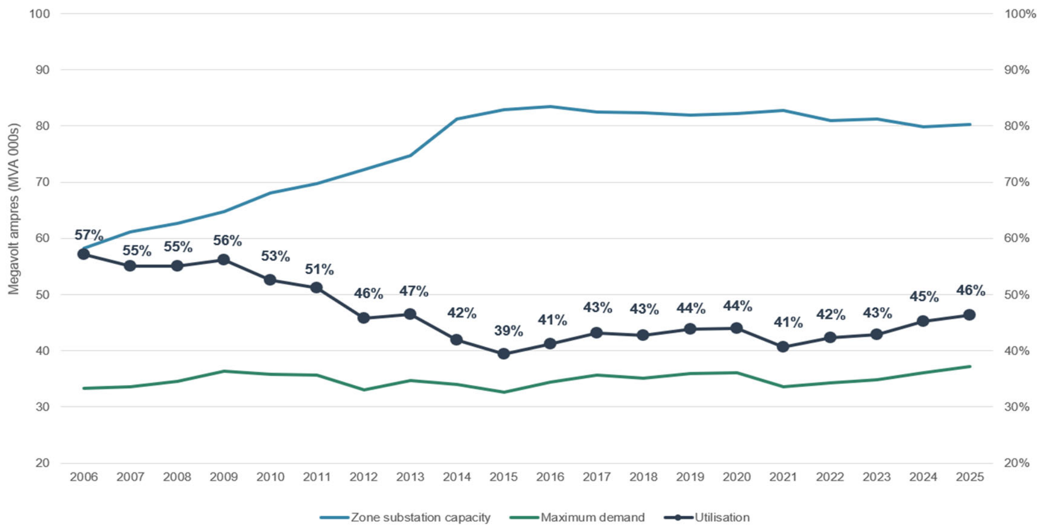
3.4.2 Higher maximum demand increases network utilisation

Network utilisation is important, as it can measure the productivity and efficiency of network assets to determine whether customers are paying the lowest unit cost of electricity possible for network services. Our current network utilisation performance data measures the extent to which an NSPs network assets can meet the maximum demand in their network. We calculate utilisation by dividing a DNSP's non-coincident maximum demand by the total capacity of its zone substation (ZSS) transformers.[31]

The ZSS transformer capacity, maximum demand and utilisation have all been relatively flat since 2014, although since 2021 there has been a slight decrease in capacity and a slight increase in aggregate maximum demand which has led to a 46% network utilisation in 2025. This increase in maximum demand resulted in 7 of the 14 DNSPs in 2025 having the highest maximum demand in their dataset (since 2006), possibly driven by a growing customer base and/or the electrification of household gas appliances and consumers using household EV charging infrastructure to charge their EVs.

31 The individual maximum demand on an DNSP's network for the regulatory year

Figure 3-20 Network utilisation - DNSPs



Source: Non-coincident summated raw system annual maximum demand' from EB RIN and AIO table 3.4.3.3 - 'Annual system maximum demand characteristics as the ZSS level' MVA measure. 'ZSS transformer capacity' from EB RIN and AIO table 3.5.2.2. Note: Utilisation calculated by dividing the DNSP and sum of jurisdiction's non-coincident summated raw system annual maximum demand by the DNSP's and sum of jurisdiction's ZSS transformer capacity.

Network utilisation differs across DNSPs and jurisdictions. Powercor has consistently had the highest network utilisation measures whilst Essential Energy has the lowest. Lower utilisation for DNSPs in NSW and Queensland can be attributable to changes in jurisdictional reliability standards and forecast demand growth, which led to systematic capital investment in ZSS transformer capacity from 2009 to 2014.

The network utilisation in Victoria increased by 3 p.p. to 63%, driven by higher maximum demands across all Victorian DNSPs. In January 2026, following extreme hot temperatures Victoria had its highest maximum demand on record of 10,736 MW. This may lead to a higher network utilisation, in the 2026 regulatory year for Victorian DNSPs and DNSPs on an aggregate basis.

3.5 More customers using export services in 2025

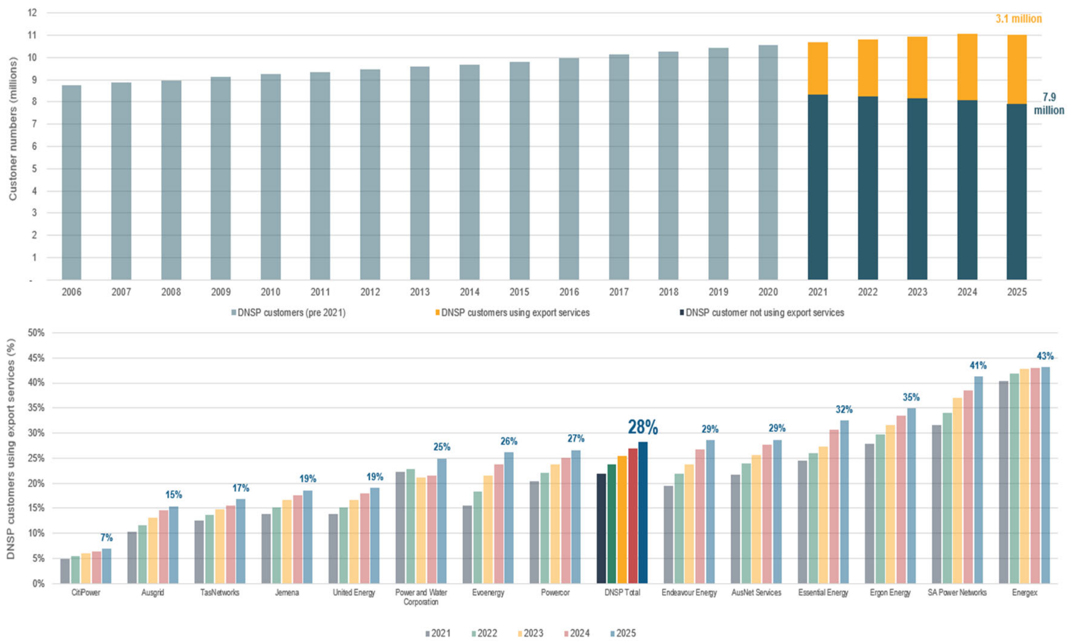
In 2025, each DNSP had an increase in the number of customers using export services, leading to an aggregate increase of 1.4 p.p. to 28% of all DNSP customers.[32] This resulted in an increase of 152,000 export service customers, for a total of 3.1 million using export services.

On a DNSP basis, Energex and SA Power Networks had the highest proportion of export service customers, whilst the higher customer density of CitiPower and Ausgrid led to a lower proportion of their customers using export services.

32 The methodology to determine DNSP customer numbers was modified for a number of DNSPs to ensure consistent reporting in the AIO. This may impact the comparison of customers numbers in the 2025 regulatory year to previous regulatory years.

Higher density areas are less likely to have export service customers, due to a higher proportion of the housing being apartments and units, where there is difficulty for customers to install CER assets. In addition, customers in higher density areas are more likely to be renters, which creates barriers in relation to the installation, ownership and economical cost of CER assets.

Figure 3-21 DNSP customers and export service customers - DNSPs



Source: Export service customers: Refer to Figure 3-19. DNSP customers: Refer to Figure 3-15. Note: Proportion of export service customers calculated by dividing export service customers by total DNSP customers. Although DNSP customers using export services network performance data is only available from 2021, customers began exporting under jurisdictional feed in tariffs prior to this period, and therefore we expect pre-2021 regulatory years to have export service customers.

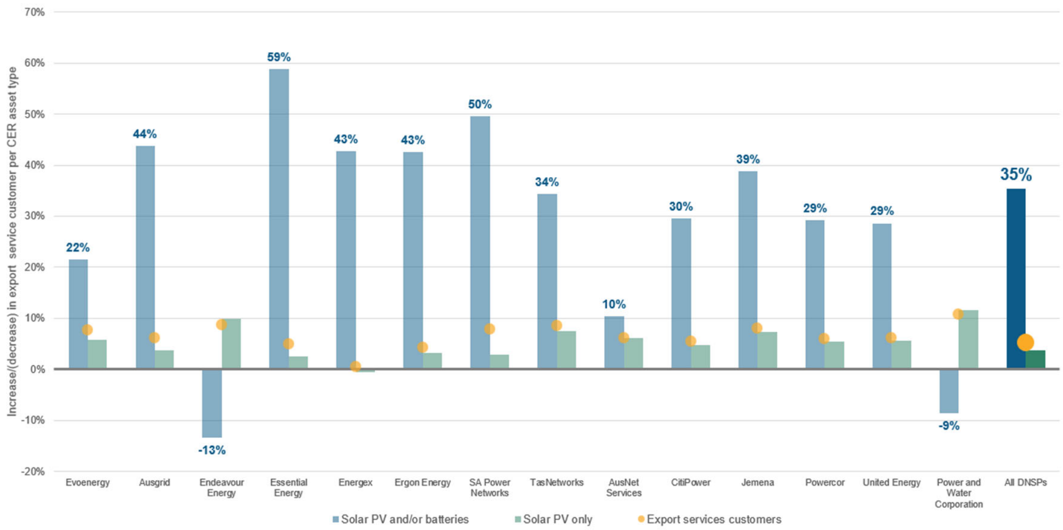
On a DNSP basis, Power and Water Corporation had the largest increase in customers using export services in 2025 (3.5 p.p.), which was followed by SA Power Networks (2.8 p.p.). Energex, despite having the largest proportion of customers using export services, only had a 0.2 p.p. increase in export service customers, the lowest across all DNSPs.

3.5.1 Exponential increase expected in export service customers with a battery

Consumer owned batteries are the second most popular exporting CER asset type used by export service customers. In 2025, 180 thousand or 5.8% of export service customers used batteries, an increase of 1.3 p.p. from the prior year.

Despite these low numbers, batteries (with and without solar PV) are proportionately the fastest growing CER asset type, with a 35% increase from the prior year. Similar increases were also noted across several DNSPs, with Essential Energy noting a 59% increase in the number of export service customers with a battery.

Figure 3-22 Movement in export service customers per CER asset type - DNSPs



Source: Export service customers calculated from AER analysis using by equipment type from DNSP information request and AIO table 3.9.5. Note: Movement calculated by comparing the export service customers by equipment type in 2025 to the export service customers by equipment type in prior year.

Next year, due to the Cheaper Home Batteries program, we expect an exponential increase in the number of customers using a battery for their export services. This program involves a potential discount on the upfront cost of installing a range of small-scale battery systems (5 kWh to 100 kWh),[33] to incentivise export service customers with only a solar PV or new potential export service customers to install a battery.

3.6 Reliability for DNSPs decreases slightly in 2025

Supply reliability is a key network service outcome. We measure reliability based on the frequency and duration of interruptions to customer supply. Our reporting is based on weather normalised measures of network interruptions, which do not include supply interruptions that are not reasonably within the control of NSPs such as those caused by natural disasters, or interruptions which occur due to planned maintenance. This includes reporting on:

- system average interruption frequency index (SAIFI), which measures the average number of interruptions each year outside of excluded events
- system average interruption duration index (SAIDI), which measures the average duration (in minutes) of interruptions each year outside of excluded events.

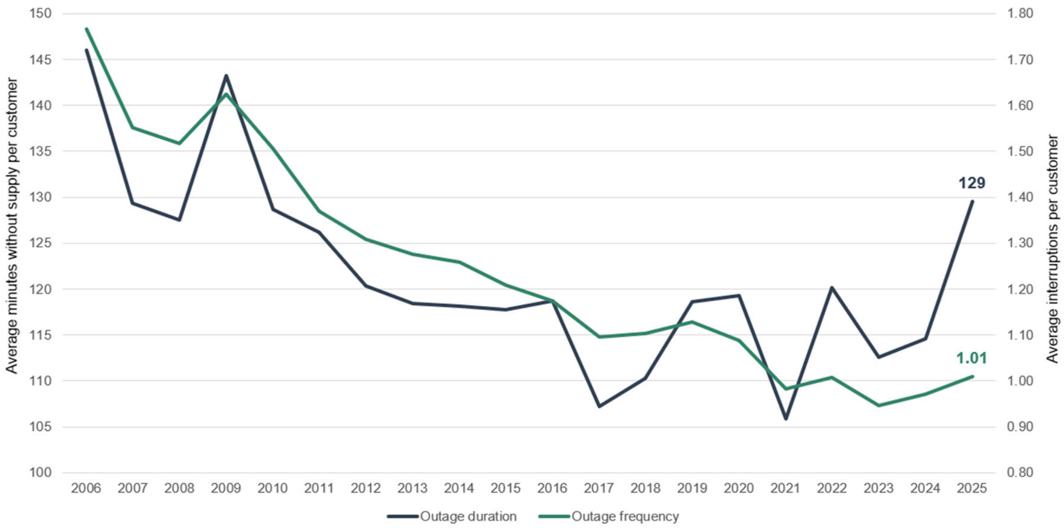
Networks are incentivised to decrease SAIFI and SAIDI through the STPIS (see above). The STPIS incentivises networks to improve reliability where the value of the extra reliability to customers exceeds the capex or opex costs of providing the improved reliability.

When normalised, the average customer experienced 1.01 outages, for an average total time without supply of electricity of 129 minutes. When compared to prior years, there was an

33 Australian Government – Department of Climate Change, Energy, the Environment and Water, Cheaper Home Batteries Program, February 2026, accessed 10 March 2026.

increase in both metrics on a normalised basis, however both measures remain below the peaks seen at the beginning of our dataset. This increase was based on the reliability performance of DNSPs throughout the regulatory year and is not attributable to a singular event.

Figure 3-23 Frequency and duration of outages - DNSPs



Source: CA RINs and AIO, AER analysis. Note: Data reflects interruptions to supply that lasted longer than 3 minutes consistent with the definition of a sustained interruption in STPIS version 2.0 (November 2018). This differs from the 1- minute threshold in STPIS version 1.0 (May 2009). Years reflect regulatory years.

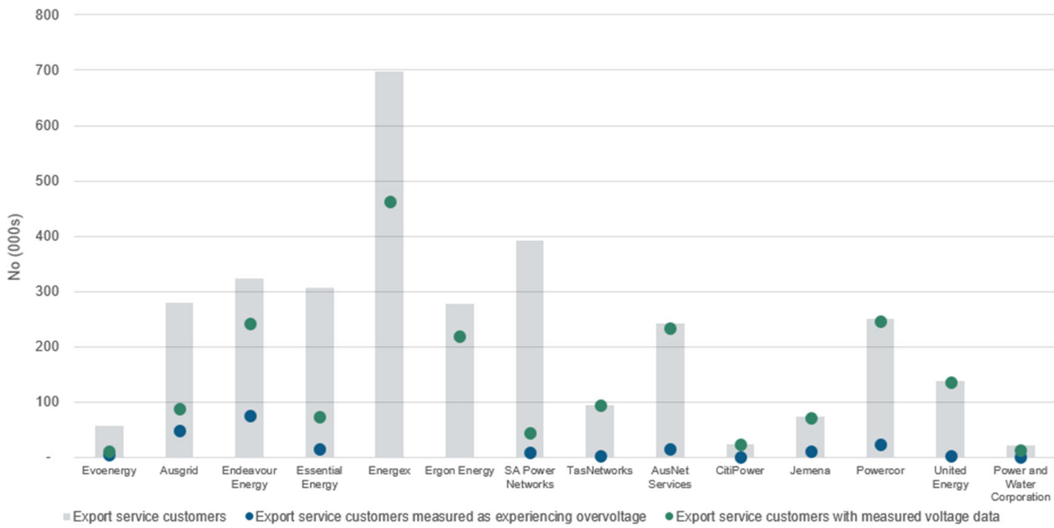
In 2025, the increase in outage duration was primarily driven by Ergon Energy and AusNet Services, which cover rural areas. Outages are highest for rural networks or networks which cover rural areas, while they are lowest for urban and CBD networks. Due to the differences in customer density of each network, the real customer impact from outages may not be apparent in the aggregate results.

Due to the higher density of urban and CBD networks, infrequent interruptions with a shorter duration experienced by urban and CBD customers will result in many customers experiencing an interruption and a higher cumulative duration of time without supply for our aggregate results. This contrasts to rural networks, where the low customer density can result in more frequent and longer duration interruptions for rural customers, despite having minimal impact on aggregate results.

3.6.1 Overvoltage for export service customers differs across the DNSPs

For export service customers, overvoltage can limit their ability to export electricity, as inverters reduce power output in response to high voltage levels. Network overvoltage is considered to occur when an export service customer's network voltage reaches a point where their generating unit should reduce its real power output in response to increased voltage.[34] This is typically considered to occur when network voltage exceeds 253 V.[35]

Figure 3-24 Export service customer numbers and customers experiencing overvoltage– DNSPs - 2025



Source: Export service customers measured as experiencing overvoltage calculated from AER analysis from DNSP information request and AIO table 3.9.5.8. Export service customers refer to Figure 3-19.

Currently overvoltage export service data differs across DNSPs, with different percentages of export service customers with measured voltage data and measured as experiencing overvoltage. In future years, we expect more evident trends and DNSP comparative analysis in overvoltage performance as DNSPs continue to report the data in the AIO under consistent methodologies.

In addition to overvoltage, DNSPs can also be impacted by undervoltage, where the electricity voltage supplied drops below the level required for certain appliances to operate effectively. This impacts voltage compliance and can possibly lead to appliance issues for customers, which was addressed recently in our Victorian final decisions.[36]

As customers increase demand by electrifying their household appliances, there may be a requirement for DNSPs to maintain voltage compliance above the functional limit, especially in distribution networks with a high number of customers who use gas appliances for heating and cooking. We do not report on the undervoltage performance of DNSPs, however data for Victorian DNSPs is reported by the ESC.

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34 Some generating units may curtail at undervoltage conditions when reactive power response is enabled in inverters; however, we do not request networks to report at this voltage level.

35 The maximum steady-state voltage allowed by AS 61000.3.100-2011 and the voltage at which volt-watt curtailment occurs for inverters compliant with AS 4777.2(2020).

36 AER, Final decision - CitiPower Distribution determination 2026–31 - Attachment 2 – Capital expenditure, April 2026, pp 18-20.

3.6.2 Inverter compliance improves for DNSPs

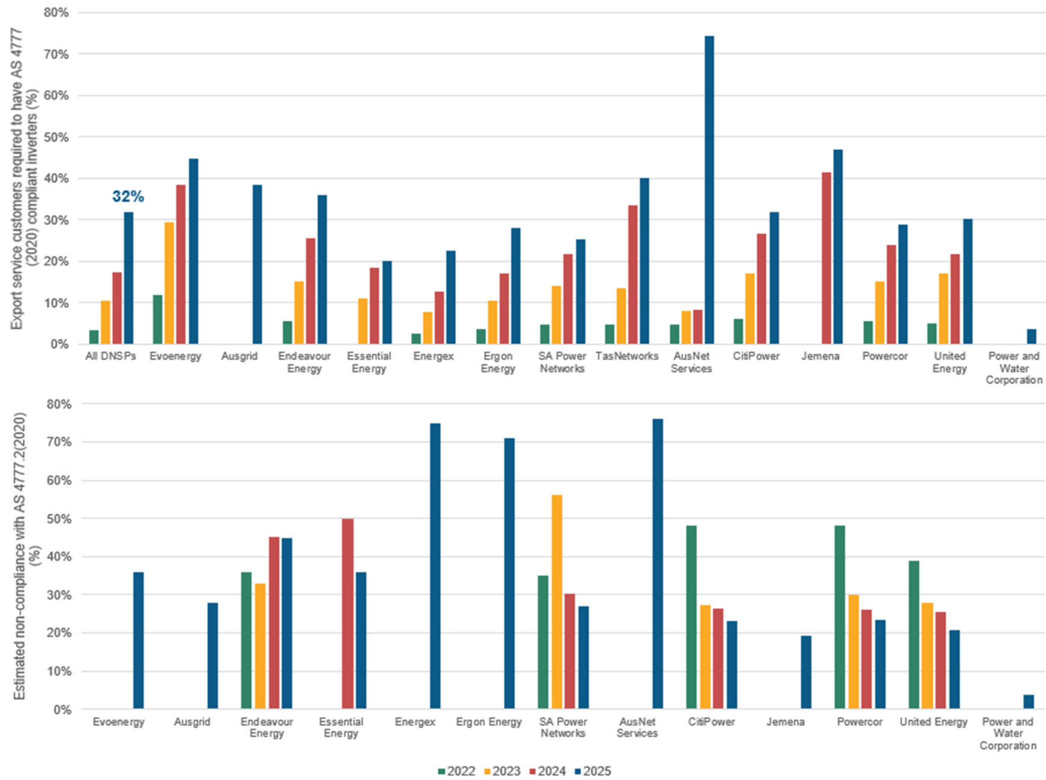
Since 2021, the NER require new inverters to comply with the standard AS 4777.2(2020), which requires inverters to be capable of a defined reduction of exports in response to overvoltage. The standard also requires inverters to be configured appropriately by installers so that overvoltage response occurs in practice. This improves system stability by minimising the sudden loss of CER during short duration low voltage events.

In 2025, there has been a significant increase in the proportion of export service customers required to have AS 4777.2(2020) compliant inverters. This reflects the new installations and replacement or upgrades of older CER assets, which are required to be compliant with AS 4777.2(2020). Inverters which were installed before the implementation of the standard in December 2021 are not required to be compliant.

In relation to non-compliance, in the 2025 regulatory year, 7 DNSPs reported their first estimates of export service customers which are non-compliant with AS4777.2 (2020). Of these DNSPs, AusNet Services, Energex and Ergon Energy estimated above 70% of its required export service customers to be non-compliant, which was significantly higher than other DNSPs.

The methodology to estimate compliance differs amongst the DNSPs. SA Power Networks assesses compliance by plotting reactive power behaviour against smart meter measured voltage. Compliant sites will demonstrate inductive reactive power behaviour relative to the export real power and voltage level in accordance with volt-var curves. This approach indicates improved gradual compliance since 2023.

Figure 3-25 Export service customers required to be compliant and estimated to be non-compliant with AS 4777.2(2020) – DNSPs

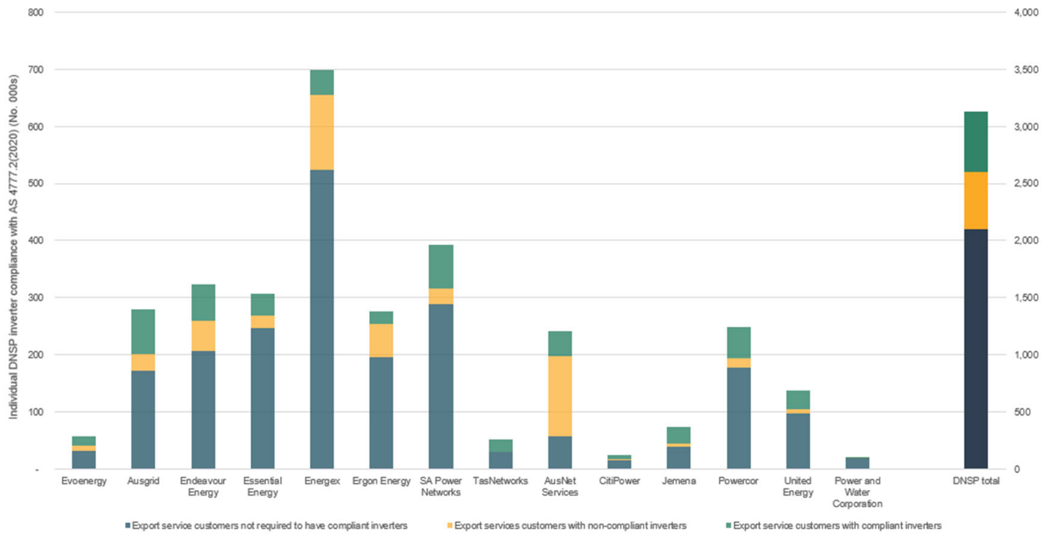


Source: Export service customers required to be compliant with AS 4777.2(2020) calculated from AER analysis from DNSP information request and AIO table 3.9.6. Export customers estimated to be non-compliant with AS 4777.2(2020) calculated from AER analysis from DNSP information request and AIO table 3.9.6. Export service customers refer to Figure 3-19. Note: Export services customers required to be compliant with AS 4777.2(2020) calculated by dividing the total export service customers required to have AS 4777.2(2020) compliant inverters by the total number of export service customers.

3.6.2.1 Most export service customers not required to comply with inverter standard

As noted above, inverters installed before the implementation of AS 4777.2(2020) in December 2021 are not required to be compliant with the standard. Currently most export service customers are not required to be compliant with AS 4777.2(2020), totalling 2.1 million or 67% of all export service customers. On an individual DNSP basis, Energex and SA Power Networks had the largest number of export service customers which are not required to be compliant, reflecting the higher number of export service customers exporting into their distribution networks in 2021.

Figure 3-26 Export service customers inverter compliance with AS 4777.2(2020)



Source: Export service customers not required to be compliant with AS 4777.2(2020) calculated from AER analysis from DNSP information request and AIO table 3.9.6. Export service customers required to be compliant with AS 4777.2(2020) and Export service customers estimated to be non-compliant with AS 4777.2(2020) refer to Figure 3-25. Note: Calculation of number of export service customers which are compliant and non-compliant adjusted for consistency with DNSPs total export service customers.

3.7 Export limits differ across DNSPs

To facilitate export services for customers to export electricity back into the grid, DNSPs need to impose export limitations or curtailment to ensure that any electricity exported is within the DNSP's hosting capacity. The AER's expectations relating to export limits and to support the efficient implementation of flexible export limits is detailed in our Export limit guidance note.

Hosting capacity refers to the ability of a power system to accept energy generated by CER without adversely impacting power quality, such that the network continues to operate within defined operational limits (without experiencing voltage or thermal violations). The hosting capacity differs across DNSPs and locations within a DNSP's distribution network and has changed over time with changes in consumption patterns and CER penetration.

Although necessary to ensure that network power quality is not negatively impacted, static curtailment can unnecessarily restrict customer exports. Due to this, new approaches and technologies are being used, such as flexible export limits and inverters capable of voltage responses to help maintain power quality whilst not unnecessarily restricting exports.

For this report, curtailment of export service customers is defined as the reduction in a customer's exports due to a network constraint.[37] Curtailment can be quantified as the difference between the amount an export service customer is allowed to export and the theoretical potential output of the installed CER assets if no network constraint was present.

[37] AEMO may also direct DNSPs under the emergency backstop mechanism to curtail CER output to support system reliability, such as in an extreme minimum demand scenario.

Currently we do not have a curtailment per export service customer metric, as not all DNSPs currently estimate curtailment, and further work would be required to ensure the metric was consistently reported across the DNSPs. Due to this, we report on a number of indirect measures of curtailment in our export services network performance data, which are detailed below.

3.7.1 Static export limits remain consistent with prior years

The electricity exported by export service customers into the distribution network has generally been managed through static export limits. DNSPs typically set static limits at a level that is considered safe when the network is congested and not able to accommodate additional exports. We report on the DNSP's static export limits through the static-zero export limits and static non-zero export limits. Currently, the vast majority of export service customers are on static non-zero export limits.

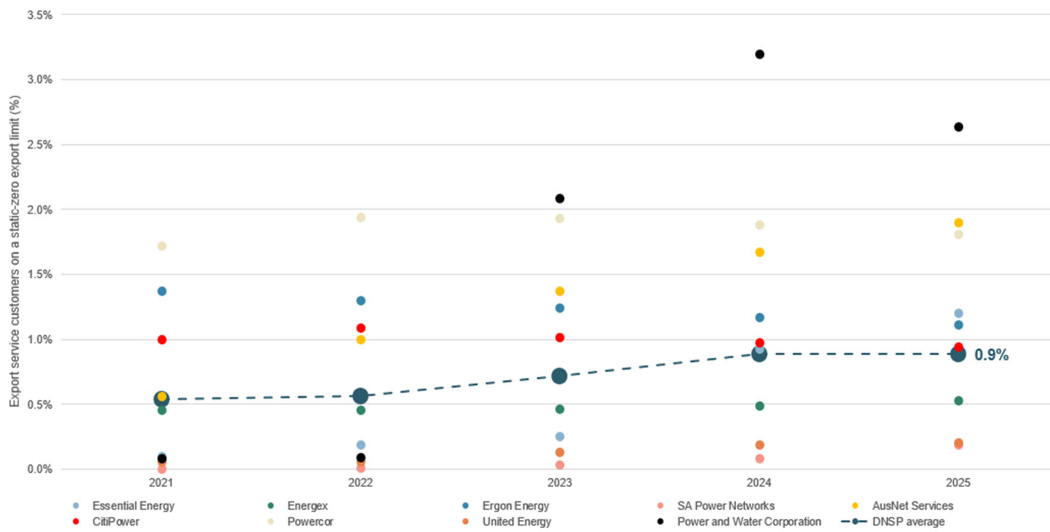
Static-zero export limits are where an export service customer is constrained from exporting any electricity. Under our Connection charge guidelines for electricity customers, DNSPs can only impose static-zero export limits on customers in the following limited circumstances:

- the export from the generator will have a high probability of resulting in the DNSP not meeting a regulatory obligation to maintain the network within its technical limits (for example, voltage or power quality standards)
- the cost of augmenting the DNSP's assets to allow a reasonable export capacity outweighs the benefits arising from providing the additional export capacity.

A DNSP may also impose a static-zero export limit if it is expressly requested by a customer.

In 2025, the proportion of export service customers on a static-zero export limit remains low, with less than 1% of export service customers on a static-zero export. The proportion of export service customers on static-zero export limits differed across the DNSPs, with Power and Water Corporation having the highest proportion in 2025, despite having the largest percentage point reduction in export service customers on static-zero export limits.

Figure 3-27 Export service customers on a static-zero export limit – DNSPs

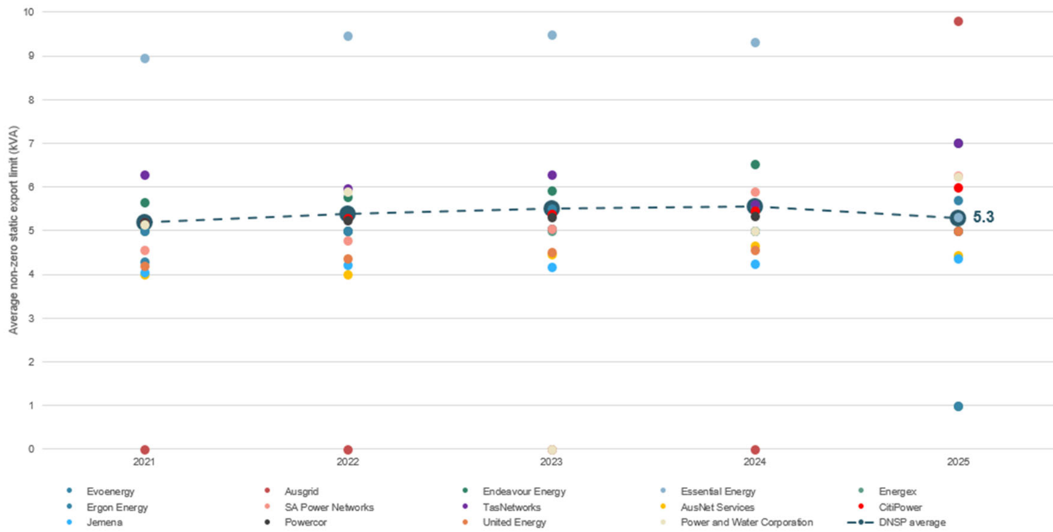


Source: Static-zero export limit calculated from AER analysis using table 3.9.5.3. Note: Ausgrid and Endeavour Energy have not reported any static-zero export limit export service customers, whilst TasNetworks and Jemena reported under 0.01% of its export service customers on static-zero export limits. Export capacity on a static-zero export limit calculated by dividing export service customers on a static-zero export limit by the number of export service customers.

As noted above, the vast majority of export service customers are on export limits above zero (i.e. can at least export some electricity), which enable an export service customer to export electricity, up to a DNSP specific export limitations. Static non-zero export limits do not guarantee a fixed or maximum level of export; rather they provide a general indication of export capability. As more CER assets are connected and more electricity is exported, export service customers may face lower static export limits due to DNSPs seeking to avoid the risk of breaching operational limits.

The non-zero (static) export limits for residential customers decreased slightly in 2025 to 5.3 kVA, with the slight decrease attributable to lower non-zero export limits for Energex and Ergon Energy. Similar to previous years, the majority of DNSPs have static export limits between 4 kVA and 7 kVA, with Ausgrid reporting the highest non-zero static export limit of 10 kVA.

Figure 3-28 Average non-zero static export limit - residential customers - DNSPs



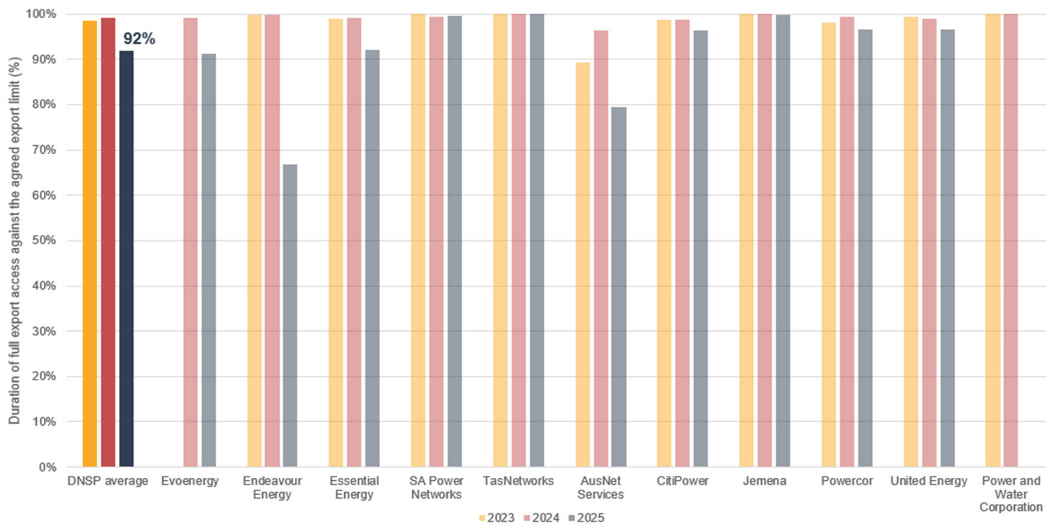
Source: Average non-zero static export limit calculated from AER analysis using average non-zero static export limit at year-end and AIO table 3.9.2.3. Notes: Ausgrid did not provide an average non-zero static export limit as they report that they typically only apply a static export limit if requested by a customer. During this period, Ausgrid allows systems up to 10 kW per phase to connect automatically without any technical assessment if they comply with AS4777. Power and Water Corporation did not report an average non-zero export limit for the 2023 regulatory year. In 2021 to 2024 regulatory years, Essential Energy reported export service customers with installed systems larger than allowed by their connection agreement to be on static non-zero export limits. This may lead to an overestimate of export limits for Essential Energy for these years when compared to other DNSPs.

DNSPs also report the non-zero static export limits on non-residential customers, however the bespoke nature of these agreements for these customers prevents comparability across the DNSPs.

Another indirect measurement of curtailment are estimates from DNSPs on how long their customers can export up to the export limit. This provides information on how often network constraints are preventing export service customers from being able to export electricity to the export limit.

In 2025, the DNSP average full access to the agreed export limit decreased to 92%, which was primarily due to decreases for Endeavour Energy and AusNet Services' export customers. Ausgrid, Energex and Ergon Energy do not currently report this metric, with Evoenergy and Power and Water Corporation not reporting the metric each regulatory year.

Figure 3-29 Duration of full export access against the agreed export limit - residential customers - DNSPs



Source: Duration of full export access against the agreed export limit calculated from AER analysis and AIO table 3.9.7.1. Note: Duration of full export access against the agreed export limit calculated by dividing the duration of full export access by the total duration of the regulatory year.

3.7.2 More DNSPs provide flexible export limits to export service customers

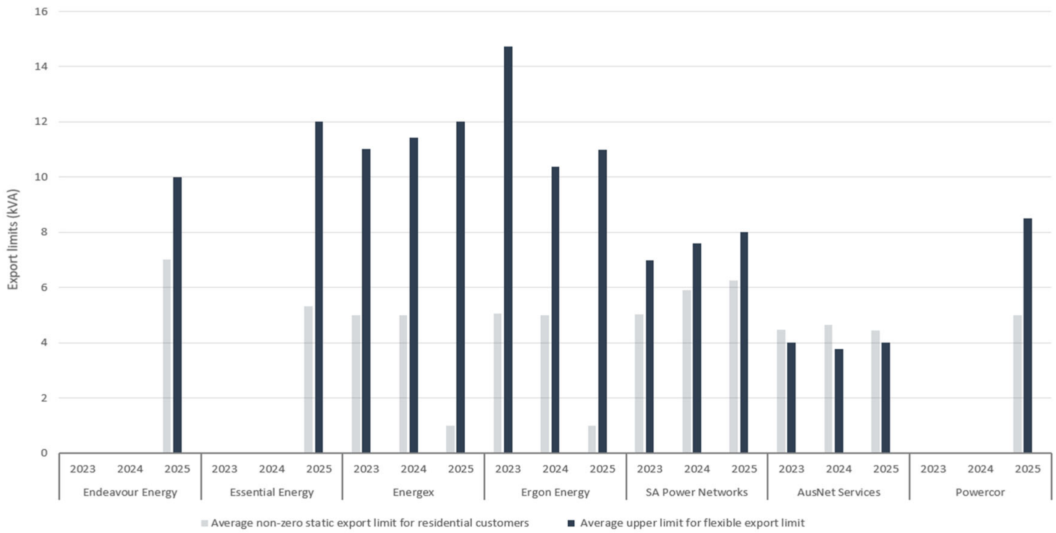
An alternative to static export limits, are flexible export limits which provides export service customers the opportunity to export greater volumes of electricity into the network than a static export limit when congestion is low or there is greater demand for exports. This involves the DNSP providing export service customers with a lower limit (minimum) and an upper limit (maximum) for the amount they may export. The DNSP then actively monitors and varies the export service customer's exports within the upper and lower limits in response to network demand and congestion.

Flexible export limits benefit all DNSPs' customers because they allow DNSPs to defer the need for costly network investment by better utilising existing network hosting capacity. Efficiently hosting and coordinating consumer CER devices can result in a greater use of exported electricity by other customers, as well as providing export service customers with greater utilisation of their CER assets.

In 2025, three more DNSPs (Endeavour Energy, Essential Energy and Powercor) had export service customers on flexible export limits, resulting in half of all DNSPs providing flexible export limits. These flexible export limits enabled the majority of DNSPs to provide an average upper limit which was higher than the average non-zero static export limit.

There was also a significant increase in the number of customers on a flexible export limit in 2025, which was driven by SA Power Networks. At the conclusion of the 2025 regulatory year there was over 20 thousand export service customers on a flexible export limit, with over 90% exporting into SA Power Network's distribution network.

Figure 3-30 Average upper limit for flexible export limits – DNSPs



Source: Average upper limit for flexible export limits calculated from AER analysis and AIO table 3.9.7.3. Non-zero static export limits for residential customers refer to Figure 3-28. Customers with flexible export limit calculated from AER analysis and table 3.9.5.6 of AIO.

Going forward, we expect an increase in the total export service customers on flexible export limits and more DNSPs to have export service customers on flexible export limits. This may be evident in our 2026 export service network performance dataset, with Jemena looking at flexible export limits,[38] and United Energy expected to complete a trial with the Australian Renewable Energy Agency (ARENA) to providing residential, commercial and industrial customers the ability to export above current static limits using flexible export limits.[39]

3.8 Rule changes to expedite the smart meter rollout

Since 2017, coordinating and installing type 4 or type 4A meters[40] (smart meters) outside of Victoria was not the responsibility of the electricity DNSPs. Therefore, smart meter penetration should not be inferred as network performance, however the rollout of smart meters will improve network visibility, as it will provide more information to both electricity DNSPs and customers.

Our prior network performance report noted that the AEMC completed a review into the regulatory framework for metering services,[41] with the final rules to enable the universal uptake of smart meters in the NEM by 2030.[42] As part of the rules, each electricity DNSP in the relevant jurisdictions was required to develop a 5-year Legacy Meter Replacement Plan (LMRP). This schedules the replacement of legacy meters (type 5 and 6, excluding type 5

38 Jemena, Future energy – Future networks, accessed 12 March 2026.

39 United Energy, Flexible services to roll out in Victoria, accessed 12 March 2026. Flexible export limits are also known as Dynamic Operating Envelopes (DOEs).

40 Type 4A meters are smart meters with remote access functions and capabilities disabled.

41 The Northern Territory is not part of the National Energy Customer Framework (NECF) and therefore the AEMC's review into the regulatory framework for metering services is not applicable to the Northern Territory.

42 AEMC, Final determination - Accelerating smart meter deployment, November 2024, p ii.

meters that are capable of remote acquisition) by 30 November 2030, with yearly interim targets.[43] The impact of this rule change will not be evident in this year's smart meter network performance data as the smart meter rollout under the LRMPs only commenced on 1 December 2025.

The installation of smart meters is an important part of the energy transition. The AEMC noted that a higher uptake of smart meters should enable a range of potential options that better integrate CER into the energy system and allow consumers to choose from different access and pricing services that best meet their needs and preferences. However, as stated by the AEMC, these benefits will rely on a minimum uptake of smart meters.[44]

We also report on the installation of smart meters (type 4 and type 4A) by electricity retailers in our retail performance reporting. Differences between the network performance smart meter data and the retail performance smart meter data can arise due to retail data reporting on the customers they serve, whilst DNSPs report on all connected electricity customers within their geographical distribution network.

3.8.1 Progress on smart meter installations

We report 'smart meters' as the sum of the Type 4 and Type 5 meters reported by DNSPs. These do not include accumulation meters, which are still a significant portion of the meters used outside Victoria.[45]

Accumulation meters are 'count up' meters which measure how much energy is consumed over a period, but not the time of day the consumption occurred. Smart meter installations are triggered by upgrades from single to 3 phase connections, solar PV installations, replacements of old accumulation meters (for example under the smart meter rollout) and new connections. Type 5 meters are more limited than type 4 meters, only allowing time of use pricing.[46]

The penetration of smart meters is different amongst jurisdictions and customer types. The proportion of customers with smart meters also varies between electricity distribution networks within jurisdictions, with this information also provided in our operational performance data published alongside this report.

We have excluded Victorian smart meter installations from our analysis. This is due to Victorian electricity DNSPs effectively completing their smart meter rollout in 2015,[47] with on average more than 99% of DNSP and export service customers having a smart meter.

In 2025, there was an increase in the smart meter installations for both residential and non-residential (low voltage) DNSP customers and export service customers. As expected, the

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43 AEMC, Accelerating smart meter deployment, November 2024, accessed 17 March 2025.

44 AEMC, Final report: Review of the regulatory framework for metering services, August 2023, pp ii-iii.

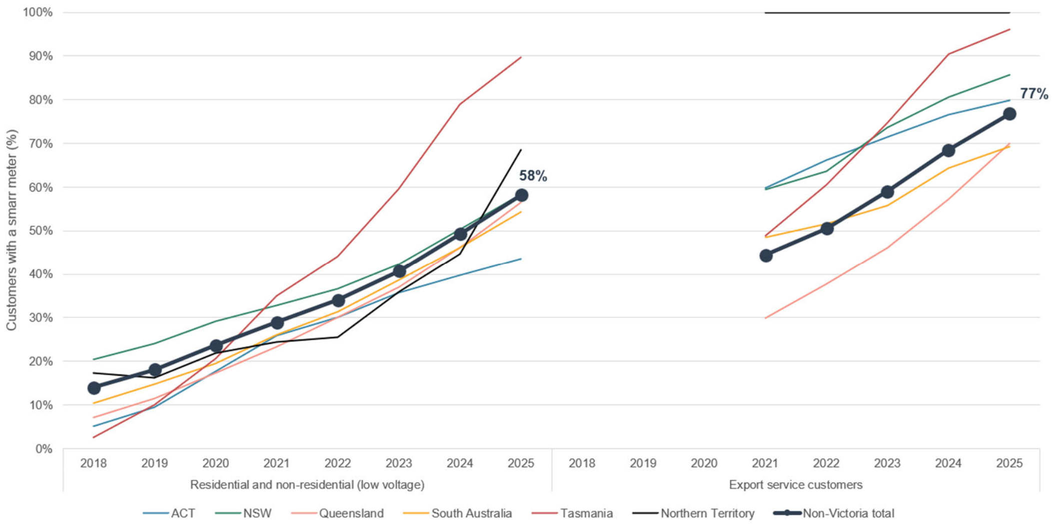
45 While Type 1-3 meters are also smart meters, these are only available to large customers. We do not report on large non-residential customers in this section as they have full smart meter penetration.

46 Although considered 'smart meters', some type 5 meters outside Victoria with no remote reading capabilities are being replaced as part of the AEMC's recommendations for the rollout of smart meters.

47 Victorian Auditor-General's Office, Realising the Benefits of Smart Meters, September 2015.

installation rate for smart meters was higher for export service customers, as a smart meter was typically required for a solar PV installation.

Figure 3-31 Low voltage and export service customers with a smart meter



Source: Residential and non-residential (low voltage) smart meters: Annual RIN, 'Table P1.1 - Distribution customers numbers by meter type' - Residential and Non-residential (low voltage) - Type 4 and 5 meters. Export service customers smart meters calculated from AER analysis and AIO table 3.9.5.1. Note: Proportion of smart meters installations for residential customers calculated by dividing the Residential smart meters by the total number of residential meters. Proportion of smart meters installations for export service customers calculated by dividing the Export service customers with a smart meter by the total number of export service customers. Ausgrid's distribution network smart meter replacement progress is slower due to inclusion of type 5 meters, refer to last year's report (pages 42 to 43) for further discussion.

On a jurisdictional basis, Tasmania (TasNetworks) has the highest installation rate, increasing to almost 90% for residential and non-residential low voltage customers, reflecting the state government's commitment to complete their smart meter rollout by the end of 2026.[48] The largest year-on-year increase was noted by Northern Territory (Power and Water Corporation) who had a 24 p.p. increase in the number of residential and non-residential low voltage customers with a smart meter.

3.9 Customers on cost reflective network tariffs increases

Network tariffs allow DNSPs to recover revenue to build, operate and maintain the network that is used to transport electricity. DNSPs charge network tariffs to retailers who then package the costs up as part of their retail tariffs to pass on to their customers.

Since November 2014, DNSPs have been required under the rules to gradually implement tariffs that are more reflective of the efficient costs (or long run marginal cost) of providing distribution services to consumers. The program of network tariff reform aims to encourage higher network utilisation and more efficient use of a network's existing capacity, which may minimise the significant future capex investment needed to meet the consumption and

48 Premier of Tasmania, Tasmania's smart meter rollout ahead of the curve, September 2024.

demand from increased electrification in the energy transition.[49] It could also allow the efficient grid integration of CER such as solar PV, batteries and EVs.

Cost reflective network tariffs can help to achieve efficient integration by encouraging and rewarding consumption when there is abundant network capacity (and encouraging and rewarding exports when network capacity is low). This is achieved by cost reflective tariffs charging a variable rate, where the charges are based on time of use and/or demand of a customer. This contrasts with flat network tariffs, which are agnostic to when a customer's consumption occurs.

3.9.1 Residential customers on cost reflective network tariffs increases

DNSPs assign network tariffs to each connection point, in accordance with the tariff assignment policy outlined in their tariff structure statement (TSS). Each DNSP's TSS needs AER approval every 5 years, alongside the DNSP's broader revenue proposal. The TSS sets out the DNSP's proposed tariffs, including a tariff assignment policy and how they are progressing tariff reform by making their tariffs more cost reflective.

Historically this has resulted in an uptick in the proportion of residential customers on cost reflective network tariffs following the start of the regulatory period. This is due to the "bulk" reassignment of customers to cost reflective network tariffs, as the reassignment policies have progressively shifted from opt-in, to opt-out and now to (mostly) mandatory. As documented in last year's report, tariff reassignment to a cost reflective tariff can also occur when a smart meter installation occurs. Since 2021, in the ACT, NSW and the NT a smart meter installation has largely resulted in residential customers being on a cost reflective network tariff.[50]

In 2025, there has been a 10 p.p. increase in the number of residential customers on cost reflective tariffs, with large increases noted by Power and Water Corporation (24 p.p.)[51] and NSW DNSPs (19 p.p.).

Despite this increase, residential customers on cost reflective tariffs in Victoria only increased by 2 p.p. in 2025. As noted in last year's report, this is due to Victorian DNSPs' retention of flat network tariff options for most small customers (residential and small business), working in conjunction with the smart meter rollout being practically completed in 2015, which decreases the triggers for reassignment to cost reflective network tariffs.[52] Due to this, a Victorian residential customer will need to actively opt-in to a cost reflective tariff through their retailer, to increase the proportion of customers on a cost reflective tariff.

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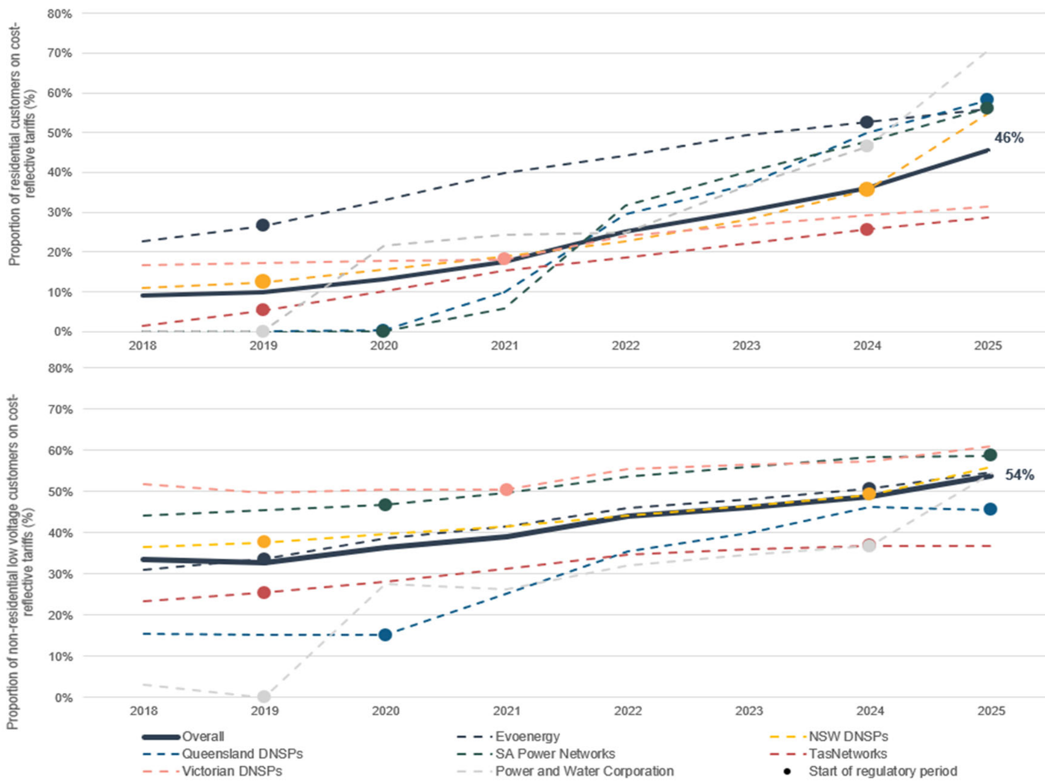
49 AER, Network tariff reform, accessed 29 April 2026.

50 Following the AEMC's review into the regulatory framework for metering services, from 1 December 2025, for a two-year period, a retailer requires a customer's explicit informed consent to change their retail tariff structure after a smart meter installation. This is discussed in last year's report (pages 50 to 52).

51 Power and Water Corporation had the same percentage point increase in their smart meter installations, reflecting that the installation has resulted in customers being assigned to cost reflective tariffs.

52 AER, 2025 Electricity and gas networks performance report, December 2025, p 45.

Figure 3-32 Proportion of residential and non-residential low voltage customers on cost reflective network tariffs



Source: Residential cost reflective tariffs: Annual RIN, ‘Table P1.3A - NMI Count - by tariff type’ - Sum of cost reflective tariffs. Non-residential low voltage cost reflective tariffs: Annual RIN, ‘Table P1.3B - NMI Count - by tariff type’ - Sum of cost reflective tariffs. Note: Proportion of cost reflective tariffs for residential and non-residential low-voltage customers calculated by dividing the sum of residential and non-residential low-voltage cost reflective tariffs by the total residential and non-residential low-voltage cost reflective and non-cost reflective tariffs.

In comparison to residential customers, there was a 5 p.p. increase for non-residential low voltage customers, resulting in more than half of non-residential low voltage customers being on cost reflective tariffs.[53]

On a jurisdictional basis, Power and Water Corporation had the largest increase, with an 18 p.p. increase in non-residential low voltage customers on cost reflective tariffs. This contrasted with the Queensland DNSPs, who had a slight decrease in the proportion of customers on cost reflective tariffs. This was driven by a large increase in non-residential low voltage customers on non-cost reflective tariffs for Ergon Energy in the 2025 regulatory year.

53 Our reporting on non-residential low voltage customers does not include larger non-residential customers energy users, which are generally on cost reflective tariffs.

4 Gas distribution network operational performance

This chapter focuses on the performance of gas DNSPs for the 2025 regulatory year. We are reporting on the three scheme (transmission) pipelines: Amadeus Gas Pipeline, Roma Brisbane Pipeline and Victorian Transmission System through the operational and financial datasets (Microsoft Excel workbooks) and gas TNSP infographics which are scheduled for publication in the second half of the 2026 calendar year. References to DNSPs relates to gas DNSPs.

The types of expenditures for gas NSPs are the same as electricity NSPs; opex is for the day-to-day operations of the network, whilst capex is spent on infrastructure investment. Similar to electricity NSPs, a gas DNSPs' capex and opex is recovered through the revenue building blocks, with forecasts determined by the AER to incentivise efficiency gains and lower spends and maintain the safe and reliable distribution of gas This incentive-based regulation will lead to lower forecasts in future years and lower network costs for customers.

4.1 Demand uncertainty continues to have an impact

In November 2021, we published an issues paper, Regulating gas pipelines under uncertainty, which addressed issues we will face when making future access arrangement determinations for NSPs. [54] The paper noted that the rate of existing residential gas customers electrifying their appliances will impact the pace of decline in gas demand in future years, which could result in:

- Network costs being shared amongst fewer customers,
- Customers being unable to electrify, particularly renters and low-income households
- Future gas customers bearing the cost of any unrecovered past network investment
- Price volatility and uncertainty further reducing demand
- Potential stranding of the gas distribution networks.

State and territory governments have already started to implement measures to reduce residential and small commercial customers reliance on gas through electrification. In our final determination for Jemena Gas Networks 2025-30 access arrangement in May 2025, we noted that declining gas demand for gas distribution network services was the most significant expected driver of future rising gas distribution network prices. Further, we noted that as more customers leave the gas distribution networks, there will be fewer customers to share the fixed costs of providing the gas distribution network services.[55]

This final determination also noted differing stakeholder views. Industrial customers expressed support for investing now into the gas distribution networks to develop renewable gas supply. While some consumer engagement processes indicated support for renewable

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54 AER, Electricity and gas networks performance report 2024, September 2024, p 51.

55 AER, Final decision – JGN access arrangement 2025-30, May 2025, pp v-vi.

gas, consumer advocates also expressed concerns about the potentially worsening asset stranding risk, with that risk inherently being transferred to households and small businesses.[56] These issues are likely to continue evolving in future years, as governments, industry and other stakeholders consider the role of gas networks in the energy transition.

The uncertainty of the pace of decline in gas demand is omnipresent in our gas network performance reporting, as it differs across each DNSP and affects their revenues, expenditures, the valuation of their network assets and their gas delivered.

4.2 Gas distribution costs increase in 2025

DNSPs are monopoly business that distribute gas to residential customers, commercial businesses, and industries. Historically, DNSPs have been regulated under a weighted average price cap form of control, which differs from a revenue cap. The weighted average price cap uses the building block revenue forecast and forecast demand over the access arrangement period to create the target revenue for the regulatory year. This involves determining a set of initial year tariffs and a series of X-factors[57] for the access arrangement period for the NSPs. The X-factors along with actual inflation, changes in demand and other factors constrain annual price increases on reference tariffs.

In contrast to revenue caps, the weighted average price cap enables NSPs to earn above or below the revenue set in the building blocks, due to actual demand being higher or lower than forecast. This places the ‘demand risk’ on NSPs and not customers, where lower demand results in lower revenues for NSPs whilst higher demand results in higher revenues.

In our final decision for JGN’s 2025-30 access arrangement, we approved JGN’s proposed hybrid tariff variation mechanism for its gas transportation reference service. This hybrid tariff variation mechanism was the first time the AER has approved a mechanism incorporating elements of both weighted average price cap regulation and revenue cap regulation.

In our draft decision for AGN South Australia 2026-31 access arrangement we accepted the broad elements of their proposed hybrid tariff mechanism,[58] whilst our draft decision for Evoenergy’s 2026-31 access arrangement required Evoenergy to submit a hybrid tariff mechanism with its revised proposal.[59] In these draft determinations we noted that the hybrid approach assigned volume risk to both customers and the DNSP, noting the balanced approach reduces the incentive to encourage gas consumption, while providing protection to consumers against large price increases if demand falls faster than forecast.[60]

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56 AER, Final decision – JGN access arrangement 2025-30, May 2025, pp v-vi.

57 The X-factor is used with CPI to smooth the revenue an NSP will collect each regulatory year. This X-factor is an input in the control formula applied in annual pricing and is the change in real revenue/price from year-to-year. The X-factor is updated annually for changes in the allowed return on debt.

58 AER, Draft decision – AGN South Australia access arrangement 2026-31 – Overview, November 2025, p 12.

59 AER, Draft decision – Evoenergy (ACT) access arrangement 2026-31 – Overview, November 2025, p viii.

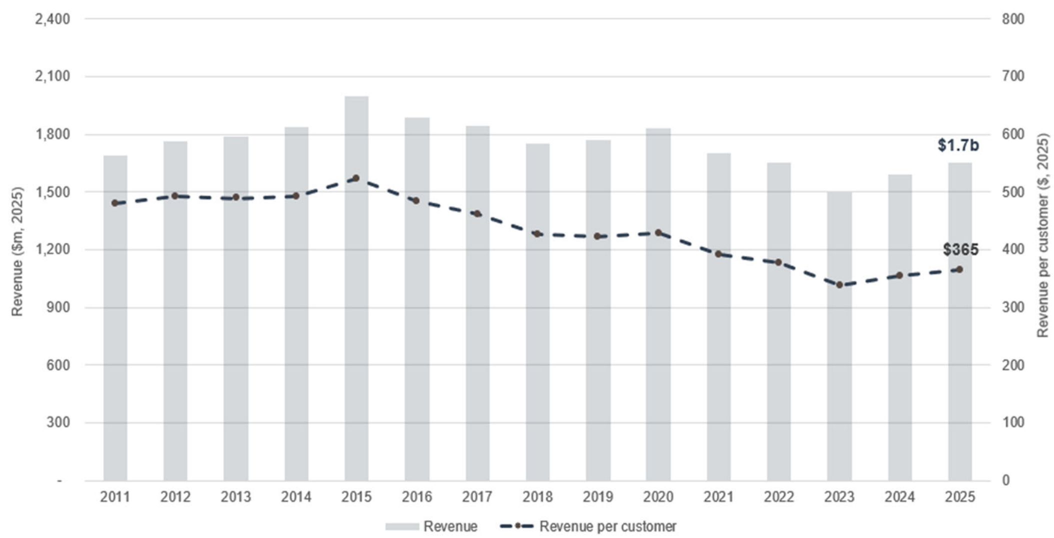
60 AER, Draft decision – Evoenergy (ACT) access arrangement 2026-31 – Overview, November 2025, p viii.

4.2.1 Gas distribution revenue increases in 2025 due to UAFG reconciliation

Revenue in this chapter relates only to the forecast and actual revenues from reference services, which for DNSPs are haulage reference services. Due to the bespoke nature of an NSP's access arrangement, this can also include non-reference services.[61] Categorising revenue in this way does not materially change our analysis, as reference prices influence the price that NSPs may charge for non-reference services.

In 2025, customers paid an average of $365 to DNSPs, an increase in real terms of $10 from 2024. Overall, this led to DNSPs recovering $1.7b in revenue from customers, a $63m (4%) increase from the previous year.

Figure 4-1 Distribution revenue and revenue per customer - DNSPs - $ real 2025



Source: Distribution revenue: Annual RINs - F3.1 Reference services, Customer numbers: Annual RINs - S1.1 Customer numbers by customer type. Note: AER calculation to convert to $ June 2025 terms. Distribution revenue per customer calculated by dividing DNSP's distribution revenue by DNSP's customer numbers.

The aggregate increase was primarily driven by Jemena Gas Networks, who had a 14% increase in their revenue, whilst Evoenergy, AGN South Australia and AusNet Services had smaller increases in their revenues.

Higher revenues for Jemena Gas Networks were due to tariff variation adjustments for UAFG. These adjustments reconciled the difference between the estimated purchase cost for gas (made during their 2020-25 access arrangement determination in April 2020) and the actual cost following the volatility in gas prices in the 2022 to 2023 period. The higher purchase cost for gas resulted in Jemena Gas Networks incurring higher opex in 2023 and 2024.

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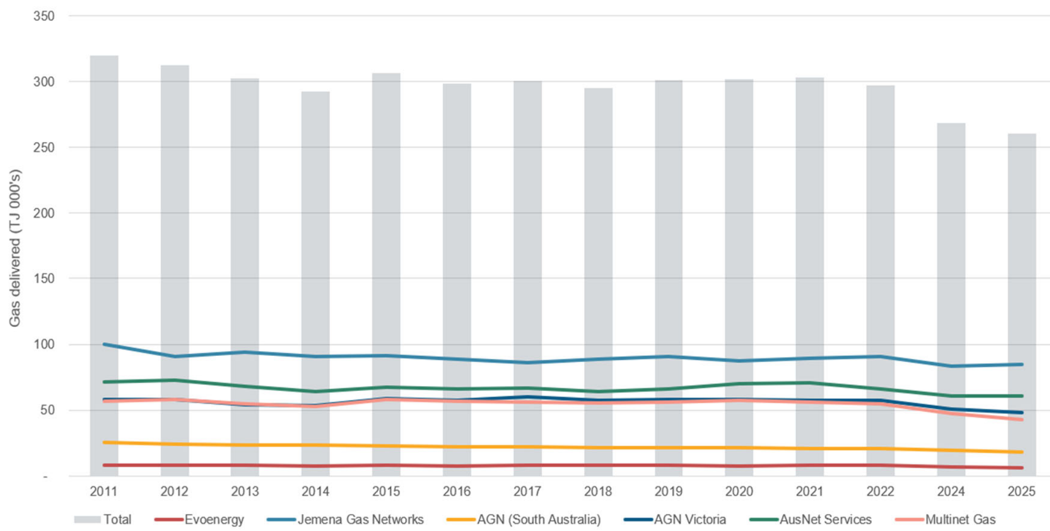
[61] This difference is more pronounced between DNSPs and TNSPs. This is due TNSPs having a higher proportion of large customers with bespoke commercial arrangements, TNSPs (particularly Amadeus and RBP) provide a higher proportion of non-reference services. As noted above, this version of the 2025 Electricity and gas networks performance report does not include information on TNSPs.

4.2.1.1 Milder temperatures contribute to lower gas delivered in 2025

In our operational performance dataset, we compare actual revenue against the target revenue for the regulatory year. Target revenue is based on the annually adjusted tariffs and actual demand from two years prior. For the 2025 regulatory year, the target revenue for all DNSPs was based on the demand from 2023.

In 2025, the aggregate gas delivered by DNSPs decreased by 3% from 2024 and resulted in every DNSP except AusNet Services earning less than their target revenue. In 2025, AusNet Services' revenue was marginally higher ($1m or 0.4%) than their target revenue.

Figure 4-2 Gas delivered - Total and by DNSP



Source: Gas delivered: Annual RINs - N1.1 Demand. Note: Due to an over representation of warmer months during the six-month transitional period for Victorian DNSPs, we have removed 2023 from our analysis. This is discussed in detail in our 2024 Electricity and gas network performance report.

This decrease in aggregate gas demand from lower residential and industrial customers, follows a large annual decrease in gas demand in 2024.[62] The annual movements in gas delivered in 2025 differed across the gas DNSPs, with Jemena Gas Networks having a slight increase in consumption, whilst there was a decrease in consumption of more than 5% for Evoenergy, AGN Victoria, AGN South Australia and Multinet Gas.

Last year's report noted that annual movement of gas delivered can be attributable to several factors, which differ between DNSPs and jurisdictions. These include the proportion of gas that is delivered to industrial and commercial customers as compared to residential customers. For instance, a higher proportion of gas is delivered to residential customers in the ACT (Evoenergy) and Victoria, as more customers in these regions use gas appliances for their heating and cooking.

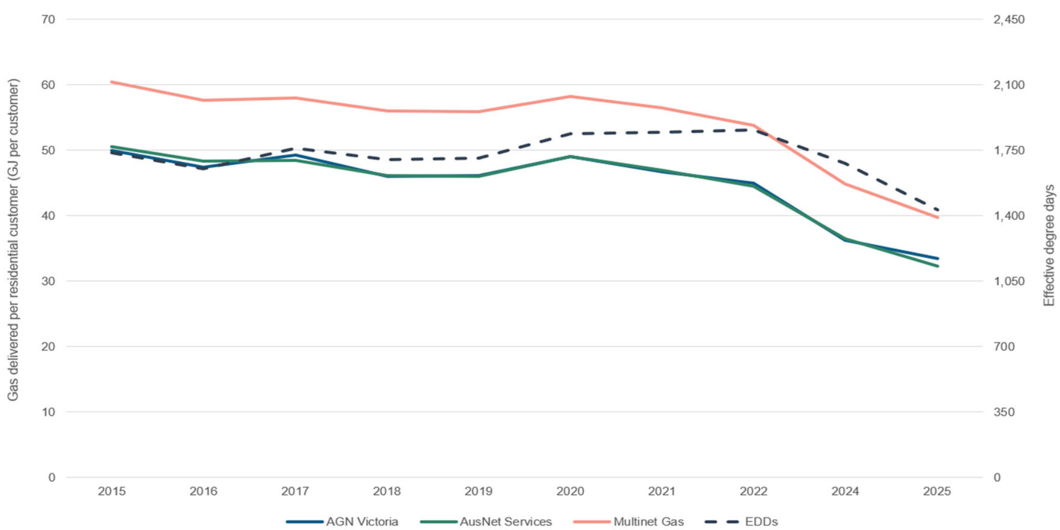
62 AER, 2025 Electricity and gas networks performance report, December 2025, p 57.

Figure 4-3 Contributions to annual movement in gas delivered - 2025

Source: Gas delivered: Refer to Figure 4-2. Note: Contributions to annual movement calculated by dividing annual movement in customer type by the total movement for regulatory year.

Changes in residential gas usage can be due to the electrification of heating and cooking appliances and associated jurisdictional policies, changing customer preferences for gas use with cost-of-living pressures and weather conditions.

Figure 4-4 Gas delivered per residential customer and EDD - Victorian DNSPs



Source: Refer to Figure 4-2. EDDs: Information request to DNSPs. Note: Due to an over representation of warmer months during the six-month transitional period for Victorian DNSPs, we have not included gas delivered and EDDs for the 2023 regulatory year.

Using effective degree days (EDDs), there is a distinct correlation between the decreasing EDDs, and residential gas delivered customers across the 2015 to 2025 period. This indicates that the milder temperatures during the 2025 regulatory year have contributed to the lower residential gas consumption in 2025 by Victorian DNSPs.

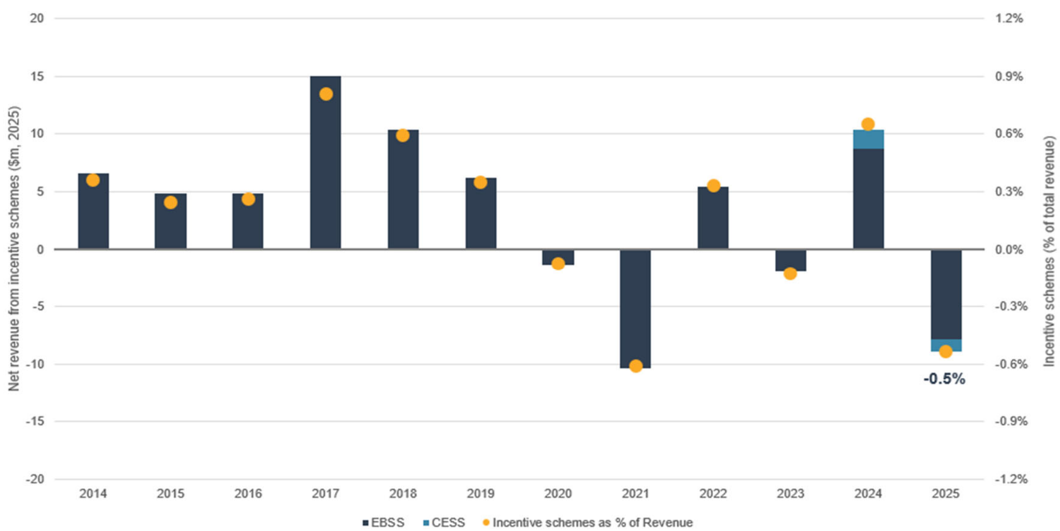
Despite EDDs being correlated with residential gas demand in Victoria, in recent years the correlation appears to be declining relative to historical trends, with weather conditions having a lower impact on residential gas delivered. This indicates that other factors including consumers using electric appliances for their heating and cooking, improved efficiency of newer gas appliances and changing consumer behaviour from cost-of-living pressures are having more of an impact on gas demand.

4.2.2 Gas DNSPs earn minimal incentive scheme rewards

The incentive schemes for gas NSPs differ from those for electricity NSPs as there are no specific incentive schemes in relation to service outcomes or reliability.[63] Similar to electricity NSPs, incentive schemes are designed to deliver better outcomes for customers and promote achievement of the NGO, with the overall benefits to customers outweighing the incentive revenues provided to the DNSPs.

Relative to electricity NSPs, historically there has been minimal revenues earned by DNSPs in relation to their incentive scheme performance in previous access arrangement periods. In 2025, DNSPs had $9m of incentive scheme penalties, which represented less than 1% of total distribution revenues. This was a decrease of $19m from 2024, where DNSPs earned $10m in revenue from incentive scheme rewards.

Figure 4-5 Revenue from incentive schemes - DNSPs - $ real 2025



Source: Incentive scheme revenues/payments from Annual RIN table F3.6 Revenue - Rewards and penalties from incentive schemes. Where incentive schemes revenue/payments are not available, data is from respective DNSP's PTRM, 'Revenue adjustments.' Note: AER calculation to convert to $ June 2025 terms.

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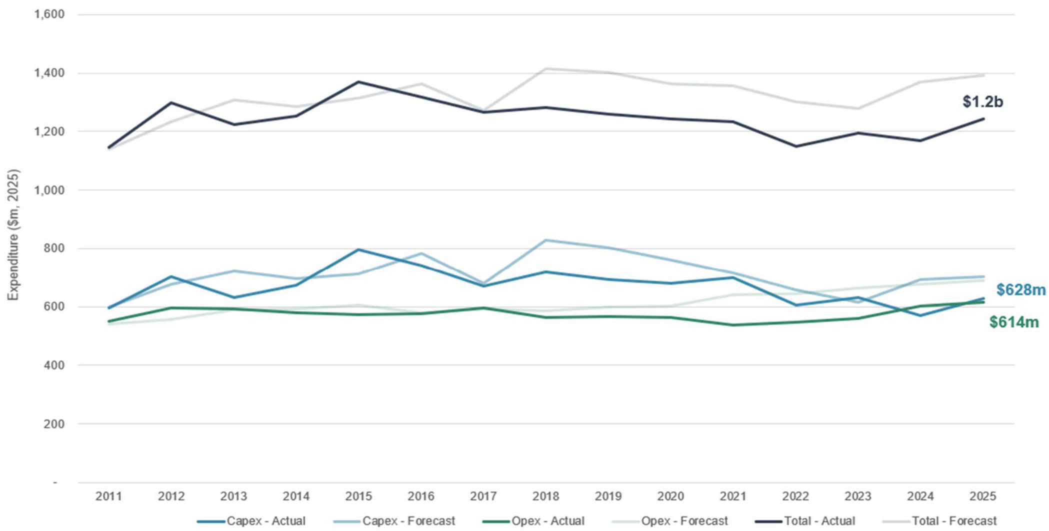
63 Although there are no incentive schemes in relation to service delivery for NSPs, the ESC requires the Victorian DNSPs to make guaranteed service level (GSL) payments to customers who receive a level of service worse than a specific threshold or level. These relate to late or missed appointments, delay to new connections, frequency of outages and the duration of outages.

4.3 Gas DNSPs underspend on expenditure allowances

In 2025, DNSP expenditure increased by 6% to $1.2b, with a 11% and 10% underspend in real terms against the aggregate opex and capex allowance respectively. In comparison to 2024, the opex spend increased by 2% whilst the capex investment increased by 12%.

Figure 4-6 Total expenditure - DNSPs - $ real 2025



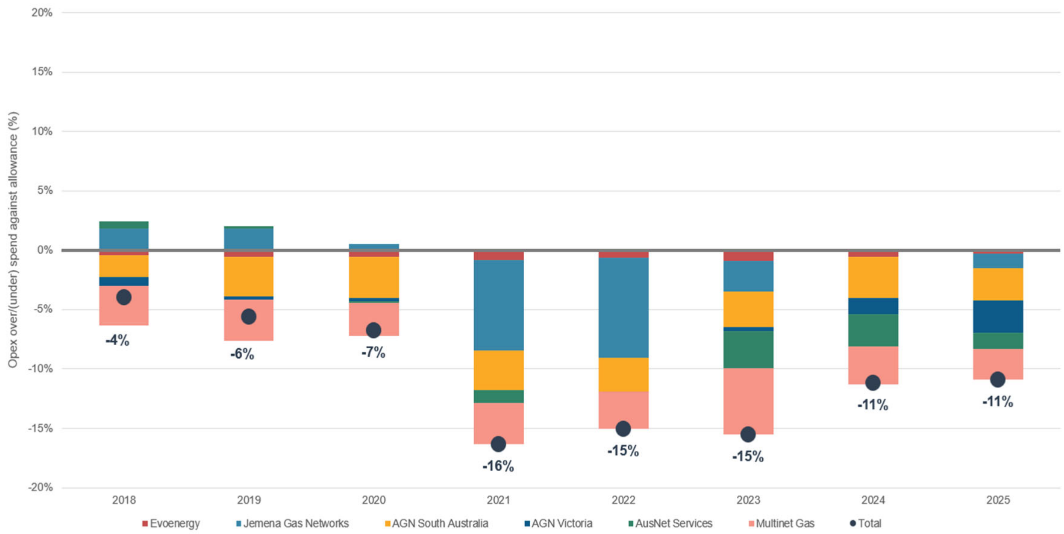
Source: Actual capex RFMs - RFM input - actual capex, actual asset disposal, actual capital contributions, or where not available in an RFM, annual RINs - F2.4 Capex by asset class, F2.5 Capital contributions by asset class, F2.6 Disposals by asset class. Actual Opex: Annual RINs - F4.1 Opex by purpose. Forecast capex: PTRM Input - 'Forecast net capex.' Forecast opex: PTRM Input - 'Forecast operating and maintenance expenditure.' Note: AER calculation to convert to $ June 2025 terms. Net capex is gross capex less capital contributions and disposals. Actual and forecast total expenditure is the sum of capex and opex.

4.3.1 Gas DNSPs' underspend on opex for eighth consecutive year

Gas DNSPs have had 8 consecutive underspends of their opex allowance (from 2018 to 2025) for a collective underspend of $543m. When compared to the total forecast opex over the eight-year period, there has been an 11% underspend of the opex allowance.

In the past five years, only two DNSPs have marginally overspent their opex allowance; AGN Victoria in 2021 and Jemena Gas Networks in 2024. This overspend by Jemena Gas Networks in 2024 was predominantly due to higher purchase costs for gas, resulting in Jemena Gas Networks incurring $35m more for UAFG than forecast in their opex allowance. As noted above, an adjustment was made to Jemena Gas Networks' revenue in 2025 for the difference between the estimated gas cost in their opex allowance and the actual cost paid.

Figure 4-7 Opex over/under spend to forecast - DNSPs – 2018 to 2025 - $ real 2025



Source: Actual Opex: Annual RINs - F4.1 Opex by purpose. Forecast opex: PTRM Input - 'Forecast operating and maintenance expenditure.' Note: AER calculation to convert to $ June 2025 terms. Opex over/under calculated by comparing actual opex against forecast opex for respective regulatory year.

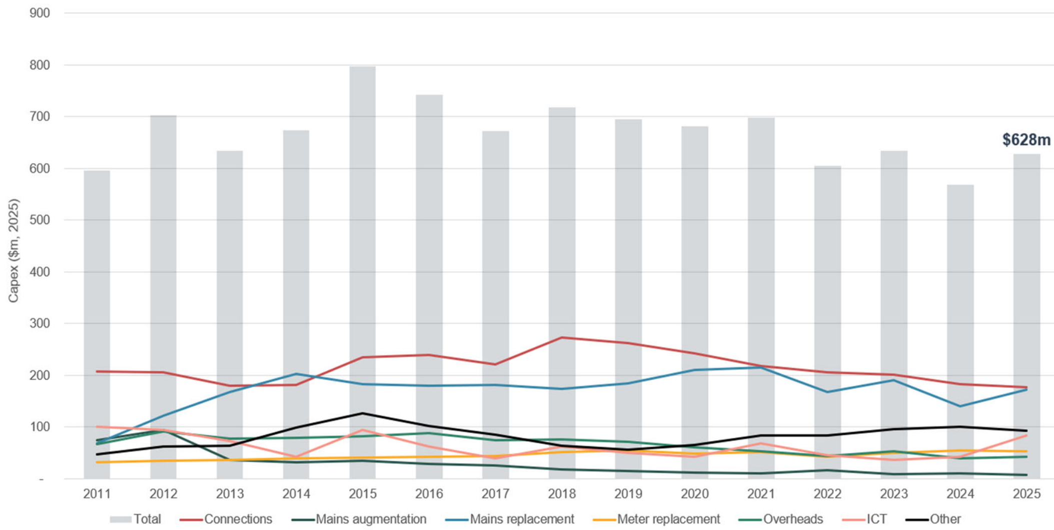
This continued opex efficiency benefits both DNSPs and consumers and is a key feature of our incentive-based regulatory framework. Lower opex enables DNSPs to earn returns higher than their allowed returns and decreases opex forecasts in future access arrangements.

4.3.2 Gas DNSPs' capex investment remains new connections and mains replacements

DNSP capital costs have historically been for new connections and mains replacements. Connections expenditure has been driven by the costs required to connect customers to gas supply, whilst mains replacement expenditure has been driven by the replacement of cast iron pipeline with pipeline using polyethene and polyamide materials. These "plastic" pipelines have several advantages, namely their resistance to damage from corrosion or the effects of gas, ease of installation and cost effectiveness.

In 2025, DNSPs invested $628m in the gas distribution networks, a 10% increase from 2024. Similar to prior years, most of the capital investment by DNSPs was in connections and mains replacements. The increase in 2025 was due to an increase in mains replacement and ICT related capex, whilst connections investment slightly decreased.

Figure 4-8 Capex by driver - DNSPs - $ real 2025



Source: Capex by purpose: Annual RINs - E1.1.1 Reference Services. Note: AER calculation to convert to $ June 2025 terms. Other consists of telemetry and other capex.

The amount of capex investment will differ across DNSPs and reflect their different capex profiles. These capex profiles reflect the differing number of customers connecting to their distribution network and DNSPs being on different stages of their mains replacement program.[64] Our prior year report noted that going forward, only AGN South Australia, AusNet Services and Multinet Gas were still completing a mains replacement program. Further details of the approved capex for mains replacement programs for these DNSPs is provided in last year's report.[65]

4.3.3 Gas DNSPs asset base increased amidst uncertainty with decline in gas demand

The capital asset base (CAB) is the total economic value of the network assets used by the DNSPs to provide network services. The valuation of a DNSP's CAB is often dependent on the geographical size and location of their network, whilst the CAB per customer is based on the customer density of their network. This is why AGN South Australia's and Multinet Gas's CAB per customers is the highest and lowest respectively across the DNSPs.[66]

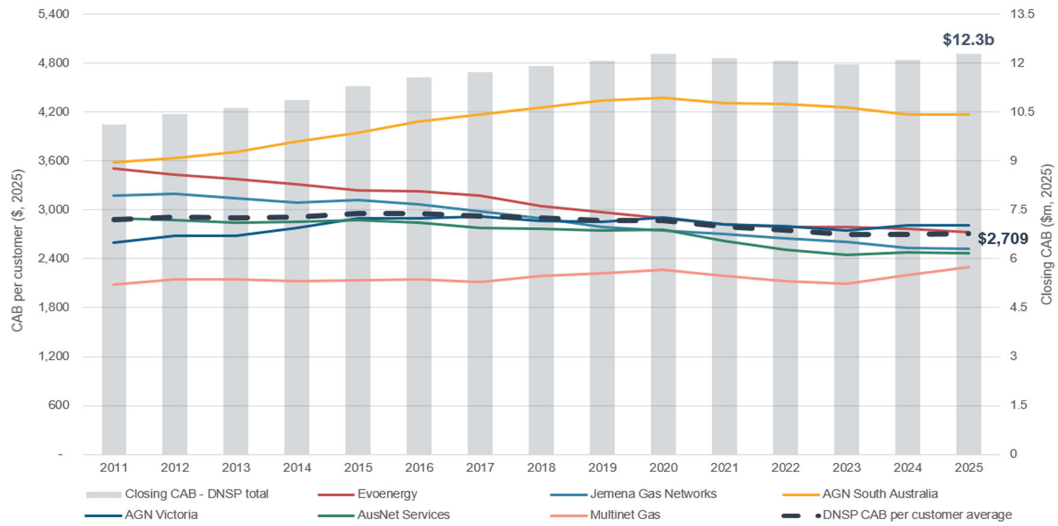
In 2025, the total CAB increased in real terms by 1.4%, with the total DNSP CAB per customer remaining consistent with last year.

64 Evoenergy's gas network was commissioned in 1982 using polyethene and polyamide materials instead of cast iron materials. Due to this, Evoenergy has not had a mains replacement program.

65 AER, 2025 Electricity and gas networks performance report, December 2025, pp 63-64.

66 Further information on CAB per network length was detailed in last year's report.

Figure 4-9 CABs and CAB per customer - DNSPs - $ real 2025



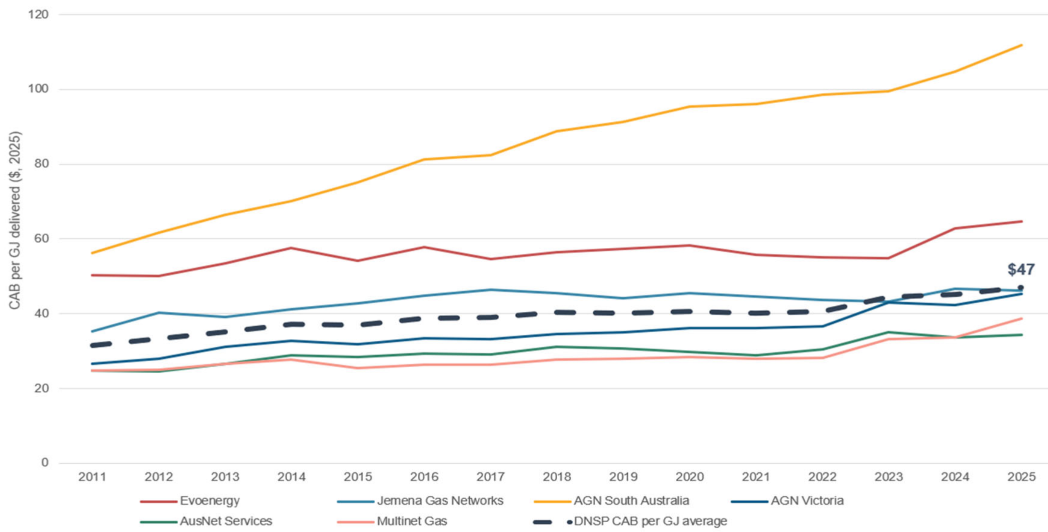
Source: CAB: RFMs - ‘Total capital base roll forward’ - Interim closing capital base, or where unavailable using Annual RINs - F10.1 ‘Capital base values’. Customer numbers: Annual RINs - S1.1 ‘Customer numbers by customer type’. Note: AER calculation to convert to $ June 2025 terms. CAB per customer calculated by dividing total CAB by total customer base and DNSPs CAB by DNSPs customer base.

The differing CAB per customer impacts the distribution network costs paid by customers, as higher CAB values are reflected in larger return on capital and return of capital building blocks. The return of capital building block decreases the CAB value as the network assets are depreciated across their working life, with the total CAB decreasing in a regulatory year in real terms when the total depreciation exceeds the new investment in network assets.

Similar to electricity, the efficiency of the DNSPs distributing gas to consumers can be measured by the CAB per gigajoule (GJ) delivered. Overall, the total CAB per GJ delivered increased by $2 in 2025 to $47 per GJ, an increase in real terms of $15 since 2011.

On a DNSP basis, AGN South Australia’s CAB per GJ delivered is significantly higher, with a CAB per GJ delivered of $115, an increase of $56 or 99% from 2011. Following AGN South Australia, the next highest increase is AGN Victoria with a $19 or 70% increase since 2011.

Figure 4-10 CABs per GJ delivered - DNSPs - $ real 2025



Source: CAB: Refer to Figure 4-9. Gas delivered: Refer to Figure 4-2. Note: AER calculation to convert to $ June 2025 terms. CAB per GJ delivered calculated by dividing total CAB by total gas delivered and DNSP's CAB by DNSP's gas delivered.

The increase in CAB per GJ delivered by AGN South Australia is due to an increase in real terms of their CAB and a decrease in the gas delivered. Like Jemena Gas Networks, AGN South Australia distributes a higher proportion of gas to large business or industry, with on average 50% of its gas delivered to industrial customers. Since 2011, there has been a 5.6 million GJ (or 40%) decrease in gas delivered by AGN South Australia to industrial customers.

For the other DNSPs, there has been an increase in the CAB per GJ delivered, especially since 2022, as gas delivered has decreased and CABs have slightly increased. Going forward, the future trajectory of this metric is expected to be driven by changes in gas delivered, with reducing gas demand leading to lower CAB efficiency.

4.3.4 Recent determinations allow accelerated depreciation

As noted above, the uncertainty in relation to the pace of decline in gas demand has led to concerns of potential stranding of network assets. One of the potential options to this issue, is to accelerate the depreciation of an NSP's network assets by shortening the life of the network assets or increasing the rate at which they are depreciated. This is allowed by the NGR, which enable us to accelerate depreciation where necessary to allow cost recovery and generate efficient prices as new information becomes available.[67]

We have considered accelerated depreciation in our recent 2026 – 2031 access arrangement final determinations for AGN South Australia and Evoenergy.[68] We have shortened asset lives to provide the DNSPs with a reasonable opportunity for cost recovery over the expected economic life of the network assets. Our final decision for Evoenergy and

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67 NGR, Rules 89(1) (b) and (c)

68 AER, Australian Gas Networks (SA) – Access Arrangement 2026-31 Final Decision, May 2026. AER, Evoenergy – Access Arrangement 2026-31 Final Decision, May 2026.

AGN SA determined $30 million and $29 million[69] ($ June 2026 terms) of accelerated depreciation over the 2026-31 period respectively.[70]

The level of accelerated depreciation determined has differed across the DNSPs reflecting the specific jurisdictional circumstances for those networks. A price limit approach was used to determine the level of accelerated depreciation for the Victorian DNSP's and Jemena Gas Networks. A limit of 1.5% per annum real price change was applied for Victorian DNSPs[71] and 0.5% per annum real price change for Jemena Gas Networks.[72]

The decision to enable some accelerated depreciation for Evoenergy, AGN South Australia, Jemena Gas Networks and Victorian DNSPs is reflective of our issues paper on *Regulating gas pipelines under uncertainty*. The paper noted that opportunity and flexibility for adjustment is greatest when we act as soon as we can to minimise the adverse impact of a decline in gas demand.

The decision to allow accelerated depreciation provides DNSPs with a reasonable opportunity for cost recovery over the expected economic life of the network assets in the transition to net zero. In this transition, DNSPs will continue to incur maintenance and replacement costs to ensure their pipeline assets can provide safe and reliable network services for the remaining customers. Without accelerated depreciation, networks may potentially deter or defer important investments in their network assets which would not be in the long-term interest of consumers.

4.3.5 Gas networks in transition – Directions paper

In March 2026, the AEMC published a directions paper in responding to rule change requests from Energy Consumers Australia and the Justice Equity Centre. These proponents are seeking changes to the regulatory framework for gas DNSP due to declining residential and small commercial gas demand.

In response the AEMC considered that declining and/or increasingly uncertain demand is creating challenges for the economic regulation of gas pipelines and risks for both gas consumers and gas DNSPs and that changes to the NGR are necessary to ensure the economic regulatory framework remains fit for purpose.[73]

The AEMC's proposed direction focuses on four key reform areas:[74]

- Employing a longer-term outlook to manage uncertainty. Requiring service providers and the regulator to demonstrate how they have considered long-term energy transition risks and impacts in the access arrangement period and beyond.

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69 Amounts reported in June 2026 dollar terms.

70 AER, Final decision - Evoenergy access arrangement 2026-31 - Overview, November 2025, p 19; AER, Final decision - AGN SA access arrangement 2026-31 - Overview, November 2025, p 19.

71 AER, Final decision - AusNet Services access arrangement 2023-28 - Overview, June 2023, p 24.

72 AER, Final decision - JGN access arrangement 2025-30 - Overview, May 2025, p. vii

73 AEMC, Gas Networks in Transition - Directions paper – Information sheet, March 2026, p 1.

74 AEMC, Gas Networks in Transition - Directions paper, March 2026, p iv.

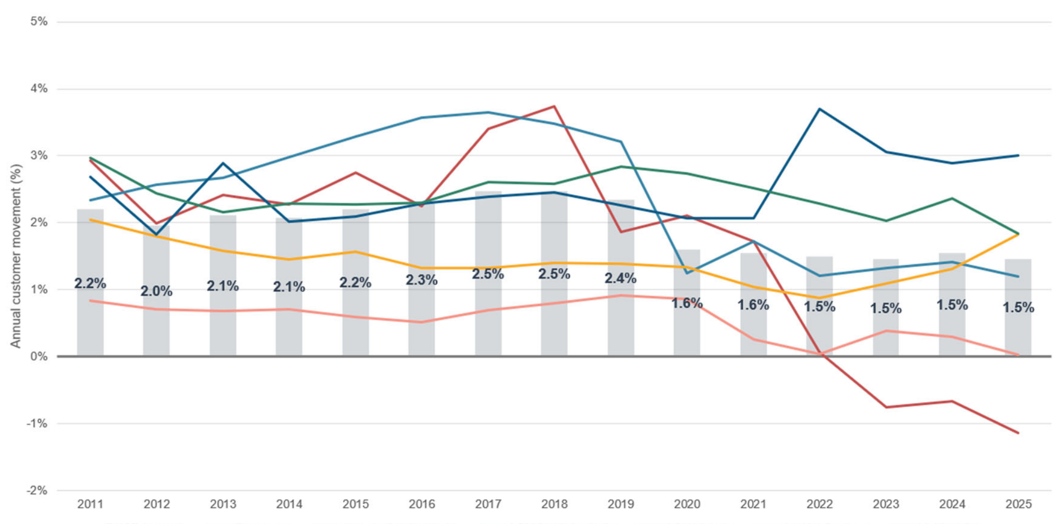
- Amending capital cost recovery provisions to support efficient capital recovery. Providing clearer guidance on the use of depreciation, compensation for inflation, redundant capital and re-use of redundant capital provisions to support efficient capital recovery that promotes the long-term interests of consumers.
- Amending capital and operating expenditure provisions to minimise expenditure while continuing to support safety and reliability. Amending the capex provisions and opex definition to reduce expenditure and better align investment decisions with uncertain demand conditions and improve regulatory clarity.
- Amending reference tariff provisions to ensure tariff arrangements can accommodate a broader range of demand scenarios.

4.4 Gas DNSP customer base increases in 2025

Gas distribution networks have traditionally been run as growth assets with costs spread over a growing customer base. Australia's energy transformation is changing the outlook for distribution networks and the role of gas as an energy source for their customers. New connections will be a key factor in determining the future of gas distribution networks going forward.

In 2025, there was a 1.5% increase in net residential customer connections, a slight decrease in growth rate from the prior year. Movements in residential customer connections differed across the DNSPs, with AGN Victoria increasing their customer base by 3%, Multinet Gas maintaining their customer base and Evoenergy decreasing its customer base (for the third consecutive year).

Figure 4-11 Residential customer numbers growth - DNSPs

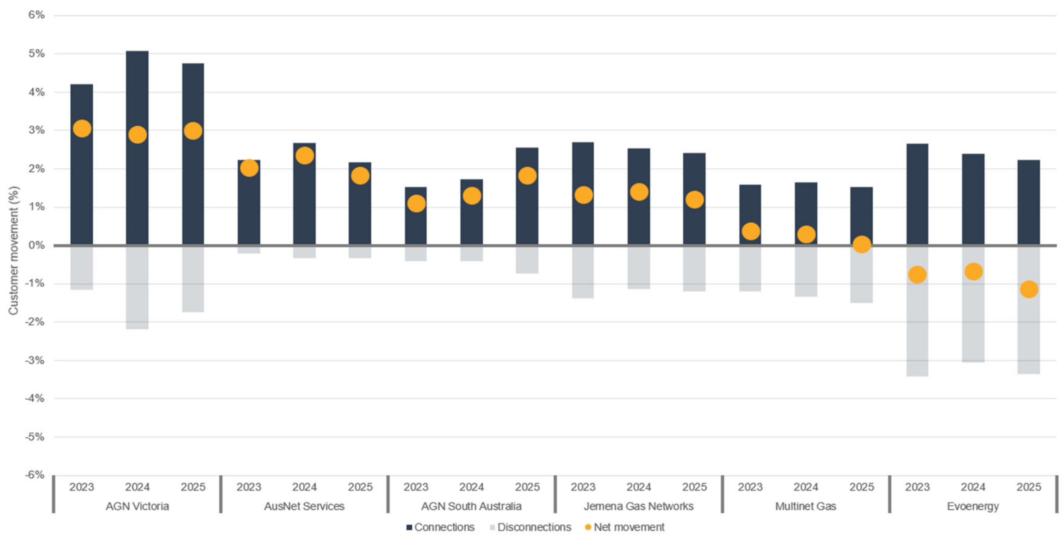


Source: Residential customer numbers: Annual RINs - S1.1 Customer numbers by customer type – Residential.
Note: Residential customer growth determined by percentage change in residential customer numbers from prior year.

The decrease in Evoenergy's customer base started following the implementation of the ACT regulations banning new gas connections from December 2023.[75] Evoenergy is still connecting customers, based on the regulations not applying to the NSW region of their network, on National Land in the ACT and to industrial customers or commercial connections in commercial zones where there is an exemption by the Minister for Water, Energy and Emissions Reduction.

Victoria also has policy settings that restrict gas connections for certain customers.[76] However, since the introduction of the policies, there has still been an aggregate increase in residential connections in Victoria, driven by an annual growth of 3% for AGN Victoria over the past three years. The observed connection trends can persist for some time after policy announcements, as any changes in customer behaviour may occur with a lag and depend on appliance replacement rates.

Figure 4-12 Residential connections and disconnections - DNSPs – 2023 to 2025



Source: Residential customer numbers: Annual RINs - S1.1 Customer numbers by customer type. Note: Connections and disconnections divided by total customer numbers.

Further, as noted in last year's report the increase in connections for the Victorian DNSPs may also be due to customers with approved planning permits being connected after the restrictions were implemented and the restrictions only applying to new dwellings which required a planning permit.

In June 2025, the Victorian Government announced their new policy in relation to electrification regulations.[77] The new regulations require all new residential and commercial

75 ACT Government, Regulation to prevent new gas connections starts in December, media release, November 2023.

76 Victorian Government, Victoria's gas substitution roadmap, Department of Energy, Environment and Climate Action, accessed 20 March 2026. ACT Government, Regulation to prevent new gas connections starts in December, media release, November 2023.

77 Victorian Government, Building Electrification Regulations Summary, June 2025, p 7.

buildings to be all-electric and existing gas hot water systems in residential buildings to be replaced with electric appliances at their end-of-life.[78]

The electrification regulations will commence in two stages. The building regulations will commence on 1 January 2027 for all-electric new homes and commercial buildings and 1 March 2027 for gas hot water system installation and replacements in existing homes.[79] Based on these dates, the impact of these restrictions will not be reported by gas DNSPs until their 2027 regulatory years.

4.5 UAFG and pipeline outages remain consistent

Although there are no prescribed AER incentive schemes for service performance for DNSPs, due to the safety risks associated with gas it is imperative that DNSPs provide a safe and reliable supply of gas to customers. Whilst there are a number of different measures of supply quality, network outages and UAFG are two measures that are readily quantifiable and reported annually.

4.5.1 UAFG differs across the gas DNSPs

UAFG is the difference between the measured quantity of gas entering the network (gas receipts) and measured gas deliveries (gas withdrawals). UAFG can have various causes, however they can be broadly itemised into 5 categories: gas leakage (fugitive emissions), metering errors, gas heating values (losses related to the quality of gas injected into the pipelines), data quality, and theft.[80] UAFG is an important measure for customers both financially and for the environment, which we discussed in detail previously.[81]

In 2025, there was an overall UAFG loss of 3.3%, a slight improvement from 3.6% in the prior year. Individually the loss rate differed across the DNSPs, with Victorian DNSPs (in particular, Multinet) having higher loss rates than Evoenergy, Jemena Gas Networks and AGN South Australia. Evoenergy had a slight negative value in 2025, which may be impacted by a measurement and calculation error in the determination of the annual UAFG loss rate.[82]

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78 The Victorian Government noted exemptions will apply to this requirement.

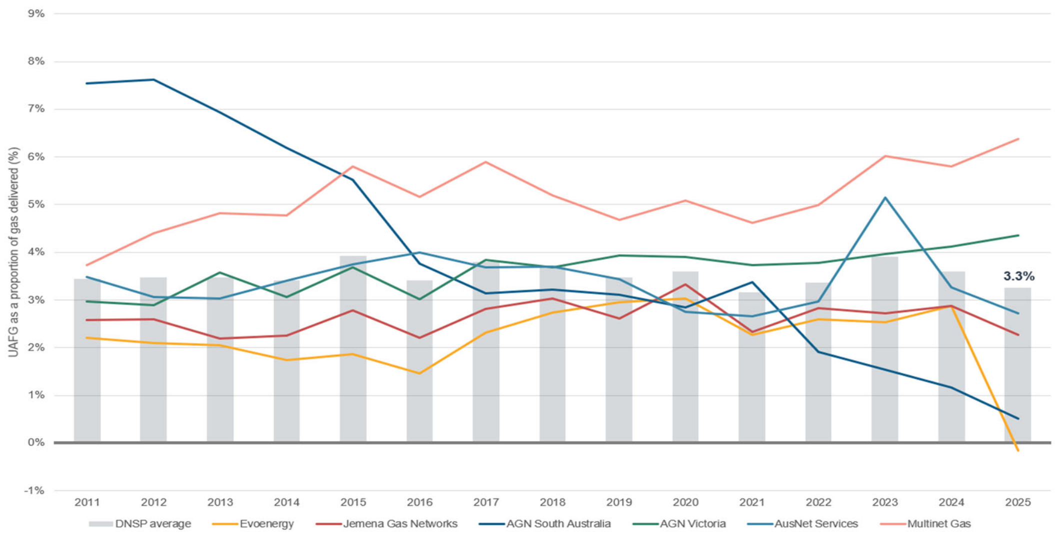
79 Victorian Government, Building Electrification Regulations Summary, June 2025, p 15.

80 ESC observed up to 17 different components within these 5 categories in Review of unaccounted for gas benchmarks: final decision, December 2022, p 7.

81 AER, Electricity and gas networks performance report 2024, September 2024, p 70.

82 Evoenergy, Evoenergy 2026-31 access arrangement proposal, June 2025 – Unaccounted for gas, p 2.

Figure 4-13 UAFG proportion of gas delivered - DNSPs



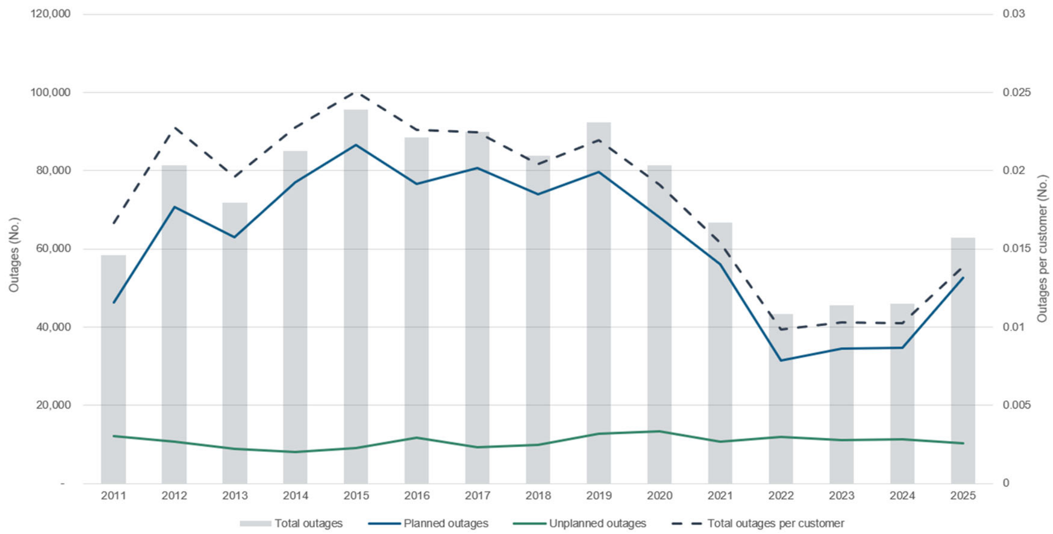
Source: Gas delivered: Annual RINs - N1.1 Demand by customer type. UAFG: Annual RINs - S11.3 - Unaccounted for gas - distribution and transmission. Note: UAFG loss rates calculated by dividing the DNSP's UAFG by the DNSP's gas delivered.

4.5.2 Pipeline outages remain infrequent

Pipeline outages remain infrequent for customers as the network assets are inherently reliable. This is due to network assets being substantially underground and more protected from adverse weather conditions than electricity networks and gas DNSPs generally being able to carry out works without causing supply outages.

Due to these factors, outages remained infrequent in 2025. Overall, there was an increase in planned outages for Jemena Gas Networks, however outages per customer remained at 0.01.

Figure 4-14 Planned and unplanned outages – DNSPs



Sources: Planned Outages: Annual RIN - Table S11.1.1 'Network outages - planned.' Unplanned outages: Annual RIN - Table S11.1.1 'Network outages - unplanned.' Customer numbers: Annual RINs - S1.1 'Customer numbers by customer type'. Note: Outages is the sum of planned and unplanned outages. Outages per customer is the total outages divided by the total DNSP's customer numbers.

Since 2021, statistically 1 in 100 customers will experience an outage on a distribution network each year. However, because gas is essential for industry and commercial businesses, as well as residential customers, a single outage can have a significant detrimental impact.

In assessing outages operational data, we note that different DNSPs may have adopted materially different approaches to reporting outages. While this data effectively tracks outage trends for individual gas DNSPs over time, it is limited in comparing the relative performance between different DNSPs.

5 Financial performance

Our performance reporting assesses the financial performance of NSPs, or network profitability, through three measures; return on assets (RoA), return on regulated equity (RoRE) and earnings before interest and tax (EBIT) per customer.

Explanatory notes which explain our approach to calculate each profitability measure are included in Appendices B, C, and D. Further information is also available in our Final position paper - profitability measures for electricity and gas network businesses and the illustrative RoRE model published alongside this report.

We report our financial performance data and the profitability measures exclusive (real) and inclusive (nominal) of inflation (through the indexation of the RAB/CAB). The RoA, RoRE[83] and EBIT per customer profitability measures included in this report are exclusive of inflation, i.e. an NSP's real returns, as our regulatory frameworks are designed to target a real rate of return. In the financial performance datasets, we publish alongside this report, we have inserted 'switches' which enable stakeholders to calculate the returns of an NSP inclusive or exclusive of the indexation of the RAB/CAB.[84]

The regulatory framework is designed to compensate NSPs for efficiently incurred costs (such as opex, depreciation, interest costs and tax costs) and to provide them with an expected profit margin in line with the required return in the capital or financial markets for an investment of similar risk. This return is designed to attract efficient investment, if set at an appropriate level and supported by the incentive-based regulatory framework.

The incentive-based regulatory framework is based on encouraging efficiency by NSPs and therefore an NSP's actual performance will differ from the forecasts and benchmarks we set. These differences can occur for a number of reasons, some of which we discussed in our 2024 report.[85]

We report each of the three profitability measures for NSPs and gas DNSPs in this section as a sector, i.e. on a weighted average basis. This means that what is reported is the result in aggregate, where there can be differences in the underlying financial performance between individual NSPs.

5.1 Networks' RoA increased in 2025

The RoA is measured as the earnings before interest and tax (EBIT) divided by the electricity NSP's RAB and the gas DNSP's CAB. This measure allows comparison of an NSP's EBIT profits against their allowed rate of return and calculates the EBIT that an NSP can earn from their RAB or CAB.

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83 Real returns exclude returns from indexation of the equity-funded portion of the RAB that would otherwise capture returns from differences in expected and actual inflation.

84 The financial performance model also enables stakeholders to assess a NSP's returns inclusive and exclusive of incentive schemes and the impact of inflation. For electricity DNSPs, stakeholders can also assess returns inclusive or exclusive of pass-through revenues.

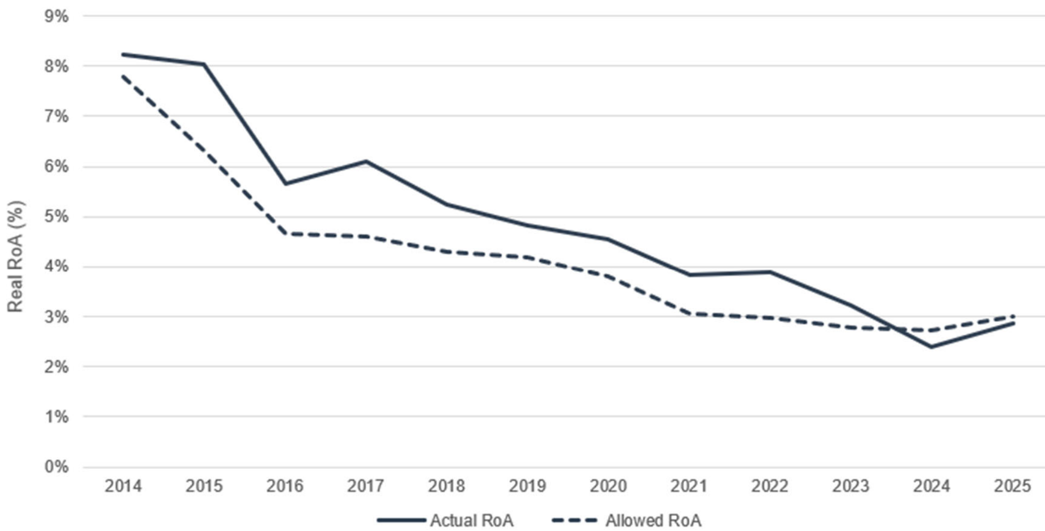
85 AER, Electricity and gas network performance report 2024, September 2024, p 73.

The RoA profitability measure is the best assessment on whether NSPs have returns greater than their allowed rate of returns and achieved the NEO or NGO. This is due to efficiency from capex, opex and incentive schemes being key features of our incentive-based regulatory framework, where the NSP's performance will benefit consumers in the form of lower network costs in the future and superior service levels.

5.1.1 Electricity NSPs have returns lower than allowed returns

In 2025, on a weighted average basis, electricity NSPs' actual and allowed RoA increased by 0.4 p.p and 0.3 p.p respectively. For the second consecutive year, on a weighted average basis electricity NSPs generated returns marginally below their allowed rate of return.

Figure 5-1 Actual compared to allowed real RoA - electricity NSPs



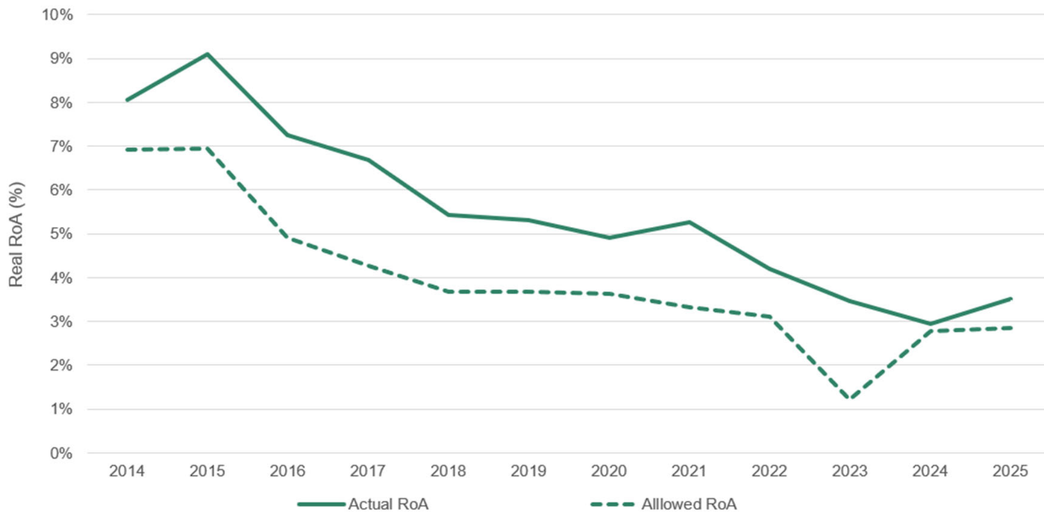
Source: Electricity/Gas financial performance model, allowed real rate of return - PTRM 'WACC' sheet. Note: Financial performance numbers are nominal. Calculation details are in the profitability model and RoA explanatory note published alongside this report. The weighted averages are weighted by the RAB/CAB of each NSP.

When compared to allowed returns, actual returns were lower due to the aggregate expenditure inefficiency (approximately 0.7 p.p.) of electricity NSPs (as detailed in section 3.2). This was offset by higher returns from incentive schemes rewards (0.4 p.p.).

5.1.2 Gas DNSPs' RoA increased in 2025

In 2025, gas DNSPs had an increase in their RoA returns (0.6 p.p.), which was the first increase in returns since 2021. On a weighted average basis, gas DNSPs had returns 0.7 p.p. above their allowed returns, which were largely unchanged on the previous year.

Figure 5-2 Actual compared to allowed real RoA - gas DNSPs



Source and Note: Refer to Figure 5-1.

The higher returns in 2025 were due to UAFG revenue adjustment to Jemena Gas Network's revenue (as discussed in section 4.2.1), which led to an aggregate 0.5 p.p. increase in returns and greater opex efficiency which increased returns by 0.2 p.p.

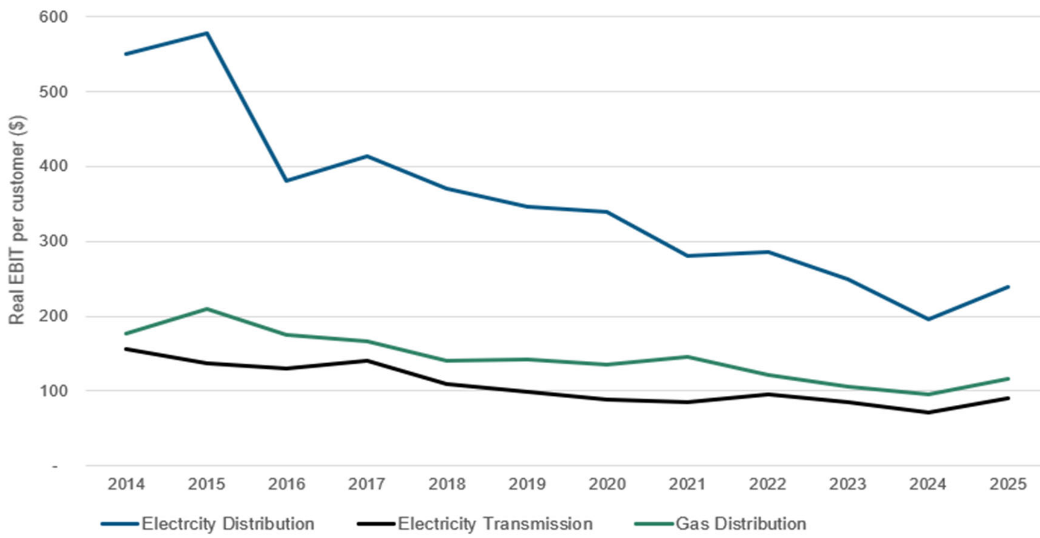
5.2 EBIT per customer increased in 2025

EBIT per customer is a measure of an NSP's operating profit divided by its customer base.[86] This measure complements the RoA by using the same measure of profit (EBIT) over a different cost driver. EBIT per customer is not a calculation of the EBIT per residential customer. It is an average of the entirety of an NSP's customer base, including businesses and large customers who contribute substantially more revenue per customer.

This follows the same trend as the RoA, with higher EBITs in 2025, leading to an increase in EBIT per customer across all sectors. The increases in 2025 are due to the same factors driving the higher RoA for electricity NSPs and gas DNSPs.

86 The customer base for electricity TNSPs is the sum of direct-connect customers and the distribution customers located in the same region as the electricity TNSPs.

Figure 5-3 Real EBIT per customer - electricity DNSPs and TNSPs and gas DNSPs



Source: Electricity and gas financial performance models. Note: Financial performance numbers are nominal. Calculation details are in the financial performance model and EBIT per customer explanatory note. The weighted averages are weighted by the customer base of the electricity NSPs and gas DNSPs.

The EBIT per customer for electricity TNSPs and gas DNSPs are materially lower than for electricity DNSPs. This is a consequence of the higher capital intensiveness of electricity distribution networks, resulting in electricity DNSPs having larger RABs per customer. However, it does not mean that electricity TNSPs or gas DNSPs are less profitable in relation to the same levels of investment.

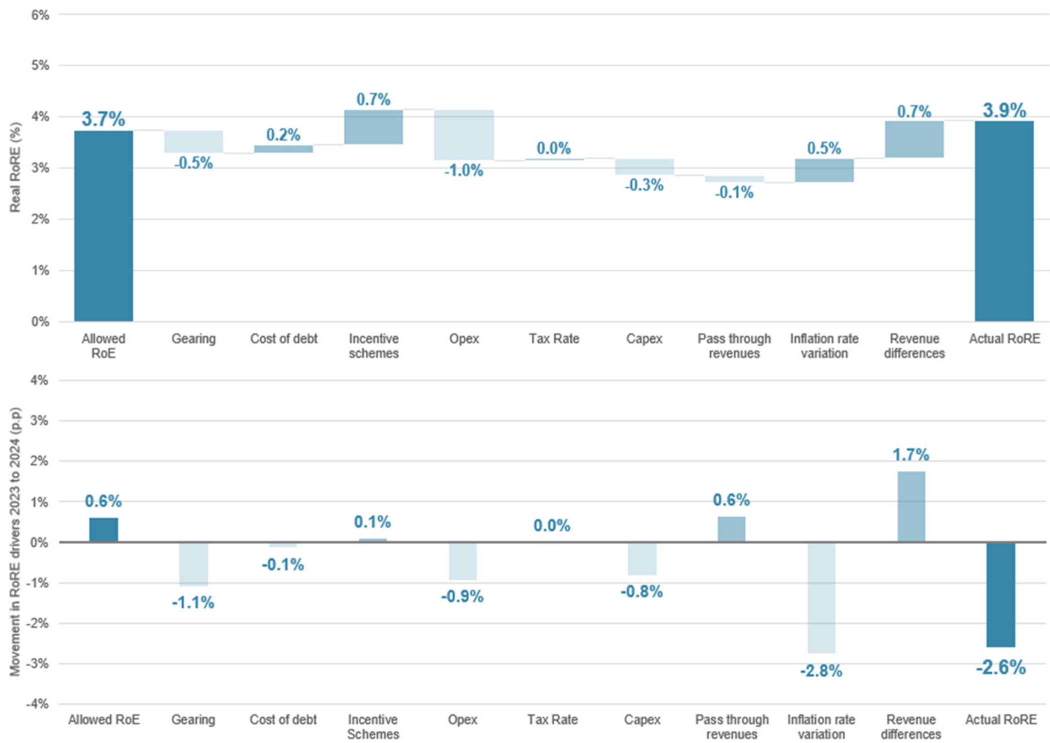
5.3 Networks’ RoRE decreased in 2025

The RoRE is the net profit after tax (NPAT) divided by the NSP’s regulated equity. As NPAT is the final or ultimate return to an NSP’s equity holders, it captures the returns arising from differences between an NSP’s actual tax expense and forecast tax allowance, and actual interest expense and forecast return on debt allowance.

The differences between actual and forecast tax and interest expense can be heavily impacted by the external environment. Changes to tax policy, as well as interest and inflation rates can result in NSP’s RoRE differing from their return on equity (RoE) allowance.

In 2025, on a combined weighted basis, electricity NSPs and gas DNSPs had aggregate returns which were equal to their allowed returns. This was due to higher returns from incentive schemes, inflation rate variation and revenue differences being offset by opex and capex inefficiency and gearing below the benchmark gearing ratio.

Figure 5-4 Contributions to real RoRE in 2025 and movement in RoRE drivers 2024 to 2025 – combined electricity NSPs and gas DNSPs



Source: Electricity and gas DNSP financial performance models (confidential versions). Note: Financial performance numbers are nominal. AER calculation of the differences in the RoRE is for indicative purposes and involves substituting actuals for each driver for the AER benchmark allowances. In this methodology, the contribution of each driver to the RoRE is impacted by the driver's sequence of substitution. We calculate the incremental change in returns with each new factor for each electricity NSP and gas DNSP and take a weighted average across all electricity NSPs and gas DNSPs.

When compared to the prior year, on a combined weighted basis, there was a 2.6 p.p. decrease in the actual RoRE, with lower returns from inflation rate variation (2.8 p.p.), gearing (1.1 p.p.), and lower opex (0.9 p.p.) and capex (0.8 p.p.) efficiency. This was offset by higher allowed returns (0.6 p.p.) and increases in returns from pass through revenues (0.6 p.p.) and revenue differences (1.7 p.p.).

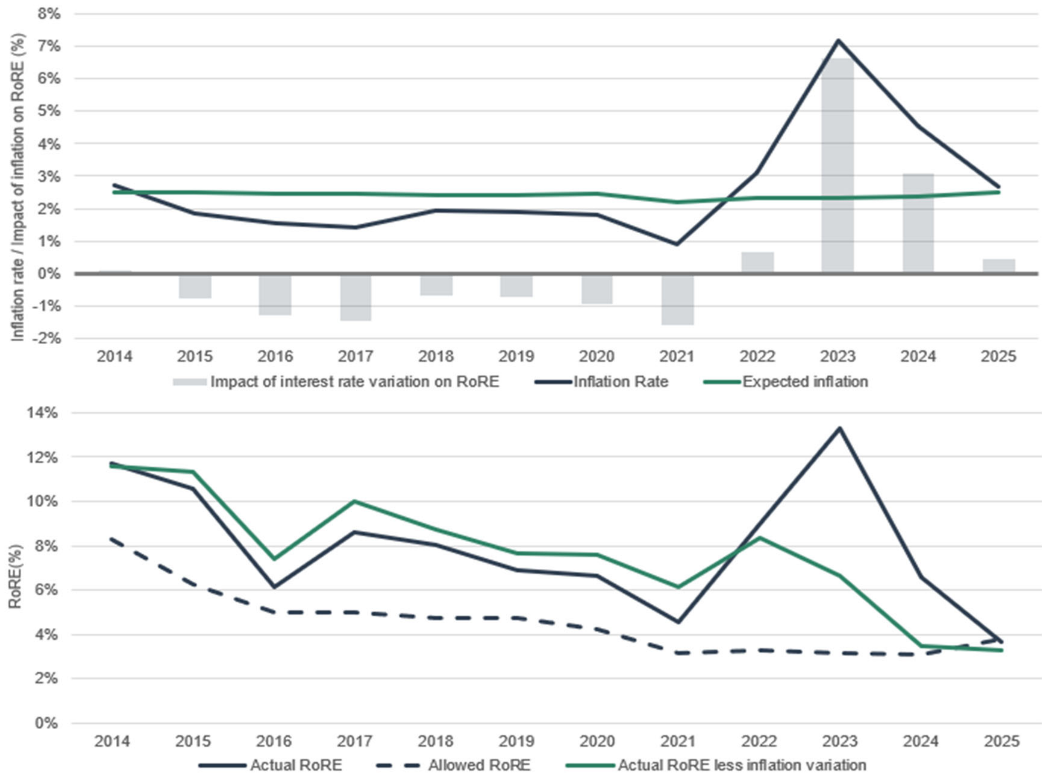
5.3.1 How does inflation impact RoRE

Our 2024 report provided extensive discussion in relation to the impact of inflation and how the calculation and interpretation of RoRE is bespoke to our regulatory framework.

The operation of the framework involves NSPs bearing the risk from actual inflation differing from expected inflation, as it is a more efficient allocation of risk. NSPs have greater resources or ability than consumers to mitigate against variations from expected inflation. As NSPs bear the risk from inflation, there will higher returns for NSPs when inflation is higher than expected, and lower returns when inflation is lower than expected.

There has been a recent shift from a very low to materially higher inflation rate environment, contributing to higher RoRE achieved by networks. Figure 5-5 illustrates how this shift affected the actual inflation rate applied to index electricity NSPs' RABs on average. It also shows how actual inflation as measured by the Consumer Price Index (CPI) diverged from regulatory forecasts and the effect this had on real RoRE since 2014.

Figure 5-5 Impact on real RoRE from inflation rate variation - electricity NSPs



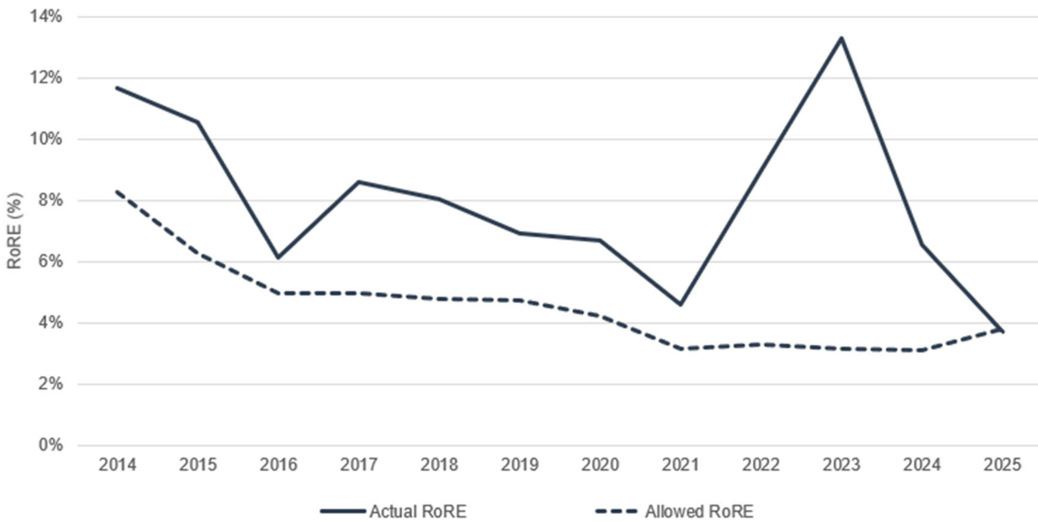
Source: Electricity financial performance model and expected inflation from Electricity NSPs regulatory determinations.

The high inflation rate environment from 2022 to 2024 has led to RoRE returns being significantly higher than allowed returns, which was most noticeable in 2023. As inflation has decreased in the 2025 regulatory year, the impact of the inflation rate variation have also decreased.

5.3.2 Electricity RoRE decreased in 2025

When compared to 2024, the weighted average electricity NSP RoRE decreased by 2.6 p.p., with the returns in 2025 being in line with allowed returns.

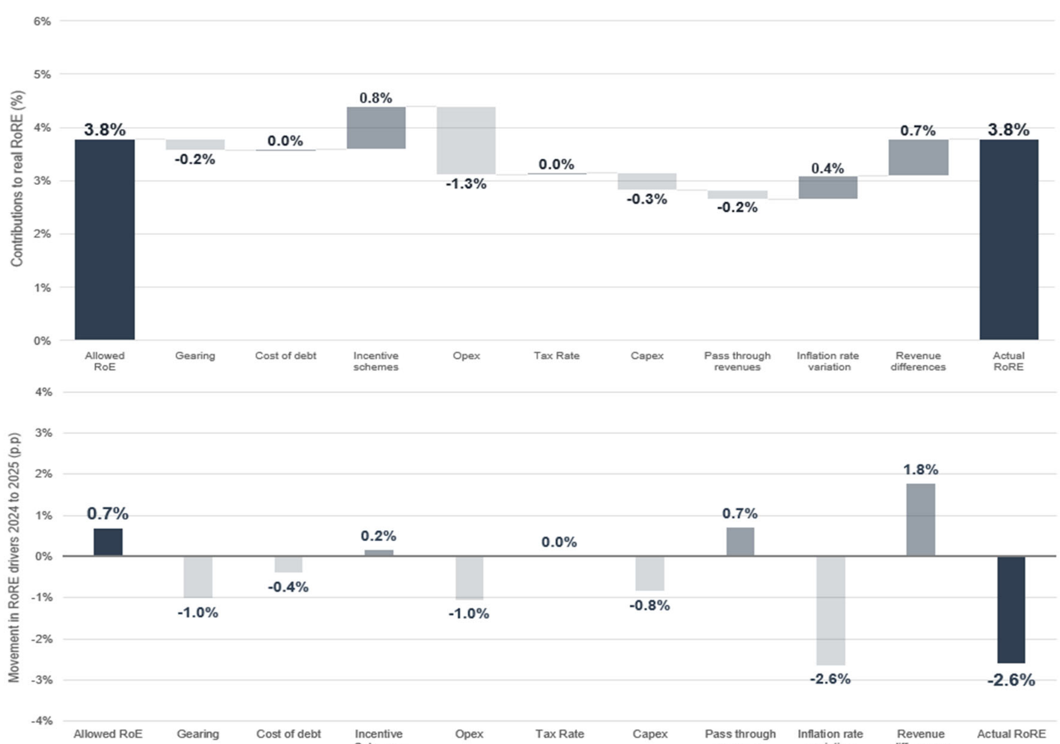
Figure 5-6 Actual compared to allowed real RoRE - electricity NSPs



Source: Electricity financial performance model. Note: Financial performance numbers are nominal. The weighted average RoRE is calculated by multiplying an NSP's real RoRE by the proportional size of the regulated equity of each NSP's sector.

In 2025, aggregate actual returns were marginally lower than allowed, as higher returns from incentive schemes (0.8 p.p.), revenue differences (0.7 p.p.) and inflation rate variation (0.4 p.p.) have been negated by lower returns from opex (1.3 p.p.) and capex (0.3 p.p.) efficiency.

Figure 5-7 Contributions to real RoRE in 2025 and movement in RoRE drivers 2024 to 2025 - electricity NSPs



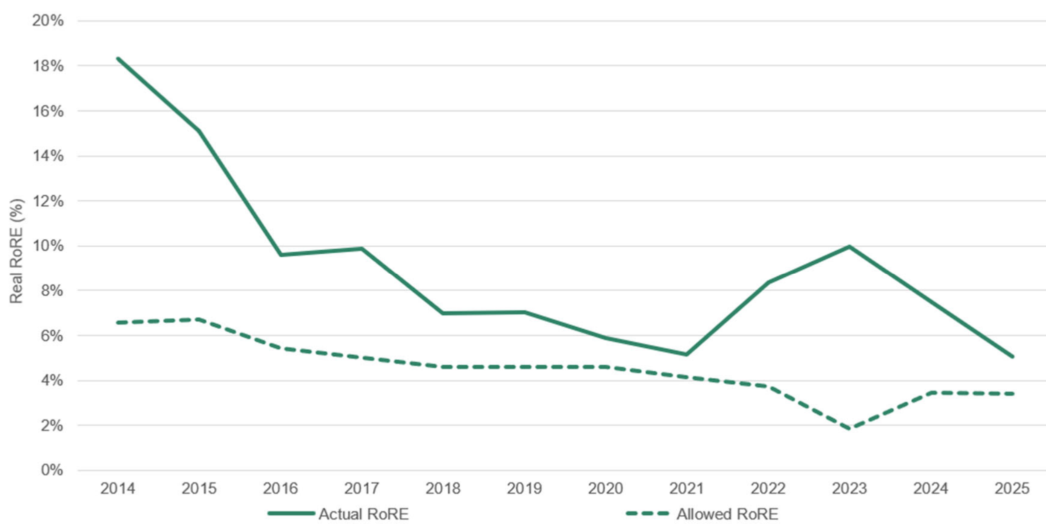
Source: Electricity financial performance models (confidential versions). Note: Refer to Figure 5-4.

The decrease from the 2024 regulatory year was due to lower returns from inflation rate variation (2.6 p.p.), lower returns from capital structures (1.0 p.p.) and cost of debt (0.4 p.p.) and lower opex (1.0 p.p.) and capex (0.8 p.p.) efficiency in the regulatory year. This was offset by higher allowed returns (0.7 p.p.), and higher returns from revenue differences (1.8 p.p.) and pass through revenues (0.7 p.p.).

5.3.3 Gas DNSPs' RoRE decreased in 2025 and narrow the gap

When compared to 2024, the weighted average gas DNSPs RoRE decreased by approximately 2.4 p.p., whilst the difference between actual and allowed returns decreased to 1.6 p.p..

Figure 5-8 Real RoRE versus allowed RoRE - gas DNSPs

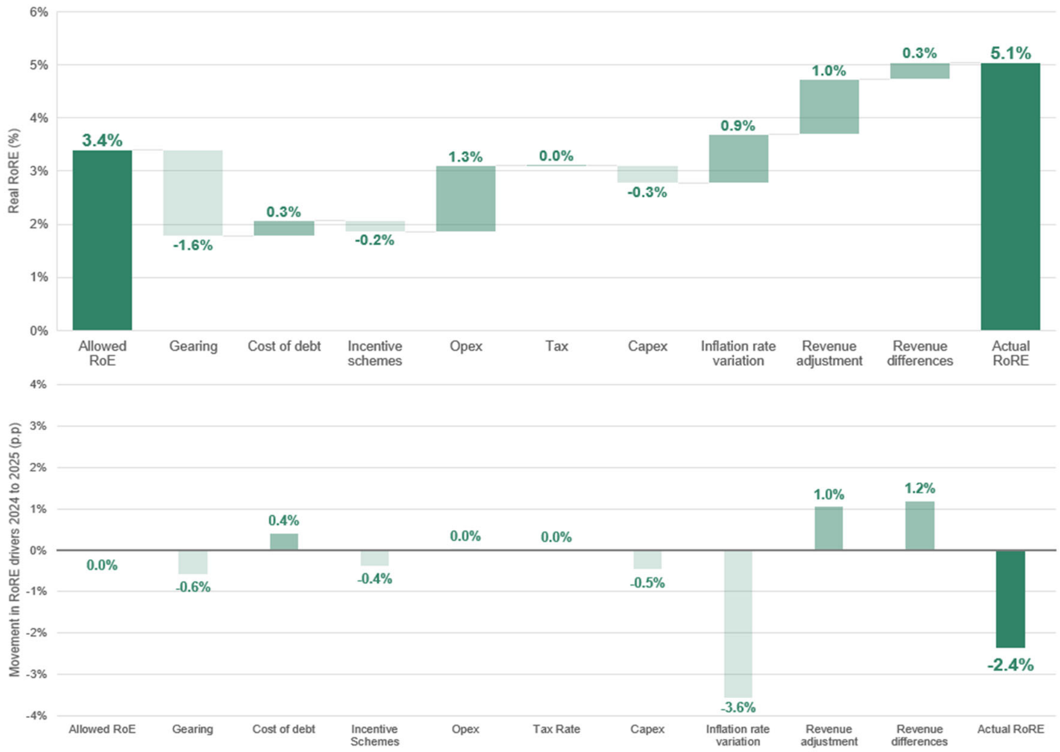


Source: Gas DNSP financial performance model. Note: Refer to Figure 5-6.

In 2025, RoRE returns higher than allowed were driven by higher returns from opex efficiency by gas DNSPs (1.3 p.p.), the Jemena Gas Networks UAFG revenue adjustment (1.0 p.p.) and inflation rate variation (0.9 p.p.). This has been offset by the lower gearing of gas DNSPs (1.6 p.p.) and capex inefficiency (0.3 p.p.).

The decrease in returns in 2025 is due to a significant decrease in the inflation rate variation (3.6 p.p.), as the inflation rate applied to returns decreased to 4.1% for Victorian DNSPs and 2.4% for Evoenergy, AGN South Australia and Jemena Gas Networks. This was primarily offset by higher returns from Jemena Gas Networks' UAFG revenue adjustment (1.0 p.p.) and revenue differences (1.2 p.p.).

Figure 5-9 Contributions to real RoRE in 2025 and movement in RoRE drivers 2024 to 2025 - gas DNSPs



Source: Gas DNSP financial performance model (confidential version). Note: Refer to notes for Figure 5-4.

6 Glossary

Term	Definition
Access arrangement	An arrangement setting out the terms and conditions of access to pipeline services
AEMO	Australian Energy Market Operator
Allowed revenue	The allowed revenue represents the total amount of money an NSP is permitted to collect from customers during a specific regulatory period
CER	Consumer energy resources
Curtailment	Any reduction on the capacity of an inverter to generate power. This could be caused by the inverter tripping in response to voltage disturbances or formally imposed through network static or dynamic export limits.
Connection agreement	An agreement between a DNSP and a customer by which the customer is connected to the distribution network and receives distribution services.
Core regulated services	Standard Control Services for electricity DNSPs and prescribed Transmission Services for electricity TNSPs. Haulage reference services and ancillary reference services for gas DNSPs, reference services and other services provided as a covered pipeline for gas TNSPs
Cost pass through	A cost pass through event refers to a situation that occurs beyond the reasonable control of a network business and has not been accounted for in its current 5-year revenue determination
CPI	Consumer Price Index
DER	Distributed energy resources
DMIAM	Demand management innovation allowance mechanism
ESC	Essential Services Commission of Victoria
Export	Electrical energy that flows from a customer's premises to a distribution network via the connection point
Export access against the agreed limit	The annual percentage of time that customers have the unconstrained ability to export to the distribution network up to the maximum export limit set in their connection agreement.
Export capacity	The maximum amount of electricity a customer's system can export to the distribution network in accordance with the connection agreement.
Gearing	The ratio of the value of debt to total capital (which includes both debt and equity)
Flexible export limit	The maximum level of export that a customer is allowed by a DNSP which can be varied based off network conditions.

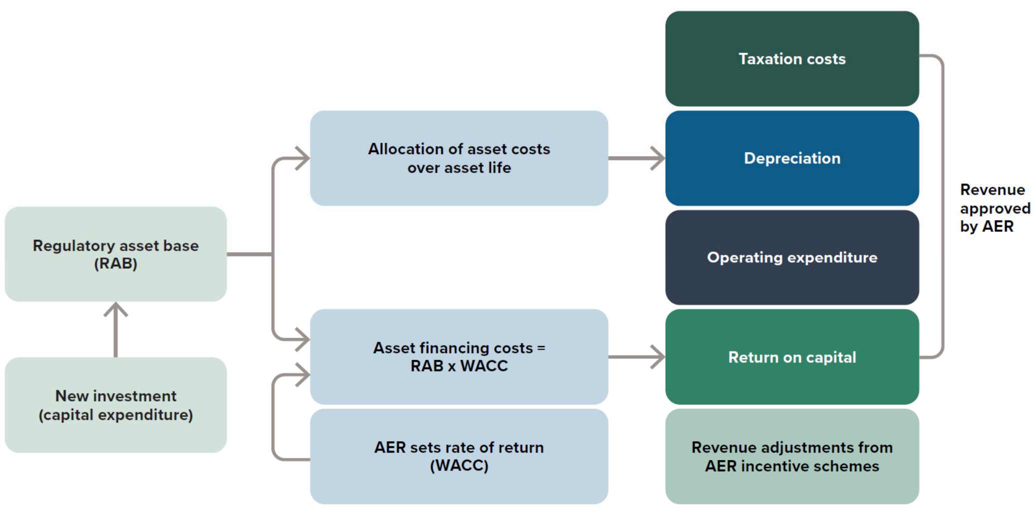
Term	Definition
Hosting capacity	The ability of a power system to accept energy generated by consumer energy resources without adversely impacting power quality such that the network continues to operate within defined operational limits
Indexation	Adjustment made to nominal values of an asset, revenue, or expenditure, so that the amounts reflect inflation rate changes
LFiT	Large-scale Feed-in Tariff
NEL/NER	National Electricity Law (NEL) and National Energy Rules (NER)
NEM	National Electricity Market
Network utilisation	Network utilisation measures the extent that network assets are used to meet customer demand
NGL/NGR	The National Gas Law (NGL) and the National Gas Rules (NGR)
Nominal terms	Values expressed in current monetary units, without accounting for changes due to inflation or other factors
PTRM	Post-Tax Revenue Model - used as part of the building block determinations for NSPs. It is used to calculate the allowed revenue for a given regulatory period.
Real terms	Values that have been adjusted for inflation
Regulatory determination	A determination of the maximum revenue an electricity NSP can recover from customers for the use of their electricity distribution or transmission networks during the regulatory period.
Reliability	The frequency and duration of interruptions to customer supply
RFM	Roll-Forward Model - establishes the method used to roll forward the capital base (increase or decrease from the previous value)
SIB capex	'Stay in business' capex
Static export limit	A fixed maximum level of export a customer is permitted by their DNSP.
Static-zero export limit	A static export limit of zero, preventing a customer from exporting any electricity to a distribution network.
Tariff variation model	The AER employs a tariff variation model to manage changes in reference tariffs for energy services. Gas DNSPs submit annual tariff variation notices to the AER for approval
WACC (or allowed returns)	Weighted Average Cost of Capital
X-factor	The X-factor is used with CPI to smooth the revenue an NSP will collect each regulatory year.

Appendix A: How are network revenues determined?

We set the MAR for electricity NSPs and price caps for gas NSPs at a level that allows NSPs to recover the costs of providing their core regulated services. These are referred to as 'building blocks.' The building blocks include:

- **return on capital** - a return on the RAB or CAB to compensate investors for the opportunity cost of funds invested in the NSP
- **return of capital (depreciation)** - which returns the initial investment in the RAB or CAB to investors over time
- **forecast operational expenditure** incurred providing network services
- the estimated cost of **corporate income tax**
- **revenue adjustments**, including revenue increments or decrements resulting from applying incentive schemes and other revenue adjustments

Figure A-0-1 The building block model to forecast revenue



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

For electricity and gas NSPs we update the target revenue each year to account for actual inflation, changes in the NSPs returns on debt, cost pass throughs and other factors.

Appendix B: Explanatory Note: RoA

This note explains our approach to reporting on the return on assets (RoA) for the NSPs we regulate. This note also explains factors to consider when interpreting RoA:

What is RoA?

RoA is a simple and commonly used ratio, indicating how profitable a company is relative to its total assets. RoA is suited to capital intensive businesses and allows us to compare NSPs' profits against their allowed rates of return. We calculate RoA using the following formula:

$$\text{ROA} = \frac{\text{EBIT}}{\text{Capital base}}$$

Where:

- EBIT is earnings before interest and tax
- Capital base is the value of the NSP's assets at the start of the regulatory year

How to interpret RoA

Our regulatory framework targets a real rate of return, compensating NSPs for actual inflation outcomes and preserving the purchasing power of NSPs and investors. To capture these two components of our framework, we report the:

- real rate of return, which excludes inflation and is compared against the real pre-tax rate of return
- nominal rate of return, which includes inflation and is compared against the nominal pre-tax rate of return

An NSP's RoA can be compared against:

- its allowed rate of return
- RoAs for other NSPs in the sector
- Australian and international regulated businesses where the RAB/CAB is valued on a similar basis to that of the NSP

It is difficult to compare an NSP's RoA directly to those of unregulated businesses. This is due to the unique characteristics of the RAB/CAB under the regulatory framework, and the resulting rules for regulatory accounting, which differ to statutory accounting requirements.

Factors contributing to differences between RoA and allowed rate of return

An NSP's returns can also temporarily deviate from its allowed rate of return each year due to the application of the regulatory framework.

Certain additional factors can affect how regulated revenues are recovered from customers in subsequent regulatory years and should be considered when interpreting the RoA. These additional factors are provided in Table B-1.

Table B-1 Factors contributing to differences between RoA and allowed rate of return

Factor	Sector	Details
NSW/ACT transitional decision and remittal	Electricity NSPs	Analysis for the NSW/ACT electricity DNSPs over the 2014-19 regulatory period should be interpreted with caution. Reported revenues for those years are not adjusted for: • the transitional decision in 2015, which set a higher revenue target than what was in the final regulatory determination. Revenues recovered in 2015 were therefore materially higher than in the final decision. This over recovery was returned to customers over the remainder of the regulatory period • our 2014-19 regulatory determinations, which NSPs appealed and were set aside. During the appeal period, we accepted undertakings by NSPs setting out how they would recover revenues for years 2017-2019. These undertakings resulted in NSPs collecting more revenue than what the final remittal decision provided. These NSPs are returning revenue over recovered from this process to customers in the 2019-24 regulatory period
Queensland solar bonus scheme	Electricity NSPs	During the 2010-15 regulatory period for Energex and Ergon Energy, we included forecast solar bonus scheme payments in the opex allowance. We included a pass-through mechanism for any difference to be applied two years later during the annual pricing process. Uptake of this scheme materially exceeded forecasts. This resulted in substantial under recoveries during regulatory years 2014 and 2015, which were recovered through higher revenue targets in 2016 and 2017. In the 2015-20 regulatory period, solar bonus scheme amounts were recovered through a different mechanism (a jurisdictional scheme obligation). This fed into network costs as part of the annual pricing process. Due to the changing treatment of this scheme, the switch in our model to remove pass through events does not 'zero out' the scheme's specific impacts as applied in the 2010-15 regulatory period. Returns in 2014 and 2015 therefore appear lower than they otherwise would and returns in 2016 and 2017 appear higher than they otherwise would.
LFiT (Large-scale Feed-in Tariff) jurisdictional scheme	Electricity NSPs	Evoenergy applied to the ACT Government to recover reasonable costs in relation to the LFiT jurisdictional scheme. As the applications occurs in the middle of the regulatory year, Evoenergy must use forecasts rather than actual expenditure. This can result in large over or under recoveries of jurisdictional revenue. Due to this, there has been substantial over and under recoveries of jurisdictional revenue in the period 2018 to 2024. As a result, when determining the RoA inclusive of jurisdictional schemes, the returns are higher and lower than they otherwise would.

Factor	Sector	Details
		Although no longer a jurisdictional scheme pursuant to the NER, the LFiT scheme continues to operate, with recovery outside of the AER's approved network prices in 2025 and 2026.
Jemena Gas Networks transitional decision and remittal process	Gas NSPs	Analysis for Jemena Gas Networks over the past (2014 to 2020) and current (2020 to 2026) access arrangement periods should be interpreted with caution. Reported revenues for those years have not been adjusted for the following factors: • the over-recovery of revenue for their 2014 to 2020 access arrangement whilst Jemena Gas Networks sought a review of the AER's determination under the limited merits review framework • the downwards adjustment of $169m following the remittal process. This reduces allowed revenues for the 2020 to 2026 access arrangement • the effect of multiple annual adjustments to account for movements in underlying price drivers being applied in 2020. This resulted in approximately a $26m increase to Jemena Gas Networks' target revenue that year, which is not captured in their PTRM forecast.
Victorian gas DNSPs transitional regulatory year	Gas NSPs	The 2023 regulatory year for the Victorian gas DNSPs was only six months. This was due to the Victorian Government deciding to move the state's DNSPs access arrangement periods from a calendar year basis to a financial year basis, which required a six-month extension to their 2018-22 access arrangements. The revenue set for the extension period for the Victorian gas DNSPs involved extending their tariff prices from 2022 with an adjustment for inflation. This decision to maintain the tariff prices in real terms resulted in expected revenues for the Victorian DNSPs which were materially above the approved building block model. This resulted in the Victorian gas DNSPs achieving returns higher than they otherwise would in 2023, with an expectation that the returns from their 2023-28 access arrangement would be lower than they otherwise would.
UAFG	Gas NSPs	Gas DNSPs in the ACT, NSW and South Australia are required to directly contract UAFG volumes. As a result, UAFG is included in their allowed opex, and therefore their revenue allowance in our access arrangement determinations. Victorian gas DNSPs operate under a slightly different framework. The ESC sets a benchmark rate of UAFG for each NSP, measured as UAFG divided by total gas delivered. Gas retailers are required to contract sufficient gas to cover customer consumption and the actual UAFG. If actual UAFG is greater than the benchmark, the NSP is required to compensate retailers for the UAFG exceeding the benchmark.

Factor	Sector	Details
		Where actual UAFG is lower than the benchmark, retailers make reconciliation payments to the NSP. Benchmark levels of UAFG for 2018 to 2028 can be found in the ESC's 2017 (for 2018 to 2022) and 2022 (for 2023 to 2028) UAFG benchmark reviews. Because UAFG is considered via the ESC's benchmark process, it is not considered in their access arrangement determinations, nor included in NSPs' opex forecasts.

How we calculate RoA

This section sets out our approach and data sources for calculating RoA. This approach aims for the best possible comparison of NSPs' actual returns against allowed returns on capital. We source data for calculating RoA from:

- the latest approved or proposed RFMs for the NSP
- the latest approved or proposed PTRMs for the NSP
- the NSP's annual data submissions, including through RINs

Revenue and expenditure

For electricity DNSPs and gas NSPs we source revenue and expenditure data from the income worksheet of the annual reporting RINs. For electricity TNSPs, we source that data from the disaggregated income statement of the annual regulatory accounts.

- data relating to electricity NSPs are standard control services for electricity DNSPs and prescribed transmission services for electricity TNSPs
- data relating to gas NSP's core regulated services are haulage reference services for gas DNSPs and reference services and other services provided as a covered pipeline for gas TNSPs

Revenue excludes the following:

- capital contributions: These are not included in the RAB and are not used in to calculate returns in the regulatory framework
- interest income: This is excluded as it is not part of the regulatory framework
- profit from the sale of fixed assets: Disposals (gross proceeds from an asset's sale) are removed from the RAB/CAB. The value of disposals in any given year is not used to calculate returns for that year and is therefore excluded from our annual calculations
- Disposals, however, affect returns on capital in future years by reducing net capex added to the RAB/CAB. We capture this effect by using the actual opening RAB/CAB as the basis for calculating returns

Expenditure excludes the following:

- finance charges: These largely comprise interest payments on debt and are therefore excluded from RoA, which is based on EBIT
- impairment losses: These are not permitted by the regulatory framework

- losses from the sale of fixed assets are excluded as the NSP is compensated through return of capital (depreciation)
- for gas NSPs, disposals affect returns on capital in future years by reducing the net capex added to the CAB. We capture this effect by using the actual opening CAB when calculating returns

Electricity DNSPs, Ausgrid and Evoenergy are owners of dual function assets. These assets operate in parallel with Transgrid's transmission network and essentially perform a transmission function by supporting the main NSW transmission network. Revenue and expenditure associated with dual function assets are treated as standard control services for the relevant DNSPs.

Depreciation

We have reported depreciation using nominal straight-line depreciation, which is measured on an as-incurred basis for all NSPs.

Depreciation is sourced from the final decision RFM where available. Where this is unavailable, we use the most recent regulatory proposal (for electricity NSPs), access arrangement proposal (for gas DNSPs) or draft decision RFM. Where those models are unavailable, we source depreciation from the PTRM, updated for the Consumer Price Index (CPI) to reflect inflation where available.

RAB (electricity)

To allow comparisons between actual and expected returns, we use the opening RAB in calculating RoA. We have reported the RAB on an as-incurred basis for electricity NSPs.

The opening RAB is sourced from the final decision RFM where available. Where this is unavailable, we use the most recent regulatory proposal or draft decision RFM. Where those models are unavailable, we calculate a partially as-incurred RAB roll-forward using as-incurred capex reported in the annual RIN. This allows us to consistently report the opening RAB on an as-incurred basis.

The PTRM calculates the opening RAB using expected inflation. We have updated the opening RAB using actual inflation where available. When calculating real RoA, we inflate the opening RAB by CPI. This is because an NSP's returns on capital are calculated using the nominal rate of return (nominal pre-tax return on debt and nominal post-tax return on equity). Inflating the RAB by CPI ensures an NSP's returns, and RAB are in the same dollar terms. When calculating nominal RoA, inflating the RAB is not required. RAB indexation is included as part of an NSP's returns, compensating the NSP for actual inflation.

CAB (gas)

To allow for comparison between actual and expected returns, we use the opening CAB in calculating RoA. We report the CAB on an as-incurred basis for both gas NSPs.

The opening CAB is sourced from the final decision RFM where available. Where a final decision RFM is unavailable, we use the most recent access arrangement proposal or draft decision RFM. Where those models are unavailable, we source opening CAB values from the annual RINs. For gas TNSPs, we calculate the CAB on as-incurred basis. This entails using the as-incurred capex reported by the gas TNSPs in their annual RINs.

When calculating real RoA, we must inflate the opening CAB by CPI. This is because an NSP's returns on capital are calculated using the nominal rate of return (nominal pre-tax return on debt and nominal post-tax return on equity). Inflating the CAB by CPI ensures that an NSP's returns, and the CAB are in the same dollar terms. When calculating nominal RoA, inflating the CAB is not required. CAB indexation is part of the returns an NSP receives, compensating the NSP for actual inflation.

Indexation of the opening RAB/CAB

Indexation of the RAB/CAB is sourced from the final decision RFM where available. Where this is unavailable, we use the most recent regulatory proposal (for electricity NSPs), access arrangement proposal (for gas DNSPs) or draft decision RFM. Where those models are not available, we calculate indexation using CPI figures sourced from the Australian Bureau of Statistics.

Incentive scheme revenues and payments

Our regulatory framework provides electricity and gas NSPs with revenues or payments through targeted incentive schemes aimed at improving network efficiency and reliability for electricity networks and to improve efficiency of gas DNSP's network expenditure.

These schemes allow the businesses to earn revenue (payments) above (below) their allowed rate of return. Customers should ultimately benefit from these schemes through lower regulated prices and improved reliability. We have calculated RoA both with and without incentive scheme outcomes to show the impact of incentives on actual returns.

- for electricity NSPs, the revenues and payments from incentive schemes have been sourced from the revenue sheet of the EB RIN (table 3.1.3), with impacts of the CESS identified in the PTRM
- for gas NSPs, the revenues and payments from incentive schemes have been sourced from the revenue sheet of the annual RINs (table F3.6)

Annual updates

We will update RoA annually, using appropriate RFM data where available.

Appendix C: Explanatory Note: EBIT per customer

This note explains our approach to reporting on earnings before interest and tax (EBIT) per customer for the electricity NSPs and the gas DNSPs. It also explains what factors to consider when interpreting these ratios. We do not report EBIT per customer for gas TNSPs.

What is EBIT per customer

EBIT per customer is a simple ratio of an electricity NSP or a gas NSP's reported EBIT over the total reported number of customers connected to its network in a year. EBIT per customer differs from other profitability measures that rely on asset or equity values and provides an alternative perspective on the drivers of operational profit margins.

$$\text{EBIT per customer} = \frac{\text{EBIT}}{\text{Customer numbers}}$$

Where:

- EBIT is earnings before interest and tax in a year
- customer numbers - These are sourced for electricity and gas as per the approach specified at the end of this note.

How to interpret EBIT per customer

EBIT per customer is best compared against the individual electricity NSP or gas DNSP's past performance. This comparison will track changes in the measure through time to identify drivers of variation in returns, such as variations in the RAB or CAB or allowed returns.

EBIT per customer is not a measure of profit per residential customer, as electricity NSPs also provide energy and gas DNSPs gas to commercial and industrial customers. All these customer types contribute to the revenue collected, and to the costs of providing network services. Due to this, the electricity NSP and gas DNSP's individual customer profiles can materially affect the average profits it earns per customer.

Comparisons between NSPs

Differences in EBIT per customer among electricity NSPs and among gas DNSPs are largely explained by the size of their capital bases and customer numbers. Other factors that can influence EBIT per customer should be considered when interpreting this metric, which includes Customer profiles and those provided in Table B-1 of the RoA explanatory note.

Customer profiles

'Customer profile' refers to the composition of customers, including the type and size of customers it services.

- an electricity NSP’s customer profile may be influenced by the geographical area it services as this can determine network size, topology, and customer density. We collect data on customers across the classifications of residential, small commercial and large scale commercial and industrial
- a gas DNSP’s customer profile may also be influenced by the geographical area it services or whether industrial customers use the gas distribution network to transport gas. We collect data on customers across the classifications of residential, commercial, and industrial

For both electricity NSPs and gas DNSPs, different classes of customers share the costs of providing network services. This makes it difficult to isolate the costs required to serve a particular customer or group of customers. It is therefore difficult to estimate EBIT per customer for the different customer classes. For example, when compared to residential customers, commercial or large-scale industrial users make up a small proportion of overall customer numbers but contribute a relatively high proportion to revenue given their higher energy consumption.

Holding other things constant, we would expect EBIT per customer for commercial and industrial users to be higher than EBIT per customer for residential customers.

How we calculate EBIT per customer

This section sets out our approach and data sources for calculating EBIT per customer. We source data for calculating EBIT per customer from:

- the latest approved or proposed RFMs
- the latest approved or proposed PTRMs
- the annual data submissions, including through annual RINs reported to the AER

Information on the revenue and expenditure, depreciation, incentive scheme revenues and payments to calculate EBIT is provided in the RoA explanatory note.

Customer Numbers

We source customer numbers from different datasets, according to their sector:

- electricity DNSPs: The STPIS reliability sheet of the annual RIN (Table 6.2.4)
- electricity TNSPs: Adding customer numbers from the electricity DNSPs connected to the electricity transmission network in the same jurisdiction; and customers connected directly to the transmission network (direct connections points). We source this data from the operational data worksheet of the EB RIN (Table 3.4.2)
- gas DNSPs: Are sourced from the customer number sheets (by type and tariff) of the annual RINs (Tables S1.1 and S1.2)

Annual updates

We will update EBIT per customer annually, using appropriate RFM data where available.

Appendix D: Explanatory Note: RoRE

This note explains our approach to reporting the return on regulated equity (RoRE) for the NSPs we regulate. It also explains factors to consider when interpreting RoRE.

What is RoRE?

RoRE is a measure of regulatory profitability. It is suited to capital intensive businesses and allows us to compare an NSP’s profits against its allowed rate of return. We calculate RoRE using the following formula:

$$\text{RoRE} = \frac{\text{Regulatory NPAT}}{\text{Regulated equity}}$$

Where:

- regulatory NPAT is regulatory net profit after tax
- regulated equity is the implied value of equity in the RAB for electricity NSPs, and CAB for gas NSPs

How to interpret RoRE

Our regulatory framework targets a real rate of return. NSPs are also compensated for actual inflation outcomes, preserving the purchasing power of NSPs and investors. To capture these components of our framework, we report the:

- real RoE, which excludes inflation of the equity base and is compared against the real post-tax return on equity
- nominal RoE, which includes inflation of the equity base and is compared against the nominal post-tax return on equity

An NSP’s RoRE can be compared against its relevant allowed return on equity, the RoE of other NSPs in the sector and Australian and international regulated businesses where the RAB/CAB is valued on a similar basis to that of the NSP

It is difficult to compare an NSP’s RoRE directly to those of unregulated businesses. This is due to the unique characteristics of the RAB/CAB under the regulatory framework, and the resulting rules for regulatory accounting, which differ to statutory accounting requirements.

Common EBIT

Calculating RoRE begins with calculating earnings before interest and tax (EBIT). EBIT is also used to calculate RoA and EBIT per customer. All notes on interpreting the RoA and EBIT per customer are therefore also relevant to this measure.

Confidentiality

Unlike the RoA or EBIT per customer, we do not publish all RoRE calculations. Specifically, we do not publish interest and tax expense calculations used in moving from EBIT to regulatory NPAT. While the interest expense incurred in providing core regulated services may not be commercially sensitive, this information could be used to 'back-out' equivalent commercially sensitive information relating to unregulated business units.

To make the information and its outcomes as transparent as possible, we have published a full version of our RoRE model using illustrative data, allowing stakeholders to understand the calculation steps.

Factors causing differences between real and forecast RoE

Factors affecting RoA and EBIT per customer also affect the RoRE. RoRE is also affected by differences between forecast and actual financing structure, forecast and actual interest rates and forecast and actual taxation. These are discussed in Table B-1 and provided in more detail below.

Differences in financing structure

To finance investments in the RAB/CAB, NSPs raise capital through a mix of equity and debt. We forecast the rate of return using a benchmark proportion of capital raised through debt—also known as the gearing level. In practice, NSPs can depart from the benchmark. Holding other things constant, raising a higher proportion of capital through debt:

- increases interest expense, decreasing the RoRE
- reduces the equity base over which profits are distributed, increasing the RoRE

The net impact of these two effects depends on whether the NSP raises debt at interest rates above or below our forecast return on debt. In general, we find that raising more capital through debt (higher gearing) results in a higher RoRE. In effect, NSPs are taking on more risk to achieve higher returns on equity as they bear the risks, costs, and benefits of departing from the benchmark gearing level.

Differences in interest paid on debt

Our rate of return instrument includes a methodology for calculating interest rates at which a benchmark efficient NSP would raise debt—that is, the allowed return on debt. In practice, NSPs may raise debt at rates above or below our benchmark.

We calculate an effective portfolio interest rate using the interest expense and interest-bearing liabilities allocated to NSPs in providing core regulated services. These calculations are more reliable where debt is clearly allocated to specific NSPs. Some company groups that raise debt at the group level must apply an allocation method to estimate debt attributable to specific NSPs. Estimated data is inherently less reliable than observed data.

Differences in forecast and actual debt costs can have various drivers, including but not limited to NSPs:

- being perceived as having higher or lower default risk than our methodology implies
- raising debt at longer or shorter terms than our benchmark 10-year assumption

- raising debt in tranches departing from the assumed structure of debt raising under our trailing average portfolio return on debt
- accessing lower interest rates due to raising debt as part of a larger diversified ownership group
- raising debt over windows differing from our specified averaging periods over which forecast rates of return are calculated

Where NSPs raise debt at rates lower than their allowed return on debt, this contributes to a higher RoRE. If NSPs raise debt at rates higher than their allowed return on debt, it contributes to a lower RoRE.

Differences in tax expense

Under our post-tax framework, allowed revenue forecasts include an amount for expected tax payments. In practice, NSPs may pay a different amount of tax to this allowance.

Because we calculate actual tax paid at the NSP level within our model, tax expense varies in response to other changes in revenue or expenses. We also adopt different tax rates based on the reported company structure for tax purposes. Differences in this tax structure can contribute to differences between forecast and actual tax expense. We describe these in greater detail in the next section.

How we calculate RoRE

This section sets out our approach and data sources for calculating RoRE. This approach aims to facilitate the best possible comparison between RoRE and allowed returns on equity.

Data for calculating an NSP's RoRE comes from the following sources:

- the latest approved or proposed RFMs for the NSP
- the latest approved or proposed PTRMs for the NSP
- annual RIN submissions the NSP reported to the AER
- the NSP's response to an AER information request, which are to be included in a future Regulatory Information Order

Illustrative model

Alongside this note, we publish a version of our full model using illustrative data. We encourage stakeholders to explore this model for greater detail on the calculation steps involved in moving from EBIT to regulatory NPAT and the relationships between variables.

Overall methodology

Calculating the RoRE begins with EBIT as calculated for the RoA and EBIT per customer measure. We then:

- deduct interest expense arising from providing core regulated services—allocated by NSPs as part of their responses to our tax and interest information request
- deduct tax expense—calculated within the model as described below

- add returns arising from distributing imputation credits—using the benchmark value of imputation credits multiplied by tax expense

This gives us what we refer to as regulatory NPAT. To calculate RoRE we then divide regulatory NPAT by the equity base.

We calculate the equity base as the value of the opening RAB/CAB each year less the value of interest-bearing liabilities (debt) the NSP allocates as arising from providing core regulated services.

We also make a series of other adjustments depending on whether we are calculating a real or nominal RoRE. These are described in our profitability measures review and are set out in our illustrative model.

Interest expense

We regulate NSPs as individual networks. In practice, most NSPs are part of larger ownership groups. Commonly, debt is raised, and interest is accounted for at the ownership group level.

Estimating RoRE for an NSP requires an estimate of its interest expense in providing core regulated services at the network level. NSPs have allocated interest expense and the value of interest-bearing liabilities (i.e., how much debt gives rise to that interest expense) in providing core regulated services. In doing so, NSPs have used a top-down approach—that is, debt used in financing the RAB/CAB.

NSPs have used several approaches to do this, which they have specified in their responses to our information request. In the first year of our reporting, we engaged accounting firm PwC to assist us reviewing the first tranche of responses. A summary of their review is available on our website.

Tax expense

Like interest expense, tax expense is typically incurred at the ownership group level. However, unlike interest expense, the tax structure an NSP is held under affects its tax expense. This includes:

- entities taxed as companies. All gas NSPs currently fall under this category.
- National tax equivalency regime (NTER) entities
- government owned non-NTER entities
- flow-through entities

Flow-through ownership structures do not pay tax at the level of the NSP. Rather, the tax obligation passes through the partnership or trust to the ultimate tax paying entity, who pays tax at their applicable statutory tax rate. As identified in our tax review, this is the relevant level of tax for consideration as 'actuals'.

To undertake a top-down approach to tax, we would need the individual tax expenses across all owners of an NSP and individual allocations of the expense for each owner. As such, we consider tax expense is better suited to a bottom-up approach. This requires EBIT to be adjusted only for relevant differences for tax purposes, and to multiply this by an applicable tax rate. Our analysis has used the following tax rates in the relevant proportions:

- entities taxed as companies—30%
- NTER entities—30%
- government-owned non-NTER entities—30%
- flow-through entities—19.5%

We requested where available a weighted average of individual investors' tax rates. Where not available, we have applied an indicative rate of 19.5%. All NSPs have advised they were unable to develop a more detailed weighted average rate.

To calculate tax expense, we start with EBIT and then:

- deduct interest expense
- add back nominal straight-line depreciation
- deduct depreciation of the tax asset base, sourced from our RFM where available
- adjust for permanent differences due to disallowed interest expense and adjustments to prior returns
- add total taxable revenue and/or income from customer contributions and gifted assets

This provides an estimate of pre-tax income, which we then multiply by the tax rate described above. We then adjust for any tax-losses carried forward, which reduce the tax allowance. This gives our estimate of raw NPAT.

Imputation credits

The building block revenue framework recognises that imputation credits are a value stream available to equity holders alongside dividends and capital gains. We adjust the estimated cost of tax allowance for the value of imputation credits, which reduces the allowed revenue. By making an adjustment to the tax allowance, we avoid double counting the value of the imputation credits and forecast returns to equity/allowed returns to equity.

We make this adjustment by adding returns from imputation credits to our estimate of raw NPAT. We calculate these returns as the benchmark value of imputation credits (i.e., gamma) multiplied by tax expense after any utilisation of tax losses.

Calculating real versus nominal RoRE

Our model allows users to calculate either real or nominal RoRE. To calculate nominal RoRE, we add indexation of the RAB/CAB to our calculation of EBIT. Nominal RoRE should be compared against the equivalent post-tax nominal return on equity.

To calculate real RoRE, we remove indexation on the equity component of the RAB/CAB from our estimate of NPAT. We then inflate the equity base of the RAB to be in common real dollar terms with our estimate of NPAT. In our model, the real RoRE flows on from the real RoA, where we have already deducted indexation of both equity and debt. As a result, to work out the real RoRE, we must add back to our estimate of NPAT the indexation on the debt component of the RAB/CAB, which we have previously deducted.