Final Decision

SA Power Networks Electricity Distribution Determination 2025 to 2030

(1 July 2025 to 30 June 2030)

Overview

April 2025

AUSTRALIAN ENERGY REGULATOR

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Version	Date	Pages
1	30 April 2025	43

List of attachments

This Overview forms part of the Australian Energy Regulator's (AER's) final decision on the distribution determination that will apply to SA Power Networks for the 2025–30 period. It should be read with all other parts of the final decision.

As a number of issues were settled at the draft decision stage or required only minor updates, we have not prepared all attachments. Where an attachment has not been prepared, our draft decision reasons form part of this final decision. The final decision attachments have been numbered consistently with the equivalent attachments to our draft decision.

The final decision includes the following attachments:

Overview

Attachment 1 – Annual revenue requirement

Attachment 2 – Regulatory asset base

Attachment 4 – Regulatory depreciation

Attachment 5 – Capital expenditure

Attachment 7 – Corporate income tax

Attachment 10 – Service target performance incentive scheme

Attachment 13 – Classification of services

Attachment 14 – Control mechanisms

Attachment 16 – Alternative control services

Attachment 18 – Connection policy

Attachment 20 – Metering services

Executive summary

The Australian Energy Regulator (AER) is responsible for the economic regulation of electricity distribution and transmission systems in all states and territories except Western Australia.

We exist to ensure energy consumers are better off, now and in the future. Consumers are at the heart of our work, and we focus on ensuring a secure, reliable, and affordable energy future for Australia as we transition to net zero emissions.

A regulated network business must periodically apply to us to determine the maximum allowed revenue it can recover from consumers for using its network. On 31 January 2024, we received revenue proposals from SA Power Networks, Ergon Energy, Energex and Directlink for the period 1 July 2025 to 30 June 2030 (2025–30 period).

This final decision relates to SA Power Networks. Each constituent component of our distribution determination is set out in section 6. The final decision will be implemented from 1 July 2025 and reflected in 2025–26 prices.

The regulatory framework guides our decisions in the long term interests of consumers

The National Electricity Law (NEL) and National Electricity Rules (NER) provide the regulatory framework under which we determine the revenue requirement for distribution and transmission businesses.

The NEL requires that we exercise our economic regulatory functions in a manner that promotes efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers. We make these decisions having regard to price, quality, safety, reliability and security of electricity supply, and targets to reduce emissions. This is referred to as the National Electricity Objective or the NEO.[1] We have also issued guidance about an interim value of emissions reduction,[2] which we must comply with in considering or applying the NEO.[3]

The central component of SA Power Networks' proposal is the revenue that it recovers from consumers over the 2025–30 period. We have assessed this by considering the constituent components of SA Power Networks' proposal, including capital expenditure (capex), operating expenditure (opex) and the tariff structure statement to ensure it complies with the NER.

We have substituted alternative forecasts where we assess SA Power Networks' proposal does not meet certain criteria in the NER. In other instances, we have substituted alternative forecasts to update for input assumptions such as for inflation. We have made our final decision such that we achieve the NEO, in the long term interests of consumers.

Our final decision provides SA Power Networks with an allowed revenue in which it can recover from consumers over 2025–30. SA Power Networks must decide how best to use

1 The full statement of the NEO is at Section 7 of the NEL.

2 AER, *Valuing emissions reduction, Final guidance and explanatory statement*, May 2024.

3 NEL, schedule 2, clause 42.

this revenue in providing distribution services that fulfill its obligations. Our regulatory framework includes incentive mechanisms that are designed to encourage SA Power Networks to operate efficiently and prudently in the long term interests of consumers.

We are focused on efficient investment to deliver a safe and reliable network that meets consumer needs

Our final decisions for the 2025–30 resets have been made against the backdrop of rising network expenditure. Our performance report shows that actual capex for electricity networks across the NEM increased by 19.7% in real terms in 2023. We have also observed increases in forecast capex and opex in recent revenue proposals.

The increase in proposed expenditure has been driven by a range of factors that affect the reliable and secure supply of electricity. This includes the steady ageing of assets, increases in the cost of inputs, managing changes in electricity demand and new sources of demand such as for electric vehicles, and the integration of consumer energy resources. We have also seen a higher incidence of extreme weather events and an increase in the risk of cyber-related activity. Network costs are also increasing due to economy-wide factors of a higher interest rate and a higher inflationary environment. Compared with when we made our determination for SA Power Networks 5 years ago, the cost of capital has increased from 4.75% to 6.12% and inflation has increased from 2.27% to 2.72%. These are key inputs in this regulatory determination.

In assessing proposals by network businesses, we continue to seek the balance of affordability, with efficient and prudent investment required to support the energy transition, and to address important emerging issues such as network cybersecurity, climate resilience and integration of CER.

We also expect electricity network businesses to submit proposals that clearly demonstrate how they plan to meet the challenges of a higher cost environment over the regulatory period in a way that achieves an affordable, stable, secure and reliable supply of energy in the long term interest of consumers. We want to see network businesses utilising the revenue determination process to propose tariff design, incentive structures and efficient and prudent expenditure that achieves the NEO.

- We want to see a continued commitment by networks toward cost-reflective tariff reform aimed at reducing the amount of network investment required to provide sufficient network capacity and stability during peak demand and export periods. We consider SA Power Networks to be at the forefront of designing cost-reflective tariffs that also consider customer impacts.
- Incentive mechanisms are a key component of our incentive-based regulatory framework. They create an impetus to drive efficient and prudent capex and opex and a desirable level of customer service. Where the business is proposing adjustments to the incentive mechanisms that impacts the balance of risk sharing between businesses and consumers, these proposed changes should be canvassed with consumers.
- We expect to see business cases that reflect the capex and opex criteria and are well supported by analysis and stakeholder engagement.[4] As any new network infrastructure will be paid by consumers, it is important that businesses effectively utilise their existing

[4] AER, *Expenditure Forecast Assessment Guideline*, October 2024.

infrastructure for distribution services, looking for non-network solutions and avoiding any unnecessary future infrastructure investment. We have accepted most of SA Power Networks forecast expenditure. This is due to the networks' strong consumer engagement, governance and forecasting methods as well as in-depth business cases.

Consumer needs should be a key focus of the DNSPs' regulatory proposals. Network businesses should engage collaboratively with consumers on key aspects of the proposal that will affect consumers, including capex and opex. To assist, we introduced the Better Resets Handbook in 2021 (the Handbook), to further guide businesses to engage and design proposals that meet consumer needs through the energy transition.[5]

SA Power Networks' engagement following the draft decision was effective in gathering feedback for the revised proposal. SA Power Networks engagement with consumers to refine the innovation fund was a standout achievement in its post-draft decision engagement process. We also commended the commitment to ongoing engagement with its Community Advisory Forum.

We note that SA Power Networks did not fully address the issue of affordability in its revised proposal that was raised by a number of stakeholders, including our Consumer Challenge Panel, sub panel 30 (CCP30), SA Council of Social services (SACOSS) and the SA Department of Energy and Mining. SA Power Networks' Consumer Advisory Forum also reiterated its position on affordability in its remarks in the revised proposal.[6]

Early signal pathway

SA Power Networks was the third business to be selected to participate in the early signal pathway (ESP). Under the ESP, AER staff had regular pre-lodgement discussions with SA Power Networks and observed parts of the engagement with consumers.

A procedural benefit of the ESP is that businesses that meet our expectations across capex and opex, depreciation and tariff structures would receive an early signal of acceptance of substantial parts of their proposal at the issues paper stage. We were unable to provide this signal for SA Power Networks' proposed expenditure forecasts because of the significant proposed uplift in capex (up 22%) and opex (up 18.9%).

Despite this, SA Power Networks' good consumer engagement, comprehensive proposals for their planned capex and opex and tariff structures, and willingness to engage with AER staff has resulted in a final decision that accepts substantial parts of the initial and revised proposal. Nevertheless, there are areas – particularly for augmentation expenditure (augex), where we do not accept the forecast and have substituted an alternative forecast in our final decision.

Our final decision on SA Power Networks' revised proposal

Our final decision is that SA Power Networks can recover $5,207.0 million ($ nominal, smoothed) in main standard control services (SCS) revenue from consumers over the 2025–30 period. This is $38.9 million (0.8%) higher than SA Power Networks' revised proposal, and $63.5 million (1.2%) more than our draft decision.

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5 AER, *Better Resets Handbook – towards consumer-centric network proposals*, December 2021.

6 SA Power Networks, *2025-30 Revised Regulatory Proposal Overview*, December 2025, page 7

The increase in overall revenue in this final decision compared to SA Power Networks' revised proposal is mainly driven by updates in data related to external economic factors, such as a lower expected inflation rate, which increases the value of regulatory depreciation and higher rate of return increasing the return on capital.

SA Power Networks' allowed revenue (smoothed) is $1,298.8 million (or 33.2%) more than SA Power Networks' allowed revenue in the 2020–25 period in nominal terms. We estimate that approximately 46% of the increase from the 2020–25 period is driven by higher inflation and interest rates. The other 54% of the increase is driven by higher capital and operating expenditure.

For illustrative purposes, we estimate that the total revenue from this final decision would result in an average increase of $9 per annum to the typical electricity bill for SA Power Networks' residential customers over the 2025–30 period. For small business customers, the impact would be an increase on average of $22 per annum.

Demand forecasts

Demand for electricity plays a crucial role in forecasting efficient levels of network expenditure. It is important for network businesses to use the most up to date forecasts for electricity demand when making expenditure decisions.

The use of the correct forecast is also important when presenting consumer bill impacts because SA Power Networks is subject to a revenue cap control mechanism. Consumer prices are adjusted each year for deviations in demand. If actual demand falls short of the demand forecasts, this means that customers could experience higher distribution network tariffs.

Capital expenditure

Our final decision does not accept SA Power Networks revised proposal and substitutes an alternative capex forecast of $2,257.2 million, which is $80.5 million or 3.4% lower than the revised proposal. This includes a:

- $36.7 million reduction in demand-driven augex due to the use of more up to date demand forecasts published in AEMO's 2024 Electricity Statement of Opportunities. It is important that capex spending decisions are based on the latest forecasts available to ensure customers are not paying more than necessary.
- $32.6 million reduction in the maintain reliability program, taking into account: network performance, which has steadily improved over time (excluding in the CBD); and other programs such as repex, vegetation management, bushfire mitigation, CBD reliability and worst served customer programs, which will contribute to maintaining network performance.

In our draft decision our alternative capex estimate did not include expenditure for the innovation fund subject to SA Power Networks providing further justification for its programs. We consider SA Power Networks' proposal for the innovation fund is robust, having firmed up a list of nine costed projects subject to a well-defined governance framework and driven by consumer engagement.

Operating expenditure

Our final decision accepts SA Power Networks' revised proposal to increase the opex forecast by a further 2.6% or $52.5 million to $2,036.2 million for main standard control services. The increase is due to higher than estimated expenditure for long-term cost drivers such as vegetation management and emergency response. We consider the revised expenditure reasonably reflects the opex criteria[7] and is prudent and efficient.

The final decision for opex reflects a total increase in opex of 19.1% over the next regulatory period and is primarily driven by step changes. We have accepted step changes that seek to improve resilience against cyber threats and improve ICT systems for an increasingly dynamic future – including integration of consumer energy resources (CER). Other step changes reflect a shift in ICT costs from capex to opex due to greater use of cloud and SaaS solutions and cyber security uplift and greater network visibility, reflecting various legislative requirements and guidance.

While we have accepted SA Power Networks' revised opex proposal, we note that the recent increases in opex over recent years has continued a significant downward trend in its productivity performance. South Australia, in which SA Power Networks is the sole distributor, has consistently been the best performing jurisdiction under our opex partial factor productivity measure since we began economic benchmarking. However, in our most recent annual benchmarking report it dropped to third behind New South Wales and Victoria.[8]

Tariff structure statement

SA Power Networks accepted our draft decision for tariffs to offer a time-of-use tariff for retailers that have customers with high demand but low consumption (i.e. electric vehicle charge point operators). We commend SA Power Networks' development of a high-quality tariff structure statement that progresses network tariff reform and responds to changes taking place in the electricity sector. We consider SA Power Networks to be at the forefront of designing cost-reflective tariffs that consider customer impacts.

Service classification

Our final decision is to not accept SA Power Networks' proposal to provide electric vehicle charging infrastructure (EVCI) of last resort services as an alternative control service. We do not consider that SA Power Networks has established the case for this approach. We are open to the idea of SA Power Networks providing EVCI of last resort services in the future, where there is a genuine need to assist the transition to electric vehicles and the energy transition more broadly. However, we consider that seeking a waiver from relevant requirements of the NER would be the more appropriate mechanism at this stage, and that SA Power Networks would need to provide additional information to enable us to make an informed decision in the long term interest of consumers.

In this Overview and the accompanying detailed attachments, we have set out the assessment approaches applied, and enquiries made as part of our review, which have enabled us to arrive at this final decision.

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7 The opex criteria are set out in cl. 6.5.6(c) of the NER.

8 Quantonomics, *Economic Benchmarking Results for the Australian Energy Regulator's 2024 DNSP Annual Benchmarking Report*, 15 October 2024, pp. 45–46.

Contents

1 Our final decision

Our final decision allows SA Power Networks to recover a total revenue of $5,252.6 million ($ nominal, smoothed) from its consumers from 1 July 2025 to 30 June 2030 which comprises: $5,207.0 million in main standard control services (SCS) revenue; and $45.6 million in metering revenue.[9]

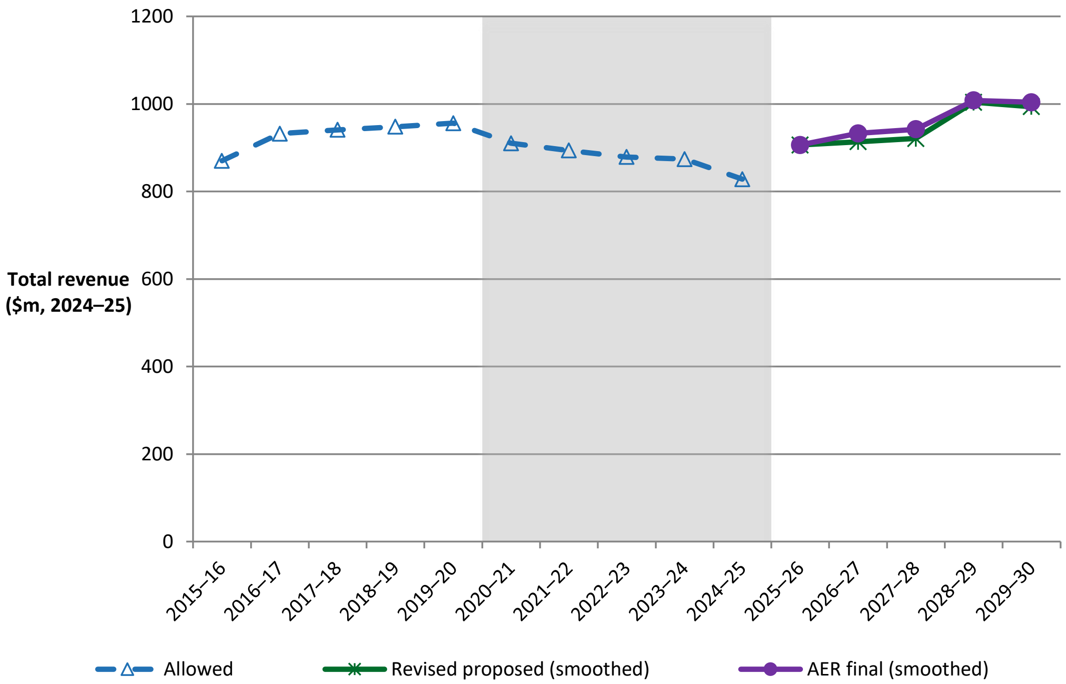
Our final decision revenue is $1,298.8 million more than SA Power Networks' allowed revenue in the 2020–25 period in nominal terms. In the sections below we briefly outline what is driving SA Power Networks' revenue, and the key differences between our final decision revenue compared to the $5,143.5 million in our draft decision, and the $5,168.1 million in SA Power Networks' revised proposal.[10]

1.1 What is driving revenue?

Revenue is driven by changes in real costs and inflation. In this section we use 'real' values that have been adjusted for the impact of inflation to compare revenue from one period to the next on a like-for-like basis.

In real terms, this final decision would allow SA Power Networks to recover $4,793.5 million ($2024–25, smoothed) over the 2025–30 period. This is 9.3% higher than our decision for the current (2020–25) period. SA Power Networks' revenue over time is shown in Figure 1.

Figure 1 Changes in regulated revenue over time ($ million, 2024–25)



Source: AER analysis.

[9] This is $0.4 million less than the $46.0 million that SA Power Networks included in its revised proposal.

[10] This overview separates main SCS revenue from metering SCS revenue (see Attachment 20) for ease of comparison with previous regulatory periods. Moreover, most metering costs are temporary.

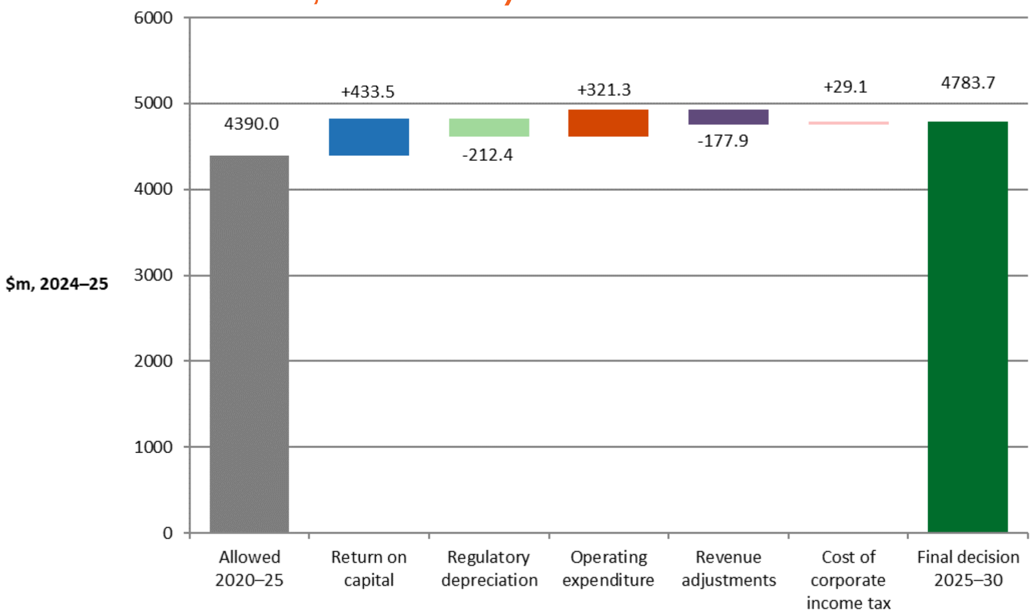
Figure 2 highlights the key drivers of the change between the revenue approved for SA Power Networks for the 2020–25 period and in this final decision for the 2025–30 period. It shows that our final decision provides for increases in revenue for:

- return on capital, which is $433.5 million (36.5%) higher than the 2020–25 period, driven by:
  - a higher rate of return being applied in the 2025–30 period in accordance with the 2022 *Rate of Return Instrument*
  - higher forecast capex over the 2025–30 period compared to the 2020–25 period.
- opex, which is $321.3 million (18.7%) higher than the forecast we approved for the 2020–25 period, primarily driven by higher actual base year opex and step changes.
- cost of corporate income tax, which is $29.1 million (231.5%) higher than the 2020–25 period, primarily due to higher customer contributions and higher return on equity determined in this final decision compared to 2020–25 period

Figure 2 also shows that our final decision provides for reductions in the building blocks for:

- return of capital (regulatory depreciation), which is $212.4 million (15.4%) lower than the 2020–25 period, driven primarily by:
  - a reduction to straight line depreciation as some assets become fully depreciated during the 2025–30 period
  - a higher indexation of the regulatory asset base (RAB), mainly driven by a higher expected inflation value in the 2025–30 period.
- revenue adjustments, which are $177.9 million (189.1%) lower than the 2020–25 period, mainly due to negative Efficiency Benefit Sharing Scheme (EBSS) outcomes applied in this final decision.

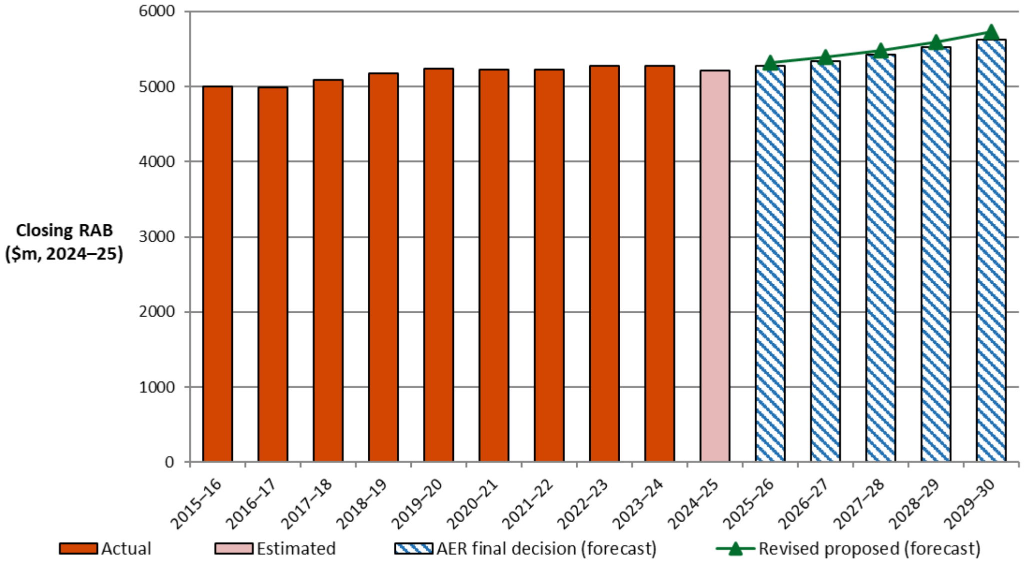
Figure 2 Changes in total revenue between 2020–25 and 2025–30 ($ million, 2024–25, unsmoothed)



Source: AER analysis.
Note: This comparison is based on converting nominal forecast amounts to real dollar terms using lagged consumer price index (CPI).

Figure 3 shows the value of SA Power Networks' RAB over time. After a RAB reduction of 0.4% in real terms over the 2020–25 period, our final decision results in a forecast increase of the RAB by $417.7 million ($2024–25) or 8.0% over the 2025–30 period. This increase is mainly driven by higher forecast capex.

Figure 3 SA Power Networks' RAB value over time ($ million, 2024–25)

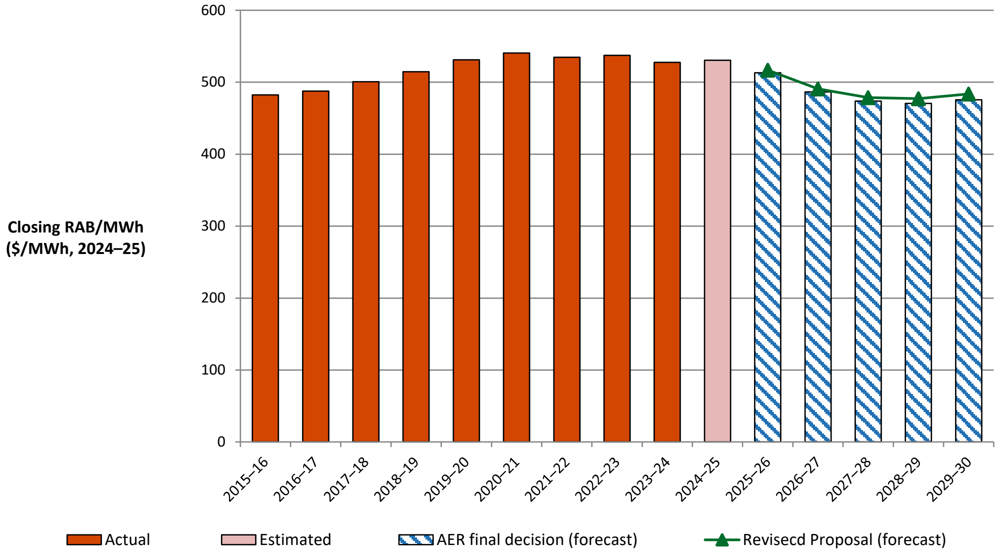


Source: AER analysis.

SA Power Networks' RAB per MWh is forecast to decline slightly over 2025–30 compared to the final year of the 2020–25 period. This is based on SA Power Networks' forecast energy delivered (MWh) and could change depending on actual network utilisation.

Figure 4 shows that for SA Power Networks, the RAB per energy consumption measure in real terms has declined since around 2022–23. This reflects consumption growth combined with a decline in the inflation adjusted real RAB ($2024–25). We consider efficient investment in, and efficient operation and use of, electricity services are important to minimise the required capital expenditure and the RAB.

Figure 4 SA Power Networks' RAB per energy consumption over time ($/MWh, 2024–25



Source: AER analysis.

1.2 Key differences between our final decision and SA Power Networks' revised proposal

Our final decision accepts some elements of SA Power Networks' revised proposal including its forecast opex for main standard control services. SA Power Networks' adopted our draft decision opex but made mechanical updates to reflect the latest available inputs. For the 2025–30 period, the main area of difference between our final decision and SA Power Networks' revised proposal relates to our lower capex forecast, primarily driven by reductions in augmentation capital expenditure.

We also made updates in our final decision to reflect movements in some market variables, such as expected inflation and rate of return, which have increased revenue outcomes for certain building blocks.

Overall, our final decision includes:

- a higher regulatory depreciation, driven by a lower expected inflation which leads to a lower indexation of the RAB.
- a higher return on capital, driven by a higher rate of return.

Our final decision also includes a higher estimated cost of corporate income tax amount, since our reduced forecast capex in turn reduces the amount of tax depreciation.

Overall, the reduced forecast capex in our final decision, has partially offset the increases from updated market parameters. Our final decision determines a total unsmoothed revenue that is $38.2 million (0.7%) ($ nominal) higher than SA Power Networks' revised proposal.

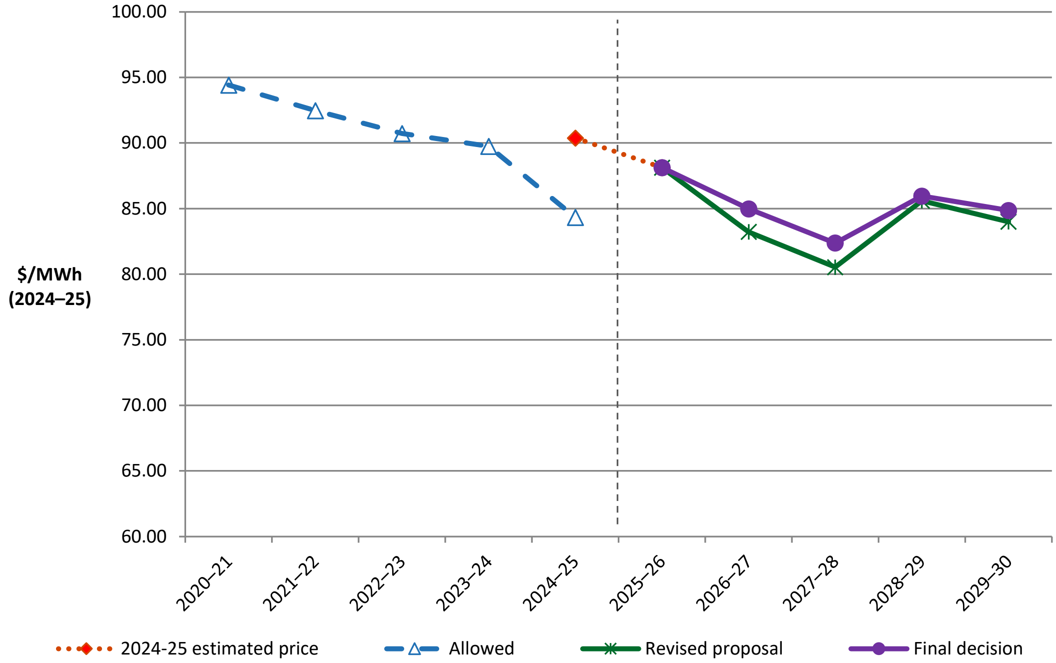
1.3 Expected impact of our final decision on electricity bills

SA Power Networks recovers its regulated revenue through distribution charges, set annually by reference to the tariff structure statement and pricing formulae approved by us as part of this decision.

For illustrative purposes only, we estimate the impact of this final decision would be a total reduction to SA Power Networks' distribution charges of around 6.1% in real terms by 2029–30 compared to 2024–25 levels, or an average reduction of 1.3% per annum.[11] This estimate will be subject to ongoing revenue adjustments and changes in consumer energy consumption. Figure 5 compares this indicative price path for the 2025–30 period to the 2020–25 period.

[11] The average reduction to indicative distribution charges of 1.3% ($2024–25) per annum reflects two components: 1) The final decision smoothed revenue average increase of 2.5% per annum ($2024–25); and 2) The forecast energy delivered in SA Power Networks' distribution network area which is expected to increase on average by 3.8% per annum.

Figure 5 Change in indicative charges for 2020–25 to 2025–30 ($2024–25, $/MWh)



Source: AER analysis.

1.3.1 Potential bill impact

Our decision on SA Power Networks' revised proposal sets the revenue allowance that forms the major component of its network charges for the next 5 years.

SA Power Networks' distribution charges make up around 27% of its residential and small business customers' electricity bills. Other components of the electricity supply chain also contribute to the prices ultimately paid by consumers. These are the cost of purchasing energy from the wholesale market, core transmission network charges, environmental scheme costs and the costs and margins applied by electricity retailers.[12] These components of the bill sit outside the decision we are making here and will also continue to change throughout the period.

For illustrative purposes only, we estimate the impact of our final decision on the average annual electricity bill for a typical customer in SA Power Networks' network area, as it is today ($ nominal), would be:

- an increase of $45 (2.0%) by 2029–30, or an average of $9 per annum for a residential customer
- an increase of $108 (2.0%) by 2029–30, or an average of $22 per annum for a small business customer. [13]

We have received stakeholder submissions on our draft decision and SA Power Networks' revised proposal stating a higher average consumption is appropriate to reflect different

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12 AEMC, *Data Portal*, *Trends in South Australia supply chain components 2023/24*.

13 Our estimated bill impact is based on the typical annual electricity usage of 4,000 kWh and 10,000 kWh for residential and small business customers in SA Power Networks' network area, respectively. This is based on the 2024–25 final decision default market offer.

residential customer profiles. This includes customers without access to solar PV and can therefore only use electricity from the grid, and customers experiencing hardship. We acknowledge these concerns and have provided additional alternative bill impacts in Attachment 1. These are based on different consumption assumptions to help customers with a different level of usage understand the potential impact of our final decision on their electricity bills. For example, based on a higher residential customer annual electricity usage of 7,684 kWh[14] and a higher annual bill of $3,751 in 2024–25, we expect that our final decision will increase the distribution component of the electricity bill in 2029–30 by about $72 ($nominal) or 1.9% from the 2024–25 total bill level.

The impact of our final decision on consumer bills is likely to change over the 2025–30 period. A variance in energy consumption, compared to those forecast by SA Power Networks, would lead to bill impacts that are higher or lower than what is estimated.

Over the 2025–30 period there are several additional mechanisms under the NER that may operate to increase or decrease those charges. These may include cost pass through events defined in the NER. The triggers we have set out for these events in this decision will, if met, allow SA Power Networks to apply for additional revenue for these projects throughout the period, at which point proposed costs will be subject to further consultation and assessment. Our final decision to apply the Service Target Performance Incentive Scheme (STPIS) over the 2025–30 period (section 3.3) will also impact these charges.

1.4 SA Power Networks' consumer engagement

Consumer engagement during the regulatory process is an important way to provide us with supporting evidence that proposals have been aligned with consumer interests and expectations. We introduced guidance on our expectations for consumer engagement to network businesses in the Better Resets Handbook (the Handbook) in December 2021.

It is the responsibility of network businesses to ensure that consumer views are considered and represented in their regulatory proposal. Often consensus is not possible, in which case the views of the differing groups and how the network sought to make its decision should be reflected in its proposal. Our role is to consider the consumer engagement process and the stakeholder submissions when making our decisions.

1.4.1 SA Power Networks' engagement

Our draft decision provided a snapshot of SA Power Networks engagement program and found that the network had largely met the expectations in the Handbook, noting the collaborative approach that SA Power Network's took to engaging with its consumers.[15]

We reiterated our concerns about SA Power Networks approach to the framing of the focused discussions, which guided consumer preferences toward higher service levels despite reliability across the network being within required targets. We also encouraged

14 SACOSS, *Submission to the Australian Energy Regulator on SA Power Networks' 2025-30 Revised Regulatory Proposal*, January 2025, pp. 13–16. This reflects median grid consumption for hardship customers based on the 2022–23 grid usage data from: ACCC, *Inquiry into the National Electricity Market Report, Appendix E*, June 2024.

15 AER, *Draft Decision - Overview - SA Power Networks - 2025-30 Distribution revenue proposal*, September 2024, p. 8.

SA Power Networks to further consider the feedback by stakeholders regarding affordability and service level provision and the innovation fund in their revised proposal.[16]

We are of the view that SA Power Networks' stakeholder engagement following the draft decision was effective in gathering feedback for the revised proposal. SA Power Networks held targeted engagement with its consumer groups to address issues we raised in the draft decision. This included the innovation fund, elements of capex including repex, augex and CBD reliability, tariffs, CSIS and public lighting.[17] SA Power Networks also held inform sessions to provide an overview of AER's draft decision, their proposed response, and the expected revenue and bill impacts of their revised proposal.

Other areas of the revised proposal that would have benefited from engagement with consumers include SA Power Networks' proposal to provide regulated electric vehicle infrastructure of last resort services and the proposal to increase the upfront payment charge threshold for a connection in its connection policy.

SA Power Networks' collaborative approach to refine the innovation fund with consumers was a standout in its post-draft decision engagement process. However, we note that SA Power Networks did not fully address the issue of affordability in its revised proposal that was raised by a number of stakeholders. We would have welcomed further consideration of the issues raised by stakeholders in the revised proposal to lower bills for consumers.

We commend SA Power Networks commitment to ongoing engagement with its community advisory forum and to be subject to scrutiny by consumers on the outcomes over the next regulatory period.

1.4.2 What we've heard from stakeholders on our draft decision and SA Power Networks' revised proposal

We called for submissions on our draft decision and SA Power Networks' revised proposal. We received 5 submissions. The key themes that emerged from these submissions focused on affordability, with some stakeholders concerned that the revised capex was excessive.

The AER consumer challenge panel, sub panel 30 (CCP30) acknowledged SA Power Networks' strong engagement but raised concerns about there being underlying tensions in the revised proposal that remain unresolved. This includes limited consumer influence on key aspects of the proposal, the lack of action on affordability issues voiced by some consumers, an emphasis on reliability despite it being within required targets, and a need to provide better context about how the proposal addresses overall network utilisation, productivity and a history of underspend relative to allowed expenditure.

SA Power Networks' Community Advisory Forum (CAF) noted that consensus among its members was not possible on the revised proposal due to the volume of information and the diversity of CAF members. Nevertheless, the CAF highlighted that:

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16 AER, *Draft Decision - Overview - SA Power Networks - 2025-30 Distribution revenue proposal*, September 2024, p. 6.

17 SAPN, *2025-30 Revised Regulatory Proposal Overview*, December 2024, p. 18.

> *SA Power Networks has been very much aware of the CAF's concerns about balancing service levels, an ageing network with the pricing and affordability of an essential service to SA.*[18]

The CAF also encouraged the AER to refine its Better Resets Handbook to better manage expectations for consumers. The CAF also recommended that the AER better articulate the impacts that the determination has on SA consumer bills by moving beyond average consumer bill impact analysis. Refer to Attachment 1 for further information on how we have addressed this feedback.

The South Australian Department for Energy and Mining (SA DEM) raised concerns about SA Power Networks' proposed capex and opex increases for 2025–30 and urged the AER to rigorously interrogate these increases to ensure they reflected prudent and efficient expenditure. [19]

The SA DEM questioned whether our draft decision applied enough scrutiny to the capex assessment. The South Australian Council of Social Services (SACOSS) and SA DEM urged a stricter review of innovation funding and repex growth to prevent unnecessary costs and future bill increases.

SACOSS acknowledged SA Power Networks' efforts but noted that the revised proposal did not sufficiently address affordability concerns.[20] SACOSS also called for updated demand forecasts and more transparency in consumer engagement.

The SA DEM also raised concerns regarding our revenue smoothing approach in the draft decision. It submitted the step increase in 2028–29 distribution revenue in our draft decision would mean the bill reductions that consumers expect at the conclusion of the solar feed-in-tariff scheme would not be visible. This is addressed in section 2 and Attachment 1.[21]

Retailers such Red Energy & Lumo Energy and Origin Energy acknowledged that cost-reflective tariff structures play a key role in the energy transition by promoting efficient use of network infrastructure, enabling consumers to reduce bills by shifting consumption from peak periods, and encouraging investment in distributed resources and efficient use of those assets. Red Energy & Lumo Energy advocated for default Time-of-Use (TOU) tariff while maintaining demand tariffs as opt-in for residential customers due to complexity.[22]

Our consideration of stakeholder feedback on these range of issues and others raised in the submission are reflected in the relevant final decision attachments.

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18 CCP30, *Submission on SAPN's revised proposal and draft decision 2025-30*, January 2025, p. 26.

19 South Australian Department for Energy and Mining, *Submission on SAPN's revised proposal and draft decision 2025-30*, February 2025, p. 1.

20 SACOSS, *Submission on SAPN's revised proposal and draft decision 2025-30*, January 2025, p. 39.

21 AER, *Final Decision Attachment 1 - Annual revenue requirement - SA Power Networks - 2025-30 Distribution revenue proposal*, April 2025.

22 Red Energy and Lumo Energy, *Submission on SAPN and Energex's revised proposals and draft decisions 2025-30*, January 2025, p. 1; Origin Energy, *Submission on SAPN, Ergon Energy and Energex's revised proposals and draft decisions 2025-30*, January 2025, p. 1.

2 Key components of our final decision on revenue

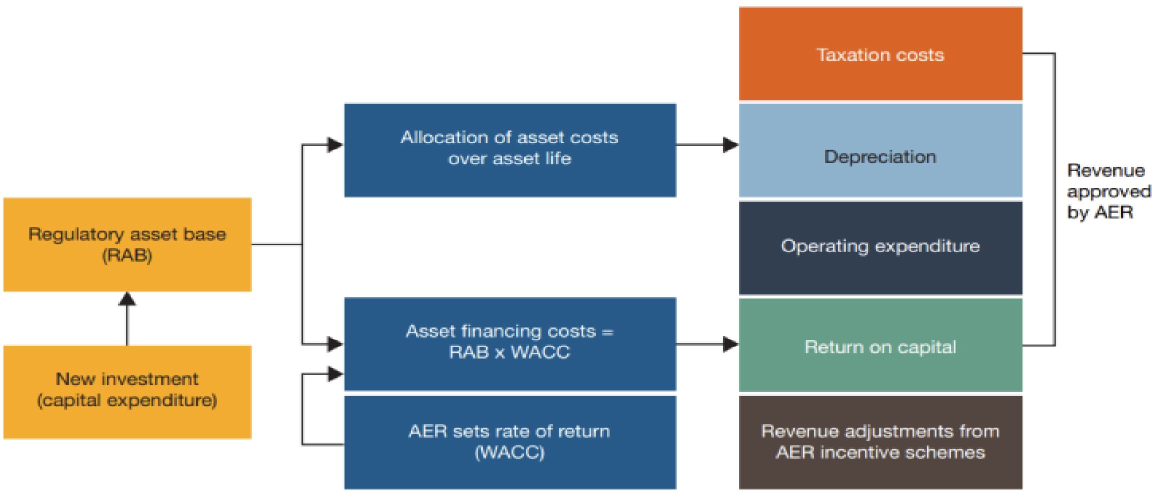
Building block approach

The foundation of our regulatory approach is a benchmark incentive framework to setting maximum revenues: once regulated revenues are set for a 5-year period, a network that keeps its actual costs below the regulatory forecast of costs retains part of the benefit. This provides an incentive for service providers to become more efficient over time. It delivers benefits to consumers as efficient costs are revealed and drive lower cost benchmarks in subsequent regulatory periods. By only allowing efficient costs in our approved revenues, we promote delivery of the NEO and ensure consumers pay no more than necessary for the safe and reliable delivery of electricity.

SA Power Networks' proposed revenue reflects its forecast of the efficient cost of providing distribution network services over the 2025–30 period. Its revenue proposal, and our assessment of it under the NEL and NER, are based on a 'building block' approach which looks at five cost components (see Figure 6):

- return on the RAB – or return on capital, to compensate investors for the opportunity cost of funds invested in this business
- depreciation of the RAB – or return of capital, to return the initial investment cost to investors over time
- forecast opex – the operating, maintenance and other non-capital expenses, incurred in the provision of network services
- revenue increments/decrements – resulting from the application of incentive schemes, such as the Efficiency Benefit Sharing Scheme (EBSS) and Capital Expenditure Sharing Scheme (CESS)
- estimated cost of corporate income tax.

Figure 6 The building block model to forecast network revenue



Source: AER.

Revenue smoothing

Our final decision incudes a determination of SA Power Networks' annual revenue requirement (ARR) (unsmoothed revenue) and annual expected revenue (smoothed revenue) across the 2025–30 period. The smoothed revenues we set in this final decision are the amounts that SA Power Networks will target for its annual pricing purposes and recover from its customers for the provision of standard control services for each year of the 2025–30 period.[23]

The ARR is the sum of the various building block costs for each year of the regulatory control period, which can be lumpy over the period. To minimise price shocks, revenues are smoothed within a regulatory control period while maintaining the principle of cost recovery under the building block approach. As such, revenue smoothing requires diverting some of the cost recovery to adjacent years within the regulatory control period.

SA Power Networks' unsmoothed revenue for the first year of the 2025–30 period (2025–26) is about 11.3% (nominal) higher than its approved revenue for the last year of the 2020–25 period (2024–25). We are mindful that the magnitude of this increase in revenue would have a significant impact on network charges for SA Power Networks' customers.

Consequently, we have smoothed the increase in expected revenues over the first 3 years of the 2025–30 period for SA Power Networks. As part of this, and consistent with our draft decision, we have:

- adopted SA Power Networks' proposed adjustment of the revenue smoothing profile to account for the impact of the cessation of the South Australian Government's Solar Feed-in Tariff Scheme from 1 July 2028
- relaxed our standard approach to the final year difference between the smoothed and unsmoothed revenues being kept to ±3%, to further help ease the price increases for customers in the earlier years of the 2025–30 period. In the present circumstances, we have determined that the final year revenue difference is about 5%.

For distribution revenue, our final decision results in nominal increases of 4.9%, 5.7% and 3.7% to the smoothed revenues in the first 3 years of the 2025–30 period (2025–26 to 2027–28), followed by a larger increase of 9.9% in 2028–29, then a smaller increase of 2.3% in 2029–30. The larger increase in 2028–29 will be offset by the impact of the expiry of the Solar Feed-in Tariff Scheme.

The SA DEM submitted the step increase in 2028–29 distribution revenue in our draft decision would mean the bill reductions that consumers expect at the conclusion of the solar feed-in-tariff scheme would not be visible.[24]

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[23] Our final decision expected revenues have not factored in any changes arising from incentive scheme amounts, cost pass throughs or unders/overs reconciliation that usually occur in the annual pricing process to come up with the total allowed revenue.

[24] Government of South Australia, Department for Energy and Mining, *Submission to SAPN revised proposal*, 12 February 2025, p.2.

While we note SA DEM's concern, our final decision smooths the reduction across the regulatory period to result in a price path that is overall smoother when considering distribution revenues plus Solar Feed-in Tariff Scheme revenues.

Inclusive of the Solar Feed-in Tariff Scheme revenue, our final decision smoothing profile provides nominal increases of 4.7%, 5.1% and 3.5% in in the first 3 years of the 2025–30 period (2025–26 to 2027–28), followed by a 1.9% increase in 2028–29 and a 2.3% increase in 2029–30. Conversely, if we did not consider the Solar Feed-in Tariff Scheme revenues in our smoothing approach, all else being equal, we would see higher revenues in the first 3 years before a reduction in 2028–29.

We consider our final decision smoothing path is more stable and effectively returns some of the reductions to customers at the earlier years of the period, resulting in smaller revenue increases for customers for years 1 to 3. This approach is consistent with our draft decision.

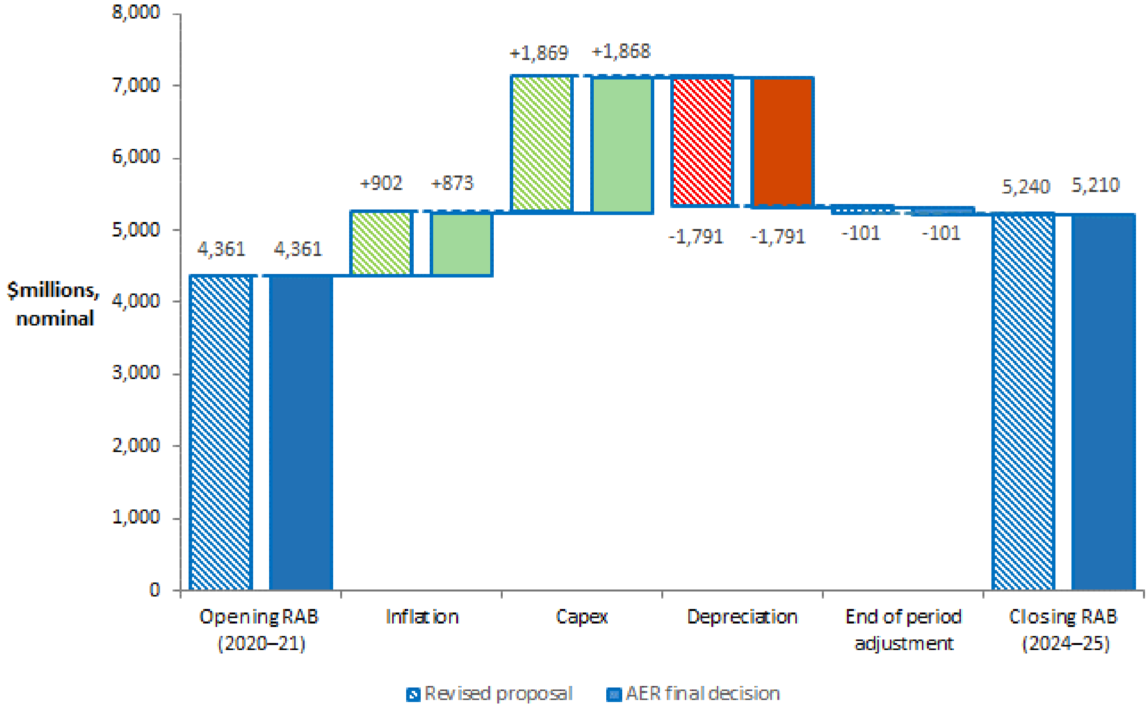
2.1 Regulatory asset base

The RAB accounts for the value of regulated assets over time. To set the revenue for a new regulatory period, we take the opening value of the RAB from the end of the last period and roll it forward year by year by indexing it for inflation, adding new capex and subtracting depreciation and other possible factors (such as disposals). This gives us a closing value for the RAB at the end of each year of the regulatory period. The value of the RAB is used to determine the return on capital and regulatory depreciation building blocks. It substantially impacts SA Power Networks' revenue requirement, and the price consumers ultimately pay. Other things being equal, a higher RAB would increase both the return on capital and regulatory depreciation components of the revenue determination.

For this final decision, we have determined an opening RAB value of $5,209.6 million ($ nominal) as at 1 July 2025. This value is $30.3 million (0.6%) lower than SA Power Networks' revised proposed opening RAB value of $5,239.9 million. This reduction is largely due to the update we made to the consumer price index (CPI) input for 2024–25 to reflect the actual outcome in the roll forward model (RFM). Figure 7 shows the key drivers of change in SA Power Networks' RAB over the 2020–25 period compared to its revised proposal.

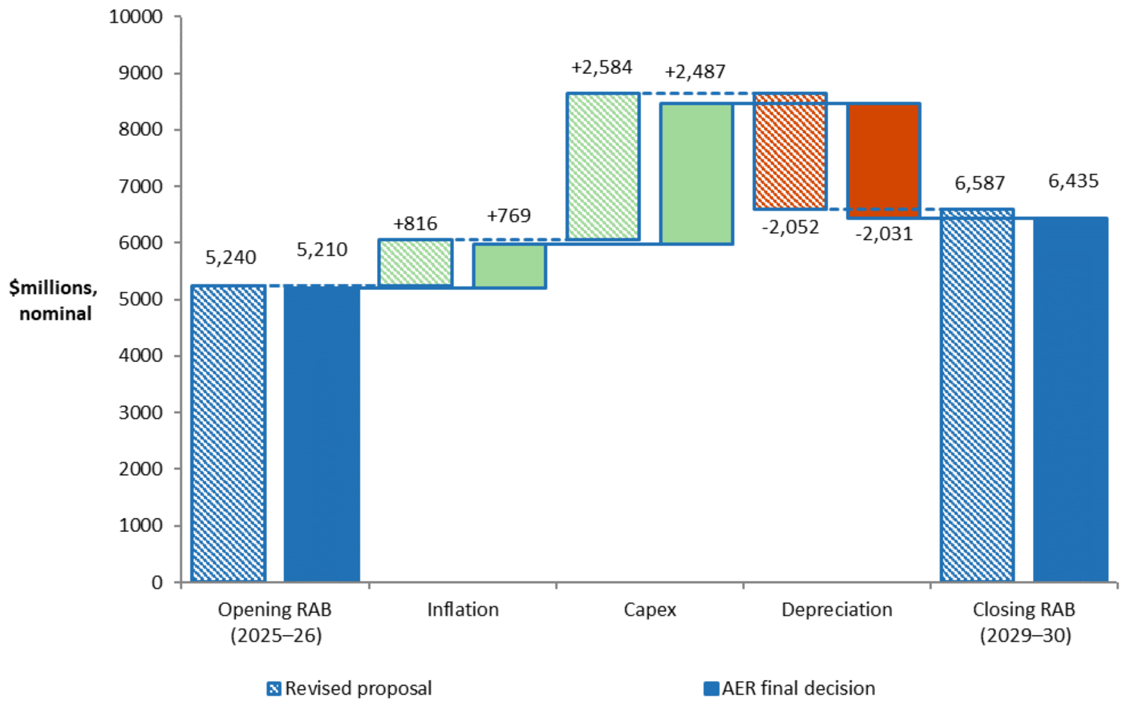
Figure 8 likewise shows the key drivers ($ nominal) of the change in SA Power Networks' RAB over the 2025–30 period compared to its revised proposal. Our final decision projects an increase of $1,225.7 million (23.5%) to the RAB by the end of the 2025–30 period compared to the $1,347.5 million (25.7%) increase in SA Power Networks' revised proposal. We have determined a projected closing RAB of $6,435.3 million ($ nominal) as at 30 June 2030, which is $152.0 million (2.3%) lower than SA Power Networks' revised proposal of $6,587.3 million. This lower value is mainly due to our final decision to reduce SA Power Networks' forecast capex (section 2.4). It also reflects our final decisions on the opening RAB as at 1 July 2025, expected inflation (section 2.2) and forecast depreciation (section 2.3). The reasons for our final decision are discussed in Attachment 2.

Figure 7 Key drivers of change in the RAB over the 2020–25 period – revised proposal compared with AER's final decision ($ million, nominal)



Source: AER analysis.
Note: Capex is net of disposals and capital contributions. It is inclusive of the half-year WACC to account for the timing assumptions in the RFM.

Figure 8 Key drivers of change in the RAB over the 2025–30 period – revised proposal compared with AER's final decision ($ million, nominal)



Source: AER analysis.
Note: Capex is net of disposals and capital contributions. It is inclusive of the half-year WACC to account for the timing assumptions in the PTRM.

2.2 Rate of return and value of imputation credits

The AER's 2022 Rate of Return Instrument (RORI) sets out the approach we will use to estimate the return on debt, the return on equity and the overall rate of return.[25]

The return each business is to receive on its RAB, known as the 'return on capital', is a key driver of proposed revenues. We calculate the regulated return on capital by applying a rate of return to the value of the RAB.

We estimate the rate of return by combining the returns of two sources of funds for investment: equity and debt. The allowed rate of return provides the business with a return on capital to service the interest rate on its loans and give a return on equity to investors.

The estimate of the rate of return is important for promoting efficient prices in the long term interests of consumers. If the rate of return is set too low, the network business may not be able to attract sufficient funds to be able to make the required investments in the network and reliability may decline. Conversely, if the rate of return is set too high, the network business may seek to spend too much and consumers will pay inefficiently high tariffs.

We are required by national energy laws and rules to apply the RORI to estimate an allowed rate of return. For this final decision, we have applied the 2022 RORI.[26]

SA Power Networks' revised proposal adopted the 2022 RORI.[27] Our final decision rate of return of 6.12% (nominal vanilla) is higher than the 6.02% placeholder in the revised proposal, principally due to an increase in interest rates.

Our calculated rate of return in Table 1 applies to the first regulatory year of the 2025–30 period. A different rate of return may apply for the remaining years of the period. This is because we will update the return on debt component of the rate of return each year, in accordance with the 2022 RORI, to use a 10-year trailing average portfolio return on debt that is rolled-forward each year. Hence, only 10% of the return on debt is calculated from the most recent averaging period, with 90% from prior periods.

Our final decision accepts SA Power Networks' proposed risk free rate[28] and debt averaging periods[29] because they were consistent with 2022 RORI.[30] For this final decision, we adopt the confidential appendix setting out the averaging periods issued with our draft decision.

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25 AER, *Rate of Return Instrument (Version 1.2)*, March 2024.

26 AER, *Rate of Return Instrument (Version 1.2)*, March 2024.

27 SA Power Networks, *SAPN - 2025-30 Revised Regulatory Proposal Overview – December 2024*, December 2024, p. 25.

28 AER, *Draft Decision Appendix A - CONFIDENTIAL Appendix to Attachment 3 - Rate of return - SA Power Networks – 2025-30 Distribution revenue proposal,* September 2024, p. 1.

29 AER, *Draft Decision Appendix A - CONFIDENTIAL Appendix to Attachment 3 - Rate of return - SA Power Networks – 2025-30 Distribution revenue proposal,* September 2024, p. 2.

30 AER, *Rate of return Instrument (version 1.2)*, March 2024, cll 7–8, 23–25.

Table 1 Final decision on SA Power Networks' rate of return (nominal)

	AER's draft decision (2025–30)	SA Power Networks' revised proposal (2025–30)	AER's final decision (2025–30)	Allowed return over the regulatory control period
Nominal risk-free rate	4.35%	4.35%	4.61%[a]	
Market risk premium	6.20%	6.20%	6.20%	
Equity beta	0.6	0.6	0.6	
Return on equity (nominal post-tax)	8.07%	8.07%	8.33%	Constant (%)
Return on debt (nominal pre-tax)	4.65%	4.65%	4.66%[b]	Updated annually
Gearing	60%	60%	60%	Constant (60%)
Nominal vanilla WACC	6.02%	6.02%	6.12%[c]	Updated annually for return on debt
Expected inflation	2.85%	2.85%	2.72%	Constant (%)

Source: AER analysis; AER, *Draft Decision Attachment 3 - Rate of return - SA Power Networks - 2025-30 Distribution revenue proposal*, September 2024, p. 2; SA Power Networks, *SAPN - 1.1 Post Tax Revenue Model – December 2024*, December 2024.

(a) Calculated using SA Power Networks' risk-free rate averaging period of 20 business days from 1 November 2024 to 28 November 2024.
(b) Calculated using SA Power Networks' actual nominated return on debt averaging period.
(c) Applied to the first year of the 2025–30 regulatory control period.

Debt and equity raising costs

In addition to compensating for the required rate of return on debt and equity, we provide an allowance for the transaction costs associated with raising debt and equity. We include debt raising costs in the opex forecast because these are regular and ongoing costs which are likely to be incurred each time service providers refinance their debt. On the other hand, we include equity raising costs in the capex forecast because these costs are only incurred once and would be associated with funding the particular capital investments. Our approach to forecasting debt and equity raising costs is set out in more detail in our draft decision.[31] SA Power Networks has proposed to use our approach to estimate debt and equity raising costs.[32]

31 AER, *Draft Decision - Attachment 3 - Rate of return - SA Power Networks – 2025-30 Distribution revenue proposal,* September 2024, pp. 4-6.

32 SA Power Networks, *SAPN - 1.1 Post Tax Revenue Model – December 2024*, December 2024.

Our final decision accepts SA Power Networks' proposed opex including debt raising costs, as set out in section 2.5 in the Overview.

We have updated our estimate for the 2025–30 period based on the benchmark approach using updated inputs. This results in zero equity raising costs.

Imputation credits

Our final decision applies a value of imputation credits (gamma) of 0.57, as set out in the 2022 RORI.[33] SA Power Networks' revised proposal also adopted this value.[34]

Expected inflation

As set out in Table 2, our estimate of expected inflation is 2.72%. It is an estimate of the average annual rate of inflation expected over a five-year period based on the outcome of our 2020 inflation review.[35] SA Power Networks' revised proposal also adopted our approach.[36]

Table 2 Final decision on SA Power Networks' forecast inflation (%)

	Year 1	Year 2	Year 3	Year 4	Year 5	Geometric average
Expected inflation	3.20%	2.70%	2.63%	2.57%	2.50%	2.72%

Source: AER Analysis; RBA, *Statement on Monetary Policy*, February 2025, Table 3.1: Detailed Forecast Table. See https://www.rba.gov.au/publications/smp/2025/feb/outlook.html#table31.

Our final decision uses the Reserve Bank of Australia's (RBA) February 2025 Statement on Monetary Policy (SMP) which contains a consumer price index (CPI) forecast for the year-ending June 2026 and June 2027. This means the first two years of the 2025–30 period are based on RBA forecasts and, thereafter, a linear glide-path from year three to the mid-point of the RBA's inflation target band of 2.5% in year five.

Figure 9 isolates the impact of expected inflation from other parts of our final decision to illustrate its effect on the return on capital and regulatory depreciation building blocks, and the total revenue allowance. Other elements held constant, lower inflation reduces the return on capital but increases regulatory depreciation.

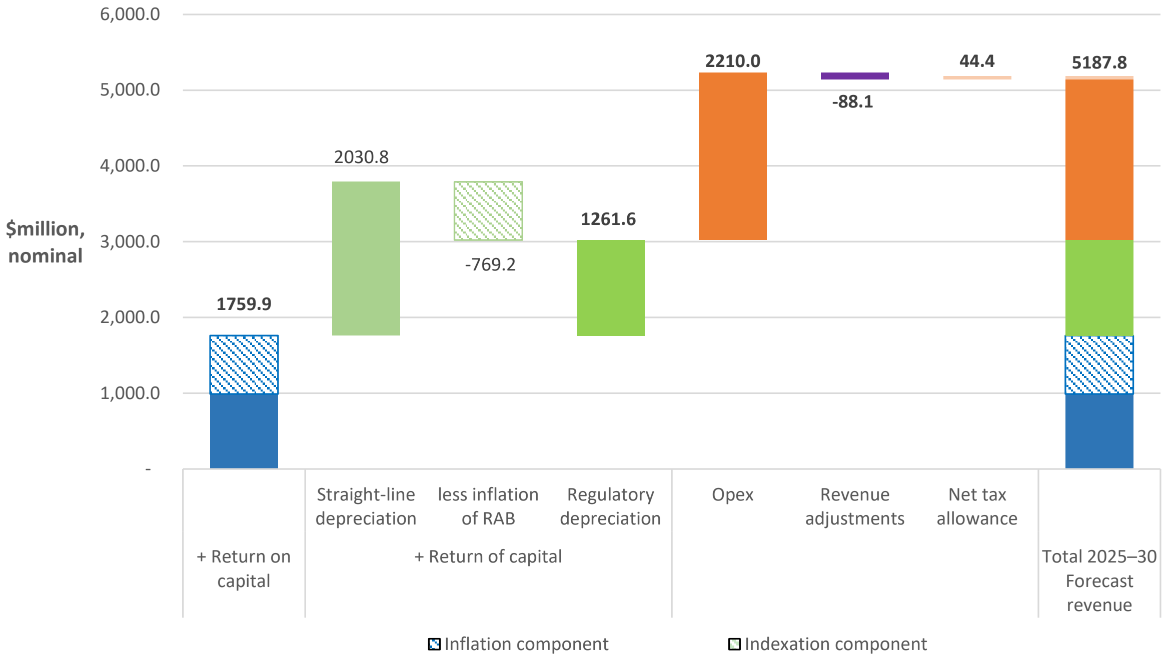
33 AER, *Rate of return Instrument (version 1.2)*, March 2024, cl. 27.

34 SA Power Networks, *SAPN - 2025-30 Revised Regulatory Proposal Overview – December 2024*, December 2024, p. 25.

35 AER, *Final position - Regulatory treatment of inflation*, December 2020.

36 SA Power Networks, *SAPN - 1.1 Post Tax Revenue Model – December 2024*, December 2024.

Figure 9 Inflation components in final decision revenue building blocks ($ million, nominal)



Source: AER analysis

2.3 Regulatory depreciation (return of capital)

Depreciation is a method used in our decision to allocate the cost of an asset over its useful life. It is the amount provided so capital investors recover their investment over the economic life of the asset (otherwise referred to as 'return of capital'). When determining total revenue, we include an amount for the depreciation of the projected RAB. The regulatory depreciation amount is the net total of the straight-line depreciation less the indexation of the RAB.

Our final decision determines a regulatory depreciation amount of $1,261.6 million ($ nominal) for the 2025–30 period. This is an increase of $24.9 million (2.0%) from SA Power Networks' revised proposal of $1,236.6 million.

This increase in regulatory depreciation is primarily due to a lower expected inflation rate in our final decision compared to SA Power Networks' revised proposal, which has reduced the indexation of the RAB.[37] This increase is partially offset by our final decisions to reduce forecast capex and the opening RAB as at 1 July 2025 which have reduced straight-line depreciation in the 2025–30 period.

[37] Since RAB indexation is deducted from straight-line depreciation, the lower RAB indexation results in a higher regulatory depreciation.

2.4 Capital expenditure

Our final decision is to not accept SA Power Networks' proposed total forecast capex of $2,337.7 million ($2024–25). Our substitute forecast is $2,257.2 million, which is 3.4% below SA Power Networks' forecast. In some distribution determination decisions, where our substitute forecast is not materially different to a network provider's forecast, we have accepted that forecast. However, in this instance, we consider that our reasons for developing an alternative estimate (as outlined below and in Attachment 5) are significant enough to mean that we are not satisfied that SA Power Networks' total forecast capex reasonably reflects the capex criteria outlined in the NER and, therefore, we do not accept SA Power Networks' forecast.[38] We are satisfied that our substitute forecast reasonably reflects the capex criteria. Overall, we found that the majority of SA Power Networks' forecast would be required to maintain the safety, reliability and security of electricity supply of its network.

Our decision is based on a balanced consideration of various factors, including the revised capex proposal from SA Power Networks, stakeholder submissions, investment need and service reliability performance. We consider our substitute forecast will sufficiently allow a prudent and efficient service provider in SA Power Networks' circumstances to meet the capital expenditure objectives.[39]

Table 3 outlines our substitute estimate of forecast capex and compares this to SA Power Networks' revised proposal of forecast capex.

Table 3 AER's final decision on SA Power Networks' total net capex forecast ($ million, $2024–25)

	2025–26	2026–27	2027–28	2028–29	2029–30	Total
SA Power Networks' revised proposal	471.6	472.9	477.5	457.2	458.4	2,337.7
AER's final decision	459.9	463.6	464.8	431.2	437.8	2,257.2
Difference ($)	-11.7	-9.3	-12.7	-26.0	-20.6	-80.5
Difference (%)	-2.5%	-2.0%	-2.7%	-5.7%	-4.5%	-3.4%

Source: AER analysis and SA Power Networks' revised proposal.

Note: Numbers may not add up due to rounding. The final decision includes modelling adjustments relating to updates to the consumer price index (CPI) and real cost escalation assumptions.

SA Power Networks' revised proposal forecasts $2,337.7 million ($2024–25) of capex over the 2025–30 regulatory control period. This represents an increase of 18.5% compared to actual and expected expenditure over the 2020–25 period.

SA Power Networks' revised capex proposal represents an increase in forecast capex compared to our draft decision, driven by factors such as higher unit rates and updated businesses cases for the CBD reliability and maintain reliability programs. The revised proposal also included an increase in information and communications technology (ICT)

38 NER, cl. 6.5.7(d).

39 NER, cl. 6.5.7(a).

expenditure following updates in the Energy Security Board's (ESB) AEMO post-2025 roadmap and provided additional information to support the proposed innovation fund.

SA Power Networks did not accept our draft decision on capex. However, in responding to our draft decision, SA Power Networks:

- amended its replacement expenditure risk model, taking into account our concerns about a number of inputs and assumptions it used.
- incorporated additional steps to strengthen the robustness of the optimal timing of demand driven augmentation projects.
- reconsidered the assumptions used and the options it considered for the CBD reliability program.
- revised its list of innovation projects and provided justification that these projects are innovative in nature.

Our assessment focused on the following unresolved issues:

- the selection of the data source for the demand forecast.
- capex programs initially included as placeholders in our draft decision, such as the innovation fund and Adelaide CBD reliability program.
- further increases in SA Power Networks' revised proposal compared to our draft decision, including for replacement and augmentation capex.

In the draft decision, we requested that SA Power Networks update its demand forecast using AEMO's 2024 Electricity Statement of Opportunities (ESOO). Instead, SA Power Networks chose to use AEMO's 2024 Integrated System Plan (ISP) to generate its demand forecast because it considered that the demand forecasts determined for the 2024 ISP are more robust than those in the 2024 ESOO. This is a departure from our approach of using the latest available demand forecast from AEMO (in this case the 2024 ESOO). The 2024 ISP projected higher demand compared to the forecast in the AEMO 2024 ESOO. SA Power Networks also maintains that its block loads forecast is neither overestimated nor duplicated.[40]

We are satisfied that AEMO's 2024 ESOO provides the best available forecast. Furthermore, we consider the ESOO is the most appropriate data source for network businesses to use in their demand forecasts, as it provides the most up-to-date demand forecast compared to the ISP, which relies on the previous year's ESOO data and assumptions.

For the maintain reliability program (including the Adelaide CBD automation component), we consider that not all the proposed expenditure is justified, as other proposed programs will address factors most recently impacting reliability, such as animals, weather and vegetation.

We have not included the full amount of augmentation capex proposed by SA Power Networks in our substitute capex forecast. Our substitute estimate accounts for our adjustments to demand driven augmentation capex and the maintain reliability augmentation program. These adjustments include:

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40 Block loads are step changes occurring over the forecast period to the historical trend in demand.

- a reduction of $36.7 million in SA Power Networks' demand driven augmentation expenditure, from $84.0 million to $47.3 million. This adjustment is based on the application of AEMO's 2024 ESOO forecast. Although our forecast is less than actual and forecast demand driven augex in the current regulatory period, we consider it will be sufficient to address the expected level of network constraints given a lower forecast of demand than previously anticipated. In deriving this forecast, we considered the location-specific network constraints identified by SA Power Networks, as well as currently available network capacity. We consider these factors are more relevant to our assessment than a broad expectation that greater demand will require greater augmentation expenditure.
- a reduction of $32.6 million in the maintain reliability program, from $100.6 million[41] to $68.0 million. This adjustment is supported by data which shows consistent improvements in service reliability over time. We expect service reliability will be maintained in the 2025–30 period.

For replacement capex, SA Power Networks addressed most of the concerns we raised in our draft decision. Our final decision is to accept SA Power Networks' revised proposal of $884.6 million for replacement capex.

Table 4 sets out our final decision for SA Power Networks by capex category. Further detail and reasons on capex for the final decision are contained in Attachment 5.

Table 4 AER final decision by capex category ($million 2024–25)

Category	SA Power Networks' revised proposal	AER final decision	Difference ($/%)	
Replacement	884.6	884.6	-	-
Connections	748.3	748.3	-	-
Augmentation	472.2	402.8	-69.4	-14.7%
ICT	321.4	321.4	-	-
Fleet	149.9	149.9	-	-
Property	115.7	115.7	-	-
CER	91.3	91.3	-	-
Non-network capex - other	50.4	50.4	-	-
Capitalised overheads	41.9	40.6	-1.3	-0.1%
Gross Total	**2,875.7**	**2,805.0**	**-70.7**	
Less customer contributions	516.2	516.2	-	-
Less Disposals	21.7	21.7	-	-
Modelling adjustments		-9.8	-9.8	
Net Total	**2,337.7**	**2,257.2**	**-80.5**	**-3.4%**

Source: SA Power Networks' capex model and AER analysis.
Note: Numbers may not sum due to rounding. Modelling adjustments relate to updates to the consumer price index (CPI) and real cost escalation assumptions.

41 We consider the $26.1 million automation component of the proposed CBD reliability program is closely linked to SA Power Networks' $74.5 million maintain reliability augmentation program and assessed the automation component as part of the efficiency of the maintain reliability augmentation program.

2.5 Operating expenditure

Our final decision is to accept SA Power Networks' revised total opex forecast of $2,036.2 million ($2024–25)[42], including debt raising costs, for the 2025–30 period.[43] Our alternative estimate of $2,023.9 million, including debt raising costs, is $12.3 million or 0.6% lower than SA Power Networks' revised proposal total forecast opex. We consider this is not materially different to SA Power Networks' revised proposal. Consequently, we consider that SA Power Networks' total opex forecast reasonably reflects the opex criteria.[44]

SA Power Networks' accepted our draft decision approach for opex, but applied mechanical updates to reflect:

- actual audited opex for the base year 2023–24, resulting in an increase of 5.7% to opex in the base year as compared to the draft decision[45]
- the latest available data on output measures (for customer numbers, circuit length and ratcheted maximum demand) and Wage Price Index (WPI) forecasts.[46]

SA Power Networks' revised proposal also included:

- further information we requested in our draft decision for the proposed smart meter rollout step change. We note, the AEMC also released their final rule determination on 28 November 2024 mandating a universal rollout of smart meters across the national energy market by 1 December 20230.[47]
- $4.0 million opex component of the proposed innovation fund as a category specific forecast, aligning with our draft decision considerations.[48] (see capex attachment 5, Table 5.3)
- removing the network program uplift step change, which we did not accept in our draft decision.
- removing the small compensation claims scheme category specific forecast, which will be recovered as a jurisdictional scheme obligation.

The difference between our alternative total opex forecast and SA Power Networks' revised proposal is due to us:

- updating inflation to reflect forecast inflation based on the 18 February 2025 Statement of Monetary Policy from the Reserve Bank of Australia.

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42 All dollars in this section are in $2024-25 unless otherwise indicated.

43 SA Power Networks, *SAPN – Attachment 6 – Operating expenditure*, December 2024, p.14.

44 The opex criteria are set out in cl. 6.5.6(c) of the NER.

45 SA Power Networks, *SAPN – Attachment 6 – Operating expenditure*, December 2024, p. 8; AER analysis.

46 SA Power Networks, *SAPN – Attachment 6 – Operating expenditure*, December 2024, p. 8.

47 National Electricity Amendment (Accelerating smart meter deployment) Rule 2024 No.20, November 2024, p. 16.

48 SA Power Networks, *SAPN – Attachment 6 – Operating expenditure,* December 2024, pp. 26-27.

- updating forecast input price growth to reflect the most up to date forecast WPI from our consultant (Deloitte).[49]
- applying the latest output weights from our 2024 Annual Benchmarking Report.[50]

Table 5 shows SA Power Networks' opex forecast over the 2025–30 period, which we have accepted as our final decision.

Table 5 SA Power Networks' opex for the period 2025–30 ($million, 2024-25)

	2025-26	2026-27	2027-28	2028-29	2029-30	Total
Opex excluding debt raising costs	392.0	402.1	406.2	409.2	413.0	2022.6
Debt raising costs	2.7	2.7	2.7	2.8	2.8	13.7
Total Opex, including debt raising costs	**394.7**	**404.8**	**409.0**	**412.0**	**415.8**	**2036.2**

Source: SA Power Networks, *SAPN – 6.1 – Opex Model,* December 2024, December 2024.
Note: Numbers may not add up to totals due to rounding.

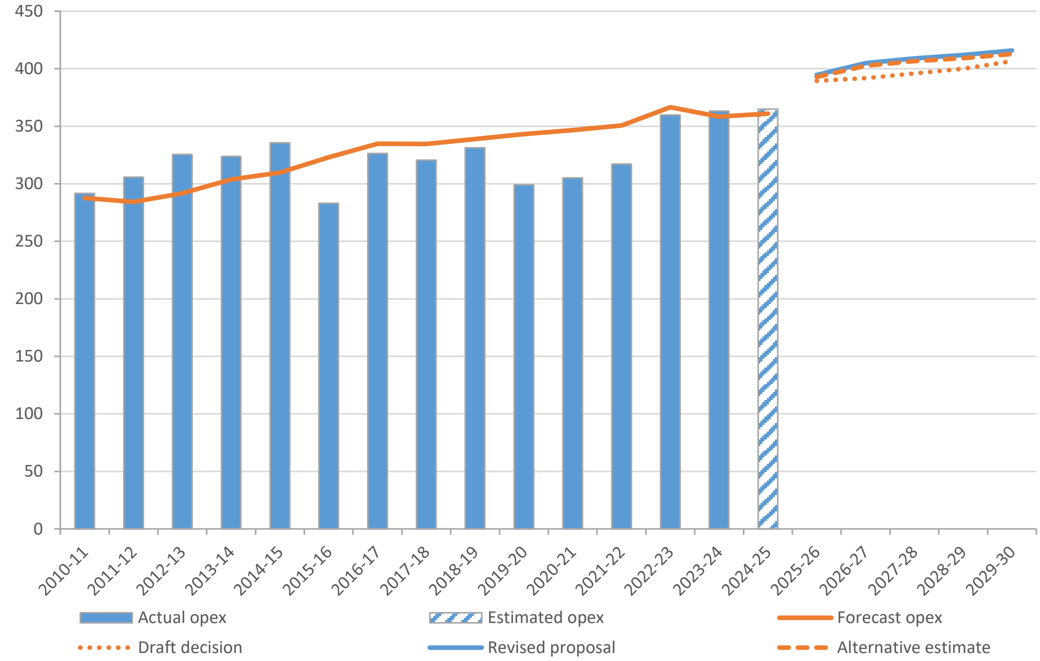
Figure 10 shows that our final decision opex forecast (SA Power Networks' revised forecast) of $2,036.2 million is:

- $253.2 million, or 14.2% higher than the opex forecast we approved in our final decision for the 2020–25 regulatory control period
- $326.1 million, or 19.1% higher than SA Power Networks' actual (and estimated) opex in the 2020–25 regulatory control period
- $52.5 million, or 2.6% higher than SA Power Networks' initial proposal (our draft decision).

49 Deloitte Access Economics, *Labour price growth forecasts – Prepared for the Australian Energy Regulator,* March 2025.

50 AER, *2024 Annual Benchmarking Report – Electricity distribution network service providers*, November 2024.

Figure 10 SA Power Networks' historical and forecast opex ($million, 2024-25)



Source: SAPN, *Economic benchmarking – Regulatory Information Notice responses 2010–24;* AER, *Final decision PTRM 2010–2015;* AER, *Final decision PTRM 2015–20;* AER, *Final decision 2020–25 PTRM and Opex model;* SAPN, *2025–30 Regulatory proposal – SAPN – 6.1 – Opex Model – December 2024 – Public*, December 2024; AER analysis

2.6 Corporate income tax

Our determination of the total revenue requirement includes the estimated cost of corporate income tax for 2025–30 period. Under the post-tax framework, this amount is calculated as part of the building blocks assessment using our post-tax revenue model (PTRM).

Our final decision determines an estimated cost of corporate income tax amount of $44.4 million ($ nominal) for SA Power Networks over the 2025–30 period. This is an increase of $13.6 million (44.3%) from SA Power Networks' revised proposal of $30.8 million.

This increase is primarily due to our final decision on a lower tax depreciation, higher regulatory depreciation and a higher return on equity (see sections 2.2, 2.4 and attachment 7). Regulatory depreciation and return on equity are both components of revenue for tax purposes. Tax depreciation is a component of tax expense. Therefore, higher return on equity, higher regulatory depreciation and lower tax depreciation will increase the estimated taxable income for SA Power Networks, thereby increasing the estimated cost of corporate income tax.

2.7 Revenue adjustments

Our calculation of SA Power Networks' total revenue includes adjustments for incentive schemes that applied in its determination for the current period, such as under the EBSS and CESS. These mechanisms provide a continuous incentive for SA Power Networks to pursue efficiency improvements in opex and capex, and a fair sharing of these between SA Power Networks and its users.

Our final decision includes:

- EBSS carryover amounts totalling -$114.8 million ($2024–25) from the application of the EBSS in the 2020-25 regulatory period. This is a $0.5 million ($2024–25) lower penalty compared to SA Power Networks' proposed carryover amounts totalling -$115.3 million ($2024–25). The driver of this difference is that we have updated for the latest inflation forecasts, based on 18 February 2025 *Statement of Monetary Policy* from the Reserve Bank of Australia.
- A revenue increment of $35.7 million ($2024–25) under the CESS, which is $12.3 million greater than SA Power Networks' initial forecast of $23.4 million. This reflects updated actual and estimated capex for 2023–24 and 2024–25, as well as the latest updates for inflation and the WACC.
- An allowance of $4.86 million ($2024–25) for the Demand Management Innovation Allowance Mechanism (DMIAM). In each year of the 2025–30 period, SA Power Networks will submit demand management projects for approval under the DMIAM. Any part of the $4.86 million that is not spent on an approved project will be returned to consumers in the subsequent period.
- A shared asset adjustment of -$9.6 million ($2024–25) to be shared with customers across the 2025–30 period.

3 Incentive schemes

Incentive schemes are a component of incentive-based regulation and complement our approach to assessing efficient costs. They provide important balancing incentives under network determinations, encouraging businesses to pursue expenditure efficiencies while maintaining the reliability and overall performance of the network. Our final decision is that the following incentive schemes will continue to apply to SA Power Networks in the 2025–30 period.

3.1 Capital Expenditure Sharing Scheme

Our final decision is to apply a CESS revenue increment amount of $0.99 million ($2024–25) from the application of the CESS in the 2020–25 regulatory control period, and $34.7 million for the corresponding CESS carryover true-up for 2019–20. This includes SA Power Networks' revised actual and estimated capex for the 2023–24 and 2024–25 regulatory years, as well as the most recent updates to inflation and the WACC.

Our final decision on the revenue impact of the application of the CESS in the 2020–25 period and the corresponding CESS carryover true-up for 2019–20 is summarised in Table 6.

Table 6 CESS revenue increments from 2025–30 ($ million, 2024–25)

CESS item	2025-26	2026-27	2027-28	2028-29	2029-30	Total
CESS revenue increment as per NER 6.4.3(a)(5)	0.20	0.20	0.20	0.20	0.20	0.99
CESS carryover true-up for 2019–20	6.94	6.94	6.94	6.94	6.94	34.71
AER final decision CESS	**7.14**	**7.14**	**7.14**	**7.14**	**7.14**	**35.70**

Source: SA Power Networks, *SAPN - RIN 4 - Workbook 4 - CESS - December 2024 – Public*, AER, *Draft decision - SAPN - 2025-30 Distribution revenue proposal - SCS CESS true-up Model*, September 2024.
Note: Numbers may not add up to totals due to rounding.

3.2 Efficiency Benefit Sharing Scheme

Our final decision is to include EBSS carryover amounts totalling -$114.8 million ($2024–25) from the application of the EBSS in the 2020–25 regulatory period. This is a $0.5 million ($2024–25) lower penalty compared to SA Power Networks' proposed carryover amount of $115.3 million ($2024–25). This difference reflects us updating for the latest inflation forecasts, based on 18 February 2025 Statement of Monetary Policy from the Reserve Bank of Australia (not available at the time SA Power Networks submitted its proposal).

We set out our final decision on SA Power Networks' EBSS carryover amounts in Table 7.

Table 7 EBSS carryover amounts in 2025–30 ($million, 2024–25)

	2025-26	2026-27	2027-28	2028-29	2029-30	Total
SA Power Networks' proposal	-25.3	-44.6	-44.0	-2.5	1.2	-115.3
AER final decision	-25.2	-44.5	-43.8	-2.5	1.2	-114.8
Difference	**0.1**	**0.2**	**0.2**	**0.0**	**-**	**0.5**

Source: SA Power Networks, *SAPN –RIN3 –Workbook - EBSS,* December 2024.
Note: Numbers may not add up to totals due to rounding.

South Australian Council of Social Service (SACOSS) submitted a stakeholder submission, citing a notable change in the EBSS carryover loss from -$20 million in the initial proposal to -$115.3 million in the revised proposal.[51] SACOSS further stated they were keen to understand the reasons behind this substantial difference and its impacts on customers.

SA Power Networks' accepted the AER's Draft Decision EBSS carryover amounts, but updated the revised EBSS proposal to reflect actual audited 2023–24 opex and latest inflation data (available at time of proposal submission). SA Power Networks' actual audited 2023–24 opex was significantly higher (5.7%) compared to the estimated 2023–24 opex used in the draft decision, resulting in a significantly lower (negative) incremental gain in 2023-24. The negative incremental gain, which is carried over for six years in EBSS calculations, generated the substantial increase in EBSS penalties in the revised proposal.

We consider the EBSS outcome also needs to be considered alongside the impact on forecast opex. The higher actual audited 2023–24 base year opex leads to higher forecast opex, but it also results in higher EBSS penalties. The impact on customers is that the higher EBSS penalties largely offset the forecast opex increase.

3.3 Service Target Performance Incentive Scheme

SA Power Networks accepted our draft decision to apply STPIS version 2.0 for the 2025–30 regulatory control period, including the customer service parameter (telephone answering parameter)[52]. We will not apply the guaranteed level component to SA Power Networks as the existing jurisdictional arrangements will continue to apply.

In accordance with the scheme[53], our final decision is to set SA Power Networks' performance targets based on average performance over the past 5 regulatory years with modification for:

- reward or penalty exceeding revenue at risk

51 SACOSS, *Submission on SAPN's revised proposal and draft decision 2025-30,* January 2025, p. 7.

52 SAPN, *Attachment 10 - Service target performance incentive scheme*, December 2024.

53 STPIS Version 2.0 clause 3.2.1.

- the change in the definition of momentary interruption from greater than 1 minute to greater than 3 minutes from 1 July 2020
- reliability improvement projects expenditure, adjusted for our partial (but not full) acceptance of the CBD reliability projects (as outlined in Attachment 5 – Capital Expenditure).

Our final decision is to also modify SA Power Networks' performance target for the expiry of a derogation that exempted SA Power Networks from notifying customers of an interruption where the duration is not more than 15 minutes.

However, our final decision is to not modify SA Power Networks' performance targets for the potential for two fewer major event days due to proposed reliability improvements.

Attachment 10 outlines the reasoning behind our final decision position.

3.4 Demand Management Incentive Scheme (DMIS) and Demand Management Innovation Allowance Mechanism (DMIAM)

Our final decision is to apply the DMIS and DMIAM to SA Power Networks in the 2025–30 regulatory control period. This approach is consistent with SA Power Networks' revised proposal[54] and our draft decision on DMIS and DMIAM.[55] The reasoning behind our position is also explained in the draft decision. The DMIAM allowance for SA Power Networks for the 2025–30 period, based on the final PTRM is contained in Table 8.

Table 8 Demand management innovation allowance ($million, 2024–25)

	2025-26	2026-27	2027-28	2028-29	2029-30	Total
SA Power Networks - DMIAM	0.98	0.98	0.97	0.97	0.97	4.86

Source: AER analysis

3.5 Customer Service Incentive Scheme (CSIS)

Our draft decision was to not accept SA Power Networks' proposed CSIS and instead apply the customer service (telephone answering) parameter of the STPIS Version 2.0. This was primarily based on the identification of data integrity issues with the first call resolution measure. The South Australian Council of Social Service (SACOSS) supported the AER's decision not to introduce an additional CSIS.[56]

Following the draft decision, we anticipated receiving a full revised CSIS proposal and evidence of stakeholder engagement and endorsement. However, while there was strong stakeholder support for the inclusion of a revised CSIS, SA Power Networks does not yet

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54 SAPN, *2025-30 Revised Regulatory Proposal Overview*, December 2024 - Public, p. 31.

55 AER, *Draft Decision Attachment 11 - DMIS and DMIAM - SAPN - 2025-30 Distribution revenue proposal*, September 2024.

56 South Australian Council of Social Services, *Submission to the Australian Energy Regulator on SA Power Networks' 2025-30 Revised Regulatory Proposal*, January 2025, p. 29.

have sufficient data to propose a suitable baseline target for the alternative CSIS measures considered.

SA Power Networks therefore accepted the AER's Draft Decision to retain the telephone answering component of the STPIS for the 2025–30 period.[57] As noted by the CCP30, this 'effectively returns to the STPIS status quo with both SAPN and the CAF agreeing to continue working on… more effective consumer service effectiveness measures."[58]

In line with the AER's draft decision and SA Power Networks' revised proposal, the final decision is to not apply a CSIS and instead apply the customer service (telephone answering) parameter of the STPIS Version 2.0.

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[57] SA Power Networks, *2025-30 Revised Regulatory Proposal*, December 2024, p. 31.

[58] CCP Sub-panel CCP30, *Advice to the AER regarding the Draft Decision and Revised Proposal 2025-30*, p. 21.

4 Tariff structure statement

SA Power Networks' revised 2025–30 regulatory proposal includes its third tariff structure statement, accompanied by an indicative pricing schedule.[59] This tariff structure statement will apply from 1 July 2025 and remain in effect for the remainder of the regulatory period. A tariff structure statement must set out a distributor's:

- proposed network tariffs (including tariff structures and charging parameters)
- export tariff transition strategy
- policies and procedures the distributor will use to assign customers to network tariffs or reassign customers from one network tariff to another.

Network tariffs provide the charging framework through which distributors recover their costs for providing network services (transporting electricity to customers). These network tariffs are charged to retailers who package them with other costs, such as the cost of wholesale energy, in their service offerings to electricity customers. After AER approval, a tariff structure statement becomes a compliance document against which the AER assesses the distributor's annual pricing proposals.

Our draft decision accepted most elements of SA Power Networks' initial tariff structure statement. SA Power Networks' proposed revised tariff structure statement addressed the remaining elements of our draft decision.[60] The changes included:

- amending the assignment policy to provide a time-of-use tariff option for customers with usage less than 160 MWh
- clarifying how customers become eligible to access individually calculated tariffs
- demonstrating how its alternative control services are compliant with the distribution pricing principles (pricing principles).

Our final decision is consistent with our draft decision and approves SA Power Networks' revised 2025–30 tariff structure statement. In making our final decision, we considered the late amendment SA Power Networks made in its proposed tariff structure statement to replace references of 'Embedded generation' alternative control services as a result of an AEMC rule change.[61] We are satisfied that the revised tariff structure statement complies with the requirements of the pricing principles and other applicable National Electricity Rules (NER) and contributes to achieving the National Electricity Objectives (NEO).[62] This overview document sets out our reasoning to support our final decision to approve SA Power Network's assignment policy to provide a time-of-use tariff option for customers using less than 160 MWh electricity per annum. It also sets out our response to a submission from the South Australian Council of Social Service (SACOSS) on SA Power Networks' tariff reform program. There is no separate tariff structure statement final decision attachment.

59 NER, cl. 6.12.3(c)(1) and (2); 6.12.3(c1); 6.18.1A(e).

60 SA Power Networks, *2025–30 Revised Regulatory Proposal Overview*, 2 December 2024, p. 36.

61 AEMC, *Integrating energy storage systems into the NEM rule change*, December 2021.

62 NER, cl. 6.12.3(k) and NEL, s 7.

We consider SA Power Networks to be at the forefront of designing cost-reflective tariffs that also consider customer impacts.

Threshold for large customer access to time-of-use tariffs

Our final decision approves SA Power Networks' revised proposal to allow all small and medium business customers with usage less than 160 MWh per annum to opt into the time-of-use small business tariff. We consider this change complies with the NER and is consistent with our draft decision. We also consider this decision will or is likely to contribute to the achievement of the NEO, in particular the achievement of targets set by jurisdictions for reducing Australia's greenhouse gas emissions.

Our draft decision required customers with usage less than 160 MWh per annum and demand greater than 120 kVA to have the option of a cost reflective time-of-use tariff. The AER's draft decisions for Ergon Energy and Energex required the same.

We received one submission on large customer access to time-of-use tariffs. The CCP30 submitted that the draft decision in 'observing the sustainability aspect of the NEO […] create[d] a precedent that will need to be considered in future [TSS proposals and decisions]'.[63] We also acknowledge that most of SA Power Networks' stakeholders considered that the assignment policy to not allow large customer access to the time-of-use tariff was appropriate.[64]

We make our decisions by assessing tariff structures against the pricing principles and other applicable requirements of the NER. Firstly, we consider that the new time-of-use tariff proposed complies with the pricing principles and other applicable requirements of the NER. Against NER cl. 6.18.5(f), they are based on long-run marginal cost, and they reflect SA Power Network's efficient costs of providing services to customers consistent with the Network Pricing Objective (NPO). They are also opt-in which mitigates the customer impacts to customers eligible for assignment to the tariff.[65]

However, we are also required to make decisions in a manner that will or is likely to contribute to the achievement of the NEO.[66] The basis for our draft decision was that a consistent approach to tariff assignment for peaky load customers, like charge point operators, better contributes to the achievement of South Australia's emissions targets - its net zero 2050 target and its aim to have 170,000 EVs on SA roads by 2030 in the National Electric Vehicle Strategy.[67] In having regard to the emissions reductions target element of the

63 CCP30, *Submission on SAPN's revised proposal and draft decision 2025-30*, January 2025, p. 21.

64 SA Power Networks, *2025–30 Revised Regulatory Proposal Overview*, 2 December 2024, pg. 36; SA Power Networks' response to information request, *SA Power Networks – information request IR#031 – Two way pricing*, July 2024.

65 NER, cl. 6.18.5(h).

66 NEL, s 16(1)(a).

67 AEMC, *Targets statement for greenhouse gas emissions*, June 2024, pp. 1, 3; SA Department for Environment and Water, https://www.environment.sa.gov.au/topics/climate-change/greenhouse-gas-emissions, accessed 27th March 2025; DCCEEW, *The National Electric Vehicle Strategy*, 2023, p. 50.

NEO, a person or body must consider, as a minimum, the targets stated in the targets statement.[68]

Our final decision maintains the reasoning in our draft decision.[69] For example, we considered that if EV charge point operators were to face a similar network tariff structure NEM-wide, such as an option for both demand and time-of-use tariffs, it could increase the confidence of charge point operators (and potential investors) to extend their charging networks. Similar network tariff structures would also assist charge point operators to roll out more consistent charging structures for their customers. We anticipate this would increase the confidence of consumers in the charges they would face to charge their EVs and would further support uptake and utilisation of EVs.

In approving the ability for peaky load customers to access a time-of-use tariff, we have considered the impact on other customers. SA Power Networks' modelling found that, based on 2022–23 demand data, the AER's decision will mean an additional $0.93m will be recovered from all small and medium business customers.[70] We acknowledge these customer impacts associated with our decision. However, we anticipate that there is a longer-term benefit of our decision. For example, extended charging networks and greater confidence in charging networks by consumers that would further support uptake of electric vehicles. Charge point operators who consume over 160 MWh per annum will continue to have access to demand-based tariffs only. We consider that the short-term impact of these tariffs on the broader group of business customers will be offset by the likely contribution to the achievement of South Australia's Emissions targets.

Finally, we acknowledge the CCP's submission on the precedent that we have set in making this decision. We reiterate that a tariff structure statement's compliance with the NER is paramount to our ability to approve it, and the AER's discretion to accept or approve, or to refuse to accept or approve, any element of a proposed tariff structure statement, is limited.[71] That is, in making decisions that will, or are likely to contribute to the achievement of the NEO, we must approve a tariff structure statement unless we are reasonably satisfied that it does not comply with the pricing principles / other requirements of the NER.[72] The decision to include time-of-use tariffs for peaky load customers is both consistent with the requirements in the NER *and* made in a way that will or is likely to contribute to the achievement of the NEO.

Tariff reform program context

We approved most elements of SA Power Network's proposed tariff structure statement in our draft decision. However, we acknowledge the submission from SACOSS, which outlines concerns on whether tariff reform is effective in reducing network expenditure and the

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68 NEL, s 32A(5)– In having regard to the national electricity objective under this Law, the Regulations or the Rules with respect to the matters mentioned in section 7(c), a person or body must consider, as a minimum, the targets stated in the targets statement.

69 AER, *Draft Decision Attachment 19 – Tariff Structure Statement – SA Power Networks – 2025–30 Distribution Revenue Proposal,* September 2024, pp. 27–30.

70 SA Power Networks, *Response to information request, SA Power Networks – information request IR#031 – Two way pricing*, July 2024.

71 NER, cl. 6.12.3.

72 NER, cl. 6.12.3(k).

impacts of these tariffs on retail offerings to customers (in relation to complexity).[73] Distribution costs are driven by how consumers use (or supply) energy during periods of maximum (and minimum) demand. In particular, distribution costs increase when distributors have to meet import (or export) demand above network capacity during network wide import (or export) peak periods. Investments in assets to increase network capacity, or augmentation, are the long run network costs which are ultimately borne by the customer. We see price signals as a low-cost mechanism to incentivise customers (through their retailers) to increase utilisation of existing capacity and to reduce long run costs.

The network tariff reform program commenced following an AEMC rule change in 2014 which required distributors to progressively make their tariffs better reflect costs of providing distribution services to customers.[74] In addition, the rule change required the AER to assess tariffs against the NER's NPO and pricing principles, which require that tariffs progress towards cost reflectivity.[75]

We make our decision by assessing whether the proposed tariff structure statement complies with the pricing principles and other applicable rules within the NER, and we make this decision in a manner that contributes to the achievement of the NEO. In assessing the proposed tariff structure statement against the pricing principles, we consider the ability for tariffs to vary from those that comply with the economic pricing principles per NER cl. 6.18.5(c), for example in consideration of customer impacts, and for retailer ability to incorporate tariffs in a retail offer and/or customer understandability.[76]

In South Australia, minimum operational demand is an emerging challenge. Tariff reform can assist with this challenge by encouraging greater consumption and less exports during low demand periods. This reduces the risk of disruptions to electricity supply and/or the need for investment to manage exports or increase network export capacity. It subsequently reduces future network costs and leads to cheaper electricity bills in the long run. One direct example of the benefits from cost reflective tariffs to consumers in another jurisdiction is when the AER rejected $76.1 million in proposed capex from Evoenergy to support electric vehicle-driven demand.[77] We rejected that capex as there would be near 100% smart meter roll out by 2030 and all EV owners would be assigned to cost reflective network tariffs. That is, there would be an incentive for EV charging to occur in times of network capacity abundance which would mitigate the need for network augmentation to meet electric vehicle charging demand occurring during peak demand periods.

We remain committed to the implementation of tariff reform as we consider this program to be in the long term interests of all consumers. However, we acknowledge that the path to realise the benefits of tariff reform is ongoing and depends on:

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73 SACOSS, *Submission on SAPN's revised proposal and draft decision 2025-30*, January 2025, pp. 31-41.

74 AEMC, *Distribution network pricing arrangements rule change*, November 2014.

75 NER, cl. 6.18.5(a); 6.18.5(e) to (g).

76 NER, cl. 6.18.5(h) and (i).

- smart meter penetration (at June 2024 less than 50% of residential customers in South Australia had smart meters and could therefore face more cost-reflective tariffs)[78]
- customers' ability to understand and respond to signals (SA Power Networks has begun to demonstrate that customers who understand how to shift behaviour can benefit from time-variable tariffs - its Electrify tariff trial showed that 71% of solar customers and 80% of non-solar customers who opted into the optional trial saved money from increasing daytime consumption and reducing peak demand).[79]

The shorter-term network bill impacts of tariff reform are also an important consideration given the accelerated smart meter roll out introduced by the AEMC (which will increase the number of customers on the default tariff).[80] Distributors are required to model the impacts to customers moving to new tariff structures, and to consider how those impacts can be mitigated or managed.[81] Their tariffs may vary from meeting cost reflectivity requirements in consideration of customers' ability to mitigate impacts. Analysis from SA Power Networks found that the proposed default residential time-of-use tariff had similar price outcomes as the flat rate tariff, without customers changing their usage.[82] This is because the time-of-use tariff had a 12-hour peak period which allows SA Power Networks to charge lower peak prices (lowering the ratio of peak to off-peak prices). A shorter peak period would need to have a higher peak period price to ensure the tariff recovers the total efficient costs of serving the customers assigned to the tariff (i.e. as SA Power Networks has done for its alternative opt-in residential time-of-use tariff). The default structure balances cost reflectivity with the ability of customers to mitigate impacts. That is, it mitigates bill impacts for customers with no or limited ability to shift load while providing some rewards for customers able to shift their load to the low demand periods. SA Power Networks' opt-in residential time-of-use tariff remains available for retailers (and their customers) who prefer a shorter peak period.

Network tariffs are charged to retailers and cost reflective pricing is intended to facilitate retailer innovation to increase network capacity utilisation. Retailers can achieve this with retail offers that encourage consumers to shift their own behaviour or with business models that offer control and orchestration of load and supply. More specifically, retailers may manage and respond to network price signals by offering customers insurance style flat tariffs (either with a price premium to account for network tariff price risk or with elements of control to manage the price risk), pass network prices through to end users, or offer 'prices for devices' style offers. With increasing levels of CER, we anticipate more retailers and intermediaries will be developing business models that seek value from cost reflective tariffs and flexible load/supply. We encourage retailers to continue to innovate to access this value through helping consumers that are willing and able to shift and reduce their load, including through drawing on energy efficiency initiatives and offering flat retail tariffs where this is preferred by customers.

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78 Annual RIN data, current at June 2024.

79 SA Power Networks, *Attachment 5.7.4 – CER Integration*, January 2024, p. 11.

80 AEMC, *National Electricity Amendment (Accelerating Smart Meter Deployment) Rule,* November 2024.

81 NER, cl. 6.18.5(h).

82 SA Power Networks, *Attachment 18 - Tariff Structure Statement - Part B*, January 2024, pp. 56–57.

Recent regulatory changes have increased the emphasis on retailers' role in innovating to manage network costs i.e. provisions in the National Electricity Retail Rules that:[83]

1. for a two-year period following the installation of a smart meter, require retailers to obtain explicit informed consent to move customers to a new retail tariff
2. enables jurisdictions to require designated retailers to offer flat retail tariff options to customers with smart meters.

Retailers have a range of options to manage and respond to network price signals, including options that do not reassign customers to new retail tariffs. Further, there is a requirement for electricity retailers in South Australia to have a standing offer which includes a retail tariff structure that incentivises electricity use in low demand periods.[84]

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83 AEMC, *National Electricity Amendment (Accelerating Smart Meter Deployment) Rule,* November 2024. The provisions will come into effect on 1 December 2025.

84 s 6A, National Energy Retail Law (Local Provisions) Regulations 2013.

5 Other price terms and conditions

In this section, we consider other aspects of our determination, which include application of the AEMC metering review and SA Power Networks' negotiated services.

5.1 Metering services

Smart meters are foundational to a more connected, modern, and efficient energy system, and are one mechanism to ensure that future technologies, services, and innovations are supported. Throughout the 2025–30 regulatory determination process, we signalled that we would consider the implications of the AEMC's final decision on the transitioning of legacy meters. This includes different classification and/or price/revenue control settings for legacy metering services.

The key objective of the AEMC's final decision, released in August 2023, is to target a 100% replacement of distribution network owned accumulation meters with smart meters offered by other parties by 30 June 2030.[85] Our draft decision considered this constituted a material change in circumstances, which justified departing from the classification of legacy metering services in the Framework and approach (F&A).[86] Subsequent to our draft decision, the AEMC made the *Accelerating smart meter deployment* rule change determination in November 2024. This rule change incorporated the outcomes of the AEMC's review into the National Electricity Rules, revising the timeframe of the completion of the rollout to November 2030.[87]

Consistent with this, our final decision accepts SA Power Network's proposal to reclassify legacy metering as standard control services and the application of a revenue cap. The reasons for our reclassification decision are outlined in attachment 13. This is consistent with our guidance note and provides an outcome that is in the long term interests of consumers.[88] It ensures no customer is worse off than other customers as a result of when their legacy meter is replaced. By comparison, customers whose meters are replaced later in the replacement program would incur inequitably higher prices than those whose meters are replaced earlier under the approach in the final F&A.

In addition, our final decision accepts SA Power Network's proposal for no new capex, and its proposed cost recovery approach (a flat per customer charge to low voltage customers). Our final decision substitutes slightly lower amounts for regulatory depreciation and the return on capital, reflecting updated inputs based on the 2022 rate of return instrument. We also substitute our slightly lower alternate estimate for forecast metering opex, reflecting mechanical updates for labour price growth and inflation. Our substitute forecast metering opex also includes the updated step changes proposed by SA Power Networks in its revised proposal. As a result, our final decision is to not accept SA Power Networks' proposed total annual revenue requirement of $46.0 million ($nominal, smoothed) but rather to substitute it

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85 AEMC, *Final Report: Review of the regulatory framework for metering services*, August 2023.

86 AER, *Draft Decision Attachment 13 – Classification of service – SA Power Networks – 2025-30 Distribution revenue proposal*, September 2024.

87 AEMC, *Final rule determination, Accelerating smart meter deployment*, 28 November 2024, p. 1.

88 AER, *Legacy metering services - guidance for revised proposals*, November 2023.

with our total annual revenue requirement of $45.6 million ($nominal, smoothed) reflecting these inputs. The reasons for our decision are discussed in detail at attachment 20.

5.2 Negotiating framework and criteria

In our draft decision, we approved SA Power Network's proposed distribution negotiating framework for the 2025–30 period.[89] We did not receive any objections or submissions on our draft decision. Our final decision maintains the decision to approve SA Power Network's negotiating framework.

We are also required to decide on the Negotiated distribution service criteria for the distributor. Our final decision is to retain the Negotiated distribution service criteria published for SA Power Network in February 2024 for the 2025–30 period.[90] Details of Negotiated distribution service criteria are set out in attachment 17 of our draft decision.[91]

89 AER, *Draft Decision Attachment 17 - Negotiated services framework and criteria - SA Power Networks - 2025-30 Distribution revenue proposal*, September 2024.

90 AER, *Proposed Negotiated Distribution Service Criteria for SAPN - 2025-30*, February 2024.

91 AER, *Draft Decision Attachment 17 - Negotiated services framework and criteria - SA Power Networks - 2025-30 Distribution revenue proposal*, September 2024, pp. 5-7.

6 Constituent decisions

Our final decision on SA Power Networks' distribution determination for the 2025–30 regulatory control period includes the following constituent decision components:

Constituent component
In accordance with clause 6.12.1(1) of the NER, the AER's final decision is that the classification of services set out in Attachment 13 will apply to SA Power Networks for the 2025–30 regulatory control period, for the reasons set out in that attachment.
In accordance with clause 6.12.1(2)(i) of the NER, the AER's final decision is to not approve the annual revenue requirement set out in SA Power Networks' building block proposal. Our final decision on SA Power Networks' annual revenue requirement for standard control services other than legacy metering services (main standard control services) for each year of the 2025–30 regulatory control period is set out in Attachment 1. Our final decision on SA Power Networks' legacy metering annual revenue requirement for each year of the 2025–30 regulatory control period is set out in Attachment 20.
In accordance with clause 6.12.1(2)(ii) of the NER, the AER's final decision is to approve SA Power Networks' proposal that the regulatory control period will commence on 1 July 2025. Also in accordance with clause 6.12.1(2)(ii) of the NER, the AER's final decision is to approve SA Power Networks' proposal that the length of the regulatory control period will be five years from 1 July 2025 to 30 June 2030.
The AER did not receive a request for an asset exemption under clause 6.4B.1(a)(1) and therefore did not make a decision in accordance with clause 6.12.1(2A) of the NER.
In accordance with clause 6.12.1(3)(ii) and acting in accordance with clause 6.5.7(d) of the NER, the AER's final decision is to not accept SA Power Networks' proposed total forecast capital expenditure. For main standard control services, we do not accept SA Power Networks' total forecast capital expenditure of $2,337.7million ($2024–25). Our final decision includes an alternative estimate of $2,257.2 million ($2024–25). The reasons for our final decision are set out in Attachment 5. For metering, we accept SA Power Networks' proposed forecast of no capital expenditure. This is set out in Attachment 20.
In accordance with clause 6.12.1(4)(ii) and acting in accordance with clause 6.5.6(d) of the NER, the AER's final decision is to not accept SA Power Networks' proposed total forecast operating expenditure.

Constituent component
For main standard control services, we accept SA Power Networks' proposed total forecasting operating expenditure, inclusive of debt raising costs and exclusive of DMIAM of $2,036.2 million ($2024–25). The reasons for our final decision are set out in Section 2.5 of this overview. For metering, we do not accept SA Power Networks' total forecast operating expenditure of $41.0 million ($2024–25) and replace it with a forecast of $40.9 million. This is set out in Attachment 20.
SA Power Networks did not propose any contingent projects and therefore the AER has not made a decision under clause 6.12.1(4A) of the NER.
In accordance with clause 6.12.1(5) of the NER and the 2022 Rate of Return Instrument, the AER's final decision is that the allowed rate of return for the 2025–26 regulatory year is 6.12% (nominal vanilla) for the reasons set out in section 2.2 of this Overview. The rate of return for the remaining regulatory years of the 2025–30 regulatory control period will be updated annually because our decision is to apply a trailing average portfolio approach to estimating debt which incorporates annual updating of the allowed return on debt.
In accordance with clause 6.12.1(5A) of the NER and the 2022 Rate of Return Instrument, the AER's final decision on the value of imputation credits as referred to in clause 6.5.3 is to adopt a value of 0.57. Our final decision is set out in section 2.2 of this Overview.
In accordance with clause 6.12.1(6) of the NER, and acting in accordance with clause 6.5.1 and schedule 6.2 of the NER, the AER's final decision on SA Power Networks' main standard control services regulatory asset base as at 1 July 2025 is $5,209.6 million ($ nominal). The reasons for our final decision are set out in Attachment 2. The AER's final decision on SA Power Networks' metering regulatory asset base as at 1 July 2025 is $0.7 million ($ nominal). This is discussed in Attachment 20.
In accordance with clause 6.12.1(7) of the NER, the AER's final decision on SA Power Networks' estimated cost of corporate income tax for main standard control services is $44.4 million ($ nominal) for the 2025–30 regulatory control period. The reasons for our final decision are set out in Attachment 7 and the amount for each regulatory year of the 2025–30 regulatory control period is set out in the table below.

($ million, nominal)	2025–26	2026–27	2027–28	2028–29	2029–30	Total
Tax payable	29.7	31.9	23.3	12.5	6.0	103.3
Less: value of imputation credits	16.9	18.2	13.3	7.1	3.4	58.9
Net cost of corporate income tax	**12.8**	**13.7**	**10.0**	**5.4**	**2.6**	**44.4**

Constituent component
The AER's final decision on SA Power Networks' cost of corporate income tax for metering is $0.1 million ($ nominal) for the 2025–30 regulatory control period.
In accordance with clause 6.12.1(8) of the NER, the AER's final decision is to not approve the depreciation schedules submitted by SA Power Networks. For main standard control services, our final decision substitutes alternative depreciation schedules that accord with clause 6.5.5(b) of the NER. The regulatory depreciation amount approved in this final decision is $1,261.6 million ($ nominal) for the 2025–30 regulatory control period. This is discussed in Attachment 4. For metering, our final decision substitutes alternative schedules amounting to regulatory depreciation for the 2025–30 regulatory control period of $0.7 million ($ nominal). This is discussed in Attachment 20.
In accordance with clause 6.12.1(9) of the NER, the AER makes the following final decisions on how any applicable efficiency benefit sharing scheme (EBSS), capital expenditure sharing scheme (CESS), export services incentive scheme (ESIS), service target performance incentive scheme (STPIS), demand management incentive scheme (DMIS), demand management innovation allowance mechanism (DMIAM) or the customer service incentive scheme (CSIS) is to apply: • We will apply version 2 of the EBSS to SA Power Networks in the 2025–30 regulatory control period. Our reasons are set out in Section 3.2 of this Overview. • We will apply the CESS as set out in the 2023 Capital Expenditure Incentives Guideline to SA Power Networks in the 2025–30 regulatory control period. Our reasons are set out in section 3.1 of this Overview. • We will not apply the ESIS for the 2025–30 regulatory control period. • We will apply the STPIS version 2.0 (including the customer service component of the STPIS) to SA Power Networks for the 2025–30 regulatory control period. Our reasons are set out in Attachment 10. • We will apply the DMIS and DMIAM to SA Power Networks for the 2025–30 regulatory control period. Our reasons are set out in section 3.4 of this Overview. • We will not apply the customer service incentive scheme (CSIS) to SA Power Networks for the 2025–30 regulatory control period. Our reasons are set out in section 3.5 of this Overview.
In accordance with clause 6.12.1(10) of the NER, the AER's final decision is that all other appropriate amounts, values and inputs are as set out in this final determination including attachments.
In accordance with clause 6.12.1(11) of the NER and our framework and approach paper, the AER's final decision on the form of control mechanisms (including the X factor) for standard control services is a revenue cap. The revenue cap for SA Power Networks for any given regulatory year is the total annual revenue calculated using the formula in

Constituent component
Attachment 14, which includes any adjustment required to move the Distribution Use of Service (DUoS) and metering unders and overs accounts to zero. The reasons for our final decision are set out in Attachment 14.
In accordance with clause 6.12.1(12) of the NER and our framework and approach paper, the AER's final decision on the form of the control mechanism for alternative control services is to apply price caps for all alternative control services. The reasons for our final decision are set out in Attachment 14.
In accordance with clause 6.12.1(13) of the NER, to demonstrate compliance with its distribution determination, the AER's final decision is that SA Power Networks must maintain both DUoS and metering unders and overs mechanisms. It must provide information on these mechanisms to us in its annual pricing proposal. The reasons for our final decision are set out in Attachment 14.
In accordance with clause 6.12.1(14) of the NER the AER's final decision is to apply the following pass through events to SA Power Networks for the 2025–30 regulatory control period in accordance with clause 6.5.10: • Insurance coverage event • Insurer's credit risk event • Terrorism event • Natural disaster event These events have the definitions set out in Attachment 15 of our draft decision. Our reasons for this constituent decision are also set out in that attachment.
In accordance with clause 6.12.1(14A) of the NER, the AER's final decision is to approve the tariff structure statement proposed by SA Power Networks, as set out in section 4 of this Overview.
In accordance with clause 6.12.1(15) of the NER, the AER's final decision is that the negotiating framework as proposed by SA Power Networks will apply for the 2025–30 regulatory control period. The reasons for our final decision are set out in section 5.2 of this overview and Attachment 17 of our draft decision.
In accordance with clause 6.12.1(16) of the NER, the AER's final decision is to apply the negotiated distribution services criteria published in February 2024 to SA Power Networks. The reasons for our final decision are set out in in section 5.2 of this overview and Attachment 17 of our draft decision.

Constituent component
In accordance with clause 6.12.1(17) of the NER, the AER's final decision on the procedures for assigning retail customers to tariff classes for SA Power Networks is set out in Attachment 19 of our draft decision.
In accordance with clause 6.12.1(18) of the NER, the AER's final decision is that the depreciation approach to be used to establish the RAB at the commencement of SA Power Networks regulatory control period as at 1 July 2030 is to be based on forecast capex. The reasons for our final decision are set out in Attachment 2.
In accordance with clause 6.12.1(19) of the NER, the AER's final decision on how SA Power Networks is to report to the AER on its recovery of designated pricing proposal charges and account for the under and over recovery of designated pricing proposal charges is the unders and overs mechanism. It must provide information on this mechanism to us in its annual pricing proposal. The reasons for our final decision are set out in Attachment 14.
In accordance with clause 6.12.1(20) of the NER, the AER's final decision on how SA Power Networks is to report to the AER on its recovery of jurisdictional scheme amounts and account for the under and over recovery of jurisdictional scheme amounts is the unders and overs mechanism. It must provide information on this mechanism to us in its annual pricing proposal. The reasons for our final decision are set out in Attachment 14.
In accordance with clause 6.12.1(21) of the NER, the AER's final decision is to approve the connection policy proposed by SA Power Networks. Our reasons for this decision, and the approved connection policy, are in Attachment 18.

7 List of submissions

We received 5 submissions in response to our draft decision and SA Power Networks' 2025–30 revised proposal. The stakeholders are listed below.[92]

Submissions from
AER Consumer Challenge Panel (CCP) Sub-Panel 30 (CCP30)
Origin Energy
Red Energy and Lumo Energy
South Australian Council of Social Service (SACOSS)
South Australian Department for Energy and Mining (SA DEM)

92 Submissions are available on the AER website at https://www.aer.gov.au/industry/registers/determinations/sa-power-networks-determination-2025-30/consultation-submissions-draft-decision-and-revised-proposal

Shortened forms

Terms	Definition
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ARR	Annual revenue requirement
augex	Augmentation expenditure
CAF	Community Advisory Forum
capex	Capital expenditure
CCP30	Consumer Challenge Panel, sub-panel 30
CER	Consumer Energy Resources
CESS	Capital expenditure sharing scheme
CPI	Consumer price index
CSIS	Customer service incentive scheme
DMIAM	Demand management innovation allowance mechanism
DMIS	Demand management incentive scheme
DNSP or distributor	Distribution Network Service Provider
DUoS	Distribution Use of System Charges
EBSS	Efficiency benefit sharing scheme
ESB	Energy Security Board
ESOO	Electricity Statement of Opportunities
ESP	Early signal pathway
EVCI	Electric vehicle charging infrastructure
F&A	Framework and approach
Handbook	Better Resets Handbook
ICT	Information and communication technology
ISP	Integrated System Plan
NEL	National Electricity Law
NEM	National Electricity Market
NEO	National Electricity Objective

NER	National Electricity Rules
opex	Operating expenditure
PTRM	Post-tax revenue model
RAB	Regulatory asset base
RBA	Reserve Bank of Australia
repex	Replacement expenditure
RFM	Roll forward model
RORI	Rate of Return Instrument
SACOSS	SA Council of Social services
SA DEM	SA Department of Energy and Mining
SAPN	SA Power Networks
SCS	Standard control service
SMP	Statement on Monetary Policy
STPIS	Service target performance incentive scheme
TOU	Time-of-Use
TSS	Tariff structure statement
WACC	Weighted Average Cost of Capital
WPI	Wage Price Index