Final Decision

SA Power Networks Distribution Determination 2025 to 2030

(1 July 2025 to 30 June 2030)

Attachment 5
Capital Expenditure

April 2025

AUSTRALIAN ENERGY REGULATOR

Inquiries about this publication should be addressed to:

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

AER reference: AER213704

Amendment record

Version	Date	Pages
1	30 April 2025	22

List of attachments

This attachment 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

Contents

5 Capital expenditure

Capital expenditure (capex) refers to the money required to build, maintain or improve the physical assets needed to provide standard control services (SCS).[1] Generally, these assets have long lives and a distributor will recover capex from customers over several regulatory control periods. A distributor's capex forecast contributes to the return of and return on capital building blocks that form part of its total revenue requirement.

Under the regulatory framework, a distributor must include a total forecast capex that it considers is required to meet or manage expected demand, comply with all applicable regulatory obligations, maintain the safety, reliability, quality, and security of its network and contribute to achieving emissions reduction targets for reducing Australia's greenhouse gas emissions (the capex objectives).[2]

We must decide whether or not we are satisfied that this forecast reasonably reflects prudent and efficient costs and a realistic expectation of future demand, cost inputs, and other relevant inputs (the capex criteria).[3] We must make our decision in a manner that will, or is likely to, deliver efficient outcomes in terms of price, quality, safety, reliability and security of supply and contribute to achieving targets for reducing Australia's greenhouse gas emissions for the benefit of consumers in the long term (as required under the National Electricity Objective (NEO)).[4]

The *AER capital expenditure assessment outline* explains our and distributors' obligations under the National Electricity Law and Rules (NEL and NER) in more detail.[5] It also describes the techniques we use to assess a distributor's capex proposal against the capex criteria and objectives. Where relevant we also assess capex associated with emissions reduction proposals taking into account our *Guidance on amended National Electricity Objectives*.[6]

Total capex framework

We analyse and assess capex drivers, programs and projects to inform our view on a total capex forecast. However, we do not determine forecasts for individual capex drivers or determine which programs or projects a distributor should or should not undertake. This is consistent with our *ex-ante* incentive-based regulatory framework.

Once the *ex-ante* capex forecast is established, there is an incentive for distributors to provide services at the lowest possible cost, because the actual costs of providing services will determine their returns in the short term. If distributors reduce their costs, the savings are shared with consumers in future regulatory control periods. Our assessment of the ex-ante capex is consistent with the NEO, which in addition to providing for the lowest possible costs

1 These are services that form the basic charge for use of the distribution system.

2 NER, cl. 6.5.7(a).

3 NER, cl. 6.5.7(c).

4 NEL, ss. 7, 16(1)(a).

5 AER, *Capex assessment outline for electricity distribution determinations*, February 2020.

6 AER, *Guidance on amended National Energy Objectives*, October 2024.

also recognises that services should be valued appropriately and adapt to changing circumstances to maintain efficiencies in the long term interest of consumers. This incentive-based framework provides distributors with the flexibility to prioritise their capex program given their circumstances and due to changes in information and technology.

Distributors may need to undertake programs or projects that they did not anticipate during the reset. Distributors also may not need to complete some of the programs or projects proposed if circumstances change, these are decisions for the distributor to make. We consider a prudent and efficient distributor would consider the changing environment throughout the regulatory control period and make decisions accordingly.

Importantly, our decision on total capex does not limit a distributor's actual spending. We set the forecast at a level where the distributor has a reasonable opportunity to recover its efficient costs.

Assessment approach

We provide guidance on our assessment approach in several documents, including the following which are of relevance to this decision:

- AER's *Expenditure Forecast Assessment Guidelines*[7]
- Regulatory Investment Test for Distribution (RIT-D) Guidelines[8]
- AER's *Asset Replacement Industry Note*[9]
- AER's *Information and Communication Technologies (ICT) Guidance Note*[10]
- AER's *Guidance on amended National Energy Objectives.*[11]

We also had regard to the guiding principles in the AER's *Better Resets Handbook – Towards consumer centric network proposals* which encourages networks to develop high quality, well-justified proposals that genuinely reflect consumers' preferences.[12]

Our final decision has been based on the information before us, which includes:

- the distributor's regulatory proposal and accompanying documents and models
- the distributor's responses to our information requests
- stakeholder comments in response to our Issues Paper, our draft decision and SA Power Networks' revised proposal.

---

7 AER, *Expenditure Forecast Assessment Guideline 2013*, August 2022.

8 AER, *2024 Review of the cost benefit analysis and regulatory investment test guidelines*, November 2024.

9 AER, *Industry practice application note for asset replacement planning*, January 2019.

10 AER, *Non-network ICT capex assessment review*, November 2019.

11 AER, *Guidance on amended National Energy Objectives*, October 2024.

12 AER, *Better Resets Handbook – Towards consumer-centric network proposals*, December 2021.

5.1 Final decision

Our final decision is to not accept SA Power Networks' proposed total forecast capex of $2,337.7 million ($2024–25) because we are not satisfied that it reasonably reflects the capex criteria (in particular, we are not satisfied that it reasonably reflects the prudent and efficient costs, and a realistic expectation of demand, cost inputs and other inputs, required to meet the capex objectives). 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 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 Network's forecast.[13] We also had regard to a number of other factors, including that SA Power Networks' revised capex forecast is materially greater than actual and forecast capex in the current regulatory period. We are satisfied our substitute forecast reasonably reflects the capex criteria.

We consider this forecast will sufficiently allow a prudent and efficient service provider in SA Power Networks' circumstances to meet the capex objectives. Table 5.1 outlines our substitute estimate of forecast capex and compares this to SA Power Networks' proposed forecast capex.

Table 5.1 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.

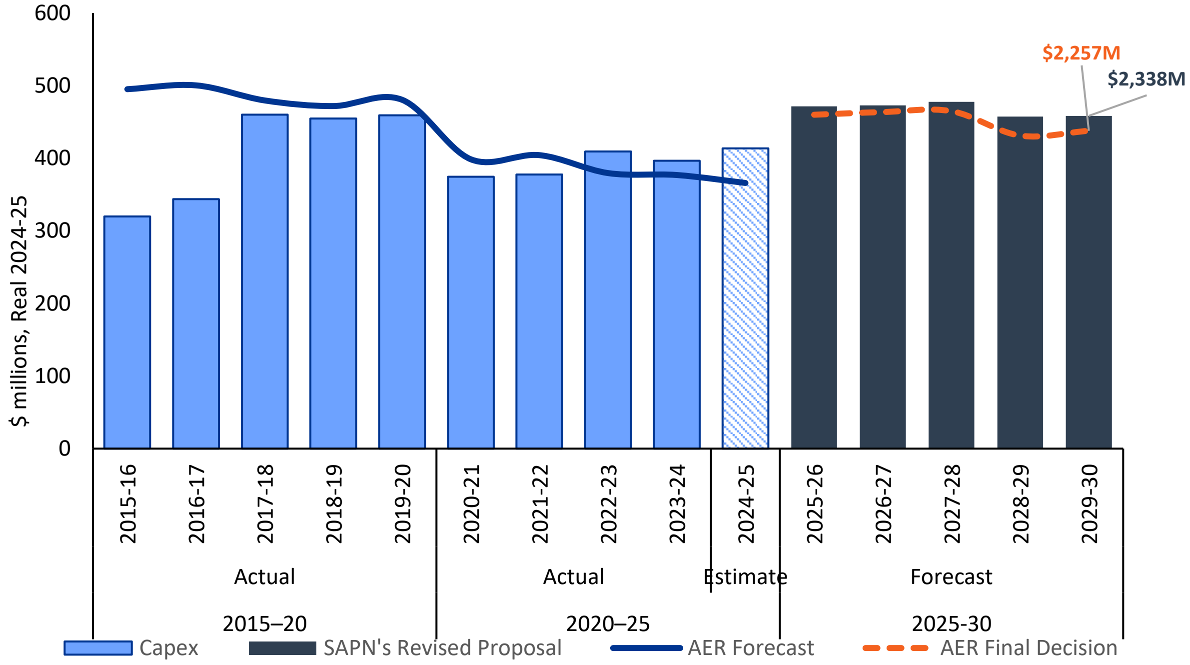
5.2 SA Power Networks' revised proposal

SA Power Networks' revised proposal forecasts $2,337.7 million ($2024–25) 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.

Figure 5.1 outlines SA Power Networks' historical capex trend, its proposed forecast for the 2025–30 regulatory control period, and our final decision.

13 NER, cl. 6.5.7(d).

Figure 5.1 SA Power Networks' historical and forecast capex ($million, $2024–25)



Source: AER RIN Database, AER Analysis.
Note: Nominal figures converted to real dollars 2024–2025.

The key aspect of SA Power Networks' revised proposal is 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. Additionally, there is an increase in ICT expenditure to update market facing systems, as the Australian Energy Market Operator (AEMO) is redesigning and replacing its own market systems as part of the Energy Security Board's (ESB) energy transition requirements and timelines. SA Power Networks also provided additional information to support its proposed innovation fund.

SA Power Networks used the demand forecast from AEMO's 2024 Integrated System Plan (ISP) to determine its demand driven augmentation capital programs. SA Power Networks considers that the demand forecasts determined for the 2024 ISP are more robust than the demand forecasts in AEMO's 2024 Electricity Statement of Opportunities (ESOO).

5.3 Reasons for final decision

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

- amended its replacement capital 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.

Notwithstanding the above, some of our key concerns remain unresolved. In the draft decision, we requested that SA Power Networks update its demand forecast using the AEMO 2024 ESOO. Instead, SA Power Networks used AEMO's 2024 ISP to generate its demand forecast. This is a departure from our standard approach of using the demand forecast from the ESOO. The 2024 ISP projected higher demand compared to the forecast in the 2024 ESOO.

The selection of the data source for the demand forecast is a key area of focus in our assessment of capex in the revised proposal.

In addition, we focused on the material capex categories, programs or projects:

- that we had initially included as placeholders in our draft decision, such as innovation funding and the CBD reliability program
- where SA Power Networks proposed further increases when compared to our draft decision, such as replacement and augmentation capex.

As for the demand forecast, we engaged with AEMO and gained a deeper understanding of its forecasting publications. Based on this, we consider the ESOO is the most appropriate data source for network businesses to use in their demand forecasts. The ESOO provides the most up-to-date demand forecast compared to the ISP, which relies on the previous year's ESOO data and assumptions. We discuss this in further detail in Appendix A.2.

In terms of augmentation expenditure, we have not included all of SA Power Networks' proposed total augmentation capex. Our alternative estimate accounts for our adjustments to demand driven augmentation capex, and our adjustments to the maintain reliability augmentation program (including the automation component of the CBD reliability program).

Our use of the AEMO 2024 ESOO resulted in a $36.7 million reduction in SA Power Networks' demand driven augmentation expenditure, from $84.0 million to $47.3 million. 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 in its proposal. SA Power Networks' proposal also indicates there is sufficient capacity to meet demand in most parts of its network. Therefore, it is not unreasonable that demand driven augex will be lower than in the current period, despite a forecast increase in demand.

We consider that the augmentation capex component of the CBD reliability program (the $26.1 million automation component) is closely tied to SA Power Networks' proposed $74.5 million maintain reliability augmentation program. Therefore, we assessed the automation component as part of the efficiency of the maintain reliability augmentation program. This results in a total forecast of $100.6 million for the maintain reliability augmentation program for our assessment purposes. We discuss our reasons for this in Appendix A.3.

Our final decision is to include $68.0 million for the maintain reliability augmentation program, which is a $32.6 million reduction relative to SA Power Networks' revised proposal. Our alternative estimate for this program is based on a $27.8 million reduction to the maintain reliability and CBD automation components (consistent with the proportional adjustment we applied in our draft decision, but now also considering CBD automation) as well as a $4.8

million reduction to the network protection management component. The revised maintain reliability program, including the CBD reliability program automation component, has not been shown to be prudent or efficient for several reasons. Despite an improving trend in reliability from 2010–11 to 2023–24, SA Power Networks cites an uptick in the duration of service interruptions, as measured by the System Average Interruption Duration Index (SAIDI), from 2019–20 to 2023–24. However, this increase falls within historical variance and is largely due to responding to asset failures in the Adelaide CBD and outages in rural areas. Additionally, the frequency of service interruptions, as measured by the System Average Interruption Frequency Index (SAIFI), has shown a more pronounced downward trend, indicating fewer supply interruptions. As such, we anticipate reliability over the 2025-30 regulatory control period will be maintained (rather than decline as SA Power Networks claims).

On replacement expenditure, SA Power Networks addressed most of our concerns raised in our draft decision, and we are satisfied that the revised expenditure uplift from our draft decision is justified. Our final decision is to accept SA Power Networks' replacement capital expenditure of $884.6 million in its revised proposal.

Table 5.2 sets out our final decision for SA Power Networks by capex category.

Table 5.2 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 integration	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.

Table 5.3 summarises our views on each of the capex categories and whether they are prudent and efficient and reflect the capex criteria, and the reasons for this. Further detail and reasons on capex for the final decision are contained in Appendices A.1, A.2 and A.3.

Our findings on each capex driver are part of our broader analysis and should not be considered in isolation. We do not approve an amount of forecast expenditure for each individual capex driver or project/program. However, we use our findings on the different capex drivers to assess a regulated business' proposal as a whole and arrive at a substitute estimate for total capex where necessary. Our decision on total capex does not limit a regulated business' actual spending.

Table 5.3 Summary of findings and reasons, by capex category

Category	Findings and reasons
Replacement	We have included SA Power Networks' proposed $884.6 million ($2024–25) for replacement expenditure in the total forecast capex. SA Power Networks addressed most of the concerns we raised in our draft decision, corrected a reporting error, updated the input assumptions for reliability, likelihood of consequence and probability of failure, and demonstrated the relationship between the risk-cost model output and network performance impact of proposed expenditure levels. We consider SA Power Networks has demonstrated that the revised expenditure uplift from the draft decision is justified and we have accepted the revised replacement expenditure. Our reasons for this are set out in Appendix A.1.
Connections	We have included SA Power Networks' gross connections expenditure of $748.3 million ($2024–25) in the total forecast capex. This represents an increase of $3.1 million compared to the proposed capex that was considered and accepted in our draft decision, due to changes to real cost escalation rates.[14] This results in a net connections capex amount (gross connections expenditure less customer contributions) of $232.1 million ($2024–25). Customer contributions are discussed under the 'Customer contributions' category in this Table 5.3.
Augmentation	We have not included all of SA Power Networks' proposed augmentation expenditure in the total forecast capex. We are not satisfied that SA Power Networks provided sufficient reasoning to support using the demand forecast from AEMO's 2024 ISP to determine its demand driven augmentation capital programs, or to support the uplift in maintain reliability augmentation, including the automation component of the CBD reliability program. SA Power Networks proposed $472.2 million ($2024–25) for augmentation capex. Our final decision is to include $402.8 million for augmentation capex. This is $69.4 million or 14.7% less than what SA Power Networks proposed. Our reasons for this are set out in Appendices A.2 and A.3.

[14] AER, *Draft Decision Attachment 5 - Capital expenditure - SA Power Networks - 2025-30 Distribution revenue proposal,* September 2024, p. 9.

Category	Findings and reasons
ICT	We have included SA Power Networks' proposed ICT capex forecast of $321.4 million ($2024–25) in the total forecast capex. We largely accepted SA Power Networks' initial ICT proposal in our draft decision, including $300.8 million of ICT capex.[15] Our draft decision provided placeholders for metering related costs and step changes arising from AEMC Rule changes. In its revised proposal, SA Power Networks proposed $321.4 million in ICT capex, with the additional $20.5 million of expenditure (when compared to its initial proposal) mainly attributed to the November 2024 AEMC legacy metering transition rule change (November 2024) and to account for the AEMO 2025 market changes requirements (July 2024).[16] We reviewed the business cases and found SA Power Networks' revised proposal to be reasonable, including the additional costs to address the rule changes on metering transition and to account for the market change requirements. The program is clearly articulated and aligns with our ICT capex guidance note.[17]
Fleet	We have included SA Power Networks' proposed fleet forecast of $149.9 million in the total forecast capex. We accepted SA Power Networks' forecasting approach for its fleet capex in our draft decision.[18] The revised proposal is based on mechanical adjustments.
Property	We have included SA Power Networks' property forecast of $115.7 million ($2024–25) in the total forecast capex. This was considered and accepted in our draft decision.[19]
CER integration	We have included SA Power Networks' CER integration forecast of $91.3 million ($2024–25) in the total forecast capex. This was considered and accepted in our draft decision.[20]
Other non-network capex, including the innovation fund	We have included SA Power Networks' non-network - other capex forecast of $50.4 million in the total forecast capex. This includes SA Power Networks' innovation funding that was not accepted at the draft decision. We are satisfied that SA Power Networks' revised proposal for innovation funding capex of $16 million ($2024–25) is consistent with the capex criteria.[21] In its initial proposal, SA Power Networks requested $16 million ($2024–25) for capex and $4 million ($2024–25) for opex.[22] Our draft decision did not include any innovation expenditure, pending SA Power Networks providing additional information to demonstrate that its proposal met our innovation criteria.[23] In its revised proposal, SA Power Networks maintained the

15 AER, *Draft Decision Attachment 5 - Capital expenditure - SA Power Networks - 2025-30 Distribution revenue proposal,* September 2024, p. 41.

16 AEMC, *Accelerating smart meter deployment*, November 2024.
AEMO, *Foundational & Strategic Initiatives Business Case*, July 2024.

17 AER, *Guidance Note – Non-network ICT capex assessment approach for electricity distributors*, 28 November 2019.

18 AER, *Draft Decision Attachment 5 - Capital expenditure - SA Power Networks - 2025-30 Distribution revenue proposal,* September 2024, p. 13.

19 AER, *Draft Decision Attachment 5 - Capital expenditure - SA Power Networks - 2025-30 Distribution revenue proposal,* September 2024, p. 11.

20 AER, *Draft Decision Attachment 5 - Capital expenditure - SA Power Networks - 2025-30 Distribution revenue proposal,* September 2024, p. 11.

21 NER, clause 6.5.7(c).

22 AER, *Draft Decision Attachment 5 - Capital expenditure - SA Power Networks - 2025-30 Distribution revenue proposal,* September 2024, p. 36.

23 AER, *Draft Decision Attachment 5 - Capital expenditure - SA Power Networks - 2025-30 Distribution revenue proposal,* September 2024, pp. 37–38.

Category	Findings and reasons
	same funding amount for both capex and opex but presented a more thorough approach compared to its initial proposal.[24] SA Power Networks' revised proposal effectively addresses the concerns raised in our draft decision and meets the innovation criteria.[25,26] In particular, the revised proposal: • removed projects from its initially extended project list, such as resilience batteries and heavy electric vehicle (EV) initiatives, which lacked adequate justification • provided a firm list of nine projects • refined its governance framework in conjunction with customers, setting out more clearly defined innovation fund principles to ensure that projects are truly innovative and deliver the desired outcomes for its customers • explored various approaches to share knowledge and customer benefits with customers, the industry and regulators. We received some stakeholder submissions which do not support the innovation fund.[27] However, we consider the investments are relatively modest and there are potential benefits of allowing businesses to test new ideas and support better utilisation of the network. On this basis, we have accepted SA Power Networks' revised proposal for innovation funding.
Capitalised overheads	We have included $40.6 million of SA Power Networks' capitalised overheads in the total forecast capex. This is $1.3 million (or 3.1%) less than the $41.9 million ($2024–25) in capitalised overheads proposed by SA Power Networks. Our alternative estimate for capitalised overheads reflects the adjustments to various capex categories in our alternative total capex estimate. SA Power Networks applied the same approach as the one used in its original proposal, which we considered and accepted in our draft decision.[28]
Customer contributions	We have included SA Power Networks' customer contribution forecast of $516.2 million ($2024–25) in the total forecast capex. This represents a marginal $1.6 million increase from its initial proposal, which was accepted in our draft decision, and is consistent with the increase in connections expenditure due to changes to real cost escalation rates.[29]
Disposals	We have included SA Power Networks' asset disposal forecast in the total forecast capex, which we considered and accepted in our draft decision.

24 SAPN, *5.13.4 - Innovation Fund - December 2024 – Public*.

25 AER, *Draft Decision Attachment 5 - Capital expenditure - SA Power Networks - 2025-30 Distribution revenue proposal,* September 2024, pp. 40–41.

26 AER, *Draft Decision Attachment 5 - Capital expenditure - SA Power Networks - 2025-30 Distribution revenue proposal,* September 2024, pp. 37–38.

27 There is opposition to the additional costs being passed on to consumers for innovation projects, with SACOSS and the SA Government strongly disagreeing with this approach and believing SA Power Networks can undertake these projects as part of its usual business practices.

28 AER, *Draft Decision Attachment 5 - Capital expenditure - SA Power Networks - 2025-30 Distribution revenue proposal,* September 2024, p. 12.

29 AER, *Draft Decision Attachment 5 - Capital expenditure - SA Power Networks - 2025-30 Distribution revenue proposal,* September 2024, p. 12.

A Reasons for decision on key capex categories

This appendix sets out our assessment of key capex categories and programs/projects within SA Power Networks' total revised capex forecast and the reasons for our decision. This appendix includes:

- Replacement expenditure (A.1),
- Demand forecast (A.2), and
- Augmentation expenditure (A.3)

A.1 Replacement expenditure

Replacement expenditure (repex) must be set at a level that allows a distributor to meet the capex criteria. Replacement can occur for a variety of reasons, including when:

- an asset fails while in service or presents a real risk of imminent failure
- a condition assessment determines that it is likely to fail soon or degrade in performance, such that it does not meet its service requirement and replacement is the most economic option[30]
- the asset does not meet the relevant jurisdictional safety regulations and can no longer be safely operated on the network
- the risk of using the asset exceeds the benefit of continuing to operate it on the network.

The majority of network assets will remain in efficient use for far longer than a single five-year regulatory control period (many network assets have economic lives of 50 years or more). As a result, a distributor will only need to replace a portion of its network assets in each regulatory control period.

A.1.1 AER's final decision

Our final decision is to accept SA Power Networks' repex of $884.6 million in its revised proposal in our alternative forecast of total capex.

A.1.2 SA Power Networks' revised proposal

SA Power Networks' proposed $884.6 million ($2024–25) of repex in its revised proposal, which is 14% greater than our draft decision of $772.6 million, but 3% lower than its initial proposal of $909.4 million.[31] SA Power Networks' revised proposal for repex includes $35.5 million for the cable replacement as a part of the CBD reliability program.

30 A condition assessment may relate to assessment of a single asset or a population of similar assets. High-value/low-volume assets are more likely to be monitored on an individual basis, while low value/high volume assets are more likely to be considered from an asset category wide perspective.

31 AER, *Draft Decision Attachment 5 - Capital expenditure - SA Power Networks - 2025-30 Distribution revenue proposal,* September 2024, p. 16.

A.1.3 Reasons for decision

SA Power Networks' revised proposal effectively addresses most of the concerns we raised in our draft decision. In particular, the revised proposal:

- identified a reporting data error in response to our concerns about some asset replacements not demonstrating performance issues. The error resulted in a number of asset failures being misreported between voltage levels. This was corrected in the annual RINs, and the updated data was used in the revised proposal.
- responded to our concerns about the risk-cost model overstating the risks. SA Power Networks adopted our suggestions in the draft decision and updated the input assumptions for reliability, likelihood of consequence and probability of failure.
- demonstrated the relationship between risk-cost model output and network performance impact of proposed expenditure levels.

The key movements in expenditure between the draft decision and revised proposal are driven by:

- updating all of the input assumptions to a 5-year averaging period and to the latest 5 years of data. This changed the risk profile for the network, resulting in some assets seeing an increase in replacement (i.e. transformers), and some assets seeing a decrease in replacement (i.e. conductors).
- correcting the failure data error identified during the draft decision.
- recalibration of the probability of failure models to address concerns of an upwards bias.
- updated unit rates that saw some asset category unit rates increase by up to 70%.
- updated Adelaide CBD business case that accounts for 25% of the difference between the draft decision and revised proposal (discussed further below).

Accounting for the issues above, (excluding the CBD program) resulted in a 12% total increase in expenditure for the asset types forecast using the risk-cost model, when compared to our draft decision.

A.1.3.1 Repex risk cost model

SA Power Networks responded well to our concerns about its risk-cost model, both in its revised proposal and in a subsequent workshop where it responded to our follow-up questions.

However, the model is a restricted in-house model that cannot be provided in an accessible and usable format. This made it difficult for us to access the model to undertake further analysis. A workaround was used to review the model in sections in Excel. This is not an ideal way to undertake the assessment. We encourage SA Power Network to consider model accessibility as an area for improvement for the next regulatory control period.

A.1.3.2 CBD reliability program – cable replacement

SA Power Networks submitted a revised proposal for the Adelaide CBD reliability program that included $35.5 million in cable replacement expenditure.

We assessed the business case and are satisfied that the proposal is prudent in that action is needed to improve CBD reliability and comply with its jurisdictional requirements. SA Power Networks' revised proposal responded to the feedback we provided in our draft decision in identifying and assessing options to address the stated network need (i.e. HV cables that are increasingly failing and causing the ESCOSA CBD reliability targets to be exceeded). It considered a reasonable range of options to address the identified need.

The fundamental network need is driven by the poor and deteriorating condition of a number of 11 kV cables within the CBD which are causing failures. Addressing the fundamental root cause requires a focus on cable replacement/rearrangement (altering topology) which reduces the number of failure events directly, and hence reduces System Average Interruption Frequency Index (SAIFI) while having a consequential impact on SAIDI.

We are satisfied that the proposed CBD cable replacement program will address the underlying problem in the CBD and will result in meeting the jurisdictional requirement. We assessed the related automation component of the CBD reliability program as part of the proposed maintain reliability program.

A.2 Demand forecast

Maximum demand forecasts are fundamental to a distributor's forecast capex and opex, and to our assessment of that forecast expenditure. This is because we must determine whether the capex and opex forecasts reasonably reflect a realistic expectation of forecast demand for services. Reasonable demand forecasts based on the most current information are important inputs to ensuring efficient levels of investment in the network.

A.2.1 AER's final decision

Our final decision is to not accept SA Power Networks' demand forecast in the revised proposal, as we are not satisfied that AEMO's 2024 Integrated System Plan (ISP) represents the most reasonable demand forecast. We consider that AEMO's 2024 Electricity Statement of Opportunities (ESOO) is the latest available and therefore most appropriate data source to rely on when forecasting demand. We are also concerned the SA Power Networks' block load adjustment to AEMO's system-wide forecast maybe over-estimated.

A.2.2 SA Power Networks' revised proposal

SA Power Networks used the demand forecast from AEMO's ISP to determine its demand driven augmentation capital programs. SA Power Networks engaged Endgame Economics to review its demand forecast. Endgame Economics supported the use of the demand forecast in AEMO's 2024 ISP and raised concerns about the reliability of AEMO's 2024 ESOO demand forecast. It argued that the 2024 ISP forecast was robust and that AEMO was not able to explain the difference between the two forecasts.[32]

As for the block load forecast, Endgame Economics advised that SA Power Networks' revised block load forecast is not over estimated or duplicated. Endgame Economics argued that AEMO's system-wide forecasts exclude SA Power Networks' block loads, which are

32 Endgame Economics, Demand Forecast Review SA Power Networks, 27 November 2024, p. 4.

forecast for industrial, agricultural, utility, and commercial sectors, and SA Power Networks applies a diversity factor to reduce the risk of over-estimating demand.

Endgame Economics also raised concerns about the impact of the recent mild weather on the weather normalisation applied by AEMO in its 2024 ESOO demand forecasts.

The key factors in the revised proposal demand forecast are as follows:

- Use of the demand forecast in AEMO's 2024 ISP, which projects higher demand compared to the 2024 ESOO forecast.
- Exclusion of the Battery Energy Storage Systems (BESS) load adjustments, in response to concerns raised in our draft decision.
- Implementation of a refined materiality threshold set at either a 5% capacity limit at a transmission connection point or a 10MW threshold, whichever is lower, to determine block load adjustments.
- Introduction of a 0.8 diversity factor and a 2-year connection deferral in the block load forecasts to account for the slow uptake in customer-requested loads.

A.2.3 Reasons for decision

Our primary focus of the assessment was the data source used for the demand forecast and the approach to the block load forecast.

Our draft decision requested that SA Power Networks update its demand forecast based on AEMO's 2024 ESOO and refine the block load forecast to avoid over-estimation or duplication. However, in its revised proposal, SA Power Network instead used AEMO's 2024 ISP, which provides a higher demand forecast than the 2024 ESOO. This approach differs from the AER's standard approach of using the latest AEMO forecasts for demand[33] which, in this case, is the demand forecast in the 2024 ESOO because it relies on the most up to date inputs and assumptions.

We consulted with AEMO to gain a better understanding of the two forecasts, the forecasting objectives, the key differences between them, and the factors driving changes in South Australia's demand forecasts between the 2024 ISP and the 2024 ESOO. Additionally, we gained further insight into AEMO's approach to forecasting large industrial loads and block loads.

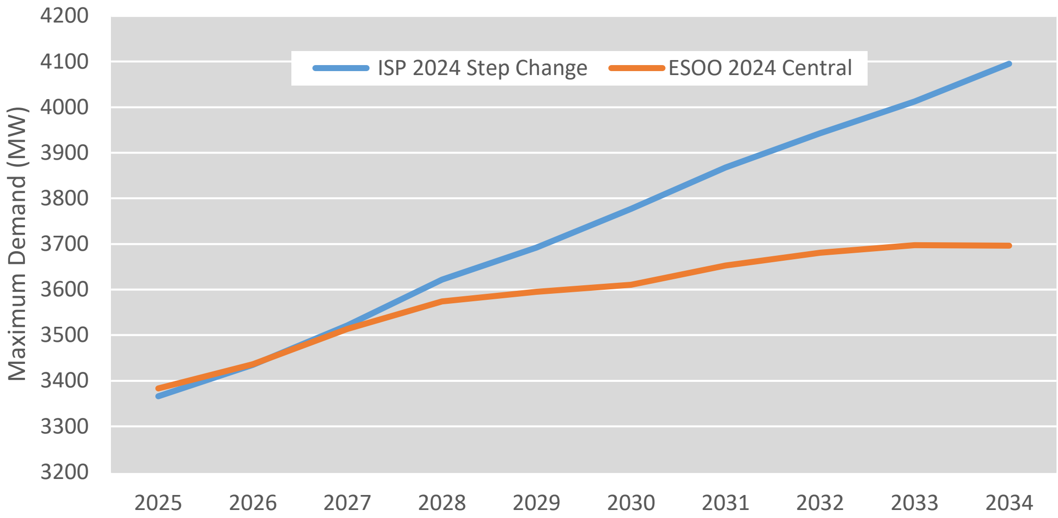
2024 ESOO vs 2024 ISP

The lower 2024 ESOO forecasts compared with the 2024 ISP reflects a slower growth in energy consumption. This is primarily due to lower electric vehicle (EV) forecasts and a lower business forecast driven by weaker economic growth over the next ten years. Other reasons for the slower demand growth include updates on rooftop solar, energy storage, load management and demand responses, energy efficiency measures and changes in consumer

33 AER, *Draft Decision Attachment 5 - Evoenergy Electricity Distribution Determination 2024 to 2029,* Appendix A.

behaviour. Figure 5.2 below compares the two maximum demand forecasts at 10% probability of exceedance (POE).

Figure 5.2: South Australia Maximum Demand, POE10 forecast



Source: AER analysis

As for Endgame Economics' concern about the likely impact of the mild weather conditions in recent years when normalising demand, AEMO's methodology for the 2024 ESOO balances between longer term data for weather patterns and short-term usage trends. We consider that AEMO's use of longer historical data in the weather normalisation process helps improve the robustness of estimating the weather-demand relationship and establishing representative weather conditions.

We maintain our view that the AEMO ESOO demand forecast is a preferable data source because the ESOO is updated annually, whilst the ISP is updated every two years. The ISP demand forecast relies on the inputs and assumptions developed from the previous year, resulting in a one-year delay in the updates. As a result, the 2024 ISP demand forecast is consistent with the 2023 ESOO, rather than the more recent and relevant 2024 ESOO forecast.

However, we acknowledge the impact of specific assumptions have not been quantified by AEMO in the 2024 ESOO. This is because AEMO updates the latest data using the same methodology used for previous updates. Although AEMO is obligated to explain the accuracy of the forecasts, it is not required to quantify the specific factors contributing to the change in demand.

We recommend that SA Power Networks engages more actively with AEMO during the annual ESOO demand forecast consultation process, to ensure that drivers of demand and changes in demand forecasts are better understood.

Block load forecasts

In its revised proposal, SA Power Networks continued its approach to forecasting block loads to adjust AEMO's system peak demand. SA Power Networks responded to several concerns we raised in our draft decision, including the exclusion of BESS load adjustments. We are satisfied with this update in its revised proposal.

SA Power Networks also applied a 0.8 diversity factor and a two-year block load deferral approach to better account for the potentially slower uptake of customer-requested loads. While this method could lead to the deferral of some projects, we do not believe that using this approach to adjust block loads in the AEMO system forecast fully addresses our concerns regarding potential duplication and the over-estimation of block load forecasts.

SA Power Networks refined its materiality threshold to determine block load adjustments, setting it at the 5% capacity threshold at a transmission connection point or 10MW threshold, whichever is lower. This approach covers block loads that meet the materiality threshold either individually or cumulatively across projects for zone substations connected to the same transmission connection point. This results in total adjustments of 126.55MW (POE10%), which is substantially higher than 55.9MW of non-BESS block loads included in its original proposal.

We consider that this updated approach does not adequately addresses our concern about the potential duplication and over-estimation of block loads. We remain concerned that SA Power Networks' method of adjusting transmission connection point block loads to the AEMO forecast has consistently overestimated the extent of materially large new loads that may be missing from the system demand projected by AEMO. Our concern is not with SA Power Networks' block load adjustments at the spatial level, but rather with how additional block load is adjusted in relation to AEMO's system forecast. SA Power Networks' method to block load adjustments would result in:

- excess block loads when aggregating block loads for zone substations linked to a transmission connection point.
- potential duplication with AEMO's large industrial loads (LILs) forecasts, even if the threshold applies to only a single block load.

In principle, block loads added to the AEMO system peak demand should only be allowed for by exception. SA Power Networks was unable to demonstrate that the additional block load from customer requests is material at the system level and has not been accounted for in the AEMO system demand forecasts.

We consider that AEMO's demand forecasts, developed under the central scenario, provide the most accurate estimates of the system demand at the time, based on available data and the drivers. These forecasts systematically incorporate the impact of structural drivers at the state level. In addition to econometrically modelling and forecasting the residential and business loads, AEMO specifically forecasts LILs, i.e., load that is greater than 10 MW for greater than 10% of the latest financial year, using a survey-based approach.

The spatial distribution of forecasted growth in system peak demand is often uneven, causing significant increases or decreases in load at specific transmission connection points or zone substations. These substantial fluctuations may not be captured in simple trend-based growth forecasts, using SA Power Networks' bottom-up approach that forecasts demand at a more localised level. While these changes could be considered as additional block loads in the forecasts for the relevant assets, they may, collectively, have already been accounted for in AEMO's broader forecasts. Since AEMO incorporates key demand drivers at the system level and specific forecasts of LILs, these block loads at the local level should not be added separately to the system peak demand.

SA Power Networks advised that it had not provided new block loads to AEMO since early 2023[34] and, therefore, the block load adjustments included in the forecast have not been accounted for in AEMO's system-wide business demand forecasts.[35]

AEMO's process for estimating demand includes the following steps:

- In preparation for the ESOO publication, AEMO has annually requested information on existing and prospective LILs from network service providers (NSPs) under its standing information requests.[36] The NSPs are also required to advise AEMO as soon as practicable after becoming aware of any material changes.[37]
- AEMO's LIL forecasts are informed by ongoing interactions with ElectraNet regarding both prospective connections and expansions to existing loads. Additionally, AEMO carries out annual surveys directly with LILs to better understand their future energy needs.
- AEMO also considers multisectoral modelling developed by CSIRO and ClimateWorks to inform LIL forecasts beyond five years. This modelling considers a least-cost pathway for decarbonisation and achieving net-zero targets across the economy. It also accounts for increases to industrial loads from electrification efforts and the emergence of the hydrogen production sector.[38]

These data sources provide AEMO with a solid foundation for developing the LIL forecast. We encourage SA Power Networks engage more proactively with AEMO throughout the ESOO and ISP consultation process to address any concerns regarding the coverage and accuracy of AEMO's demand forecasts.

A.3 Augmentation expenditure

Augmentation is capital expenditure required to build or upgrade the network to address changes in demand and network utilisation to enable the network service provider to comply with quality, safety, reliability and security of supply and greenhouse gas emission reduction target requirements. SA Power Networks' augmentation consists of, but is not limited to, expenditure on capacity augmentation (including both demand and compliance driven) and maintain reliability augmentation capital programs.

A.3.1 AER's final decision

We are not satisfied that SA Power Networks' proposed augmentation forecast of $472.2 million ($2024–25) reflects the capex criteria.[39] Our decision is to include $402.8 million for

34 SA Power Networks, Response to Information Request #042, p. 4.

35 Endgame Economics, Demand Forecast Review, 27 November 2024, p. 19.

36 AEMO, Standing Information Requests, available at: https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/standing-information-requests.

37 AEMO, *Standing Information Request for 2024*, January 2024, p. 2.

38 AEMO, Response to Follow-up Questions for AEMO, pp. 6-7.

39 We must determine whether forecast capex reflects the capex criteria under cl. 6.5.7(c) of the NER.

augmentation in our alternative capex estimate. This is a $69.4 million ($2024–25) or 14.7% reduction in augmentation. This includes a $32.6 million reduction in the maintain reliability program and a $36.7 million reduction in demand driven augex resulting from the use of AEMO's 2024 ESOO demand forecast rather than AEMO's 2024 ISP demand forecast.

A.3.2 SA Power Networks' revised proposal

SA Power Networks' revised proposal for augex is $472.2 million, which is 11.5% greater than our draft decision and 1.4% less than its initial proposal.

The reduction in SA Power Networks' proposal (relative to its initial proposal) is related to demand driven augex, which has reduced to $84.4 million, i.e. $56.4 million lower than the initial proposal of $140.8 million and $19.9 million lower than our draft decision of $104.3 million. This is primarily due to the lower demand forecast in the 2024 ISP compared to the 2022 ESOO that SA Power Networks used in its initial proposal.

In responding to our draft decision, SA Power Networks incorporated additional steps to strengthen the robustness of the optimal timing of demand driven augmentation projects. It also adopted EMCa's recommended benefit-cost ratio of 1.2 and delayed block load triggered projects by two years to address overestimation concerns.

A.3.3 Reasons for decision

A.3.3.1 Demand driven augex

In responding to concerns raised about the demand driven augex forecast in our draft decision, SA Power Networks incorporated a Benefit-Cost-Ratio (BCR) analysis recommended by EMCa and introduced a 2-step project selection process[40] to more effectively assess the optimal timing of projects for the 2025–30 regulatory control period. We are satisfied that SA Power Networks has adequately addressed our primary concern regarding the optimal timing of the demand driven augex programs.

However, we are not satisfied with the demand forecast used to project the demand driven augex programs. The reduction in demand driven augex in our alternative forecast is due to the use of the AEMO 2024 ESOO demand forecast rather than the AEMO 2024 ISP demand forecast proposed by SA Power Networks. By applying the AEMO 2024 ESOO demand forecast, we found that the demand driven augex has decreased by $36.7 million.

We have used SA Power Networks' Capacity Augex tool to forecast the demand driven augex. This model is based on a pro-rata scaling approach rather than a bottom-up forecasting method. We believe this approach reasonably reflects the efficient capex required by SA Power Networks to meet or manage expected demand for the 2025–2030 regulatory control period. We do not expect that our forecast of demand driven augex using the pro-rata scaling approach would be materially different than an updated bottom-up forecast, based on the size of the proposed program. We also consider that our forecast represents the best possible estimate given the information available to us.

40 SAPN, Attachment 5 - Capital Expenditure - December 2024 – Public, p. 29.

In considering the impact of block loads on augex, we found that the change resulting from our alternative block load forecast is minimal. This aligns with SA Power Networks' view. Therefore, we have not made any adjustments to augex based on block load changes.

A.3.3.2 Maintain reliability augex

SA Power Networks' revised proposal was $74.5 million. The revised proposal stated:

- The program consists of two projects – maintain reliability ($64.9 million) and network protection management ($9.6 million)
- Other capex programs have been taken into account to remove double counting
- The program is not to meet Essential Services Commission of South Australia (ESCOSA) reliability targets, which SA Power Networks acknowledges it is meeting, but to maintain STPIS targets
- That reliability performance is worsening and expected to worsen due to bats, CBD cables (if revised proposal is not accepted) and weather and vegetation events

We consider there is overlap between the proposed automation component of the CBD reliability program ($26.1 million) and the proposed maintain reliability augex. We found that SA Power Networks' options analysis for its CBD reliability program favoured automation solutions, however we consider that automation solutions should be assessed as part of an overall capex portfolio aimed at addressing reliability concerns (across the entire network and not necessarily for the Adelaide CBD). Therefore, we assessed the automation component as part of maintain reliability augex, which changed the total program amount we have assessed to $100.6 million.

Our final decision is to include $68.0 million for reliability augex, a reduction of $32.6 million from SA Power Networks' revised proposal. This is further discussed below.

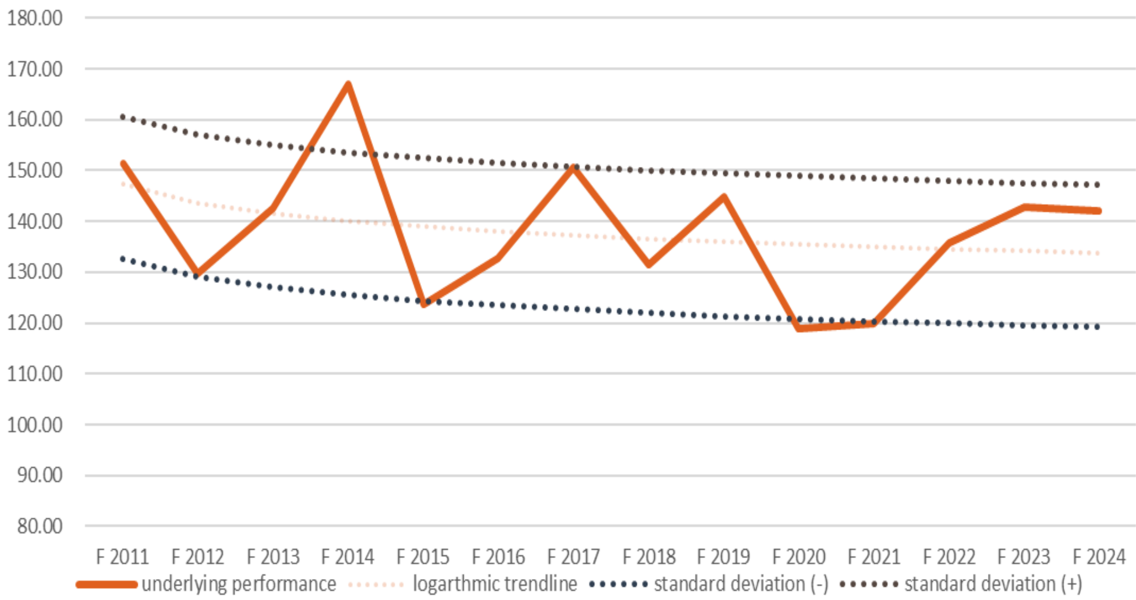
Maintain reliability (including CBD automation)

We are not satisfied that the maintain underlying reliability performance program (including CBD automation) has been demonstrated as prudent and efficient for the following reasons:

- SA Power Networks states that the maintain underlying reliability performance program is not primarily to meet jurisdictional reliability targets which are established over 10 years of performance, but to maintain reliability with the incentive-based STPIS targets as established over the last five years of performance.
- Examination of the reliability data shows an improving trend from 2010–11 to 2023–24. DNSPs maintain STPIS rewards if they maintain reliability improvements. We consider that funding this program at the extent proposed by SA Power Networks will further improve rather than maintain reliability, and lead to customers paying more than necessary for reliability improvements.
- SA Power Networks points to an uptick in SAIDI from 2019–20 to 2023–24, but this is within the historical variance (one standard deviation). Figure 5.3 indicates that there is no variation that would not reasonably be expected over the period from 2019–20 to 2023–24, other than two consecutive lows that suggest improving performance.

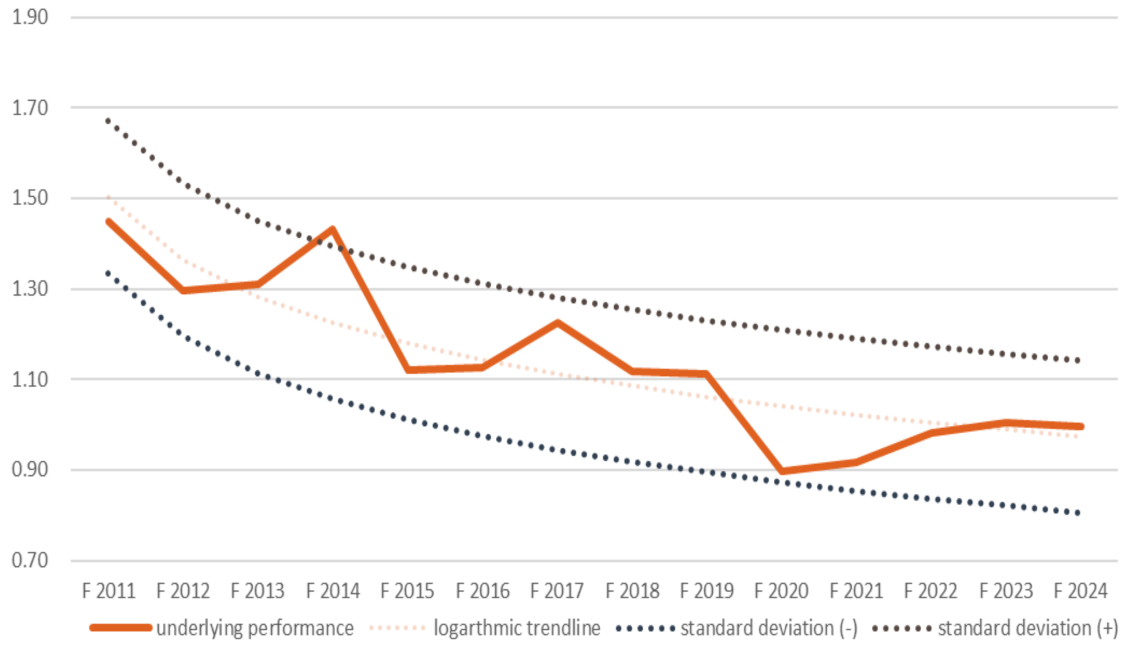
- Closer examination of the underlying SAIDI performance shows that most of the upward variation in the 2019–20 to 2023–24 period is related to the CBD and long rural feeders. The drivers of this upward variation are predominantly caused by animals and weather, with some small contribution from vegetation. These areas will be addressed through other programs such as repex, vegetation management, bushfire mitigation, the CBD reliability program (cable replacement) and the worst served customer program.

Figure 5.3: Whole of network system average interruption duration index



- Figures 5.3 and 5.4 use logarithmic trendlines to account for the trend in long term reliability and then produce an expected range of one standard deviation either side. If performance is between the deviation lines, we consider it acceptable performance variation and consider reliability to be maintained.
- Very similar observations can be made in regard to SAIFI (Figure 5.4), noting the downward trend from 2010-11 to 2023-24 is even more pronounced (i.e. there are less events causing supply interruption).

Figure 5.4: Whole of network system average interruptions frequency index



We have accepted the proposed expenditure for CBD cables and worst served customers (mostly associated with long rural feeders), an uplift in repex, bushfire prevention/mitigation, resilience and ongoing opex for vegetation management. SA Power Networks has not demonstrated that the positive performance from these programs has been accounted for in the maintain reliability program.

Given the above reliability analysis, and the various expenditures to manage reliability, we expect that reliability over the 2025–30 regulatory control period will be maintained (rather than decline as SA Power Networks states). Our alternative includes $63.2 million for these components (maintain reliability and CBD automation), which is approximately 30% lower than the proposed capex and in line with historical expenditure. This proportional adjustment is consistent with our draft decision, which was based on the long-run average of revealed costs over the last eight years, but now is also applied to the proposed CBD automation capex. As noted in Appendix A.1, we consider that the proposed CBD cable replacement program will address underlying reliability problems in the CBD.

Network Protection Management program

The proposed maintain reliability program also includes $9.6 million for Network Protection Management program. The Network Protection Management program is described as internal activities to conduct routine reviews and investigations of protection settings as the network changes to manage the protection devices on the network to ensure they function correctly.

We sought clarification from SA Power Networks on the need for additional capex given that expenditure to manage network protection has already been included in its opex forecast. SA Power Networks provided additional information on staffing requirements and functions at a high level, however the information did not satisfy us that the program of capex is prudent and efficient. We consider that the proposed staffing requirements for ongoing protection management activities are overstated, and the work program is more likely to be periodic in nature. Therefore, our alternative estimate for the maintain reliability program includes only $4.8 million of the proposed $9.6 million for network protection management.

Shortened forms

Term	Definition
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
capex	capital expenditure
CCP30	Consumer Challenge Panel, sub-panel 30
CER	customer energy resources
DNSP or distributor	Distribution Network Service Provider
ESCOSA	Essential Services Commission of South Australia
EV	electric vehicle
HV	high voltage
kV	kilovolts
ICT	information and communication technology
NEL	National Electricity Law
NEO	National Electricity Objective
NER	National Electricity Rules
NPV	net present value
NSP	Network Service Provider
opex	operating expenditure
RAB	regulatory asset base
repex	replacement expenditure
SAIDI	system average interruption duration index
SAIFI	system average interruption frequency index
SCS	standard control service