Draft Decision

SA Power Networks Electricity Distribution Determination 2025 to 2030

(1 July 2025 to 30 June 2030)

Attachment 6
Operating expenditure

September 2024

AUSTRALIAN ENERGY REGULATOR

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AER reference: AER213704

Amendment record

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6 Operating expenditure

Operating expenditure (opex) refers to the operating, maintenance and other non-capital expenses incurred in the provision of network services. This attachment discusses opex for the main standard control services (SCS), with metering SCS being discussed in Attachment 20. Forecast opex is one of the building blocks we use to determine a service provider's annual total revenue requirement.

This attachment outlines our assessment of SA Power Networks' proposed opex forecast for the 2025–30 regulatory control period.

6.1 Draft decision

Our draft decision is to accept SA Power Networks' total opex forecast of $1,983.7 million[1], including debt raising costs, for the 2025–30 regulatory control period.[2] This is because our alternative estimate of $1,945.3 million is not materially different ($38.4 million, or 1.9% lower) than SA Power Networks' total opex forecast proposal. Therefore, we consider that SA Power Networks' total opex forecast satisfies the opex criteria.[3]

Our draft decision, which is the same as SA Power Networks’ proposed total opex forecast, is:

- $200.7 million (or 11.3%) higher than the opex forecast we approved in our final decision for the 2020–25 regulatory control period
- $314.8 million (or 18.9%) higher than SA Power Networks' actual (and estimated) opex in the 2020–25 regulatory control period.

The significant drivers of the increase in opex over the next regulatory control period are consistent with our base-trend-step framework. They include:

- The reclassification of Information and Communication Technology (ICT) costs from capex to opex, largely as a result of the use of cloud and Software as a Service (SaaS) solutions as well as the ongoing operationalisation of cyber security responses.
- Other ICT related costs, including for cyber security uplift and greater network visibility, reflecting various legislative requirements and guidance, and customer preferences and benefit.
- Other costs such as Consumer Energy Resources (CER) integration, insurance premiums and increased data requirements driven by major external factors outside the control of the business.

In our final decision, we will update our alternative estimate of total opex to reflect actual opex for 2023–24. Our draft decision is based on the estimate of base year opex included in SA Power Networks’ initial proposal because actual data for 2023–24 was not available at

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1 All dollars are in this document are in $2024-25 terms unless otherwise stated.

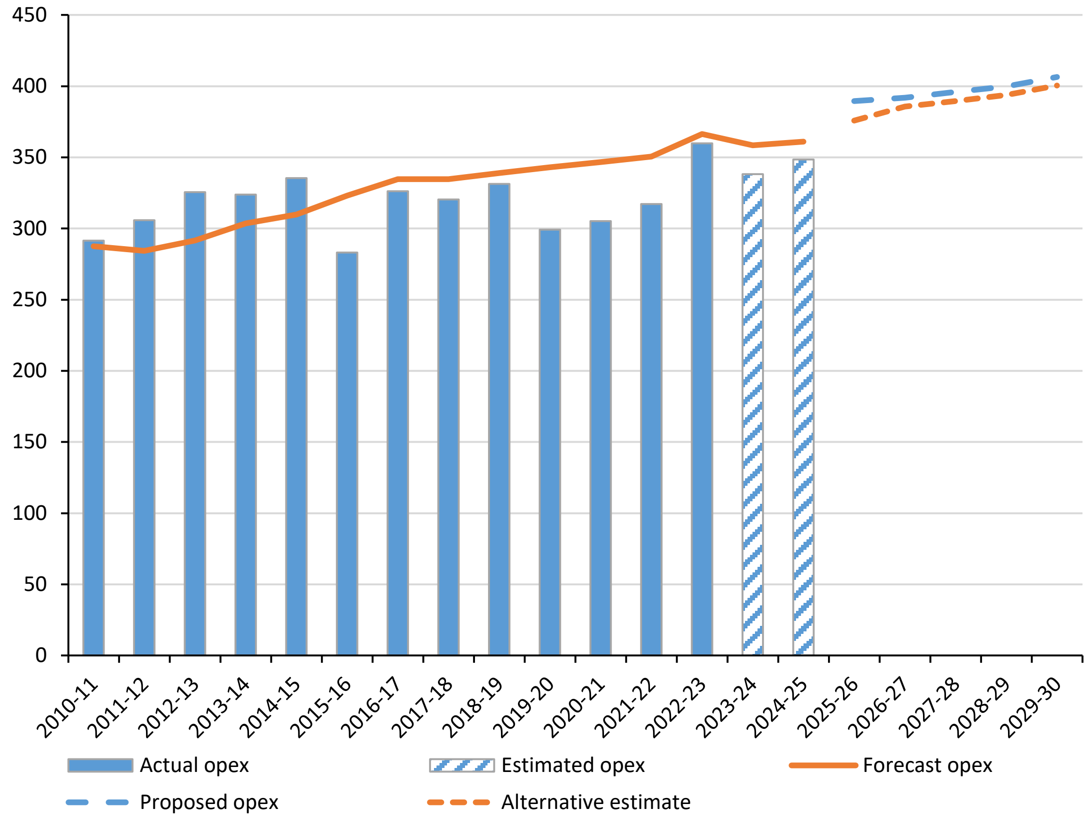
2 SA Power Networks, *SAPN – 6.1 – Opex Model,* January 2024. As noted above, this is for main SCS, with metering SCS discussed separately in Attachment 20 of our draft decision.

3 See section 6.3 Assessment approach.

the time the proposal was submitted. We will also update for any required mechanical adjustments (e.g. latest inflation and labour price growth forecasts). We also encourage SA Power Networks in its revised proposal to include the further information we have requested (outlined in section 6.4.4.5 and 6.4.5.2) for the proposed smart meter rollout step change and innovation fund category specific forecast.

In Figure 6.1 we compare our alternative estimate of opex to SA Power Networks' proposal for the next regulatory control period. We also show the forecasts we approved for the last two regulatory control periods and SA Power Networks' actual and estimated opex over these periods.

Figure 6.1 Historical and forecast opex ($million, 2024–25)



Source: SA Power Networks, *SAPN – 6.1 – Opex Model*, January 2024; AER, *AER – SAPN distribution determination 2020–25 – PTRM – 2024–25 RoD update*, March 2024; AER, *AER – SA Power Networks distribution determination – 2019–20 return on debt update – PTRM*, April 2019: AER, *AER Final decision – SA distribution determination 2010–2011 to 2014–2015*, May 2010; AER analysis.

Note: Includes debt raising costs. Forecast opex includes updated forecasts for the revocation and substitution determination (for the minor cable and conductor repairs error) and the 2022–23 River Murray flood event cost pass through.

Table 6.1 sets out SA Power Networks’ opex proposal, our alternative estimate for the draft decision and the differences between these forecasts.

Table 6.1 Comparison of SA Power Networks' opex proposal and our alternative opex estimate ($million, 2024–25)

	SA Power Network's initial proposal	Our alternative estimate	Difference ($)
Based on reported opex in 2023–24	**1,691.2**	**1,688.1**	**–3.2 (–0.2%)**
Base year adjustments (Software as a Service)	**84.7**	**84.6**	**–0.1 (–0.0%)**
2023–24 to 2024–25 increment	**14.9**	**12.7**	**–2.3 (–0.1%)**
Trend – Output growth	31.9	32.2	0.3 (0.0%)
Trend – Price growth	25.2	35.5	10.3 (0.5%)
Trend – Productivity growth	–26.9	–26.9	0.0 (0.0%)
Total trend	**30.2**	**40.8**	**10.6 (0.5%)**
Step change – Cyber security uplift	47.6	47.6	–0.0 (–0.0%)
Step change – Operationalising cyber security	17.4	17.4	–0.0 (–0.0%)
Step change – IT infrastructure refresh	9.9	9.9	–0.0 (–0.0%)
Step change – Network visibility	6.8	6.7	–0.0 (–0.0%)
Step change – Smart meter rollout – IT upgrades	4.8	–	–4.8 (–0.2%)
Step change – CER integration	4.4	4.4	–0.0 (–0.0%)
Step change – CER compliance	2.5	2.5	–0.0 (–0.0%)
Step change – Increases to insurance premiums	19.4	19.4	–0.0 (–0.0%)
Step change – Network program uplift	18.0	–	–18.0 (–0.9%)
Step change – Reliability improvements	–0.7	–0.9	–0.2 (–0.0%)
Step change – Transitioning to electric vehicles	–1.3	–1.3	0.0 (0.0%)
Total step changes	**128.8**	**105.7**	**–23.1 (–1.2%)**
Small compensation claims scheme	20.0	–	–20.0 (–1.0%)
Innovation Fund	–	–	–
Debt raising costs	13.8	13.4	–0.4 (–0.0%)
Total category specific forecasts	**33.8**	**13.4**	**–20.4 (–1.0%)**
Total	**1,983.7**	**1,945.3**	**–38.4 (–1.9%)**

Source: SA Power Networks, *SAPN – 6.1 – Opex Model*, January 2024; AER analysis.
Note: Numbers may not add up to total due to rounding. Values of '0.0' and '–0.0' represent small non-zero amounts and '–' represents zero.

While there is not a material difference between our alternative estimate of total opex and SA Power Networks' proposed total opex, we have arrived at our alternative estimate in a different way to SA Power Networks. The key differences between SA Power Networks' opex proposal, which we have accepted, and our alternative estimate are that we have:

- Included price growth based on our latest wage price index (WPI) forecasts, which are higher than the placeholder forecasts SA Power Networks used in its initial proposal ($10.3 million).
- Not included the smart meter rollout step change ($4.8 million as initially proposed). This is a placeholder decision and is expected to be updated in the final decision, in light of further information.
- Not included the network program uplift step change ($18.0 million) proposed to account for the expected uplift in resourcing costs to support the proposed uplift in capex. We do not consider this is required as it is already accounted for by our trend forecast (via output growth).
- Not included the Small Compensation Claims Scheme (SCCS) category specific forecast ($20.0 million). We do not consider this is required given it will likely be treated as a Jurisdictional Scheme and revenues will therefore be recovered via annal tariff true-ups.
- Updated the 2020–25 total opex forecast to calculate the final year increment, accounting for the revocation and substitution determination and the 2022–23 River Murray flood event cost pass through (–$2.3 million).[4]
- Used the latest data for the inflation (consumer price index (CPI)). [5]

Table 6.2 also provides our assessment of SA Power Networks' proposal against the opex expectations included in the Better Reset Handbook.[6]

Table 6.2 Assessment of proposal against Better Reset Handbook Expectations

Opex expectations	Comment
1. Opex forecasting approach	• SA Power Networks met this expectation as it applied our standard base–trend–step forecasting approach to forecast opex for the 2025–30 period. SA Power Networks' opex forecast is also consistent with the opex forecast used in the Efficiency Benefit Sharing Scheme (EBSS). • We consider that while the opex forecast was not explicitly corrected for the cable and conductor minor repair Revocation and Substitution determination, this has not impacted the opex forecast.

4 AER, *Revocation and substitution of SA Power Networks' 2020–25 distribution determination,* March 2024; AER, *SA Power Networks – Cost pass through – 2022–23 River Murray flood event,* March 2024.

5 Australian Bureau of Statistics (ABS), *Consumer Price Index, Australia, released on 31 July 2024* (accessed on 31 July 2024: https://www.abs.gov.au/statistics/economy/price-indexes-and-inflation/consumer-price-index-australia/latest-release); Reserve Bank of Australia (RBA), *Statement on monetary policy*, *August 2024*, (accessed on 6 August 2024: https://www.rba.gov.au/publications/smp/2024/aug/outlook.html#3-5-detailed-forecast-information).

6 AER, *Better Resets Handbook – Towards consumer–centric network proposals Update,* July 2024.

Opex expectations	Comment
2. Base opex	• SA Power Networks met this expectation. While it did not use the latest year for which actual data is available for the draft decision, this will be the case for the final decision. It also examined our benchmarking results in determining its opex in the base year and that no efficiency adjustment is required. • SA Power Networks also proposed an $84.7 million increase to base year costs representing 4.3% of total forecast opex. This relates to SaaS costs as a result of a change in accounting standards. Given the materiality and complexity of these adjustments we have undertaken a detailed review of these costs.
3. Trend	• SA Power Networks met this expectation. It applied our standard approach to forecast the opex rate of change or trend growth forecast for price, output, and productivity growth.
4. Step changes	• SA Power Networks did not meet this expectation. It proposed 11 step changes, representing 6.5% of total forecast opex. • We have undertaken a detailed review of these step changes.
5. Category specific forecasts	• SA Power Networks met this expectation. It applied our standard approach to forecast debt raising costs. • SA Power Networks also proposed a SCCS. We agree with the treatment of this item as a category specific forecast if these costs are to be treated as opex, but have undertaken a detailed review of the proposed costs.
6. Genuine consumer engagement on operating expenditure forecasts	• SA Power Networks met this expectation. Overall, we consider SA Power Networks has demonstrated a genuine approach to consumer engagement in relation to its opex proposal.

6.2 SA Power Networks' proposal

SA Power Networks’ proposal applied a base–step–trend approach to forecast opex for the 2025–30 regulatory control period, consistent with our standard approach.[7]

In applying our base step trend approach to forecast opex, SA Power Networks:[8]

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7 SA Power Networks, *SAPN – Attachment 6 – Operating expenditure,* January 2024*,* p. 16.

8 SA Power Networks, *SAPN – Attachment 6 – Operating expenditure*, January 2024, pp. 20–35.

- used estimated opex in 2023–24 as the base from which to forecast ($338.2 million or $1,691.2 million over the next regulatory control period)
- adjusted its total base forecast opex by adding $84.7 million for a change in accounting treatment for SaaS costs
- added an estimate of the difference between the base year opex and the opex it will incur in the final year of the current regulatory control period, increasing opex by $14.9 million
- applied its overall rate of change forecast to its final year adjusted opex estimate, increasing opex by $30.2 million. This included:
  - output growth ($31.9 million)
  - price growth ($25.2 million)
  - productivity growth (–$26.9 million)
- added eleven step changes totalling $128.8 million for:
  - cyber security uplift ($47.6 million)
  - operationalising cyber security ($17.4 million)
  - IT infrastructure refresh ($9.9 million)
  - network visibility ($6.8 million)
  - smart meter rollout IT upgrades ($4.8 million)
  - CER integration ($4.4 million)
  - CER compliance ($2.5 million)
  - increases to insurance premiums ($19.4 million)
  - network program uplift ($18.0 million)
  - reliability improvements (–$0.7 million)
  - transitioning to electric vehicles (–$1.3 million)
- added $20.0 million for the proposed SCCS, accounted for as category specific forecast
- added $13.8 million for debt raising costs to arrive at a total opex forecast of $1,983.7 million over the 2025–30 regulatory control period, as set out in Table 6.3.

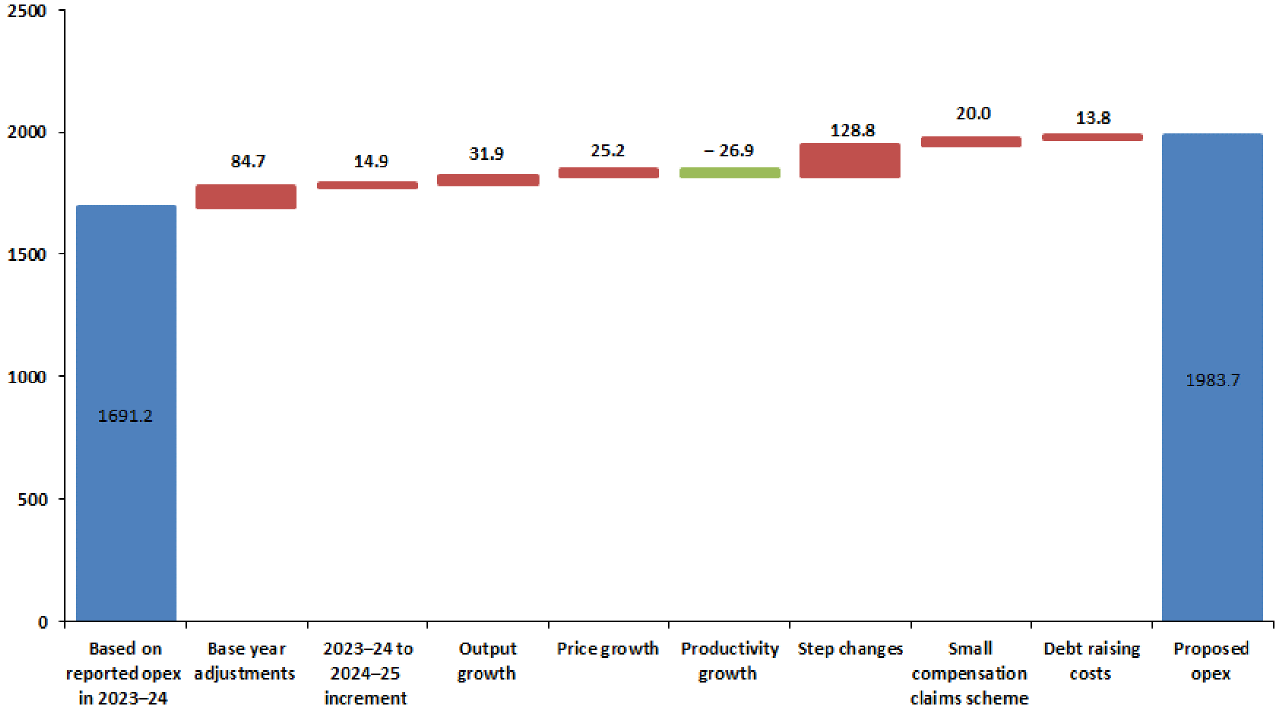
Table 6.3 SA Power Network's opex for the 2025–30 period ($million, 2024–25)

	2025–26	2026–27	2027–28	2028–29	2029–30	Total
Total Opex, excluding category specific forecasts	377.4	386.4	390.6	394.5	401.0	1,949.9
SCCS	9.5	2.6	2.6	2.6	2.6	20.0
Debt raising costs	2.7	2.7	2.7	2.8	2.9	13.8
Total Opex, including debt raising costs	**389.5**	**391.8**	**396.0**	**399.9**	**406.5**	**1,983.7**

Source: SA Power Networks, *SAPN – 6.1 – Opex Model,* January 2024.
Note: Numbers may not add up to total due to rounding. Values of '0.0' and '–0.0' represent small non-zero amounts and '–' represents zero.

Figure 6.2 shows the different components that make up SA Power Networks' opex forecast for the 2025–30 period.

Figure 6.2 SA Power Networks' opex forecast ($million, 2024–25)



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

6.2.1 Stakeholder views

We received 11 submissions on SA Power Networks' proposal which discussed issues related to the total opex forecast, productivity growth, step changes, category specific forecasts and innovation.

We have taken these submissions into account in developing the positions set out in this draft decision. The stakeholder issues raised in the submissions in relation to opex were:

- AER Consumer Challenge Panel 30 (CCP30), SA Power Networks' Customer Advisory Board (CAB), South Australian Wine Industry Association (SAWIA) and the South Australian Council of Social Service (SACOSS) all supported the AER's initial assessment of SA Power Networks' proposal and the key opex areas identified by the AER for targeted (detailed) review in the Issues Paper.[9]
- CCP30 noted that there are probably more opex aspects being considered by targeted review than might be the ideal situation for an early signal pathway business, but that

[9] CCP30, *CCP30 – Submission – 2025–30 Electricity Determination – SA Power Networks*, May 2024, p. 4; SA Power Networks Customer Advisory Board, *CAB Reset Subcommittee – Submission – 2025–30 Electricity Determination – SA Power Networks*, April 2024, p.1; South Australian Wine Industry Association, *SAWIA – Submission – 2025–30 Electricity Determination – SA Power Networks*, May 2024, p. 6; South Australian Council of Social Service, *SACOSS – Submission – 2025–30 Electricity Determination – SA Power Networks*, May 2024, p.12.

circumstances are such that the issues being considered by network businesses are likely more complex than in the past with potentially higher impact on customers.[10]

- SAWIA noted that it is concerned with the proposed increases in opex. It believes that SA Power Networks should strive to achieve further productivity gains and cost efficiencies.[11] Origin Energy supported SA Power Networks' proposal to apply annual opex productivity growth of 0.5%.[12] The SA Government submitted that, 'given the notable escalation in proposed opex', it would expect additional savings to consequently flow because of efficiency gains.[13]
- The Clean Energy Council (CEC) and the Smart Energy Council were both supportive of the $20 million ($16 million capex and $4 million opex) Innovation Fund promoting the trialling of new systems and services for the CER industry. Sonnen highlighted that the innovation investment per customer is lower compared to Ausgrid and Endeavour, suggesting more could be done to support innovation. The Energy and Water Ombudsman of South Australia (EWOSA) supported the AER conducting an in-depth targeted review of the proposed $20 million Innovation Fund and any potential interactions it might have with the various incentive schemes, so that the expenditure is appropriate.[14]
- EWOSA supported the introduction of a new SCCS, noting the AER only needs to undertake a high–level review to determine whether the quantum of expenditure involved and proposed by SA Power Networks is reasonable.[15]
- SMA Australia supported SA Power Networks continued leadership role on CER and urged the AER to favourably consider SA Power Networks' ICT and CER integration expenditure proposals.[16]

6.3 Assessment approach

Our role is to decide whether to accept a business's total opex forecast. We are to form a view about whether a business's forecast of total opex 'reasonably reflects the opex

[10] CCP30, *CCP30 – Submission – 2025–30 Electricity Determination – SA Power Networks*, May 2024, p. 18.

[11] South Australian Wine Industry Association, *SAWIA – Submission – 2025–30 Electricity Determination – SA Power Networks*, May 2024, p. 6.

[12] Origin Energy, *Submission, 2025–30 Electricity Determination, Energex, Ergon & SA Power Networks*, May 2024, p. 3.

[13] Department for Energy and Mining, *Submission, 2025–30 Electricity Determination, SA Power Networks*, May 2024, p. 4.

[14] Clean Energy Council, *Clean Energy Council – Submission – 2025–30 Electricity Determination – SA Power Networks*, May 2024, p. 4; Smart Energy Council, *Smart Energy Council – Submission – 2025–30 Electricity Determination – SA Power Networks*, May 2024, p. 2; Energy & Water Ombudsman SA, *EWOSA – Submission – 2025–30 Electricity Determination – SA Power Networks*, May 2024, p. 3; SONNEN, *SONNEN Australia – Submission – 2025–30 Electricity Determination – SA Power Networks*, May 2024, p. 3.

[15] Energy & Water Ombudsman SA, *EWOSA – Submission – 2025–30 Electricity Determination – SA Power Networks*, May 2024, p. 2.

[16] SMA Australia, *SMA Australia – Submission – 2025–30 Electricity Determination – SA Power Networks*, May 2024, p.1.

criteria'.[17] In doing so, we must have regard to the opex factors specified in the National Electricity Rules (NER).[18]

The *Expenditure forecast assessment guideline* (the Guideline), together with an explanatory statement, sets out our assessment approach in detail.[19] While the Guideline provides for greater regulatory predictability, transparency and consistency, it is not mandatory. However, if we make a decision that is not in accordance with the Guideline, we must state the reasons for departing from the Guideline.[20]

Our approach is to assess the business's forecast opex over the regulatory control period at a total level, rather than to assess individual opex projects. To do so, we develop an alternative estimate of total opex using a 'top-down' forecasting method, known as the 'base-step-trend' approach.[21] We compare our alternative estimate with the business's total opex forecast to form a view on the reasonableness of the business's proposal. If we are satisfied the business's forecast reasonably reflects the opex criteria, we accept the forecast.[22] If we are not satisfied, we substitute the business's forecast with our alternative estimate that we are satisfied reasonably reflects the opex criteria.[23]

In making this decision, we take into account the reasons for the difference between our alternative estimate and the business's proposal, and the materiality of the difference. Further, we take into consideration interrelationships between opex and the other building block components of our decision.[24]

Figure 6.3 summarises the 'base-step-trend' forecasting approach.

17 NER, cl. 6.5.6(c).

18 NER, cl. 6.5.6(e)

19 AER, *Expenditure forecast assessment guideline for electricity distribution*, August 2022; AER, *Explanatory statement – Expenditure forecast assessment guideline*, November 2013.

20 NER, cl. 6.2.8(c).

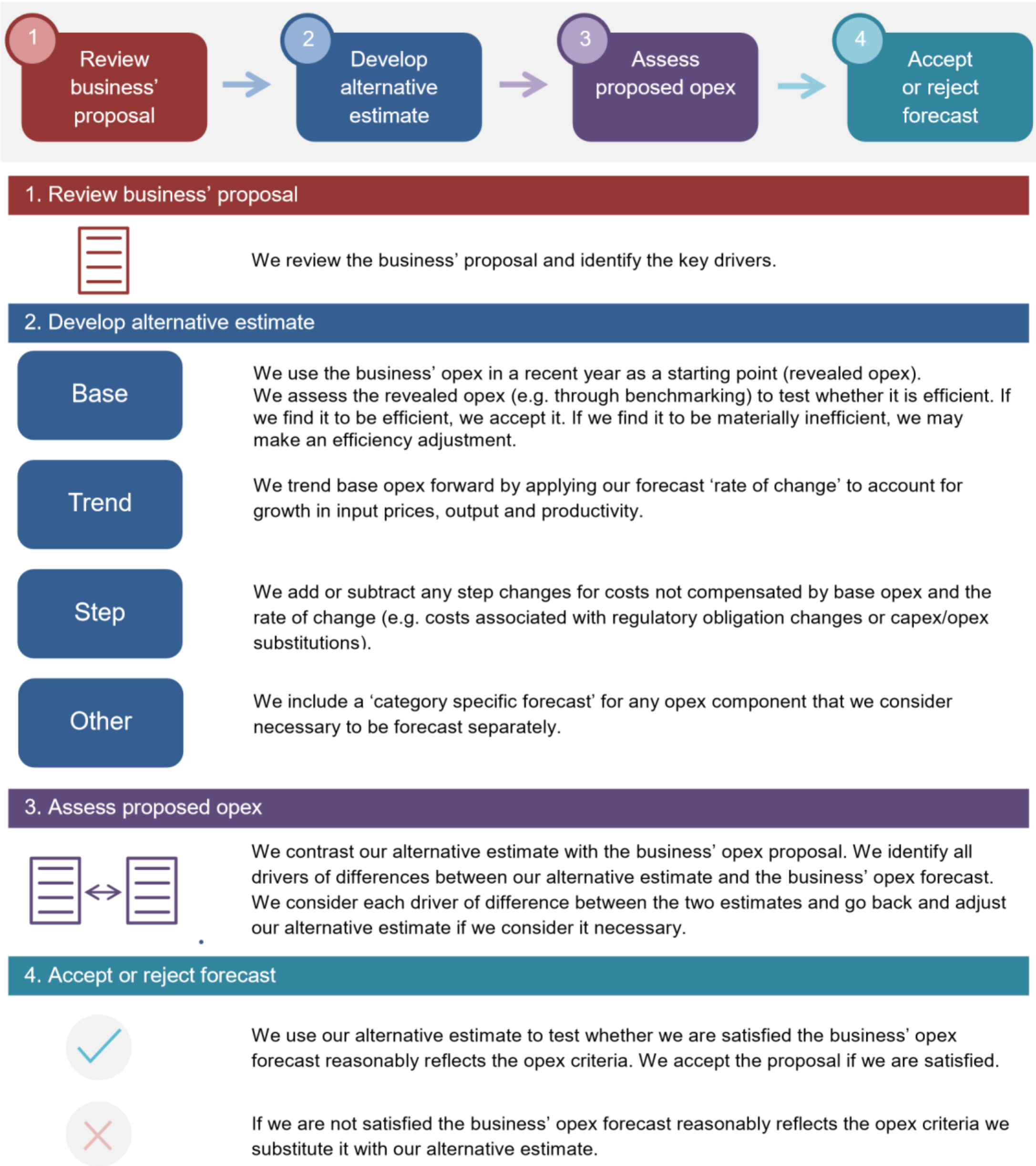
21 A 'top-down' approach forecasts total opex at an aggregate level, rather than forecasting individual projects or categories to build a total opex forecast from the 'bottom up.'

22 NER, cl. 6.2.8(c).

23 NER, cl. 6.12.1(3).

24 We are required to consider these interrelationships under s. 16(1)(c) of the NEL.

Figure 6.3 Our opex assessment approach



6.3.1 Interrelationships

In assessing SA Power Networks' total forecast opex, we also take into account other components of its proposal that could interrelate with our opex decision. The matters we considered in this regard included:

- The EBSS carryover—the estimate of opex for 2024–25 (the final year of the current regulatory control period) that we use to forecast opex should be the same as the level of opex used to calculate EBSS carryover amounts. This consistency ensures that the business is rewarded (or penalised) for any efficiency gains (or losses) it makes in the final year the same as it would for gains or losses made in other years.
- The operation of the EBSS in the 2020–25 regulatory control period, which provided SA Power Networks an incentive to reduce opex in the base year.

- The impact of cost drivers that affect both forecast opex and forecast capital expenditure (capex). For instance, forecast labour price growth affects forecast capex and our forecast price growth used to estimate the rate of change in opex.
- The approach to assessing the rate of return, to ensure there is consistency between our determination of debt raising costs and the rate of return building block.
- The outcomes of SA Power Networks' engagement with consumers and stakeholders in developing its proposal and any feedback we have had.

6.4 Reasons for draft decision

Our draft decision is to accept SA Power Networks' total opex forecast of $1,983.7 million, including debt raising costs, for the 2025–30 regulatory control period.[25] Our alternative estimate of $1,945.3 million is not materially different ($38.4 million or 1.9% lower) from SA Power Networks' total opex forecast proposal. Therefore, we are satisfied that SA Power Networks' total opex forecast satisfies the opex criteria, having regard to the opex factors.[26]

Table 6.1 sets out SA Power Networks' proposal, our alternative estimate that has informed this draft decision, and the difference between our alternative estimate and the proposal.

The main drivers for this difference are also set out in section 6.1 and we discuss each of the components of our alternative estimate, and our assessment of SA Power Networks' proposal, below. Full details of our alternative estimate are set out in our opex model, which is available on our website.

CCP30, CAB, SAWIA and SACOSS all supported the AER's initial assessment of SA Power Networks' proposal and the key opex areas of consideration identified by the AER for targeted (detailed) review in the Issues Paper. Consistent with our view in the Issues Paper, and many submissions, our draft decision assessment included a detailed review of SA Power Networks' proposed SaaS base adjustment ($84.7 million) and step changes. We set out our assessment below, in sections 6.4.2.1 and 6.4.4, and overall we consider these significant drivers of the proposed increase in opex are largely consistent with our base-trend-step framework.

6.4.1 Base opex

This section provides our view on the prudent and efficient level of base opex that we consider SA Power Networks would need for the safe and reliable provision of electricity services over the 2025–30 regulatory control period. We discuss the choice of base year in section 6.4.1.1 and set out our analysis of the efficiency of base year opex in section 6.4.1.2.

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25 SA Power Networks, *SAPN – 6.1 – Opex Model,* January 2024. As noted above, this is for main SCS, with metering SCS discussed separately in Attachment 20 of our draft decision.

26 NER, cl. 6.5.6(c)-(e).

6.4.1.1 Proposed base year

SA Power Networks proposed a base year of 2023–24 and base year opex of $338.2 million. This equates to $1,691.2 million over the five years of the next regulatory control period.[27]

SA Power Networks' estimated base year actual opex is $20.1 million, or 5.6%, lower than the forecast opex approved for that year and $10.9 million, or 3.3%, higher than the average actual opex over the period 2020–21 to 2022–23.[28]

SA Power Networks submitted that 2023–24 is the most suitable base year because:

- it will be the most recent year for which actual audited data will be available at the time of the AER's final decision
- it expects it will best reflect the costs required to efficiently maintain and operate the distribution network over the 2025–30 regulatory control period
- earlier years of the 2020–25 regulatory control period do not provide an adequate base for the 2025–30 period due to external factors.[29]

In the Better Resets Handbook, we set out our expectations for a network's opex proposal. We stated that a business should use a base year for which audited actual opex is available.[30] In practice, this typically means the third year of the current regulatory control period since this will be the most recent year for which audited actual opex data is available at the time a network submits its regulatory proposal. In SA Power Networks' case, that would be 2022–23. However, as noted by SA Power Networks, actual opex in 2022–23 was significantly higher than the prior years due to extreme weather and flooding. This resulted in higher GSL payments and higher costs from deploying resources to respond to the flooding. Given the abnormal events that occurred in 2022–23, and the consequential impact on total opex, we are satisfied that 2022–23 is not an appropriate year to use to forecast SA Power Networks' opex for the 2025–30 period.

While there will be year to year fluctuations in reported opex over the current regulatory period, due to the interaction with the EBSS, we do not generally have concerns with the choice of base year, provided we find SA Power Networks' opex in the base year to be efficient.

We consider it is feasible to use 2023–24 as the base year because it will be based on actual opex in the final decision. However, we will not be able to determine if 2023–24 will be representative of the nature of costs that SA Power Networks requires for the next regulatory control period, until we have audited actual opex, which SA Power Networks will provide in its revised proposal.

SA Power Networks has indicated that its actual opex for 2023–24 will be higher than the estimate it used in its initial proposal. In its revised proposal, SA Power Networks should

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27 SA Power Networks, *SAPN – Attachment 6 – Operating expenditure*, January 2024; SA Power Networks, *SAPN – 6.1 – Opex Model*, January 2024.

28 SA Power Networks, *SAPN – 6.1 – Opex Model*, January 2024; AER, *SAPN distribution determination 2020–25, PTRM, 2024–25 RoD update,* March 2024; AER analysis.

29 SA Power Networks, *SAPN – Attachment 6 – Operating expenditure*, January 2024, p. 21.

30 AER, *Better Resets Handbook – Towards consumer–centric network proposals Update,* July 2024, p. 25.

discuss why its actual opex was higher than the estimate it used in its initial proposal and explain why 2023–24 remains an appropriate choice of base year. We will consider this, and if 2023–24 is an appropriate choice of base year, in our final decision.

In our alternative estimate for the draft decision, we have updated the base opex amount for 2023–24 to $337.6 million, or $1,688.1 million over the next regulatory control period. The difference between SA Power Networks' proposed amount and our alternative estimate is because we have used different inflation values to convert the nominal amount into real terms. We have used the actual inflation for the year to June 2024, from the Australian Bureau of Statistics, and the Reserve Bank of Australia's (RBA) forecast of inflation for the year to June 2025, from its August Statement on monetary policy.[31] These inflation forecasts are the best forecast possible in the circumstances because they are the most up-to-date information available at this time.

6.4.1.2 Efficiency of SA Power Networks' opex

As summarised in our Guideline, our preferred approach for forecasting opex is to use a revealed cost approach. This is because opex is largely recurrent and stable at a total level. Where a distribution business is responsive to the financial incentives under the regulatory framework, the actual level of opex it incurs should provide a good estimate of the efficient costs required for it to operate a safe and reliable network and meet its relevant regulatory obligations. However, we do not assume that the business's revealed opex is efficient. We examine the trend in opex and use our top-down benchmarking tools, and other assessment techniques, to test whether the business is operating efficiently historically and particularly in the base year.

We consider SA Power Networks' estimate of its opex in 2023–24 is relatively efficient as indicated by its opex trend over time and our benchmarking results. Accordingly, we have used SA Power Networks' estimate of its revealed costs in 2023–24 to develop our alternative estimate.

In terms of the trend in opex, Figure 6.1 shows SA Power Networks' opex forecast for the next regulatory control period, its actual opex in previous regulatory control periods and our previous regulatory decisions.

Overall, SA Power Networks' opex has been lower than our approved forecast in the first three years of the current regulatory control period. SA Power Networks' estimated actual opex in the base year (2023–24) of $338.2 million is $20.1 million or 5.6% below the approved forecast opex for that year. SA Power Networks' actual opex was also below our forecast for the first and second year of the current regulatory control period by $41.5 million and $33.4 million respectively. This is in the context of its actual average annual opex for 2020–21 to 2022–23, of $327.3 million, being $15.3 million higher than its average annual actual opex for the 2015–20 regulatory control period.

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31 Australian Bureau of Statistics (ABS), *Consumer Price Index, Australia, released on 31 July 2024* (accessed on 31 July 2024: https://www.abs.gov.au/statistics/economy/price-indexes-and-inflation/consumer-price-index-australia/latest-release); Reserve Bank of Australia (RBA), *Statement on monetary policy*, *August 2024*, (accessed on 6 August 2024: https://www.rba.gov.au/publications/smp/2024/aug/outlook.html#3-5-detailed-forecast-information).

While increasing over time, SA Power Networks' actual and estimated opex in the current regulatory control period (2020–25) is $114.2 million or 6.4% below our opex forecast.[32]

In line with our standard approach, we have used our benchmarking tools and other cost analysis to assess and establish whether SA Power Networks is operating relatively efficiently, both over time and in the base year. We conclude that SA Power Networks performs well compared to other networks and is not materially inefficient.

6.4.1.2.1 Benchmarking the efficiency of SA Power Networks' opex over time and in the base year

We have used a variety of economic benchmarking tools to test the efficiency of SA Power Networks' opex. Benchmarking broadly refers to the practice of comparing the economic performance of a group of service providers that all provide the same service as a means of assessing their relative performance. Our annual benchmarking reports include information about the use and purpose of economic benchmarking, and details about the techniques we use to benchmark the efficiency of distribution businesses in the National Electricity Market (NEM).[33]

While opex at the total level is generally recurrent, year-to-year fluctuations can be expected. To shed light on SA Power Networks' general level of operating efficiency, we first look at the efficiency of its opex over a period of time, using our top-down benchmarking tools, as well as other supporting techniques. We then look at the efficiency of opex in the base year (2023–24).

In terms of historical performance, our benchmarking results from the *2023 Annual Benchmarking Report*[34] for distribution indicate that SA Power Networks' opex has been relatively efficient.

Figure 6.4 shows that over the period 2006 to 2022 SA Power Networks (SAP in the chart) ranks third out of 13 distribution businesses based in terms of the econometric opex cost function benchmarking. It has an average efficiency score of 0.93 over the period 2006 to 2022. It also ranked third out of 13 distribution networks in the shorter period 2012 to 2022 (with an average efficiency score of 0.88). We use a 0.75 comparator point to assess the relative efficiency of distribution businesses, noting that when by comparison a distributor's average opex efficiency score is below 0.75 we also take into consideration the operating environment factors (OEFs) not already captured in the modelling. Allowing for OEFs enables us to account for some factors beyond a distributor's control that can affect its benchmarking performance.

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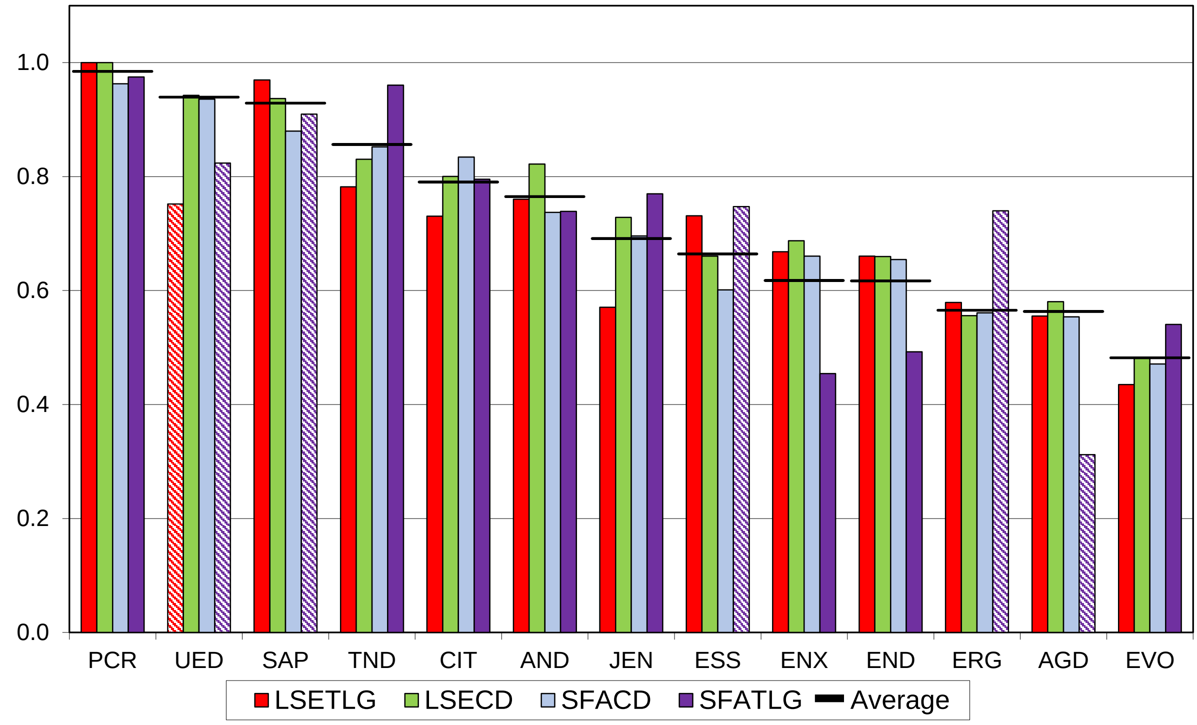
32 AER, *SAPN distribution determination 2020–25, PTRM, 2024–25 RoD update,* March 2024; AER analysis.

33 AER, *Annual Benchmarking Report, Electricity distribution network service providers*, November 2023.

34 AER, *Annual Benchmarking Report, Electricity distribution network service providers,* November 2023.

Figure 6.4 Distributors' average opex cost efficiency scores, 2006–22



Source: AER, *2023 Annual Benchmarking Report – Electricity distribution network service providers*, 2023 November 2023; AER analysis.

Note: These results reflect our preferred approach to addressing corporate overhead capitalisation differences and incorporate updated circuit line length and corporate overhead data for Evoenergy that was updated since the release of the *2023 Annual Benchmarking Report* and used in the Evoenergy 2024–29 final decision. Columns with a hatched pattern represent results that do not satisfy the monotonicity requirement (that an increase in output is only achieved with an increase in opex) and are not included in the model–average efficiency score for each distribution business (which is represented by the black horizontal line).

We consider 2023–24 opex is relatively efficient as indicated by the trend of SA Power Networks' opex over time and our benchmarking results. As a result, we have used SA Power Networks' estimate of its opex in 2023–24 to develop our alternative estimate. In our final decision we will update our alternative estimate to reflect actual opex in 2023–24.

6.4.2 Adjustments to base year opex

SA Power Networks proposed adjustments to its base year opex of $19.9 million or $99.6 million over the regulatory control period.[35] These were for adding SaaS costs ($84.7 million) and the final year increment ($14.9 million).

We have considered these proposed adjustments and in our alternative estimate we have adjusted opex in the base year by:

- Adding $16.9 million for SaaS costs. This increases our alternative estimate by $84.6 million over the 5 years of the 2025–30 regulatory control period. We explain this adjustment in sections 6.4.2.1.

35 SA Power Networks, *SAPN – 6.1 – Opex Model,* January 2024.

- Adding $2.5 million for the increase in opex between base year 2023–24 and the final year, 2024–25 (final year increment). This increases our alternative estimate by $12.7 million over the 5 years of the 2025–30 regulatory control period. We explain this adjustment in 6.4.2.2.

6.4.2.1 Software as a Service (SaaS) costs

SA Power Networks' proposed a $16.9 million base adjustment ($84.7 million over the 2025–30 regulatory control period), for the capex to opex transfer of SaaS implementation and customisation costs.[36] This is driven by a change in accounting standard guidance (that implementation and configuration SaaS costs should be treated as opex (historically treated as capex)) as well as recurrent updates and end of life replacement. We have included a forecast of $16.9 million in our alternative estimate, which is $0.1 million lower than SA Power Networks' proposal. This is due to using the latest actual and forecast inflation rates. The opex costs have an associated $162.7 million in non-recurrent capex costs (see Attachment 5 of our draft decision, section 4) and were supported by business cases.

SA Power Networks stated that an accounting rule clarification in 2021 confirmed that the costs of implementing and customising application software in a cloud-computing, or SaaS arrangement, should not be capitalised. SA Power Networks noted it had followed the AER's guidance with regard to the treatment of SaaS expenditure by including these as a base year adjustment.[37]

As shown in Table 6.4, SA Power Networks identified the proposed costs are driven by:

- the required patching and updates on SaaS systems (recurrent upgrades)
- implementation of new SaaS systems replacing end of life assets
- changes to current SaaS systems to maintain existing services which will facilitate the energy transition and deliver improved online services.

Across these drivers there is a $34.3 million Customer Technology Program (CTP) to refresh core customer systems at end of life and for two new digital services to deliver improved response times to key customer interactions and enquiries.

Table 6.4 Base year adjustments program detail (million, $2024–25)

SaaS program	Driver	Expenditure type	Proposed opex
IT applications refresh	Patching and updates on SaaS systems	recurrent	16.2
Data, analytics, and intelligent systems refresh		recurrent	3.2
CTP – CRM replacement and data consolidation		non-recurrent	10.6

[36] SA Power Networks, *SAPN – Attachment 6 – Operating expenditure,* January 2024, p. 22.

[37] SA Power Networks, *SAPN – Attachment 6 – Operating expenditure,* January 2024, p. 22.

SaaS program	Driver	Expenditure type	Proposed opex
CTP – meter data and insights system replacement	Implementation of new SaaS replacement systems	non-recurrent	2.0
CTP – customer portals consolidation		non-recurrent	11.0
CTP – website replacement		non-recurrent	2.4
Click replacement		non-recurrent	16.2
Enterprise data warehouse replacement and consolidation		non-recurrent	2.1
SAP small module lifecycle management and optimisation	Implementation or changes to SaaS systems	non-recurrent	1.2
CTP – personalised on demand services		non-recurrent	8.3
Asset and work phase 3 (Asset management transformation program)		non-recurrent	11.4
Total			**84.7**

Source: SA Power Networks, *SAPN – 5.12.27 – Program Overview – ICT Non Recurrent Customer Technology Program*, January 2024, p. 14; AER analysis.
Note: Numbers may not add up to totals due to rounding.

We engaged Energy Market Consultants associates (EMCa) to assist in our assessment of the prudency and efficiency of the proposed opex SaaS base adjustments and related capex. EMCa's review considered SA Power Networks satisfying the key aspects of our ICT Assessment Guideline.[38]

EMCa considered that SA Power Networks' business cases justified all the proposed programs in Table 6.4.[39] EMCa was satisfied that SA Power Networks' choice of its preferred options for replacing end of life assets, new SaaS systems and application patching and updates, represented a prudent and supportable approach.[40] EMCa was also satisfied that SA Power Networks' approach to forecasting costs was reasonable and the proposed expenditures represented efficient costs.[41]

38 Energy Market Consulting Associates, *SA Power Networks: Review of aspects of proposed expenditure*, September 2024, p.110.

39 Energy Market Consulting Associates, *SA Power Networks: Review of aspects of proposed expenditure*, September 2024, p.102.

40 Energy Market Consulting Associates, *SA Power Networks: Review of aspects of proposed expenditure*, September 2024, p.102.

41 Energy Market Consulting Associates, *SA Power Networks: Review of aspects of proposed expenditure*, September 2024, p.103.

Specifically, EMCa's review considered whether SA Power Networks':[42]

- Business case options analysis aligned with our ICT Assessment Guideline and in each case found:
  - Identified risk assessments were used to support the view that some form of action was required. EMCa identified the primary driver being risk for end of life of the system or application the trigger for replacement/upgrade.
  - The range of options considered by SA Power Networks was sufficient to explore the technically viable alternatives based on scope or time variation.
  - SA Power Networks had chosen the option with the highest NPV for all programs and provided the derivation of benefits. EMCa noted a key AER criterion for establishing the prudency of the preferred option is that it should be the technical viable solution with the highest (often least negative) NPV.
- Approach to determining the timing for projects was appropriate. While it noted there were some instances where perhaps a year deferment may be possible, it considered the risk-reward trade-off is likely to favour the proposed timing.
- IT forecasting methodology was sound, and the costs reasonable. EMCa was satisfied SA Power Networks' forecasting methodology was applied satisfactorily based on SA Power Networks:
  - Providing detailed bottom-up forecasts for every project, typically based on one or more of:
    - Vendor budget quotes (but not tendered prices)
    - Leveraging off relevant historical costs
    - Third party input (i.e. consultants) either to shaping the scope or the cost or both
  - Providing benchmarking showing its costs are reasonable compared to other DNSPs.
  - Proposing to self-fund extra recurrent opex incurred.
- Treatment of cost saving benefits was reasonable overall. EMCa noted that the cost reductions relative to the base year that SA Power Networks modelled are very modest compared to the 'cost avoidance' benefit included in the business cases. It considered there is potential for SA Power Networks' upgraded and replacement systems to deliver higher cost reductions than it has forecast. However, given these benefits are mostly not forecast to commence until late in the next regulatory control period, and that they are difficult to quantify, EMCa did not propose adjustments to SA Power Networks' expenditure forecasts.

SA Power Networks' engagement program (in 2023) included focused conversations on the CTP component of the proposed SaaS base year adjustments and the new customer service

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[42] Energy Market Consulting Associates, *SA Power Networks: Review of aspects of proposed expenditure*, September 2024, pp.101-104.

capabilities.[43] SA Power Networks' proposal stated its Peoples Panel recommended a significant up-lift in digital capability and customer interface, but there was no consensus, partly due to costs involved.[44] In response to the lack of consensus SA Power Networks' proposal included a more modest expenditure and scope (less than half). This was recognised in SA Power Networks Customer Advisory Board's (CAB) independent report, which stated SA Power Networks' proposal included a more modest program to replace and consolidate its customer systems, which is expected to improve information available to customers.[45]

SA Power Networks' engagement program (in 2022) also undertook a willingness to pay survey of 1250 South Australian households and 140 businesses. Survey results indicated that households, on average, were willing to pay for new digital services (these are the CTP-personalised on demand services and website replacement in Table 6.4) as the bill impact was less than the indicated willingness to pay. Businesses did not support the willingness to pay for these services.[46]

Based on our analysis, and review of EMCa's advice, we consider that SA Power Networks' proposed base adjustment costs are both prudent and efficient. We consider this is also supported by SA Power Networks' stakeholder engagement in relation to the CTP. In terms of the prudency of these projects, this shows that SA Power Networks has also taken into consideration that customers did support the CTP in principle and addressed customer cost concerns by including a more modest expenditure in its proposal. The willingness to pay surveys also showed household support for improved customer digital experiences.

We are also satisfied via our analysis of SA Power Networks' Regulatory Information Notices, and business cases, that the SaaS capex being transferred to opex has been excluded from the 2025–30 ICT capex forecasts. Further, we are satisfied that these costs are not already included in base year opex, hence that there is no double counting of forecast costs.

On this basis we have included a $84.6 million base year adjustment in our alternative estimate.

As can be seen in Table 6.4, many of the proposed base adjustments are non-recurrent. This means that the expenditure in the next regulatory control period will not likely be consistent year on year. This may impact our assessment of opex in our next determination process, particularly in terms of opex in the base year, as the revealed costs may not be reflective of ongoing costs.

As a result, we expect SA Power Networks to consider, in preparing its next regulatory proposal (for the 2030–35 period), whether it will likely require the same amount of non-recurrent SaaS costs as it has forecast, and incurred, for the 2025–30 period. At that time, we encourage SA Power Networks to consider whether any adjustment to its 2030–35 opex

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43 SA Power Networks, *SAPN – 0.1 – Community Advisory Board Independent Report,* November 2023, p. 30.

44 SA Power Networks, *SAPN – 5.12.27 – Program Overview – ICT Non-Recurrent Customer Technology Program,* January 2024, p. 7.

45 SA Power Networks, *SAPN – 0.1 – Community Advisory Board Independent Report,* November 2023, p. 30.

46 SA Power Networks, *SAPN – 0.2 – Customer values research,* January 2024, p. 57

forecast will be required to account for any decrease in its level of non-recurrent SaaS costs relative to those forecast, and incurred, in the 2025–30 regulatory period, particularly in relation to any base year. To assist with this SA Power Networks should consider how it records and reports its annual SaaS expenditures against the programs in Table 6.4 over the 2025–30 regulatory control period.

6.4.2.2 Final year increment

Our standard practice to calculate final year opex is to add the estimated change in opex between the base year (2023–24) and the final year (2024–25) of the current regulatory control period to the base year opex amount.[47]

We have added $2.5 million for the final year increment in our alternative estimate, increasing our alternative estimate by $12.7 million over the 2025–30 regulatory control period. This is $0.5 million ($2.3 million over the 2025–30 regulatory control period) lower than SA Power Networks' proposal. This is due to using the updated SA Power Networks' 2020–25 approved total opex forecast, which reflects the revocation and substitution decision (for the minor cable and conductor repairs error) and the 2022–23 River Murray flood event cost pass through.[48] These decisions were made after SA Power Networks submitted its initial proposal.

6.4.3 Rate of change

Having determined an efficient starting point, or base opex, we trend it forward to account for the forecast growth in prices, output and productivity. We refer to this as the rate of change.[49]

SA Power Networks applied our standard approach to forecast the rate of change, including:

- **Price growth:** adopting our standard input price weightings of 59.2% labour and 40.8% non-labour. It forecast labour price growth using an average of forecasts of the growth in the wage price index (WPI) from BIS Oxford Economics (its consultant) and KPMG (our consultant, as a placeholder). It also added the legislated superannuation guarantee increases to its labour price growth forecasts.
- **Output growth:** applying the weights from our four econometric models, consistent with our standard approach. It forecast growth in its customer numbers and circuit length based on historic growth rates. It used AEMO's forecast of maximum demand growth to forecast ratcheted maximum demand growth.
- **Productivity growth:** using our 0.5% per year productivity growth forecast.

The rate of change proposed by SA Power Networks contributed $30.2 million, or 1.5%, to SA Power Networks' total opex forecast of $1,983.7 million. This equates to an average opex increase of 0.7% each year. We have included a rate of change that increases opex by 0.9% each year in our alternative estimate.

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47 AER, *Expenditure forecast assessment guideline for electricity distribution*, August 2022, pp. 24–25.

48 AER, *Revocation and substitution of SA Power Networks' 2020–25 distribution determination,* March 2024; AER, *SA Power Networks – Cost pass through – 2022–23 River Murray flood event,* March 2024.

49 AER, *Expenditure forecast assessment guideline for electricity distribution*, August 2022, pp. 22–24.

We compare SA Power Networks' and our alternative estimate forecasts in Table 6.5 and the reasons for the differences are set out below.

Table 6.5 Forecast annual rate of change in opex (%)

	2024–25	2025–26	2026–27	2027–28	2028–29
SA Power Networks' proposal					
Price growth	0.7	0.4	0.3	0.4	0.4
Output growth	0.5	0.5	0.5	1.0	1.3
Productivity growth	0.5	0.5	0.5	0.5	0.5
Rate of change	**0.6**	**0.3**	**0.3**	**0.9**	**1.3**
AER alternative estimate					
Price growth	0.9	0.6	0.5	0.6	0.7
Output growth	0.5	0.5	0.5	1.0	1.3
Productivity growth	0.5	0.5	0.5	0.5	0.5
Rate of change	**0.8**	**0.5**	**0.4**	**1.1**	**1.5**
Difference	**0.2**	**0.2**	**0.2**	**0.2**	**0.3**

Source: SA Power Networks, *SAPN – 6.1 – Opex Model*, January 2024; AER, *SA Power Networks 2025–30 – Distribution – Draft decision – Opex model*, September 2024; AER analysis.

Note: Numbers may not add up to totals due to rounding. Values of '0.0' and '–0.0' represent small nonzero amounts and '–' represents zero.

6.4.3.1 Forecast price growth

SA Power Networks proposed average annual price growth of 0.4%, which increased its total opex forecast by $25.2 million. We have used real average annual price growth of 0.6% in our alternative estimate of total opex. This increases our total opex alternative estimate by $35.5 million.

Both we and SA Power Networks' forecast price growth as a weighted average of forecast labour price growth and non-labour price growth:

- Both we and SA Power Networks used an average of two WPI growth forecasts for the electricity, gas, water and waste services (utilities) industry in South Australia to forecast labour price growth, consistent with our standard approach. SA Power Networks used forecasts from its consultant, BIS Oxford Economics, and KPMG.[50] It sourced the KPMG forecasts from our April 2023 final decision for the South Australian transmission network service provider, ElectraNet. In our alternative estimate, we have replaced the KPMG forecasts with the more recent forecasts from our consultant Deloitte Access Economics.[51]

[50] SA Power Networks, *SAPN – Attachment 6 – Operating expenditure*, January 2024, p. 24.

[51] Deloitte Access Economics, *Labour price growth forecasts*, 20 August 2024, p. 10.

- Both we and SA Power Networks applied a forecast non-labour real price growth rate of zero.
- Both we and SA Power Networks have applied the same weights to account for the proportions of opex that is labour and non-labour, 59.2% and 40.8%, respectively.

Consequently, the key difference between our real price growth forecasts and SA Power Networks' is that we have updated our labour price growth forecast to include the more recent forecasts from our consultant Deloitte Access Economics, instead of the older KPMG forecasts.

We have updated our forecasts of WPI to reflect the latest available information

Our standard approach to forecasting labour price growth is to use an average of two WPI growth forecasts for the utilities industry in the relevant state. We use one set of forecasts provided by the distribution business, and one set from our own consultant. For this determination we engaged Deloitte Access Economics to provide WPI growth forecasts for the South Australia utilities industry.

Consistent with this approach, SA Power Networks used forecasts from its consultant, BIS Oxford Economics, and KPMG.[52] It sourced the KPMG forecasts from our April 2023 final decision for ElectraNet's 2023–28 regulatory control period. These were the most recent set of forecasts for South Australia available to it at the time it submitted its regulatory proposal.

Since SA Power Networks submitted its regulatory proposal, we have received new WPI growth forecasts from Deloitte Access Economics, which reflect more up-to-date economic information.[53] We used these newer, higher, forecasts in place of the KPMG forecasts that SA Power Networks used.

Table 6.6 compares our forecast labour price growth with SA Power Networks' proposal.

Table 6.6 Forecast labour price growth (%)

	2024–25	2024–25	2025–26	2026–27	2027–28
SA Power Networks' proposal					
KPMG	0.2	0.2	0.2	0.2	0.2
BIS Oxford Economics	1.1	1.0	0.9	1.1	1.3
Average	0.7	0.6	0.5	0.7	0.7
Superannuation guarantee increases	0.5	–	–	–	–
Average, including superannuation guarantee increases	**1.2**	**0.6**	**0.5**	**0.7**	**0.7**
AER's alternative estimate					
Deloitte Access Economics	0.8	0.8	0.7	0.8	1.1

52 SA Power Networks, *SAPN – Attachment 6 – Operating expenditure*, January 2024, p. 24.

53 Deloitte Access Economics, *Labour price growth forecasts*, 20 August 2024, p. 10.

	2024–25	2024–25	2025–26	2026–27	2027–28
BIS Oxford Economics	1.1	1.0	0.9	1.1	1.3
Average	1.0	0.9	0.8	1.0	1.2
Superannuation guarantee increases	0.5	–	–	–	–
Average, including superannuation guarantee increases	**1.5**	**0.9**	**0.8**	**1.0**	**1.2**
Overall difference	**0.3**	**0.3**	**0.3**	**0.3**	**0.4**

Source: SA Power Networks, *SAPN – 6.1 – Opex Model*, January 2024; Deloitte Access Economics, *Labour price growth forecasts*, 20 August 2024, p. 10; AER analysis.
Note: Numbers may not add up to totals due to rounding. Values of '0.0' and '–0.0' represent small non-zero amounts and '–' represents zero.

We will receive updated WPI forecasts prior to our final decision. We will use these to update our labour price growth forecasts in the final decision.

6.4.3.2 Forecast output growth

SA Power Networks proposed average annual output growth of 0.7%, which increased its proposed opex forecast for the 2025–30 regulatory control period by $31.9 million. We have also forecast average annual output growth of 0.7%. This increases our alternative estimate of total opex by $32.2 million.

We and SA Power Networks have forecast output growth by:

- calculating the growth rates for three outputs (customer numbers, circuit line length, and ratcheted maximum demand)
- calculating four weighted average overall output growth rates using output weights derived from the econometric opex cost function modelling results in our *2023 Annual Benchmarking Report*
- averaging the four model specific weighted overall output growth rates.

We discuss these components below.

6.4.3.2.1 Forecast growth of the individual output measures

We are satisfied that SA Power Networks' forecast of the growth in customer numbers, circuit length and ratcheted maximum demand, as set out in Table 6.7, reflect a realistic expectation. They are largely consistent with forecast trends from external sources or historical growth rates. Specifically:

- **Customer numbers:** SA Power Networks forecast 0.9% growth per annum in its customer numbers based on its historical growth rate.
- **Circuit length:** SA Power Networks forecast 0.3% growth per annum in its circuit length based on its historical growth rate.
- **Ratcheted maximum demand:** SA Power Networks forecast ratcheted maximum demand based on its actual demand in 2022–23, escalated by AEMO's forecast of maximum demand growth under the central scenario from its *2023 Electricity statement*

of opportunities. SA Power Networks' forecast maximum demand does not surpass its historic peak until 2026–27, resulting in no growth in ratcheted maximum demand until 2026–27. We note that SA Power Networks used different maximum demand forecasts to develop its capex forecast. We discuss the maximum demand forecasts SA Power Networks used to forecast capex in section A.2.3.1 of Attachment 5 of our draft decision. Since SA Power Networks submitted its proposal, AEMO published its *2024 Electricity statement of opportunities*. We expect that SA Power Networks will update its maximum demand forecasts in its revised proposal to reflect the updated forecasts from AEMO in the *2024 Electricity statement of opportunities*.

Table 6.7 Forecast growth in individual output measures, %

	2024–25	2024–25	2025–26	2026–27	2027–28
Customer numbers	0.9	0.9	0.9	0.9	0.9
Circuit length	0.3	0.3	0.3	0.3	0.3
Ratcheted maximum demand	–	–	–	1.4	2.2

Source: SA Power Networks, *SAPN – Attachment 6 – Operating expenditure*, January 2024, p. 23; AER analysis.
Note: Numbers may not add up to totals due to rounding. Values of '0.0' and '–0.0' represent small non-zero amounts and '–' represents zero.

6.4.3.2.2 Output weights

We have used the output weights set out in Table 6.8 in our alternative estimate. We derived these from the results of the four econometric models in our *2023 Annual benchmarking report*.[54]

In our *2023 Annual benchmarking report* we presented results from our new preferred approach to control for differences in capitalisation between distributors. Under this approach, we used the same four econometric models we previously used, but with an opex series that included all corporate overheads as opex. Given this was the first year we implemented this new approach, we also presented the results using our previous approach. This enabled readers to see the impact of the change in approach. The output weights we have used, as shown in Table 6.8, are based on the results from this new approach.

SA Power Networks, however, used the results from the old approach. As can be seen in Table 6.8, the two sets of econometric modelling results do not produce significantly different output weights. In turn, the small difference in outputs weights does not produce a material difference in forecast output growth.

Table 6.8 Output weights, %

	Cobb Douglas SFA	Cobb Douglas LSE	Translog LSE	Translog SFA	Average
SA Power Networks' proposal					

54 Quantonomics, *Benchmarking results for the AER*, *Distribution*, November 2023, pp. 165–167.

	Cobb Douglas SFA	Cobb Douglas LSE	Translog LSE	Translog SFA	Average
Customer numbers	37.5	58.1	41.9	40.7	**44.6**
Circuit length	13.6	17.5	19.0	10.2	**15.1**
Ratcheted maximum demand	48.9	24.5	39.0	49.1	**40.4**
AER alternative estimate					
Customer numbers	38.9	57.7	42.2	43.2	**45.5**
Circuit length	12.7	17.7	19.1	9.9	**14.9**
Ratcheted maximum demand	48.3	24.7	38.7	46.9	**39.6**

Source: SA Power Networks, *SAPN – Attachment 6 – Operating expenditure*, January 2024, p. 23; Quantonomics, *Benchmarking results for the AER*, *Distribution*, November 2023, pp. 165–167; AER analysis.

Note: Amounts of '0.0' and '–0.0' represent small non-zero values and '–' represents zero.

We will publish our *2024 Annual benchmarking report* in November 2024. In our final decision, we will update the output growth forecast in our alternative estimate to reflect the output weights derived using the results from this report. Full details of our approach to forecasting output growth are set out in our opex model, which is available on our website.

6.4.3.3 Forecast productivity growth

SA Power Networks proposed average productivity growth of 0.5% per year, which decreased its total opex by $26.9 million. We have forecast the same average productivity growth rate, which reflects our standard approach.[55] This decreases our alternative opex estimate by $26.9 million over the 2025–30 regulatory control period.

In terms of stakeholder submissions, the SAWIA submitted that SA Power Networks should strive to perform as if it were in a normal competitive market where continuous productivity growth is fundamental business practice.[56] We agree that electricity networks should endeavour to improve their productivity, and have included forecast productivity growth of 0.5% per year in our alternative estimate of opex.

Origin Energy supported SA Power Networks' proposal to apply annual opex productivity growth of 0.5%.[57]

55 AER, *Forecasting productivity growth for electricity distributors*, *Final decision*, March 2019.

56 South Australian Wine Industry Association, *SAWIA – Submission – 2025–30 Electricity Determination – SA Power Networks*, May 2024, p. 6.

57 Origin Energy, *Origin Energy – Submission – 2025–30 Electricity Determination – Energex, Ergon & SA Power Networks*, May 2024, p. 3.

The SA Government submitted that, 'given the notable escalation in proposed opex', it would expect additional savings to consequently flow because of efficiency gains.[58] The step changes we have included in our alternative estimate have been included to meet new regulatory obligations and to maintain the services delivered to customers which are not otherwise included in the opex forecast. We do not include step changes in our alternative estimate on the basis that they will reduce costs for the network. We expect networks to self-fund any such activities from the avoided costs. Consequently, we remain satisfied that a forecast productivity growth rate of 0.5% is appropriate.

6.4.4 Step changes

In developing our alternative estimate for the draft decision, we include prudent and efficient step changes for cost drivers such as new regulatory obligations or efficient capex / opex trade-offs. As we explain in the Guideline, we will generally include a step change if the efficient base opex and the rate of change in opex of an efficient service provider does not already include the proposed cost for such items and they are required to meet the opex criteria.[59]

SA Power Networks' proposal included eleven step changes totalling $128.8 million or 6.5% of its proposed total opex forecast.[60] These are shown in Table 6.9 along with our alternative estimate for the draft decision, which is to include step changes totalling $105.7 million. This is $23.1 million lower than SA Power Networks' proposal. While we consider most of these step changes are prudent, we consider our lower alternative estimates better reflects the efficient costs associated with these step changes, as we discuss below for each step change.

Table 6.9 SA Power Networks' proposed step changes and the AER's alternative estimate ($million, 2024–25)

Step change	SA Power Networks' proposal	AERs alternative estimate – draft decision	Difference
Cyber security uplift	47.6	47.6	–0.0
Operationalising cyber security	17.4	17.4	–0.0
IT infrastructure refresh	9.9	9.9	–0.0
Network visibility	6.8	6.7	–0.0
Smart meter rollout – IT upgrades	4.8	–	–4.8
CER integration	4.4	4.4	–0.0
CER compliance	2.5	2.5	–0.0
Increases to insurance premiums	19.4	19.4	–0.0

58 Government of South Australia, *Department for Energy and Mining – Submission – 2025–30 Electricity Determination – SA Power Networks*, May 2024, p. 4.

59 AER, *Expenditure forecast assessment guideline for electricity distribution*, August 2022, p. 26.

60 SA Power Networks, *SAPN – 6.1 – Opex model*, January 2024.

Step change	SA Power Networks' proposal	AERs alternative estimate – draft decision	Difference
Network program uplift	18.0	–	–18.0
Reliability improvements	–0.7	–0.9	–0.2
Transitioning to electric vehicles	–1.3	–1.3	0.0
Total step changes	**128.8**	**105.7**	**–23.1**

Source: SA Power Networks, *SAPN – 6.1 – Opex model*, January 2024; AER analysis.
Note: Numbers may not add up to totals due to rounding. Values of '0.0' and '–0.0' represent small non-zero amounts and '–' represents zero.

6.4.4.1 Cyber security uplift step change

SA Power Networks proposed a step change of $47.6 million for a cyber security uplift over the 2025–30 regulatory control period.[61] This was for the implementation of a cyber security uplift program related to improving its controls in order to reduce both the likelihood and consequence of cyber threats. Our alternative estimate for the draft decision includes a forecast of $47.6 million for the cyber security uplift step change. We have included this as we consider, based on our review, that the proposed uplift contains actions that are a reasonable response to the risks identified in the context of increasing cyber threat landscape and the costs are prudent and efficient.

Table 6.10 SA Power Networks' cyber security uplift step change ($million, 2024–25)

	2025–26	2026–27	2027–28	2028–29	2029–30	Total
SA Power Networks' proposal	4.6	10.9	11.3	10.4	10.4	47.6
AER alternative estimate	4.6	10.9	11.3	10.4	10.4	47.6
Difference	**–0.0**	**–0.0**	**–0.0**	**–0.0**	**–0.0**	**–0.0**

Source: SA Power Networks, *SAPN – 6.1 – Opex model*, January 2024; AER analysis.
Note: Numbers may not add up to totals due to rounding. Values of '0.0' and '–0.0' represent small non-zero amounts and '–' represents zero.

A significant focus of SA Power Networks' ICT component of the stakeholder engagement program related to cyber security.[62] Both the Focused Conversations engagement and People's Panel recommended an uplift in investment for cyber security relative to the current expenditure level. The People's Panel recommended that SA Power Networks invest sufficiently to exceed expected legislated obligations in the 2025–30 regulatory period, highlighting the high importance customers attributed to mitigating cyber security risks.[63] We note this recommendation did not extend to whether this was funded by additional opex or

61 SA Power Networks, *SAPN – Attachment 6 – Operating expenditure,* January 2024, p. 27.

62 SA Power Networks, *SAPN – Attachment 6 – Operating expenditure,* January 2024, p. 27.

63 SA Power Networks, *SAPN – 5.12.9 – Cyber Security Uplift,* January 2024, p. 53.

through a reprioritisation of the existing IT program. SA Power Networks included this recommendation as the cyber security uplift step change in its Draft Plan.

In response to the Draft Plan some customers and CAB members believed that any investment above the minimum regulatory obligations should be paid by SA Power Networks as part of balancing its own risk. [64] In preparing its initial proposal, SA Power Networks responded by ensuring its cyber security ICT proposal was both prudent and efficient. SA Power Networks did this by removing $4.4 million in opex costs and taking what it described as a more risk prioritised approach to cyber security investment.[65]

SA Power Networks' stated its forecast was built on a threat and risk based approach to uplifting cyber security capability. It proposed controls and measures based on the specific risks faced by SA Power Networks, with controls drawn from the compliance with the Australian Energy Sector Cyber Security Framework (AESCSF) as well as other controls that sit outside these frameworks.[66] There is also an associated $3.0 million in proposed capex (refer to Attachment 5 of our draft decision, section A.4). All costs were supported by SA Power Networks' business case.

To develop this step change, SA Power Networks assessed three options, before selecting option 2 'Risk Based Approach' as the preferred strategy. The preferred investment option (option 2) was selected because it represented the most efficient option, with benefits outweighing costs and delivering what SA Power Networks considered was a prudent reduction in cyber security risk to an acceptable level.[67] This incorporated practices from both the AESCSF and other relevant cyber security frameworks. SA Power Networks' proposed opex costs for option 2 are shown in Table 6.11.

Table 6.11 Option 2 Risk Based Approach – Proposed Cyber security uplift costs ($million, 2024–25)

Cost type	Description	Proposed Opex
Non-recurrent	Development and implementation of systems capabilities as well as process uplifts associated with the new systems	29.6
Recurrent	Licensing fees, software, and additional resources	18.0
Total step change		**47.6**

Source: SA Power Networks, *SAPN – 5.12.9 – Cyber Security Uplift*, January 2024, p. 44. These figures have been inflated from June $2022 (used in SA Power Networks' business case) to June $2025.

We engaged EMCa to assist in our assessment of the prudency and efficiency of the proposed opex and related capex components of the cyber security uplift step change. EMCa's assessment considered that SA Power Networks had demonstrated a good

64 SA Power Networks, *SAPN – 0.1 – Community Advisory Board Independent Report,* November 2023, p. 38.

65 SA Power Networks, *SAPN – Attachment 6 – Operating expenditure,* January 2024, p. 27; AER analysis.

66 SA Power Networks, *SAPN – 5.12.9 – Cyber Security Uplift,* January 2024, p. 21.

67 SA Power Networks, *SAPN* – 5.12.9 – *Cyber Security Uplift,* January 2024, pp. 6-7.

understanding of its risks and identified appropriate controls to manage them, and that the costs were developed on a reasonable basis.[68] Overall EMCa found that in terms of risk cost / economic benefit analysis, while the net economic benefit of the uplift was overstated, sensitivity testing (outlined below) showed it was still sufficient (positive) to justify the preferred option 2.[69] Therefore, EMCa considered that SA Power Networks' proposed cyber security step change was likely to be prudent and efficient.

In forming this assessment, EMCa noted that SA Power Networks' cyber security expenditure represented a significant uplift from the current regulatory control period (2020–25) and that this was in response to increasing cyber security risks.[70] EMCa also observed that SA Power Networks presented its expenditure requirements in two tranches being:[71]

- An 'uplift' program (this cyber security uplift step change) based on adding depth and breadth of controls to offset the risk of cyber security breaches from an expected increased cyber security threat landscape and SA Power Networks' increasing attack surface area.
- A cyber security 'refresh' program (see section 6.4.4.2) which is essentially based on maintaining throughout the 2025–30 regulatory control period the cyber security operations capability it expects to achieve by the end of the 2020–25 regulatory control period.

In our most recent assessments of cyber security step changes for distribution businesses, in the absence of any obligation beyond the minimum SP1 maturity level under the *Security of Critical Infrastructure Act,* we based our analysis on the economic case / net economic benefit of the proposed investment.[72] In this regard, our recent 2024–29 Ausgrid final decision approved expenditure based on the demonstrated economic benefits rather than the SP level achieved. Prior to this our historical decisions had been approved on the basis of distribution businesses meeting the regulatory obligations under the *Security of Critical Infrastructure Act* of being compliant to a SP1 maturity level.

EMCa was satisfied that the combination of SA Power Networks' risk register, and the identification of gaps and controls to manage exposures throughout the course of the 2025–30 regulatory control period, was a sound approach, with the detail provided to support its proposed option 2 a sufficient justification for the scope of works.[73] EMCa considered that SA Power Networks' chosen option of adopting a risk based approach to mitigate increasing

68 Energy Market Consulting Associates, *SA Power Networks: Review of Cyber Security and ADMS expenditure forecast*, September 2024, p. 25.

69 Energy Market Consulting Associates, *SA Power Networks: Review of Cyber Security and ADMS expenditure forecast*, September 2024, pp. 24-25.

70 Energy Market Consulting Associates, *SA Power Networks: Review of Cyber Security and ADMS expenditure forecast*, September 2024, p. iv.

71 Energy Market Consulting Associates, *SA Power Networks: Review of Cyber Security and ADMS expenditure forecast*, September 2024, p. iv.

72 AER, *AER – Final Decision Attachment 5 – Capital Expenditure – Ausgrid – 2024–29 Distribution revenue proposal*, April 2024, pp. 12–17.

73 Energy Market Consulting Associates, *SA Power Networks: Review of Cyber Security and ADMS expenditure forecast*, September 2024, pp. iv-v.

cyber risks, with fit for purpose controls, was good practice.[74] EMCa also noted that SA Power Networks' selected option is slightly less expensive than full achievement of the AESCSF Version 2 SP3 practices, but substantially achieves the same level of benefits.[75] EMCa considered this demonstrates a prudent outcome from the risk-cost approach that SA Power Networks took.

EMCa's assessment of SA Power Networks net present value (NPV) calculations also considered that the avoided risk-cost benefits are likely to be significantly lower than SA Power Networks had derived.[76] This was due to what EMCa viewed as overly pessimistic assumptions regarding the likelihood (frequency) of severe cyber security breaches in the 2025–30 regulatory control period. EMCa undertook NPV sensitivity testing, based on reduced likelihood of the occurrences of Priority 1 and Priority 2 cyber security breaches. Following this sensitivity testing, EMCa considered that the net benefit is still likely to be positive, with SA Power Networks' chosen option 2 having the highest NPV.

EMCa also considered SA Power Networks' cost estimation approach, combining a bottom-up and top-down approach, to be satisfactory.[77] The bottom-up forecast included:

- estimating delivery team effort
- expenditure calculated using standard IT labour rates
- assessing new software licensing requirements and costs.

SA Power Networks then subjected the bottom-up forecast to a peer review, and benchmarking with other distributors and other external entities to confirm its estimate.

On this basis EMCa considered the costs for each control proposed by SA Power Networks to be reasonable.[78]

We consider, based on our review, including of EMCa's findings and the customer engagement undertaken, that the proposed uplift is prudent and that the costs are efficient. While some customer and CAB members were concerned about SA Power Networks funding any investment above the regulatory obligation, our assessment finds the proposed actions are a reasonable response to the identified risks, particularly in an increasing cyber threat landscape, the costs are prudent and efficient, and there is a demonstrated economic benefit. This is also consistent with our recent decisions.

74 Energy Market Consulting Associates, *SA Power Networks: Review of Cyber Security and ADMS expenditure forecast*, September 2024, p. 16.

75 Energy Market Consulting Associates, *SA Power Networks: Review of Cyber Security and ADMS expenditure forecast*, September 2024, p. v.

76 Energy Market Consulting Associates, *SA Power Networks: Review of Cyber Security and ADMS expenditure forecast*, September 2024, p. 24.

77 Energy Market Consulting Associates, *SA Power Networks: Review of Cyber Security and ADMS expenditure forecast*, September 2024, p. 19.

78 Energy Market Consulting Associates, *SA Power Networks: Review of Cyber Security and ADMS expenditure forecast*, September 2024, p. 19.

On this basis we have included $47.6 million for the cyber security uplift step change in our alternative estimate

6.4.4.2 Operationalising cyber security step change

SA Power Networks proposed a step change of $17.4 million for operationalising cyber security over the 2025–30 regulatory control period.[79] This was for a capex to opex reclassification of activities that it considered were operational in nature and required to maintain its cyber security and ICT resilience capabilities. Our alternative estimate for the final decision includes a forecast of $17.4 million for the operationalising cyber security step change. This reflects that from our assessment we consider the reclassification is appropriate, these activities are operational in nature, and the costs are both prudent and efficient.

Table 6.12 SA Power Networks' operationalising cyber security step change ($million, 2024–25)

	2025–26	2026–27	2027–28	2028–29	2029–30	Total
SA Power Networks' proposal	3.5	3.5	3.5	3.5	3.5	17.4
AER alternative estimate	3.5	3.5	3.5	3.5	3.5	17.4
Difference	**–0.0**	**–0.0**	**–0.0**	**–0.0**	**–0.0**	**–0.0**

Source: SA Power Networks, *SAPN – 6.1 – Opex model*, January 2024; AER analysis.
Note: Numbers may not add up to totals due to rounding. Values of '0.0' and '–0.0' represent small non-zero amounts and '–' represents zero.

SA Power Networks proposed a $17.4 million step change for a capex to opex reclassification associated with maintaining the current cyber security risk level (given current threat levels). This was for both its Operational Technology and Information Technology systems and data.[80]

SA Power Networks stated that in the 2020–25 period it is completing the development of the capability and systems for its recurrent ICT cyber security (capex), to manage increasing cyber security risks and regulatory requirements. In the 2025–30 regulatory period SA Power Networks considered the focus of this program should shift to ongoing maintenance of these technologies, processes, and information assets.[81] SA Power Networks proposed these activities (e.g. incident response, vulnerability management, threat intelligence and hunting and security logging) are operational in nature and the appropriate accounting treatment is opex. This reclassification and treatment as opex was supported by an accounting view from BDO Australia, engaged by SA Power Networks.[82] BDO Australia provided a review of the proposed accounting treatment of these costs as opex. It supported this reclassification. The proposed opex costs have an associated $3.4 million in capex (for ongoing hardware and

79 SA Power Networks, *SAPN – Attachment 6 – Operating expenditure,* January 2024, p. 31.

80 SA Power Networks, *SAPN – 5.12.6 – Cyber Security Refresh,* January 2024, p. 6.

81 SA Power Networks, *SAPN – Attachment 6 – Operating expenditure,* January 2024, p. 31.

82 SA Power Networks, *SAPN – 5.12.24 – External Review of ICT Cyber Expenditure Treatment,* January 2024, p. 12.

installation costs, see Attachment 5 of our draft decision, section A.4) and were supported by a business case.

To develop this step change, SA Power Networks assessed two options. Option 1 continued investment in operational cyber security activities at the actual/forecast levels for the 2020–25 regulatory period (noting the proposal to classify the majority of this expenditure as opex going forward). SA Power Networks considered this was an insufficient level of funding to cover the increase in the scale of operational cyber security activities required to address increasing volume of activity into the 2025–30 regulatory period.[83] Therefore, it also considered option 2 (its preferred option) which maintained its operations, digital identity and risk and resilience capabilities at the 2020–25 regulatory period level but added $0.5 million (totex) to support the material increase in the volume of activity covered within the teams supporting its operational cyber security capability.

SA Power Networks did not undertake any stakeholder engagement with consumers on this specific step change.

We engaged EMCa to assist in our assessment of the prudency and efficiency of the proposed operationalising cyber security step change. EMCa's assessment considered it appropriate for SA Power Networks to continue its proposed level of annual expenditure to maintain the underlying cyber security capability it had established.[84]

EMCa noted the options considered were option 1 maintain current level of investment and option 2 maintain the current level of risk while addressing the increasing threat volumes.[85]

SA Power Networks' preferred option 2 proposed a level of expenditure slightly higher than current levels to support the required increase in recurrent cyber security activity. This included the refresh of Operational Technology equipment coming to the end of its useful life. EMCa was satisfied that option 2 was the prudent option, due to SA Power Networks extreme overall risk rating at the end of the 2025–30 regulatory control period being a reasonable position to take without addressing the increasing volume of cyber activity.[86]

EMCa noted that SA Power Networks presented cost benefit analysis for both option 1 and 2, but in the absence of benefits it essentially presents the present cost of the options over a 10–year period.[87] EMCa also noted that for expenditure to maintain capability, a positive cost benefit analysis is not necessary under the AER's ICT Assessment Guideline. EMCa

83 SA Power Networks, *SAPN – 5.12.6 – Cyber Security Refresh,* January 2024, p. 17.

84 Energy Market Consulting Associates, *SA Power Networks: Review of Cyber Security and ADMS expenditure forecast*, September 2024, p. v.

85 Energy Market Consulting Associates, *SA Power Networks: Review of Cyber Security and ADMS expenditure forecast*, September 2024, p. 16.

86 Energy Market Consulting Associates, *SA Power Networks: Review of Cyber Security and ADMS expenditure forecast*, September 2024, p. 15.

87 Energy Market Consulting Associates, *SA Power Networks: Review of Cyber Security and ADMS expenditure forecast*, September 2024, p. 17.

therefore considered only the costs, which in its view are reasonably derived (from extrapolation of the 2024–25 forecast).[88]

EMCa was also satisfied that the proposed costs from the extrapolation of the 2024–25 forecast are likely to be efficient given that:[89]

- SA Power Networks has introduced a large number of controls during the 2020–25 regulatory control period as evidenced by its mapping of controls versus the AESCSF Security Profiles
- the proposed recurrent expenditure (currently capex) enables maintenance of current cyber security controls.

In terms of the reclassification of costs from capex to opex, we examined the report SA Power Networks submitted from its consultant BDO. BDO considered that the treatment of these expenditures as opex is supported by the Australian Accounting Standards Board (AASB) frameworks.[90] Further, it considered that the proposed activities do not materially add to the value of existing assets by extending their life or increasing their capacity. Therefore, BDO believed the expenditure associated with these activities should be treated as opex. We consider this view to be reasonable, consistent with the accounting standards and the treatment of costs in the regulatory framework.

Overall, based on our review, including of EMCa's findings, we consider the proposed opex step change is the prudent approach to maintain the underlying cyber security capability it has established. Further, we consider that the proposed costs are efficient. We also agree the reclassification of these costs from capex to opex is appropriate. We are also satisfied via our analysis of SA Power Networks' Regulatory Information Notices and business cases that the SaaS capex being transferred to opex has been excluded from the 2025–30 ICT capex forecasts. Further, that it is not included in base year opex, and hence there is no double counting of forecast costs.

On this basis we have included $17.4 million for the operationalising cyber security step change in our alternative estimate.

6.4.4.3 IT infrastructure refresh step change

SA Power Networks proposed a step change of $9.9 million for its ICT infrastructure refresh program over the 2025–30 regulatory control period.[91] This was for opex associated with an increase in its ICT data storage, processing and analytics capabilities. It also included a small amount of reclassified costs (capex to opex), to maintain SA Power Networks' existing data storage and processing systems. Our alternative estimate for the draft decision includes a forecast of $9.9 million for the ICT infrastructure refresh step change. We have included

88 Energy Market Consulting Associates, *SA Power Networks: Review of Cyber Security and ADMS expenditure forecast*, September 2024, p. 17.

89 Energy Market Consulting Associates, *SA Power Networks: Review of Cyber Security and ADMS expenditure forecast*, September 2024, p. 17.

90 SA Power Networks, *SAPN – 5.12.24 – External Review of ICT Cyber Expenditure Treatment,* January 2024, p. 12.

91 SA Power Networks*, SAPN – Attachment 6 – Operating Expenditure*, January 2024, pp. 29-30.

this step change in our alternative estimate as we are satisfied the proposed ICT infrastructure refresh expenditure is sufficiently justified, prudent, efficient, and not already accounted for elsewhere in either the opex or capex components in SA Power Networks' proposal.

Table 6.13 SA Power Networks' ICT infrastructure refresh step change ($million, 2024–25)

	2025–26	2026–27	2027–28	2028–29	2029–30	Total
SA Power Networks' proposal	0.8	1.3	2.0	2.7	3.2	9.9
AER alternative estimate	0.8	1.3	2.0	2.7	3.2	9.9
Difference	**–0.0**	**–0.0**	**–0.0**	**–0.0**	**–0.0**	**–0.0**

Source: SA Power Networks, *SAPN – 6.1 – Opex model*, January 2024; AER analysis.
Note: Numbers may not add up to totals due to rounding. Values of '0.0' and '–0.0' represent small non-zero amounts and '–' represents zero.

SA Power Networks proposed a $9.9 million ICT infrastructure refresh opex step change for a variety of ICT projects that it grouped together. It also proposed $39.5 million[92] in recurrent capex alongside the opex required for this program as set out in Attachment 5 section A.4 of our draft decision. SA Power Networks stated its ICT infrastructure refresh program is required to ensure its information technology systems continue to function with sufficient capacity to meet forecast growth and efficiently manage storage, given the increasing use of its services.[93] SA Power Networks also noted that, historically, some of this type of expenditure was considered capex but that it is proposing reclassification to opex due to the change in accounting standards guidance around the treatment of SaaS costs.[94]

SA Power Networks included forecast opex costs (previously capex) in the business case for this step change associated with three separate drivers:[95]

- $6.0 million for business-as-usual data storage and computing capabilities (excluding smart meter impacts). This is for forecast increases in use, including in response to the strategic requirements to manage a more dynamic grid and enable more data-driven decision-making. Additionally, it is for replacing its key data centre hardware assets reaching end of life and requiring replacement.
- $1.9 million for growth in cloud data consumption for smart–meter analytics, billing data storage and computing, based on its current rate of smart meter growth (separate to the accelerated smart meter rollout in the step change examined in section 6.4.4.5). SA Power Networks stated the current growth of smart meters would increase the number of

92 This amount is recorded in June $2025 and corresponds with the $34.1 million in June $2022 in SA Power Networks' business case.

93 SA Power Networks, *SAPN – 5.12.7 – IT infrastructure refresh*, January 2024, p. 15.

94 SA Power Networks, *SAPN – 5.12.7 – IT infrastructure refresh*, January 2024, p. 12.

95 Amounts are in June $2025, but otherwise reflect the June $2022 values represented in SA Power Networks' business case ($5.3 million, $1.6 million, and $1.8 million respectively, inclusive of related overheads).

streams of data (i.e. five–minute meter reads) to be stored, but also the amount of storage, capacity and computing required by the associated analytics and billing systems.

- $2.1 million for a capex to opex reclassification (due to the change in accounting standard guidance around SaaS costs) to cater for the costs of managing its existing compute and storage systems while it migrates more of its applications to the cloud. SA Power Networks proposed that applications are only migrated to the cloud when greater value can be obtained or achieved than from the traditional hosting model, or where the vendor no longer provides non–cloud–based options. SA Power Networks estimated a $2.4 million decrease in capex hardware costs over the 2025–30 regulatory period as a result of its proposed cloud migration.[96]

SA Power Networks considered 3 options in its business case:

- option 1: Limit its expenditure to current 2020–25 levels
- option 2: Business as usual with strategic migration to cloud (its preferred option for all drivers)
- option 3: Accelerated transition to the cloud.

SA Power Networks' business case was supported by a three-tier risk assessment for each option against a variety of categories. For each of these categories, SA Power Networks described its considerations in arriving at a rating of high, medium or low risk against each of these categories, for each of the three options together with a 'do nothing' option.

SA Power Networks did not undertake any targeted consumer or stakeholder engagement on this step change. However, it stated that customers expect that it will maintain its existing levels of service and risk.[97]

We engaged EMCa to assist with the assessment of SA Power Networks' capex and opex ICT components, which included this step change. EMCa investigated the drivers SA Power Networks detailed in its business case for the IT infrastructure refresh and reviewed the basis for its assessments at the granular level. EMCa found SA Power Networks' three-tier risk assessment for each option to be comprehensive and considered its judgments represent a reasonable assessment of the overall residual risk of each option.[98] EMCa concluded that:[99]

- SA Power Networks' rejection of option 1 (current expenditure), due to the extreme residual risk, and option 3 (accelerated transition), due to its considerably higher cost, were both reasonable.

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96 SA Power Networks, *SAPN – 5.12.7 – IT infrastructure refresh*, January 2024, p. 13.

97 SA Power Networks, *SAPN – 5.12.7 – IT Infrastructure refresh*, January 2024, p. 15.

98 Energy Market Consulting Associates, *SA Power Networks: Review of aspects of proposed expenditure*, August 2024, pp. 110-111.

99 Energy Market Consulting Associates, *SA Power Networks: Review of aspects of proposed expenditure*, August 2024, pp. 111-112.

- It was satisfied that SA Power Networks' preferred option, option 2 (strategic cloud migration), was the prudent choice given it has the same residual risk as option 3 but a lower net present cost.
- In terms of timing, given option 3 would involve an accelerated transition, and that the more negative NPV demonstrates that this is not justified, option 2 represented the optimal timing.
- The proposed opex is for cloud computing services and so are reasonably defined as 'opex'.

As a part of our assessment, we also considered the detailed cost breakdown information supporting the business case. This showed how the underlying costs had been estimated and confirmed that SA Power Networks had estimated them separately from the ICT costs it proposed in its other opex step changes (namely, smart meter rollout – ICT upgrade, network visibility and the CER integration step changes). Additionally, we compared SA Power Networks' historical ICT total expenditure with its forecast costs and found that it had removed those capex costs associated with the proposed reclassification from its 2025–30 forecast. Therefore, we are satisfied that this step change does not include costs found elsewhere in its proposal.

We consider the proposed opex to be prudent and efficient, based on both EMCa's findings and our own internal assessment. On this basis we have included an ICT infrastructure refresh step change of $9.9 million in our alternative estimate.

6.4.4.4 Network visibility step change

SA Power Networks proposed a step change of $6.8 million for network visibility over the 2025–30 regulatory control period.[100] This was for systems to receive and store additional power quality data and for the data analytics that will enhance visibility of its network, providing customer safety benefits and reducing export curtailment. Our alternative estimate for the draft decision includes a forecast of $6.7 million[101] because we consider this step change is prudent and efficient. We have included this as a placeholder given the economic viability of this step change is contingent on the provision of free basic power quality data. This in turn is subject to the AEMC's final determination on the *Accelerating smart meter deployment* rule change due in November 2024. Should the AEMC's final rule change match its draft rule change, we would continue to include this step change, as currently proposed, in our alternative estimate for the final decision.

Table 6.14 SA Power Networks' network visibility step change ($million, 2024–25)

	2025–26	2026–27	2027–28	2028–29	2029–30	Total
SA Power Networks' proposal	1.0	1.2	1.4	1.5	1.6	6.8
AER alternative estimate	1.0	1.2	1.4	1.5	1.6	6.7
Difference	**–0.0**	**–0.0**	**–0.0**	**–0.0**	**–0.0**	**–0.0**

100 SA Power Networks, *SAPN – Attachment 6 – Operating Expenditure*, January 2024, p. 26.
101 Our slightly lower alternative estimate reflects the use of more recent inflation figures.

Source: SA Power Networks, *SAPN – 6.1 – Opex model*, January 2024; AER analysis.
Note: Numbers may not add up to totals due to rounding. Values of '0.0' and '–0.0' represent small non-zero amounts and '–' represents zero.

SA Power Networks proposed a $6.8 million opex step change to enhance its data analytical framework and storage and processing capabilities. This opex cost has an associated capex cost of $9.1 million[102] as set out in Attachment 5 of our draft decision, section A.5. The program is aimed at utilising the 'basic' smart meter power quality data that under a proposed rule change is expected to become available to distribution businesses at no cost.[103] In this regard SA Power Networks' preferred option seeks alignment with the AEMC's recommendations in its 2023 *Review of the Regulatory Framework for Metering Services* and the proposed *Accelerating smart meter deployment* rule change.

In terms of the rule change, on 29 September 2023, SA Power Networks, Intellihub and Alinta Energy jointly submitted a request to the AEMC to accelerate the deployment of smart meters.[104] The draft rule proposed several reforms, including the accelerated deployment of smart meters and access to free 'basic' power quality data for DNSPs. On 4 April 2024, the AEMC published a draft determination and draft rule, which supported the proposed rule changes for accelerated smart meter deployment and access to free 'basic' power quality data. The AEMC initially aimed to publish its final determination and final rule in July 2024, but extended its timeframe to consider the 149 submissions it received. The AEMC is now expected to publish its final rule determination in November 2024, with the new changes to come into full effect on 26 June 2025.[105]

SA Power Networks' business case for this step change leveraged off the target set in the AEMC's metering review.[106] In particular, 100% smart meter rollout by 2030 and the provision of basic meter data to DNSPs at no cost.[107] Basic meter data includes 5-minute power quality data provided between 6-hourly and daily. SA Power Networks' proposed program comprises development of a scalable data analytics platform to provide the capability to receive the expected basic power quality data. Its program will provide specific data analytics and development of associated business processes to realise targeted use cases, together with some other use cases that will be trialled.

SA Power Networks' business case was based on three use cases providing the following benefits:

- customer safety benefits from detecting neutral integrity faults on services
- reduced export curtailment due to more accurate information on hosting capacity used in calculating Dynamic Operating Envelopes, enabling flexible export limits

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102 This corresponds to the $7.9 million in June $2022 shown in SA Power Networks' business case.

103 SA Power Networks, *SAPN – 5.7.6 – Network Visibility*, January 2024, p. 7.

104 AEMC, *Rule change: Accelerating smart meter deployment*, Accessed on 4 July 2024 at: https://www.aemc.gov.au/rule-changes/accelerating-smart-meter-deployment.

105 AEMC, *Draft National Electricity Amendment (Accelerating smart meter deployment) Rule 2024*, 4 April 2024, p. 2.

106 SA Power Networks, *SAPN – 5.7.6 – Network Visibility*, January 2024, p. 23.

107 AEMC, *Review of the Regulatory Framework for Metering Services, Final Report*, 30 August 2023, pp. iii-iv.

- energy conservation for consumers from reducing average network supply voltages that are unnecessarily high.

It investigated the following options:[108]

- The base case of no smart meter data being sourced, other than the very small amount currently obtained for small-scale trials.
- Option 1 (preferred) of obtaining and utilising the basic power quality data from all smart meters as it becomes available. This had the highest NPV under the free basic power quality data assumption (which is why it is preferred). We note from our analysis that this option has a lower NPV if SA Power Networks must purchase the basic power quality data (as can be seen in Table 6.15 via option 1a). The 'energy conservation' benefit is the dominant driver behind this NPV result.
- Option 2 of obtaining power quality data from only 30% of smart meters. This had a lower NPV than option 1 under the free basic power quality data assumption. However, from our analysis it had a higher NPV if SA Power Networks must purchase the basic power quality data (option 2b in Table 6.15). Safety benefits would be reduced to 30% of the benefit achieved under option 1. Reduced export curtailment and energy conservation benefits would also be less than with 100% data, although SA Power Networks estimates that 70% of these benefits can be achieved with only 30% of the data.

Table 6.15 SA Power Networks' CBA of alternative options to the base case ($m, 2021–22)

	Net Present Cost			Net Present Benefit				
	Capex	Opex	NPC	Neutral integrity	CECV	Voltage reduction	NPB	NPV
Base case	0	0	**0**	0	0	0	**0.00**	**0.00**
Option 1 – 100% data	–7.43	–15.06	**–22.49**	8.98	6.58	65.20	**80.76**	**58.26**
Option 2 – 30% data	–9.53	–11.27	**–20.80**	2.69	4.60	45.64	**52.93**	**32.14**
Option 1a – 100% data with data purchase	–7.43	–82.61	**–90.04**	8.98	6.58	65.20	**80.76**	**–9.29**

108 SA Power Networks, *SAPN – 5.7.6 – Network Visibility*, January 2024, p. 20.

	Net Present Cost			Net Present Benefit				
	Capex	Opex	NPC	Neutral integrity	CECV	Voltage reduction	NPB	NPV
Option 2b – 30% data with data purchase	–9.53	–30.20	**–39.73**	2.69	4.60	45.64	**52.93**	**13.20**

Source: SA Power Networks, *SAPN – 5.7.6 – Network Visibility*, January 2024, p. 22; AER analysis.
Note: Base case has been subtracted from all other options. Numbers may not add up to totals due to rounding. Values of '0.0' and '–0.0' represent small non-zero amounts and '–' represents zero.

SA Power Networks did not undertake any stakeholder engagement with consumer on this specific step change. However, it noted the AEMC's metering review and the extensive consultation it undertook as evidence that consumers support this step change.

We engaged EMCa to help us assess the network visibility step change. A key finding from EMCa's analysis was that SA Power Networks had overstated the economic benefit from the energy conservation (voltage reduction) use case in its analysis. This was because it based its energy conservation benefit on the retail price of electricity to consumers. EMCa argued that the economic value of energy saved is more reasonably given by the wholesale cost of the energy itself, accounting for network losses and environmental costs.[109]

EMCa considered ACIL Allen's advice to the AER in setting the Default Market Offer for 2024–25, and its estimated Total Energy Cost for SA Power Networks' residential and small customers, was a more reasonable proxy for the economic cost of energy delivered and therefore of the economic benefit per until of energy saved.[110] EMCa noted applying the ACIL Allen economic benefit per unit of energy saved reduces the voltage reduction benefit by just over a half. It found, as can be seen in Table 6.16, that even with this reduction the network visibility program's NPV remained clearly positive, with option 1 providing significantly more benefits than option 2. However, it noted that if SA Power Networks needs to purchase the data the NPV of both options becomes negative (options 1a and 2b).[111] If this was the case, including the proposed step change in our alternative estimate would not be justified.

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109 Energy Market Consulting Associates, *SA Power Networks: Review of aspects of proposed expenditure*, August 2024, pp. 120-121.

110 Energy Market Consulting Associates, *SA Power Networks: Review of aspects of proposed expenditure*, August 2024, pp. 120-121.

111 Energy Market Consulting Associates, *SA Power Networks: Review of aspects of proposed expenditure*, August 2024, p. 121.

Table 6.16 EMCa and AER alternative proxy CBA with reduced voltage benefits ($m, 2021–22)

	Net Present Cost			Net Present Benefit				
	Capex	Opex	NPC	Neutral integrity	CECV	Voltage reduction	NPB	NPV
Base case	0	0	**0**	0	0	0	**0.00**	**0.00**
Option 1 – 100% data	–7.43	–15.06	**–22.49**	8.98	6.58	30.96	**46.52**	**24.03**
Option 2 – 30% data	–9.53	–11.27	**–20.80**	2.69	4.60	21.67	**28.96**	**8.16**
Option 1a – 100% data with data purchase	–7.43	–82.61	**–90.04**	8.98	6.58	30.96	**46.52**	**–43.52**
Option 2b – 30% data with data purchase	–9.53	–30.20	**–39.73**	2.69	4.60	21.67	**28.96**	**–10.77**

Source: SA Power Networks, *SAPN – 5.7.6 – Network Visibility*, January 2024, p. 22; EMCa's analysis; AER analysis.

Note: Base case has been subtracted from all other options. Numbers may not add up to totals due to rounding. Values of '0.0' and '–0.0' represent small non-zero amounts and '–' represents zero.

EMCa also concluded that while the values of individual parameters can be debated, SA Power Networks' estimate of the safety (neutral integrity) benefit was more granular and included greater supporting evidence than the benefit proposed by Ergon Energy in its current revenue proposal. It also observed SA Power Networks' estimate is an order of magnitude lower than that of Ergon Energy, which further supports the validity of this estimate and its business case.[112]

EMCa agreed with SA Power Networks' proposed treatment of this expenditure as a step change as it arises from the impact of external factors (notably the AEMC's metering review and CER) that are not accounted for under the opex trend component.[113] Additionally, EMCa considered SA Power Networks had segregated this proposed new expenditure from its business-as-usual expenditure to ensure no double counting of costs in its base year.

Based on our review, including of EMCa's advice, we are satisfied that SA Power Networks has adequately demonstrated and justified the need for this step change under the assumption of free 'basic' power quality data. Further, we are satisfied that its proposed cost

112 Energy Market Consulting Associates, *SA Power Networks: Review of aspects of proposed expenditure*, August 2024, p. 122.

113 Energy Market Consulting Associates, *SA Power Networks: Review of aspects of proposed expenditure*, August 2024, p. 122.

of $6.8 million in opex is likely prudent and efficient. This in part reflects that it aligns with the AEMC's *Review of the Regulatory Framework for Metering Services* recommendations as it aims to unlock further benefits from smart meter data and services for customers. However, the AEMC's final determination on the proposed *Accelerating smart meter deployment* rule change will not be made until November 2024. Therefore, we have included a step change of $6.7 million in our alternative estimate as a placeholder. This placeholder value is subject to the AEMC's final determination allowing DNSPs access to free 'basic' power quality data. Should the AEMC's final rule change match its draft rule change, we would continue to include this step change, as currently proposed, in our alternative estimate for the final decision.

6.4.4.5 Smart meter rollout IT upgrades step change

SA Power Networks proposed a step change of $4.8 million for smart meter rollout IT upgrades over the 2025–30 regulatory control period.[114] This was for its main SCS opex. It was for ICT upgrades required to facilitate and enable an accelerated smart meter rollout by 2030. Our alternative estimate for the draft decision includes a zero forecast for this step change, which is $4.8 million lower than SA Power Networks' proposal. This is a placeholder for the draft decision and is expected to be updated in the final decision in light of further information.

Table 6.17 SA Power Networks' smart meter rollout IT upgrades step change ($million, 2024–25)

	2025–26	2026–27	2027–28	2028–29	2029–30	Total
SA Power Networks' proposal	0.4	0.6	0.8	1.2	1.8	4.8
AER alternative estimate	–	–	–	–	–	–
Difference	**–0.4**	**–0.6**	**–0.8**	**–1.2**	**–1.8**	**–4.8**

Source: SA Power Networks, *SAPN – 6.1 – Opex model*, January 2024; AER analysis.
Note: Numbers may not add up to totals due to rounding. Values of '0.0' and '–0.0' represent small non-zero amounts and '–' represents zero.

SA Power Networks initially proposed a $4.8 million step change for increased ICT data storage and computational capacity upgrades required to accommodate an accelerated smart meter rollout to all customers by 2030.[115] SA Power Networks indicated this step change is influenced by the AEMC's pending decision on the *Accelerating smart meter deployment* rule change. Specifically that with the proposed rule change in place it will store and secure more data from the increasing number of smart meters.[116] This is the same rule change as outlined in section 6.4.4.4 (for the network visibility step change) which the AEMC

114 SA Power Networks, *SAPN – Attachment 6 – Operating expenditure*, January 2024, p. 28.

115 SA Power Networks, *SAPN – 19.4 – Legacy Metering Transition – Towards 2030,* January 2024. p. 5.

116 SA Power Networks, *SAPN – 19.4 – Legacy Metering Transition – Towards 2030,* January 2024. pp. 4, 6-7, 24-25.

is now expected to publish a final rule determination for in November 2024. If approved, the new changes would come into full effect in July 2025.[117]

SA Power Networks stated that it currently receives smart meter data based in 5-minute intervals, which is a considerably higher volume of data points than it receives from the older accumulation meters that the smart meters are replacing.[118] It expected that the additional smart meters brought about by the accelerated timeline would significantly increase its data storage, licensing, and management costs next period. The cost impact is expected to be exponentially cumulative as more smart meters are installed, but will reach a peak a few years after the last meter is changed. Further, SA Power Networks limited the costs included in this step change to those directly associated with the accelerated rollout and excluded costs it would have recovered under a normal rollout scenario.

However, SA Power Networks' initial (January 2024) business case did not provide much more detail regarding the specific ICT costs it had proposed. It noted that they were cloud-based (opex), primarily related to data storage and compute capabilities, and it had assumed replacement of 50,000 meters per year.[119] It stated this business case was only an initial cost estimate and that an updated and final cost estimate would be shared with the AER during the review process as specific details became clearer, or incorporated into its revised proposal if this was required.[120]

On 10 July 2024, SA Power Networks submitted an entirely new business case and supporting models which superseded its initial business case. In this new business case, it proposed:[121]

- a reduced main SCS opex step change for increased storage and compute capabilities of $1.6 million (down from $4.8 million in the initial business case)
- a new non-recurrent ICT capex component of $6.7 million for system upgrades required to meet compliance and market obligations (there was no capex proposed in the initial business case, see Attachment 5 of our draft decision, section A.4)
- a reduced legacy metering services transition costs step change of $9.6 million (down from $34.5 million in the initial business case) (see Attachment 20 of our draft decision, section 7).

The legacy meter transition cost step change is not directly tied to the costs in this main SCS opex step change, but features the same driver (the accelerated smart meter rollout by 2030).

117 AEMC, *Draft National Electricity Amendment (Accelerating smart meter deployment) Rule 2024*, 4 April 2024, p. 2.

118 SA Power Networks, *SAPN – 19.4 – Legacy Metering Transition – Towards 2030,* January 2024. p. 24.

119 SA Power Networks, *SAPN – 19.4 – Legacy Metering Transition – Towards 2030,* January 2024. p. 24.

120 SA Power Networks*, SAPN – Attachment 6 – Operating Expenditure,* January 2024, p. 28.

121 SA Power Networks, *SAPN – 19.4 – Legacy Metering Transition – Towards 2030,* January 2024, p. 6; SA Power Networks, *19.4 – Legacy Metering Transition – Towards 2030,* July 2024, p. 7. The June $2022 values shown in SA Power Networks' business cases correspond to the values shown in this section once escalated into June $2025 terms.

SA Power Networks had conducted limited stakeholder engagement on this matter at the time of its January 2024 initial proposal, but noted it aimed to consult with customer focus groups and stakeholders to inform and refine the development of its Legacy Metering Retirement Plan.[122] However, whether this will include any engagement on the opex smart meter ICT upgrade step change was unclear.

We engaged EMCa to assist with the assessment of SA Power Networks' capex and opex ICT components, which included this step change. However, EMCa was not able to complete its assessment due to SA Power Networks not providing sufficient justification in its initial business case.[123] The new business case SA Power Networks submitted on 10 July 2024 was received too late to be considered by EMCa and we also did not have sufficient time to review it internally (this also included the related capex and legacy metering expenditure).

As such, we have included a placeholder forecast of zero in our alternative estimate for opex and the other components (capex and the legacy metering opex).

While we have not completed our assessment in this draft decision, we believe the rationale behind these step changes appears broadly reasonable, and we are likely to include higher values in our final decision. We note, however, that this is dependent on the pending nature of the AEMC's related rule change final determination (November 2024). SA Power Networks may decide to further update the information in its 10 July 2024 business case if it believes this final determination impacts its proposed approach for the revised proposal.

6.4.4.6 CER integration step change

SA Power Networks proposed a step change of $4.4 million for CER integration over the 2025–30 regulatory control period.[124] This was for the continued maintenance and scaling of its IT systems that support flexible exports and Smarter Homes regulations, necessary for the ongoing provision of the export service. Our alternative estimate for the final decision includes a forecast of $4.4 million. We have included this step change in our alternative estimate as we consider it to be prudent and efficient and not already included in SA Power Networks base opex, trend, or its other capex or opex ICT programs. We also consider that there is broad support for SA Power Networks' CER integration proposal, and inequitable outcomes will be avoided so long as only export customers pay for these investments. While we have concluded that SA Power Networks' forecast benefits are likely overstated, the proposed investments will provide positive net benefits in large part when emissions reduction benefits are included (which is not currently the case in the business case). We recommend this approach is reassessed in the next period.

Table 6.18 SA Power Networks' CER integration step change ($million, 2024–25)

	2025–26	2026–27	2027–28	2028–29	2029–30	Total
SA Power Networks' proposal	0.6	0.7	0.9	1.0	1.1	4.4
AER alternative estimate	0.6	0.7	0.9	1.0	1.1	4.4

122 SA Power Networks, *SAPN – 19.4 – Legacy Metering Transition – Towards 2030,* January 2024. p. 26.

123 Energy Market Consulting Associates, *SA Power Networks: Review of aspects of proposed expenditure*, August 2024, pp. 104-105.

124 SA Power Networks, *SAPN – Attachment 6 – Operating expenditure*, January 2024, p. 32.

	2025–26	2026–27	2027–28	2028–29	2029–30	Total
Difference	**–0.0**	**–0.0**	**–0.0**	**–0.0**	**–0.0**	**–0.0**

Source: SA Power Networks, *SAPN – 6.1 – Opex model*, January 2024; AER analysis.
Note: Numbers may not add up to totals due to rounding. Values of '0.0' and '–0.0' represent small non-zero amounts and '–' represents zero.

SA Power Networks proposed $4.4 million in opex for its CER integration step change to maintain and scale flexible exports and other systems necessary for the ongoing provision of export services. SA Power Networks proposed this opex step change alongside $16.6 million in capex to maintain and scale flexible exports and other systems necessary for the ongoing provision of the export service. See Attachment 5 of our draft decision, section A.5.

As discussed in section 6.4.4.7 (for the CER compliance step change), under the SA Government's Smarter Homes regulations, all new solar PV systems in South Australia are required to be compatible with flexible exports. As such, SA Power Networks proposed to progressively expand its flexible exports offer to more areas of its network. It expected the number of customers on the scheme to escalate rapidly and by the end of 2024 that flexible exports will be the default connection arrangement for new solar customers connecting anywhere on the network.[125]

SA Power Networks submitted that this expenditure, together with an additional $53.5 million in capex to increase hosting capacity, will maintain a 95% export service level for 95% of customers.[126] It forecast that these investments would result in a NPV of $18.9 million.[127] It recommended this 95% service level over other options considered, including a 90% and 98% service level (both for 95% of customers), because:[128]

- it best reflects the level of export service performance that customers are willing to pay for, based on Focused Conversion workshop voting, People's Panel endorsements and SA Power Networks' Customer Values Research survey
- it will deliver the highest positive market benefits of the options considered.

SA Power Networks did not consider an option which maximises market benefits to be credible, as it was the least popular option among stakeholders in its Focused Conversation workshops even though it had a lower level of investment, and hence lower estimated bill impacts, than other options considered.[129] A key reason for this was that stakeholders took into consideration SA Power Networks' intention to recover the costs of these investments from export customers only, via export tariffs. Stakeholders placed a high value on the principles of fairness and equity and felt strongly that SA Power Networks should, within the

125 SA Power Networks, *SAPN – 5.7.4 – CER Integration*, January 2024, p. 13.

126 Measured on an annual basis as the number of hours where exports are constrained, divided by the total number of daylight hours.

127 Presented in June $2022 dollars, as per SA Power Networks' business case; SA Power Networks, *SAPN – 5.7.4 – CER Integration*, January 2024, p. 24.

128 SA Power Networks, *SAPN – 5.7.4 – CER Integration*, January 2024, p. 25.

129 SA Power Networks, *SAPN – 5.7.4 – CER Integration*, January 2024, p. 22.

bounds of practicality, seek to provide all export customers with broadly the same level of service performance, since all export customers pay for the investments in export capacity.

In response to our information requests, SA Power Networks provided a comprehensive cost build-up.[130] This detailed the specific costs it incurred in its base year, along with its estimated additional capex and opex costs for the continued scaling and operation of the IT systems that support flexible exports and the Smarter Homes regulations (discussed further in section 6.4.4.7). We consider that these costs have been estimated based on historical development and maintenance costs for the relevant IT components, with growth forecasts derived from AEMO input forecasts for CER growth. As such, we consider these costs to be prudent and efficient. We also consider the costs included in this step change are not already included in SA Power Networks base opex, trend forecast, or its other capex or opex ICT programs.

As set out in Attachment 5 of our draft decision, section A.5, we conducted a sensitivity analysis on SA Power Networks' business case for the proposed CER integration program. This included shortening the NPV analysis period from 25 years to 20 years, adjusting the Customer Export Curtailment Value benefit assumptions and quantifying emissions reduction benefits. From this analysis, we concluded that although SA Power Networks' forecast benefits are likely overstated, but that when emissions reduction benefits are incorporated the proposed investments will still provide positive net benefits.

As a part of this assessment, we also set out in Attachment 5 that the associated capex reasonably reflects the capex criteria because the target export service level reflects the outcome of customer engagement, the proposed investments will provide net customer benefits costs and the investment costs are only recovered from export customers. This assessment also applies to the associated opex in this step change. Additionally, we consider the proposed non-network activities are reflective of a sound overall CER integration strategy, which will increase the utilisation of existing capacity.

As a part of the draft decision, as set out in Attachment 5, we also consider it appropriate that SA Power Networks reports on its export service level performance. This will place a reputational incentive on SA Power Networks to efficiently invest in the export service and provide its customers with transparency. New customers are already able to view the historical indicative export capacity available in its local area under a flexible connection offer.[131] However, SA Power Networks should report on its export service performance more prominently, either on its website or in its Distribution Annual Planning Report. In addition, our export services network performance report also includes related export curtailment metrics and expenditure incurred to provide export services.[132]

Finally, we note that export service levels beyond 2030 will not be defined by this decision and remain uncertain. This issue will be revisited in the future, taking into account customer preferences, the impact of export tariffs and potentially new incentive arrangements for export services.

130 SA Power Networks, *Response to information requests IR#002 and IR#024*, 13 March and 19 June 2024.

131 SA Power Networks, *Flexible Exports Eligibility*, accessed 22 August 2024.

132 AER, *Export services network performance report 2023*, December 2023.

On the above basis, and consistent with the capex position, we have included SA Power Networks' proposed $4.4 million opex step change for CER integration cost in our alternative estimate.

6.4.4.7 CER compliance step change

SA Power Networks proposed a step change of $2.5 million for the expansion of its CER compliance program over the 2025–30 regulatory control period.[133] This was for additional staff resourcing required to implement phase 2 of its CER compliance program. Our alternative estimate for the draft decision includes a forecast of $2.5 million. We have included this step change in our alternative estimate as we consider it accords with the relevant AEMO and AEMC guidance, is supported by stakeholders, and comprises costs not covered elsewhere in SA Power Networks' proposal.

Table 6.19 SA Power Networks' CER compliance step change ($million, 2024–25)

	2025–26	2026–27	2027–28	2028–29	2029–30	Total
SA Power Networks' proposal	0.3	0.5	0.5	0.6	0.6	2.5
AER alternative estimate	0.3	0.5	0.5	0.6	0.6	2.5
Difference	**–0.0**	**–0.0**	**–0.0**	**–0.0**	**–0.0**	**–0.0**

Source: SA Power Networks, *SAPN – 6.1 – Opex model*, January 2024; AER analysis.
Note: Numbers may not add up to totals due to rounding. Values of '0.0' and '–0.0' represent small non-zero amounts and '–' represents zero.

SA Power Networks proposed a $2.5 million CER compliance step change for additional resourcing to execute the second phase of its 10-–year CER compliance program.[134] It placed increased importance on managing CER compliance as it has new responsibilities in maintaining system security at the direction of SA Government and AEMO due to the increased role CER is playing in the mix of system generation.[135] This opex has an associated $5.7 million in additional proposed capex. See Attachment 5 of our draft decision, section A.5.

In the supporting business case, SA Power Networks noted this step change is driven by a variety of obligations that have been progressively put in place.[136] These include:

- The SA Government's 'Smarter Homes' regulatory changes which introduced a pair of new regulatory guidelines (Remote Updating Methods guideline and Export Limiting Method Guideline) for dynamic export control. These require all sites that include relevant electricity generating plant (new/upgraded inverter connected generators) to be dynamic exports capable for the purposes of regulation 55E of the Electricity (General) Regulations 2012.[137]

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133 SA Power Networks, *SAPN – Attachment 6 – Operating expenditure*, January 2024, p. 31.
134 SA Power Networks, *SAPN – 5.7.3 – CER Compliance*, January 2024, p. 24.
135 SA Power Networks, *SAPN – 5.7.2 – Compliance Strategy*, January 2024, p. 4.
136 SA Power Networks, *SAPN – 5.7.2 – Compliance Strategy*, January 2024, pp. 4-9.
137 Government of South Australia, *The South Australian Government Gazette*, 24 September 2020, p. 4679.

- Following the advice of AEMO, the SA Government also introduced several new technical standards and requirements for smaller generating systems (such as rooftop solar). This included a new technical standard requiring that all systems be capable of being remotely disconnected and reconnected by an agent registered with the Technical Regulator (SA Power Networks is such an agent).[138]

- The AEMC's final determination on its *Access, pricing and incentive arrangements for DER* rule change requires SA Power Networks to provide customers a basic level of network access for CER exports from 2025.[139] SA Power Networks' provision of this basic level of network access is dependent on its customer connections being dynamic export capable and in compliance with the new technical standards.

- The AEMC also recommended in its *Review into CER technical standards* that original equipment manufacturers provide additional CER device compliance information to DNSPs and AEMO to better monitor compliance with CER technical standards and therefore be in a better position to take action to rectify the identified non-compliance.[140] While AEMO and AEMC make clear that DNSPs are not responsible for rectifying the non-compliance themselves, they recommend that DNSPs could take actions such as active steps to monitor and detect potential non-compliance.

SA Power Networks stated that both it and AEMO rely on installers and customers complying with a suite of technical standards and regulatory requirements to ensure the system operates correctly and to stabilise the system when a major incident occurs. However, AEMO investigations into the level of compliance of CER with required technical settings found that less than half of systems installed are set correctly to the required standard.[141]

Phase 1 of SA Power Networks' compliance strategy, currently underway, focused on improving the CER connection application process and raising industry understanding of compliance obligations. Phase 2 (the subject of this step change) represents a continuation of its existing functions with the addition of new functions, which focus on:[142]

- detecting and requiring the correction by installers and customers of potential non-compliance with standards and regulations for already-installed CER

- making use of the increasing availability of smart meter data to detect potential compliance issues automatically through data analytics.

As such SA Power Networks proposed in phase 2 to include contacting non-compliant customers, assisting customers in relation to the rectification of non-compliant devices

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138 Government of South Australia, Department for Energy and Mining Website: *Remote disconnect and reconnection of electricity generating plants*, accessed on 19/07/2024 at: https://www.energymining.sa.gov.au/industry/hydrogen-and-renewable-energy/solar-batteries-and-smarter-homes/regulatory-changes-for-smarter-homes/remote-disconnect-and-reconnection-of-electricity-generating-plants

139 AEMC, *Rule determination – Access, pricing and incentive arrangements for DER*, 12 August 2021, p. vi.

140 AEMC, *Review into CER technical standards, Final Report*, September 2023, p. 38.

141 AEMO, *Compliance of Distributed Energy Resources with Technical Settings*, April 2023, p. 47.

142 SA Power Networks, *SAPN – 5.7.3 – CER Compliance*, January 2024, p. 5.

efficiently and effectively, and working with original equipment manufacturers to explore options for over-the-air reprogramming to address non-compliant inverter settings.

SA Power Networks considered that implementing phase 2 required a small increase in the number of dedicated staff supporting the broadening scope of compliance activities. Specifically, it proposed additional staff resourcing compared to the 2020–25 program of:[143]

- a dedicated compliance manager (1 full time equivalent (FTE))
- a business and a data analyst (0.25 FTE each)
- a CER customer, retailer and installer liaison and an original equipment manufacturer and technical vendor liaison (0.25 FTE each).

As this additional staffing requirement arises from the impact of CER, which is not accounted for in the AER's standard opex output growth factors, SA Power Networks proposed recovery of these costs via an opex step change of $2.5 million over the 2025–30 period.

SA Power Networks engaged with the South Australian Government throughout the development of its compliance strategy to ensure alignment with government policy direction.[144] Stakeholders in its Focused Conversation workshops and its subsequent People's Panel strongly supported its CER integration program, including its compliance program, and endorsed the proposed expenditure.[145]

We recognise that SA Power Networks relies on compliance of CER connections and installations with technical standards and regulatory requirements to facilitate the performance of its new responsibilities, including with respect to system security and maintaining quality of supply. We also recognise that recent studies by AEMO have revealed very significant levels of non-compliance to these standards across the population of installed CER equipment in South Australia.

We also note the AEMC's *Review into CER technical standards* final report did not include a recommendation that DNSPs develop and follow a defined process for contacting customers whose devices may not be compliant with CER technical standards (and explain options for returning to compliance). This recommendation was in the AEMC's draft report but was removed in the final report to avoid creating the expectation of a new customer facing role for DNSPs.[146] SA Power Networks had allocated a fraction of its proposed FTE resourcing to customer liaison activities in its compliance step change. However, we found that removing the related costs had only a slight ($0.1 million) impact on the proposed step change amount.

In the AER's *Draft interim export limit guidance note*, we outlined our expectations for DNSPs with respect to compliance to CER technical standards, stating that:[147]

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143 SA Power Networks, *SAPN – 5.7.3 – CER Compliance*, January 2024, p. 24.

144 SA Power Networks, *Response to information request IR#002, SAPN – 5.7.3 – CBA CER Compliance – Public.xlsm*, 13 March 2024.

145 SA Power Networks, *SAPN – 5.7.3 – CER Compliance*, January 2024, p. 29.

146 AEMC, *Review into CER technical standards, Final Report*, September 2023, p. 15.

147 AER, *Draft export limit interim guidance note*, November 2023, p. 32.

- DNSPs should take practical steps aimed at improving rates of compliance of consumer energy resources with relevant technical standards.
- In their expenditure proposals, DNSPs should demonstrate any steps they have taken to improve compliance for new CER connections. As per section 4.3.2 (engagement and awareness) of this guidance note, we also expected to see DNSPs set aside regulated revenue for engagement and awareness because this feeds into compliance.

We consider SA Power Networks' proposed CER compliance program to be in accordance with AEMO's, AEMC's and our own previous guidance on CER compliance. We also note that stakeholders broadly support its proposed CER compliance program.

In response to our information request, SA Power Networks provided a detailed cost build-up of the additional opex resources it proposed to facilitate phase 2 of its compliance program.[148] We consider that although some of its proposed FTE related labour and business overheads costs might have been slightly overstated, they are broadly consistent with SA Power Networks' existing per FTE costs for similar roles and are not already accounted for elsewhere in its proposal. From our very high-level review of the proposed labour costs benchmarked against existing similar roles we found a slight reduction to these costs (as noted above) in the order of $0.1 million may be appropriate.

We consider the additional resources proposed in this step change are required to enable the new functions to be rolled out in the proposed phase 2 of the CER compliance program. Our potential modifications to this step change (the removal of the customer liaison activities and use of slightly lower FTE costs) only produced a minor difference to the proposed amount. As such, we find the proposed expenditure prudent and efficient, and propose to include a CER compliance step change of $2.5 million in our alternative estimate.

6.4.4.8 Increases to insurance premiums step change

SA Power Networks proposed a step change of $19.4 million for increases to insurance premiums over the 2025–30 regulatory control period.[149] This was for the significant market driven increases which SA Power Networks considers a major external factor that is material and not capable of being managed under forecast opex. Our alternative estimate for the final decision includes a forecast of $19.4 million for increases to insurance premiums. We have included this step change in our alternative estimate as we consider the insurance premium increase results in forecast expenditure that is likely to be prudent and efficient.

Table 6.20 SA Power Networks' increases to insurance premiums step change ($million, 2024–25)

	2025–26	2026–27	2027–28	2028–29	2029–30	Total
SA Power Networks' proposal	2.2	3.3	4.1	4.6	5.1	19.4
AER alternative estimate	2.2	3.3	4.1	4.6	5.1	19.4

148 SA Power Networks, *Response to information request IR#002*, *SAPN – 5.7.3 – CBA CER Compliance.xlsm*, 13 March 2024.

149 SA Power Networks, *SAPN – Attachment 6 – Operating expenditure,* January 2024, p. 33.

	2025–26	2026–27	2027–28	2028–29	2029–30	Total
Difference	**–0.0**	**–0.0**	**–0.0**	**–0.0**	**–0.0**	**–0.0**

Source: SA Power Networks, *SAPN – 6.1 – Opex model*, January 2024; AER analysis.
Note: Numbers may not add up to totals due to rounding. Values of '0.0' and '–0.0' represent small non-zero amounts and '–' represents zero.

In its proposal, SA Power Networks' stated that current and likely insurance market conditions will lead to continued increases in insurance premiums over the next regulatory control period.[150] It engaged Marsh to provide insurance premium cost forecasts, with Marsh expecting the upward pressure seen in recent years on insurance premiums to continue over the 2025–30 period for SA Power Networks combined liability and property premiums.[151]

SA Power Networks' insurance premium forecasts provided by Marsh also assume no future increases in asset bases which form premium forecasts, noting that any increase in the value of the asset base will result in higher premiums than those reflected in the forecasts.[152] Given the magnitude of the expected increases, and the fact they are outside its control, SA Power Networks considered this a major external factor that is material and not capable of being managed under forecast opex, including through inbuilt provisions under output, price and productivity growth (rate of change).

Our assessment showed that the SA Power Networks' forecast insurance premiums, prepared by Marsh, are consistent with forecasts from our recent determinations for NSW and Tasmania. We therefore consider SA Power Networks' forecast to reflect current market conditions and to be prudent.[153]

In our assessment we also considered the rate of change forecast, which includes an allowance for non-labour price growth of CPI, and covers any potential increases in costs like insurance premiums. We expect some non-labour components in opex will increase by more than CPI and some less than CPI. To the extent that higher insurance premiums rise by more than CPI, we expect this will to an extent be offset by other non-labour costs rising by less than CPI. We note, however, that there may be specific circumstances where it is appropriate to consider increasing costs of individual cost categories as they are increasing by more than CPI, particularly where they represent a material proportion of opex.

In this case, we are satisfied the proposed step change likely reflects a reasonable expectation of cost inputs, and is not likely to be captured in base opex or the rate of change. We consider the proposed insurance premium costs represent a material proportion of total forecast opex and are materially above the non-labour price growth (CPI) included in the rate of change, and therefore less likely to be offset by lower growth in other non-labour costs.

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150 SA Power Networks, *SAPN – Attachment 6 – Operating expenditure,* January 2024, p. 33.

151 SA Power Networks*, 6.7 – Marsh Insurance Report,* July 2023, p. 16.

152 SA Power Networks, *SAPN – Attachment 6 – Operating expenditure,* January 2024, p. 34.

153 AER, *AER – Final Decision Attachment 6 – Operating Expenditure – Ausgrid – 2024–29 Distribution revenue proposal,* April 2024, pp. 18–19; AER, *AER* – Draft *Decision Attachment 6 – Operating Expenditure – Endeavour Energy – 2024–29 Distribution revenue proposal,* April 2024, pp. 28–29; AER, *AER* – Draft *Decision Attachment 6 – Operating Expenditure – TasNetworks – 2024–29 Distribution revenue proposal,* April 2024, pp. 22–24.

On this basis we have included $19.4 million for this step change in our alternative estimate of total forecast opex.

6.4.4.9 Network program uplift step change

SA Power Networks proposed a step change of $18.0 million for its network program uplift over the 2025–30 regulatory control period.[154] This was for increased opex arising from its proposed increase in augmentation capex (augex) and replacement capex (repex). Our alternative estimate for the draft decision does not include the network program uplift step change. We have not included this step change in our alternative estimate as we consider the trend component, and particularly the output growth forecast, is the appropriate mechanism to forecast opex costs associated with increased network growth.

Table 6.21 SA Power Networks' network program uplift step change ($million, 2024–25)

	2025–26	2026–27	2027–28	2028–29	2029–30	Total
SA Power Networks' proposal	3.5	3.0	3.9	3.6	4.0	18.0
AER alternative estimate	–	–	–	–	–	–
Difference	**–3.5**	**–3.0**	**–3.9**	**–3.6**	**–4.0**	**–18.0**

Source: SA Power Networks, *SAPN – 6.1 – Opex model*, January 2024; AER analysis.
Note: Numbers may not add up to totals due to rounding. Values of '0.0' and '–0.0' represent small non-zero amounts and '–' represents zero.

SA Power Networks proposed an $18.0 million step change for its network uplift program. It submitted this step change is to account for the expected uplift in resourcing costs (additional support services and ICT costs) required to support the proposed uplift in its total network capital program (augex and repex related).[155] Specifically for costs above those it considered were already included in the opex forecast via the trend component.

SA Power Networks derived its proposed step change amount by modelling the amount of augex and repex required to complete its proposed capex programs, then using that estimate to forecast the additional opex resources required to support its capex programs. It then identified the opex cost categories where it forecast an uplift would be required and applied the opex trend component to those categories. It then removed the trended cost categories from its forecast of additional opex resources based on its augex and repex, to get its network uplift step change amount.[156] As the forecast network uplift costs were greater than the trended opex cost categories, SA Power Networks stated that its ability to recover its network uplift costs would not be sufficiently provided via the base and trend components. It therefore considered a step change was required. Given the magnitude of the expected increases and the fact they are outside its control, it considered this a major external factor that is material and not capable of being managed under forecast opex.[157]

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154 SA Power Networks, *SAPN – Attachment 6 – Operating Expenditure,* January 2024, p. 34.
155 SA Power Networks, *SAPN – Attachment 6 – Operating Expenditure,* January 2024, p. 34.
156 SA Power Networks, *SAPN – Attachment 6 – Operating Expenditure,* January 2024, p. 34.
157 SA Power Networks, *SAPN – Attachment 6 – Operating Expenditure,* January 2024, p. 34.

SA Power Networks did not undertake any stakeholder engagement on its proposed opex network uplift program step change.

We use a top-down methodology to assess forecast opex and our standard approach is to use the trend component (more specifically output growth) to account for increases in opex related to network growth. Our forecast of output growth uses the industry-wide relationships between growth in certain output measures, such as circuit length, ratcheted maximum demand and customer numbers, and growth in total opex, identified by our economic benchmarking. As such, any increase in opex a network requires to operate and maintain a growing network is already accounted for by the output growth included in the opex model.

We understand SA Power Networks forecast an increase in certain opex cost categories which exceeded the trended amount it spent on those cost categories in its base year. As we state in our Guideline, our top down opex assessment approach does not expect all categories of opex will increase by the same rate as the opex trend component. We expect that some cost categories will increase or decrease by greater than trend and other cost categories by less than trend, but the net impact on total opex will be approximately equal to the trend component. As such, we do not typically include step changes for changes in individual existing cost categories which differ from the trend growth rate.

We have made limited exceptions to this standard approach where we deem the cost is not adequately accounted for in the opex model by our trend forecast. An example of an exception to this approach in relation to price (not output growth) is for insurance premiums. These were expected to increase significantly over recent regulatory periods but had no real forecast cost increase in the trend component (only CPI) as they are a non-labour expense. Additionally, the weighting the CPI basket places on insurance premiums differed substantially from the revealed network cost weighting. We considered these factors combined caused the trend component to not adequately account for changes in insurance premiums at that time.

However, we do not believe such an exception is required for the network program uplift costs as the costs noted in the proposed step change are factors captured by our output measures. We consider the output component already accounts for the increased opex related to SA Power Networks' forecast network growth and that a further $18.0 million step change is not required. As such, we have not included a step change for SA Power Networks' proposed network program uplift in our alternative estimate.

6.4.4.10 Reliability improvements step change

SA Power Networks proposed a negative step change of –$0.7 million for costs avoided by reliability improvements it proposed.[158] We have included a forecast of –$0.9 million in our alternative estimate. This is $0.2 million ($2024–25) more than SA Power Networks' proposal. We have included this step change in our alternative estimate because we consider it reasonably reflects the reduction in opex that will result from the proposed reliability improvement works. We discuss the associated capex for these works in section A.2.3.2 of Attachment 5 of our draft decision.

[158] SA Power Networks, *SAPN – Attachment 6 – Operating expenditure*, January 2024, p. 26.

Table 6.22 Reliability improvements step change ($million, 2024–25)

	2025–26	2026–27	2027–28	2028–29	2029–30	Total
SA Power Networks' proposal	–0.0	–0.1	–0.1	–0.2	–0.2	–0.7
AER alternative estimate	0.0	–0.1	–0.2	–0.2	–0.3	–0.9
Difference	**–0.0**	**–0.0**	**–0.0**	**–0.1**	**–0.1**	**–0.2**

Source: SA Power Networks, *SAPN – Attachment 6 – Operating expenditure*, January 2024, p. 26; AER analysis.
Note: Numbers may not add up to totals due to rounding. Values of '0.0' and '–0.0' represent small non-zero amounts and '–' represents zero.

In its proposal, SA Power Networks proposed capex for programs to improve reliability for some of its worst served customers. The proposed negative step change relates to the avoided emergency response opex resulting from the reduction in network interruptions as a result of this proposed capex.[159]

We have included a step change of –$0.9 million in our alternative estimate. This reflects our draft finding that the proposed capex is prudent and efficient, meaning we consider it likely these avoided emergency response costs will be realised. In addition to the avoided emergency response costs that SA Power Networks proposed, we have also included the guaranteed service level payments that will be avoided. The associated reliability improvement programs are designed to improve the network reliability for some of SA Power Networks' worst served customers. SA Power Networks is subject to a guaranteed service level (GSL) scheme that requires it to pay GSL payments to customers that suffer outages of a specified duration or frequency. These payments are designed to acknowledge the inconvenience experienced by SA Power Networks' worst served customers.

To the extent the proposed capex programs improve the service received by SA Power Networks' worst served customers, they should also reduce the amount of GSL payments that SA Power Networks will need to pay. SA Power Networks estimated that the proposed reliability programs would reduce its reliability duration GSL payments by 0.7%. Reliability duration payments make up a significant majority of SA Power Network's GSL payments. These payments average $6.2 million (nominal) each year over the 2020–25 period. The reduction in GSL payments (0.7% of $6.2 million, nominal) represents 36.7% of the proposed step change. Consequently, we have increased the step change by 36.7% so that it also reflects the GSL payments that will be avoided by undertaking the proposed reliability improvement works.

In terms of stakeholder submissions, the Regional and Remote Customers Sub-Committee of SA Power Networks' Community Advisory Board considered that SA Power Networks' proposed reliability improvements (and capex) 'struck a reasonable balance between affordability pressures while improving service levels for worst served customers in the state'.[160]

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159 SA Power Networks, *SAPN – Attachment 6 – Operating expenditure,* January 2024, p. 35.

160 Regional and Remote Customers sub-committee, *Regional and Remote Customers sub-committee – Submission – 2025–30 Electricity Determination – SA Power Networks*, May 2024, p. 2.

6.4.4.11 Transitioning to electric vehicles step change

SA Power Networks proposed a negative step change of –$1.3 million for its program transitioning to electric vehicle over the 2025–30 regulatory control period.[161] This is for the expected reduction in vehicle operating costs as vehicles with internal combustion engines (ICE vehicles) are replaced with electric vehicles (EVs). Our alternative estimate for the draft decision includes a forecast of –$1.3 million for the transitioning to electric vehicle step change, which is the same as SA Power Networks' proposal.

Table 6.23 SA Power Networks' transitioning to electric vehicles step change ($million, 2024–25)

	2025–26	2026–27	2027–28	2028–29	2029–30	Total
SA Power Networks' proposal	–0.0	–0.1	–0.3	–0.4	–0.5	–1.3
AER alternative estimate	–0.0	–0.1	–0.3	–0.4	–0.5	–1.3
Difference	**0**	**0**	**0**	**0**	**0**	**0**

Source: SA Power Networks, *SAPN – 6.1 – Opex model*, January 2024; AER analysis.
Note: Numbers may not add up to totals due to rounding. Values of '0.0' and '–0.0' represent small non-zero amounts and '–' represents zero.

We have included this step change in our alternative estimate as we consider this proposed opex / capex trade-off to be prudent as it is the result of SA Power Networks' proposal to replace ICE vehicles with EVs, when it is efficient to do so. Allowing an opex / capex trade-off step change for the transition of fleet to EVs is consistent with the Guideline[162] and recent revenue determinations, including for Essential Energy 2024–29.[163]

We consider the step change for the proposed transition to EVs step change to be efficient, in that we are satisfied that the fleet replacement option adopted by SA Power Networks has the least negative NPV of options considered[164] and that EVs will only replace ICE vehicles when they are the least total cost of ownership option. Under this program, SA Power Networks' proposes to acquire 235 EVs to replace existing ICE vehicles.[165] In turn we consider the proposed reduction in vehicle operating costs are prudent.

The fleet replacement option proposed by SA Power Networks is also consistent with People's Panel recommendation that SA Power Networks should only incur expenditure transitioning to EVs where it is more efficient than replacing with ICE vehicles. The People's Panel deliberated and affirmed this recommendation.[166]

We note that the fleet replacement option proposed by SA Power Networks in its proposal did not consider the monetary value of reducing emissions. SA Power Networks' proposal

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161 SA Power Networks, *SAPN – Attachment 6 – Operating Expenditure,* January 2024, p. 35.

162 AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution*, August 2022, p. 11.

163 AER, *Draft Decision Attachment 06 – Operating Expenditure – Essential Energy – Distribution 2024–29 revenue proposal,* September 2023, p 32.

164 SA Power Networks, *SAPN – 5.10.1 – Fleet Business Case,* January 2024, pp. 19-21.

165 SA Power Networks, *SAPN – Attachment 5 – Capital expenditure,* January 2024, p. 70.

166 SA Power Networks, *SAPN – Attachment 5 – Capital expenditure,* January 2024, p. 70.

notes that once the AER provides guidance on the methodology for determining the value of emission reductions, there are potentially further benefits to consumers in transitioning to EVs beyond just capex / opex cost which SA Power Networks may consider in its revised proposal.[167] The AER's guidance for valuing emissions reduction was published in May 2024.[168]

For these reasons we have included this negative step change as proposed by SA Power Networks in our alternative estimate.

6.4.5 Category specific forecasts

SA Power Networks' proposal included two category specific forecasts, which were not forecast using the base-step-trend approach.[169] These were for debt raising costs ($13.8 million) and the proposed SCCS ($20.0 million). We have included category specific forecasts for debt raising costs, but not for the SCCS in our alternative estimate. For the SCCS, this reflects that we understand it is likely that this scheme will be treated as a Jurisdictional Scheme. This is discussed below.

SA Power Networks also proposed, a $20.0 million innovation fund, comprising $16.0 million of capex and $4.0 million of opex.[170] It proposed to recover the $4.0 million of opex through a revenue adjustment in the Post Tax Revenue Model, rather than via its opex forecast. We discuss this in section 6.4.5.2 as we consider that in its revised proposal SA Power Networks should consider including this as a category specific forecast.

6.4.5.1 Small compensation claims scheme

SA Power Networks' proposal included a $20.0 million category specific forecast to meet the expected costs over the 2025–30 regulatory control period from the proposed introduction of a new regulatory obligation, the SCCS.[171] We have not included this forecast in our alternate estimate, on the basis that it now appears likely that SA Power Networks will apply to the AER to determine that the SCCS is a Jurisdictional Scheme. As a Jurisdictional Scheme, the forecast costs of the SCCS will not be recovered via opex, but rather via annual tariff true-ups.

Table 6.24 Small compensation claims scheme costs ($million, 2024–25)

	2025–26	2026–27	2027–28	2028–29	2029–30	Total
SA Power Networks' proposal	9.5	2.6	2.6	2.6	2.6	20.0
AER alternative estimate	–	–	–	–	–	–
Difference	**–9.5**	**–2.6**	**–2.6**	**–2.6**	**–2.6**	**–20.0**

Source: SA Power Networks, *SAPN – 6.1 – Opex model*, January 2024; AER analysis.

167 SA Power Networks, *SAPN – 5.10.1 – Fleet Business Case,* January 2024, p. 11.

168 AER, *Valuing emission reduction - Final guidance and explanatory statement*, May 2024.

169 SA Power Networks, *Combined proposal 2024–2029 Attachment 8 – Operating expenditure*, January 2024, p. 13.

170 SA Power Networks, *SAPN* – 5.7.7 – *Innovation Fund,* January 2024.

171 SA Power Networks, *SAPN – Attachment 6 – Operating Expenditure,* January 2024, p. 28.

Note: Numbers may not add up to totals due to rounding. Values of '0.0' and '–0.0' represent small non-zero amounts and '–' represents zero.

SA Power Networks' proposal explained that the proposed SCCS would be a no–fault claims scheme under which SA Power Networks would need to compensate small customers for damage to their property caused by certain claimable incidents. This would occur without customers needing to demonstrate fault, negligence, or bad faith.[172] It noted that the SCCS was in the process of being considered by the SA Government under the National Energy Retail Law and was expected to commence prior to 1 July 2025.[173]

SA Power Network engaged with its customers on this proposal. In its deep-dive Focused Conversation, customers recommended that SA Power Networks should itself institute a new claims regime ahead of being formally obligated to do so.[174] However, the People's Panel did not achieve consensus on this topic, and instead urged SA Power Networks to engage in discussions with the SA Government as a matter of government policy.[175] SA Power Networks did this, resulting in the above proposal.

In its submission on the AER's Issues Paper (on SA Power Networks' Electricity Distribution Determination 2025–30), the Energy and Water Ombudsman (SA) noted its support for the SA Government putting in place a claims regime applying to SA Power Networks.[176]

The SA Government is currently establishing the SCCS by amending the *National Energy Retail Law (Local Provisions) Regulations 2013* (the Regulations). On 13 September 2024 it released draft Regulations[177] for public consultation, with submissions due on 27 October 2024.[178] Based on our engagement with the SA Government, we expect the SCCS to be established in late 2024 or early 2025 and to commence prior to 1 July 2025.

In mid-September 2024, SA Power Networks confirmed it will apply to the AER to determine the SCCS is a Jurisdictional Scheme.[179] It indicated it will do this once the Regulations for the SCCS are proclaimed. It also advised it considered the SCCS meets the eligibility criteria for a Jurisdictional Scheme under the NER.[180]

Given this, we consider it likely Jurisdictional Scheme the forecast costs will not be recovered via opex (but rather via annual tariff true-ups). As a result, we have not included these costs in our alternative estimate for the draft decision. We will continue to engage with the SA

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172 SA Power Networks*, SAPN – 6.5 – National Energy Retail Law Claims Regime,* January 2024, p. 6.

173 SA Power Networks*, SAPN – 6.5 – National Energy Retail Law Claims Regime,* January 2024, p5.

174 SA Power Networks*, SAPN – 6.5 – National Energy Retail Law Claims Regime,* January 2024, p. 8.

175 SA Power Networks*, SAPN – 6.5 – National Energy Retail Law Claims Regime,* January 2024, p. 8.

176 Energy and Water Ombudsman of SA, *Submission to the Australian Energy Regulator's Issue Paper: SA Power Networks Electricity Distribution Determination 2025–30*, May 2024, p. 2.

177 Specifically the *National Energy Retail Law (Local Provisions) (Small Compensation Claims Regime) Amendment Regulations 2024*.

178 Department of Energy and Mining (South Australia), *Establishing a small claims compensation scheme for small electricity customers in South Australia*, September 2024.

179 SA Power Networks, *Response to information requests* IR#038, 11 September 2024.

180 NER, cl. 6.18.7A(x).

Government and SA Power Networks to understand progress in legislating the SCCS to ensure this approach remains appropriate in our final decision.

6.4.5.2 Innovation Fund

SA Power Networks, proposed a $20.0 million innovation fund, comprising $16.0 million of capex and $4.0 million of opex to enable customer-supported, innovation-driven projects.[181] It considered that without this innovation fund, the types of projects it was considering, due to their novel nature, may not be justified if presented as stand-alone programs using standard cost-benefit analysis within business cases. The categories of initiatives, identified as important to customers during engagement, that SA Power Networks proposed to target were:

- community resilience
- enabling and leveraging the future market
- sustainability solutions.

As noted above, it proposed to recover the $4.0 million of opex through a revenue adjustment in the Post Tax Revenue Model, rather than via its opex forecast.

Our assessment recognises the importance of innovation investment in supporting the energy transition, however, considers that SA Power Networks needs to do further work on its innovation proposal. Our draft decision, as a placeholder, has not included SA Power Networks' proposed innovation fund expenditure in either the total opex or capex forecasts. We require SA Power Networks' revised proposal to undertake further consideration of the suite of proposed innovation programs, in conjunction with its stakeholders, and provide us with firmer plans and more detail on the costs for the proposed innovation programs. Our full assessment of the innovation fund expenditures (capex and opex), and our draft decision, is set out in Attachment 5 of our draft decision, section A.3.

In terms of how any innovation fund opex that is found to be prudent and efficient should be recovered, our view is that this is more appropriately done via an opex forecast rather than a revenue adjustment. We consider the innovation fund does not satisfy the criteria for a revenue adjustment under the NER (clause 6.4.3.(b)(5)) because it is not listed as an allowable revenue increment application. We also consider that any opex approved for an innovation fund should be recovered via a category specific forecast, particularly given it is unclear that it will be forecast on a revealed cost basis going forward. We have discussed this with SA Power Networks, and it indicated it had no objections to the recovery being via a category specific forecast. We encourage SA Power Networks to use this approach in its revised proposal.

6.4.5.3 Debt raising costs

We have included debt raising costs of $13.4 million in our alternative estimate. This is $0.4 million lower than the estimate proposed by SA Power Networks.

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181 SA Power Networks, *SAPN* – 5.7.7 – *Innovation Fund,* January 2024, p. 5.

Table 6.25 Debt raising costs ($million, 2024–25)

	2025–26	2026–27	2027–28	2028–29	2029–30	Total
SA Power Networks' proposal	2.7	2.7	2.7	2.8	2.9	13.8
AER alternative estimate	2.6	2.7	2.7	2.7	2.7	13.4
Difference	–0.0	–0.1	–0.1	–0.1	–0.1	–0.4

Source: SA Power Networks, *SAPN – 6.1 – Opex model*, January 2024; AER analysis.
Note: Numbers may not add up to totals due to rounding. Values of '0.0' and '–0.0' represent small non-zero amounts and '–' represents zero.

Debt raising costs are transaction costs incurred each time a business raises or refinances debt. Our preferred approach is to forecast debt raising costs using a benchmarking approach rather than a service provider's actual costs in a single year. This provides consistency with the forecast of the cost of debt in the rate of return building block. This is the basis for our alternative estimate Table 6.25.

We used our standard approach to forecast debt raising costs, which is discussed further in Attachment 3 to the draft decision.

Shortened forms

Term	Definition
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
AESCSF	Australian Energy Sector Cyber Security Framework
capex	capital expenditure
CCP14	Consumer Challenge Panel, sub-panel 14
CPI	consumer price index
CRM	customer relationship management
CTP	customer technology program
DMIAM	demand management innovation allowance (mechanism)
DNSP	distribution network service provider
distributor	distribution network service provider
EBSS	efficiency benefit sharing scheme
Guideline	Expenditure Forecast Assessment Guideline for Electricity Distribution
FTE	Full Time Employee
GSL	guaranteed service levels
NEL	national electricity law
NEM	national electricity market
NEO	national electricity objective
NER or the rules	national electricity rules
NPV	net present value
NSP	network service provider
opex	operating expenditure
PPI	partial performance indicator
PTRM	post-tax revenue model
repex	replacement expenditure
RIN	regulatory information notice
SCS	standard control services
SOCI	Security of Critical Infrastructure