# Attachment 6 - Operating Expenditure

**2025–30 Revised Regulatory Proposal**

December 2024

SA Power Networks

Empowering South Australia

## Company information

SA Power Networks is the registered Distribution Network Service Provider for South Australia. For information about SA Power Networks visit sapowernetworks.com.au

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## Disclaimer

This document forms part of SA Power Networks' Revised Regulatory Proposal to the Australian Energy Regulator for the 1 July 2025 to 30 June 2030 regulatory control period. The Revised Proposal and its attachments were prepared solely for the current regulatory process and are current as at the time of lodgement.

This document contains certain predictions, estimates and statements that reflect various assumptions concerning, amongst other things, economic growth and load growth forecasts. The Revised Proposal includes documents and data that are part of SA Power Networks' normal business processes and are therefore subject to ongoing change and development.

Whilst care was taken in the preparation of the information in this Revised Regulatory Proposal, and it is provided in good faith, SA Power Networks, its officers and shareholders accept no responsibility or liability for any loss or damage that may be incurred by any person acting in reliance on this information or assumptions drawn from it for a different purpose or in a different context.

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# Note

This attachment forms part of our Revised Proposal for the 2025–30 Regulatory Control Period. It should be read in conjunction with the other parts of the Revised Proposal.

Our Revised Proposal comprises the Overview document and Attachments listed below, and the supporting documents that are listed in Attachment 20. The light grey listed attachments below were submitted in our January 2024 Proposal and are not being resubmitted with our Revised Proposal.

| Document | Description |
|---|---|
| | Revised Regulatory Proposal overview document |
| Attachment 0 | Customer and stakeholder engagement program |
| Attachment 1 | Annual revenue requirement and control mechanism |
| Attachment 2 | Regulatory Asset Base |
| Attachment 3 | Rate of Return |
| Attachment 4 | Regulatory Depreciation |
| Attachment 5 | Capital expenditure |
| **Attachment 6** | **Operating expenditure** |
| Attachment 7 | Corporate income tax |
| Attachment 8 | Efficiency Benefit Sharing Scheme |
| Attachment 9 | Capital Expenditure Sharing Scheme |
| Attachment 10 | Service Target Performance Incentive Scheme |
| Attachment 11 | Customer Service Incentive Scheme |
| Attachment 12 | Demand management incentives and allowance |
| Attachment 13 | Classification of services |
| Attachment 14 | Pass through events |
| Attachment 15 | Alternative Control Services |
| Attachment 16 | Negotiated services framework and criteria |
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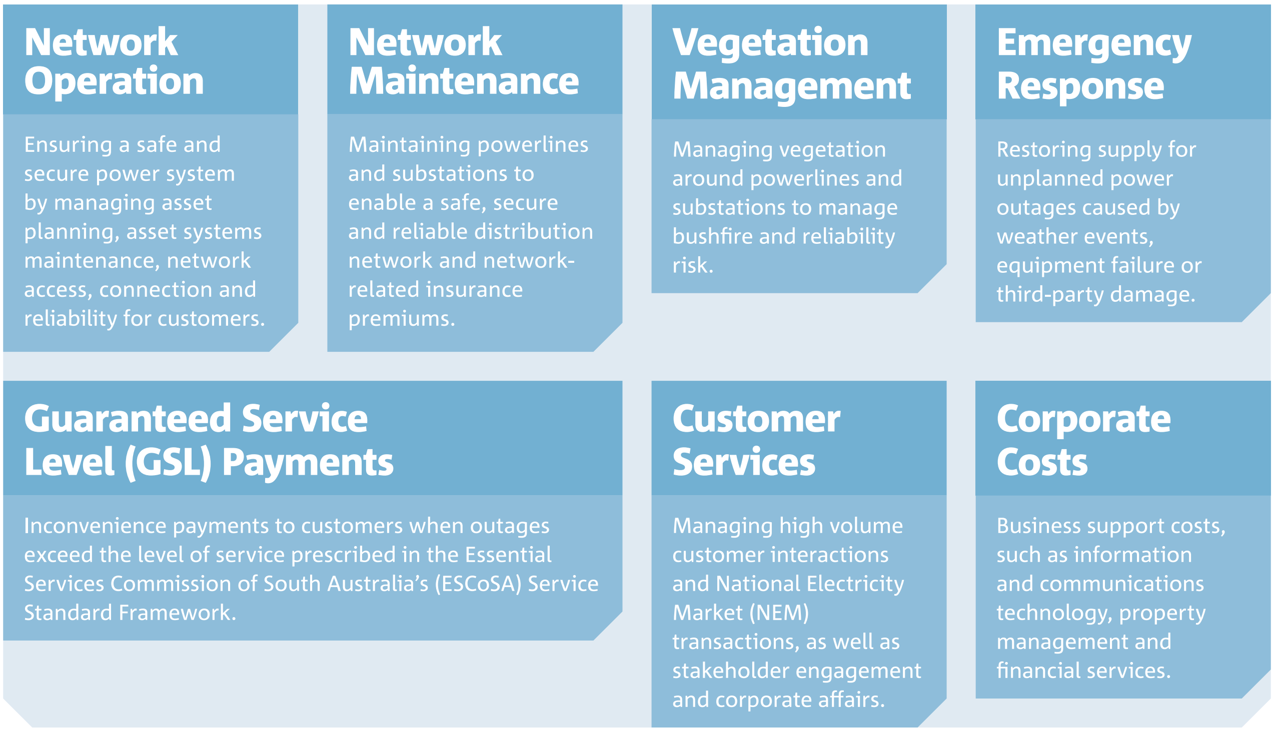
# 1 Background

Operating expenditure (**Opex**) is required to maintain and operate our distribution network assets and includes supporting corporate costs involved in providing distribution network services to customers.

Figure 1 includes a high-level summary of opex costs.

**Figure 1. Summary of opex costs**




Opex is typically recurrent in nature, however some categories of opex including guaranteed service level (**GSL**) payments and emergency response work, fluctuate with the number and severity of weather events impacting our network in any regulatory year. Some external factors may also arise which have a material impact on the recurrent nature of opex, an example being the COVID-19 pandemic which impacted our operations and affected some areas of expenditure over the last few years.

# 2 Overview

SA Power Networks submitted a Regulatory Proposal for the 2025-30 Regulatory Control Period (**RCP**) in January 2024 (**Original Proposal**). In our Revised Regulatory Proposal (**Revised Proposal**), we forecast a revised total opex requirement of $2.0 billion for Main Standard Control Services (**SCS**)[1] in 2025-30.

### We have been measured and balanced through our engagement and proposal development

This opex forecast responds to the circumstances of a time in which significant challenges and opportunities facing our network and the services that we provide customers, are converging including:

- the management of ageing network assets in deteriorating condition;
- resurgent and strong increases in demand driven by electrification;
- heightened bushfire risk across our network;
- increased risk of cyber threats;
- increased frequency and severity of extreme weather due to climate change;
- desires for customers to have more personalised and on demand service interactions; and
- other ongoing needs to maintain sufficient/effective supporting assets to provide our services.

In considering how to respond to these challenges and opportunities, we undertook a multi-staged and outcomes (service/price trade-offs) focused engagement program that drew on a diverse range of information sources to identify customers' preferences. These included workshops with 'broad and diverse' communities, customer representatives/stakeholders via 'Focused Conversations', everyday citizens via a 'People's Panel' and feedback on a Draft Proposal which reached all stakeholders. In engagement subsequent to our Original Proposal and Draft Decision, we observed no change in customers' preferences nor their desire for prudency and efficiency.

At each stage of our engagement, the total quantum of the six iterations of our opex forecast were communicated to our customers and stakeholders, as we sought to continue to engage transparently on the total expenditure and price implications / trade-offs of various options on how we could respond to the needs in 2025-30. For opex, the deeper engagement focused on the step changes and category specific forecasts. While consistently mindful of affordability, our customers were clear in our engagement that they do not want service compromised, and want us to achieve the following:

- maintain overall service by continuing current service levels, particularly network safety, reliability and export services, whilst recognising the cost of supporting spends to achieve this;
- make targeted improvements – by relatively few service improvements that are focused on reliability for our worst served customers, and mitigate bushfire risks where efficient;
- enable the energy transition – continue investing to support the transition, by enabling Customer Energy Resources (**CER**), flexibility in customer loads, and efficiently greening our fleet; and
- prudency and efficiency – only investing where prudent and efficient for customers, and examining ways of doing more for less, by being as productive and efficient as possible.

Our opex forecast together with our forecast capital expenditure (**capex**) achieves these outcomes.

[1] Main Standard Control Services operating expenditure excludes debt raising costs, and legacy metering costs which are proposed to be reclassified from Alternative Control Services to SCS. All financial figures in this document are expressed in June 2025 dollars unless otherwise specified.

### Our revisions have prudently and efficiently addressed the Australian Energy Regulator's Draft Decision

We are pleased, having assessed our proposal over many years including via the Early Signal Pathway, that the Draft Decision found that our proposal for $1,969.9 million (excluding debt raising costs) was prudent and efficient in its entirety, having determined that its own alternative opex forecast was not materially different. The Australian Energy Regulator (**AER**) also commented favourably on the combined strong consumer engagement, governance and forecasting methods, and comprehensive / in-depth business cases.

However, consistent with regulatory practice for opex the AER expect our Revised Proposal to be updated for our opex base-year with actual opex, and in doing so have regard to the other considerations in their Draft Decision. Whilst also undertaking other typically expected updates to the opex forecast to account for latest available information.

We undertook several revisions to our opex forecast to address the Draft Decision, including:

- base year - updating to our now audited revealed opex – as per standard regulatory practice;
- trend escalation - updating output growth and real labour price escalation forecasts using latest available information – as per standard regulatory practice;
- step changes – addressing AER concerns by removing a step change that the AER disagreed with (network program uplift, $18.0 million), increasing one of our negative step changes (reliability improvements to $0.9 million); and revising the costs of the step change that the AER had accepted as only a 'placeholder' (smart meter rollout – information technology (**IT**) upgrades to $1.3 million); and
- category specific forecasts - removing a forecast no longer requiring ex-ante funding (small compensation claims regime, $20.0 million), no longer seeking ex-ante funding for the resourcing costs included in this item ($1.6 million) and adding in a forecast to align to the AER's preference on cost recovery (innovation fund, $4.0 million).

Addressing the Draft Decision has resulted in our revised opex forecast being $52.6 million and 2.7 percent higher than our original forecast.

### Our revised opex forecast is in customers' interests

Our Revised Proposal evidences why we firmly consider that our revised opex forecast is in customers' interests and should be capable of AER acceptance. In summary:

- the Draft Decision found that our forecast opex was prudent and efficient and approved the forecast;
- forecast opex has only been revised to address the Draft Decision and follows typical regulatory practice with respect to the opex framework, including by:
  - revising base opex year costs to audited actual revealed costs, checking for and removing costs we expect to be non-recurrent – reflecting the efficient base opex requirements to manage our overall and regular service performance needs for customers, and is reasonable, being based on our revealed costs as a network on the efficiency frontier;
  - reflecting reasonably estimated changes in output growth, productivity, and input price escalations, applying standard AER practice and expectations;
  - only forecasting step changes and category specific forecasts for genuine incremental identified needs for the 2025-30 RCP;
- all step changes, category specific forecasts, and base-year adjustments (capex to opex transfers), are supported by business cases and addendums (for areas subject to revision) justifying the prudency and efficiency of these forecasts in the context of the National Electricity Rules (**NER**).

# 3 Summary of key revisions to our Original Proposal

While the Draft Decision approved our opex forecast, our Revised Proposal responds to the fact that the Draft Decision and standard regulatory practice for opex under the 'base-trend-step' method expect:

- our base-year opex would be revised to reflect our now audited revealed actual opex for our nominated base year of 2023/24, as only estimates were available at the time of our Original Proposal;
- our forecast trend and input price growth would be updated to account for latest available information – applying the standard methods set out in the Better Resets Handbook;
- step changes and category specific forecasts address concerns that the Draft Decision raised, in developing its alternative opex forecast (which it did not apply to us); and
- one of our proposed step changes, noted as only being a 'placeholder' would be revised.

Therefore, our Revised Proposal:

- focuses only on the aspects of the Draft Decision that pertain to the above-mentioned areas; and
- accepts and leaves unchanged, all other areas.

Table 1 summarises the key revisions to our Original Proposal and how they address the Draft Decision.

**Table 1. Comparison of AER's Draft Decision and our response**

| Component | AER Draft Decision | Revised Proposal |
|---|---|---|
| **Opex forecasting approach** | AER accepted our opex forecasting approach using the base-step trend. | We continued to apply the base-step trend in our Revised Proposal. |
| **Base opex** | AER accepted our 2023/24 base year forecast and Software as a Service (**SaaS**) adjustments | We do not accept the Draft Decision. We have updated our base opex to reflect audited actuals for the 2023/24 regulatory year.<br>We also checked our base year and removed an item that represented a 'one-off' cost and accounted for movements in provisions. |
| | AER amended our application of the Expenditure Forecast Assessment Guideline (**EFAG**) equation to estimate the final year of opex in the current RCP to include the revocation and substitution decision, and River Murray floods cost pass through. | We accept the AER's amendments. |
| | AER accepted our adjustments for SaaS. | We accept the Draft Decision and retain these in our Revised Proposal. |
| **Trend – Output growth** | AER updated the output weights to reflect the 2023 Annual Benchmarking report. | We have maintained the output weights from the 2023 Annual Benchmarking Report. |
| | AER accepted our use of the Australian Energy Market Operator's (**AEMO**) consumption and demand forecast and requested we update for the latest Electricity Statement of Opportunities (**ESOO**). | We have updated the AEMO forecast of consumption and demand in the 2024 ESOO. |
| | AER accepted our forecasted customer numbers and circuit length growth which was consistent with historic trends. | We have updated customer numbers and circuit length growth forecasts consistent with historic trends included in the actual Regulatory Information Notice (**RIN**) results for 2023/24. |
| **Trend – Price growth** | AER accepted our zero real non-labour price growth forecast. | We accept the Draft Decision. |

| Component | AER Draft Decision | Revised Proposal |
|---|---|---|
| | AER updated the average of the two state-specific utilities industry wage price index growth (**WPI**) forecasts to represent latest forecast for real labour price growth. | We updated the average, by updating the state specific utility industry WPI growth forecast based on Oxford Economics' forecast and applying the Draft Decision's forecast from Deloitte Access Economics. |
| **Trend – productivity** | AER accepted our use of their productivity growth forecast of 0.5 percent per annum. | We have maintained productivity growth consistent with the Draft Decision. |
| **Step Changes** | AER accepted the following step changes:<br>• Cyber security uplift<br>• Network visibility<br>• Information and communications technology (**ICT**) infrastructure refresh<br>• Operationalising cyber security<br>• CER compliance<br>• CER integration<br>• Increases to insurance premiums<br>• Transition to electric vehicles | The step changes found by the AER to be acceptable have been justified and explored with customers in our engagement process for the Original Proposal. We have retained these step changes (unchanged) in our Revised Proposal. |
| | AER provided an alternative estimate of the negative step change for reliability improvements. | We accept the AER's alternative estimate for this step change. |
| | AER did not accept the network program uplift step change in their alternative forecast. | We disagree these costs are already accounted for but decided to not include this in our Revised Proposal. |
| | AER applied a 'placeholder' of zero dollars in their alternative forecast, requiring additional information to determine the smart meter rollout – IT upgrades step change. | Our Revised Proposal provides additional information to support this step change. |
| **Category specific forecasts** | AER rejected the inclusion of the category specific forecast for the enactment of the small compensation claims regime. | We accept the Draft Decision as we expect that the South Australian Government will enact the regime as a jurisdictional scheme obligation. |
| | AER suggested the inclusion of an innovation fund as a category specific forecast. | We accept the Draft Decision and have included the opex component of our innovation fund as a category specific forecast in our Revised Proposal. |
| **Genuine consumer engagement on opex forecasts** | AER considered there was a demonstrated genuine approach to consumer engagement by SA Power Networks in relation to our opex forecasts. | We continued engaging with consumer / stakeholder groups subsequent to our proposal and Draft Decision. The total quantum of opex was discussed, and the Innovation Fund was subject to more substantive engagement (further discussed in capex attachment). |

Having addressed the Draft Decision, our revised opex forecast for 2025-30 is as detailed in Table 2.[2]

**Table 2. Comparison of Main SCS Opex Forecasts**

| | Original Proposal | AER Draft Decision | Revised Proposal |
|---|---|---|---|
| Reported base year opex | 1,691.2 | 1,691.2 | 1,816.4 |
| Base year efficiency and provision adjustments | - | - | (34.5) |
| Final year adjustment | 14.9 | 14.9 | 12.7 |
| Base year SaaS adjustment | 84.7 | 84.7 | 84.6 |
| Rate of change | 30.2 | 30.2 | 32.3 |
| Step changes | 128.8 | 128.8 | 107.0 |
| **Opex excluding category specific forecasts** | **1,949.9** | **1,949.9** | **2,018.6** |
| Category specific forecast[3] | 20.0 | 20.0 | 4.0 |
| **Total forecast opex, excluding debt raising costs** | **1,969.9** | **1,969.9** | **2,022.6** |
| Debt raising costs | 13.8 | 13.8 | 13.7 |
| **Total forecast opex, including debt raising costs** | **1,983.7** | **1,983.7** | **2,036.2** |
| Legacy metering services[4] | 60.2 | 26.2 | 41.0 |
| **Total forecast opex** | **2,043.9** | **2,009.9** | **2,077.3** |

[2] Numbers throughout this document may not add due to rounding.

[3] The South Australian Government is proposing to amend *National Energy Retail Law (Local Provisions) Regulations 2013* to establish the small compensation claims regime. Further information is provided in section 9.1.

[4] See **Attachment 19 – Legacy Metering** for details.

# 4 Our Original Proposal

Our original forecast opex for 2025-30 was shaped by customer preferences and meets our regulatory obligations in delivering reliable, safe and secure services to customers in an efficient and prudent manner.

In developing our original forecast, we applied an iterative, scenario-based, and outcomes focused approach to consumer engagement and forecasting. The total quantum of our opex forecast iterations were communicated to customers at each stage of our engagement program to allow for informed 'trade-off' considerations on how to address needs in 2025-30. For opex, the more substantive engagement focused on the step changes, category specific forecasts, and base-year adjustments for ICT, consistent with the engagement scope determined with our Community Advisory Board (now Community Advisory Forum).

Our original opex forecast reflected the following:

- application of the 'base-trend-step' forecasting method from the AER Better Resets Handbook;
- expected efficient base opex requirements of managing our overall and regular service performance needs for customers – being a network on the efficient frontier;
- changes in the nature of ICT investments between capex and opex aligned with accounting rules;
- expected changes at the time in real increases in labour costs, growth in network outputs and expected productivity gains of an efficient business;
- step changes for the new regulatory obligations and externally driven material cost increases;
- step changes for the opex costs of new capex investments to deliver on efficient service outcomes that customers have told us they prefer, including with respect to cyber security, CER integration and network reliability, safety and security; and
- a deliberate response to affordability concerns by:
    - › reducing our expected costs of resourcing our capital program;
    - › not requesting new funding to deliver two new programs requested by customers which we will still deliver;
    - › not requesting additional funding for new increases in our distribution license fees (as advised by the South Australian Government); and
    - › removing some costs relative to our Draft Proposal, to take a more risk-prioritised approach to cyber security investment.

Table 3 summarises our originally proposed opex forecast for 2025-30.

**Table 3. SA Power Networks' Original Proposal opex forecast for the 2025-30 RCP ($ million, June 2025)**

| | 2025/26 | 2026/27 | 2027/28 | 2028/29 | 2029/30 | 2025–30 RCP |
|---|---|---|---|---|---|---|
| Opex excluding category specific forecasts | 377.4 | 386.4 | 390.6 | 394.5 | 401.0 | 1,949.9 |
| Category specific forecast | 9.5 | 2.6 | 2.6 | 2.6 | 2.6 | 20.0 |
| Total opex forecast, excluding debt raising costs | 386.9 | 389.1 | 393.2 | 397.1 | 403.6 | 1,969.9 |
| Debt raising costs | 2.7 | 2.7 | 2.7 | 2.8 | 2.9 | 13.8 |
| Total forecast opex, including debt raising costs | 389.5 | 391.8 | 396.0 | 399.9 | 406.5 | 1,983.7 |
| Legacy metering services SCS | 11.8 | 12.1 | 12.1 | 12.2 | 11.9 | 60.2 |
| **Total forecast opex** | **401.4** | **403.8** | **408.1** | **412.1** | **418.4** | **2,043.9** |

# 5 AER Draft Decision

The Draft Decision accepted our Original Proposal opex as it was not materially different from the AER's alternative forecast of $1931.9 million for the Main SCS opex (excluding debt raising costs), which was $38.0 million or 1.9 percent less than our original forecast.

The AER's alternative opex forecast arose from several key factors:

- applying latest available information for Consumer Price Index (**CPI**);
- updating the final year increment adjustment to reflect the latest allowance based on the revocation and subsitution determination, and the River Murrary flood event cost pass-through;
- updating price growth to reflect the latest WPI forecasts, which were higher than the placeholder forecasts that were applied in our Original Proposal;
- not accepting and therefore removing the network program uplift step change for the additional requirements in resourcing to support the proposed uplift in capex, being of the view that these costs are already provided for by the trend forecast;
- not accepting the smart meter rollout – IT upgrades step change and applying a placeholder of zero dollars noting the step change, pending further/updated information on the associated Australian Energy Market Commision's (**AEMC's**) rule change determination (published 28 November 2024) and its implications;
- amending the reliability improvements negative step change to include a reduction of GSL payments.
- removing the small compensation claims regime category specific forecast as it is currently proposed by the South Australian Government to become a jurisdictional scheme obligation.[5]

The AER acknowledged it could not ascertain if the forecast base year costs for 2023/24 were indicative of the nature of costs that we require for the upcoming RCP until they had a chance to review the audited actuals.

[5] The South Australian Government is proposing to amend *National Energy Retail Law (Local Provisions) Regulations 2013* to establish the small compensation claims regime. Further information is provided in section 9.1.

# 6 Our Revised Proposal

Our Revised Proposal opex forecast for 2025-30 retains the base-trend-step method as provided in our Original Proposal. Our Revised Proposal forecast is detailed in Table 4, with the basis for the forecast provided in sections below.

**Table 4. SA Power Networks Revised Proposal opex forecast for the 2025–30 RCP ($ million, June 2025)**

| | 2025/26 | 2026/27 | 2027/28 | 2028/29 | 2029/30 | 2025–30 RCP |
|---|---|---|---|---|---|---|
| Base year | 363.3 | 363.3 | 363.3 | 363.3 | 363.3 | 1,816.4 |
| Base year efficiency and provision adjustment | (6.9) | (6.9) | (6.9) | (6.9) | (6.9) | (34.5) |
| Final year adjustment | 2.5 | 2.5 | 2.5 | 2.5 | 2.5 | 12.7 |
| Base year SaaS adjustment | 16.9 | 16.9 | 16.9 | 16.9 | 16.9 | 84.6 |
| Rate of change | 2.3 | 4.3 | 6.2 | 8.4 | 11.1 | 32.3 |
| Step changes | 13.0 | 21.2 | 23.4 | 24.1 | 25.2 | 107.0 |
| **Opex excluding category specific forecasts** | **391.2** | **401.3** | **405.4** | **408.4** | **412.2** | **2,018.6** |
| Category specific forecast | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 4.0 |
| **Total forecast opex, excluding debt raising costs** | **392.0** | **402.1** | **406.2** | **409.2** | **413.0** | **2,022.6** |
| Debt raising costs | 2.7 | 2.7 | 2.7 | 2.8 | 2.8 | 13.7 |
| **Total forecast opex, including debt raising costs** | **394.7** | **404.8** | **409.0** | **412.0** | **415.8** | **2,036.2** |
| Legacy metering services[6] | 9.0 | 9.5 | 8.9 | 7.5 | 6.2 | 41.0 |
| **Total forecast opex, including legacy metering services** | **403.6** | **414.3** | **417.9** | **419.4** | **422.0** | **2,077.3** |

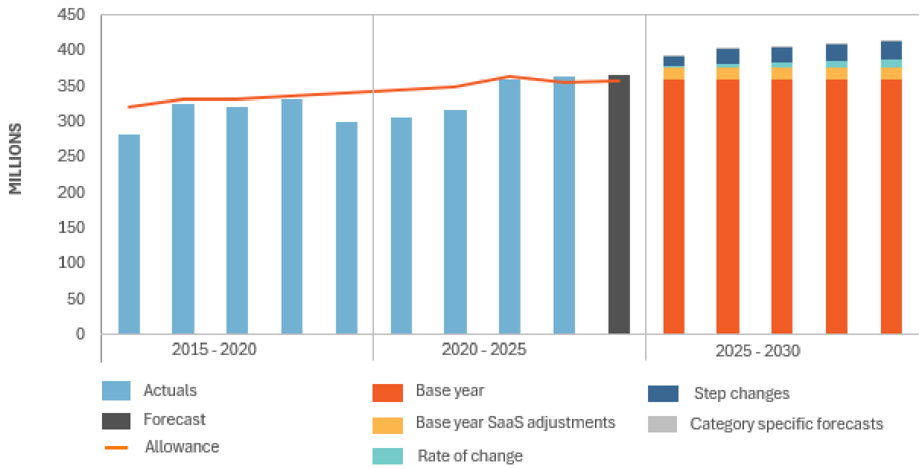
## 6.1 Base year

### 6.1.1 The efficiency of our revealed opex

Our opex has followed a steady long-term trend, as seen in Figure 2, despite having to confront the challenges of managing a network with the oldest asset fleet in the NEM and which is at the forefront of the energy transition. We employ prudent and efficient practices in maintenance and operations to not compromise service delivery and have a continuous focus on minimising opex and improving our efficiency.

6 See **Attachment 19 – Legacy Metering** for details.

**Figure 2. SA Power Networks historical and forecast opex ($ million, June 2025)**

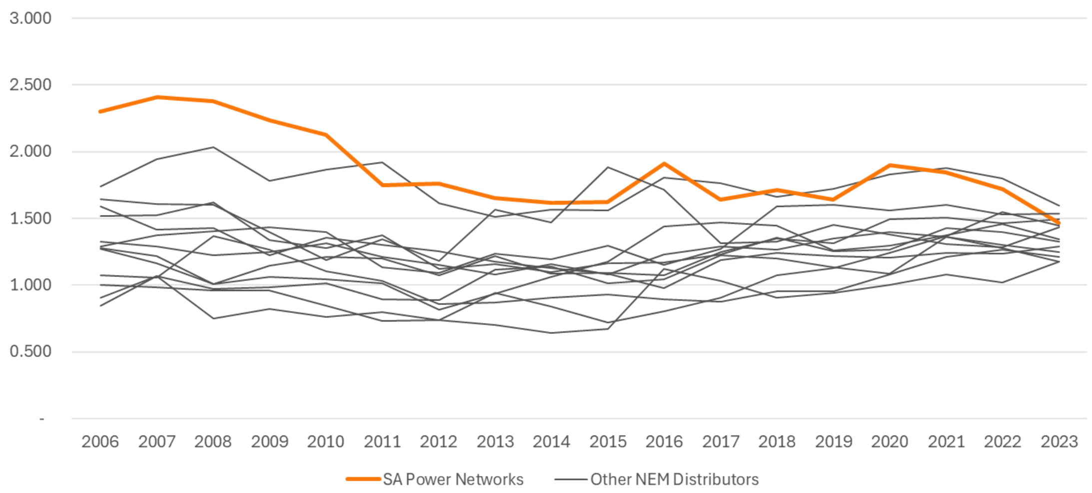



The efficiency of our practices is evidenced by the AER's benchmarks, where we continue to be amongst the most efficient Distribution Network Service Providers (**DNSP**s) in terms of opex efficiency scores, as reported in the AER's recently published 2024 benchmarking report:[7]

- retaining average econometric efficiency scores above the 0.75 benchmarking comparator referred to in the AER's Better Resets Handbook; and
- ranking fourth in the NEM for opex multilateral partial productivity (**MPFP**), as seen in Figure 3.

For these reasons, our revealed opex can be presumed to reflect prudency and efficiency, such that it can therefore serve as a reasonable basis (via the base-year) for forecasting opex for the 2025-30 RCP.

**Figure 3. Opex MPFP by individual DNSP under the preferred capitalisation approach, 2006-23**




## 6.1.2 Our revised base-year

The Draft Decision accepted our proposal which nominated the 2023/24 regulatory year as our base year, considering it to be a relatively efficient forecast. The Draft Decision noted that our base-year would be updated with audited actual revealed costs.

[7] AER 2024 Annual Benchmarking Report – Distribution network service providers – November 2024.

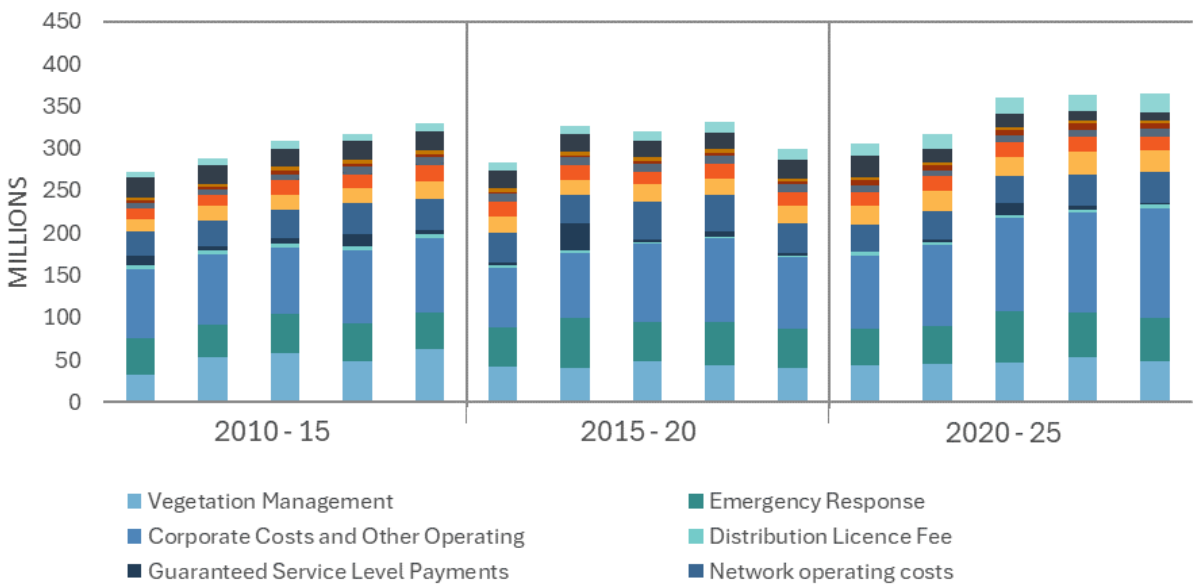
Therefore, our Revised Proposal has now updated our base-year to account for our 2023/24 audited actuals, resulting in a revised adjusted base year opex of $375.9 million per annum.[8] Our revised adjusted base year provides a reasonable estimate of our base requirements for the 2025-30, and we arrived at this revised figure by having:

- maintained the base-year adjustments for SaaS costs of $16.9 million, which were accepted in the Draft Decision;
- taken our actual opex unadjusted for categories of opex to be excluded in the base year, which was $25.0 million higher than our Original Proposal. This is a 7.4 percent increase from our proposed base year forecast of $338.3 million;
- checked for any 'one-off' / non-recurrent costs that should be excluded from the base year used to forecast requirements for 2025-30. Identifying a $1.2 million cost associated with an internal operating model review (corporate costs category) that we have therefore removed[9]; and
- consistent with the AER EFAG, we also adjusted our base year to apply:
  - › a reduction of $5.7 million to remove movements in provisions which is also is removed from the opex category of corporate costs;[10] and
  - › an addition of $2.5 million for the incremental adjustment for final regulatory year 2024/25 in the 2020-25 RCP.

## Factors explaining our recent opex trends and revised base year

Our revealed base year opex reflects continued long-term trends manifesting in opex as Figure 4 shows.[11]

**Figure 4. SA Power Networks historical opex by Regulatory Information Notice category ($ million, June 2025)**




8 This base year includes adjustments for operating model costs, provisions movement, 2024/25 incremental adjustment, and the SaaS adjustment.

9 This adjustment will be treated in the opex model as a non-recurrent efficiency gain in the base year.

10 Once the operating model costs and movement in provisions are removed from the corporate cost category, the increase in corporate costs is immaterial. This is 2 percent higher than the forecast in our Original Proposal base year.

11 The categories in this figure are based on Economic Benchmarking RIN categories which are different from categories in the opex cost categories in Figure 1.

The underlying long-term trends were difficult to discern when we forecast our base year opex as our historical opex particularly in 2021/22 and 2022/23 was heavily impacted by the external factors:

- extreme weather resulting in varying costs associated with emergency response and GSL payments;
- the COVID-19 pandemic impacting several areas of expenditure; and
- a reduction of labour capacities from protected industrial action that reduced work in 2021/22 but led to an increase in work in 2022/23.

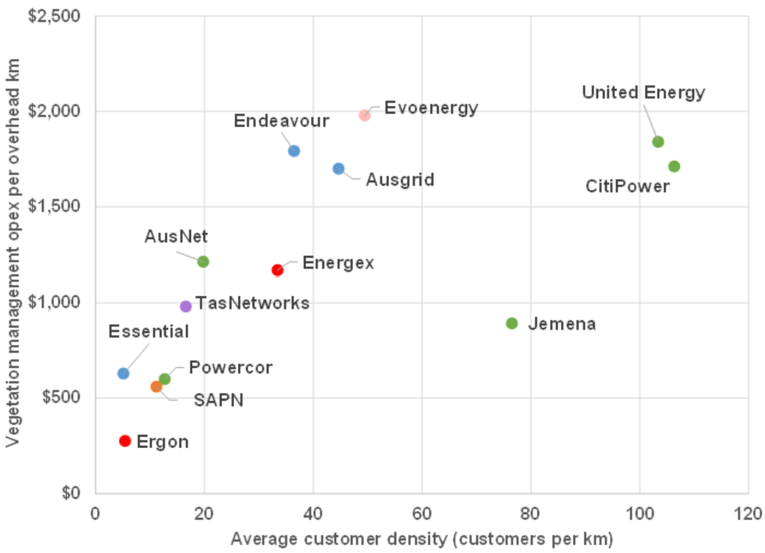
Having further assessed our revealed expenditure in 2023/24, we identified several factors explaining the variation to the base year estimated in our original proposal, as discussed below.

### *Vegetation management costs*

Vegetation management costs which represent 15 percent of the Revised Proposal base year costs, were 11 percent higher than the forecast in our Original Proposal base year.

Although, our actual base year costs were a significant increase from our Original Proposal base year they continue to be representative of efficient costs. In the 2024 benchmarking report for partial performance indicators, SA Power Networks had the second lowest vegetation management expenditure per kilometre of overhead circuit line length and is comparable to other DNSPs who have similar customer densities as seen in Figure 5.

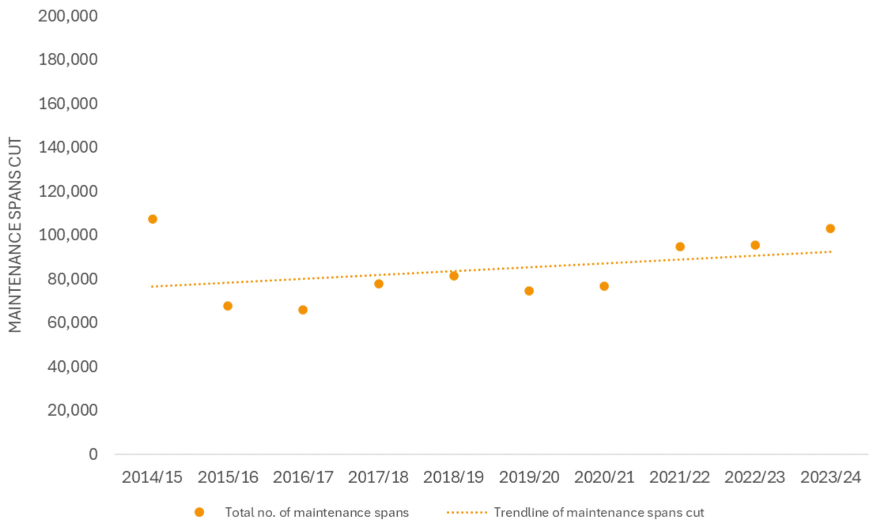
**Figure 5. Vegetation management opex per km of overhead circuit length ($2023) (average 2019-23)**




Source AER, 2024 Annual Benchmarking Report - Distribution Network Service Providers

Furthermore, the long-term increasing trend of vegetation management costs is correlated with the higher volumes of vegetation spans which require cutting. This is seen in Figure 6 which is based on our annually submitted RIN data. We note, the slight decrease in 2020/21 is partially attributed to the reduction in labour capacity from protected industrial action during this period.

**Figure 6. Long-term ten-year trend for the cutting of vegetation maintenance spans**



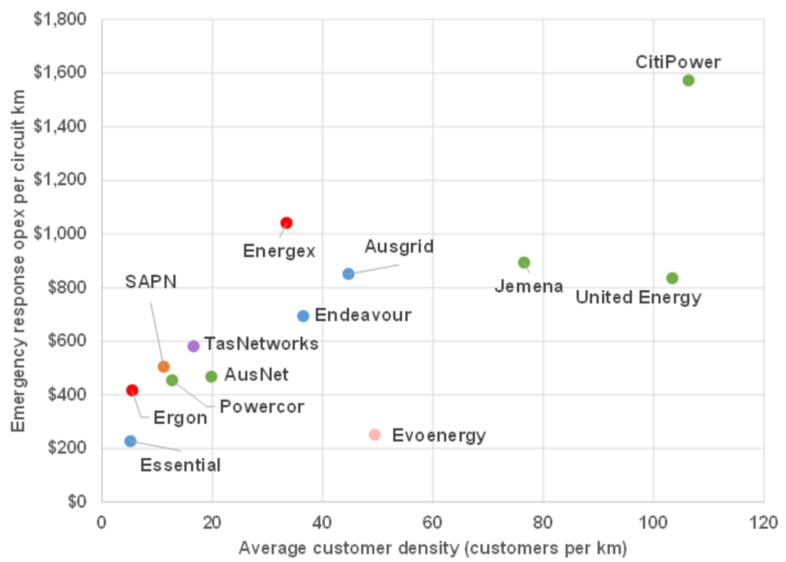

Most of our vegetation management costs are spent on cutting in high and medium bushfire risk areas to reduce fire start events. The threat of bushfires, with the escalating impact of climate change, is on the rise due to lengthening fire seasons and a growing number of hazardous fire weather days. Consequently, we consider the slightly elevated vegetation management expenses in our base year to be both necessary and indicative of efficient costs for the ongoing safe management of the network for the 2025-30 RCP.

### *Emergency Response Costs*

Emergency response costs which represent 14 percent of the Revised Proposal base year costs were 18 percent higher than the forecast in our Original Proposal base year. The spend increase for 2023/24 was not anticipated at the time of forecasting the opex base year. Emergency response expenditure is heavily influenced by weather conditions, with more frequent and severe weather events occurring across our network.

Our emergency response expenditure benchmarks well with other DNSPs with similar customer densities as seen in Figure 7, detailing the average emergency response spend per circuit kilometre.

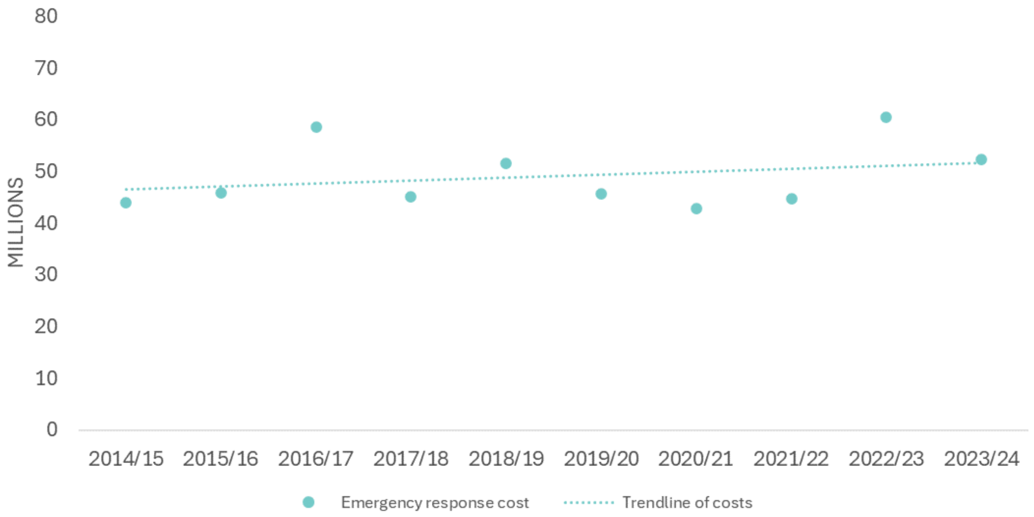
**Figure 7. Average emergency response spend per circuit km ($2023) (average 2019-23)**




Source AER, 2024 Annual Benchmarking Report - Distribution Network Service Providers

Furthermore, although emergency response costs do vary year on year and are driven by external weather impacts, we do not consider the base year's emergency response costs to be materially different on a five or ten year average basis. The increase in emergency response costs for 2023/24 is reflective of a longer-term trend as seen in Figure 8, which given the impact of climate change is expected continue as we experience more frequent severe weather events.

**Figure 8. Long-term ten-year trend of emergency response costs ($ millions, June 2025)**




### *Network operating costs*

Network operating costs represent approximately 10 percent of our total base year costs. The actual 2023/24 expenditure was 10 percent higher than the forecast in our Original Proposal base year.

This increase is largely due to the continuous and progressive expansion in the capabilities needed to manage an increasingly dynamic network which now includes both energy load and exports. The drivers for these increased costs primarily relate to:

- the costs involved in carrying out managing the network operations through real time live network access, monitoring and control, and
- the related network telephony costs that allow the network to be monitored and controlled via various systems.

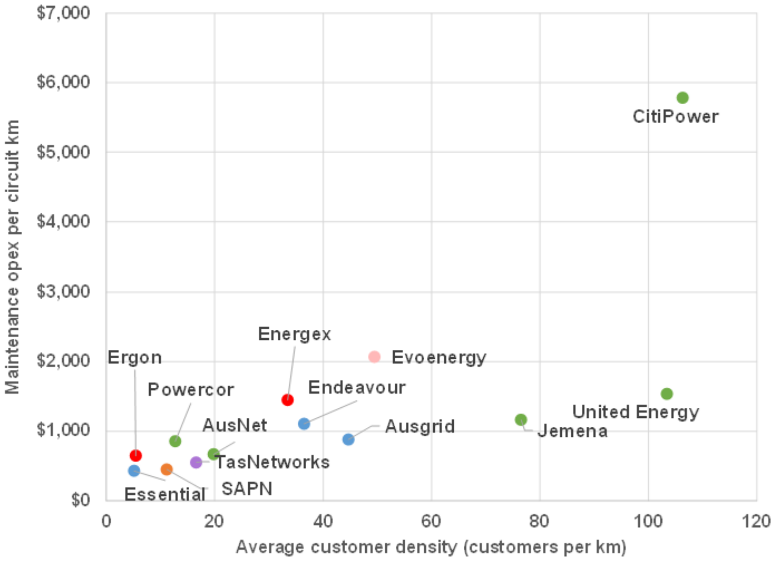
These costs do not encompass those included within the CER compliance step change, which involves expanding the scope of compliance activities through scaling and extending our capabilities to detect and manage the growing number of small CER installation applications per year. Nor do these costs include low voltage planning costs associated with the CER integration step change that considers the expansion and operation of IT systems to primarily support the flexible export and smarter homes integration.

It is expected the transition of the energy market will continue to pose challenges to facilitating energy reliability, quality and security. Therefore, we are likely to continue to experience similar costs into the future for this category.

### *Asset Maintenance and repair costs*

The actual reported asset maintenance and repair costs for 2023/24 represents approximately 8 percent of base year costs and were 23 percent higher than the forecast included in our Original Proposal base year. The AER's partial performance indicator for maintenance costs serves as a useful tool for benchmarking and comparison, given that 60 percent of the total maintenance costs are attributed to asset maintenance and repair costs. Based on the AER's 2024 benchmarking report we benchmark as the second most efficient for maintenance opex as seen in Figure 9. Although this does not include data from our base year we will continue to be among the most efficient distribution network service providers and benchmark comparably when considering average customer density.

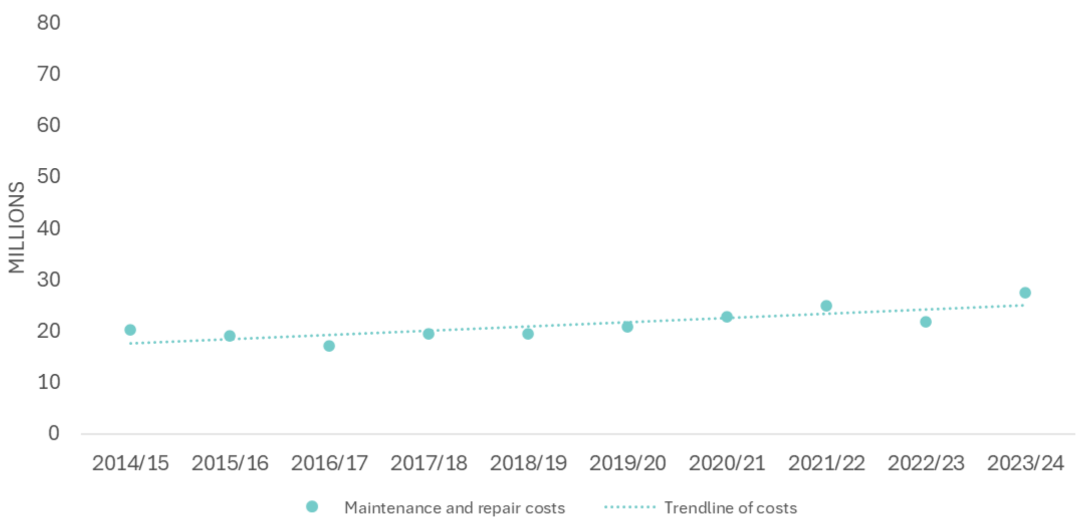
**Figure 9. Average maintenance opex spend per circuit km ($2023) (average 2019-23)**




Source AER, 2024 Annual Benchmarking Report - Distribution Network Service Providers

The increase in costs also represents a broader long-term trend of escalating maintenance expenditure, as illustrated in Figure 10. This is due to the deteriorating condition of substation network assets, a trend that will continue to occur as the assets age. Predicting costs in this category has been challenging given the reduction in labour capacities from protected industrial action that impacted work in 2021/22 and 2022/23.

**Figure 10. Long-term ten-year trend for maintenance and repair costs**



# 7 Rate of Change

The AER accepted our rate of change approach which was consistent with the formula in the EFAG and Better Resets Handbook.[12]

## 7.1 Output growth

We have applied the AER's Draft Decision output weightings to determine the forecast output growth. The inputs that have been updated, specifically include:

- customer numbers now applies a forecast 1.0 percent growth per annum when incorporating the latest 2023/24 RIN data;
- circuit length now applies a forecast 0.3 percent growth per annum when incorporating the latest 2023/24 RIN data; and
- ratcheted maximum demand now applies a forecast of 0.0 percent per annum when applying the AEMO 2024 ESOO central scenario.

We have maintained a consistent methodology as applied in our Original Proposal when deriving the inputs for customer numbers, circuit length and ratcheted maximum demand.

This has resulted in the following output growth forecast as detailed in Table 5.

**Table 5. SA Power Networks forecast output growth for the 2025-30 RCP**

| | 2025/26 | 2026/27 | 2027/28 | 2028/29 | 2029/30 | Average/Total |
|---|---|---|---|---|---|---|
| Weighted output growth (year by year) | 0.49% | 0.49% | 0.49% | 0.49% | 0.49% | 0.49% |
| **Output growth ($ million, June 2025)** | 1.8 | 3.7 | 5.6 | 7.4 | 9.3 | **27.8** |

## 7.2 Real price growth

We have applied the AER's Draft Decision forecast price growth weightings for labour and non-labour.

We have updated the forecast labour price growth based on the latest report from Oxford Economics[13] and accept the Deloitte Access Economics forecast. We expect the AER will update the Deloitte Access Economic forecast with the latest data in its Final Decision. The revised annual labour price growth for 2025-30 RCP is detailed in Table 6, with the proposed real price growth provided in Table 7.

12 We expect the AER will follow its standard regulatory practice of updating rate of change inputs to the latest available at the time of the Final Decision.

13 See **Supporting Document 6.2 - Oxford Economics - Utilities Construction Wage Forecasts to 2029-30 - October 2024** for details.

**Table 6. SA Power Networks annual labour price growth for the 2025–30 RCP**

| | 2025/26 | 2026/27 | 2027/28 | 2028/29 | 2029/30 |
|---|---|---|---|---|---|
| Deloitte Access Economics forecast | 0.84% | 0.84% | 0.74% | 0.85% | 1.08% |
| Oxford Economics forecast | 0.31% | 0.91% | 0.99% | 1.19% | 1.28% |
| Average labour price growth | 0.57% | 0.87% | 0.86% | 1.02% | 1.18% |
| Legislated Superannuation Guarantee Increase | 0.50% | 0.00% | 0.00% | 0.00% | 0.00% |
| **Average labour price growth plus Superannuation Guarantee Increase (year by year)** | **1.07%** | **0.87%** | **0.86%** | **1.02%** | **1.18%** |

**Table 7. SA Power Networks forecast real price growth for the 2025-30 RCP**

| | 2025/26 | 2026/27 | 2027/28 | 2028/29 | 2029/30 | Average/ total |
|---|---|---|---|---|---|---|
| Real price growth (year by year) | 0.63% | 0.52% | 0.51% | 0.60% | 0.70% | 0.59% |
| **Price growth ($ million, June 2025)** | **2.4** | **4.3** | **6.3** | **8.6** | **11.2** | **32.7** |

## 7.3 Productivity growth

We have applied the AER's Draft Decision productivity growth to our opex for this Revised Proposal. The outcome is provided in Table 8.

**Table 8. SA Power Networks productivity growth for the 2025-30 RCP**

| | 2025/26 | 2026/27 | 2027/28 | 2028/29 | 2029/30 | Average/ total |
|---|---|---|---|---|---|---|
| Productivity growth (year by year) | 0.50% | 0.50% | 0.50% | 0.50% | 0.50% | 0.50% |
| **Productivity growth ($ million, June 2025)** | **-1.9** | **-3.8** | **-5.6** | **-7.5** | **-9.4** | **-28.3** |

# 8 Step Changes

In our Original Proposal, we submitted step changes totalling $128.8 million ($June 2025).

We accept the AER's alternative forecast for the approved step changes. Noting these were accepted in the AER's Draft Decision, we have not provided any additional details in our Revised Proposal. We have retained these in full as per the AER's Draft Decision. These step changes include the following:

- Cyber security uplift
- ICT infrastructure refresh
- Operationalising cyber security
- CER compliance
- CER integration
- Network visability
- Increases to insurance premiums
- Reliability program uplift
- Transition to electric vehicles

We have provided additional information required by the AER for the smart meter rollout – IT upgrades and the network program uplift for which we are no longer seeking ex-ante funding.

Table 9 provides a comparison of our original step changes, the AER's Draft Decision alternative forecast on those step changes and our revised step changes, for the 2025-30 RCP.

**Table 9. SA Power Networks summary of step changes for the 2025-30 RCP ($ million, June 2025)**

| | Original Proposal | AER Alternative Forecast[14] | Revised Proposal |
|---|---|---|---|
| **Regulatory Obligation** | | | |
| Cyber security uplift | 47.6 | 47.6 | 47.6 |
| Smart meter rollout – IT upgrades | 4.8 | - | 1.3 |
| **Capex/Opex Trade-off** | | | |
| ICT infrastructure refresh | 9.9 | 9.9 | 9.9 |
| **Major external factor** | | | |
| Operationalising cyber security | 17.4 | 17.4 | 17.4 |
| CER compliance | 2.5 | 2.5 | 2.5 |
| CER integration | 4.4 | 4.4 | 4.4 |
| Network visibility | 6.8 | 6.7 | 6.7 |
| Increases to insurance premiums | 19.4 | 19.4 | 19.4 |
| Network program uplift | 18.0 | - | - |
| Reliability improvements | (0.7) | (0.9) | (0.9) |
| Transition to electric vehicles | (1.3) | (1.3) | (1.3) |
| **Total step change** | **128.8** | **105.7** | **107.0** |

[14] While, the AER Draft Decision accepted SA Power Networks' opex, as it was not materially different to the AER's alternative forecast, we have used the AER's alternative forecast in this table as it better reflects the AER's decisions on step changes.

## 8.1 New regulatory obligations - smart meter rollout – IT upgrades

In our Original Proposal we proposed a $4.8 million step change over 2025-30 to store and secure greater volumes of data due to the increased number of smart meters.

The AEMC's Metering Contestability Review, completed in August 2023 proposed significant changes to the NER and National Energy Retail Rules (**NERR**) to accelerate the pace of the smart meter rollout, targeting a completion by 2030. The final rule change was published on 28 November 2024. Therefore, we have updated our forecasts for this step change to reflect outcomes of the final rule.

Our Original Proposal, and subsequent responses to AER information requests, discussed how SA Power Networks will require an uplift in data storage capabilities to store and secure increased volumes of data associated with the accelerated number of smart meters. Over the accelerated rollout period legacy meters (quarterly read) will be replaced with smart meters which record meter readings every five minutes. This results in an uplift of over 105,000 data points processed and stored per year per smart meter. All this data will be required to be stored and analysed by our systems for billing purposes.

This will require upgrades to our current ICT storage capabilities which are cloud based. We have reassessed the need for this step change as discussed in our information request (IR027) response mentioned in the AER's Draft Decision and continue to believe it is prudent and efficient. We have further revised this step change to $1.3 million based on the outcomes of the AEMC's accelerating smart meter deployment rule change, with the accelerated rollout now scheduled to commence on 1 December 2025.

**Table 10. Revised annual expenditure for smart meter rollout – IT upgrades ($ million, June 2025)**

| | 2025/26 | 2026/27 | 2027/28 | 2028/29 | 2029/30 | Average/Total |
|---|---|---|---|---|---|---|
| Original Proposal | 0.36 | 0.60 | 0.84 | 1.20 | 1.80 | 4.80 |
| Revised Proposal | 0.02 | 0.08 | 0.17 | 0.41 | 0.61 | 1.30 |

The predicted uplift in meters is discussed further in the **Supporting Document 19.4 – Legacy Metering Transition – Towards 2030 – December 2024.**

We confirm the ICT infrastructure refresh step change assumes business as usual rollout rates and does not include costs for the uplift in data storage capabilities from the accelerated number of smart meters. We have ensured we have not double counted costs between these step changes.

## 8.2 Major external factor - network program uplift

In our Original Proposal, we forecast opex of $18.0 million to support the proposed uplift in our total network capital program, due to the additional support services and ICT costs needed. The AER's Draft Decision did not include the network uplift step change in its alternative forecast, stating that it had already been provided within the trend component of opex.

We do not agree that the network program uplift is included in the trend component for base opex. Our build-up of costs for this step change considered the effect of the rate of change, which is applied to the opex base year to account for changes in output growth, price growth and productivity. When calculating the expected increase in support and ICT costs over base year costs, we applied the rate of change to base year costs to remove any possibility of double counting. Therefore, demonstrating that the network program uplift step change is additional to the trend component for opex.

An uplift in resources across corporate support functions (such as training, procurement, human resources, fleet maintenance, health, safety and environment, and ICT) is necessary to support the proposed uplift in our capital program over 2025-30. Although these costs are expected to be substantial, we have decided to not seek ex-ante funding for this step change which is aligned with our commitment of providing affordable and equitable energy supply.

We will not be requesting this step change as part of the Revised Proposal.

## 8.3 Reliability improvements

In our Original Proposal, we forecast a reduction in opex of $0.7 million reflecting improved outcomes for network interruptions and emergency response costs. We accept the AER's alternative forecast increasing the negative step change to $0.9 million.

Further details about the Original Proposal's reliability improvements step change are provided in **Supporting Document 5.9.5 - Worst Served Customers Reliability Improvement Programs** as well as **Attachment 5 - Capital expenditure**.

# 9 Category Specific Forecasts

In our Original Proposal, we forecast one category specific forecast for the small compensation claims regime totalling $20.0 million.

We accept the AER's removal of the small compensation claims regime and addition of the innovation fund. We have revised the opex forecast for the innovation fund to $4.0 million. This will be recovered via a category specific forecast as discussed in the Draft Decision.

Our revised category specific forecast is seen in Table 11 below.

**Table 11. Revised category specific forecasts for 2025-30 ($ million, June 2025)**

| | Original Proposal | AER Draft Decision | Revised Proposal |
|---|---|---|---|
| Small compensation claims regime | 20.0 | 20.0 | 0.0 |
| Innovation fund | 0.0 | 0.0 | 4.0 |
| **Total** | **20.0** | **20.0** | **4.0** |

## 9.1 Enactment of the small compensation claims regime

Our Original Proposal included forecast opex of $20.0 million over 2025–30 to meet an expected new regulatory obligation relating to claims and damages, effective from 1 July 2025. The South Australian Government is now establishing a new small compensation claims regime through amending the *National Energy Retail Law (Local Provisions) Regulations 2013*.

We will be applying to the AER for this small compensation claims regime to be considered a jurisdictional scheme. Consequently, compensation costs will be not recovered via opex and therefore we accept the AER's alternative estimate. Furthermore, in our Original Proposal we had included $1.6 million to administer the small compensation claims regime and we will not be seeking ex-ante funding for these costs.

This scheme was strongly supported by the Energy and Water Ombudsman South Australia and by not seeking ex-ante funding for the administration of the scheme we are continuing to balance the objectives of customer experience and providing an affordable and equitable energy supply.

## 9.2 Innovation fund

In our Original Proposal, we allocated $4.0 million to opex for innovation fund projects and we proposed for this opex to be recovered via a revenue adjustment in the Post Tax Revenue Model. We agree with the AER in the Draft Decision that any opex for the innovation fund should instead be recovered via the opex as a category specific forecast. The AER's Draft Decision included a zero dollar placeholder value for the innovation fund as further information was sought before the AER could consider approving a forecast. This included:

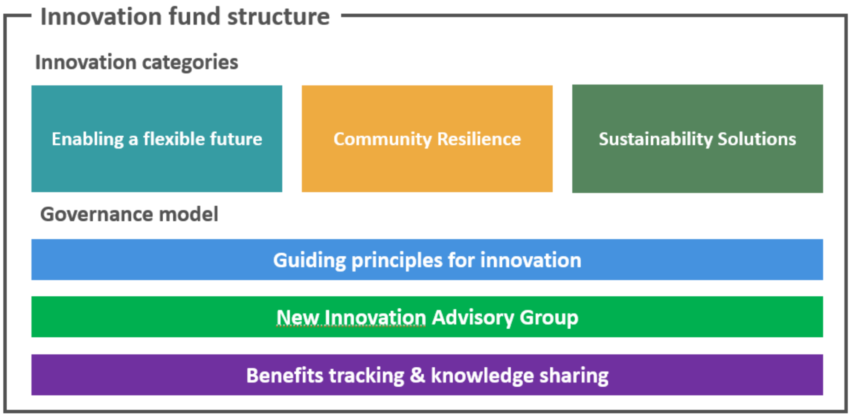
- an assessment of each proposed project against the AER's new assessment criteria;
- further information on estimated costs and consumer benefits of the innovation fund; and
- a firm list of proposed projects.

We do not accept the AER's Draft Decision but recognise that our original business case did not provide sufficient information. We recommend $4.0 million as a prudent and efficient opex required to pursue innovation in 2025-30, as the innovation fund revised proposal now includes:

- a customer prioritised project list;
- compliance with the AER's new assessment criteria;
- costs of the proposed innovation fund projects which are now scoped and estimated;
- outlines the range and sources of material customer benefits that we expect to achieve from successful innovation; and
- includes a detailed customer-led governance model.

The overall structure of our proposed innovation fund is displayed in Figure 11.

**Figure 11. Innovation Fund structure**




Further details about the innovation fund are found in **Supporting Document – 5.13.4 - Innovation Fund - December 2024.**

# 10 Relationship with Efficiency Benefit Sharing Scheme

The Efficiency Benefit Sharing Scheme (**EBSS**) provides a continuous incentive for DNSPs to pursue efficiency improvements in opex and provides for a fair sharing of savings between DNSPs and customers. Customers benefit from improved efficiencies through lower network prices in future regulatory periods.

The EBSS allows for the exclusion of categories of operating costs that have not been derived using a single revealed year cost forecasting approach. These categories were outlined in our Original Proposal **Attachment 8 - Efficiency benefit sharing scheme** and include costs such as debt raising costs and legacy metering costs.

SA Power Networks proposes that the EBSS continue to operate and be applied for the 2025–30 RCP.

# Glossary

| Acronym / term | Definition |
| --- | --- |
| **AEMC** | Australian Energy Market Commission |
| **AEMO** | Australian Energy Market Operator |
| **AER** | Australian Energy Regulator |
| **Capex** | Capital expenditure |
| **CER** | Customer Energy Resources |
| **CPI** | Consumer Price Index |
| **DNSP** | Distribution Network Service Provider |
| **EBSS** | Efficiency Benefit Sharing Scheme |
| **EFAG** | Expenditure Forecast Assessment Guideline |
| **ESOO** | Electricity Statement of Opportunities |
| **ESCoSA** | Essential Services Commission of South Australia |
| **GSL** | Guaranteed Service Level |
| **ICT** | Information and Communication Technology |
| **IT** | Information Technology |
| **MPFP** | Multilateral Partial Factor Productivity |
| **NEL** | National Electricity Law |
| **NEM** | National Electricity Market |
| **NER** | National Electricity Rules |
| **NERR** | National Energy Retail Rules |
| **Original Proposal** | SA Power Network’s Regulatory Proposal for the 2025-30 RCP submitted in January 2024 |
| **Opex** | Operating expenditure |
| **RCP** | Regulatory Control Period |
| **Revised Proposal** | SA Power Network’s Revised Regulatory Proposal for the 2025-30 RCP submitted in December 2024 |
| **RIN** | Regulatory Information Notice |
| **SaaS** | Software as a service |
| **SCS** | Standard control services |
| **WPI** | Wage Price Index |