Augex capacity - Business case addendum

2025-2030 Regulatory Proposal

Supporting document 5.4.2

December 2024

SA Power Networks

Empowering South Australia

Contents

Glossary

Acronym / term	Definition
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ARENA	Australian Renewable Energy Agency
BCR	Benefit Cost Ratio
BESS	Battery Energy Storage System
Capex	Capital expenditure
CER	Customer Energy Resources
DLF	Distribution Loss Factor
DSP	Demand-Side Participation
EAC	Equivalent Annual Cost
EOI	Expression of Interest
EMCa	Energy Market Consulting Associates
ESOO	Electricity Statement of Opportunities
EV	Electric Vehicle
HEMS	Home Energy Management Systems
ISP	Integrated System Plan
LV	Low Voltage
NEL	National Electricity Law
NER	National Electricity Rules
NSSA	Network System Support Agreements
NPV	Net Present Value
POE	Probability of Exceedance
RCP	Regulatory Control Period
RIT-D	Regulatory Investment Test for Distribution
RIT-T	Regulatory Investment Test for Transmission
SAPS	Stand-Alone Power Systems
SCADA	Supervisory Control and Data Acquisition
SCAP	State Commission Assessment Panel
USE	Unserved Energy
VCR	Value of Customer Reliability

1 About this document

1.1 Purpose

This document is an addendum to the to *'5.4.2: Augmentation - Capacity Business Case'* (the 'original business case'), submitted to the Australian Energy Regulator (AER) as a supporting document to our Regulatory Proposal in January 2024 (the 'Original Proposal'). This document should be read in conjunction with the original business case for further context, including the detail on our evolving distribution network planning criteria, the alternative investment options we considered, the identified need and the preferences of our customers.

This business case addendum, responds to the AER's Draft Decision having not accepted and therefore substituted our proposed forecast capital expenditure (capex) on augmentation of network capacity, with a lower expenditure forecast for the 2025-30 Regulatory Control Period (RCP). This addendum addresses the concerns set out in, and that led to, that Draft Decision, and contains our revised capacity expenditure forecast as comprising our Revised Proposal.

1.2 Expenditure category

All expenditure forecasts outlined in this document are expressed in June $2022 (excluding overheads).

This addendum pertains to our proposed forecast capex on one component of our forecast network asset augmentation expenditure (augex), being in relation to capacity augmentation expenditure (capacity augex, or capacity).

1.3 Related documents

This document should be read in conjunction with the following documents that specifically relate to capacity augex:

- 5.4.2. Augmentation - Capacity Business Case Jan 2024 (the 'original business case')
- 5.4.2.1. Endgame Economics Demand Forecast Review
- Project-specific justification documents for demand-driven projects that exceed $4 million
    - 5.4.2.2 Mount Barker East new substation
    - 5.4.2.3 Salisbury South new substation
    - 5.4.2.4 Smithfield West substation upgrade
- 5.4.2.5 ElectraNet Support for use of AEMO's 2024 ISP in SA Power Networks' Revised Revenue Proposal - Confidential
- 5.4.2.6. Capacity Augex Tool (available on request)
- 5.4.2.7. Capacity Augex Tool Explanatory Document (available on request)
- 5.4.2.8. Augex Capacity CBA - Option 1 – Preferred (available on request)

2 Executive summary

This business case addendum recommends, as our Revised Proposal, forecast capex of $176.2 million to augment the capacity of the network by upgrading or expanding assets to ensure the network has the capacity and security to meet forecast demand and can maintain service quality, reliability, security and compliance with obligations. This specifically concerns projects and programs to meet anticipated demand by expanding or upgrading our sub-transmission distribution network and low voltage (LV) networks, including transmission connection points and substations.

The original business case in our Regulatory Proposal had forecast $208.6 million in capex on capacity augex. This comprised of several programs including: (1) compliance driven augex on connection point upgrades (2) compliance driven augex on quality of supply, and (3) augex for demand driven projects. The demand driven projects were forecast by applying a 'hybrid planning' method, which combined the selection of projects based on our long-standing distribution network planning criteria ('deterministic planning' for 10% POE projects under normal operating conditions 'N'); and probabilistic planning for 'N-1' contingency projects.

The AER Draft Decision did not challenge the basis of our overall 'hybrid planning' method for forecast expenditure, and it accepted that most of our proposed forecast was prudent and efficient. The AER endorsed all of our forecast compliance driven expenditure, and some of our demand driven expenditure. However, the Draft Decision substituted our forecast demand driven expenditure with a forecast that was $31.5 million lower, resulting in a total capacity forecast of $177.0 million. In reducing our demand driven expenditure, the AER considered there were opportunities for project deferral contingent on their analysis of optimal project timing. The AER also requested that we update our demand forecast to incorporate the most recent information and instructed us to resolve further issues identified in their assessment.

This addendum addresses each of the concerns identified in the Draft Decision through additional information, analysis and a revised approach to forecast inputs to ensure efficient project selection, including:

- **updated demand forecasts** - updating our forecast with the latest available and prudently usable information, adjustments to the treatment of block loads, and improved transparency in the reconciliation process;
- **forecast to project mapping** - mapping demand forecasts to specific projects to demonstrate optimal project timing;
- **economically optimal timing** - adopting optimal timing, drawing on the method outlined in the AER's Industry Practice Application Note - Asset Replacement Planning[1] and incorporating a Benefit-Cost-Ratio (BCR) threshold;
- **sensitivity testing** - introducing additional testing, including a deferral test for targeted projects; and
- **consideration of alternatives** - providing greater visibility of the alternative non-network investment options that were explored to address identified needs.

The revisions that we have made to address the concerns raised in the Draft Decision have resulted in our revised forecast of $176.2 million, being $32.4 million less than our original proposal and $0.8 million lower than the Draft Decision. We consider that our revised expenditure forecast represents the prudent and efficient level of forecast expenditure required to achieve the identified need over the 2025-30 RCP, on the basis that:

- **efficient in NPV terms** - our revised expenditure forecast in total is shown in this addendum to be efficient for customers, driving benefits to customers that outweigh costs, with a Net Present Value (NPV) result of $811.6 million over a 20-year period;

[1] AER, *Industry Practice Application Note – Asset Replacement Planning*, July 2024, p.g.36

- **balanced considerations** - our overall approach reflects a prudent balance between aligning regulatory expectations with those of our customers who seek to ensure sufficient investment in the network to meet future demand in order to maintain services;
- **amended only areas in contention** - we retained the components of our forecast that were endorsed in the Draft decision, ensuring continuity in areas of agreement;
- **improved benefit quantification** - the benefit quantification in our analysis has been improved, providing a clearer and more detailed justification for our proposed investments;
- **updated demand forecast inputs** - our updated demand forecast reflects our best available expectations, and incorporates the latest data and latest / prudently usable AEMO forecast; and
- **efficient project selection** - our revised approach demonstrates that our projects have resulted from a well-considered approach to efficient project selection, which now includes a two-step deferral test ensuring that only projects meeting stringent criteria on prudency and efficiency are selected, thereby avoiding investments from occurring earlier than necessary which would add to costs for consumers:
    - this process was designed to address the AER's concerns with ensuring that capital investments are made at the optimal time, avoiding premature expenditure, and are based on robust demand forecasts that reflect the most current and accurate data available and incorporating sensitivity analysis;
    - the first step of the process involves a benefit-cost ratio (BCR) analysis; and
    - the second step of the process applies a deferral test under a low demand scenario.

3 Background

3.1 Our original proposal

Our original business case forecast $208.6 million for capacity expenditure in the 2025-30 RCP, for works required to meet or manage forecast demand, necessitating the extension or upgrade of our sub-transmission, distribution and LV networks including transmission connection points and substations. This comprised of demand-driven projects ($121.9 million) and compliance-driven projects ($86.7 million).

This expenditure forecast was driven by a material increase in forecast demand compared to our current RCP. Macro factors driving this demand growth included electrification, particularly in the business, transport and the residential sector, the up-take of Electric Vehicles (EVs) and new renewable targets. As well as localised factors, such as in-fill housing, greenfield residential developments and commercial and industrial loads.

In developing this forecast, we engaged our customers via Focused Conversations on the needs, expenditure and price impacts. The position formed via these Focused Conversations was endorsed by our People's Panel. The preferences recommended by our customers were to:

- maintain current emergency backup capability in the network, for potential high impact events;
- use the same approach that has been in place since before privatisation to identify investment requirements with increasing demand; and
- maintain long term security of supply to current standards.[2]

We were also cognisant of our customers' general affordability concerns and their overall expectation for us to minimise costs as far as practicable. In response, following our engagement program and through a top-down challenge, we modelled an additional investment option using a 'hybrid planning' approach, consisting of elements of our long-standing planning criteria combined with a new probabilistic planning approach, predominantly for assessment of contingency (N-1) projects. In doing so, we were able to demonstrate that investments were also efficient through a purely economic/probabilistic approach. This hybrid option was presented in our original business case as the preferred Option 1.

We considered that our long-standing Planning Criteria, presented as Option 2, provided ideal long-term consumer outcomes balancing service risk and cost. However, we recommended Option 1 as an approach that best balanced the outcomes customers recommended, as it would:

- maintain current levels of service over the 2025-30 RCP;
- align the approximate level of expenditure reflected in the recommendation of the People's Panel;
- ensure we can meet our compliance obligations; but
- with the exception that it is unlikely to support long term security of supply in the network.

In developing our final recommendation, we also considered a base-case Option 0 and conducted option analysis on all the options summarised below:

- **base-case** (Option 0 – $139.9M) consisting of projects to meet compliance obligations and projects that relieved constraints forecast to occur at a 50 POE level under normal (N) operating conditions, as well as supporting capitalised expenditure relating to labour, procurement, and land acquisition;
- **hybrid case** (Recommended) (Option 1 – $208.6M) which included all options in the base case combined with additional projects that relieved constraints forecast to occur at a 10 POE level under

[2] Further details are contained in our original business case. SAPN, *5.4.2. Augmentation - Capacity Business Case*, January 2024.

normal operating conditions, as well as projects to relieve forecast constraints at 50 POE level under contingency (N-1) conditions that had a positive benefit versus cost result in NPV terms; and

- a **deterministic case** (Option 2 – $275.9M) in which expenditure was consistent with the level of investment needed to maintain current levels of service, modelled using the methodology and approach outlined in our existing Planning Criteria[3].

3.2 How we have revised our approach

The Draft Decision allowed a capacity expenditure forecast of $177.0M. While the AER accepted our $86.7M compliance driven expenditure forecast, the AER reduced our forecast demand driven expenditure by $31.5M. Th AER removed projects that its consultant, EMCa, suggested could be deferred to the 2030–35 RCP due to being susceptible to small variations in key variables such as the demand forecast and cost. The key concerns outlined in the Draft Decision were that:

- the demand forecasts needed to be updated with the most recent information;
- measures implemented to avoid duplication or overestimation of block load adjustments and reconciliation to the system level forecast both need demonstrating;
- the Battery Energy Storage Systems (BESS) block loads should not be included;
- the project timing and sensitivity analysis lacked robustness and transparency; and
- information is needed on why the identified needs cannot be addressed by means other than capacity augmentation.

This addendum now implements several revisions in response to, and addressing each specific concern identified in the AER's Draft Decision, as summarised in Table 1 and as detailed throughout this addendum.

Table 1: AER Considerations and our response

	AER considerations	How we responded
Demand forecast	**Forecast update**	
	• Use the latest available information in the Revised Proposal.[4]	• Updated to the latest available and prudently useable information - using the latest historic measurements and the AEMO ISP 2024 Central forecast. • This is our most robust and complete forecast available at the time of this Revised Proposal – we have concerns with the more recent ESOO 2024 forecast not having key updates completed, key inflection points being unexplained and at odds with sector targets, and have supplied an independent report by consultants, Endgame Economics to substantiate our concerns.
	• **Block load adjustments**	
	• Demonstrate how AEMO and SAPN's forecasts reconcile and that block loads are not already accounted for in AEMO's forecast trend, driving duplication / overestimation. • Expect BESS to be excluded from the forecast. • Concerned with SAPN's application of its 5% materiality threshold for block	• Provided a detailed reconciliation between AEMO's forecast and our adjustments, showing how we have prevented duplication and overestimation using a method recommended by Endgame Economics. • Removed BESS adjustments. • Engaged Endgame Economics to review our demand forecasting approach and adapted our method to incorporate their recommendations relating to materiality thresholds, block load treatment and evaluation of potential overestimations.

[3] SAPN - 5.4. - Augex Capacity - January 2024 – Public, Page 11

[4] AER, (2024) Draft Decision Attachment 5 – Capital expenditure – SA Power Networks Distribution Determination 2025-2030, p.30.

	• load adjustment, which results in overestimation. • Evaluation needed of potential over-estimations in customer requested loads, the likelihood of projects not proceeding, and impact of project loads on seasonal and system peak time.	• Implemented an assumed 2 year lag in our forecasting and project selection method, based Endgame Economic findings on the timing of customer requested loads.
Optimal project timing	• **Demand forecasts mapped to projects**	
	• Demand forecast must be clearly mapped to specific augmentation projects to demonstrate optimal timing.	• Mapped demand forecasts to specific projects to demonstrate optimal timing, and implemented a clear audit trail in our Capacity Augex Tool, showing when the cost to customers (expressed in the Value of Customer Reliability) exceeds the annualised investment cost.
	• **Economically optimal timing of projects**	
	• SAPN's analysis does not inform economically optimal timing - benefit cost ratio analysis is needed. • Concerned that some projects with low but positive NPVs are susceptible to variances in demand or costs. • Projects cut had a BCR less than 1.2, having economic timing beyond the regulatory period, relatively low BCRs and mostly negative NVPs even with a 20 year analysis period.	• Applied project selection based on economically optimal timing, drawing on the method in the AER Industry Practice Application Note - Asset Replacement Planning[5]. • In addition to NPV analysis proving benefits outweigh costs, we also conducted benefit-cost ratio (BCR) analysis to guide the economically optimal timing of projects and introduced a two-step project selection approach for projects susceptible to small variances in key inputs. • To ensure the robustness of forecast expenditure we completed deferral tests (step 2) on projects with a BCR less than 1.2.
	• **Sensitivity analysis**	
	• Further analysis needed, to test the sensitivity of the project forecasts to ensure they are robust and the proposed expenditure is truly necessary in the circumstances	• Completed sensitivity analysis on proposed expenditure. • Applied the EMCa recommended 'BCR>1.2 test' to identify projects susceptible to small variances. • Our deferral test method incorporates a sensitivity test for low demand growth.
	• **Consideration of alternatives**	
	• Demonstrate that the identified needs cannot be addressed through other means that avoid building more network infrastructure.	• Provided greater visibility of the alternative options we explored to minimise the network investment costs of addressing the identified needs. • Manually deferred projects close to the end of the RCP where network risks could be operationally managed, or future alternative solutions may be suitable.
	Stakeholder views	**How we responded**
	No specific and new views were expressed in relation to capacity augmentation through our subsequent engagement. There was no apparent change in our customers' preferences, nor in their desires to ensure prudency and efficiency.	We recognised the complex nature, due to the changing energy landscape, of the demand forecast as a key input into the expenditure forecast and engaged Endgame Economics to review our methodology and assist us in our engagement with AEMO to understand the drivers behind their system level forecast and how we can best use this information in determining a prudent demand driven investment program.

5 AER, *Industry Practice Application Note – Asset Replacement Planning*, July 2024.

Based on the abovementioned revisions, Table 2 summarises how our revised expenditure forecast compares to the AER's Draft Decision with respect to the specific components of the expenditure forecast.

Table 2: Summary of revised expenditure forecast compared to the AER Draft Decision

Forecast component	AER Draft Decision	Revised Proposal
Base expenditure: compliance – connection point projects	$50.8m accepted in full	Revised to reflect updated advice from ElectraNet on the timing of the Mannum Connection Point upgrade. We have reduced the forecast by $7.4m resulting in a revised forecast of $43.4m.
Base expenditure compliance – LV quality of supply	$35.8m accepted in full	We accept the Draft Decision and have therefore not revised our proposal on this aspect.
Base expenditure compliance – Operational compliance [6]	$0.8m accepted in full	We accept the Draft Decision and have therefore not revised our proposal on this aspect.
Demand Driven expenditure – Land purchase and Preliminary design works.	$20.1m accepted in full	Revised to reflect changes to timing and expenditure of acquiring land for new substations – increasing the land component by $2.9m resulting in a revised forecast of $23.1m.
Demand Driven expenditure – projects driven by forecast energy at risk under network normal or contingency scenarios.	$69.5m, or $31.5m less than proposed	Revised to incorporate the most recent demand forecasts, NPV analysis, incorporate optimal economic timing for N-1 projects, and applying the deferral test to ensure projects are robust against input sensitivities. This has led to a revised forecast of $73.1m.

[6] This refers to the expenditure component that the AER identified as non-demand driven compliance in their Draft Decision, excluding costs related to Connection Point Compliance and LV Quality of Supply Compliance.

4 The context to the investment need

The underlying driver for our capacity augex forecast overall, remains unchanged from our original business case. That is, we forecast that demand will exceed the intended operating conditions of some of our assets, resulting in the need to consider upgrades or extensions to our network that accommodate customer demand. Failure to address this need will result in reduced services levels experienced by our customers from:

- a reduction in quality of supply compliance;
- increasing periods and quantity of customers being load shed (i.e., increase in unserved energy);
- decreasing network capacity to maintain security of supply during contingencies or planned maintenance; and
- compromising between asset condition and supply security (i.e., avoiding operating our assets outside of their design ratings by load shedding).

Considering our regulatory obligations, directives under the NER and NEL, and the preferences of our customers, the identified need for the total sum of our capacity augex is as follows:

- to prudently and efficiently meet or manage expected demand for Standard Control Services[7] by responding to customers' concerns[8], identified through our consumer and stakeholder engagement process, regarding their service level recommendations that we:
    - maintain current emergency backup capability in the network;
    - use the same approach that has been in place since before privatisation to identify investment requirements with increasing demand;
    - maintain long term security of supply to current standards; and
    - remain mindful of energy affordability.
- to prudently and efficiently comply with all applicable regulatory obligations / requirements[9] relating to power quality, short circuit capability, system stability clearing times, reliability and system security;
- as part of our applicable regulatory obligations / requirements, to prudently and efficiently comply with Australian Standards and good industry practice[10], to ensure the distribution network is designed, constructed, operated and maintained such that a customer's point of supply complies with stipulated requirements; and
- also, as part of our applicable regulatory obligations / requirements, to prudently and efficiently comply with requirements outlined in our Transmission Connection Agreement with ElectraNet[11], which seeks to pass on obligations to comply with levels of reliability and security of supply as specified in the ETC.

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7 This is pursuant to clause 6.5.7(a)(1) of the NER.

8 This is pursuant to Clause 6.5.7(c)(5A) of the NER, which requires regard to be had to the extent to which forecast capex seeks to address the concerns of distribution service end users identified by the distributor's engagement process.

9 This is pursuant to Clause 6.5.7(a)(2) of the NER, which requires expenditure in order to comply with all appliable regulatory obligations or requirements associated with the provision of standard control services.

10 This is pursuant to voltage requirements set out in AS60038, voltage fluctuations are contained within limits of AS/NZS 61000 and harmonic voltage distortions do not exceed values set out in AS/NZS 61000. These obligations are similarly specified in NER clause 5.2.1(a)(3), and in clause 5.2.3(b) and schedule 5.1 which specify quality of supply standards.

11 Upgrade works are mandated through the alteration of existing connection points categorised within the ETC or due to the timing of asset replacement works by ElectraNet, as approved by the AER as part of ElectraNet's most recent price Determination in 2023. Connection Point Substation augmentation expenditure is necessary to comply with our TCA.

5 Revised proposal

5.1 The options considered in our original business case

The original business case considered three alternative investment options as comparative counterfactuals which included:

1. **base case** – undertaking compliance driven projects on (a) connection point upgrades and (b) LV quality of supply works[12];
2. **hybrid planning expenditure** – undertaking (a) base case expenditure (b) deterministic planning expenditure for 10% POE projects under normal 'N' operating conditions and (c) probabilistic planning expenditure for N-1 contingency projects; and
3. **deterministic planning expenditure** – as an alternative forecasting approach for N and N-1 projects.

Option 2 'hybrid planning' was the recommended option in our original business case.

5.2 Our revised expenditure proposal

This addendum addresses the concerns that led the AER to accept a lower expenditure forecast in its Draft Decision. Having revised our approach to take account of the latest available information, ensure our demand forecasting is reasonable, and to implement more efficient project selection, this addendum now:

- no longer seeks to present the three counterfactual investment options from our original business case, as the choice of investment option is no longer in question, noting the Draft Decision and the report by EMCa, accepted that option 2 represents a prudent approach by which to forecast spend. The issues in question, that this addendum now responds to, is the approach to selecting the demand driven capacity projects that comprise parts (b) and (c) option 2, and the resulting efficiency of that expenditure – this addendum now refers to this option as the 'enhanced hybrid planning' option; and
- recommends a revised total forecast of $176.2m in capacity augex as the prudent and efficient level of expenditure to address the identified need over the 2025-30 RCP. This revised forecast is $32.4m lower than our original forecast, and is efficient overall with the benefits outweighing costs, with an NPV result of $807.1m.

Table 3 below outlines how our Revised Proposal compares to our Regulatory Proposal and to the Draft Decision at an expenditure by asset class level.

Table 3: Comparison of expenditure ($ million, June 2022)

Category	AER Allowance (2020-25)	Actuals + Forecast (2020-25)	Original Proposal Forecast (2025-30)	AER Draft Decision (2025-30)	Revised Proposal Forecast (2025-30)
Sub-transmission (AUG006)	$12	$15.1	$49.3	$35.8	$20.5
Substation (AUG004, AUG005, AUG008 & AUG009)	$40.9	$53.6	$66.9	$48.8	$63.5
Distribution (AUG003 & AUG007)	$7.7	$8.7	$5.8	$5.8	$13.1

12 Refer to section 3.1 and our original business case for more details about this option and the treatment of demand driven constraints under N conditions.

5.2.1 Summary of estimated costs - Enhanced Hybrid planning option

Table 4 outlines the costs of our Revised Proposal by cost type, which have been aggregated from the individual projects comprising the types.

Table 4: Costs by Cost Type ($ million, June 2022)

Cost Type	2025-26	2026-27	2027-28	2028-29	2029-30	Total 2025-30
Sub-Transmission capex	$11.9	$5.9	$0.7	$0.1	$2.0	**$20.5**
Substation capex	$9.5	$4.0	$9.8	$22.1	$18.1	**$63.5**
Distribution Feeder capex	$3.8	$2.0	$2.4	$4.7	$0.1	**$13.1**
Connection Point capex	$0.8	$13.8	$12.1	$4.5	$12.2	**$43.4**
Low Voltage capex	$7.2	$7.2	$7.2	$7.2	$7.2	**$35.8**
TOTAL COST	$33.2	$32.8	$32.1	$38.6	$39.5	**$176.2**

5.2.2 Summary of estimated benefits - Enhanced Hybrid planning option

Table 5 summarises the benefits of our Revised Proposal by cost type. Benefits are derived from the value of avoided energy at risk, which are calculated for each demand-driven project, as well as terminal asset value.

Table 5: Benefits by Expenditure Type ($ million, June 2022)

	2025-26	2026-27	2027-28	2028-29	2029-30	Total 2025 - 30	Total for analysis period
Sub-Transmission	$0.0	$1.0	$2.7	$5.1	$9.0	**$17.8**	**$991.4**
Substation	$0.0	$3.8	$4.4	$5.1	$6.6	**$20.0**	**$378.3**
Distribution Feeder	$0.6	$3.2	$4.0	$5.0	$6.3	**$19.2**	**$271.3**
Connection Point	$0.0	$0.0	$0.0	$0.0	$0.0	**$0.0**	**$25.3**
TOTAL	$0.7	$8.0	$11.2	$15.2	$22.0	**$57.0**	**$1,666.3**

5.2.3 Summary of Overall result in NPV terms of recommended option

Table 6 summarises the total costs, benefits and NPV over the 20-year analysis period.

Table 6: Costs, benefits and NPV over the 20-year period, $m, $Jun 2022 real.

Option	Costs[13]			Benefits[14]			NPV[15]
	Capex	Opex	PV[16]	Capex	Opex	PV[17]	
Revised Option	199.4	0.0	177.6	1,623.4	0.0	989.2	811.6

[13] Represents the total capex associated with the proposed option over the 20-year cash flow period (1 July 2025 to 30 June 2045).

[14] Represents the total capital and operating benefits, including any quantified risk reductions compared to the risk of Option 0 (base case), over 20-year cash flow period (1 July 2025 to 30 June 2045) expected across the organisation as a result of implementing the proposed option.

[15] NPV of the proposal over 20-year cash flow period (1 July 2025 to 30 June 2045), based on discount rate of 4.05%.

[16] Present value (PV) of the costs over 20-year cash flow period (1 July 2025 to 30 June 2045), based on discount rate of 4.05%.

[17] Present value (PV) of the benefits over 20-year cash flow period (1 July 2025 to 30 June 2045), based on discount rate of 4.05%.

6 Revised expenditure forecasting approach

6.1 The structure of our overall approach

The expenditure forecasting methodology presented in our original proposal, as shown in Figure 1, has been adapted to address the concerns set out in the Draft Decision and supporting EMCa report. Our revised approach assesses N and N-1 (contingent) projects using a new two-step process outlined in Figure 2.

Figure 1: Expenditure forecasting methodology[18]

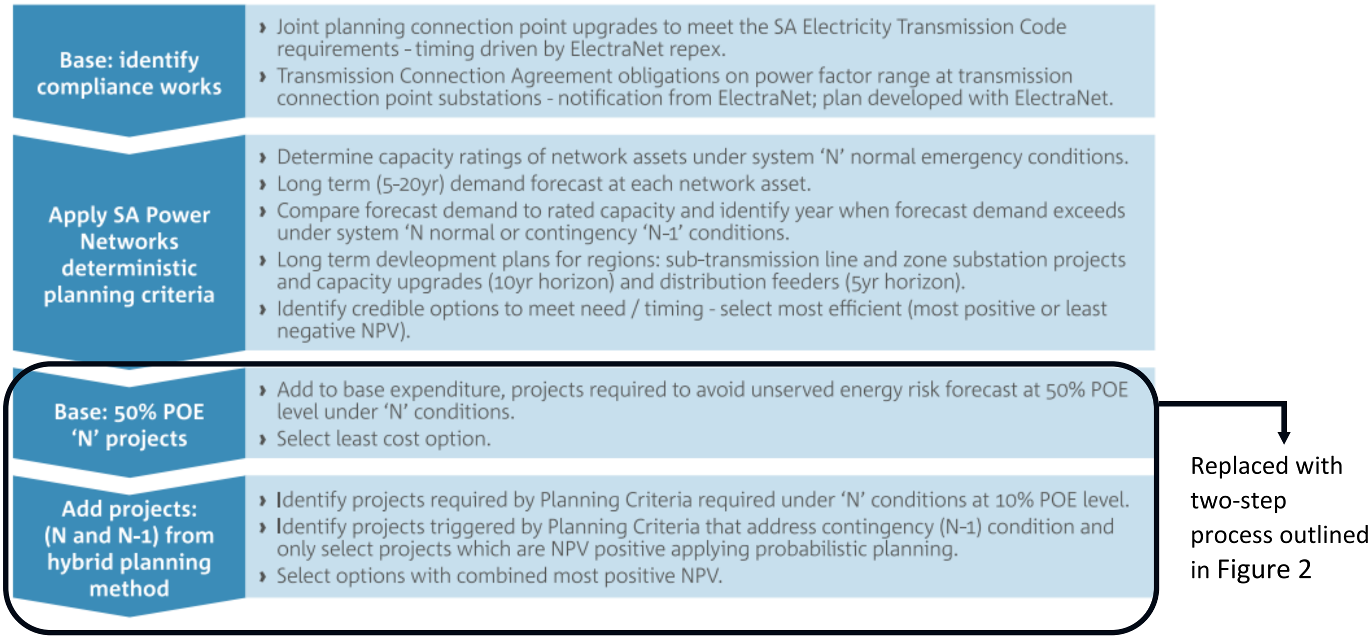
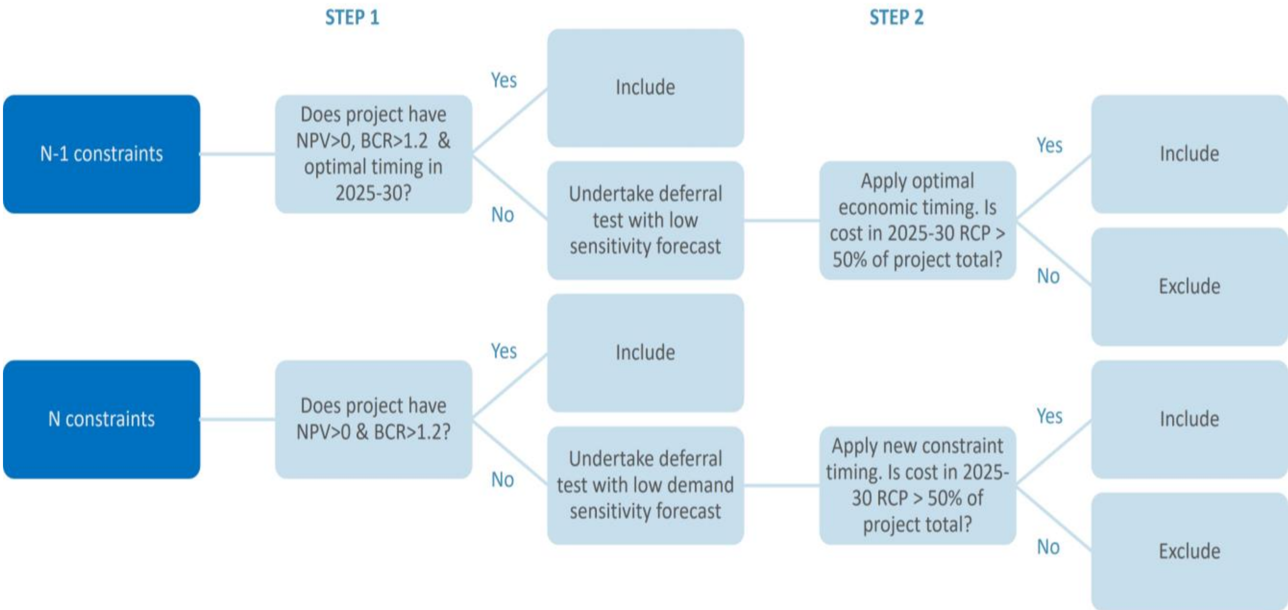


Figure 2: Representation of the two-step process for demand-driven projects.



[18] This was described in the capex attachment to our Regulatory Proposal. SAPN, *Attachment 5 – Capital Expenditure: 2020-25 Regulatory Proposal*, January 2024, p.36.

Our revised project selection approach involves the following:

- it adopts the optimal timing methodology outlined in the AER Industry Practice Application Note - Asset Replacement Planning[19] for N-1 constraints;
- to enhance the economic assessment of project timing, we conducted both NPV analysis to determine overall efficiency with respect to consumer benefits versus costs, and Benefit-Cost Ratio (BCR) analyses to determine the optimal efficiency of project timing;
- a two-step project selection process was implemented to address potential variances in critical factors like demand forecasts and costs. Specifically, for projects where the BCR is below 1.2, we applied a second layer of scrutiny—deferral test under scenario of low demand, set at 80% of the forecast growth derived from the ISP 2024 (see 6.5 for further detail), to confirm the necessity of proceeding with the investment during the current regulatory period; and
- this rigorous evaluation ensures that our capex decisions are resilient to fluctuations in cost and discount rates, thereby safeguarding the integrity of our project selection process.

6.2 We incorporated our most recently available information to forecast demand

The Draft Decision considered that we should seek to update our demand forecast to make use of the latest available information, noting that our original business case was based on AEMO demand forecast inputs from 2022.

We accept the need to make use of latest available and prudently usable information and have therefore:

- updated our demand forecasting to integrate the latest information to enhance the accuracy of our expenditure forecast;
- specifically, we have integrated the growth rates from the AEMO ISP 2024, which represents the most up-to-date and detailed forecast available, and prudently usable information, for the purpose of our bottom-up planning and expenditure forecasting;
- while we considered making use of growth rates from the AEMO ESOO 2024, we concluded it would be imprudent to incorporate these inputs instead of the AEMO ISP 2024 inputs on the basis that:
    - the length of time required for full bottom-up incorporation, validation and testing, into the vast number of capacity projects, made the use of the ESOO 2024 inputs impractical and susceptible to risk of error;
    - we noted a lack of transparency in the justification for the latest trend predictions in the ESOO 2024, such that that the use of the AEMO ISP 2024 inputs represented a more complete and rigorous approach by which to base network planning decisions on, given this the explicit purpose of the ISP forecasts (that is, it ensures alignment between transmission and distribution network planning); and
    - based on our concerns, we sought the advice of independent forecasting experts, Endgame Economics who advised us that it would be most prudent to base our network investment decisions for the 2025-30 RCP on the AEMO ISP 2024 inputs[20] – their justification is provided in their report, attached as a supporting document to this addendum.

[19] AER, *Industry Practice Application Note – Asset Replacement Planning*, July 2024, p.g.36

[20] Endgame Economics, *Demand Forecast Review*, 2024.

6.2.1 Independent expert advice on the prudent choice of demand forecast inputs

To guide or decision on the demand forecast inputs to base our network planning decisions on, we sought the independent advice of forecasting experts, Endgame Economics. Their analysis identified significant concerns with the ESOO 2024, particularly the absence of crucial updates and the presence of unexplained inflection points that deviate from expected sector trends. This assessment reinforced our decision to rely on the ISP 2024 for our demand forecasting.

A comparative analysis between the ESOO 2024 and ISP 2024 forecasts highlighted a marked discrepancy, particularly a downward trend projected by the ESOO circa 2028, depicted in Figure 3. The component which contributes most to this discrepancy is the residential and business component, shown in Figure 4.

Endgame Economics suggested that the ESOO 2024 forecast may lack the comprehensive rigor found in the ISP, leading to potential gaps in data and an unanticipated and unexplained shift in forecast trajectory.

Figure 3: Forecast maximum demand comparison between the ISP 2024 and ESOO 2024.[21]

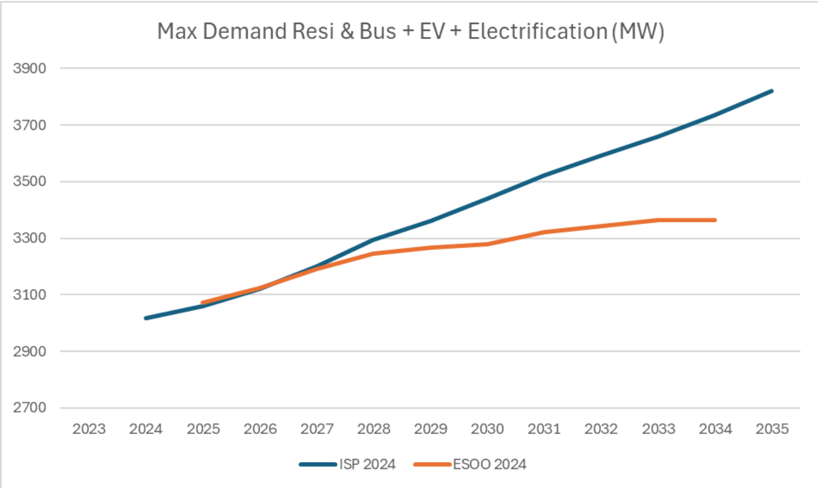
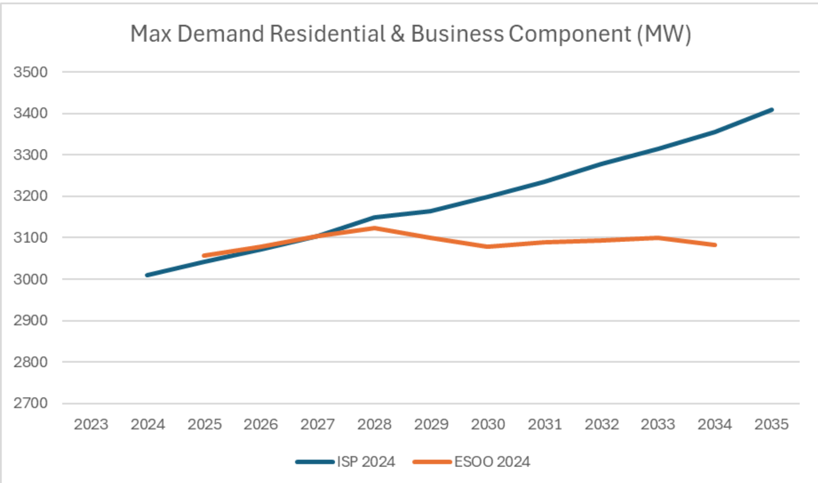


Figure 4: Forecast maximum demand residential and business component comparison between the ISP 2024 and ESOO 2024.[22]



[21] AEMO, data extracted from Electricity Forecasting Data Portal, South Australia Residential & Business, Electric Vehicles, and Electrification, available at: https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/electricity-forecasting-data-portal.

[22] AEMO, data extracted from Electricity Forecasting Data Portal, South Australia Residential & Business component only, available at: https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/electricity-forecasting-data-portal.

6.3 Our block load adjustments do not overstate forecasts

The Draft Decision identified concerns that our block load adjustments may lead to forecast duplication and over-estimation and required that we demonstrate that this is not the case.

We accept that the information we provided in our original business case insufficiently explained our approach. However, we remain of the view that our approach is reasonable and does not drive over-estimation. We have implemented the following to demonstrate that our block load adjustments are both accurate and conservative:

- **independent Review by Endgame Economics:** to ensure and demonstrate the accuracy of our block load adjustments, we sought an independent review by forecasting experts Endgame Economics, which confirmed the robustness of our methodology and suggested some improvements that we have implemented. Refer to section 6.3.2 for details;
- **removed BESS Adjustments**: in line with Draft Decision, we excluded BESS loads from our forecasts, acknowledging that they are unlikely to contribute to peak demand; and
- **reconciliation to AEMO forecast**: Endgame Economics undertook an independent review of the reconciliation with AEMO's forecast to confirm that there is no material duplication or overestimation of block loads.

Evidence Supporting Our Approach:

- **Endgame Economics Review**: Confirmed that our revised methodology prevents duplication and overestimation;
- **AEMO's last request**: Noted that AEMO had not requested block load information for new block loads since early 2023, validating our inclusion of new block loads; and
- **materiality threshold analysis**: Endgame Economics advised against using a 5% system-wide threshold, which would be excessive, and instead recommended a more granular approach at the connection point level.

6.3.1 Application of materiality threshold

The Draft Decision identified the need for a more nuanced application of materiality thresholds to avoid overestimation. We accept that our original business case may have provided insufficient information justifying our approach.

In response we engaged Endgame Economics to review our block load forecasting approach (5% of a connection point as a threshold), to determine if block loads should be included in the system forecast. Endgame Economics concluded that *5% of a connection point* as a threshold is a significant amount and, in some cases, greater than 10MW which is AEMO's threshold. Endgame Economics also recommended against the AER's suggestion of using *5% of the total system* as a threshold, as it would be 152 MW which is extreme for a load connecting to a distribution network.

Therefore, to ensure that only block loads that are truly material and not already accounted for in the system demand forecast, Endgame Economics recommended that we should:

- refrain from accumulating block loads before assessing against the 5% materiality threshold at the Connection Point level;
- remove residential new loads from the system forecast and instead add them to the bottom-up zone substation and connection point level; and
- conduct sensitivities to investigate the probability of block loads entering and the impact of delays.

Consistent with these recommendations, we developed a method ensuring only block loads that are truly material and not already accounted for in the system demand forecast are included.

6.3.2 Customer requested loads

The Draft Decision sought further demonstration that we consider the potential for customer requested loads to be over-estimated by considering the likelihood of projects not proceeding. We accept that our original proposal provided insufficient information in this regard.

Therefore, in response to the Draft Decision, we undertook the following:

- we revaluated the potential for overestimations in customer-requested loads, the likelihood of projects not proceeding, and the impact of new loads on seasonal and system peak times;
- we employed Endgame Economics to review our approach, and informed by their findings, we developed a 'slow uptake base assumption' to account for the variability in project progression and customer demand, as illustrated in Table 7. This assumption is applied within the Capacity Augex Tool by incorporating 80% of the block load (applied after the diversity factor, which is used in the forecasting process) with a 2-year connection delay; and
- these considerations are integrated into our revised demand forecast and expenditure forecast, ensuring our forecasts reflect reasonable and realistic demand expectations.

Table 7: Slow Uptake base assumption adjustment

Committed load	Diversity factor applied	Adjustment within the Capacity Augex Tool	Resultant slow uptake sensitivity applied
Industrial load 2MVA, 2025	70%	80% + 2yr connection delay	1.12MVA, 2027

6.4 We have selected projects based on optimal economic timing

The Draft Decision considered that we had not applied economically optimal timing in selecting some of our demand driven projects. We accept that the approach we applied to our original business case could be enhanced and also better explained.

Therefore, in response to the Draft Decision we implemented several changes to our approach and presented an 'enhanced hybrid planning' approach to our demand driven augex. This ensures that each project undergoing a probabilistic assessment (N-1 constraint projects) also undergoes an evaluation to determine its economically optimal timing, ensuring that capital investments are made when they are most needed and efficient.

6.4.1 Optimal project timing methodology

To address the AER's concerns, we added steps to our project selection criteria to test the robustness of marginally positive probabilistic projects.

Our modelling for probabilistic projects now clearly demonstrates adherence to the methodology outlined in the AER Industry Practice Application Note - Asset Replacement Planning.[23] Our process is as follows:

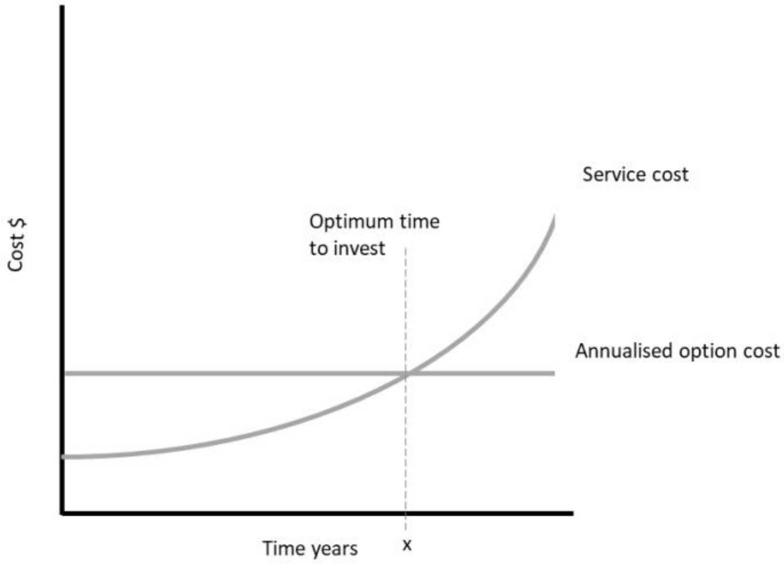
[23] AER, Industry practice application note, Asset replacement planning, p.g.36

1. Calculate the annualised option cost using equivalent annual cost (EAC) formula:

$$EAC = \frac{Asset\ Price * Discount\ Rate}{1 - (1 + Discount\ Rate)^{-asset\ life}}$$

2. Calculate the cost to customers by valuing energy at risk with a suitable VCR value (shown as 'Service Cost' below).

3. Investing in the first period where the cost to customers exceeds the EAC, a graphic example is below[24]:



Optimal project timing is determined for all projects, but is only used for N-1 constraint projects. For N constraint projects, which are treated deterministically (and this approach has not been challenged by the AER or EMCa), projects are timed such that they are complete by the first year in which there is load at risk.

6.4.2 Project Selection Methodology

Our methodology for determining the timing of projects involves a comprehensive analysis that considers both the cost of delaying a project against the potential risks and the benefits of proceeding. This analysis is underpinned by the following steps:

- detailed demand forecasting to predict when network constraints will arise;
- application of the NPV and BCR analyses to assess the economic efficiency (benefits relative to costs) as well as the economically optimal timing modelling described above; and
- implementation of a two-step deferral test, for projects with a BCR less than 1.2 (which aligns to the recommendation of EMCa as reflecting good practice in accounting for minor variations in demand or cost), to ensure robustness against demand variability for projects with low levels of load at risk.

The application of our economic timing methodology has been documented in our Capacity Augex Tool along with the NPV, BCR and deferral test assessments. This tool provides a transparent audit trail, demonstrating the cost-benefit analysis for each project and the resulting decision on timing. Projects that do not meet the economic criteria for immediate investment are considered for deferral.

[24] AER, Industry practice application note, Asset replacement planning, p.g.36

6.4.3 Manual Deferral of Projects

In addition to the formulaic project timing and selection methods described above, some N constraint projects with high cost and/or low load at risk have been manually deferred, reducing expenditure in the RCP. This addresses EMCa's feedback that "The 10% PoE deterministic criterion is an adequate 'first step' filter but we consider it is not appropriate to apply it mechanistically as a determining selection criterion"[25] as "load found to be 'at risk' under this approach may be extremely small within the next RCP even to the extent that the NPV for the project may not be positive for many years"[26] and their suggestion to apply "prudency cross-checks of all projects selected using the N/10 PoE criterion"[27].

Projects manually selected for deferral are done so on the basis of balancing network risk, project cost and customer outcomes, and also considering the potential for alternative solutions to adequately defer the project to the following RCP. These projects are shown below in Table 8, resulting in a total cost deferral of $16.7 million to the following RCP.

Table 8: Manually Deferred Projects

Project	Cost ($m)	Peak Load at risk in 2025-30 RCP (MVA)	N Constraint Year	Deferred Completion Year	Resultant Cost in RCP ($m)
Morgan 66/11kV Substation Upgrade	$2.3	0.01	2029	2031	-
Portee sub upgrade	$2.0	0.03	2028	2031	-
Qualco sub upgrade	$2.5	0.09	2029	2031	-
Mount Barker East new sub[28]	$16.5	2.42	2026	2031	6.6

6.4.4 Project-Specific Justification Documents

For projects exceeding a threshold of $4 million, we have developed detailed individual project justification documents that articulate the need, the demand forecast, optimal timing calculations, project costs, and other contextual information. This ensures that each significant investment is scrutinised and justified on its own merits, in line with regulatory expectations and best industry practices. Higher level details are provided for all projects in the Capacity Augex Tool[29].

25 EMCa, *SAPN 2025/26 to 2029/30 Regulatory Proposal, Review of Aspects of Proposed Proposal Expenditure*, p.g.50
26 EMCa, *SAPN 2025/26 to 2029/30 Regulatory Proposal, Review of Aspects of Proposed Proposal Expenditure*, p.g.50
27 EMCa, *SAPN 2025/26 to 2029/30 Regulatory Proposal, Review of Aspects of Proposed Proposal Expenditure*, p.g.50
28 SA Power Networks, 5.4.2.2. Project Justification: Mount Barker East New Substation, December 2024, p.g.7
29 SA Power Networks, 5.4.2.5. Augex Capacity Reset Tool, December 2024

6.4.5 Summary of Program Selection

Our revised approach has led to a refined list of projects selected as being prudent and efficient to undertake in the 2025-30 RCP. This list has been compared against the projects that the Draft Decision and EMCa report identified as candidates for potential deferral. The outcome is a balanced capital works program that aligns with the most current and accurate demand forecasts, ensuring that we invest responsibly and in accordance with the economic timing principles. For a detailed breakdown of the projects, please see Table 12 in Appendix 2.

The updates to the demand forecast and changes to our expenditure timing methodology have resulted in several significant projects either reducing in expenditure or removed entirely from our proposed expenditure forecast, compared to our original submission. A summary is provided in Table 9 of those projects with a net reduction greater than $1 million.

Table 9: Projects with a net reduction greater than $1 million that were excluded from our revised proposal

Project	Category	Net Reduction in revised proposal ($m)	Reason for exclusion or reduction
Virginia sub upgrade	Substation	6.9	Implementation of optimal timing and demand forecast reduction
Nairne sub upgrade	Substation	4.6	Demand forecast reduction
Northfield sub upgrade	Substation	8.2	Demand forecast reduction and block load sensitivity applied
Kingston SE sub upgrade	Substation	1.5	Demand forecast reduction
Square Waterhole new Sub	Substation	7.0	Implementation of optimal timing and block load sensitivity applied
Clarence Gardens-Tee new 66kV line	Subtransmission	9.0	Implementation of optimal timing
Athol Park-Woodville new 66kV line	Subtransmission	12.8	Implementation of optimal timing and demand forecast reduction
Hatherleigh-Robe #2 33kV line	Subtransmission	10.6	Replaced with Robe BESS project
Pinnaroo 3MVAr StatCom Project	Subtransmission	1.0	Replaced with Lameroo BESS project
Mannum Connection Point Upgrade	Connection Point	7.4	Project brought forward into 2025-30 RCP due to ElectraNet timing.

6.5 Our proposed projects have been subject to sensitivity analysis

The AER's Draft Decision identified a concern that further analysis was needed to test the sensitivity of project forecasts to ensure they are robust and that proposed expenditure is truly needed in the 2025-30 RCP. We accept that our approach to sensitivity analysis could be enhanced.

Therefore, we responded to the AER Draft Decision by undertaking the following:

- addition to NPV analysis, we conducted BCR analysis, to inform the economically optimal timing of projects;
- we implemented the two-step project selection approach outlined in Section 6.1 for those projects susceptible to small variances in key inputs such as the demand forecast or cost;
- to ensure the robustness of proposed expenditure we have completed deferral tests (step 2) using a low demand sensitivity on projects with a BCR less than 1.2 – implementing the sensitivity approach that was recommended by EMCa as reflecting good practice; and
- the low demand sensitivity is applied within the Capacity Augex Tool using 80% of the central ISP 2024 forecast.

Table 10 illustrates how our two-step process is applied in developing the capacity augex program. This approach has demonstrated that variations in cost and discount rates do not significantly affect the selection of projects.

Table 10: Two-step process for developing the capacity augex program, $m

Expenditure Category	**Constraint-driven capex[30] accepted as part of Step 1**	**Capex assessed as part of deferral test Step 2**	**Capex included i.e. Pass of Deferral Test**	**Total constraint-driven capex**
Substation	$21.4	$23.2	$18.6	$40.0
Distribution (11kV and 7.6kV)	$12.5	$0.6	$0.4	$12.9
Sub-transmission	$18.5	$2.7	$1.7	$20.3
Total	**$52.4**[31]	**$26.6**[32]	**$20.7**[33]	**$73.1**[34]
No. Projects	43	9	4	47

For a detailed breakdown of the outcomes of the deferral test at a project level, please see Table 13 in Appendix 3.

In addition, EMCa suggested some deterministic N constraint projects with minimal load at risk could be delayed by marginally overloading assets beyond their capacity. In response we consider that:

- loading assets beyond their cyclic rating under normal conditions is not in line with good industry practice as it reduces asset life, increases the risk of asset failure, increases fire-start risk and (in the case of overhead conductor) increases safety risk to the public; and
- however, we believe that the use of our proposed two-step project selection process addresses this concern by ensuring that projects with minimal load at risk are only included if they withstand variances in demand forecast assumptions, and additionally manually excluding some N constraint projects on the basis of low load at risk, as identified in Section 6.4.3.

30 Constraint-driven capex refers to the demand-driven expenditure from projects driven by forecast energy at risk under network normal or contingency scenarios.

31 $52.4M represents expenditure associated with those projects that passed step 1 and automatically included in our revised proposal.

32 $26.6M represents expenditure associated with those projects identified as needing to undergo the deferral test in step 2.

33 $20.7M represents expenditure associated with those projects that passed the deferral test and would be included in the revised proposal.

34 $73.1M represents the total expenditure associated with those projects that passed either step 1 or step 2 tests and would be included in the revised proposal.

6.6 We have considered available alternatives to capacity augmentation

The Draft Decision sought further demonstration that the identified needs for our demand-driven capacity augex cannot be addressed via other means that can avoid or mitigate building more network. We accept that our original business case may have provided insufficient information on how we consider alternatives.

Therefore, in response to the Draft Decision, we evaluated, and better explained our approach to evaluating, alternatives to network augmentation to ensure that investments are justified and represent the most efficient solution for our customers. This is summarised in the sections below and further detailed on a project specific basis in our project justification documents for significant investments (exceeding $4 million).

6.6.1 Demand Management and Non-Network Opportunities

SA Power Networks is dedicated to rigorously exploring and evaluating non-network solutions and flexible load connections as effective strategies for managing the increasing demand on our network. We acknowledge that alternative solutions can provide a more cost-effective approach or deliver broader benefits to the electricity market, including end consumers. We evaluate all options, both network and non-network, using identical criteria that reflect both the regulatory requirements under the NER RIT-D process and our desire to implement the least cost solution to resolve the identified need.

6.6.2 Approaches to Non-Network Solutions

Our exploration of non-network solutions encompasses a variety of strategies, including but not limited to:

- **peak lopping:** using embedded generation or storage to alleviate demand on the network during peak times;
- **consumption shifting:** encouraging the shift of energy usage to off-peak periods to balance network load;
- **energy efficiency:** working with customers to enhance energy efficiency and reduce overall consumption;
- **Power Factor Correction:** improving the power factor to optimise the quality and efficiency of the power supply.
- **demand curtailment:** Agreeing with customers to curtail demand during peak periods to manage network load; and
- **Network System Support Agreements (NSSAs):** Collaborating with customers to create or amend NSSAs that enable generation or load curtailment on demand.

6.6.3 Technology trials and evaluations

We actively trial and evaluate emerging demand management technologies to identify economically viable opportunities to improve the levels of network security and reliability provided to customers and to reduce the costs of providing standard control services. The technologies investigated include the use of smart meter data and services, transformer monitoring, energy storage, dynamic voltage management and direct communication with customer devices such as air conditioners, electric vehicle chargers, smart hot water systems, solar and battery inverters and Home Energy Management Systems (HEMS).

6.6.4 Economic viability and technical feasibility

As demand side initiatives become more economically viable and technically feasible, particularly those that allow for dispatchable load curtailment, we anticipate a reduction in peak demand that could defer the need for certain capital augmentation projects. Demand management solutions will be adopted when they are proven to be cost-effective, technically sound, and can be implemented swiftly enough to address the identified network constraint. The savings from deferring traditional network solutions are considered alongside the costs associated with implementing demand management solutions, which typically include initial capital outlay and ongoing operational expenses.

6.6.5 Strategic approach to alternative network solutions

Our strategic approach is anchored in the proactive exploration of alternatives to network augmentation. We are committed to identifying and implementing cost-effective and innovative solutions that align with the evolving needs of our network and our customers. Our goal is to ensure that network augmentation is considered only after a comprehensive evaluation of all viable alternatives, ensuring the most beneficial outcome for all stakeholders.

Key non-network solutions considered:

- **Network Support Agreements (NSSAs):** we successfully utilised NSSAs to manage demand and defer network augmentation. Notable examples include the extended NSSA in Bordertown and the new demand management solution established in the Tailem Bend region in 2023;
- **community battery initiatives:** our revised proposal includes the implementation of Network Support Community Batteries in Robe and Lameroo, which are instrumental in deferring significant network investment; and
- **Lower-cost network investments:** we strategically invest in lower-cost network projects as a deferral mechanism to postpone higher-cost network investments.

Evidence of Consideration:

- **Expression of interest (EOI) process and insights:** The 2023 EOI for Non-Network solutions process has yielded valuable insights, particularly highlighting the potential of network support batteries for peak lopping in regions such as Tailem Bend, South East, and Bordertown.
- **Network support battery limitations and opportunities:** Most of the non-network solutions proposed via our EOI process involve using BESS for peak lopping. While these systems are effective in alleviating network constraints, they have inherent limitations in storage capacity, making them economically viable only up to a certain scale. The capacity to charge these batteries from the network is often constrained by the same network limitations they are designed to mitigate, which can restrict the potential for additional revenue through other market mechanisms, thus affecting their service offering and financial viability. Despite these challenges, our analysis has shown that a network support BESS can address certain energy supply issues and potentially delay the need for substation upgrades. However, the substantial capital investment required for these systems often renders them less economically feasible than traditional network options. Nonetheless, the feasibility of a large network support BESS has been thoroughly tested to determine its role in deferring network investment and inform the selection of the preferred option for each demand-driven network constraint.
- **Community battery initiatives:** Leveraging nation-wide funding from the Australian Renewable Energy Agency (ARENA), we will be commissioning Network Support Community Batteries in Robe and Lameroo. This initiative has allowed us to reduce our forecast expenditure by providing an alternative solution that defers the need for significant network investment in these regions.

- **Demand Flexibility:** this project, which has been approved in the Draft Decision for 2025-30, reflects our nation leading commitment to exploring the potential to extend the capabilities and functions we currently have for flexibly managing demand for export services on our network, to also flexibly manage demand for load services on our network, thereby improving network utilisation and minimising future augmentation;
- **Innovation fund initiatives:** our proposed Innovation Fund for 2025-30 will allow us to be at the forefront of exploring new technologies and market models to unlock greater flexibility in Customer Energy Resources and customer loads in addition to export, with view to proving the viability of solutions which can help to materially mitigate the need for additional capacity in the network in coming years arising from electrification and continued connection of distributed renewables.

6.6.6 Reducing Network Investment for the 2025-30 RCP

To optimise network investment, we considered and implemented lower-cost network projects that serve as effective deferral mechanisms for more substantial network investments. For instance:

- **deferral of substation upgrades:** by establishing a new 11kV feeder out of Morphettville Substation, we have proposed to defer the need for the Ascot Park Substation upgrade, which has a forecast N and N-1 constraint in the 2025-30 RCP;
- **deferral of new substations:** by proposing the conversion of SD523 33kV line and feeder extension out of Gawler Belt substation to address a feeder N constraint on the GA25 feeder, we have proposed to defer the need for the new Concordia Substation and $19.8M of expenditure, beyond the 2025-30 RCP. Similarly, to defer the need for the new Mount Barker substation, we have proposed to construct a new MTB16 feeder, which mitigates a feeder N constraint and defers the need for the new substation partly beyond the 2025-30 RCP, deferring $9.9M of expenditure outside the RCP.
- **included lower-cost network projects:** lower-cost network projects that have successfully deferred the need for higher-cost network investment, such as the Network Support BESS projects at Robe and Lameroo, which has displaced higher cost sub-transmission projects and resulted in cost savings of $10.6m and $1.4m respectively.

These initiatives highlight our proactive approach to network management and our commitment to delivering cost-effective solutions that serve the best interests of our customers and the broader NEM.

6.6.7 How we determine the ‘preferred’ solution

The selection of the ‘preferred’ solution is influenced by factors such as:

- major project cost variations;
- major new or increased customer connections;
- possible Demand-Side Participation (DSP) options;
- new third party embedded generation;
- performance of preliminary RIT-Ds to determine the market benefits associated with both network and non-network solutions;
- results of formal public consultations such as Regulatory Investment Tests (both RIT-D and RIT-T) or third-party approvals (e.g. SCAP) which may affect the solution’s costs (e.g. overhead conductors versus underground cables);
- changes in forecast demand;
- long term master plan for the region; or
- economic evaluation of technically feasible solutions.

The process involves understanding the available solutions their associated cost. The following are general examples of solutions considered (for the HV network), which may be necessary to meet increasing demand on our network and alleviate network inadequacies and constraints, assuming all other deferral options utilising the existing network (e.g. load transfers and dynamic and responsive solutions such as flexible load management utilising Dynamic Operating Envelopes) have been exhausted:

- establish new, upgrade or up-rate[35] existing sub-transmission lines;
- establish new or upgrade existing high voltage distribution feeders;
- upgrade existing zone substations (e.g. add or upgrade existing transformers);
- establish new zone substations;
- improve power factor through capacitor installation, either to reduce substation demand, improve system voltages or improve power factor at the connection point level to comply with the NER requirements;
- install reactor or STATCOM to improve system voltages or improve power factor to comply with the NER requirements;
- install in-line voltage regulators to improve system voltages;
- upgrade existing or establish new connection points in consultation with ElectraNet;
- establish new generation stations to provide network support;
- implement non-network solutions such as load curtailment, third party generation proposals;
- DNSP-led SAPS (Stand-Alone Power System) solutions; or
- DNSP-led Network Support Community Batteries (with relevant exemptions in place).

Where there are multiple options available, we aim to consider at least one 'non-traditional' solution (e.g. Network Support Community Battery or third-party generation via a Network Support Service Agreement) in addition to one or two technically feasible network solutions.

In addition, all projects estimated to cost above the RIT-D threshold, in accordance with section 5.17 of the NER, where it is determined as a result of the Screening Test that publication of an Options Screening Report (OSR) is warranted, an OSR is created and issued for public consultation seeking alternative solutions to remedy the identified network constraint.

Demand management initiatives have a limited potential to impact on our 2025-30 expenditure forecast, especially given our performance of preliminary RIT-Ds, where only one or two of which have historically suggested the adoption of a non-network solution as being economically viable and with few (if any) proposals being submitted. Furthermore, any successful demand management initiative is not expected to permanently eliminate the need for network reinforcement projects but rather defer them for some period of time (typically 1 – 10 years). As discussed above, our goal through initiatives such as 'Demand Flexibility' and our proposed 'Innovation Fund' is to increasingly unlock in coming years, greater potential for flexibility on the customer side, though their customer energy resources (CER), their agents, and new marketplaces, to elicit greater responses including by energy services providers. However, we consider that these initiatives are unlikely to deliver sufficient scale to materially defer any augmentation projects over the 2025-30 period.

[35] The term "up-rate" relates to the alteration of the overhead conductor's design temperature in order to increase the rating of the *line* or *feeder*.

6.6.8 Evidence of avoided network expenditure

There are several sub-transmission lines, zone substations and 11kV feeders that are forecast to be overloaded where we consider it prudent and efficient to monitor and perform load transfers (network configuration changes) to defer the need for major upgrades. We have thus excluded any expenditure from our capacity augex forecast. Details of the load monitoring and transfer program are set out in Table 11.

Table 11: Load transfers and monitoring program

Constrained Asset	Limitation	Constraint (MVA)	Year of Constraint
Clearview Substation 11kV	N Overload	0.77	2024/25
Cordola 11kV feeder	N Overload	0.19	2024/25
Loxton North 11kV feeder	N Overload	0.19	2024/25
Port Clinton 11kV feeder	N Overload	0.02	2026/27
Littlehampton 11kV feeder	N Overload	0.08	2025/26

Note that this list only includes constraints where augmentation projects have not been identified and are therefore not considered in the range of potential projects to include in this Revised Proposal, i.e. our probabilistic approach defers significant expenditure related to load at risk that will continue to be monitored, but is not presented in this table.

Appendix 1: Assumptions

The following assumptions have been made in determining the NPV analysis. For further information on how these assumptions are applied, see the Capacity Augex Tool Guide.

- **Discount Rate:**
  - A Central Discount Rate of 4.05% has been used.
- **Demand Forecast:**
  - Both 10% PoE and 50% PoE forecasts are used to identify constraints.
  - Where a 10% PoE or 50% PoE forecast is not available, this forecast is estimated based on a 10% PoE to 50% PoE ratio of 1.10.
- **Avoided involuntary load shedding:**
  - Involuntary load shedding occurs when a customer's load is interrupted from the network without warning or their agreement. This can occur due to unavailability of network elements and the resulting reduction in network capacity to supply the load.
  - The unserved energy (USE) is the probability weighted average amount of load that customers request to utilise but would need to be involuntarily curtailed due to loss of network connectivity or a network capacity limitation. We forecast load over the assessment period and have quantified the USE by comparing forecast load to network limits under normal (N) and contingency (N-1) conditions. A reduction in involuntary load shedding results in a positive contribution to market benefits of the credible option being assessed.
  - In practice, SCADA-controllable devices would be used by network controllers to perform involuntary load shedding. The USE has been quantified using the number of SCADA devices to determine the granularity of load shedding (e.g. if a Feeder has 3 SCADA midline devices, load shedding will occur in increments of quarters).
  - The market benefit that results from reducing the involuntary load shedding with a network solution is estimated by multiplying the quantity of USE in MWh by the VCR. The VCR is measured in dollars per MWh and is used as proxy to evaluate the economic impact of USE on customers.
  - VCR has been calculated on a site-specific basis for each constraint based on the affected customer type and locality, with values based on the 2022 VCR Annual Adjustment[36].
  - The VCR rates used in the tool apply the same probability weighting methodology used in the AER's headline VCR figures but have been adjusted to better reflect the outage timing and duration characteristic of a network capacity outage.
  - We assumed outages that our peak events will occur in the peak load period on a weekday, in summer. As this corresponds to the highest load on our network. An exception is made for 66kV line projects and projects where load shedding occurs at less than 60% of the load forecast, which use the 'normal' VCR value.
  - We assumed that outages will be shorter than 6 hours for each customer. As per our load shedding procedures we rotate outages to limit the impact of power loss on individual customers. We do not expect power loss for individual to customers to exceed 6 hours during a peak demand event.
  - Although the assessment period for the economic analysis is 20 years, the amount of additional USE per year does not grow beyond the 10th year.
- **Load Duration Curve:**

[36] AER, VCR Update Annual Adjustment, 2022 available at Update - Annual adjustment | Australian Energy Regulator (aer.gov.au)

  - Load duration curves have been calculated using 5 years of measured data (2017-2022) for each specific project. The underlying demand (without customer energy resources) has been estimated using site-specific solar PV estimations applied to the time series data. As such, the resulting load duration curves reflect a 5-year period of underlying demand.
  - USE is derived by applying the ratio of the constraint rating against the forecast peak to the normalised load duration curve.

- **Load shedding forecast scenarios**
  - For all constraints where avoided load shedding is modelled, the value of USE is determined under both 10% PoE and 50% PoE conditions. The resulting value of USE is apportioned based on the following ratios:

	Forecast Proportions
10% PoE	0.3
50% PoE	0.7

- **Likelihood of Failure:**
  - Feeder exit failure rates are derived based on historic failures of both feeder exit cables and feeder circuit breakers. This is calculated based on the following:
    - Number of faults (2010-2022) = 97 = 7.46 faults per year
    - Number of feeder exits = 657
    - Feeder CB Failure Rate = 0.0033

$$Fault\ Rate\ (pa)_{Feeder\ Exit} = \frac{Faults\ (pa)}{No\ of\ feeder\ exits} + CB\ Failure\ Rate = 0.0147$$

  - A simplified 66kV overhead line faults per km per annum factor is used to estimate the expected likelihood of an unplanned 66kV line outage upon critical sections of sub-transmission lines, as outlined in the table below:

	Overhead	**Underground**
Metro 66kV	0.011	0.010
Country 66kV	0.006	N/A
33kV	0.048	0.014

  - For both SA Power Networks and ElectraNet substation transformers, a fault rate of 0.02 pa has been used. This reflects a one in 50-year failure rate.

- **Distribution Loss Factor:**
  - A distribution loss factor (DLF) is applied to the estimated USE to account for network losses.
  - For all constraints, a DLF of 1.107 is used. This reflects the published SA Power Networks 2022/23 DLF for low voltage small customers.

- **Terminal Value:**
  - Project benefits are made up of both VCR (detailed above) and asset terminal value. Terminal value assumes linear depreciation over the asset life, which is assumed to be 20 years for BESS and 40 years for other assets. Terminal value is applied as a benefit in the last period in the analysis period, according to the following:

$$Terminal\ Value = Remaining\ Asset\ life\ (\%) \times Asset\ Cost$$

Appendix 2: Project Summary

Table 12: Summary of Projects Included

Project	Constraint	Criteria for Inclusion	Capex - 25-30 RCP	Design Year / Construct Year
		Connection Point		
		AUG001: Connection Point Capacity Augmentation (ETC/NER) - Resulting from ElectraNet Works		
Tailem Bend 33kV CP Upgrade and Segregation	Mandatory Project	Compliance	$6,695	2026 / 2027
Mount Gambier CP Upgrade	Mandatory Project	Compliance	$1,361	2028 / 2029
Balhannah 66kV Reactor	Mandatory Project	Compliance	$3,176	2026 / 2027
Cheltenham 66kV Reactor	Mandatory Project	Compliance	$3,448	2028 / 2029
Elizabeth South 66kV Reactor	Mandatory Project	Compliance	$3,448	2028 / 2029
Magill 66kV Reactor	Mandatory Project	Compliance	$3,448	2027 / 2027
Morphett Vale East 66kV Reactor	Mandatory Project	Compliance	$3,448	2027 / 2028
Northfield 66kV Reactor	Mandatory Project	Compliance	$3,448	2026 / 2026
Norwood 66kV Reactor	Mandatory Project	Compliance	$3,448	2029 / 2030
Port Noarlunga 66kV Reactor	Mandatory Project	Compliance	$3,448	2029 / 2030
Renmark 11kV Reactor	Mandatory Project	Compliance	$1,588	2029 / 2030
Salisbury 11kV Reactor	Mandatory Project	Compliance	$1,588	2027 / 2028
Victor Harbor 11kV Reactor	Mandatory Project	Compliance	$1,588	2026 / 2026
Willunga 66kV Reactor	Mandatory Project	Compliance	$3,267	2027 / 2027
	Subtotal		**$43,401**	
		Low Voltage		
		AUG002: LV & Distribution Transformers (QoS BAU) - LV augmentation expenditure (unrelated to reverse power flows)		
LV & Distribution Transformers	Mandatory Project	Compliance	$24,192	2025 / 2030
		AUG010: LV & Distribution Transformers (QoS BAU) - LV augmentation expenditure (unrelated to reverse power flows)		
LV Two Way Network	Mandatory Project	Compliance	$11,587	2025 / 2030

	Subtotal		**$35,779**	
		Distribution (11kV and 7.6 kV)		
		AUG003: Distribution Feeder (11 & 7.6kV) Capacity Augmentation		
Brownhill 11kV SM411C Restring	N-1 Constraint	Demand	$50	2025 / 2025
Clapham 11kV Feeder Backbone Restring	N-1 Constraint	Demand	$50	2025 / 2026
Concordia GA745A Extension and SD523 Conversion	N Constraint	Demand	$1,430	2028 / 2028
Cowandilla 11kV Feeder Backbone Upgrade	N Constraint	Demand	$413	2025 / 2025
Diagonal Road 11kV SM216F Restring	N-1 Constraint	Demand	$61	2025 / 2026
Emmerson Drive 11kV NL115F Restring	N-1 Constraint	Demand	$179	2025 / 2026
Encounter Bay VH10-Victor Harbor West VH16 11kV Restring	N-1 Constraint	Demand	$59	2025 / 2026
Glenelg 11kV SM410B Cable Upgrade	N-1 Constraint	Demand	$100	2025 / 2026
Intertrip Pedlar Creek gen on Ochre 11kV NL544B	N-1 Constraint	Demand	$100	2026 / 2027
Loxton West LX51 11kV survey & upgrade	N-1 Constraint	Demand	$405	2025 / 2025
New 11kV Feeder from Kilburn Substation	N-1 Constraint	Demand	$438	2025 / 2025
New Happy Valley 11kV Feeder	N-1 Constraint	Demand	$3,346	2028 / 2029
New Kingswood 11kV Feeder Urrbrae	N Constraint	Demand	$1,358	2027 / 2027
New Morphettville 11kV Feeder Maxwell Avenue	N Constraint	Demand	$764	2027 / 2027
New Victor Harbor 11kV Feeder McCraken	N Constraint	Demand	$1,559	2026 / 2026
Ridleyton 11kV Feeder Backbone Upgrade	N Constraint	Demand	$138	2025 / 2025
Smithfield West New EL260E Feeder	N Constraint	Demand	$1,190	2028 / 2028
Somerton Park 11kV SM410D Restring	N-1 Constraint	Demand	$248	2025 / 2026
St Marys 11kV SM402D Restring	N-1 Constraint	Demand	$130	2026 / 2026
Tapleys Hill 11kV NL210B Cable Upgrade	N-1 Constraint	Demand	$152	2025 / 2026
Town Centre VH11-Victor Harbor West VH16 11kV Restring	N-1 Constraint	Demand	$50	2025 / 2026
Trott Park Feeder Backbone Restring	N Constraint	Demand	$266	2025 / 2026
Urimbirra VH15-Inman Valley VH17 11kV Restring	N-1 Constraint	Demand	$83	2026 / 2027

Victor Harbor West VH16-Inman Valley VH17 Restring	N-1 Constraint	Demand	$83	2025 / 2026
Westbourne Park 11kV SM179A Restring	N-1 Constraint	Demand	$220	2025 / 2025
Goolwa 11kV Feeder Exit Load Switches	Mandatory Project	Compliance	$50	2030 / 2030
Oaklands 11kV Feeder Exit Load Switches	Mandatory Project	Compliance	$150	2029 / 2029
	Subtotal		**$13,070**	
		Substation		
	AUG004: Strategic Network Capacity (Other) - Labour capitalization for long term planning and network architecture			
Design Work 2025-2030	Mandatory Project	Compliance	$16,334	2025 / 2030
		AUG005: Substation Capacity Augmentation		
Jervois Sub 2nd TF Upgrade	N-1 Constraint	Demand	$1,627	2025 / 2026
Mount Barker East new sub	N Constraint Manually Included	Demand	$6,609	2029 / 2031
Mount Barker New MTB16 Feeder	N Constraint	Demand	$1,522	2025 / 2026
Mount Burr sub upgrade	N Constraint	Demand	$392	2025 / 2025
New Morphettville Feeder for Ascot Park	N-1 Constraint	Demand	$685	2026 / 2027
Salisbury South new Sub & Line	N Constraint	Demand	$18,183	2028 / 2029
Smithfield West sub upgrade	N-1 Constraint	Demand	$6,858	2028 / 2029
Two Wells Substation Upgrade	N-1 Constraint	Demand	$3,691	2028 / 2029
FS Prelim Design - Substation Capacity 2025-2030	Mandatory Project	Compliance	$272	2025 / 2030
Lyndoch Substation Cable Replacements	Mandatory Project	Compliance	$699	2029 / 2030
		AUG008: Voltage Regulation - To maintain QoS within NER requirements		
Lameroo 11kV Reg	N Constraint	Demand	$389	2025 / 2026
		AUG009: Land - Substation capacity augmentation		
Concordia Land	Mandatory Project	Compliance	$1,000	2029 / 2029
Mount Barker East Land	Mandatory Project	Compliance	$2,000	2028 / 2028
Salisbury South Land	Mandatory Project	Compliance	$2,200	2025 / 2025
Sellicks Land	Mandatory Project	Compliance	$1,000	2029 / 2029
	Subtotal		**$63,461**	

		Sub-transmission		
		AUG006: Subtransmission Capacity Augmentation		
American River-Kingscote Tee 33kV Line Uprate	N Constraint	Demand	$998	2025 / 2026
Angle Vale - Virginia Meshing	N-1 Constraint	Demand	$2,336	2025 / 2026
Athol Park-Woodville new 66kV line	N-1 Constraint	Demand	$1,897	2030 / 2032
Coonalpyn to Binnies 33kV line uprate	N Constraint	Demand	$1,709	2026 / 2026
Dorrien New Greenock 11kV Feeder	N Constraint	Demand	$1,466	2026 / 2027
East Tce-Norwood 66kV Line upgrade	N-1 Constraint	Demand	$1,741	2026 / 2027
Freeling to Kapunda 33kV line uprate	N Constraint	Demand	$507	2025 / 2026
Lameroo BESS	N Constraint Manually Included	Demand	$1,946	2025 / 2026
North Unley - Whitmore Square 66kV line uprate	N-1 Constraint	Demand	$476	2025 / 2026
Penola Tee to Penola Line Uprate	N Constraint	Demand	$703	2025 / 2025
Robe BESS	N Constraint Manually Included	Demand	$1,946	2025 / 2026
Southern Outer Metro 66kV restring loop	N-1 Constraint Manually Included	Demand	$3,600	2025 / 2026
Waterloo to Riverton Tee 33kV Line Upgrade	N Constraint	Demand	$924	2025 / 2026
FS Prelim Design - Line Capacity 2025-2030	Mandatory Project	Compliance	$272	2025 / 2030
	Subtotal		**$20,522**	
	Total		**$176,233**	

Appendix 3: Deferral Test Outcomes

Table 13: Deferral Test Outcomes by Project

				Step 1 - First Pass	Step 2 - Deferral Test		
Project	Type	Project Total Cost (k)	BCR	Timing	Timing	Cost ($k) in 25-30 RCP	Outcome
Coonalpyn to Binnies 33kV line uprate	N	$1,709	0.75	2026.2	2026.2	$1,709	Pass
Moonta Tee-Moonta SWER 33kV Line T Uprate	N	$1,009	0.76	2029.2	2031.2	$0	Reject
Kalangadoo sub upgrade	N	$835	0.59	2029.2	2031.2	$0	Reject
Mount Burr sub upgrade	N	$392	1.06	2025.2	2025.2	$392	Pass
Northfield sub upgrade	N	$2,806	1.03	2030.2	2031.2	$0	Reject
Salisbury South Sub & Line	N	$18,183	0.65	2029.2	2030.2	$12,728	Pass
Sandy Creek Sub Upgrade	N	$1,019	1.15	2030.2	2032.2	$0	Reject
Cowandilla 11kV Feeder Backbone Upgrade	N	$413	0.95	2025.2	2025.2	$413	Pass
Fawnbrake 11kV Feeder Backbone Upgrade	N-1	$206	1.03	2030.1	2031.1	$0	Reject