



SA Power Networks

2025-30 Draft Regulatory Proposal - Part B



Disclaimer

Company information

SA Power Networks is the primary electricity distribution network service provider for South Australia. For information about SA Power Networks visit sapowernetworks.com.au.

Disclaimer

This document is designed to gain feedback on proposed plans for the 2025-30 regulatory period.

It contains certain predictions, estimates and statements that reflect various assumptions concerning, amongst other things, economic growth and load growth forecasts that, by their nature, may or may not prove to be correct and are subject to ongoing change and development.

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About this document

This document outlines our understanding of the services and service levels that customers expect us to provide over the 2025-30 period. In preparing our Draft Proposal we have engaged widely with customers, stakeholders and the South Australian community. We are now seeking wider feedback as to whether this Draft Proposal has the price-service balance right.

SA Power Networks is the primary electricity distribution network service provider in South Australia. Our revenues are determined by an independent regulator, the Australian Energy Regulator¹ (AER), every five years in accordance with a legislated regulatory framework.

We must prepare a 'Regulatory Proposal' outlining our proposed work plans, forecast expenditures and overall revenue requirements to deliver those plans over the next Regulatory Control Period, which is from 1 July 2025 to 30 June 2030. Our full Regulatory Proposal will be submitted to the AER in January 2024.

This Draft Proposal document outlines the engagement process undertaken and the recommendations we have received from our customers during our engagement to date. It also details the latest forecast expenditure, revenue and customer price outcomes and our proposed tariff structures for 2025-30. We are seeking written feedback on this

Draft Proposal, before we finalise and lodge our full 2025-30 Regulatory Proposal.

Part A is a separate document of our Draft Proposal, and outlines how we have developed our proposed plans and expenditure forecasts, the stakeholder engagement program we have undertaken to date and how we have based this proposal on customer preferences and feedback from that program. It briefly summarises proposed expenditure, revenue and customer bill forecasts and key tariff proposals for the 2025-30 period.

This Part B provides a more detailed summary of our proposed expenditure and revenue forecasts and tariff structures for 2025-30 and other details which, subject to customer feedback on our Draft Proposal, will be included in our full Proposal to the AER in January 2024.

All data and figures unless sourced in this document has been provided by SA Power Networks.

1. The AER is established under the Competition and Consumer Act 2010. More information on the AER's role is available at www.aer.gov.au/about-us

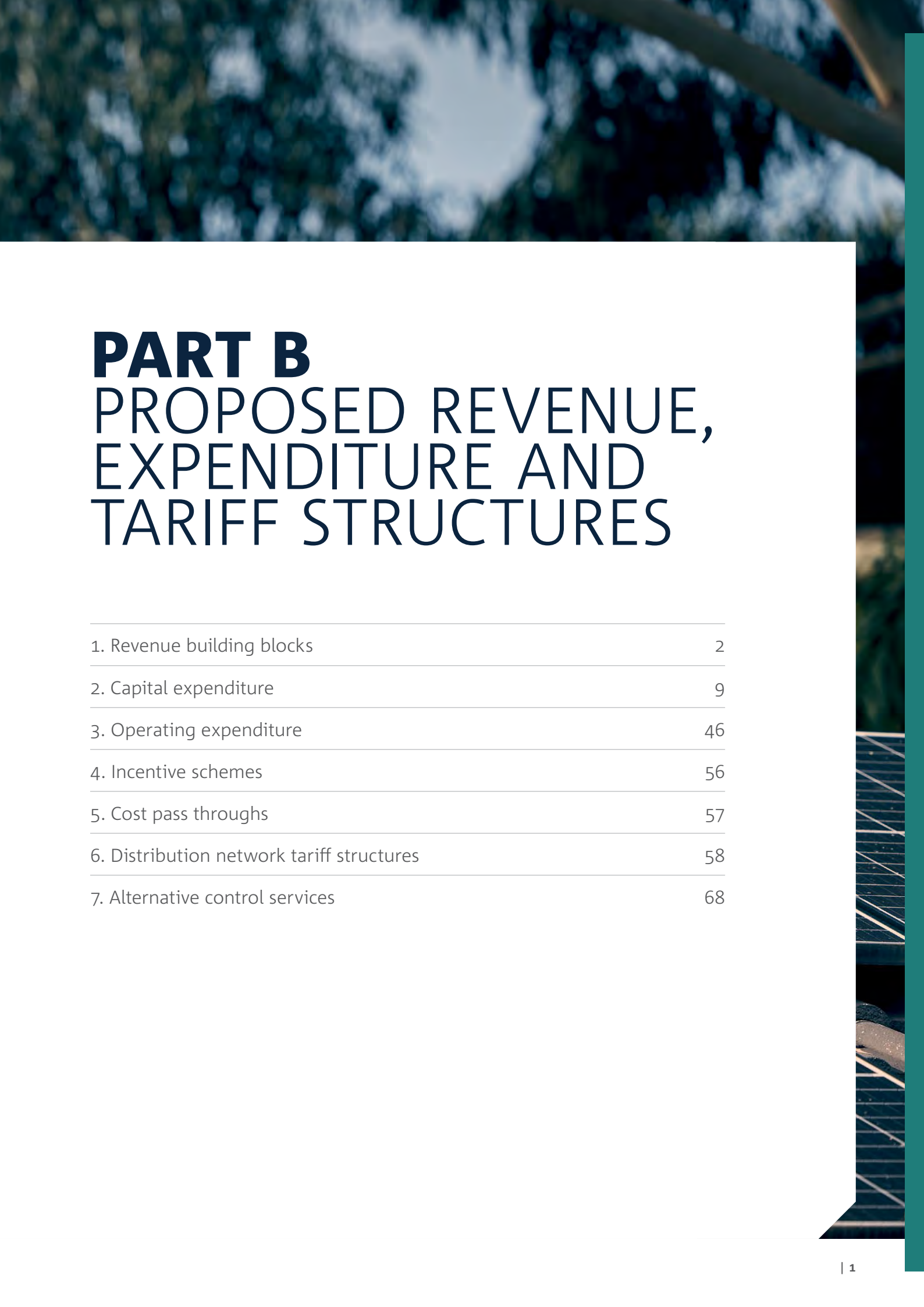
Glossary

Acronym	Full Name
ACS	Alternative Control Services
ADMS	Advanced Distribution Management System
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AESCSF	Australian Energy Sector Cyber Security Framework
ARENA	Australian Renewable Energy Agency
CAB	Community Advisory Board
Capex	Capital Expenditure
CBD	Central Business District
CECV	Customer Export Curtailment Value
CER	Customer Energy Resources
CESS	Capital Efficiency Sharing Scheme
CPI	Consumer Price Index
CSIRO	Commonwealth Scientific and Industrial Research Organisation
CSIS	Customer Service Incentive Scheme
DERM	Distributed Energy Resources Management
DIT	Department for Infrastructure and Transport
DMIAM	Demand Management Innovation Allowance Mechanism
DMIS	Demand Management Incentive Scheme
DOE	Dynamic Operating Envelopes
EBSS	Efficiency Benefit Sharing Scheme
EDP	Enterprise Data Platform
ESCoSA	Essential Services Commission of South Australia
EV	Electric Vehicle
GIS	Geographic Information System
GSL	Guaranteed Service Level
HID	High Intensity Discharge

Acronym	Full Name
HV	High Voltage
ICE	Internal Combustion Engine
ICT	Information and Communications Technology
IRR	Incremental Revenue Rebate
kVA	kilo Volt Amperes
kW	kilo Watt
LED	Light Emitting Diode
LEG	Large Embedded Generator
LV	Low Voltage
MPFP	Multilateral Partial Factor Productivity
MW	Mega Watt
MWh	Mega Watt hour
NEL	National Electricity Law
NEM	National Electricity Market
NEO	National Electricity Objective
NER	National Electricity Rules
Opex	Operating Expenditure
pa	Per Annum
PLEC	Powerline Environment Committee
RAB	Regulatory Asset Base
RORI	Rate of Return Instrument
SaaS	Software as a Service
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCS	Standard Control Services
STPIS	Service Target Performance Incentive Scheme
URD	Underground Residential Development
V2G	Vehicle to Grid
VCR	Value of Customer Reliability
WACC	Weighted Average Cost of Capital



IV | Solar panel on a roof in Adelaide



PART B

PROPOSED REVENUE, EXPENDITURE AND TARIFF STRUCTURES

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1. Revenue building blocks

1.1 Revenue

Revenue needs to be set at a level that enables SA Power Networks to recover its efficient costs and provide an adequate return to investors as it invests in the network and maintains a safe, reliable and secure supply.

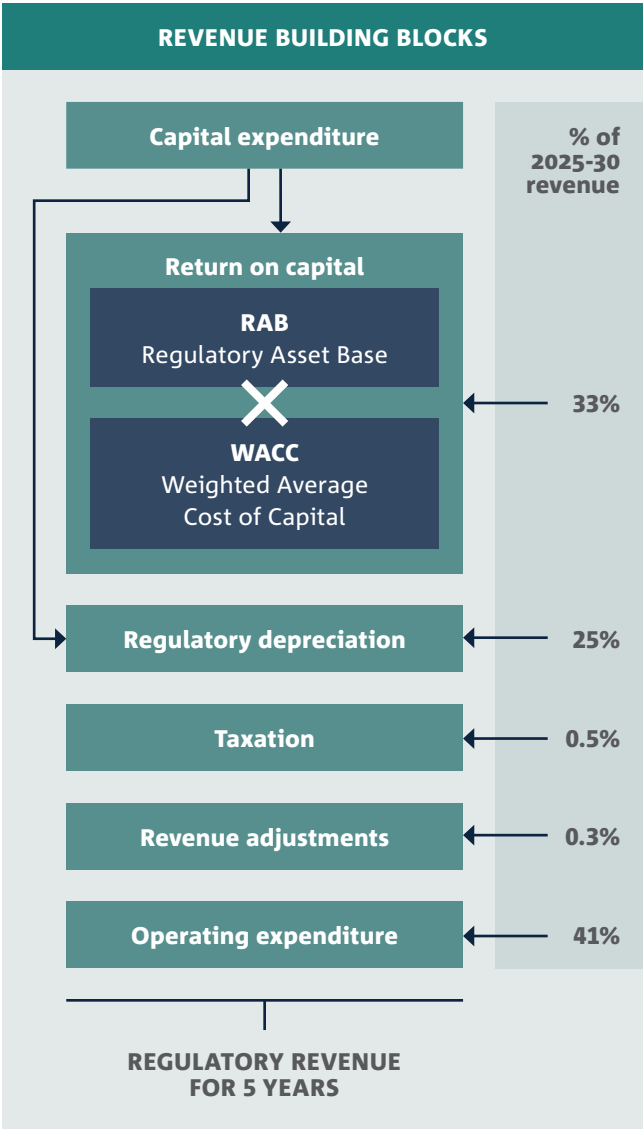
The National Electricity Rules (NER) establish a building block method (Figure B1) for determining our revenue requirements. The building block method recognises the different types of costs that we need to recover through network charges, namely:

- › return on capital to recover inherent costs of debt and a return to investors on their equity invested;
- › return of capital or depreciation;
- › operating expenditure;
- › outcomes from incentive scheme arrangements; and
- › corporate income tax.

Our indicative forecast capital and operating expenditures contribute to our total revenue requirement in the next regulatory period, but most of our revenue is determined by the following financial factors and historic expenditure:

- › the value of the existing asset base, reflecting historic investment in the network;
- › the remaining life of our assets;
- › the financial market data, which is used to assess the current cost of capital; and
- › the corporate income tax rate.

Figure B1. Revenue building blocks



1.2 Total revenue forecast

Our total revenue requirements for our distribution network are based on the Australian Energy Regulator's

(AER's) post-tax building block approach. The revenue building block components are shown in Table B1.

Table B1. Revenue building blocks (\$ million, 2025)

	2025/26	2026/27	2027/28	2028/29	2029/30	Total
Return on capital	287	294	303	316	330	1,530
Return of capital (depreciation)	265	265	253	202	200	1,186
Operating expenditure*	382	387	390	392	393	1,943
Revenue adjustments	7	(13)	(12)	27	14	23
Tax allowance	6	5	2	-	-	13
Unsmoothed revenue	946	938	936	936	938	4,695
Smoothed revenue	940	940	939	939	938	4,695
X factors	-5.92%	0.05%	0.05%	0.05%	0.105%	

*Note: operating expenditure includes the forecasts set out in section B3 as well as debt raising costs of \$13 million.

Figure B2 compares forecast revenue required in 2025-30 with revenue allowances and actuals in the previous periods.

Figure B2. Forecast Distribution Revenue (\$ million, 2025)

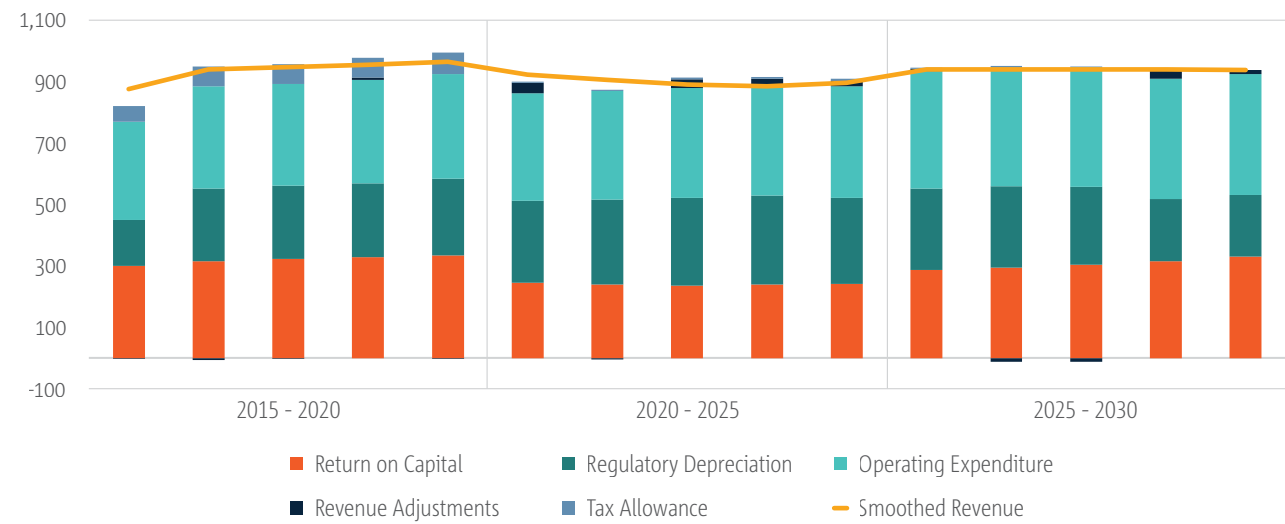
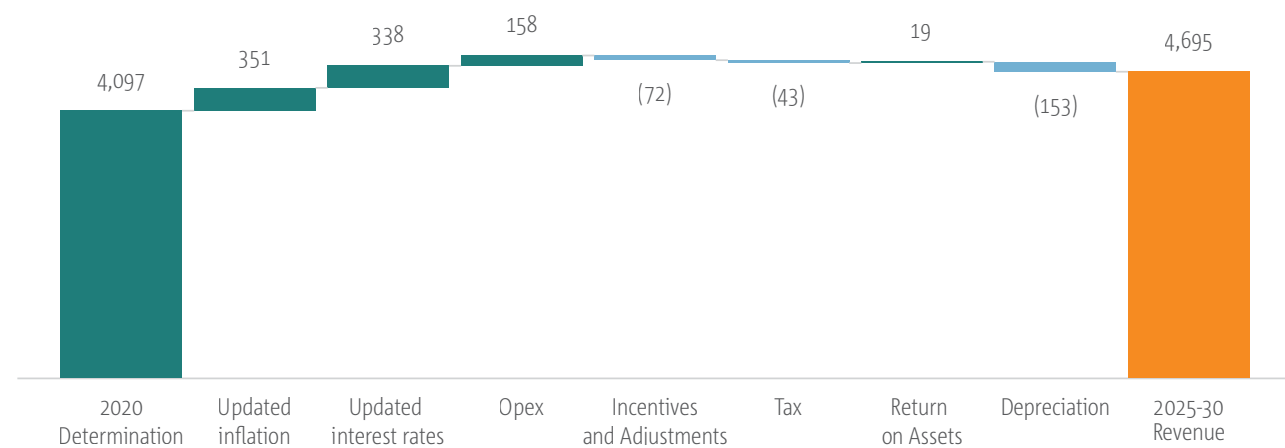


Figure B3 illustrates the key movements in forecast 2025-30 revenue compared to the 2020-25 revenue allowance.

Figure B3. Regulatory period revenue differences 2020-25 to 2025-30 (\$ million, 2025)



The increase in revenue in real terms next period is largely due to increases in inflation (impacting escalation to 2025 dollar terms) and market interest rates (increasing the

regulated return on assets). Other building block items are discussed further below.

1.3 Return on capital

1.3.1 Regulatory asset base

Our Regulatory Asset Base (RAB) is the unrecovered value of capital invested in our network and non-network assets. It is the basis on which the 'return on asset' building block is calculated, and a key input for calculating the 'regulatory depreciation' building block.

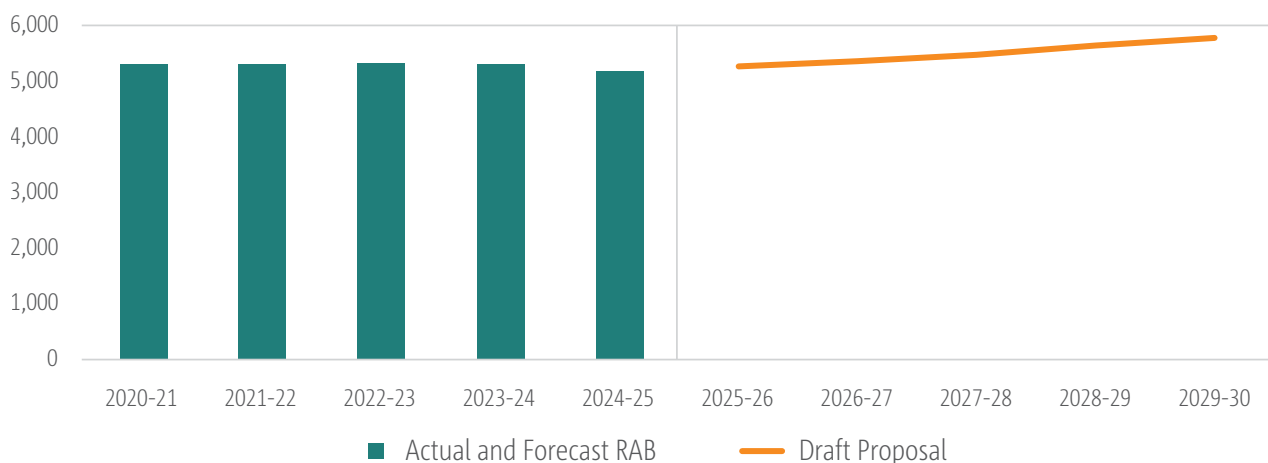
This makes it one of the largest drivers of our overall revenue requirement.

To calculate the value of our RAB in the 2025-30 period (Figure B4), we:

- › used the AER's standard models to estimate its opening value (as at 1 July 2025) and rolled this value forward to estimate its closing value (as at 30 June 2030); and
- › used a placeholder forecast for regulatory inflation of 2.50% per annum.

The estimated annual value of our RAB increases to \$5.81 billion by the close of the 2025-30 period. Our real asset value per customer is expected to increase by 6.7% over the 2025-30 period.

Figure B4. Actual and forecast standard control services regulatory asset base (\$ million, 2025)



1.3.2 Rate of Return

The rate of return is an estimate of what it costs a business to fund capital investments. The AER’s 2022 Rate of Return Instrument (RORI) sets out how it will determine the return that all National Energy Market (NEM) network businesses in Australia can earn on their investments. This is done using a Weighted Average Cost of Capital (WACC) formulation.

The WACC is made up of the cost of the two investment funding sources — equity and debt. The cost or return that investors expect on their investments is known as the return on equity. The cost or interest rate

that a business pays to borrow money to invest is known as the return on debt. The WACC is a weighted combination of these two costs.

The AER calculates the WACC as:

**WACC = return on equity x 40%
+ return on debt x 60%**

This Draft Proposal uses placeholder measures for market rates, comprising:

- Cost of debt rolled forward using our averaging period rate for 2023/24 of 6.3%.

- Return on Equity risk free rate of 3.38% based on market rates in May 2023.

For this Draft Proposal, our indicative rate of return on capital, or WACC, is set out in Table B2. Each of these parameters has been determined in accordance with the AER’s 2022 Rate of Return Instrument.

The placeholder market rates will be updated again for our full Proposal to be submitted to the AER in January 2024.

Table B2. Average rate of return comparison

Average Rate of Return	2020-25	2025-30
Risk Free Rate	0.90%	3.38%
Market risk premium	6.10%	6.20%
Equity Beta	0.6	0.6
Return on Equity	4.56%	7.10%
Gearing Ratio	60%	60%
Portfolio Trailing average cost of debt	4.57%	4.98%
Nominal Vanilla WACC	4.57%	5.83%

1.3.3 Forecast inflation

We forecast inflation using the AER’s published methodology which uses a combination of the Reserve Bank of Australia’s short-term forecast of inflation and the mid-point of

its longer-term target range for inflation. For this Draft Proposal, we have applied a placeholder forecast inflation of 2.5% for the 2025-30 period. This placeholder

forecast will be updated for our full Proposal in accordance with the AER’s methodology.

1.4 Return of capital (depreciation)

Depreciation is designed to return capital investment to investors over the expected useful life of the assets.

We have no proposed changes to our depreciation approach. We continue to calculate depreciation:

- › using the year-by-year tracking approach approved by the AER at our 2020 determination; and

- › applying the same standard asset lives and straight-line depreciation approach approved by the AER in 2020.

Our depreciation allowance is expected to decline significantly over the 2025-30 period. This is an outcome of the transition to the year-by-year tracking approach in 2015. This approach aggregated the

RAB value at 2010, by asset class, and depreciated these values over their remaining lives at 2010. Many of these asset class balances at 2010 become fully depreciated over the 2025-30 period, with corresponding depreciation on these balances going to zero.

1.5 Operating expenditure

Our operating expenditure requirements are discussed in Section 3.

1.6 Revenue adjustments

Table B3 outlines the 2025-30 revenue adjustments proposed, as outlined below.

The AER has developed the following incentive arrangements in accordance with the National Electricity Rules:

- › Efficiency Benefit Sharing Scheme (EBSS) — this provides incentives to achieve and maintain operating expenditure efficiency improvements. Operating expenditure below/above allowance results in savings/additional costs that are shared approximately 85% with customers and 15% with the distribution business at current interest rates.

- › Capital Expenditure Sharing Scheme (CESS) — this provides incentives to make capital expenditure efficiency gains. Similar to the EBSS, capital expenditure below/above allowance results in savings/additional costs that are shared approximately 70% with customers and 30% with the distribution business for under spends less than 10 percent.
- › Demand Management Incentive Scheme (DMIS) — this provides incentives to implement non-network solutions over network solutions for an ‘identified need’.

We are also proposing a new \$20 million Innovation Fund. The revenue impact of the operating component of the Innovation Fund is \$4 million over the 2025-30 period. See **Part A Section 10 Our expenditure have been subject to significant challenge** for further details.

Our capex forecast for the 2025-30 period includes two projects deferred from the 2020-25 period. We therefore excluded these two deferrals from our CESS calculations to avoid impacting customers. The details of these deferrals are that:

- › they involve network augex on upgrading two connection points (at Mount Gambier and Mannum) between our distribution network and ElectraNet’s transmission network – the two projects were deferred due to decisions by ElectraNet; and
- › we expect that these two projects will be required in the 2025-30 period at a cost of \$13.9 million.

We also identified two additional capex projects that have either been deferred or cancelled. We expect that these two projects will not be required in the 2025-30 period and they are not included in our capex forecast. However, even though these two projects are not in our forecast for 2025-30, we are volunteering to also exclude these from our CESS

calculations, due to the general affordability concerns expressed by our customers.

We are again forecasting that we will receive unregulated revenue for services provided from regulated 'Shared Assets' over the 2025-30 period. This will reduce our regulated revenue allowance in accordance

with the AER's Shared Assets guideline. We will apply the same methodology as approved by the AER in our 2020 Determination, whereby a Shared Assets adjustment is made to reflect the cost of assets that are being recovered through unregulated services revenue.

Table B3. Revenue adjustments (\$ million, 2025)

	2025/26	2026/27	2027/28	2028/29	2029/30	Total
EBSS	(7.4)	(26.9)	(26.2)	12.4	-	(48.0)
CESS	13.9	13.9	13.9	13.9	13.9	69.6
DMIS and DMIAM	1.0	1.0	1.0	1.0	1.1	5.1
Innovation Fund	0.8	0.8	0.8	0.8	0.8	4.0
Shared Assets	(1.6)	(1.6)	(1.6)	(1.6)	(1.6)	(7.8)
Total Revenue adjustments	6.8	(12.7)	(12.1)	26.6	14.2	22.9

1.7 Taxation Allowance

As with the 2020 Determination, our taxation allowance is calculated in accordance with the AER's 2018 Review of the Regulatory tax approach. The forecast Taxation

allowance over the 2025-30 period has fallen to \$13 million, largely due to the treatment of asset replacement expenditure which is immediately deductible for taxation purposes.

2. Capital expenditure

We forecast a capital expenditure (capex) requirement of \$2.4 billion for the 2025-30 period to deliver the service/price balance that our customers have told us that they seek, and to otherwise ensure that we meet our regulatory and legal obligations in delivering reliable, safe and secure services to customers.

As outlined in Part A of our Draft Proposal, there are some significant challenges and opportunities facing our distribution network and the services we provide our customers. These include:

- › Strong increases in demand, driven by electrification.
- › Challenges of managing an aged network in deteriorating condition.
- › Increasingly heightened bushfire risk across our rural network.
- › Strong customer demand to export excess renewable energy through our network.
- › Needing greater equity in service performance across a vast state-wide urban and rural network.
- › Ongoing needs to maintain adequate supporting assets including in an environment of increasing cyber security risk.

While some of these issues are common to distribution networks, they are heightened for our network, as we have the oldest network assets in the National Electricity Market (NEM) with the majority built in a relatively confined period of time, and we are at the forefront of the renewable energy transition.

Addressing these challenges and opportunities, guided by the views of our customers, will require a 25 percent increase in our capex relative to our expected spend in 2020-25. We recognise this is a significant increase. Therefore, throughout each stage of our engagement program, we have sought to ensure that our customers have understood this, by being transparent on the total quantum of expenditure (capital and operating expenditure) under different potential scenarios of how we could respond to the challenges and opportunities in our service provision.

As outlined in **Part A Section 9 Affordable and equitable energy supply**, electricity affordability (and cost of living pressures generally) has been a key theme throughout our engagement with customers and stakeholders and was heightened in 2022 when NEM wholesale electricity prices rose sharply. Our initial engagement with customers and stakeholders on quantifying price-service trade-offs occurred in the second half of 2022 – when the full impacts of inflation and predicted retail electricity price increases became clear. By the time their price-service deliberation sessions occurred in February and March of this year the People's Panel were highly attuned to community concerns on future electricity price outcomes.

While our customers have highlighted the affordability challenges facing many South Australians, at the same time they have been very clear to us that they do not want service to be compromised in the 2025-30 period. The consistent feedback that we have heard from customers is that they want:

1. service levels to be largely maintained, particularly in relation to network safety and reliability, with recognition of the required supporting non-network spends;
2. a few highly targeted service improvements, particularly in respect of the reliability experienced by our worst served regions and customers, and in bushfire risk management; and
3. continued investments to support the energy transition, enabling Customer Energy Resources (CER), enabling flexibility in customer loads, and greening our fleet where economic.

The following sections provide further detail of the drivers of our capex forecast, and the key projects and programs that we will seek to provide in the 2025-30 period.

Through our engagement process, we have provided our customers and stakeholders the opportunity to shape approximately 65% of the capital expenditure forecast in this Draft Proposal.

2.1 What comprises capital expenditure

Capex is grouped into expenditure categories that are used by the AER. Figure B5 provides a high level description of what these categories comprise.

Figure B5. Key categories of capex²

NETWORK	Augex Augmentation/ upgrades to network assets to ensure sufficient capacity and security of the network in meeting demand, and to manage reliability and bushfire risks.	Repex Replacement of network assets in response to network condition – i.e. assets that need to be retired because they have either reached their end of technical life (i.e. failed) or reached the end of their economic life (i.e. risk costs > costs of replacement).	Connections The cost of connecting customers to our distribution network (net of customer contributions toward their connection costs).	CER Augmentation/ upgrades to the network to enable energy exports from Customer Energy Resources; enablement of flexible customer loads; and industry compliance improvement costs.
NON-NETWORK	ICT Refreshing, replacing, upgrading and investment in new ICT technology supporting our delivery of distribution services to customers. This includes: client devices used by our staff; IT infrastructure hardware; software systems and applications; and data and information storage and management.	Property Renewal, refurbishment and replacement of property assets (eg offices, depots, workshops) supporting the delivery of distribution services to customers.	Fleet Replacement and purchase of additional vehicles, including passenger and commercial, forklifts, elevated work platforms, cranes, trucks and vans.	Other Refreshing and replacing telecommunications systems, the distribution network management system, and operational telephony.

2. For simplicity, in Figure B5 we placed CER under ‘Network’, although it includes expenditure that is both network (eg voltage regulation equipment on zone substations, regulators, upgrading transformers) and non-network (eg systems to enable Dynamic Operating Envelopes).

2.2 How we have performed in 2020-25

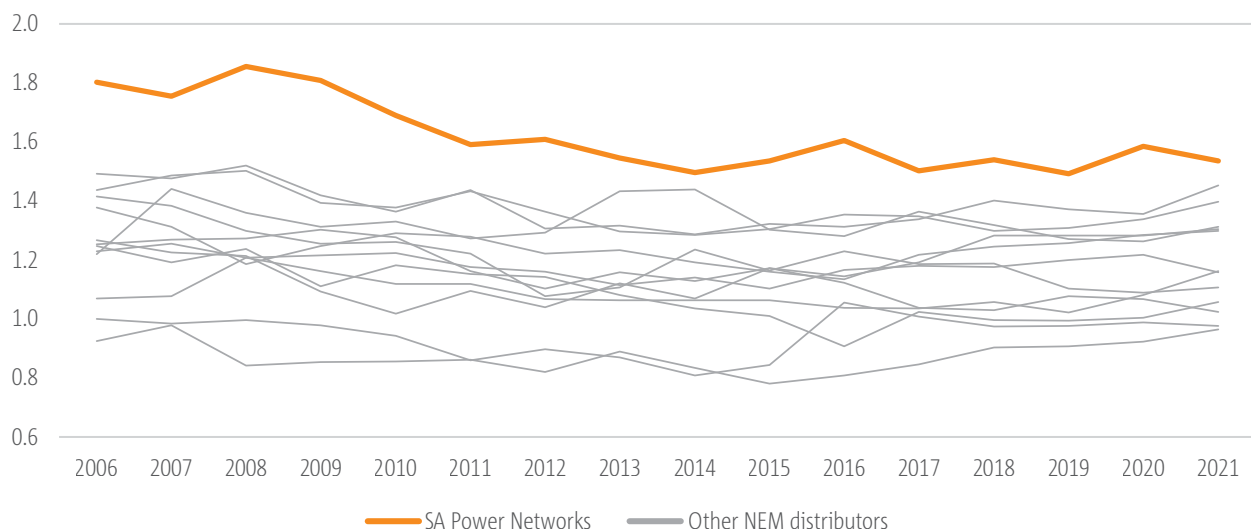
2.2.1 Benchmarking with our industry peers

We remain consistently among the most efficient distribution networks in the NEM, under a range of measures published by the AER. This is the product of our ongoing focus on managing our assets as efficiently as possible to deliver the services that our customers expect and value.

We have retained strong relative performance notwithstanding the significant challenges of managing a network with the oldest asset fleet in the NEM and being at the forefront of the renewable energy transformation.

We rank as the most efficient NEM electricity distribution network, on the measure of Multilateral Total Factor Productivity, which accounts for all capital and operating inputs and outputs, displayed in Figure B6.

Figure B6. Electricity distribution multilateral total factor productivity indexes by distributor, 2006-2021

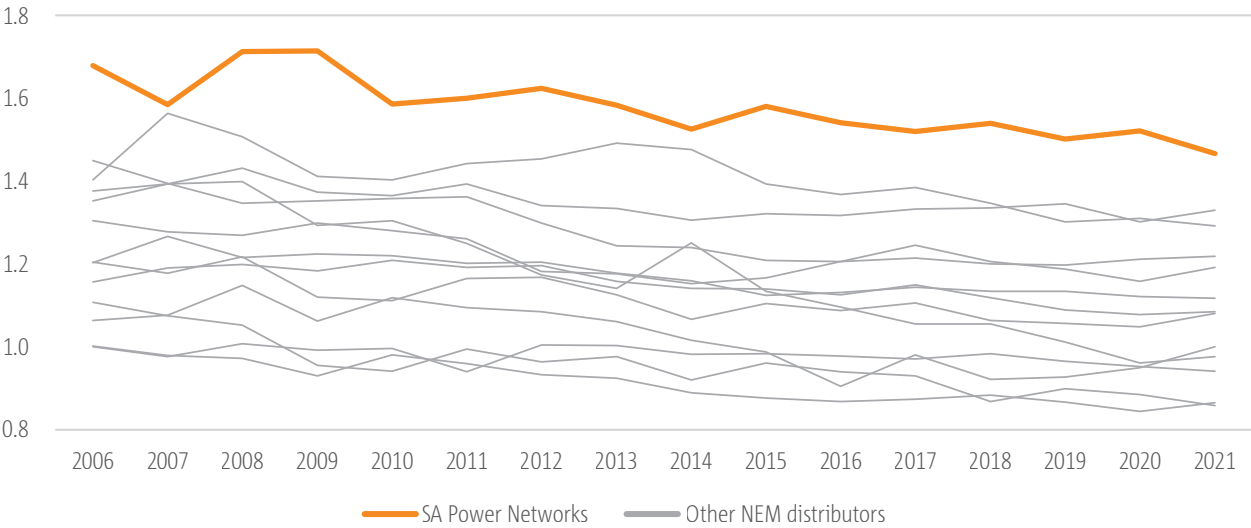


Source: Adapted from AER, Annual benchmarking report – Electricity Distribution Network Service Providers, November 2022, p.iv.

We also rank as the most efficient NEM electricity distribution network in more specific reference to capital performance, under the measure

of capital multilateral partial factor productivity, which accounts for capital inputs and outputs (Figure B7).

Figure B7. Distributor capital multilateral partial factor productivity indexes by distributor, 2006-2021



Source: Adapted from AER, Annual benchmarking report – Electricity Distribution Network Service Providers, November 2022, p.25.

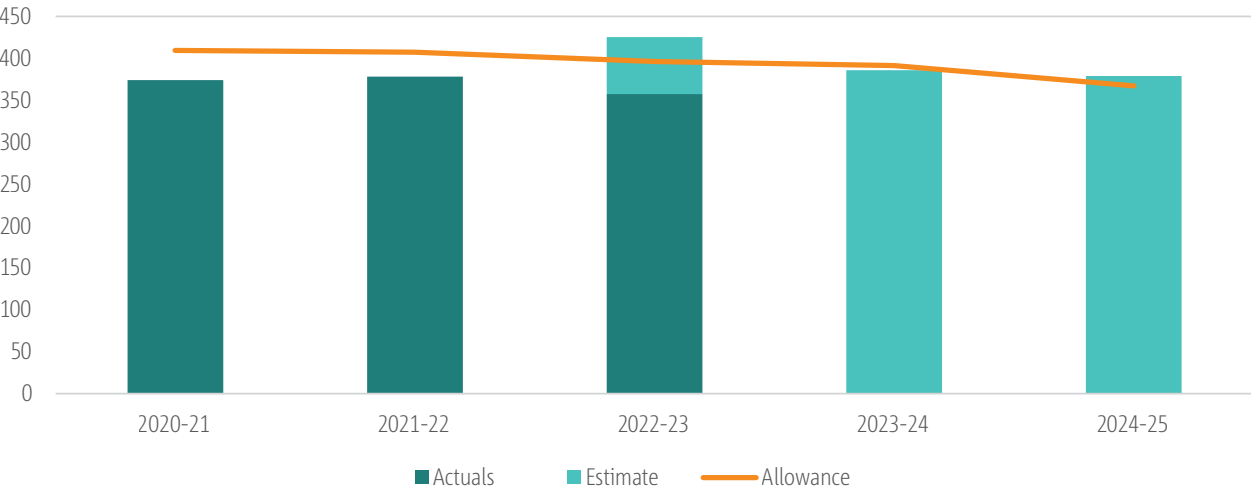
2.2.2 Our spend performance in 2020-25

Over the 2020-25 period we have been delivering the key service outcomes and initiatives that we

outlined in our last Regulatory Proposal. By the end of this period, we anticipate our actual net capex

will be approximately in line with the AER capex allowance as outlined in Figure B8.

Figure B8. 2020-25 actuals/estimates versus AER allowance (\$ million, 2025)



Over this period, we have delivered significant and transformational projects underpinning much of our operations, and have continued to balance and re-prioritise how we manage our distribution network in the face of significant changes and challenges in our operating environment. Examples include:

- › increasing network asset replacement expenditure (replex) to above the AER 2020-25 replex forecast³ to manage significant risks arising from an aged and deteriorating network – we also rebalanced our spend between the asset classes of replex based on their risk criticality at the time, directing more spend to assets such as overhead conductors, where we have experienced increasing failures, supply outages and safety risks;
- › continuing to deploy our long-standing program of feeder automation,⁴ where feasible, to further mitigate the reliability impact of the deteriorating condition of our assets and partially off-set the escalating impact of grey headed flying foxes (bats) – allowing us to mitigate asset failure consequences by segmenting the network and re-routing supply so that a smaller number of customers are impacted by an asset failure/fault;
- › continuing to invest in the transition to a truly ‘two-way’ distribution network able to support a 100 percent renewable electricity system – this includes investments to develop our world leading capability to efficiently integrate very high levels of rooftop solar and other CER using ‘Dynamic Operating Envelopes’, enhancements to voltage management, and new emergency measures to help support system security at times of minimum demand;
- › implementing major changes to our Information and Communications Technology (ICT) infrastructure including implementing our new billing system, upgrading our SAP Enterprise Resource Planning system which underpins most of our key customer and business processes, implementing the technologies to facilitate the flexible grid management capabilities, completing our Geographic Information System (GIS) consolidation and implementing investments and changes required to meet our Cyber Security requirements and obligations;
- › deploying our program of targeting efficient mitigation of bushfire start risk in high bushfire risk areas, within the scope of what we set out to achieve; and
- › commencing a major project to replace the Northfield Substation Gas Insulated Switchgear via the Regulatory Investment Test for Distribution, confirming the merit of a project that was not included in our total capex allowance as part of our AER Determination for 2020-25.

Despite these efforts, our overall reliability performance (particularly in relation to the duration of supply interruptions Figure B9) has been deteriorating since 2019/20 driven principally by the effects of more frequent and severe weather events, vegetation outside our clearance zone damaging equipment, and other causes being mainly outages caused by grey headed flying foxes (bats) which we forecast to continue to increase in coming years based on assessments of bat colonies.

3. The AER replex forecast refers to expenditure that the AER included in its approved total capex allowance for our 2020-25 period.

The AER provides a total capex allowance, allowing networks flexibility to prioritise their expenditure over the regulatory period.

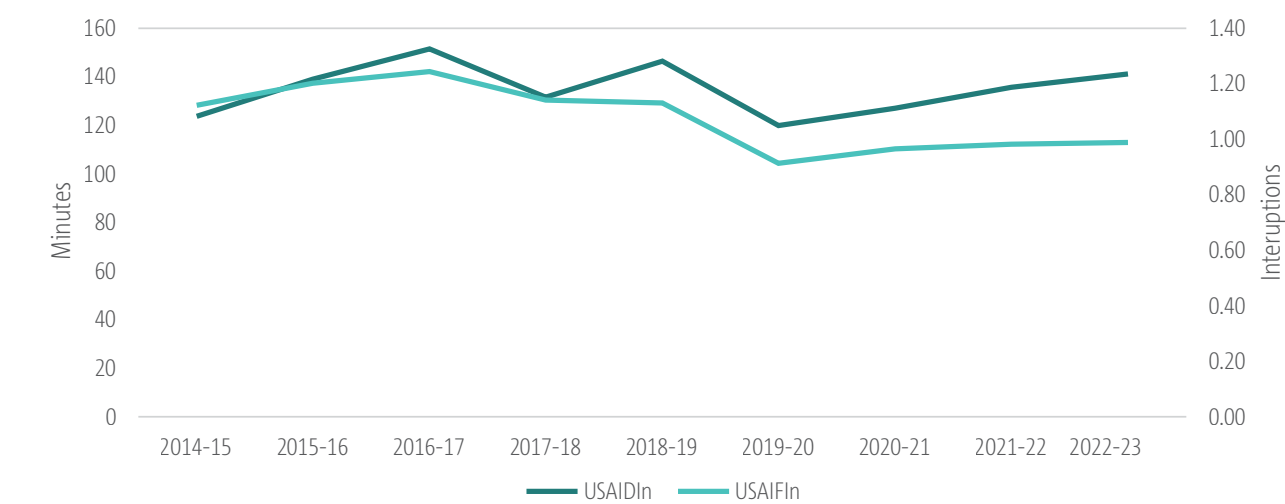
4. Feeder Automation refers to a program by which we install centrally controlled high voltage switches on our network allowing us to reduce the number of customers impacted by an outage on our network. Our Advanced Distribution Management System (ADMS) can determine the location of a fault on our network and then use these switches to isolate the fault and re-route power to surrounding customers that would otherwise have been impacted.

Further, while observed trend data does not show that network asset condition has been a key driver of reliability performance. The underlying risk that asset condition poses for reliability has to date been masked by our feeder automation program. While feeder automation

will continue to have a role in response to underlying and non-asset condition causes of impacts on reliability, there are limits to what further we can achieve via this solution. These solutions cannot address bushfire safety risks and tend to be uneconomic where there

is low customer density and even for reliability management there is a point where it becomes more efficient to address the underlying cause of an outage rather than just mitigate its impact.

Figure B9. Distribution system reliability - normalised⁵



5. USAIFI refers to Unplanned System Average Interruption Frequency Index – which measures the number of interruptions to supply. USAIDI refers to Unplanned System Average Interruption Duration Index – which measures the duration of time of interruptions to supply.

2.3 Our capital expenditure forecast for 2025-30

Our total capex requirement of \$2.4 billion for the 2025-30 period is a 25 percent increase on our expected spend in 2020-25. Our total capex forecasts are shown in Table B4, and Figure B10 at a total and primary category level, with Figure B10 displaying our forecast relative to the last ten years of expenditure.⁶

As discussed later in this section, one of the projects ('Assets and Work') we propose in relation to ICT will drive long-term cost efficiency benefits for delivery of our network expenditure, including a \$30 million saving in 2025-30.

Table B4 displays forecast capex with and without this benefit included. All expenditure category level figures displayed in this section show forecasts excluding this top-down efficiency adjustment.

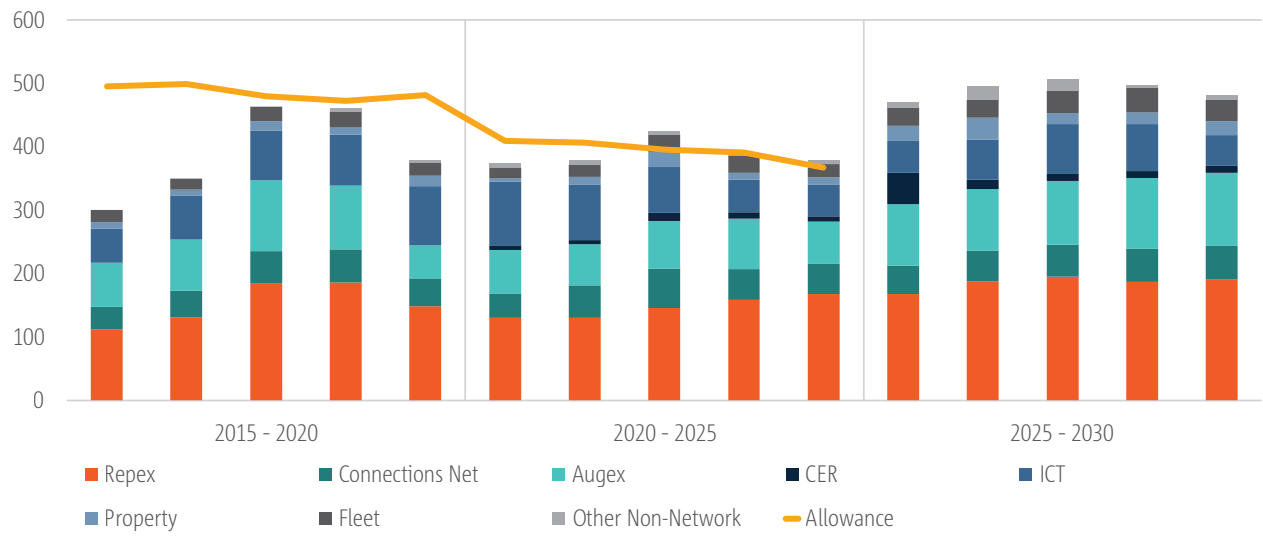
Table B4. Capex forecast for 2025-30 - by category and totals (\$ million, 2025)

	2025/26	2026/27	2027/28	2028/29	2029/30	Total capex	% change ⁷
Repex	168.0	188.0	195.5	187.2	190.8	929.4	27%
Augex	96.6	97.0	101.2	111.4	114.7	520.9	47%
Connections Net	44.7	48.2	49.7	51.7	53.2	247.6	-1%
CER	49.8	14.7	10.8	10.9	11.5	97.8	119%
ICT	49.7	63.0	78.2	74.9	48.4	314.3	-13%
Fleet	29.3	28.9	34.7	39.6	34.1	166.5	52%
Property	23.9	34.5	17.8	17.8	21.7	115.7	82%
Other Non-Network	8.6	21.4	18.4	4.8	6.2	59.4	135%
Total Capex	470.6	495.8	506.3	498.4	480.7	2,451.7	26%
Efficiency adjustment						-30.0	
Total Capex (post adj)						2,421.7	25%
Disposals						-22.1	
Total Net Capex						2,399.6	

6. We show total capex net of customer contributions and before disposals. We incur gross connections expenditure, but the individual connecting make contributions toward the cost of their connection to the network in accordance with our Connections Policy.

7. This represents the percentage change compared with our expected actual expenditure in 2020-25.

Figure B10. Capex – historic expenditure versus AER allowance, and forecast (\$ million, 2025)



2.4 Key drivers of our capital expenditure forecast for 2025-30

The key drivers of our capex and their contribution to our forecast are shown in Figure B11 and discussed below:

- › **Repex** - responding to the risk posed by deteriorating network asset condition, by increasing our rate of asset replacement toward sustainable levels in order to maintain reliability at a geographic region level, improve/restore reliability in the Adelaide CBD to meet jurisdictional service standards, and to maintain safety at an aggregate level.
- › **Augex** - increasing network upgrades to:
 - › meet forecast strong increases in demand, driven by increasing customer electrification by ensuring sufficient capacity in our network;
 - › respond to non-asset condition impacts on reliability (including flying foxes, weather and other damage causes); make targeted and optimised upgrades alongside repex to improve reliability in the Adelaide CBD; and make targeted improvements for regions and customers who repeatedly experience poor reliability performance; and
- › **CER integration** - meeting and managing expected demand for export services by increasing network hosting capacity to provide efficient service levels expected by customers, and investing in new capabilities to enable flexibility in customer loads on the network and to improve compliance to CER technical standards.
- › **Property** - responding to the condition of property assets by increasing our spend on refurbishing and renewing our existing properties, and investing in new depots to respond to end of life assets through efficient consolidation of activities and to meet an expected uplift in work volumes.
- › **Fleet** - responding to increases in input costs, transitioning to Electric Vehicles (EV) where efficient to do so, and responding to an uplift in expected work volumes.
- › **ICT** - while ICT capex is forecast to decrease, particularly the recurrent costs of maintaining existing services, there are required replacements of existing systems to maintain current services, investments in new capabilities for more personalised and on-demand services to customers via digital channels, investments to improve the efficiency of asset management practices, and reinforcements to cyber security.

Figure B11. Capex forecast for 2025-30 - total and category (\$ million, 2025)



*before \$30 million efficiency adjustment and \$22 million disposals

2.5 How we have forecast our capital expenditure

Our capex has been forecast by applying a comprehensive and multi-faceted expenditure forecasting methodology, guided by two principal and related objectives:

- 1. developing an expenditure forecast aligned to the expectations of our customers on the services and service levels we provide and the customer price outcomes for these services; and
- 2. aligning to the expectations and guidance provided by the AER in its Better Resets Handbook⁸ and related expenditure guidelines and guidance notes, and more broadly the National Electricity Objective (NEO) in the National Electricity Law (NEL) and the National Electricity Rules (NER).

The key features of our approach to forecasting expenditure, displayed in Figure B12 are that we have:

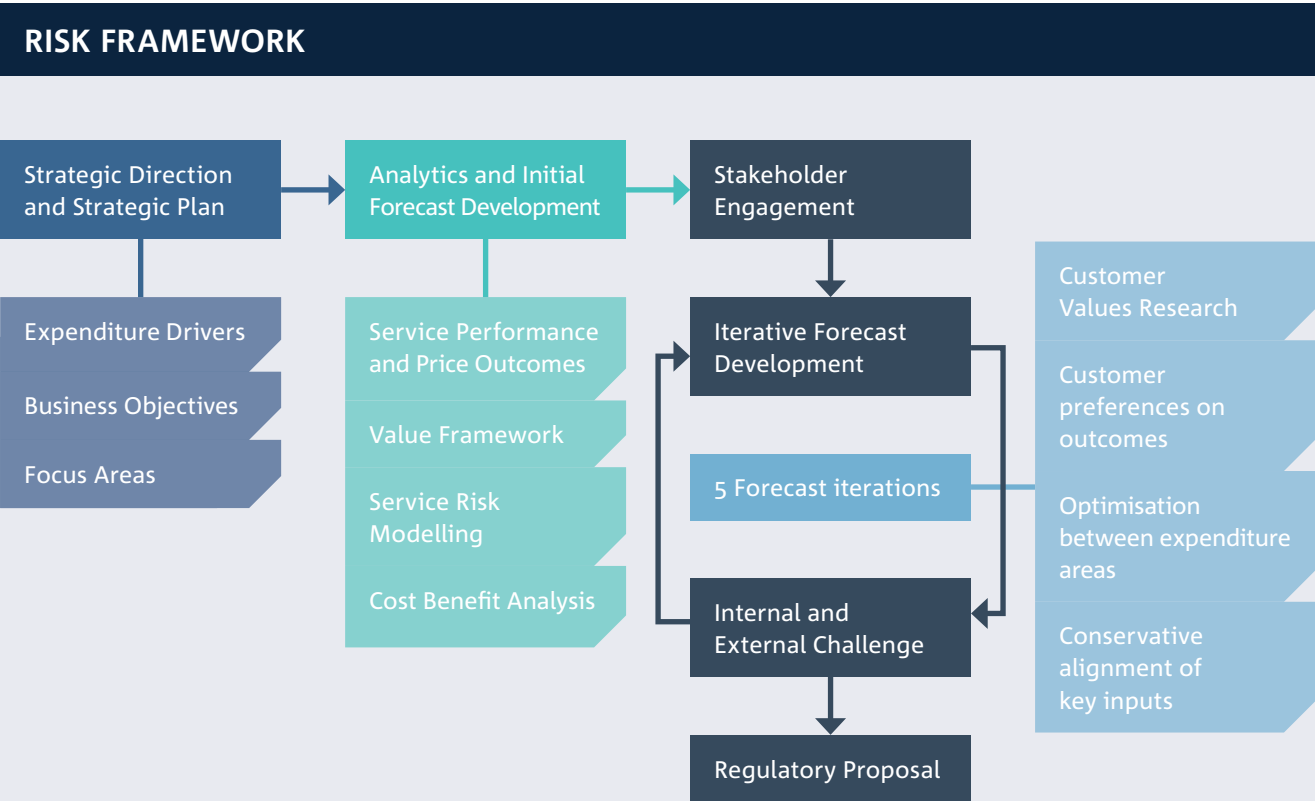
- › a sound organisational governance framework through which we continually take stock of long-term investment drivers by way of the challenges and opportunities facing our customers, community, and our network, and the implications for our customer services;
- › comprehensive analytics to assess the impact of various investment drivers on the services we provide our customers and to form scenarios of alternative outcomes, particularly in the areas of assessing the effects of network asset condition and demand/export on service levels

for customers at highly precise and granular levels;

- › a multi-stage engagement program to develop our expenditure forecasts over five iterations with our customers, in a transparent, objective and outcomes focused way; and
- › applied multiple tiers of external challenge by customers and internal challenge within our business to ensure that our forecasts are aligned to customer expectations, are reasonable in their cost estimation and as efficient as possible.⁹

Further details on our approach are set out in our Expenditure Forecasting Methodology document.¹⁰

Figure B12. Overview of expenditure forecasting process



8. AER, Better Resets Handbook - Towards consumer-centric network proposals, December 21, available at: www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/better-resets-handbook-towards-consumer-centric-network-proposals

9. Our approach to external and internal challenge has been detailed in Part A of this Draft Proposal.

10. Our Expenditure Forecasting Methodology has been submitted to the AER and is available via their website. SAPN, Expenditure Forecasting Methodology for 2025-30 Regulatory Proposal, June 2023. Accessible on: www.aer.gov.au.

2.6 Key projects and programs we will undertake in 2025-30

This section outlines the key projects and programs that we propose within each area of capex, focusing on initiatives contributing greater

than circa 10 percent to each capex category. In some areas we bundled programs comprising of several sub-programs, and also included

some programs which do not contribute circa 10 percent but which were specifically discussed in our engagement program.

2.6.1 Network asset replacement (replex)

Capex \$929.4 million

38% of total capex

Replex comprises several asset classes with key contributors being overhead conductors, poles, pole top structures and circuit breakers. Since our 2020-25 Regulatory Proposal, we vastly improved our analytics to quantify risks to customers in monetary terms, posed by the condition of our network assets, and to form scenarios of alternative investment levels and service outcomes. This has allowed us for the first time, to optimise across all asset classes to achieve a target service level outcome for our customers.

Our replex forecast overall responds to the risk posed to customer service by deteriorating network asset condition and the need for assets to be retired. If we continued with our business-as-usual approach and maintained only our historic levels

of replex we would be unable to maintain reliability at an efficient level, unable to maintain safety (particularly bushfire start risk) and would not comply with our jurisdictional regulatory service standard for the Adelaide CBD.

We sought customers' views on several scenarios of how to respond to the identified need, maintaining our business-as-usual approach versus scenarios of differing service level outcomes. Our replex forecast aligns to what our customers consider to be an appropriate service-price balance, reflected in the People's Panel recommendations (summarised in **Part A, Section 6 A reliable, resilient and safe network**), and achieves outcomes which are also efficient for customers (benefits outweigh costs). The overall target service level need of our replex is to: maintain reliability at a geographic region level; maintain safety in aggregate; and improve reliability in the Adelaide CBD to comply with jurisdictional service standards.

Our replex forecast was developed by forecasting the risk for customers of our assets failing in service and quantifying the monetised effect this would have by way of reliability and safety outcomes for customers, being the two key risks of asset failure.

Figure B13 and Figure B14 show our historic risk costs for reliability and safety and outline two alternative scenarios of service outcomes under different expenditure levels:

- ▶ a 'base-case' showing a forecast increase in reliability and safety risk if we were to continue with our business-as-usual approach and maintain only to our current replacement expenditure level; and
- ▶ a scenario showing a forecast maintenance of reliability and safety risk if we increase replex as per our proposal – our forecast replex represents the minimum level of expenditure that we need to achieve the overall service level targets for replex that we outlined above as recommended by our customers.

Figure B13. Replex reliability risk cost - historic vs forecast (base case versus risk outcome from our proposal) (\$ million)

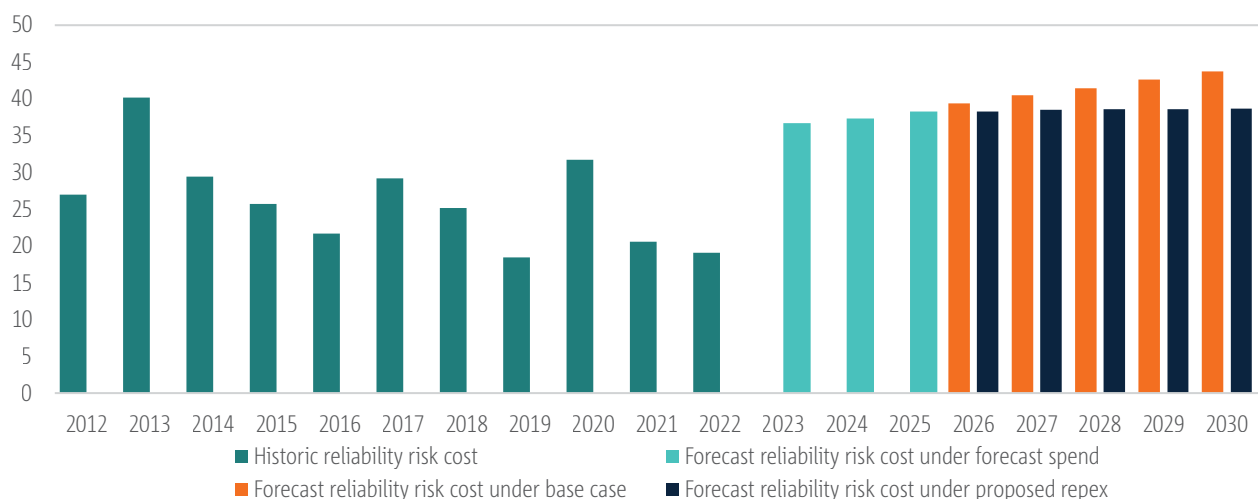
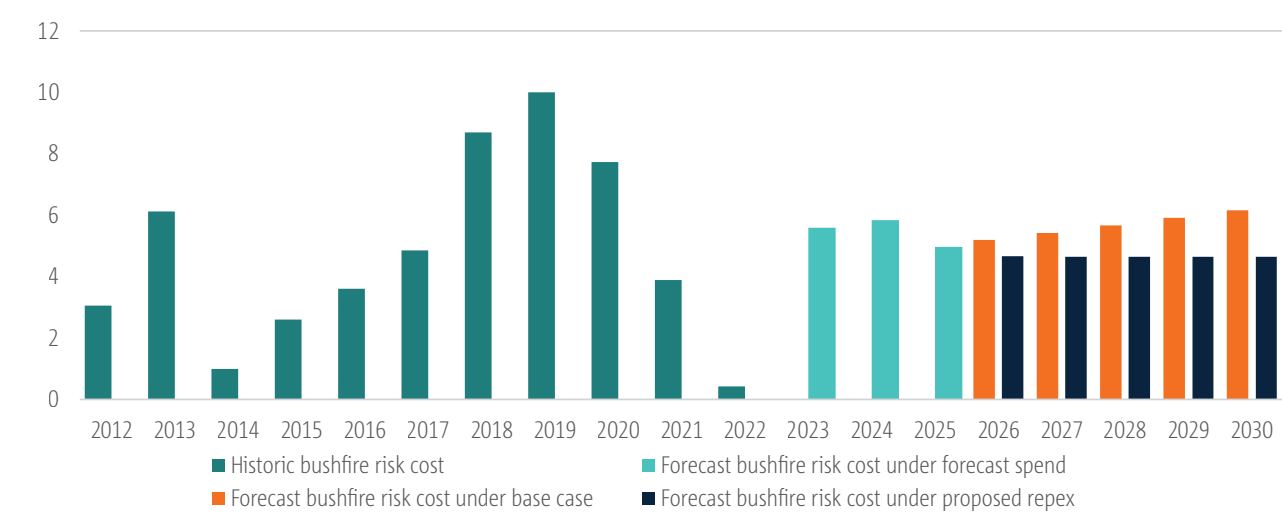


Figure B14. Repex safety risk cost - historic vs forecast (base case versus risk outcome from our proposal) (\$ million)



The key areas of our proposed repex forecast are set out below.

Table B5. Network asset replacement > Overhead conductor

Overhead conductor (capex \$84.6 million, 9% of total repex)	
The need	Our proposal
Our historic, business-as-usual approach of ‘fixing-on-fail’ with little proactive replacement, would result in deteriorating service levels of reliability and safety: - continuing our current spend level averaged over the last five years implies our conductors would need to last approximately 2,500 years on average which is unrealistic; - we have observed trends of increasing conductor failures impacting reliability and safety risks (mainly bushfire start); and - we forecast in 2025-30 a risk of deteriorating reliability and safety levels.	Increase conductor repex by \$46.6 million. This represents a 123% increase on our expected spend in 2020-25. The program will replace 1,740km of overhead conductor, with repex configured to achieve the highest benefits relative to costs for customers.

Table B6. Network asset replacement > Pole replacement

Pole replacement (capex \$153.1 million, 16% of total repex)	
The need	Our proposal
Our business-as-usual approach to pole asset management involves proactive replacement based on condition and risk or, where economic, extending the life of our poles through ‘plating’ refurbishment (welding steel plates onto corroded poles). However, maintaining expenditure at current levels risks deteriorating reliability and safety service levels given: - it implies our poles last on average more than 300 years, which is unsustainable, with the expected life averaging circa 100 years depending on location; and - our pole repex over 2020-25 insufficiently reflects the need for repex in 2025-30, noting that in this current period, we had to reprioritise repex to higher risk/consequence for underground cable and conductors and away from pole repex – a decision that was only appropriate as a short term measure for poles given that we had previously proactively replaced more poles.	Increase repex by \$34.1 million. This represents a 29% increase on what we expect to spend in 2020-25 and will align back up to our AER forecast for 2020-25 – noting in the current period we had to prioritise cables over pole replacements. We will replace circa 6,100 poles and refurbish 21,300 poles.

Table B7. Network asset replacement > Circuit breakers

Circuit breakers (capex \$89.7 million, 10% of total repex)	
The need	Our proposal
Our business-as-usual approach has been to proactively manage based on condition and risk and where economic we continue to extend the life of our circuit breakers through a refurbishment program. We assess that maintaining our business-as-usual approach and the level of repex over the 2020-25 period is likely to be sufficient. An alternative to our business-as-usual approach would involve 'run-to-fail', which would result in deteriorating reliability and safety.	Maintain repex of \$89.7 million, to replace 129 circuit breakers, consistent with our actual spend in 2020-25.

Table B8. Network asset replacement > Pole top structures

Pole top structures (capex \$161.5 million, 17% of total repex)	
The need	Our proposal
Our business-as-usual approach is to replace or refurbish on a benefits versus costs approach where we identify a defective asset, as well as replacing on failure. While most of our repex forecasts rely on detailed modelling, the large volume and variety of equipment of pole top structures make detailed modelling impractical and we relied on historic spend to inform our forecast.	Maintain repex in line with historic expenditure levels. We will replace approximately 100,000 pole top structures.

Table B9. Network asset replacement > Other repex programs

Other repex programs (capex \$440.5 million, 47% of total repex)	
The need	Our proposal
Other repex comprises a broad range of asset classes each of which contribute less than 10% to the total repex forecast: - high volume assets for which sufficient data is available for modelling. Forecast is based on: volumetric risk-based modelling for work that is condition-based; historic spend for reactive work; and individual business cases for planned works; - high volume assets for which there is insufficient data for modelling is forecast on the basis of historic spend; and - high value assets are forecast on the basis of individual business cases for condition-based works, historic spend for reactive works, and individual cases for planned works.	This proposed spend includes: - the repex component of our CBD reliability program (discussed later in this section) to meet jurisdictional service standards – we will replace 22km of underground cables; - replacing or refurbishing 81 zone substation power transformers to maintain the risk posed by transformers to current levels, representing a 12% increase on our spend in 2020-25; and - replacing circa 1,040 distribution transformers, which represents a 21% decrease on our 2020-25 expenditure – this decision to decrease our forecast relative to our actual spend results from our optimisation of the overall risk costs within our repex forecast, by directing investment instead to replacing other assets that represent more risk to service outcomes and value to customers.

2.6.2 Augmentation expenditure (augex)

Capex \$520.9 million

21% of total capex

Our augex forecast comprises several expenditure areas each with their own overall and specific needs.

2.6.2.1 Capacity augex

Capex \$247.8 million

48% of total augex

Our capacity augex meets and manages expected customer demand for service, while maintaining the security of supply of our distribution system.

We forecast an increase in capacity augex driven mainly by the significant increase in peak demand growth forecast by the Australian Energy Market Operator (AEMO) for South

Australia over the coming decade. Without investment, service levels delivered by our network in 2025-30 will reduce, with forecast demand either exceeding network capacity or reducing security of supply. Electrification of homes and businesses and the uptake of Electric Vehicles are the primary drivers of forecast operational demand growth across the NEM and in South Australia, particularly as the economy evolves to target net zero emissions.

We engaged with our customers on the need for capacity augex and various scenarios of how we could

respond, and our 2025-30 forecast aligns to the service-price balance reflected in the People’s Panel recommendations (summarised in **Part A Section 6 A reliable, resilient and safe network**). It will increase the capacity of our network to maintain current levels of reliability and security of supply and ensure compliance with our reliability and power quality requirements set out in ESCoSA’s Electricity Distribution Code (EDC).

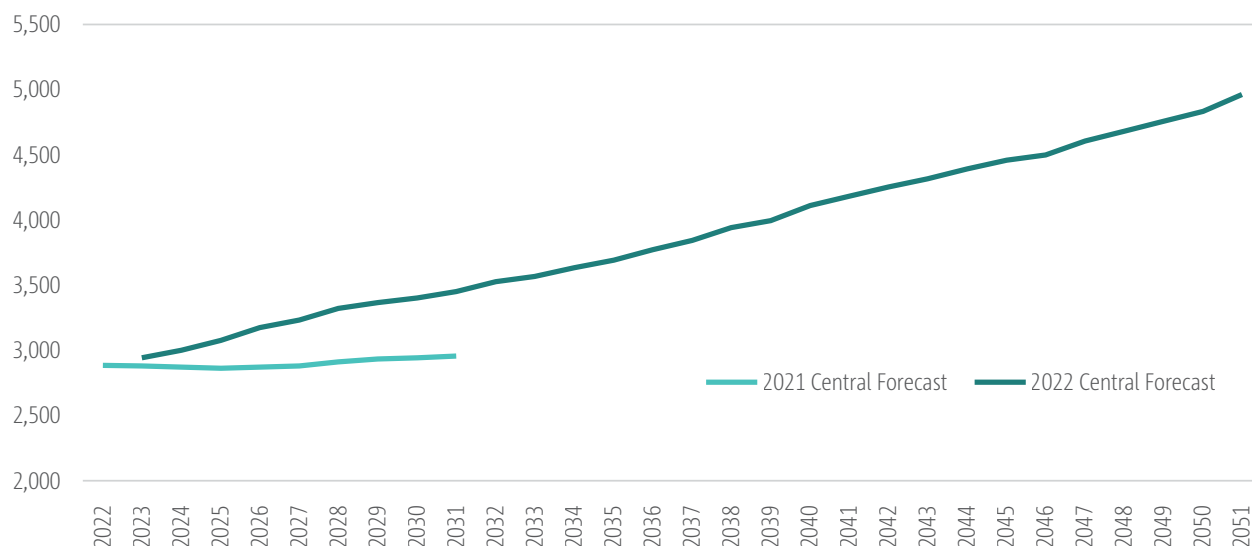
The key projects and programs comprising capacity augex are set out below.

Table B10. Augmentation expenditure > Capacity augex > Connection point upgrades

Connection point upgrades (capex \$59.3 million, 11% of total augex)	
The need	Our proposal
To comply with regulatory requirements in relation to joint network planning with the South Australian electricity transmission network service provider, ElectraNet, to meet and manage customer demand, and maintain the security of supply of our services and system. Neither a business-as-usual option of maintaining expenditure at 2020-25 levels nor a ‘do-nothing’ option is sufficient to meet the need in 2025-30: - in 2020-25, we spent less and upgraded less sites than anticipated due to decisions by ElectraNet to defer some works; - the need for increased expenditure in 2025-30 is forecast ‘bottom up’, directly dependent on information concerning our joint planning obligations and connection point agreements with ElectraNet; and - we will fail to meet obligations under the Transmission Connection Agreement, due to changing network load characteristics leading to transmission over-voltage and compromising system security – driven by changing customer in-house appliances.	Increase capex by \$57.6 million, in order to: - comply with our component of joint planning upgrades by undertaking works at three transmission connection points; and - works to comply with our Transmission Connection Agreement to address over voltage issues by installing 66kV and 11kV reactors at thirteen substations.

Table B11. Augmentation expenditure > Capacity augex > Substation and sub-transmission capacity

Substation and sub-transmission capacity (capex \$112.8 million, 22% of total augex)	
The need	Our proposal
The program meets and manages increasing local demand while maintaining the security of the distribution system. With significant growth forecast (Figure B15), several of our substations and sub-transmission assets would exceed their secure capacity in 2025-30 because of increased demand during peak periods. Our expenditure forecast is an output of our long-standing Distribution Network Planning Criteria – which seeks to comply with our service obligations in the EDC, our Distribution Licence, and service requirements in the NER. We consider when forecast network demand will breach network capacity, requiring augmentation through network or non-network solutions. We consider that the current regulatory framework inadequately values High Impact Low Probability events, and that our Distribution Network Planning Criteria provides the optimal long term outcomes for the community, balancing risk and cost. However, as a result of our own ‘top down’ challenge, we have chosen to apply an additional layer of economic analysis to our expenditure forecasts for 2025-30 in consideration of: 1. the general affordability concerns expressed by our customers; 2. erring on the side of conservatism, while we further evaluate the significant demand growth now forecast by AEMO for South Australia, and the potential for non-network solutions and flexible load connections to manage this demand; and 3. to reduce the rate of workforce scale-up required to deliver our overall capital program. This economic (probabilistic) analysis showed positive customer benefits versus costs for all substation and sub-transmission categories, as well as the Capacity program overall. However, it resulted in the removal of a number of projects dealing with single contingency (N-1) conditions on the network that would otherwise have been required to comply with our standard Planning Criteria.	Increase capex by \$71.2 million and 171%. Substation capacity projects include \$62.5 million towards: ▶ transformer upgrades at six substations; ▶ additional transformers at two substations; ▶ two new feeders to provide capacity for contingency conditions; and ▶ a new substation at Middleton. Sub-transmission capacity projects include: ▶ \$50.3 million towards line upgrades to address eleven sub-transmission line system limitations.

Figure B15. SA operational demand (summer 50% Probability of Exceedence, step change scenario)

2.6.2.2 Reliability augex

Capex \$122.3 million

23% of total augex

We propose several programs to manage reliability via network augex. These are distinct from repex (which also manage reliability), as they do not directly respond to address deteriorating network asset condition, but rather to the need for network enhancements to maintain or improve reliability where needed for compliance or where efficient. We considered the interactions of

reliability augex with our repex, and this expenditure is not duplicative.

The expenditure includes five programs with distinct investment needs:

- › a program to maintain underlying reliability on our network; and
- › four programs to make targeted improvements to either meet jurisdictional service standards or where efficient (program costs are outweighed by consumer benefits of reduced risk costs) and supported by customers.¹¹

As outlined in **Part A Section 6 A reliable, resilient and safe network**, we engaged with our customers on the need for these programs and various scenarios of how we could respond, from maintaining expenditure at 2020-25 levels, to making targeted improvements in particular customer segments and where we are not meeting jurisdictional service standards. The outcomes provided by our proposal align to the service-price balance sought by our customers as reflected in the recommendations of the People’s Panel.

Table B12. Augmentation expenditure > Reliability augex > Maintaining underlying reliability

Maintaining underlying reliability (capex \$61.3 million, 50% of reliability augex)	
The need	Our proposal
To maintain the underlying reliability of supply to our customers at historic levels and to continue to meet jurisdictional reliability standards, in line with the AER’s service incentive and jurisdictional reliability requirements relevant to the 2025-30 period. We assess that maintaining our business-as-usual approach, and continuing expenditure at the same level as in 2020-25, will be sufficient to maintain underlying reliability. Our analysis considers our historic reliability spend against performance levels and trends and suggests that our historic level of expenditure would reasonably reflect the ongoing need to maintain reliability at average levels: › our expenditure on reliability has been increasing historically, and in the 2015-20 period this saw an overall improvement in underlying reliability; › more recently in this period, reliability has been worsening, partly driven by increasing animal-related outages (particularly grey headed flying fox populations) and weather related outages; and › without continuing the underlying reliability program at historical levels, the average level of duration of interruptions (SAIDI) could worsen by 20 to 30 minutes over the 2025-30 period.	Continue our program of maintaining underlying reliability and maintain expenditure at 2020-25 levels. This program is limited to upgrade works to maintain historic performance in the 2025-30 period, and does not allow for additional upgrade works necessary to improve reliability, eg to worst served customers and regions, rural long supply restoration times and in the CBD.

Table B13. Augmentation expenditure > Reliability augex > CBD reliability improvement program

CBD reliability improvement program (capex \$27.1 million, 22% of reliability augex)	
The need	Our proposal
This program is discussed further in Section 2.6.3. The augex component of this program has a need of improving the reliability of CBD customers to bring performance into line with jurisdictional reliability standards over the next period. We estimate that if we did nothing to address this need, we will not comply with our jurisdictional service standard in relation to the CBD, set by the Essential Services Commission of South Australia (ESCoSA).	Improve CBD reliability to meet our jurisdictional service standard via an optimised combination of asset augex (feeder automation) and repex (replacing cables).

11. The improvement programs target improvements that would be insufficiently rewarded by the AER Service Target Performance Incentive Scheme (STPIS).

Table B14. Augmentation expenditure > Reliability augex > Low reliability feeders improvement program

Low reliability feeders improvement program (capex \$11.8 million, 10% of reliability augex)	
The need	Our proposal
To efficiently respond to customers' concerns regarding consistently low reliability experienced by some customers throughout our network. If we did not spend to address this issue, customers on low reliability feeders (predominantly in rural and remote areas) will in the 2025-30 period continue to experience repeatedly poorer reliability than their regional average. Customers on these feeders are our 'worst served customers'. We expect to have 107 feeders, which will be consistently classified as 'low reliability feeders' under our jurisdictional reliability requirements, at the commencement of the 2025-30 period (supplying 23,319 customers). On average these feeders have a SAIDI of 142% worse than their regional average	Improve reliability (by 31%), via remediations specific to each feeder and outage causes to 58 feeders (supplying 13,904 customers) of the 107 feeders we expect to be classified as 'low reliability feeders'. The 58 feeders are those for which improvements can be applied efficiently for customers, with benefits (using the Value of Customer Reliability, VCR) greater than costs relative to a situation where we do nothing. In addition to being supported by the People's Panel, the program is also supported by our willingness to pay survey which evidences that there is willingness across the general customer base to effectively subsidise improvements for worst served customers.

Table B15. Augmentation expenditure > Reliability augex > Regional reliability improvement program

Regional reliability improvement program (capex \$16.3 million, 13% of reliability augex)	
The need	Our proposal
To efficiently respond to customers' concerns that we need to improve reliability to customers in our worst served regions. If we did nothing to respond to this need, three regions (South East, Eyre Peninsula, Upper North) would continue to experience reliability levels significantly worse than the other seven regional areas (excluding the Adelaide CBD and metropolitan region) we report to ESCoSA. We estimate there is a level of improvement to the reliability performance of these three regions that would be efficient to achieve, with benefits to customers (applying the VCR) outweighing costs.	Bring performance in these three regions more in line with similar regions via various remediation works specific to the outage causes affecting poor performing feeders in those regions – either to address current outage causes or reduce the number of customers interrupted when outages occur. Target 52 feeders where it is efficient for customers to make improvements (benefits greater than costs) relative to a situation where we do nothing.

Table B16. Augmentation expenditure > Reliability augex > Rural long feeders supply restoration improvement program

Rural long feeders supply restoration improvement program (capex \$5.9 million, 5% of reliability augex)																																																																																																										
The need	Our proposal																																																																																																									
Respond efficiently to customers’ concerns regarding extended duration outages that are experienced by customers in remote areas of our network (Figure B16). If we did nothing to address the need, there would be a continued long term decline in the average restoration times of customers on rural long feeders, and we would continue to not meet our jurisdictional targets for these rural long feeders in the EDC. This is being driven by a number of factors including: › increasing network asset condition related failures; › damage to assets caused by individuals (such as farmers hitting poles); and › the fact that these fault types (repairing poles and wires that have come down) generally take longer to repair than weather related outages (which may involve replacing lightning damaged insulators). We are not obligated to achieve these jurisdictional targets, but we do want to explore how to make efficient progress toward meeting our targets and achieving more equitable and efficient outcomes for our customers.	Make efficient and prudent progress toward meeting EDC targets for rural long feeders. Aim to improve reliability to circa 18,000 customers, targeting rural long feeders where there is an economic benefit to customers (using the VCR) to improve restoration times. In addition to being supported by the People’s Panel, this program is also supported by our willingness to pay survey, suggesting there is willingness across the general customer base to effectively subsidise improvements for customers with long duration outages.																																																																																																									
Figure B16. Rural long network restoration, % of customer base restored after ‘x’ hours <table><caption>Estimated data for Figure B16: Rural long network restoration, % of customer base restored after ‘x’ hours</caption><tr><th>Year</th><th>% restored after 4 hrs</th><th>% restored after 7 hrs</th><th>Target - 4 Hrs</th><th>Target - 7 Hrs</th></tr><tr><td>05-06</td><td>29%</td><td>9%</td><td>30%</td><td>10%</td></tr><tr><td>06-07</td><td>42%</td><td>15%</td><td>30%</td><td>10%</td></tr><tr><td>07-08</td><td>22%</td><td>6%</td><td>30%</td><td>10%</td></tr><tr><td>08-09</td><td>22%</td><td>7%</td><td>30%</td><td>10%</td></tr><tr><td>09-10</td><td>34%</td><td>8%</td><td>30%</td><td>10%</td></tr><tr><td>10-11</td><td>36%</td><td>8%</td><td>30%</td><td>10%</td></tr><tr><td>11-12</td><td>21%</td><td>7%</td><td>30%</td><td>10%</td></tr><tr><td>12-13</td><td>25%</td><td>10%</td><td>30%</td><td>10%</td></tr><tr><td>13-14</td><td>31%</td><td>12%</td><td>30%</td><td>10%</td></tr><tr><td>14-15</td><td>28%</td><td>6%</td><td>30%</td><td>10%</td></tr><tr><td>15-16</td><td>32%</td><td>12%</td><td>30%</td><td>10%</td></tr><tr><td>16-17</td><td>28%</td><td>9%</td><td>30%</td><td>10%</td></tr><tr><td>17-18</td><td>29%</td><td>11%</td><td>30%</td><td>10%</td></tr><tr><td>18-19</td><td>36%</td><td>14%</td><td>30%</td><td>10%</td></tr><tr><td>19-20</td><td>30%</td><td>8%</td><td>30%</td><td>10%</td></tr><tr><td>20-21</td><td>29%</td><td>13%</td><td>30%</td><td>10%</td></tr><tr><td>21-22</td><td>35%</td><td>8%</td><td>30%</td><td>10%</td></tr><tr><td>22-23</td><td>30%</td><td>10%</td><td>30%</td><td>10%</td></tr><tr><td>23-24</td><td>30%</td><td>10%</td><td>30%</td><td>10%</td></tr><tr><td>24-25</td><td>30%</td><td>10%</td><td>30%</td><td>10%</td></tr></table>		Year	% restored after 4 hrs	% restored after 7 hrs	Target - 4 Hrs	Target - 7 Hrs	05-06	29%	9%	30%	10%	06-07	42%	15%	30%	10%	07-08	22%	6%	30%	10%	08-09	22%	7%	30%	10%	09-10	34%	8%	30%	10%	10-11	36%	8%	30%	10%	11-12	21%	7%	30%	10%	12-13	25%	10%	30%	10%	13-14	31%	12%	30%	10%	14-15	28%	6%	30%	10%	15-16	32%	12%	30%	10%	16-17	28%	9%	30%	10%	17-18	29%	11%	30%	10%	18-19	36%	14%	30%	10%	19-20	30%	8%	30%	10%	20-21	29%	13%	30%	10%	21-22	35%	8%	30%	10%	22-23	30%	10%	30%	10%	23-24	30%	10%	30%	10%	24-25	30%	10%	30%	10%
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2.6.2.3 Network resilience

Capex \$16.8 million

3% of total augex

Climate change and recent extreme weather events, both locally and interstate, have raised customer concerns about the resilience of their communities to these events and have made the issue of long duration power outages of central importance to our customers. Customers also rightly observe that increased electrification, particularly of transportation, will make network resilience increasingly important in future.

However, other than risks in relation to bushfires and extreme heat, which we continue to manage via our regular programs as discussed above, we have insufficient confidence in climate model forecasts to predict the way that climate change will impact our network and customers. We therefore consider it prudent to take

a more measured approach in 2025-30 until we have more certainty to justify greater ex-ante expenditure on network resilience (i.e. expenditure to improve the ability of the network to withstand or recover quickly from major weather events) and community resilience.

Our approach to resilience in this Draft Proposal is to:

1. not use climate change forecasts to justify our proposed expenditure, and instead err on the side of conservatism by using climate change forecasts to test the sensitivity of the assumptions supporting our network expenditure;
2. propose a modest program of investing in additional mobile generation (discussed below) to address customer concerns regarding existing issues in relation to long duration power outages in regional and remote areas based on historic

performance – a program that is also likely to provide additional flexibility should climate change lead to increased frequency of extreme weather events; and

3. also consider resilience in our proposed Innovation Fund (refer **Part A Section 10 Our expenditures have been subject to significant challenge**) to trial alternative solutions, including partnerships, to improve customer experience during severe weather and other events that may cause long duration outages.

Initiatives (1) and (2) and aspects of initiative (3) were supported by our customers as reflected in the recommendations of the People's Panel (refer **Part A Section 6 A reliable, resilient and safe network**). Our proposal to deal with aspects of initiative (3) via an Innovation Fund was supported by our Community Advisory Board.

Table B17. Augmentation expenditure > Network resilience > Resilience program

Resilience program (capex \$16.8 million, 3% of total augex)	
The need	Our proposal
To address concerns raised by customers in relation to long duration outages in regional and remote areas and the downstream impact of these outages on other critical services. We acknowledge that community resilience is the responsibility of many stakeholders and that SA Power Networks is only one part of this. While we focus this program on earlier restoration for towns and regional centres where many critical services are located, we assessed the costs and customer benefits (using the VCR) and only proposed a program that provides a net benefit. This will be complemented by the use of our proposed Innovation Fund (section 2.6.9) to trial alternative solutions, including partnerships, to improve the customer experience with regards to long duration outages in these areas.	Implement a program to procure three mobile generators, with two located in key regional areas (Upper North and South East) and one to provide additional capacity to regional areas closer to Adelaide.

2.6.2.4 Powerline Environment Committee Program (PLEC)

Capex \$59.5 million
11% of total augex

Table B18. Augmentation expenditure > Powerline Environment Committee Program

Powerline Environment Committee Program (capex \$59.5 million, 11% of total augex)	
The need	Our proposal
Complying with jurisdictional government requirements. We have a long-standing requirement to underground selected parts of the distribution network in accordance with requirements stipulated in South Australian legislation and a PLEC charter, to improve the aesthetics of electricity infrastructure for the South Australian community, having regard to road safety and electrical safety. Projects funded are approved by an independent committee convened by the South Australian Office of the Technical Regulator, funded two thirds by SA Power Networks and one third by local councils.	Continue our legislated PLEC expenditure program.

2.6.2.5 Bushfire management

Capex \$26.0 million
5% of total augex

This comprises a suite of programs to manage bushfire risk through network upgrades (augex). These programs mitigate the risk of our assets starting a bushfire, and reduce customer supply interruptions associated with our public safety power shutoffs during bushfire risk times.

These programs are distinct from our repex programs, which also help to manage bushfire risk by replacing assets that are deteriorating in condition and could fail and risk starting a bushfire. We have considered the interactions of both programs to ensure there is no duplication in our expenditure.

We engaged customers on the needs of the bushfire management augex programs and various scenarios of how we could respond, from do nothing, to achieving differing safety

levels. The outcomes of our proposed programs align to our customers’ expectations as reflected in the People’s Panel recommendations (refer **Part A Section 6 A reliable, resilient and safe network**).

Table B19. Augmentation expenditure > Bushfire management > Bushfire risk mitigation program

Bushfire risk mitigation program (capex \$21.7 million, 83% of bushfire management)	
The need	Our proposal
Customers’ concerns and the need to reduce the risk of our network assets starting bushfires where it is efficient to do so (where program costs are outweighed by customer benefits of reduced risk costs). To date, we have previously only undertaken bushfire mitigation programs targeting high bushfire risk areas. However, our most recent analysis undertaken by CSIRO indicates that the opportunity exists to further reduce risk, largely in medium bushfire risk areas, and that it would be efficient to do so. That is, the costs to customers are outweighed by the benefits (via avoided risks of property damage, crop loss and personal injury/death).	Spend to mitigate bushfire risk where efficient for customers (benefits greater than costs). We propose to achieve this by implementing ultra-fast sensitive protection on 239 feeders to reduce the risk of a fire start, a solution that is considerably more efficient than others we have explored (eg undergrounding).

Table B20. Augmentation expenditure > Bushfire management > Public safety power shutoff mitigation

Public safety power shutoff mitigation (capex \$4.3 million, 17% of bushfire management)	
The need	Our proposal
Address customers' concerns, and reduce customer impacts of Public Safety Power Shutoffs where power is disconnected on the highest bushfire risk days. Currently, our business as usual approach is that at times of high bushfire risk, we have authority to switch off power to customers' premises. While this mitigates risks during bushfire risk times, it costs customers via reduced reliability (valued using the VCR). If we continued to not undertake expenditure to address this need, there would continue to be lost value/negative benefits to customers by way of poorer reliability outcomes than might otherwise be the case.	Target a level of consequence mitigation that is efficient, where customer benefits (using the VCR) outweigh costs. Implement remotely operated switchgear and limited/targeted powerline upgrading/undergrounding to maintain supply to high risk regions. This approach is demonstrably more efficient than alternatives considered, including extensive undergrounding. We note the VCR is probably understated during high temperature, high bushfire risk conditions, but we have only used the AER VCR for this analysis.

2.6.2.6 Augex – other

Capex \$48.5 million
9% of total augex

Table B21. Augmentation expenditure > Augex – other

Augex – other (capex \$48.5 million, 9% of total augex)	
The need	Our proposal
This expenditure comprises a diverse range of initiatives. These include programs to maintain network safety through largely recurrent spend on lighting, fencing and security for our substations, earthing systems, and continuing to implement backup protection on our rural network. This also includes expenditure to manage our environmental compliance, particularly with respect to oil containment. Expenditures on these initiatives are largely forecast on the basis of historic expenditure.	Continue these largely recurrent programs which mainly seek to manage network safety and environmental compliance.

2.6.3 CBD reliability improvement program

Capex \$91.2 million

5% of total augex, 7% of total repex

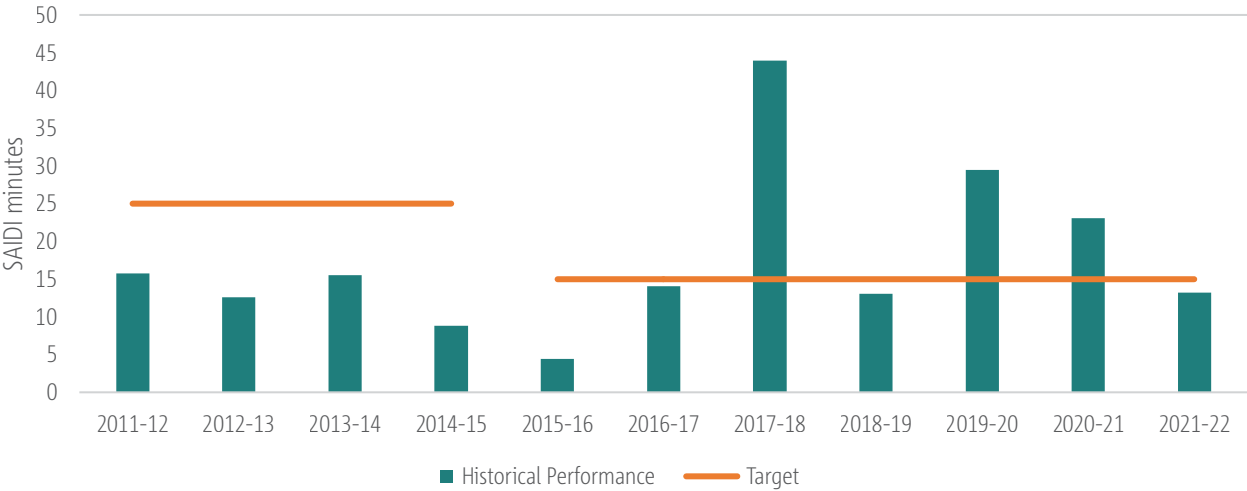
This program comprises repex and augex and is discussed separately here given the importance of this

initiative for our customers, with its own specific Focused Conversation and People’s Panel deliberation.

Table B22. CBD reliability improvement program > CBD reliability program

CBD reliability program (capex \$91.2 million, 5% of total augex, 7% of total repex)	
The need	Our proposal
To improve CBD reliability service levels in order to comply with our jurisdictional reliability service standards set by ESCoSA (Figure B17). Our business-as-usual practice has been to run the underground cables in the CBD network to failure with minimal proactive investment, and the CBD is now the oldest underground cable network in the South Australian distribution network. While we have been increasing our proactive replacement of CBD cable in the 2020-25 period in response to increasing failures, we have been failing to meet our jurisdictional target, predominantly due to cable asset failures. For the 2025-30 period, jurisdictional reliability service standards are set at a SAIDI of 15 minutes, and we will not be able to comply with this standard under a business-as-usual scenario. We engaged with our customers on various scenarios of how we could respond to the investment need. Our customers recognised the importance of CBD reliability to the prosperity of the economy and community of Adelaide. Our customers’ view, as reflected in the recommendations of the People’s Panel, was that we must invest to improve reliability in the CBD in order to meet regulated service standards (refer Part A Section 6 A reliable, resilient and safe network).	Implement an optimised combination of solutions to improve CBD reliability – selecting the most efficient combination of repex and augex to achieve the overall target need. Program includes augex via feeder automation (\$27.1 million), and repex (\$64.1 million) to retire and replace underground cables proactively and reactively. The program aims to improve current reliability in the CBD in line with ESCoSA’s standard over the 2025-30 period.

Figure B17. SAIDI performance of Adelaide CBD vs ESCoSA target - historic and forecast



2.6.4 Connections expenditure

Capex \$247.6 million

10% of total capex

This is the total net expenditure to connect customers to our distribution network in 2025-30, consistent with NER obligations and procedures in our Connections Policy. Our approach to forecast net connections expenditure for 2025-30 remains largely as per our current approach. The key change we propose is to add an additional connections category, to capture Large Embedded Generator connections (LEGs). We are seeing increasing demand and complexity for CER connection services associated with LEGs and large load connections such as firm and flexible load/export

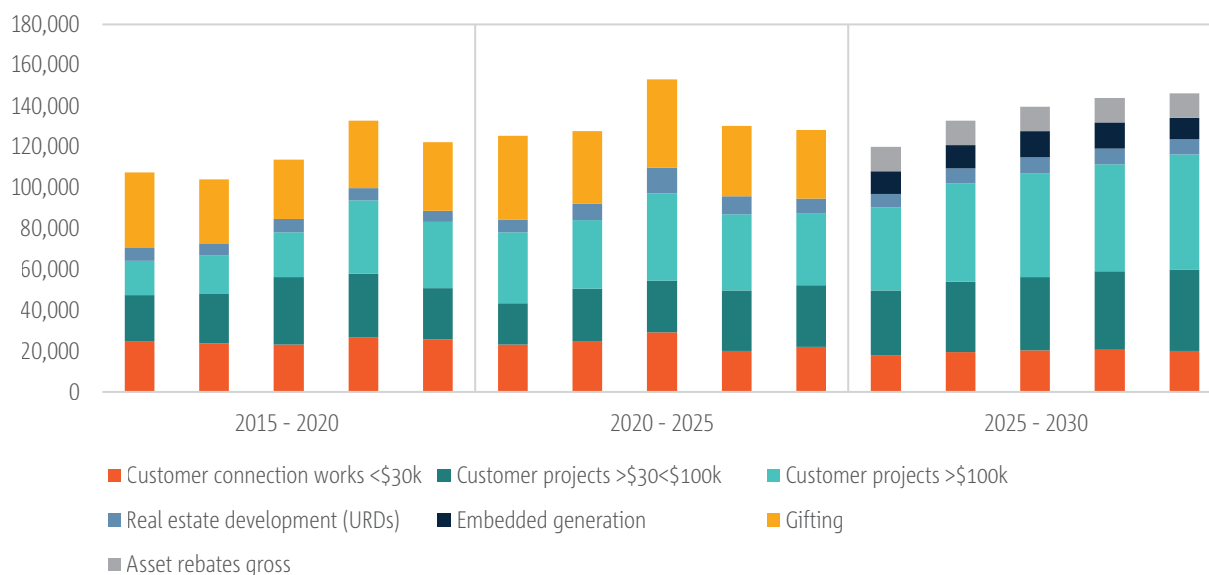
combinations. These loads include battery energy storage systems, solar farms and fast electric vehicle chargers or a combination thereof. LEGs include NEM scheduled generators (greater than 30 MW) which previously have not connected to our distribution network.

For 2025-30, we forecast gross connections expenditure (Figure B18), to be higher than in 2020-25, with continued economic recovery and strong growth particularly in major customer connections and embedded generation. We forecast gross connections will return to

more historic levels experienced pre 2015/16, but not to the high averages seen over the 2008/09 to 2010/11 period.

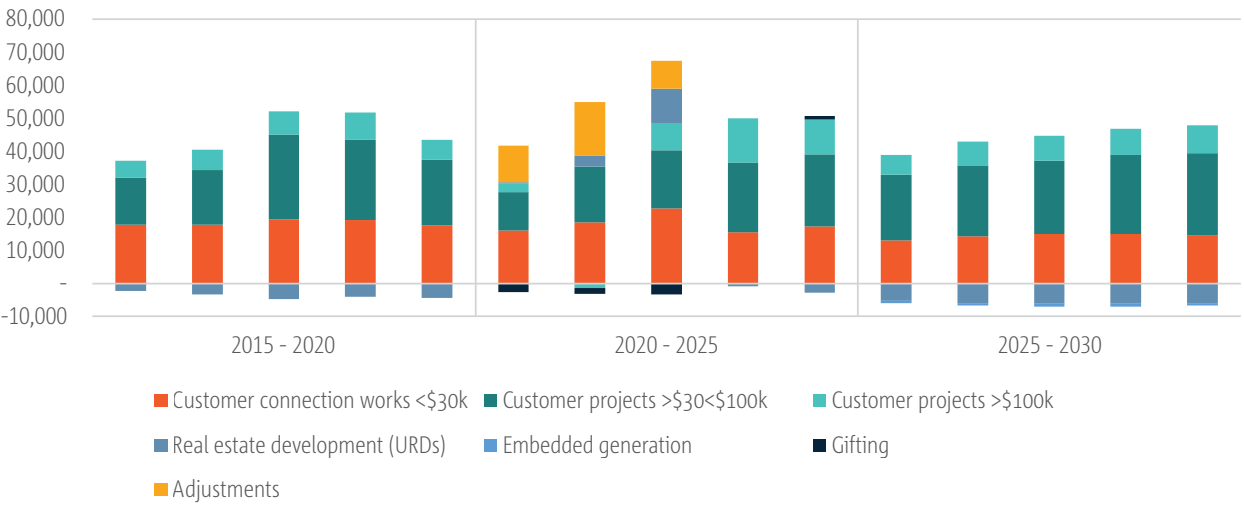
However, customer contributions are also expected to increase due to changes in the WACC¹², particularly for non-residential connections (including medium and major customer connections), and this is forecast to offset the increase in gross connection costs. We therefore forecast a slight decrease in net expenditure for the 2025-30 period (Figure B19).

Figure B18. Customer connections gross – by category (\$ million, 2025)



12. As the WACC increases, the amount an individual connecting customer must contribute (pay directly) to their connection costs via connection charges increases (the WACC is an input to calculating the Incremental Revenue Rebate determined by our Connection Policy), which decreases the net connections expenditure to be recovered from the general customer base.

Figure B19. Customer connections net - by category (excluding gifting) (\$ million, 2025)



2.6.5 Customer Energy Resources (CER) integration

Capex \$97.8 million

4% of total capex

Our CER integration expenditure covers a range of customer and industry-facing initiatives to efficiently support forecast growth in CER in South Australia. The two key programs in this area were deliberated on by the People's Panel and the outcomes they provide align with the Panel's recommendations (refer **Part A Section 8 Enabling clean energy**):

- the expenditure's primary purpose is to upgrade network capacity, and the systems we use to flexibly manage network capacity, in order to enable customers to export energy from their CER (i.e. 'export services') and achieve service levels that customers value; and
- we also propose to invest in systems and capabilities to enable greater flexibility in customer energy loads (the demand side) and to facilitate and encourage shifting of loads to the daytime, building on our existing capabilities for flexibly managing solar exports.

We also propose modest spend to work proactively with industry to improve compliance with standards for CER installation and operation, recognising the importance of high levels of industry compliance in managing a safe and secure distribution system and market in the face of high levels of renewables on our network.

The key programs and projects comprising CER integration expenditure are set out below.

Table B23. Customer Energy Resources integration > Demand flexibility

Demand flexibility (capex \$15 million, 15% of total CER integration)	
The need	Our proposal
To manage and minimise the costs of managing customer demand on our network (in this case, electrical load) by improving our capabilities to offer and incentivise flexible services for customer loads and generation, ultimately increasing network utilisation. Currently, our business-as-usual approach and that of all NEM networks is to manage network demand by either building more capacity or interacting with the demand-side typically by paying third parties to reduce demand or draw on energy storage devices during peak demand periods. However, technological advances, such as those SA Power Networks is at the global forefront in employing in flexibly managing exports on our network via Dynamic Operating Envelopes (DOEs), are now enabling us to consider applying the same approaches to the load side. This will help mitigate future growth in peak demand, minimise costs to integrate Electric Vehicle (EV) charging, and facilitate increased shifting of loads to the daytime to 'soak up' surplus solar.	Develop 'flexible load' connection services for small and large customers – extend the ICT systems, technical standards, network capacity models and business processes developed to support flexible export connections, and a full 'DOE' solution for import and export. Develop new customer services and operational capabilities to help customers activate their smart devices like home batteries, smart electric vehicle chargers, hot water and smart appliances.

Table B24. Customer Energy Resources integration > CER compliance

CER compliance (capex \$6.1 million, 6% of total CER integration)	
The need	Our proposal
To meet and manage demand for customer export services, maintain the security of our distribution services and system and ensure compliance with regulatory requirements. The aim is to improve compliance to technical standards, connection rules, and regulatory requirements for CER installations in South Australia in 2025-30. Network connected generators must conform to several technical standards and regulatory requirements, critical to ensuring the distribution network system operates safely and reliably at South Australia's high level of CER penetration. Recent AEMO studies reveal high levels of non-compliance with these standards across the population of installed equipment in South Australia, findings also reflected in our own investigations.	Continue extending our compliance program initiated in 2021, shifting our focus to data analytics to detect non-compliance, taking advantage of the expected increase in available data from smart meters in 2025-30, including developing compliance analytics applications with associated business rules for response to detected non-compliance.

Table B25. Customer Energy Resources integration > Export service

CER integration – Export service (capex \$76.8 million, 78% of total CER integration)	
The need	Our proposal
To meet and manage forecast demand for customer export services. Our customers currently (2020-25) receive a high grade of export service. A sample of customers on our flexible exports program (enabled via DOEs) indicates that circa 98% of solar customers currently experience an export service of at least 95%, meaning their exports are curtailed for fewer than 5% of daylight hours through the year. We forecast that under a counterfactual scenario were we to make no new investments in increasing network hosting capacity in the 2025-30 period, our network will be increasingly unable to meet demand for service due to voltage and thermal constraints. This would require increased curtailment of customer exports using dynamic operating envelopes meaning customers would see a degradation in service levels, resulting in lost economic value to exporting customers and ultimately to all customers as a result of energy no longer available to the NEM. We considered several alternative investment scenarios with higher or lower expenditure and corresponding differences in service levels and posed these options to our customers to determine the outcome they value and expect. Through our engagement, customers indicated that they expect us to invest in sufficient capacity to broadly maintain current service levels, favouring a target service level of at least 95% for most customers.	Align to the expenditure level recommended by the People’s Panel and enable maintenance of a minimum service level of 95% for at least 90% of customers. Upgrade works to address emerging constraints on the LV network, improving voltage and increasing available export capacity for circa 150,000 customers who would otherwise experience reduced levels of service. The costs of this program are expected to be broadly aligned to the customer benefits expected by applying the AER Customer Export Curtailment Value. Further, the program’s cost is significantly less than what our Customer Values Research survey shows is the willingness of our customers to pay for the service outcome.

2.6.6 Information and Communications Technology (ICT)

Capex \$314.3 million

13% of total capex

Our proposed ICT expenditure enables the delivery of electricity distribution services to customers across the full spectrum of our operations including:

- › the means by which we communicate with customers;
- › the management of our business activities;
- › the data capture tools and analytics we employ to understand the condition and capacity of our network;
- › how we deploy our resources in the field; and

- › how we protect our environment from cyber threats, among other critical activities.

Reliance on ICT (and data) has increased significantly as it has become the primary means to adapt to and cost effectively manage our changing energy services, while maintaining a reliable and safe network.

Our forecast for 2025-30 is driven by distinct identified needs and is grouped according to the needs following the approach the AER sets out in its ICT guidance note¹³, as follows:

- › **recurrent** expenditure - regular and frequent spend on cycles of one to five years to 'maintain existing services'; and

- › **non recurrent** expenditure – new initiatives or expenditure incurred on cycles greater than every five years, and grouped according to three identified need categories: (1) **maintaining existing services**; (2) **meeting new or altered compliance requirements**; and (3) **enabling new or expanded capability**.

All of our ICT totex was communicated to customers for information. Our customers more specifically deliberated on and provided recommendations on initiatives to 'meet new or altered compliance requirements' and 'enable new or expanded capabilities' and the initiatives included in our forecast accord with customer expectations as reflected in the recommendations of the People's Panel.

2.6.6.1 Recurrent ICT – maintain existing services

Capex \$161.8 million

51% of total ICT capex

Recurrent ICT comprises various programs with an identified need of maintaining our existing ICT systems, services, functions, capabilities and/or benefits and managing technology

risk. It is categorised according to each asset sub-class. Key initiatives within this area of expenditure are discussed below.

Table B26. Information and Communications Technology > Recurrent ICT – maintain existing services > IT applications refresh

IT applications refresh (capex \$67.8 million, 22% of total ICT)	
The need	Our proposal
The need to refresh our existing applications seeks to ensure that our systems maintain their existing functionality, are secure and evolve with the rapidly changing environment. The need is increasing as we seek to manage the risk and retain the value from large non-recurrent programs (circa \$170 million) undertaken in the 2020-25 period as well as managing the increased use of ICT across our business – which increases the reliance on our applications portfolio.	Increase capex by \$4.5 million or 7%. Deliver our regular program of small periodic application version upgrades, security patching, minor enhancements and defect remediation for our ICT application portfolio.

13. AER, Non-network ICT capex assessment approach, November 2019 available at: www.aer.gov.au/system/files/AER%20-%20Guidance%20Note%20-%20Non-network%20ICT%20capex%20assessment%20approach%20for%20electricity%20distributors%20-%2028%20November%202019.pdf

Table B27. Information and Communications Technology > Recurrent ICT – maintain existing services > ICT infrastructure refresh

ICT infrastructure refresh (capex \$40.4 million, 13% of total ICT)	
The need	Our proposal
Refresh our existing ICT infrastructure to ensure that we maintain existing functionality and security. Our ICT infrastructure underpins our delivery of all customer services and is increasingly critical to our ability to maintain and operate the electricity network. The need to spend capex is decreasing as more of this spend shifts to operating expenditure, where this spend is associated with ‘Cloud’ technologies – this reflects the accounting treatment of this expenditure.	Spend \$6.0 million or 13% less in capex. Ensure ICT infrastructure and associated services are maintained and secured with acceptable risk levels by continuing our regular infrastructure refresh.

Table B28. Information and Communications Technology > Recurrent ICT – maintain existing services > Client devices refresh

Client devices refresh (capex \$37.0 million, 12% of total ICT)	
The need	Our proposal
Refresh our client devices such as laptops, personal computers, mobile phones, tablets among other devices, to ensure our staff continue to have the tools they need to perform work effectively and efficiently. Replacement of devices is needed to mitigate risks from declining reliability and performance as these devices age, become unreliable, require increased maintenance and ultimately fail. The need is increasing, particularly with respect to mobile devices driven by the shift to working from home, as well as the utility cyber requirements that have reduced the sharing of field mobile devices.	Increase capex by \$2.5 million or 7% to continue our regular replacements of devices.

2.6.6.2 Non-recurrent ICT – maintain existing services: large upgrades and replacements

Capex \$105.2 million

33% of total ICT

This comprises several programs with a need of maintaining existing ICT systems and services and managing technology risk. Expenditure is driven

by large and critical systems reaching their 'end of useful life' in the 2025-30 period, with that 'end' being either:

- › an announced end to vendor or supplier support arrangements, requiring us to take action to ensure we maintain long term secure and reliable services; and/or

- › systems that are legacy and no longer 'fit for purpose', being unable to cost effectively adapt to the requirements of the energy transition.

The two largest capex projects in this category are detailed below.

Table B29. Information and Communications Technology > Non-recurrent ICT – maintain existing services: large upgrades and replacements > Replacing the Service Order Management System

Replacing the Service Order Management System (capex \$23.9 million, 8% of total ICT)

The need

Our service order management system will be due for replacement, triggered by the vendor ceasing normal support, extended support and legal use in 2030. This system is critical to managing all customer and electrician requests and activity related to national market transactions, customer connections (including disconnections and reconnections), quotes and associated billing.

If we maintained only our business-as-usual spend and did not replace this system, the risk to customer services would significantly increase post 2030 as we no longer have access to security patching and we will also breach our software licensing obligations. Costs to maintain services would increase significantly, to try and keep the software operating, including through third-party support to try and maintain the software.

Our proposal

Replace the system to ensure that we cost effectively maintain our NEM obligations, continue to deliver reliable customer services and manage our cyber security risk.

Table B30. Information and Communications Technology > Non-recurrent ICT – maintain existing services: large upgrades and replacements > Enterprise data warehouse replacement project

Enterprise data warehouse replacement project (capex \$18.4 million, 6% of total ICT)

The need

Our legacy SAP data warehouse was unable to meet the requirements to manage the diversity of data sources created by the energy transition and we have created a modern Enterprise Data Platform (EDP) in Microsoft Azure. There is now a need to consolidate all remaining data sets from the SAP data warehouse into the EDP and decommission it when extended support ends in 2030, aiming to simplify our technology landscape to keep costs down.

Under a business-as-usual approach of continuing with the current system, service risk increases when we no longer have access to security patching for our legacy system (2030). We would then need to seek additional third-party support (at extra cost) to support the software. Further we would not gain the efficiencies from consolidating onto a single data platform and trusted source of truth.

Our proposal

Consolidate our legacy data warehouse onto the EDP in 2025-30. This will maintain our current levels of services and risk, and drive the most cost-effective approach to our data management long term – particularly important given the increasingly fundamental role of data in network and customer decisions.

2.6.6.3 Non-recurrent ICT – meet new or altered regulatory compliance requirements or obligations

Capex \$2.4 million
1% of total ICT

Table B31. Information and Communications Technology > Non-recurrent ICT – meet new or altered regulatory compliance requirements or obligations > Cyber security

Cyber security (capex \$2.4 million, 1% of total ICT)	
The need	Our proposal
If we do not increase expenditure on cyber security, we will see increasing risk of cyber threats in 2025-30 and non-compliance with obligations in the Australian Energy Security Cyber Security Framework (AESCSF) that we expect to be in force at the end of the 2025-30 period. We sought customers’ views on several scenarios of how to respond to the need, from only ensuring compliance with expected requirements, to exceeding these requirements by the end of 2025-30. Our customers recommended, via the People’s Panel, that we increase cyber security investment to exceed obligations on the basis that, by 2030, the cyber threat landscape will have significantly evolved and customers will be exposed to greater impacts of cyber risk as the electricity grid becomes a more fundamental part of their lives due to increased electrification.	Spend \$2.4 million in capex on cyber security, with most of the required expenditure being in opex given this is its predominant nature. Ensure that we exceed cyber security obligations by 2030.

2.6.6.4 Non-recurrent ICT – new or expanded capability¹⁴

Capex \$45 million
14% of total ICT

Table B32. Information and Communications Technology > Non-recurrent ICT – new or expanded capability > Personalised and on-demand services improvements

Personalised and on-demand services improvements (capex \$9.8 million, 3% of total ICT)	
The need	Our proposal
If we did nothing new, we forecast an increasing rate of high volume communication interactions with customers, driving costs to customers via (1) increasing costs to us in responding to these high volume interactions; and (2) the length of time customers spend waiting for resolution to those interactions. To date we have observed: - growing energy sector complexity, with increased CER use impacting average call duration and call volumes to our contact centre; - average call time increasing from five to nine minutes and annual demand for digital services increasing by 10% from 2017-2022, more than double the growth in customer numbers; and - growth across a number of key service areas including outage reporting, planned notification jobs, claims, complaints and digital channels, with the total number of interactions having grown by 276% from 2017-2022. We need to consider how to more effectively leverage digital channels to manage the cost to serve customers, without compromising our level of service to customers. We sought customers' views on how to respond to the need, from a scenario of do-nothing to investing in ICT for more personalised and on demand services. The People's Panel recommendation did not achieve consensus on this topic.	While the People's Panel did not achieve consensus, we note that there has been some support through our engagement for this project, particularly via our Focused Conversations, and that it is beneficial to customers. We therefore revised and scaled-down the project to focus only on improving communications where there are quantified benefits to customers outweighing costs. We also undertook a customer willingness to pay survey providing another reference check which demonstrates that our customers see value in improving the way they can communicate with us and vice-versa as enabled via digital technologies.

14. The personalised and on demand services improvement project listed, only pertains to the component of our personalised and on-demand services program that is associated with enabling 'new or expanded capability', following the AER's ICT assessment approach. There are also related replacements required to enable these improvements. The total cost of the whole 'Personalised and on-demand services program' is \$38m.

Table B33. Information and Communications Technology > Non-recurrent ICT – new or expanded capability > Assets and Work phase 3

Assets and Work phase 3 (capex \$34.6 million, 11% of total ICT)	
The need	Our proposal
We forecast a long-term uplift in network work volumes, driven by a need to increase the rate of repex (due to asset condition) and undertake more augex (due to stronger demand). We want to consider opportunities to minimise the cost of delivering this work. In considering how to respond to the need, we posed various scenarios to customers, from doing nothing, to investing to improve asset management efficiency via ICT and our customers expect, as reflected in recommendations of the People’s Panel, that we should invest in improving asset management efficiency providing that benefits to customers outweigh costs.	Align to customer expectations. Invest in ICT to improve the efficiency of our asset management practices, particularly in scheduling and executing work, to reduce the unit cost of delivering network work (ie repex, augex, CER programs). The program will achieve customer benefits via cost reduction/avoidance outweighing investment costs, with \$30 million of these benefits accruing to customers in the 2025-30 period. Our total capex forecast includes an adjustment to this amount that will be applied to all network expenditure. Additional benefits will accrue to customers in the years subsequent to 2030.

2.6.7 Fleet expenditure

Capex \$166.5 million

7% of total capex

Our vehicle fleet supports our delivery of distribution services to customers. The majority of our fleet

expenditure is recurrent in nature. However, we forecast an increase in fleet expenditure, principally due to the need to expand our fleet to support the forecast increase in network field work, as well as to transition some of our fleet to Electric Vehicles where efficient to do so.

Fleet expenditure does not comprise specific projects or programs per se, but addresses distinct investment drivers, discussed below. The transition to Electric Vehicles was explicitly deliberated on by our People's Panel.

Table B34. Fleet expenditure > Base expenditure

Base expenditure (capex \$126.7 million, 76% of total fleet)	
The need	Our proposal
To maintain our existing fleet according to set vehicle replacement cycles that accord to the AER decision for our 2020-25 period and practice of other networks. This expenditure relates only to our existing fleet and does not address needs over the 2025-30 period to increase the volume of our fleet assets to support an uplift in network work volumes nor to enable a transition to Electric Vehicles.	Increase capex by \$17 million to maintain our existing replacement cycles, with the increase explained by the lumpy nature of when some of our fleet is due for replacement.

Table B35. Fleet expenditure > Trend escalation

Trend escalation (capex \$31.4 million, 19% of total fleet)	
The need	Our proposal
To increase the volume of our fleet assets to support the increased volume of network work that we are forecasting for 2025-30.	Spend an additional (on top of the base) \$31.4 million in capex to meet and support forecast increases in network work volume, by acquiring 163 additional vehicles.

Table B36. Fleet expenditure > Step change

Step change (capex 8.4 million, 5% of total fleet)	
The need	Our proposal
EVs are lowering in cost and reaching cost parity with Internal Combustion Engine (ICE) vehicles for some categories of our fleet. While EVs generally require higher upfront capital cost of purchase, they drive lower comparative opex due to savings in fuel and maintenance – i.e. they are more efficient on a total cost of ownership basis. We engaged with customers on various scenarios of how we could progress toward a net zero future, posing scenarios from doing what is economic to more aggressive transitioning of our vehicle fleet to EVs. Our customers expected, as reflected in the People's Panel recommendations, that while we should be taking a position of leadership in decarbonising our business, that we should only invest in transitioning our fleet to EVs where it is economic to do so.	Spend an additional \$8.4 million (on top of the base) in capex, to acquire 234 EVs instead of ICE vehicles, when these are flagged for replacement according to our replacement cycles, and the present value cost of these vehicles is lower than alternative ICE vehicles on a total cost of ownership basis. Align to customer expectations as reflected in the People's Panel recommendations. Increase capex in the short term for longer term savings to enable a gradual transition to EVs.

2.6.8 Property expenditure

Capex \$115.7 million

5% of total capex

Our proposed property expenditure provides a fit-for-purpose, safe, and compliant asset portfolio that effectively and efficiently supports our delivery of services to customers, and is separated into:

› ‘recurrent expenditure’: planned cyclical activities to retain existing functionality, capability and service, on regular cycles set out in our Property Asset Register, including refurbishments and

more frequent replacements and renewals to maintain existing services. These respond to key drivers of:

- › needing to shift from reactive to proactive property asset replacement/refurbishment, to optimise long term outcomes;
- › the lumpy nature of our depot renewal, with two of our largest depots being due for renewal in the 2025-30 period; and
- › the need for site upgrades to enable a transition of our vehicle fleet toward EVs.

› ‘non-recurrent expenditure’ – less frequent replacements and upgrades to provide more discernible benefits, largely strategic projects that do not fall under planned cyclical works in recurrent expenditure.

Our total property forecast and the needs it responds to were discussed with our customers in our Focused Conversations, and deliberated on and supported by the People’s Panel recommendations.

Table B37. Property expenditure > Recurrent – replacements and refurbishments

Recurrent – replacements and refurbishments (capex \$22.3 million, 19% of total property)	
The need	Our proposal
This area covers a broad range of cyclical activities with an investment need of seeking to maintain functionality, capability and service. It responds to the poor condition of a significant proportion of our property assets, with our comprehensive assessment of our property portfolio by independent consultants finding that 90% of our portfolio is in the high-to-medium criticality range, due to poor-to-very-poor condition. Over 25% of our assets are reaching their end of useful life in the 2025-30 period. In 2020-25 we significantly increased our analytical capability in identifying and assessing the condition of property assets to prioritise and optimise our spend. In 2021 we engaged consultants KPMG to independently assess the condition, risk and criticality of our property portfolio – physically inspecting property assets, cataloguing assets in an Asset Register and assigning a condition rating to each asset in accordance with Institute of Public Works Engineering Australasia Guidelines. Risk was assessed with each asset rated based on our company Risk Framework – assessing asset criticality to identify property assets essential to support operations, defined by a high-risk consequence in the event of failure, with likely implications for service delivery, safety or compliance. Assessed outputs were used to prioritise renewal and replacement investments to optimise costs while keeping the risk at an acceptable level.	Propose \$22.3 million to undertake regular replacements and refurbishments to maintain existing functions, capabilities and service. Our proposal minimises costs relative to other options we considered.

Table B38. Property expenditure > Recurrent – renewals

Recurrent - renewals (capex \$60.9 million, 53% of total property)	
The need	Our proposal
To address the risk posed by poor asset condition as well as to efficiently and prudently meet growing work volume demand. Our 15-year renewal plan across our whole portfolio identifies two major depots as due for renewal in 2025-30, Port Augusta and Mount Barker, comprising 30% of the total renewal program. The rest of the overall renewal expenditure comprises a broad range of more regular and minor works to renew facilities across our entire property portfolio. Mount Barker Depot: The identified need is to respond to the current depot's capacity constraint: › this is one of our highest utilised operational works depots, constructed in 1980, storing equipment and offices for field crews to meet operational and public safety needs of our network in delivering customer services – the depot is located in what has become a densely populated residential area experiencing rapid population growth. › if we continue to operate and maintain the existing site as currently, we forecast the site will have insufficient capacity to handle current work volumes and be unable to meet the expansion in network work volumes required to deliver customer services in coming years. Further, continuing to operate this depot in this location is presenting an increasing safety risk to the community given its proximity to residences. Port Augusta depot: This identified need is to respond to the impractical and unsafe environment and capacity constraints of the current depot: › our current depot was built in 1970 and is one of our operational works depots servicing 10,507 customers living/working in an area covering more than 37,000 km². Field crews operate from the site to provide planned and unplanned restoration and repair work in the Port Augusta and surrounding region – the depot is in the centre of Port Augusta CBD, with no option to expand; and › under our current business as usual approach of continuing to operate and maintain this depot, we forecast continued inadequacies in operational requirements, constraints in location expansion to meet demand, and unsafe and inefficient movements of people and equipment to and from the site and within the surrounding area.	Mount Barker depot: Propose \$14 million, to rebuild the depot on a new site, remediating and selling the existing site and purchasing a new site outside of the currently congested suburban area and construction of new buildings. This option is preferable to alternatives including rebuilding on the same site (requiring demolition of the existing depot and replacement with new buildings) and leasing a new site (requiring leasing an appropriate site in Mount Barker to eliminate the existing site constraints). Port Augusta depot: Propose \$10.3 million to rebuild the depot on a new site – remediating and selling the existing site and purchasing an outer suburb site and constructing new buildings. This option is preferable to alternatives we considered including rebuilding on the same site – requiring demolition of the existing depot and replacement with new buildings and, leasing a new site – involving leasing a suitable depot site and fitting with suitable building offices and facilities.

Table B39. Property expenditure > Non recurrent – transformer workshop

Non recurrent – transformer workshop (capex \$26.9 million, 23% of total property)	
The need	Our proposal
To respond to the workshop's poor condition which is past its useful life (built in the 1950s). This is a critical asset, enabling essential services on critical network assets, such as power and distribution transformers, and switching cubicles. This key industrial facility comprises a workshop, associated storage areas and an oil recycling plant. If we maintain a business-as-usual approach of operating and maintaining the existing site, we forecast needing significant ongoing capital upgrades and replacements due to its poor condition. We engaged with customers on how to respond to the need, and they expect, reflected in the People's Panel recommendations that we build a new dedicated site. Land for a new site was recently purchased.	Relocate and rebuild our Transformer Workshop. This option is preferable to alternatives, maximising benefits versus costs, deriving advantages of a dedicated, in-house facility for repairing and refurbishing power transformers versus the installation of new transformers on the network.

2.6.9 Other non-network expenditure

Capex \$59.4 million

2.4% of total capex

Table B40. Other non-network expenditure > Innovation fund

Innovation fund (capex \$14.8 million, 25% of other non-network)	
The need	Our proposal
This is an initiative supported by our Community Advisory Board (CAB), aiming to consolidate several initiatives that our customers supported in our engagement program, including via the People’s Panel. The initiative responds to the fact that currently the funds available under the AER Demand Management Innovation Allowance Mechanism (DMIAM) are focused on management of demand on the network, have typically been exhausted, and do not address a range of broader innovation opportunities. There is a need to explore innovation on a broader range of drivers facing our business and the services we provide customers. This fund would bring together initiative areas that could drive long-term customer benefits, but which are difficult to scope and develop economic cases for because: 1. they are difficult to quantify/monetise at this time; and 2. the actual initiatives remain uncertain as to the specific delivery model, technology and partnering arrangement that could be used. As agreed with our CAB, we propose three broad themes to address via this fund: 1. community resilience – exploring joint funding with third parties for resilience initiatives such as battery backup for extreme weather events; information sharing with other utilities and emergency services agencies; and other initiatives to be determined. 2. enabling and leveraging the future market – exposing information on the dynamic condition/state of the network to third parties (eg dynamic locational pricing models, market interfaces); leveraging services from CER (particularly Virtual Power Plants and community batteries); innovation in managing increasing system security challenges; supporting future market reforms arising from the Energy Security Board’s Post-2025 market review. 3. sustainability solutions – improving sustainability in our business technology innovation and potential partnering to explore means of electrifying our heavy fleet on a customised basis and developing modelling of scheduling system changes required to integrate Electric Vehicles into our fleet en-masse.	The fund’s scope would cover the three themes agreed with our CAB, and the arrangements would be as follows: › a cap of \$20 million, split 80% capex and 20% opex; › excluded from the EBSS and CESS, ensuring we do not benefit if funds are underspent; › a ‘use-it-or-lose-it’ fund with underspends returned in the next period, and opex excluded from the base year in future periods; › commitment to knowledge sharing to benefit the broader NEM, and to seek opportunities to increase the fund’s value via government funding opportunities (eg via the Australian Renewable Energy Agency (ARENA) and the Commonwealth Government’s Reliable Affordable Clean Energy for 2030 Cooperative Research Centre), and › governance arrangements are still being defined with our CAB, but could include forming a CAB sub-group to refine the innovation investment principles and to provide oversight of project selection.

Table B41. Other non-network expenditure > Telecommunications systems

Telecommunications systems (capex \$6.6 million, 11% of other non-network)	
The need	Our proposal
We incur largely recurrent costs to maintain existing telecommunications systems used to manage the electricity network.	Continue to maintain our telecommunications systems.

Table B42. Other non-network expenditure > Telecommunications systems

Advanced Distribution Management System (ADMS) upgrade (capex \$34.6 million, 58% of other non-network)	
The need	Our proposal
Our ADMS is used to manage our distribution system in a safe and secure manner. The identified need is to keep the ADMS operational, mitigate cyber security risks and maintain compliance with Security of Critical Infrastructure Act requirements. We assess that under a business as usual option, where we continue to operate the existing system, that cyber security risks will increase to an unacceptable level over the 2025-30 period due to the product vendor withdrawing support for key components of our current ADMS environments over the 2025-30 period.	Continue to proactively refresh systems using current refresh rates across the operational systems environment, and ensure coverage for: › increased functionality and integration, such as refreshing software and more complex project costs for Distributed Energy Resource Management (DERMs) and Outage Management implemented in the 2025-30 period; › increased usage and business requirements for the current systems; and › protection from increasing cyber security threats.

3. Operating expenditure

3.1 What comprises operating expenditure

Figure B20. Opex for the 2025-30 regulatory period by category¹⁵ (\$ million, 2025)



Operating expenditure (opex) is utilised to maintain and operate the distribution network assets and includes supporting corporate costs involved in providing distribution network services to customers.

At a high level, opex includes costs (Figure B20) associated with:

- › **Network Operation:** ensuring a safe and secure power system by managing asset planning, asset systems maintenance, network access, connection and reliability for customers.
- › **Network Maintenance:** maintaining powerlines and substations to enable a safe, secure and reliable distribution network and network-related insurance premiums.

- › **Vegetation Management:** managing vegetation around powerlines and substations to manage bushfire and reliability risk.
- › **Emergency Response:** restoring supply for unplanned power outages caused by weather events, equipment failure or third-party damage.
- › **Guaranteed Service Level (GSL) Payments:** inconvenience payments to customers when outages exceed the level of service prescribed in ESCoSA's Service Standard Framework.
- › **Customer Services:** managing high volume customer interactions and National Electricity Market transactions, as well as stakeholder engagement and corporate affairs.

- › **Corporate Costs:** business support costs, such as information and communications technology, property management and financial services.

Operating costs typically recur each year and are forecast based on historical expenditure, however there are a few exceptions, including GSL payments and emergency response work which fluctuate with weather events. 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 has affected some areas of expenditure over the last few years.

15. Our opex forecast referred to in this section excludes debt raising costs of \$13 million.

3.2 Performance to date

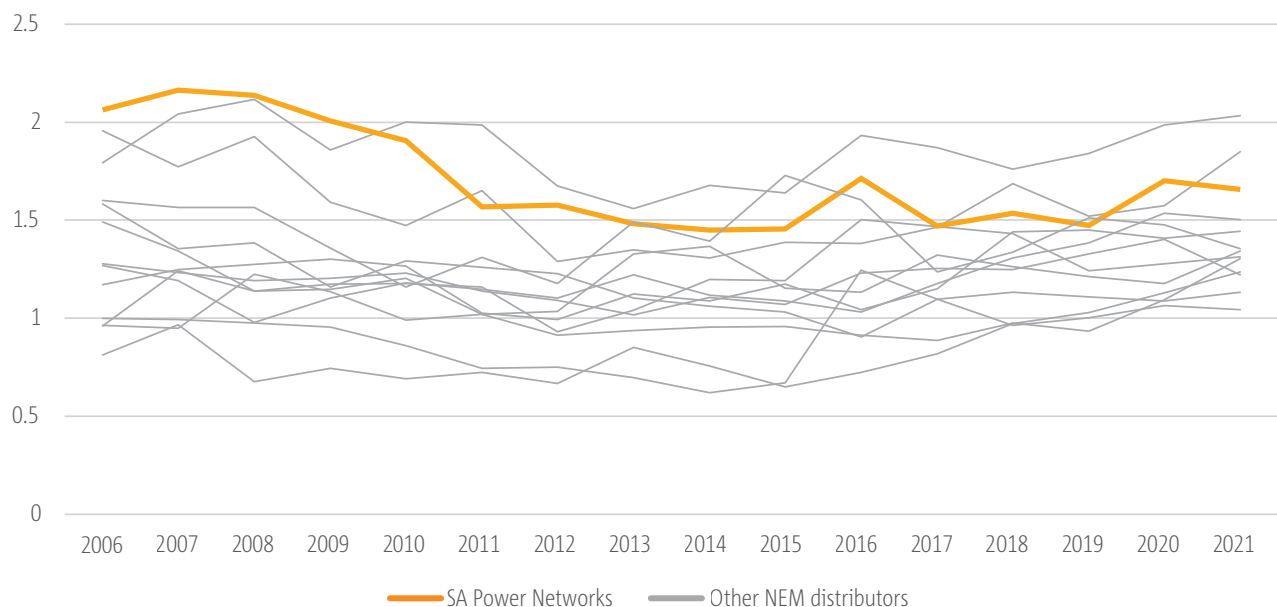
The AER conducts an annual benchmarking process designed to measure how efficient businesses are at delivering electricity distribution services over time and compared with their peers (Figure B21 and Figure B22). Where distribution networks are more efficient, customers benefit through downward pressure on network charges and customer bills. SA Power Networks

consistently benchmarks in the top quartile of distribution businesses for a range of opex measures.

In the AER's 2022 Annual Benchmarking Report¹⁶ (reporting on 2020/21 performance), SA Power Networks ranked third amongst electricity distributors in terms of Opex Multilateral Partial Factor Productivity (MPFP).

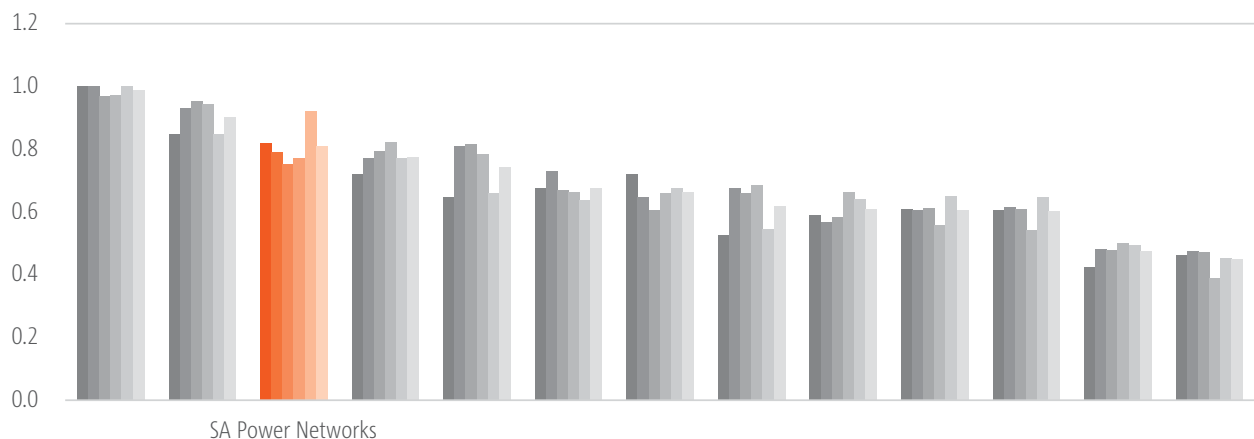
SA Power Networks also ranked third amongst other electricity distributors in terms of opex efficiency benchmarking - our average score is above the 0.75 benchmarking score that the AER uses to determine if a distributor's opex can be assumed to be efficient.

Figure B21. Multilateral opex partial factor productivity indexes, 2006-21



Source: Adapted from AER, Annual benchmarking report – Electricity Distribution Network Service Providers, November 2022, p.iv.

Figure B22. Opex efficiency scores and opex multilateral partial factor productivity, 2006-21



Source: Adapted from AER, Annual benchmarking report - Electricity Distribution Network Service Providers, November 2022, p.34

16. AER, 2022 Annual Benchmarking Report – Electricity distribution network service providers, November 2022

In the 2020-25 period, expenditure is forecast to be lower than allowances each year. The first two years (2020/21 and 2021/22) were significantly underspent due to a number of factors including:

- benign weather resulting in lower emergency response and GSL payments;
- the COVID-19 pandemic which impacted several areas of expenditure;
- the redeployment of some resources to work on strategic capital projects;

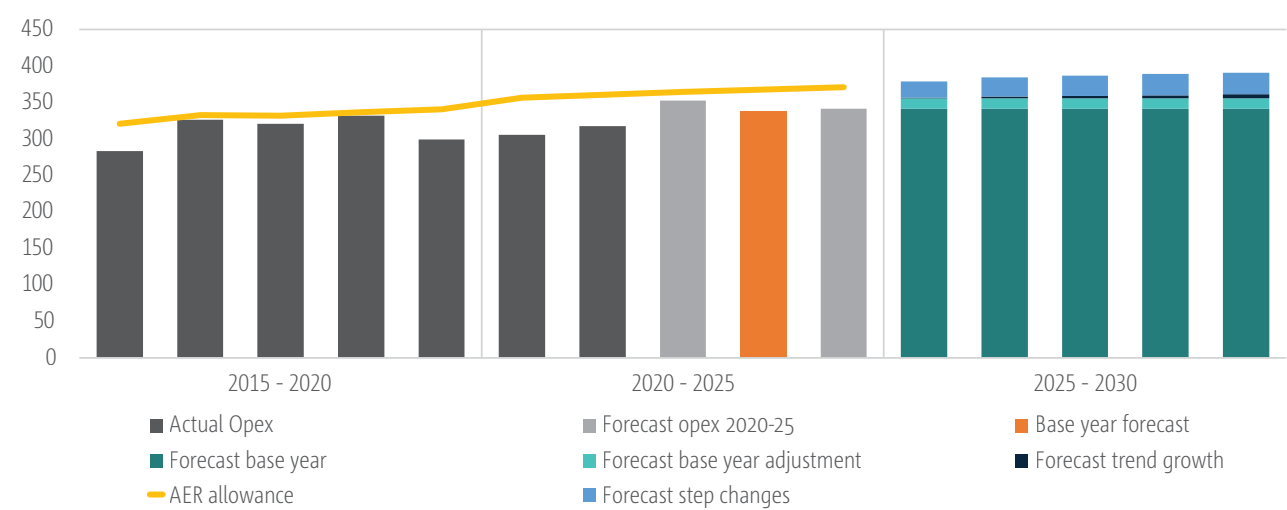
- a change to the South Australian GSL scheme which affected the timing of GSL payments (2020/21 only); and
- reduced labour capacities from protected industrial action (2021/22 only).

Opex in 2022/23 will be closer to allowance. In 2022/23, South Australia experienced periods of extreme weather which saw an increase in GSL payments as well as resources deployed to manage our response to flooding that occurred over summer in parts of the State.

SA Power Networks’ annual historical and forecast operating expenditure is shown in Figure B23.

We continually strive to find innovative ways to reduce opex over time, to improve benchmarked outcomes and maintain our position as an efficiency leader in the distribution industry, however real increases are forecast, largely due to accounting changes and increased cyber compliance.

Figure B23. Historical and forecast operating expenditure (\$ million, 2025)

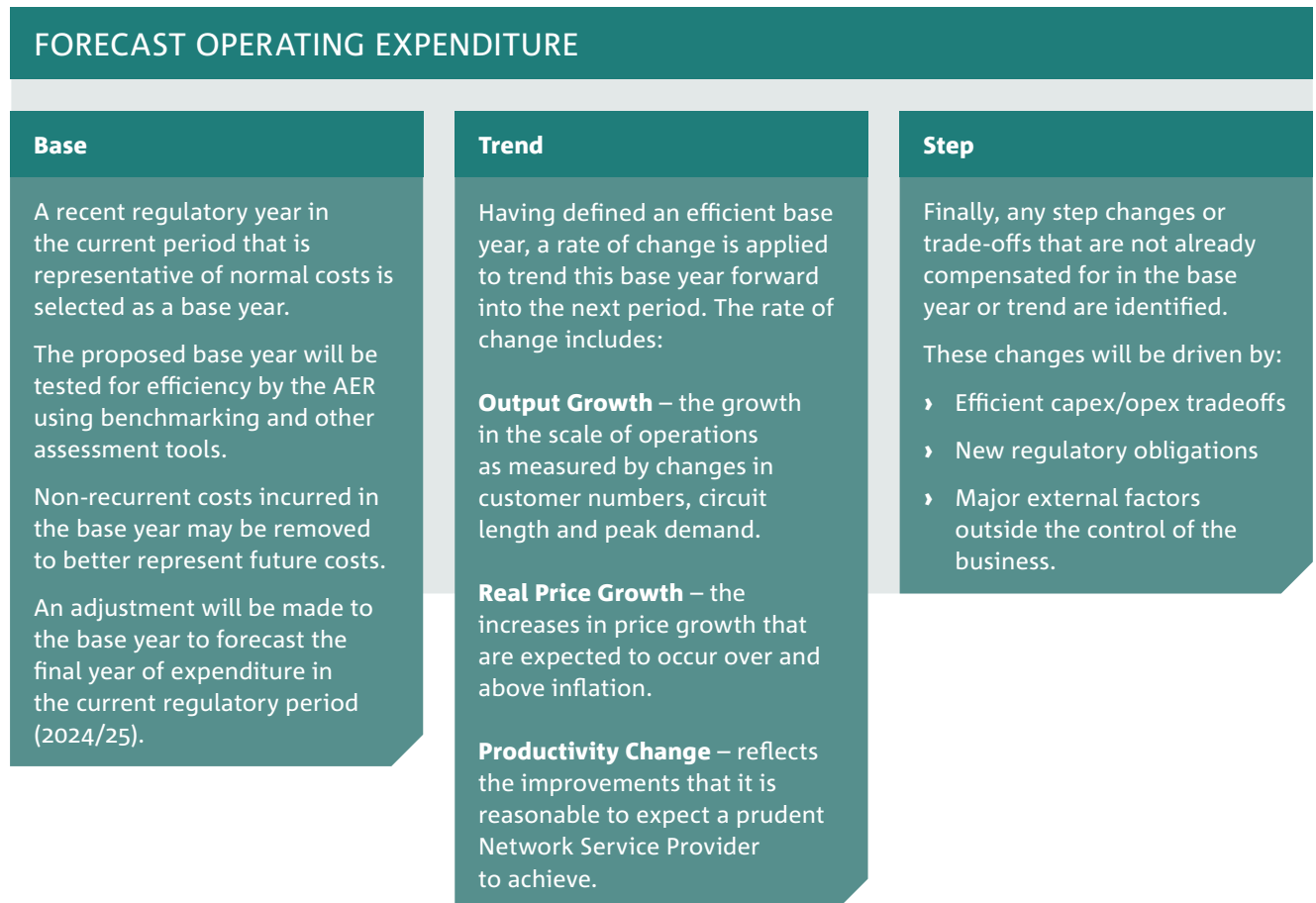


3.3 How we forecast operating expenditure

We have applied the AER's preferred 'base-trend-step' methodology to forecasting opex for the 2025-30

period. The three main components of this methodology are outlined in Figure B24.

Figure B24. Base-trend-step components



3.3.1 Base year

We propose the 2023/24 regulatory year (year four of the 2020-25 period) as our efficient base as:

- › it will be the most recent year for which actual audited data will be available at the time of the AER’s final decision (due in April 2025);
- › it is expected to best reflect the costs required to efficiently maintain and operate the distribution network over the 2025-30 period; and
- › it will incorporate the accumulated efficiency gains for the period up to 30 June 2024.

We consider earlier years of the 2020-25 period do not provide an adequate base for the 2025-30 period due to a number of external factors as covered in section B3.2.

Our delivery of operating costs below allowance has not compromised service delivery in the current period. Our most recent benchmarked position indicates an efficiency score above the required 0.75 comparison point which confirms that our opex is efficient. It will then be at the discretion of the AER to determine whether our proposed base year is acceptable, or whether an alternative year would be preferred.

Adjustments

There may be certain categories of expenditure where the expenditure profile is not well reflected in the base year. In these cases we make adjustments to the base year to reflect these costs.

One such adjustment will be in relation to the accounting treatment of implementation costs associated with Software as a Service (SaaS) products. In the current period these have been treated as capital expenditure, however, in the future they will be recognised as operating expenditure in accordance with a change in interpretation of audit standards (by the IFRS) and direction from the AER.

Other adjustments may be identified once actual expenditure for the base year is known.

3.3.2 Trend

‘Trend’ refers to the net change in costs that is expected to occur over the next period as result of output growth, price growth, and productivity improvements.

Output Growth

Output growth should reflect the increase (or decrease) in the scale of operations of a Network Service Provider.

We have applied the AER’s standard formula to determine output growth. Under this approach, we forecast the growth in customer numbers, circuit length and demand that will occur over the 2025-30 period based on actual historical data.

Price Growth

Real price growth occurs where annual price increases exceed the rate of the Consumer Price Index (CPI).

We have applied labour escalation costs based on an average of two independent forecasts for the utilities industry Wage Price Index growth in South Australia, consistent with the AER’s accepted approach. This forecast increase in labour costs is reflective of the high level of skills required to work in a high-risk environment where safety to both the public and workers is paramount.

We are proposing no real price increases for non-labour costs.

Productivity

The productivity factor works on the premise that each year the business will generate additional savings through the delivery of new productive, or efficient, initiatives.

Finding ongoing efficiencies year-on-year is proving to be increasingly difficult as SA Power Networks, has consistently benchmarked in the most efficient quartile of distributors for a range of opex measures. Nonetheless, we have committed to achieving an opex productivity factor of 0.5 percent per annum for the 2025-30 period. This is in line with the AER’s preferred productivity growth forecast for electricity distribution businesses as stated in their Better Resets Handbook.

In aggregate, the net impact of these three trend factors contributes to a \$17 million increase over five years in total opex in our 2025-30 Draft Proposal.

3.3.3 Step changes

We have identified several areas that will increase (or decrease) opex over and above what is accounted for in the base and trend components. To ensure we have a reasonable

opportunity to recover our efficient costs of providing standard control services we have proposed 10 step changes that will reflect the material changes in expenditure.

A summary of SA Power Networks' proposed step changes is contained in Table B43.

Table B43. 2025-30 Draft Proposal step changes (\$ 2025)

Step change	Driver	Detail	Total
Reliability Improvements	Negative step change	As a result of our proposed reliability feeder improvement programs, we expect a reduction in interruptions which will result in reduced supply restoration costs.	-\$0.7million
'Knock before you disconnect' program	Major external factor	Program to allow us to undertake a pre-disconnection site visit to minimise the number of vulnerable customers disconnected for non-payment. This identified need was supported by customers as reflected in the People's Panel recommendations.	\$1.7million
CER Compliance	Major external factor	The CER Compliance program identifies the need to improve the level of compliance to technical standards, connection rules, and regulatory requirements for CER installations in South Australia in 2025-30.	\$4.4million
Flexible Exports Scaling	Major external factor	This represents the forecast growth in cloud-based system costs associated with our flexible exports connection service. Under SA Government regulations, all new solar PV systems installed in SA after July 2023 must be flexible exports-capable.	\$3.8million
Transition to Electric Vehicles	Negative step change	As a result of our proposed program to transition a portion of our fleet to Electric Vehicles (discussed in Part A Section 8 Enabling clean energy), we expect a decrease in opex due to a reduction in fuel and maintenance charges.	-\$1.4million
IT Infrastructure Refresh	Capex/Opex substitution and Major external factor	This is required to ensure that our IT infrastructure and associated systems and services are maintained and secure with the current acceptable levels of risk. Half of this step change relates to a capex/opex shift as we move more systems to the Cloud while the other half relates to increased capacity required for the expansion of our systems. For example, as a result of the forecast increase in smart meters across 2025-30. This is independent of the proposed accelerated smart meter rollout discussed below.	\$10.8million
Operationalising Cyber Security	Capex/Opex substitution	In our last two Determinations the AER has included non-recurrent and recurrent capex for us to implement and augment our capability to address the increasing cyber threat levels. In 2020-25 we are completing development of the capability and systems. Moving forward, the focus shifts to ongoing maintenance of these technologies, processes and information assets. As these activities are operational in nature, we propose to reclassify the majority of this recurrent expenditure from capex to opex from the start of the 2025-30 period.	\$17.5million

Step change	Driver	Detail	Total
Cyber Security Uplift	Major external factor and Regulatory obligation	This relates to an uplift in our cyber security capabilities to minimise and mitigate the increasing cyber security risks. This includes addressing all elements of the AESCSF, as well as additional aspects that we consider necessary to mitigate the increase in risk anticipated during the 2025-30 period. The identified need of this step change was supported by customers as reflected in the People's Panel recommendations outlined in Part A Section 6 A reliable, resilient and safe network .	\$52.0million
Network Uplift	Major external factor	This change seeks to ensure that we have a reasonable opportunity to recover at least our efficient costs of providing SCS. In order to deliver on the uplift we have proposed to increase our network expenditure in the areas of repex, augex and CER integration as set out in Part A Section 6 A reliable, resilient and safe network and Part A Section 8 Enabling clean energy, we require a corresponding uplift in our resources across corporate support (ie training, procurement, human resources, fleet maintenance and health, safety and environment) and ICT. These costs are material and our ability to recover our costs will not be sufficiently provided via the opex base and trend components. The underlying identified need of this change (achieving the reliability, safety and security service levels provided by our capex forecast) was supported by customers as reflected in the People's Panel recommendations. The need for and magnitude of resourcing costs was also discussed in Focused Conversations.	\$26.1million
Insurance Premium Increases	Major external factor	This reflects a material increase in premiums that are being forecast by our insurance broker. It responds principally to a tightening of the global insurance market.	\$20.6million

Through our engagement process, we have provided customers and stakeholders the opportunity to shape approximately 63 percent of the operating expenditure step changes, and seven percent of the total operating expenditure forecast in this Draft Proposal.

There could be further step changes to include in our forecasts pertaining to potential new regulatory obligations. We are awaiting confirmation on these changes and will advise the AER and our customers accordingly.

The indicative costs of these further changes are discussed in Table B44.

Table B44. 2025-30 Draft Proposal placeholder for step changes (\$ 2025)

Step change	Driver	Detail	Total
Smart Meter Accelerated Rollout	Regulatory obligation	The AEMC is consulting on a rule change which aims to accelerate smart meter rollouts to enable 100% uptake of smart meters by 2030. Ahead of an AEMC decision, there is uncertainty on the extent to which distributors would be required to pay Metering Coordinators for data and on distributors' role in coordinating the rollout process. We anticipate that if this rule change proceeds, it would drive material costs to our business in relation to: ▶ data purchasing; ▶ systems and licensing costs; and ▶ planning and ongoing support costs involved with developing and executing the rollout of the rule change.	\$60 million
National Claims Scheme	Regulatory obligation	The SA Government is currently considering its policy response to interest demonstrated by our customers through our customer engagement program, to change the eligibility criteria of the SA Power Networks claims and damages scheme, wherein we provide compensation to customers when a voltage variation incident on our network causes damage to their appliances. A change in the eligibility criteria of a compensable event, may result in additional claims being approved and paid by SA Power Networks for an estimated 490 customers per year.	\$7 million

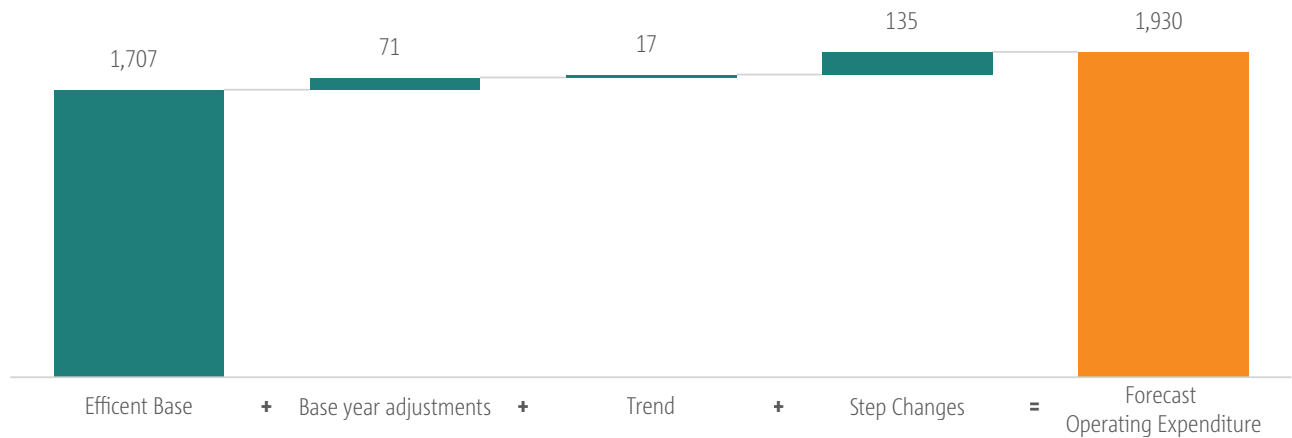
3.4 Summary

Our total forecast opex for the 2025-30 period is \$1,930 million, excluding debt raising costs (Figure B25). This forecast was achieved through the

application of the AER's preferred base-trend-step methodology and feedback received through our customer and stakeholder

engagement workshops. This forecast represents a 17% increase on our expected opex for the current period (2020-25).

Figure B25. Total operating expenditure (\$ million, 2025)



4. Incentive schemes

For the 2025-30 period we propose to again apply the following incentive schemes developed by the AER:

Service Target Performance Incentive Scheme (STPIS)

The AER's Service Target Performance Incentive Scheme v2.0¹⁷ provides a financial incentive for distribution businesses like SA Power Networks to maintain and improve their service performance. It provides a balance to the Efficiency Benefit Sharing Scheme (EBSS) and Capital Expenditure Sharing Scheme (CESS) that rewards distributors for lowering expenditure. The STPIS ensures that rewards under these schemes are not achieved at the expense of lowering service quality for customers. Unlike the EBSS and CESS where rewards (or penalties) from one regulatory period are factored into the next period, STPIS-based financial rewards (or penalties) in a regulatory period are added to (or subtracted from) the distributor's annual revenue requirement within the same period.

Customer Service Incentive Scheme (CSIS)

As outlined in **Part A Section 7.5 Customer experience, choice and empowerment**, we are considering a new Customer Service Incentive Scheme for the 2025-30 period. This scheme is still under development and subject to AER approval. If approved, this scheme would replace the telephone answering customer service component of the STPIS v2.0.

Efficiency Benefit Sharing Scheme (EBSS)

The EBSS¹⁸ provides a continuous incentive for distributors to reduce operating expenditure below allowance and shares the benefit of any outperformance approximately 85% with customers and 15% with distributors (based on current market rates).

Capital Expenditure Sharing Scheme (CESS)

The CESS¹⁹ provides incentives for distributors to undertake efficient capital expenditure and shares the benefit of outperforming allowances approximately 70% with customers and 30% with the distributor. The scheme was amended in April 2023 where the benefit to the distributor reduces to 20% for underspending the allowance by more than 20%. The new scheme will apply to SA Power Networks in 2025-30.

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

The DMIS provides incentives for distributors to actively seek out and contract third parties to deliver efficient non-network demand management solutions to network constraints. The DMIAM provides funding for innovative trials.

17. AER, Electricity distribution network service providers—Service target performance incentive scheme, version 2.0 update December 2018.

18. AER, Efficiency Benefit Sharing Scheme for Electricity Network Service Providers, November 2013

19. AER, Capital Expenditure Incentive Guideline for Electricity Network Service Providers, April 2023

5. Cost pass throughs

The regulatory framework recognises that a distribution business cannot reasonably be expected to forecast costs for unforeseen events that could potentially occur during a regulatory period. It addresses this

by including a cost pass through mechanism for certain events specified in Chapter 6 of the National Electricity Rules (NER). Under the pass through mechanism, distributors can seek AER approval to recover costs (or

pass through the savings) in excess of a 'materiality' threshold, that are related to the occurrence of certain defined events.

5.1 Defined pass through events

The NER²⁰ defines the following as pass through events:

- › a **regulatory change event** – a change in a regulatory obligation or requirement that falls within no other category of pass through event;
- › a **service standard event** – a legislative or administrative act or decision that substantially varies how a distributor provides standard control services or imposes, removes or varies a service standard;
- › a **tax change event** – a change in a relevant tax that materially increases or decreases the cost of providing standard control services;
- › a **retailer insolvency event** – a failure of a retailer to pay network charges to which the distributor is entitled, if an insolvency official is appointed and the distributor cannot claim that amount in full under any credit support provided by the retailer; and

- › any other event specified in a distribution determination as a pass through event for the determination (refer below).

A materiality threshold applies for all pass through events, except the retailer insolvency event. The materiality threshold is that total costs incurred from the event in one regulatory year must exceed 1% of allowed annual revenue in that year.

5.2 Nominated pass through events

We are not proposing any new events for 2025-30 but will again propose that the following four events - which were approved by the AER for the 2020-25 period - should apply in the 2025-30 period:

- › a **natural disaster event** - means any natural disaster (including but not limited to cyclone, fire, flood or earthquake) that materially increases the cost of providing standard control services;
- › an **insurance cap event** – occurs when the cost of an event materially exceeds the insurance cap limit;
- › an **insurer credit risk event** – occurs when SA Power Networks' insurer becomes insolvent, and SA Power Networks is subject to higher or lower costs or a higher or lower claims limit or deductible than those allowed under its insurance policy with that insurer;
- › a **terrorism event** – means an act (including, but not limited to, the use of force or violence or the threat of force or violence) of any person or group of persons (whether acting alone or on behalf of or in connection with any organisation or government) which materially increases the cost of providing standard control services.

In 2021 the AER approved a **service standard event** cost pass through application from SA Power Networks in respect of \$30 million capital expenditure associated with new power system security standards introduced by the South Australian Government. Also, we continue to incur significant additional costs from the Murray River floods in South Australia and are considering a **natural disaster event** cost pass through application to the AER in respect of these costs, should the materiality threshold be reached.

20. NER Rule 6.6.1.

6. Distribution network tariff structures

SA Power Networks, along with stakeholders we consulted, consider many of our current tariff structures will remain fit for purpose over the 2025-30 period and therefore these will be proposed again with minimal or no change.

However, as we face a period of great change with the continued rapid uptake of rooftop solar, batteries and increasingly, Electric Vehicles (EVs) and other smart Customer Energy Resources (CER), we will also be proposing new tariff structures designed to recognise the changing profile of our customers and maximise utilisation of the distribution network.

In addition to consumption tariffs, for the first time and in accordance with recent changes in the rules under which we operate, we are proposing new export tariffs for customers with small embedded generation systems, defined as less than 30kW in capacity.

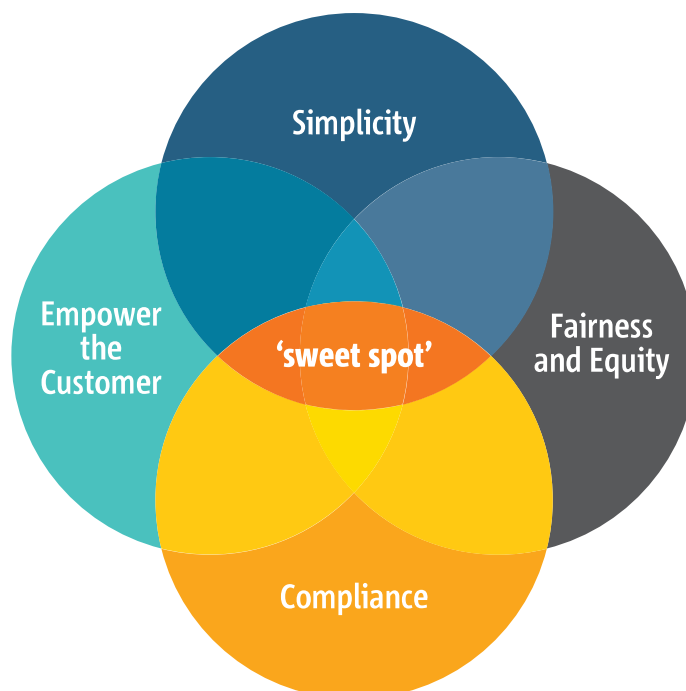
If accepted, our proposal would result in all customers with these systems being assigned to an export tariff from 1 July 2025. These tariffs will recover the costs associated with alleviating forecast congestion in our low voltage network due to high levels of energy exports. This promotes more equitable cost recovery, as non-exporting customers will not be charged an export tariff.

In the development of our 2025-30 tariff structures, we remain guided by the Customer Impact Principles developed by stakeholders to inform our first Tariff Structure Statement in 2017 shown in Figure B26:

- › **Empower the Customer** – Customers should be allowed to see, understand and manage their own behaviour. Understanding, through the provision of information, is central to making the system work.

- › **Fairness and Equity** – Fairness requires the system to recognise the diversity of customers and that some households and businesses are particularly vulnerable to sudden changes. Education, sufficient lead-in times and the provision of complementary measures are seen as having key roles.
- › **Simplicity** (to inform decision making) – Tariffs have to be understandable if customers are going to respond to them. To be understandable, tariffs need to be simple and transparent.
- › **Compliance** – Tariffs must be compliant with the National Electricity Rules and capable of acceptance by the AER.

Figure B26. Customer impact principles



Our tariff offerings are dependent on the type of customer metering. South Australian customers have two types of meters: accumulation and interval. Interval meters are remotely-read meters which record how much electricity a customer consumes (or generates) every 30 minutes. These meters enable more cost-reflective, Time of Use tariff arrangements to be developed. Since a 2017 rule change, all new and replacement customer metering must be of the interval meter type.

Currently 40% of our customers have interval meters. The remainder have accumulation meters which record total energy data only: they do not record what time of day the energy is consumed (or generated). Accumulation meters are typically manually read every quarter (approximately every 90 days). As accumulation meters are unable to differentiate the time of day that consumption occurs, we are unable

to design tariffs with different time of day pricing signals for customers with accumulation meters.

There are no changes proposed to the accumulation meter tariff structures in 2025-30.

Interval meter penetration is expected to be accelerated in 2025-30 based on the Australian Energy Market Commission's draft metering review which has a goal of 100% of customers having interval meters by 2030. We propose that all customers with an interval meter will be assigned to a Time of Use tariff. This is a continuation of our current tariff assignment policy which has allowed us to progress tariff reform through introducing more cost reflective tariffs in South Australia.

The key tariff concepts for 2025-30 on the following pages have been informed by stakeholder feedback.

6.1 Consumption default interval meter tariff structures

6.1.1 Residential customers

Our **Residential Time of Use** tariff continues to have pricing signals which encourage customers to change their consumption behaviour, where they can efficiently do so, by shifting load into lower-priced time windows. These times are where the distribution network has the highest available capacity. Our higher-priced windows represent periods where the distribution network is more constrained. The time windows proposed for 2025-30 will increase

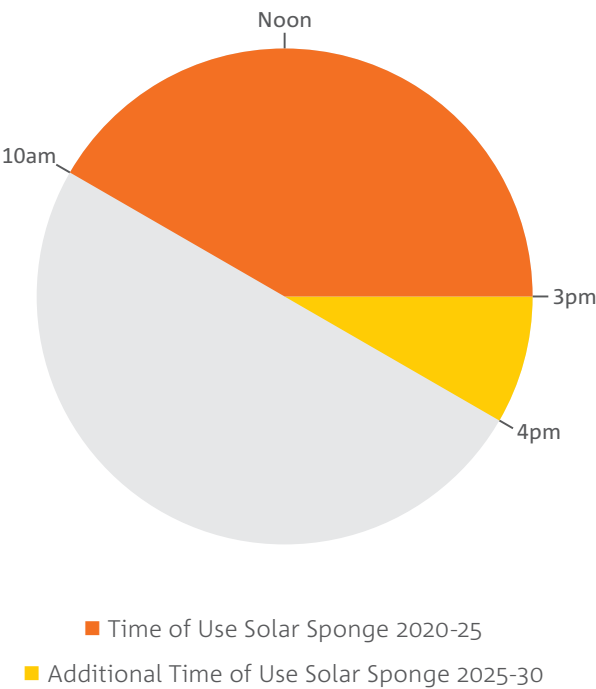
the Solar Sponge and Off-Peak windows by one hour each and therefore reduce the Peak window by two hours (Figure B27).

The extension of the Solar Sponge window enables customers an additional hour to shift load during the day and encourages, for example, preheating and cooling of homes during the lowest priced time window. For simplicity we have also increased the Off-Peak window to

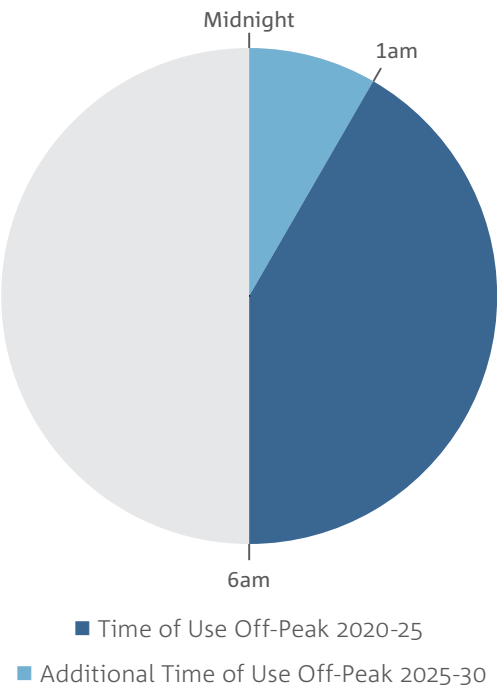
six hours. The additional hour in on the following pages allows for an EV owner to get a sufficient charge overnight for a daily commute without a dedicated wall charger. These changes impact the pricing relativities between time windows however a **Residential Time of Use** customer on average will have a similar outcome compared to being on the **Residential Single Rate** tariff.

Figure B27. Residential Time of Use tariff window changes in 2025-30

Residential Time of Use Solar Sponge



Residential Time of Use Off-Peak



These changes are in direct response to feedback from stakeholders who stated that there were too many hours in the Peak windows and that it was not realistic for a customer without time delayed appliances to be awake at 1:00am to make use of

this cheaper time window. Whilst incorporating this feedback, it was still important to maintain the pricing principle of providing an incentive for customers to change their behaviour rather than a penalty for those who cannot.

All Residential interval meter tariffs are proposed to have a six-hour Solar Sponge window.

6.1.2 Small Business customers

Small Business customers are defined by South Australian legislation as consuming less than 160 MWh pa. However, 94% of Small Business customers have usage between 0-40MWh pa. Through our stakeholder engagement, we were asked to consider segmenting the Small Business tariff class into a subcategory and create a pricing differential to recognise the differing consumption levels for the cohort of Small Business customers consuming less than 40MWh pa. In response to this feedback, we are proposing to define a Small Business customer

tariff subcategory as consuming 0-40MWh pa, and Medium Business customers as consuming 40-160 MWh pa.

Under this proposal, Small Business customers would have the same daily supply charge as Residential customers, recognising that their distribution network usage is similar. Medium Business customers would have a higher daily supply charge paired with a lower-priced usage charge reflecting the increased consumption volumes. The demand tariff structure is proposed to be the

default tariff structure for Medium Business, however customers can opt out if their demand is less than 120kVA, and switch to a Small Business Time of Use tariff.

There are no changes proposed to Small Business default interval meter tariff structures. The structures in place for 2020-25 are proposed to continue for 2025-30. It is the eligibility criteria for these tariffs which have changed: 0-40MWh pa and 40-160 MWh pa.

6.1.3 Large and Major Business customers

There are no changes proposed to Large and Major Business default interval meter tariff structures.

We are not changing the tariff time windows as the expected peak network periods will not materially

shift. The structures in place for 2020-25 are proposed to continue for 2025-30.

6.1.4 Generation customers

In the 2020-25 period we have 'generation' tariffs for customers connected at the low and high voltage parts of the distribution network. We have experienced an increasing number of customer enquiries seeking to connect at higher voltage steps: zone substation

and sub transmission. In 2025-30 we are proposing new generation tariffs at these higher voltage steps to reflect the needs of these customers.

It is important to note that generation tariffs are not export tariffs. For example, a customer who

has a generation tariff can be a solar farm or battery and the generation tariff is focused on the demand requirements of that operation. It is not a tariff which charges for the export of energy into the distribution network.

6.1.5 Transition tariffs

In 2020-25 we closed three demand based tariffs to new customers: **Small Business Actual Demand**, **Large LV Business Actual Demand** and **HV Business Actual Demand**.

Customers were encouraged through annual price increases to transition to more suitable tariffs in their tariff class. All customers who remain on these tariffs at the end of the current

regulatory period will be assigned to the default tariff in their tariff class, effective 1 July 2025.

6.1.6 Fixed and Variable tariff components

In a continuation of our practice in 2020-25, we are proposing to further increase the fixed per day supply charge component of our Residential, Small Business and Medium Business customer tariffs. This means that a greater proportion of the customer related distribution network costs, including the service wire and the

low voltage wires will be recovered on a per customer basis. This will be more cost reflective for smaller and medium sized customers and will result in lower usage charges. It also promotes a more equitable outcome between those customers with CER and those without.

In addition to the above default time of use tariffs for customers with interval meters, the following section discusses other tariff options to enable the energy transition over 2025-30.

6.2 Consumption tariffs enabling the energy transition

6.2.1 Residential customers

Residential Electrify is an energy-based customer choice tariff designed for customers who predominantly or solely meet their energy needs with electricity, but have sufficient flexibility in their appliances, eg EVs, heat pumps, energy storage etc, to optimise their usage outside peak demand periods. These customers are expected to have an above

average energy consumption, so the tariff is structured to provide more opportunities throughout the day to access lower cost electricity outside of distribution network peak periods. **Residential Electrify** has stronger pricing signals than the **Residential Time of Use** default tariff and a simpler structure than the **Residential Prosumer** customer

choice tariff by having no demand component. **Residential Electrify** has been designed as the new prosumer tariff and is proposed to replace **Residential Prosumer** in 2025-30. For those customers on **Residential Prosumer** at the end of the regulatory control period we propose to reassign them to **Residential Time of Use**, effective 1 July 2025.

6.2.2 Small Business customers

Small Business Electrify is an energy-based customer choice tariff designed to encourage consumption during the middle of the day when there is an abundance of solar energy being exported into the distribution network. This concept is an extension

of our original Solar Sponge window in our Residential tariffs. This tariff was created in response to stakeholder feedback and includes strong pricing signals in the Peak window to encourage customers to shift load outside this time.

A business with less than 160 MWh pa usage and demand less than 120 kVA can access this tariff. This tariff is designed to be a customer choice tariff.

6.2.3 Electric vehicle charging

EV sales are continuing to grow, representing 2.5% of sales in South Australia in 2022. Whilst the majority of vehicle charging happens at home today, we are seeing a growth in public EV charging stations. Charging station operators are requesting connection sizes of more than 120kVA per charger to enable multiple EVs to be charged at the same time. Whilst demand for public charging is currently low, it will increase in the future as EV sales continue to grow.

Under our proposed tariff structures for Small and Medium Business customers with less than 160 MWh pa, demand levels from customers such as those with public EV charging stations would be allocated to a demand tariff if their demands were greater than 120kVA. This is a continuation of our current approach in 2020-25.

Through our stakeholder engagement, we were asked to consider the opportunity to allow these customers to opt out of demand tariffs. SA Power Networks presented analysis to stakeholders outlining the impact to pricing to all Small and Medium Business customers. Our analysis showed that prices would have to increase for all Small and Medium Business customers to allow for the appropriate amount of revenue to be recovered from that tariff class. Furthermore, once a customer reaches the Large Business threshold of greater than 160MWh pa there would be a material step up in pricing. SA Power Networks does not want to create large price steps between tariff classes and create tariff boundary issues. The ability to opt out and not be subject to demand charges was also deemed by some stakeholders as giving special consideration to one customer cohort over another.

We considered the views of all stakeholders and determined that allowing customers to opt out of demand tariffs did not align with the principles of tariff cost reflectivity. Public EV charging stations have considerable network demands and it is important to price them appropriately to reflect their usage of the distribution network. If charging station demand levels are less than 120kVA then the site can access a Time of Use tariff without demand.

6.2.4 Large and Major Business customers

Customer choice flexible tariffs are designed to reward efficient use of the distribution network. If a Large or Major Business can be flexible when they use the distribution network, then we are proposing to reward them with a discounted Anytime Demand tariff for the components

of their usage that are not causing the distribution network to be upgraded. This tariff structure also redefines the Peak time window which is a component of all Large and Major Business tariff structures. For customers on this tariff, Peak Demand would only apply during November

to March between 11:00am – 5:00pm (CBD) or 5:00pm – 9:00pm (Rest of South Australia), on days when the following day's temperature forecast at West Terrace Adelaide at 4:00pm is 38 degrees or above. Outside of this time, the Anytime Demand tariff price would apply.

6.2.5 Generation customers

We are also proposing to apply the customer choice flexible tariff concept to generation tariff structures. If a generator can be flexible when they use the distribution network, they will be rewarded with a discounted Anytime Demand tariff as their usage is not

causing the distribution network to be upgraded. The tariff structure also redefines the Peak time window. Peak Demand would only apply during November to March between 11:00am – 5:00pm (CBD) or 5:00pm – 9:00pm (Rest of South Australia) local time, on days when the

following day's temperature forecast in Adelaide (West Terrace) at 4:00pm is 38 degrees or above. Outside of this time, the Anytime Demand tariff price would apply. This tariff could be particularly attractive for large battery proponents.

6.3 Export tariffs

In 2025-30 SA Power Networks will need to invest in new capacity in the low voltage distribution network to relieve solar-related congestion and enable more export into the distribution network. This expenditure would largely benefit small embedded generation customers, who can export less than 30 kW. Today, these are predominantly customers with rooftop solar systems and/or batteries and in the future would include customers with EVs with 'Vehicle to Grid' (V2G) capability.

Export tariffs are designed to recover this expenditure and provide a cost reflective pricing signal to enable export customers to understand the cost to the distribution network of exporting energy at particular

periods of the day. Expenditure incurred prior to 2025-30 to enable more solar PV exports is not proposed to be recovered via export tariffs.

All of the export tariffs have a defined basic kWh export level based on the intrinsic export capacity that the distribution network can provide. Export up to this basic export level is proposed to be free in accordance with the rules²¹. There is a level of intrinsic export capacity existing in the distribution network because these network assets were constructed to supply load but can also support some reverse power flow from customer exports. Modelling undertaken by SA Power Networks suggests that our distribution network has a basic

export level in the order of 1.5kW per customer. If every customer on the distribution network had a solar PV system installed, and each customer exported into the distribution network, highly congested parts of the distribution network could only support 1.5kW of exports from each of those customers. Today, we already face distribution network congestion and this has been the impetus for the development of our flexible exports program. This program, in conjunction with the introduction of export tariffs, aims to provide efficient signalling to customers as to how exports are best supported by the distribution network.

21. National Electricity Rules clause 11.141.12

6.3.1 Residential customers

It is proposed that all Residential interval meter customers can export up to 9kWh per day between 10:00am – 4:00pm free of charge. If exports between 10:00am – 4:00pm

are less than 9kWh, the remainder of the free allowance would roll over to the next day, within a single billing period. For example, a billing period of 30 days would include 270kWh

of free export between 10:00am – 4:00pm. All additional export between 10:00am – 4:00pm would incur a charge. All export outside 10:00am – 4:00pm would be free.

Figure B28. Residential Time of Use Export tariff

RTOUE | Residential Time of Use Export



The basic export level of 9kWh is calculated by multiplying 1.5kW by the six-hour Solar Sponge window of 10:00am – 4:00pm.

The tariff is structured to only have a charge on the amount of export above the free basic export level, there is no daily supply charge component. The tariff would be

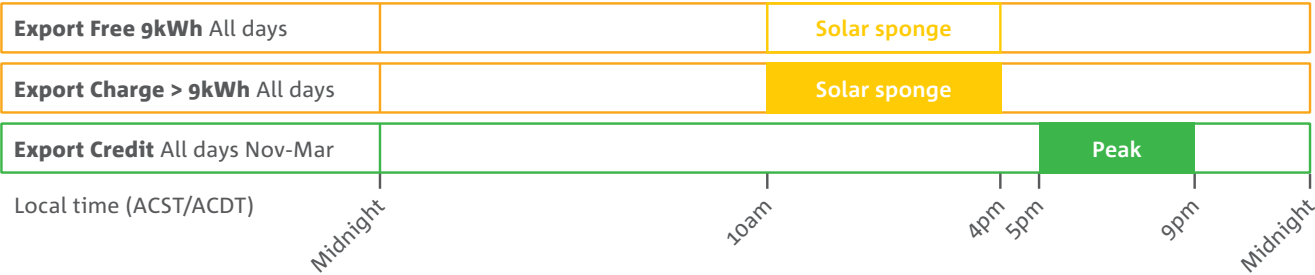
partnered with the **Residential Time of Use** consumption tariff.

An additional export tariff structure has been proposed for those customers who can export into the distribution network during the summer peak of November to March. This tariff has the same free export levels and charging

parameters as outlined above for 10:00am – 4:00pm. In addition, if a Residential customer can export to the distribution network between 5:00pm – 9:00pm November to March, then they would be rewarded with a credit for each kWh exported during this time. The tariff can only be partnered with the **Residential Electrify** consumption tariff.

Figure B29. Residential Electrify Export tariff

REE | Residential Electrify Export



The development of this export credit was in direct response to stakeholder feedback. Initially a demand export credit was developed to partner with the **Residential Prosumer** tariff

to recognise export in the summer peak, however given the small number of customers on this tariff it was considered inadequate by stakeholders.

6.3.2 Small and Medium Business customers

It is proposed that all Small and Medium Business interval meter customers can export up to 9kWh per day between 10:00am – 4:00pm free of charge. If exports between 10:00am – 4:00pm are less than 9kWh, the remainder of the free allowance would roll over, within a single billing period.

Small and Medium Business consumption tariff structures categorise days of the week by Work Days and Non Work Days. Work Days are Monday – Friday and Non Work Days are Saturday, Sunday and Public Holidays. Unused free export on a Work Day can only be rolled over to another Work Day. Unused free export on a Non Work Day can only be rolled over to another Non Work Day.

For example, a billing period of 30 days with five weekends would include 180kWh of Work Day and 90kWh of Non Work Day free export between 10:00am – 4:00pm. All additional export between 10:00am – 4:00pm incurs a charge. All export outside 10:00am – 4:00pm is free.

Figure B30. Small and Medium Business Time of Use Export tariff

SMBTOUE | Small and Medium Business Time of Use Export

Export Free 9kWh Work days		Solar sponge	
Export Charge > 9kWh Work days		Solar sponge	
Export Free 9kWh Non work days		Solar sponge	
Export Charge > 9kWh Non work days		Solar sponge	

Local time (ACST/ACDT)

Midnight 10am 4pm Midnight

The basic export level of 9kWh is calculated by multiplying 1.5kW by the six-hour Solar Sponge window of 10:00am – 4:00pm.

The tariff is structured to only have a charge on the amount of export above the free basic export level, with no daily supply charge component. The tariff would be partnered with the **Small Business**

Time of Use and Medium Business Time of Use Demand consumption tariffs.

An additional export tariff structure has been proposed for those Small and Medium Business customers who can export into the distribution network during the summer peak of November to March. This tariff has the same free export levels and

charging parameters as outlined above for 10:00am – 4:00pm. In addition, if a Small or Medium Business customer can export to the distribution network between 5:00pm – 9:00pm November to March, then they would be rewarded with a credit for each kWh exported during this time. The tariff can only be partnered with the **Small Business Electrify** consumption tariff.

Figure B31. Small Business Electrify Export tariff

SBEE | Small Business Electrify Export

Export Free 9kWh Work days		Solar sponge	
Export Charge > 9kWh Work days		Solar sponge	
Export Free 9kWh Non work days		Solar sponge	
Export Charge > 9kWh Non work days		Solar sponge	
Export Credit All days Nov-Mar		Peak	

Local time (ACST/ACDT)

Midnight 10am 4pm 5pm 9pm Midnight

6.3.3 Accumulation meter export tariffs

Accumulation meters cannot distinguish what time of day export is occurring and to recognise this these customers would have 11kWh per day of free export. If daily exports are less than 11kWh, the remainder of the free allowance rolls over to the next day, within a single billing period. For example, a billing period of 90 days would include 990kWh of free export. All additional export incurs a charge.

The tariff structure and free basic export level is designed so that on average, a customer is neither advantaged nor disadvantaged because of their meter type.

This level was determined based on analysis of solar customers with accumulation meters. This determined that the allowance needed to be greater than 9kWh to recognise that some export

could occur before 10:00am and after 4:00pm and not be subject to an export tariff if the export was recorded on an interval meter.

Figure B32. Residential Single Rate Export tariff

RSRE | Residential Single Rate Export

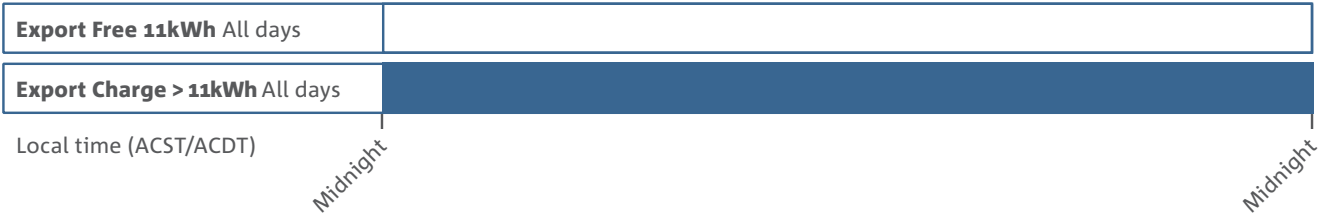


Figure B33. Small and Medium Business Single Rate Export tariff

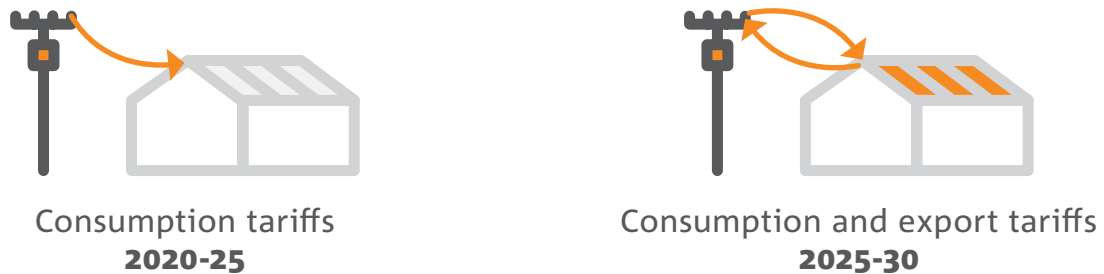
BSRE | Small and Medium Business Single Rate Export



The accumulation meter export tariff can only be partnered with the **Residential Single Rate, Business Single Rate** and **Business Two Rate** consumption tariffs.

6.3.4 Transition to export tariffs

Figure B34. Transition to export tariffs



As outlined in **Part A - 8 Enabling clean energy**, based on stakeholder feedback, we are proposing that all customers with the ability to export into the distribution network would be assigned an export tariff from 1 July 2025. There is no distinction when customers installed their CER.

Customers would not be able to opt in or opt out of export tariffs. This approach has been informed by our

experience with opt in/out consumption tariff options and through consultation with our stakeholders who reiterated the need for simplicity in messaging and application.

We recognise, and customers and stakeholders reinforced, that customer awareness and education is critical to the successful implementation of export tariffs.

In the lead up to 1 July 2025 (and beyond) SA Power Networks will develop communications utilising a variety of media to ensure all customers can develop an understanding and make informed decisions about the value and cost of their exports.

7. Alternative control services

The preceding sections of this Draft Proposal set out our plans and expenditure forecasts to build, maintain and operate the shared electricity network. These costs are recovered from all our customers through our network tariffs.

This section summarises the range of specific services we provide to individual customers upon request. The costs of providing these services are recovered directly from the customers who receive them. For the 2025-30 period, the AER has

classified legacy metering services, public lighting, enhanced connection services and a range of ancillary network services as Alternative Control Services (ACS) and will set individual prices for these services.

7.1 Metering Services

With the introduction of metering contestability on 1 December 2017, retailers became responsible for all new and altered metering arrangements. All meters installed from this date must be remotely-read interval meters, often referred to as 'smart' meters. SA Power Networks remains responsible for the operation, manual reading and maintenance of legacy meters until they are replaced with a smart meter.

To calculate our proposed prices for legacy metering, we use the building block approach consistent with the previous regulatory period. For the 2025-30 period we will only apply a non-capital charge to recover the efficient operation and maintenance costs of providing metering services to the declining legacy meter population. No charges to recover the capital cost of meters will be applied as our metering asset base will be fully depreciated on 30 June 2025.

We acknowledge the Australian Energy Market Commission's (AEMC's) review of the regulatory framework for metering services is ongoing. The outcomes of this review may impact the regulatory framework for metering services, including consideration of the classification of services and the role of distributors in providing these services. We continue to monitor the AEMC's review and will incorporate the final recommendations into our regulatory proposal where appropriate.

7.2 Public Lighting

SA Power Networks provides public lighting services to 69 customers throughout South Australia, including local councils and the Department for Infrastructure and Transport (DIT).

There are approximately 238,000 public lights installed across our network. Of these, 136,000 (57%) have been upgraded to Light Emitting Diodes (LEDs), providing improved energy and maintenance outcomes for our customers. We are continuing to consult with councils and DIT to proactively upgrade the remaining High Intensity Discharge (HID) lights to LEDs where this is cost-effective.

We also use a building block approach to develop prices for public lighting services. Before

developing prices for the 2025-30 period, we consulted extensively with public lighting customers to better understand their service level expectations. Public lighting customers told us they wanted the following changes:

- › replacement of public lighting columns with an 'extreme' condition rating, with all other columns continuing to be inspected every five years in high corrosion zones and every 10 years in low corrosion zones;
- › repair simple faults within five business days (metropolitan and regional) and complex faults within 30 business days;

- › prolong lamp replacements, with no bulk lamp replacement program undertaken for high intensity discharge (HID) lighting; and
- › explore smart lighting opportunities on a council-by-council basis as a quoted service.

Proposed public lighting prices for 2025-30 vary from customer to customer depending on the specific services selected. We are forecasting price reductions for most HID lights, with marginal increases for LEDs associated with forecast increased weighted average cost of capital (WACC) and inflation.

7.3 Ancillary Network Services

Ancillary Network Services are a diverse range of customer-requested services that we provide on an as-needs basis (for example network asset relocations, premises energisation/de-energisation, and special meter reading services).

The cost of each service is paid for by the customer requesting the service. Services are charged as a fixed fee where they are relatively standard and predictable in nature or on a quoted service basis for non-routine work.

Our charges will be built-up using historical data. Proposed prices for 2025-30 are expected to be largely consistent with those currently charged.

7.4 Connections services

Connections services we perform include:

- › connecting a customer's home, business, or other premises to the distribution network (premises connection);
- › increasing network capacity to enable more electricity supply to customer premises (augmentation); and
- › extending the network to reach a customer's premises (extension).

No changes are proposed to the charging arrangements for basic, negotiated or enhanced connection services.

As part of our Focused Conversations, customers supported updating the export connection pricing arrangements to mirror the current load connection framework. We propose to treat large embedded generator connections as a negotiated connection. This is a change from our current classification, where large embedded generators are all treated as enhanced connections.

As a negotiated connection, customers will fully fund the premises connection (as an ACS charge) and may be required to pay a capital contribution towards augmentation of the network as determined in accordance with SA Power Networks' Connection Policy. This treatment will provide greater consistency between consumption, generation and battery connections for the 2025-30 period.







Empowering South Australia