



Supporting  
document 5.9

# Repex Overview

2020-2025  
Regulatory Proposal  
January 2019





# Repex Overview

## January 2019

2020-25 RCP

**SA Power Networks**

[www.sapowernetworks.com.au](http://www.sapowernetworks.com.au)

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## Document Version

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<b>Version</b>	<b>Date</b>	<b>Author</b>	<b>Notes</b>
0.1	3/8/2018	Sarah Stephen	First draft for comment.
0.2			Expanded documents structure and context
0.3	20/12/2018	Mark Pynn	Final draft.
0.4	22/1/2019		Revised to incorporate Minter Ellison review comments

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## ABBREVIATIONS

<b>AC</b>	alternating current
<b>ACCC</b>	Australian Competition and Consumer Commission
<b>AER</b>	Australian Energy Regulator
<b>AEMC</b>	Australian Energy Market Commission
<b>AEMO</b>	Australian Energy Market Operator
<b>Augex</b>	augmentation expenditure
<b>Capex</b>	capital expenditure
<b>CBRM</b>	Condition Based Risk Management
<b>CCP</b>	Customer Consultative Panel
<b>CNAIM</b>	common network asset indices methodology
<b>DC</b>	direct current
<b>DNSP</b>	distribution network service provider
<b>EATL</b>	EA Technology Limited
<b>ESCoSA</b>	Essential Services Commission of South Australia
<b>GIS</b>	geographic information system
<b>GSL</b>	guaranteed service level
<b>HI</b>	health index
<b>HV</b>	high voltage
<b>IEEE</b>	Institute of Electrical and Electronics Engineers
<b>LIDAR</b>	light detection and ranging
<b>LV</b>	low voltage
<b>MED</b>	major event day
<b>MRV</b>	maintenance risk value
<b>MTFP</b>	multilateral total factor productivity
<b>NEL</b>	National Electricity Law
<b>NEM</b>	National Electricity Market
<b>NER</b>	National Electricity Rules
<b>NERL</b>	National Energy Retail Law
<b>NSP</b>	network service provider
<b>OMS</b>	Outage Monitoring System
<b>Opex</b>	operational expenditure
<b>OTR</b>	South Australian Office of the Technical Regulator
<b>PAMP</b>	Power Asset Management Plan
<b>POF</b>	probability of failure
<b>PILC</b>	paper insulated lead covered

<b>PPI</b>	partial performance indicator
<b>RCP</b>	regulatory control period
<b>repex</b>	replacement expenditure
<b>RIN</b>	regulatory information notice
<b>ROI</b>	return on investment
<b>SAIDI</b>	system average interruption duration index
<b>SAIFI</b>	system average interruption frequency index
<b>SAMP</b>	Strategic Asset Management Plan
<b>SAP</b>	Systems, Applications & Products
<b>SAPN</b>	SA Power Networks
<b>SAPS</b>	stand alone power systems
<b>SCADA</b>	supervisory control and data acquisition
<b>SCONRRR</b>	Steering Committee on National Regulatory Reporting Requirements
<b>SME</b>	subject matter expert
<b>SRMTMP</b>	Safety, Reliability, Maintenance and Technical Management Plan
<b>SSF</b>	ESCoSA's service standard framework
<b>SWER</b>	single wire earth return
<b>TNC</b>	telecommunications network control
<b>V</b>	volt
<b>V&amp;V</b>	valuing and visibility tool

# 1 Introduction

## 1.1 Purpose

The purpose of this renewal expenditure (**repex**) overview and justification document is to outline the methods we have used to forecast our expenditure on asset renewal (ie our forecast expenditure for asset replacement<sup>1</sup> and asset refurbishment<sup>2</sup>) for our regulated distribution network assets for the regulatory control period (**RCP**) from 1 July 2020 to 30 June 2025 (**2020-25 RCP**).

The repex proposed throughout this document is required to ensure that we:

- meet and manage the expected demand for standard control services during the 2020-25 RCP;
- comply with all applicable regulatory obligations and requirements associated with the provision of standard control services;
- maintain the quality, reliability and security of supply of standard control services (where there are no applicable regulatory obligation or requirement);
- maintain the reliability and security of the distribution system through the supply of standard control services (where there are no applicable regulatory obligation or requirement); and
- maintain the safety of the distribution system through the supply of standard control services.

## 1.2 Scope

This document covers the forecast repex for our regulated distribution network assets that collectively form the:

- sub-transmission system;
- substations;
- distribution network including the high and low voltage network and service lines/customer connections;
- mobile plant; and
- telecommunication and control centres and their associated facilities.

The repex for asset classes covered by this document include:

- **Poles:** the support structure for overhead conductors at a height above ground level and at a distance from all other objects that exceeds prescribed safety clearances.
- **Pole top structures:** structures that enable overhead conductors to be securely attached to their support structures, support other pole mounted equipment and connect the overhead conductors to other equipment. Pole top structures include cross arms, insulators, overhead switchgear, joints and taps, and other components.
- **Underground cables:** cables located underground that transmit electricity between substations and from substations to customers.
- **Overhead conductors:** conductors supported by poles and pole top structures, that transmit electricity between substations and from substations to customers.
- **Switching cubicles:** devices mounted on the ground that connect components of the underground cable network. These devices enable the safe connection and disconnection (ie switching) of cables and transformers for operational and maintenance purposes.

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<sup>1</sup> Asset replacement: an option that involves replacing an asset for which a retirement decision has previously been made. This will involve installing a new network asset with the modern equivalent and similar functionality to the asset being retired (AER, *DRAFT Industry practice application note – Asset replacement planning*, 2018).

<sup>2</sup> Asset refurbishment: expenditure to extend the engineering life expectancy of an asset (but not increase its functionality) by replacing or repairing parts of an asset rather than the whole. These activities are generally capex as they extend the productive life of an asset, but could also be opex depending on the work performed and relevant accounting practices (AER, *DRAFT Industry practice application note – Asset replacement planning*, 2018).

- **Distribution transformers:** transformers that progressively change the voltage of electricity to a level that can be used by customers.
- **Reclosers and sectionalisers:** specialised switchgear located on the overhead network to reduce the risk of damage from electrical faults and to improve the reliability of supply to customers. Includes supervisory control and data acquisition (**SCADA**) controlled load switches which act as sectionalisers.
- **Service lines:** lines that connect the distribution network to customers. The term 'service line' refers to the wire (whether overhead conductor or underground cable) that connects a customer to the shared network (eg low voltage (**LV**) conductor or cable network generally).
- **Substation power transformers:** transformers that provide voltage transformation and regulation of electricity in the high voltage (**HV**) network (eg sub-transmission system and HV distribution network).
- **Substation circuit breakers:** circuit breakers that act as controlled switching devices within zone substations and control the energisation of electricity distribution equipment.
- **Protection relays:** relays that automatically protect personnel and the network in the event of fault conditions.
- **Other un-modelled line assets:** assets include line voltage regulators and capacitors, cable ducts, manholes, earthing systems, ancillary equipment (line fault indicators, access roads, locks) and other safety programs required to meet current safety standards.
- **Other unmodeled substation assets:** assets include HV instrument transformers, surge arrestors, capacitor banks, AC & DC auxiliaries, buildings, buswork & support structures, substation cables & terminations, secondary wiring and ancillary asset types.
- **Telecommunication assets:** telecommunication assets including:
  - **Linear communication assets:** copper and fibre optic cables that provide a physical communication line between network assets;
  - **Other communication assets:** microwave radio, 48V DC power systems, radio systems, private mobile radio network, multiplexers, operational telephony and data network equipment to transfer data and communications across the network;
  - **Communications monitoring assets:** telecommunications network control (**TNC**) management systems that ensure data and services are delivered safely and securely across network; and
  - **Communications site infrastructure:** for mounting or housing communication assets.

This document does not cover metering equipment and public lighting. It also does not include augmentation of regulated distribution network assets, non-network related assets such as business and commercial telecommunications systems, motor vehicles, properties, office buildings and building equipment (eg furniture, computers).

### 1.3 Audience

The target audience for this document is primarily:

- regulators, including the Australian Energy Regulator (**AER**), Essential Services Commission of South Australia (**ESCoSA**) and the Office of the Technical Regulator (**OTR**); and
- SA Power Networks' customers and other stakeholders that would like to understand how forecast repex for managing the assets and the services we provide is determined.

## 1.4 How to use this document

This document is structured as follows:

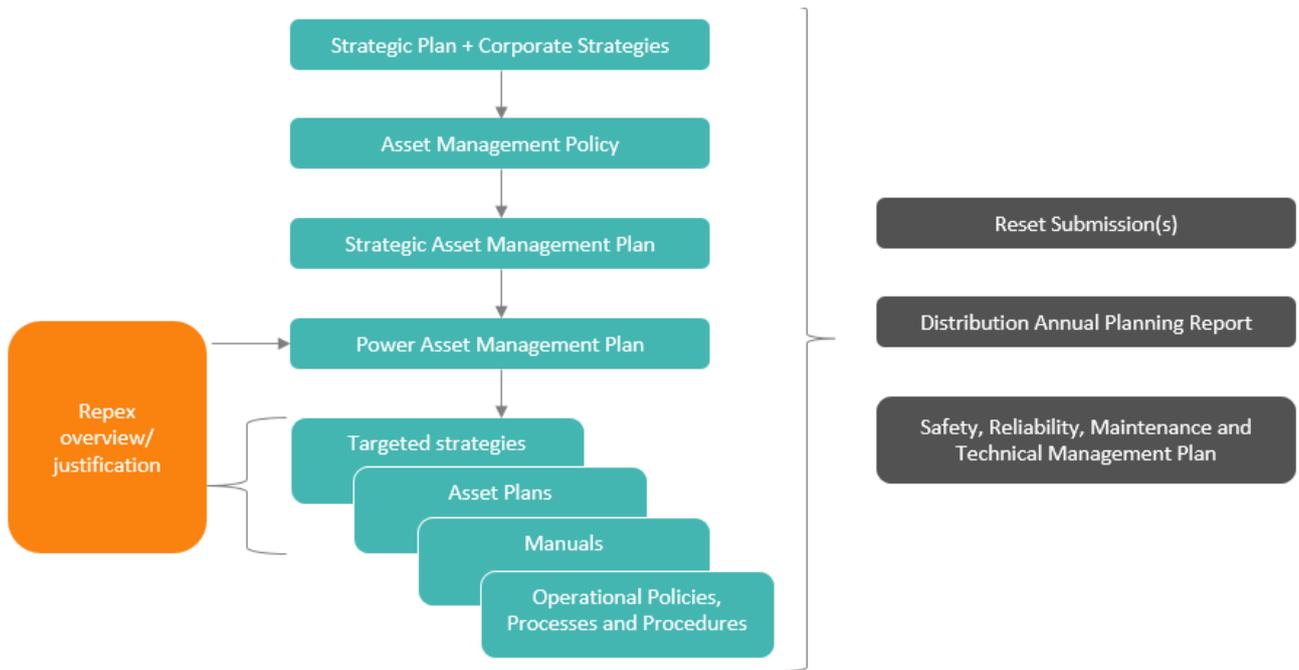
- **Section 1** introduces the purpose of this document, its audience, its structure, and how it fits within the overall structure of our regulatory proposal for the 2020-25 RCP (**Proposal**).
- **Section 2** outlines our proposed repex for the 2020-25 RCP in contrast to our repex for the 2010-15 and 2015-20 RCPs.
- **Section 3** describes our prior approach to asset renewal prioritisation, our history of low rates of asset renewal and the declining rate of augmentation, which factors have all combined to cause a low rate of change in the regulated asset base (**RAB**). It also describes the performance of the network (considering the age of our network) and our current asset management practices that enable us to continue to defer asset renewal prudently and efficiently.
- **Section 4** describes why our proposed level of repex for the 2020-25 RCP is required to meet our regulatory obligations.
- **Section 5** describes how our proposed level of repex for the 2020-25 RCP has considered and addressed the relevant capex objectives, criteria and factors.
- **Section 6** describes the various forecasting methodologies considered in developing our repex forecast and a comparison of the model outputs in developing the proposed repex forecast.
- **Section 7** describes the repex forecast for each of the asset classes described in section 1.2.

## 1.5 Relationship with other plans and strategies

Several of our plans and strategies are related and collectively form part of the Asset Management System documentation:

- **Strategic Plan and other corporate strategies** (including our Customer Engagement Strategy, Future Network Strategy (see Supporting document 5.17) and Digital Strategy): detail our strategic direction, key priorities and core areas of focus, and set the overarching direction for SA Power Networks;
- **Asset Management Policy**: sets out the principles applied to asset management activities.
- **Strategic Asset Management Plan (SAMP)**: outlines the operating environment and the challenges faced by SA Power Networks in delivering services now and into the future, and the overarching strategies implemented to deliver a valuable services to customers (see Supporting Document 5.7).
- **Power Asset Management Plan (PAMP)**: details the levels of service delivered, the assets required to deliver those levels of service, the risks faced, asset life-cycle strategies, historical and forecast expenditure to deliver the levels of service and/or to address identified risks.(see Supporting Document 5.8)
- **Reset Submission(s)**: summarises our business plans with a focus on a specific RCP submitted to the AER for consideration during five-yearly price determinations.
- **Distribution Annual Planning Report**: informs National Electricity Market (**NEM**) regulators, participants, customers and other stakeholders about the existing and forecast system limitations on our distribution network; preparation of this document is a regulatory requirement.
- **Safety, Reliability, Maintenance and Technical Management Plan (SRMTMP)**: details the management framework, key procedures and associated performance indicators for the safety and technical management of our electricity infrastructure through its life cycle; preparation of this document is a regulatory requirement and subject to approval by the OTR. (see Supporting Document 5.3)
- **Detailed strategies, plans, manuals, policies, processes and procedures**: gives detailed guidance for maintenance and day-to-day operation activities.
- **Repex overview (this document)**: outlines the methodologies considered in developing our repex forecast and the justification for the proposed methodology.

Figure 1 shows the relationship between these plans and strategies.



**Figure 1: Repex overview/justification relationship to other SA Power Networks plans and strategies**

## 2 Historical and proposed repex

Figure 2 shows our past, current and forecast repex allowance and spending profiles for the 2010-15, 2015-20 and 2020-25 RCPs.

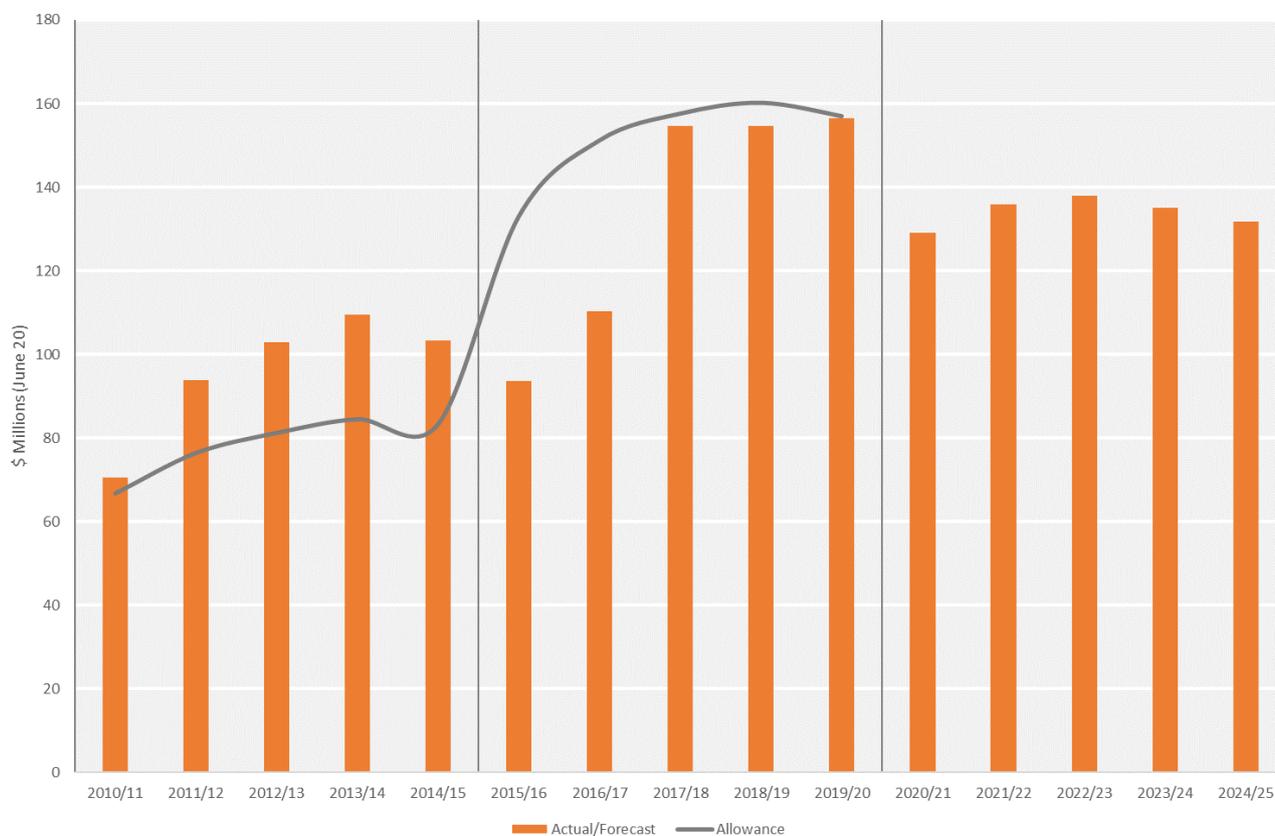


Figure 2: SA Power Networks repex allowances and actual spend for the 2010-15, 2015-20 and 2020-25 RCPs

### 2.1 2010-15 RCP

Figure 2 shows that SA Power Networks exceeded its repex allowance in the 2010-15 RCP. This was because improvements in our asset inspection program resulted in a significant increase in the volume of identified defects. Importantly, the volume of identified defects and consequential renewal activity was what we envisaged when we submitted our 2010-2015 regulatory proposal to the AER. It was also significantly above what the AER allowed for in its 2010-2015 distribution determination.

### 2.2 2015-20 RCP

In 2015, SA Power Networks agreed with the OTR and ESCoSA to assess and rectify outstanding defects using a prudent long term risk-based approach – with the objective of returning overall asset condition and risk to more satisfactory historical levels consistent with the SRMTMP over a 10-year period (from 2015 to 2025).

During the 2015-2020 RCP, our repex has been progressively increasing as we bring on additional resources to manage the larger volume of smaller defect rectifications identified during inspections. However, we have spent less than the AER repex allowance for the following reasons.

In the first part of the 2015-2017 period, we deferred expenditure where possible to allow us to change to our 'risk-based renewal' approach which enabled us to adopt a more efficient and prudent 'value-based renewal' approach using our Valuing and Visibility (V&V) Tool for a number of asset categories.

Our value-based approach considers both the risk and cost associated with addressing a defect to improve work selection and defer rectification work that has a low risk reduction to capex ratio. Our value-based approach also facilitates efficient bundling of work to improve efficiency.

To further minimise repex, our asset refurbishment and life extension programs have been extended where possible. In particular, we have continued the refurbishment of our pole assets, at approximately 15% of the cost of replacement. Research on Stobie pole strength testing has also been undertaken with the results used to determine whether pole plating or pole replacement is required or whether works can be deferred.

### **2.3 2020-25 RCP**

The proposed repex forecast and asset renewal program for the 2020–25 RCP is a flattening off of the 2015-20 RCP repex profile with the aim of maintaining network risk at historical satisfactory levels. A major factor in developing our repex forecasts has been the desire to keep the network cost component of customers' bills to an absolute minimum during the 2020-25 RCP. The 2020-25 RCP repex forecasts are based on more accurate information and improved modelling techniques than those previously available. We have undertaken condition-based risk management (**CBRM**) modelling across four major asset classes (poles, circuit breakers, power transformers and protection relays) to optimise repex based on risk. We have also been developing CBRM models for several other asset classes (eg conductors, cables, switching cubicles). The process of work selection and bundling to improve work delivery will be further improved during the 2020-25 RCP.

### 3 Asset management overview – repex context

This section:

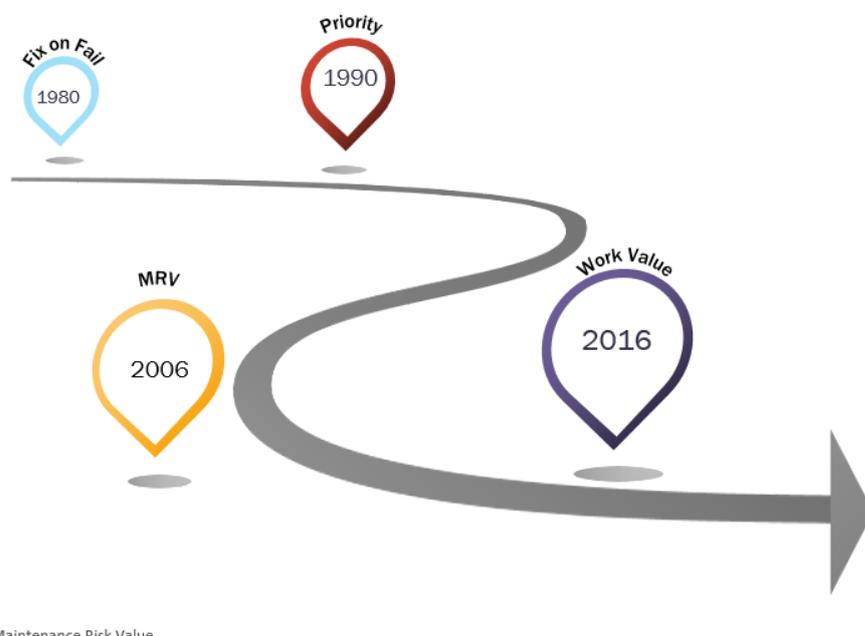
- discusses our asset management approach;
- outlines our transition from a priority-based system for asset renewal to one based on risk and return on investment;
- discusses our history of low repex combined with declining asset renewals through augmentation, while maintaining required levels of service to customers and a safe and reliable network; and
- outlines the impact these trends are having on our ageing asset base and the asset management approach that we are now applying to maximise the life of the RAB.

#### 3.1 Asset management history

We have significantly improved our asset management systems over the last decade. The need for this improvement has been brought into sharp focus by events such as the 2009 Black Saturday bushfire in Victoria and the 2014 Parkerville bushfire in Western Australia. These events have provided a greater awareness across the industry of the significant safety risks posed by defective network assets in sensitive areas.

The volume of aged assets in our network and the concerns of our customers regarding electricity prices drive the need to ensure our asset renewal decision making processes and resulting repex is as efficient as possible while maintaining safety and reliability.

Figure 3 shows our evolution of the prioritisation of asset renewal.



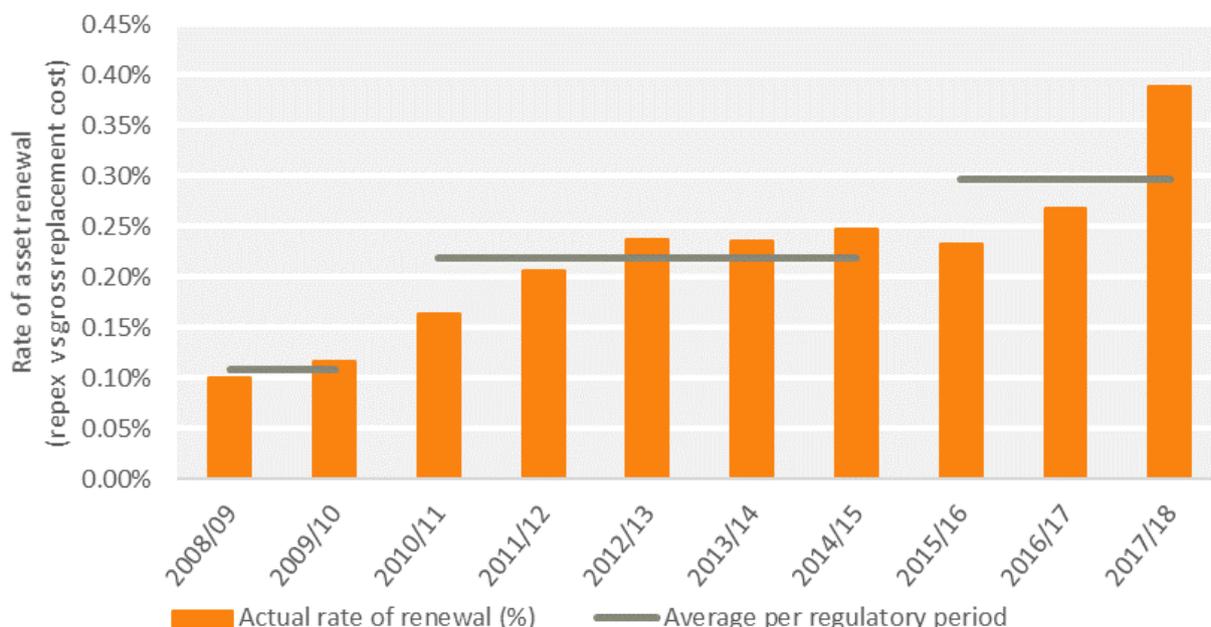
**Figure 3: SA Power Networks' approach to asset renewal journey**

Figure 3 demonstrates our evolution over the past 40 years from a reactive 'fix on fail' approach, to a priority (time-based system) to one that considers maintenance risk values (**MRV**) on the network. Finally, over the last decade, we have moved to a concept of value which considers not only the risk reduction afforded by rectifying a defect but also the cost of rectifying that defect. We use this ratio of risk reduction and cost to ensure the most prudent and efficient allocation of resources is applied to maintain risk. This is discussed further in Section 5.2.

### 3.2 History of repex

We have a demonstrated history of low levels of repex.

Figure 4 shows the rate at which we have renewed distribution network assets through repex based on our previously reported category analysis regulatory information notices (**RINs**) covering repex. The rate of average asset renewal compares the historical annual repex (\$ real) (ie what SA Power Networks actually spent on asset renewal) relative to the estimated gross asset replacement cost (\$ real) (ie the estimated cost to replace the RAB).



Source: AER Annual Category Analysis Regulatory Information Notices (repex) and AER repex model (replacement cost)<sup>3</sup>

**Figure 4: Rate of average annual asset renewal in real terms (2008-09 to 2017-18)**

Figure 4 shows a doubling in the average rate of renewal from the 2005-10 RCP to the 2010-15 RCP. A more moderate increase occurred between the 2010-15 RCP and the 2015-20 RCP (based on actual expenditure to date).

If we maintained the average rate of renewal of 0.3% in the 2015-20 RCP, some of our assets would be required to last more than 330 years which is both an unrealistic and unsustainable outcome.

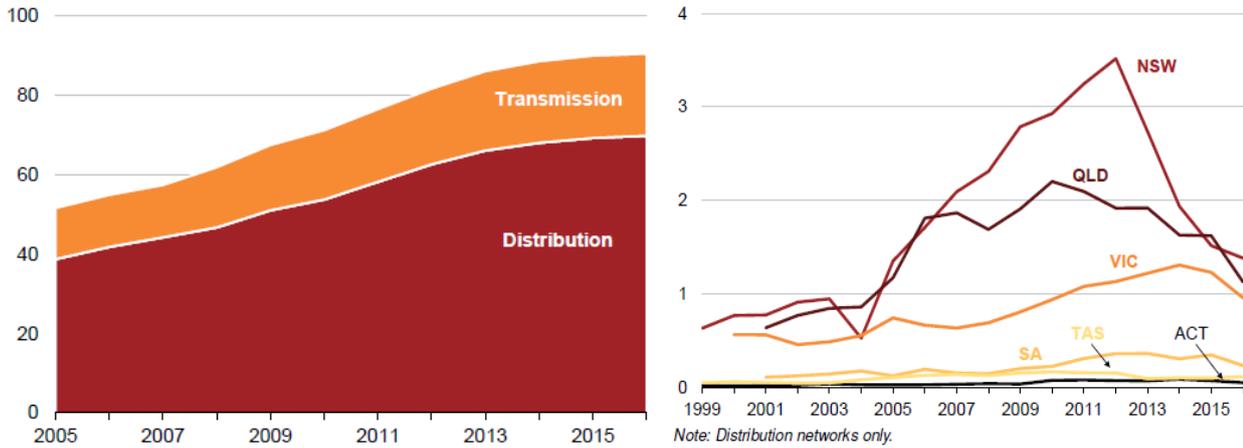
Our current asset renewal approach typically results in localised network defects being identified and addressed based on risk. Non-network options are typically not viable for addressing localised defects, even on relatively short lengths of conductors and cables identified for renewal. However, non-network options will become of increasing importance in the future where long lengths of powerlines are identified for renewal. This could include decommissioning of long lengths of single wire earth return (**SWER**) conductors in rural areas where microgrids can be implemented (where it complies with our legislative requirements and is technically and economically viable to do so). This is discussed further in Section 5.2.3.

### 3.3 History of growth in the regulated asset base

As mentioned in Section 3.2, we have undertaken limited investment in our RAB over the last 10 years. Rather, we have sought to maximise the life of our existing assets. In March 2018, the Grattan Institute, an independent body focused on Australian public policy, undertook a review of the electricity supply chain

<sup>3</sup> Back casting of cable and conductor minor repair work as repex shows a similar profile with the average renewal rates per RCP increasing by <0.1%.

(Grattan Institute Review) in response to rising electricity prices and declining customer demand due to the proliferation of photovoltaic solar systems. Through reviewing NSPs determinations by the AER, the value of the RAB across the NEM for both transmission and distribution networks was found to have increased from around \$50 billion in 2005 to \$90 billion in 2016 in real terms. The majority of this was found to be due to the increased RAB investments by DNSPs in the eastern states as shown in Figure 5.



**Regulated asset base (2017 \$ billions)**

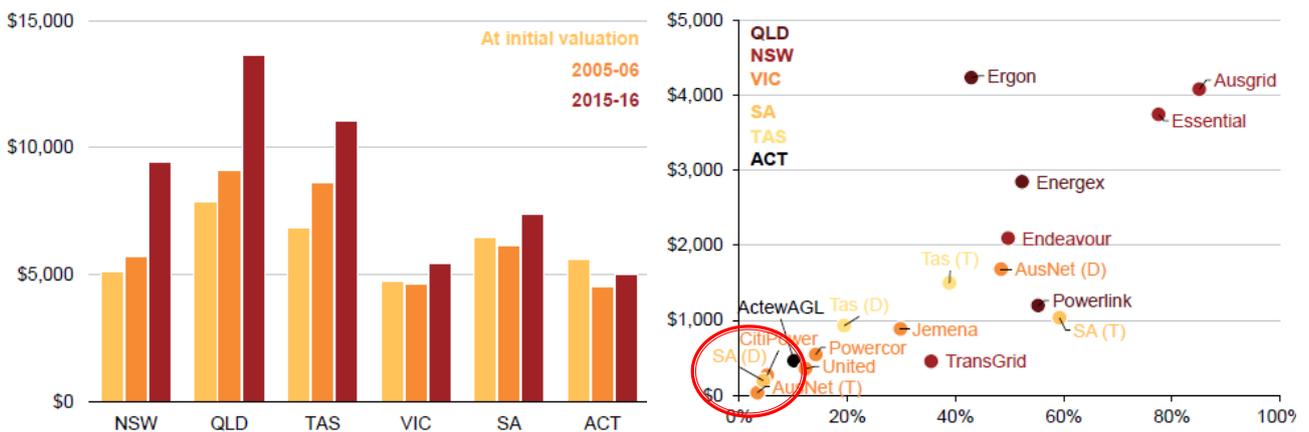
**Capital expenditure (2017 \$ billions)**

Source: Wood, T., Blowers, D., and Griffiths, K. (2018). Down to the wire: A sustainable electricity network for Australia. Grattan Institute.

**Figure 5: The NEM regulated asset base and jurisdictional capex (2017 \$ billions)**

The Grattan Institute concluded that over investment was largely due to excessive reliability standards in some jurisdictions, which resulted in significant capital investments.

As a result of the over investment in other jurisdictions, the Grattan Institute Review identified that the value of SA Power Networks’ RAB per customer is significantly lower than most other jurisdictions and the relative change in our RAB over time per customer was the lowest of all DNSPs in the NEM as shown in Figure 6.



**Regulated asset base value per customer (2017 \$)**

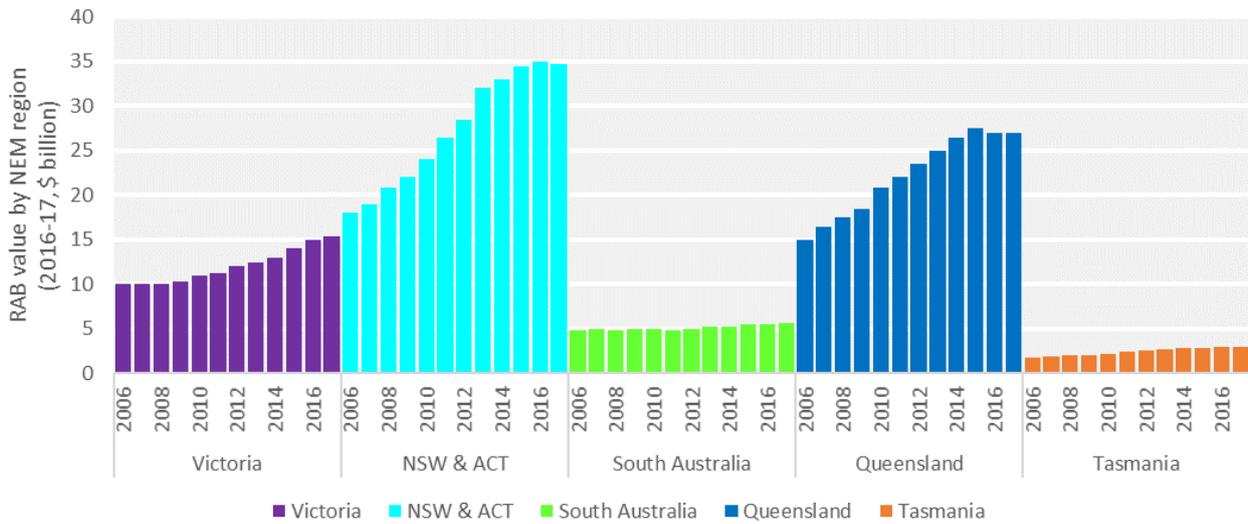
**Change in regulated asset base value per customer from 2005/06 to 2015/16 (2017 \$ and %)**

Source: Wood, T., Blowers, D., and Griffiths, K. (2018). Down to the wire: A sustainable electricity network for Australia. Grattan Institute.

**Figure 6: RAB value per customer (2017 \$) and change per customer (per cent) (2005/06 to 2015/16)**

Figure 6 demonstrates that SA Power Networks capital investment (including repex) has, and continues to be, modest.

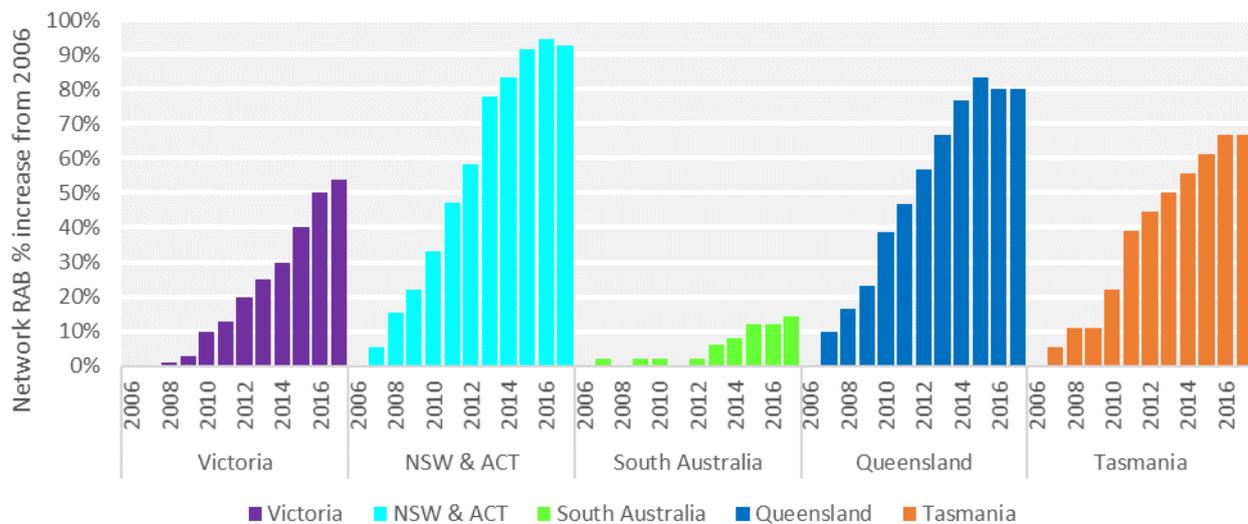
In addition, in June 2018, the Australian Competition and Consumer Commission (ACCC) undertook a review of electricity pricing across the NEM in response to increasing customer electricity bills. This covered the full electricity supply chain and made numerous recommendations. The ACCC concluded that SA Power Networks has seen little increase in its RAB over the past 10-15 years relative to other DNSPs in the NEM as shown Figure 7.



Source: Replicated from the Australian Competition and Consumer Commission, Restoring electricity and affordability and Australia's competitive advantage – Retail pricing enquiry – Final Report, June 2018.

**Figure 7: Network RAB from 2006-17, by NEM region (2016-17 \$ real)**

Figure 7 demonstrates that NSPs across all jurisdictions, including South Australia, have increased their RAB from the 2006 baseline levels. Due to the significant variations in RAB values shown in Figure 7, the data from Figure 7 has also been displayed as an rate of change of the RAB by jurisdiction from 2006 levels in Figure 8.



Source: Replicated from the Australian Competition and Consumer Commission, Restoring electricity and affordability and Australia's competitive advantage – Retail pricing enquiry – Final Report, June 2018.

**Figure 8: Network RAB increase from 2006-17, by NEM region, % increase from 2006 levels**

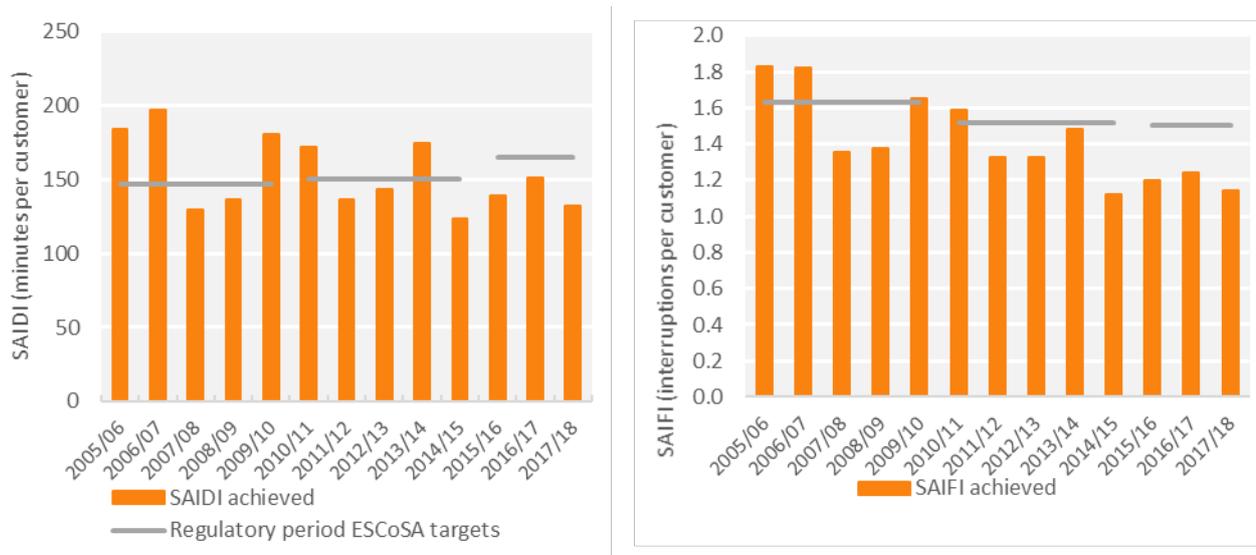
Figure 8 shows the percentage increase in RABs from 2006 highlighting that SA Power Networks has clearly seen the smallest increase across the NSPs in the NEM. This has translated to limited price increases for

customers to maintain SA Power Networks RAB. As a result, both the ACCC and the Grattan Institute found little evidence of excessive investment or growth in South Australia’s distribution network assets.

### 3.4 Performance history

As a DNSP, we have a regulatory obligation to provide a safe and reliable network (see Section 4.2). SA Power Networks’ customer centric levels of service measures and targets include measures for reliability and safety. Our reliability targets include measures of unplanned SAIDI<sup>4</sup> and SAIFI<sup>5</sup> and are set by ESCoSA and designed to maintain historical reliability performance for unplanned interruptions excluding major event days (MEDs).

SA Power Networks historical reliability performance is shown in Figure 9.



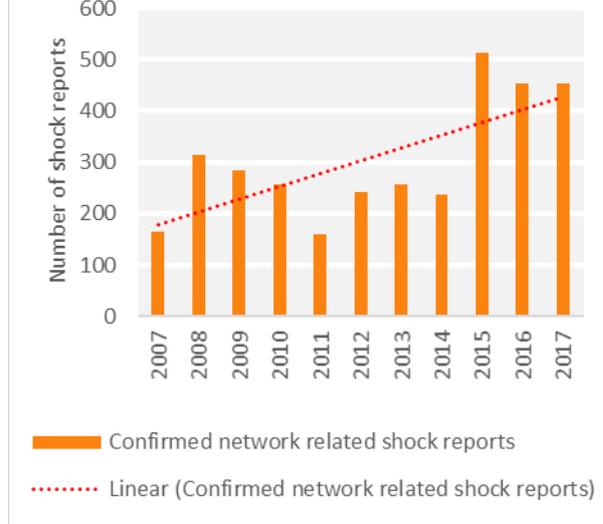
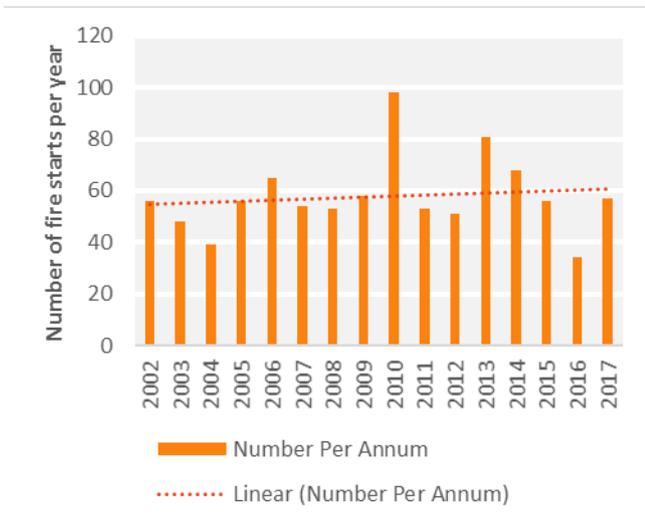
**Figure 9: Historical SAIDI and SAIFI performance against ESCoSA regulatory targets (excluding MEDs)**

Figure 9 shows that the underlying reliability trend (excluding MEDs) is stable with the average reliability performance maintained at historical levels.

Our service level measures for safety include fire starts and shock reports. While the number of fire start events has remained stable there has been a concerning increase in the number of shock reports which can be attributed to network assets as shown in Figure 10.

<sup>4</sup> System Average Interruption Duration Index (SAIDI) is the average outage duration for each customer served.

<sup>5</sup> System Average Interruption Frequency Index (SAIFI) is the average outage frequency for each customer served.

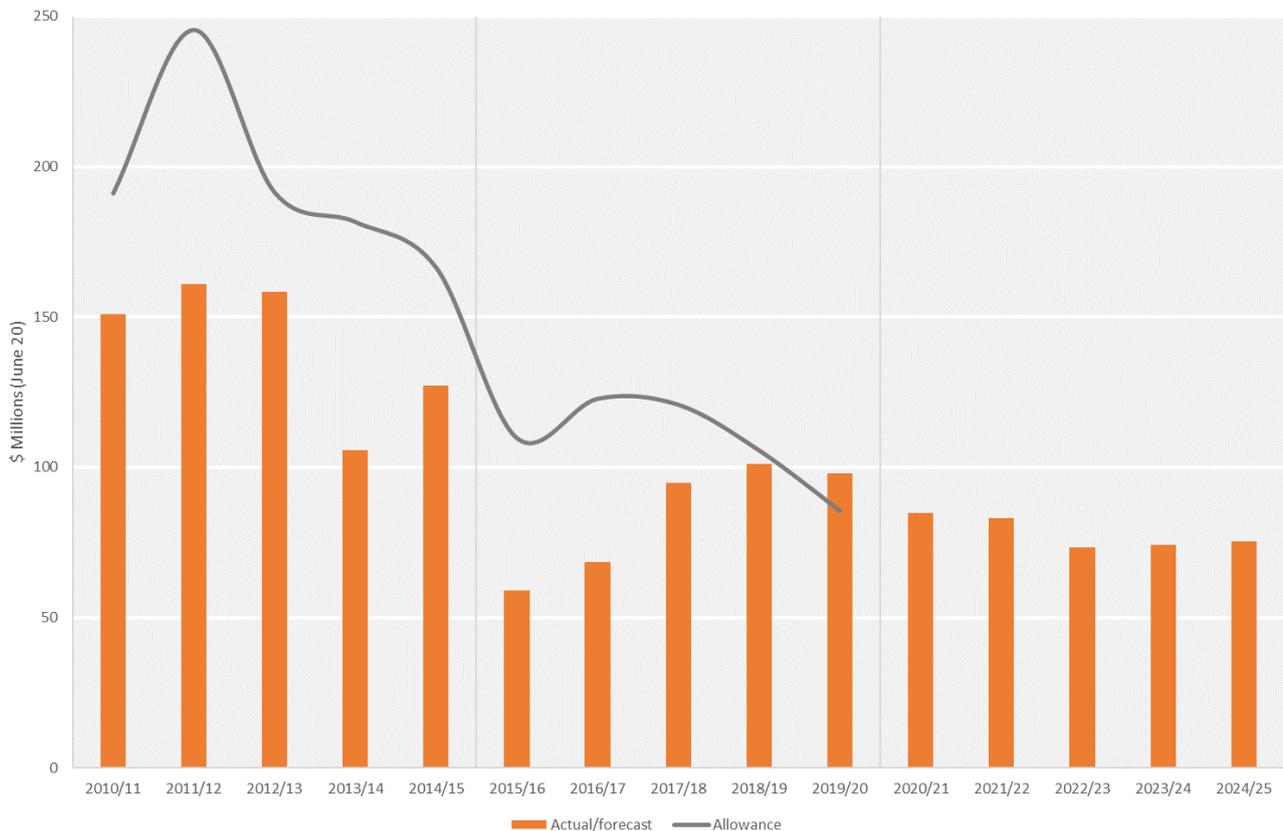


**Figure 10: Historical fire starts and shock reports**

Figure 10 shows the fire starts trend being relatively stable over the long term largely attributed to our Bushfire Risk Management Committee which regularly monitors performance and the implementation of risk management strategies. Conversely, the number of LV shock reports attributed to distribution network assets is showing a concerning long-term increasing trend. Historically, we have undertaken a reactive approach to inspection and used shock reports to identify the cause and any remedial work required to our service lines. As an effort to counter this trend, and to ensure the continued safety of our customers, we have proposed an increase in proactive repex for service lines for the 2020-25 RCP. This is discussed further in the service line expenditure justification (see Section 7.8).

### 3.5 Augmentation expenditure (augex) impact on asset renewal

There has been a significant reduction in augmentation work and consequently augex since the 2010-15 RCP as shown in Figure 11.



**Figure 11: SA Power Networks augex allowance and actual/planned spend for the 2010-15, 2015-20 and 2020-25 RCPs**

Figure 11 shows a continued reduction in our forecast augex for the 2020–25 RCP. This is due to a decrease in capacity related work and expenditure as a result of relatively flat demand across our network. At a system level, the Australian Energy Market Operator (**AEMO**) forecasts the net summer demand (after solar and batteries) will decrease at an annual average rate of 1% over the 2020–25 RCP, as traditional drivers of peak demand growth (eg summer air-conditioning load) continue to be offset by solar, increasingly efficient appliances, housing stock and slow economic growth. Notwithstanding the above, there are some localised parts of the network experiencing increased demand.

While capacity related work and expenditure is driven by ensuring sufficient network capacity, network capacity upgrades invariably lead to the replacement of some network assets in addition to the construction of new assets. The forecast reduction in required augmentations and augex will therefore reduce this type of ancillary asset replacements and this reduction will only be partly offset by a marginal increase in repex.

Our observed long-term trends in repex (see Figure 2) and augex (see Figure 11) align with the views of the Australian Energy Market Commission<sup>6</sup> (**AEMC**) that:

- electricity demand growth has flattened;
- in the current and expected environment, repex has been a growing proportion of total capex; and
- technological changes are challenging the previous presumption of like-for-like replacement.

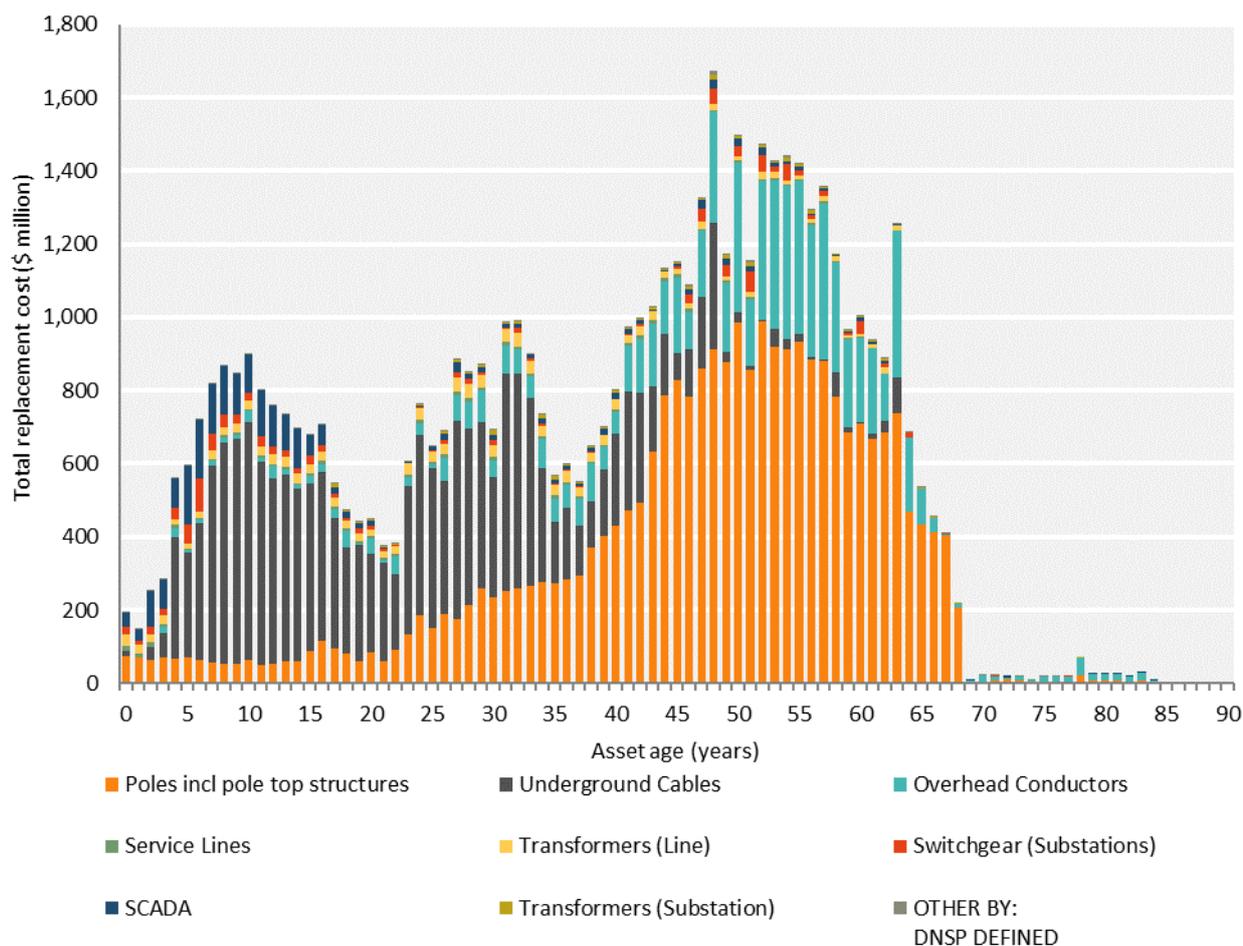
In other words, there is an increasing focus on managing existing network assets as compared to the historical focus of expanding the network to meet growing demand. At the same time, technological changes have emerged whereby non-network solutions are becoming more viable alternatives to traditional network capacity upgrades and to a lesser extent, asset renewals.

<sup>6</sup> AEMC, *Rule Determination, National Electricity Amendment (Replacement expenditure planning arrangements) Rule 2017*, 18 July 2017, p. i.

### 3.6 Asset age

The large-scale electrification of South Australia commenced in around 1950 and continued through the 1960s and 1970s resulting in a large proportion of the distribution networks assets now being between 40-70 years of age. Our asset age profile reflects our asset management practice of repairing and maintaining assets (asset maintenance<sup>7</sup>) to extend their expected life (technical life<sup>8</sup>) wherever it is cost-effective to do so taking into account risk consideration, ahead of more costly asset renewals. Our approaches to asset management that aim to maximise asset life are discussed further in Section 3.7.

Figure 12 shows when most of our current assets were installed, and where we have invested in new assets in recent years.



Source: SA Power Networks Repex model

**Figure 12: SA Power Networks asset replacement cost profile**

<sup>7</sup> Asset maintenance: ‘business as usual’ or routine preventative (eg inspection and testing) and corrective (eg minor repairs) activities to sustain the asset’s functionality and keep it in service to achieve its expected technical life (AER, DRAFT Industry practice application note – Asset replacement planning, 2018).

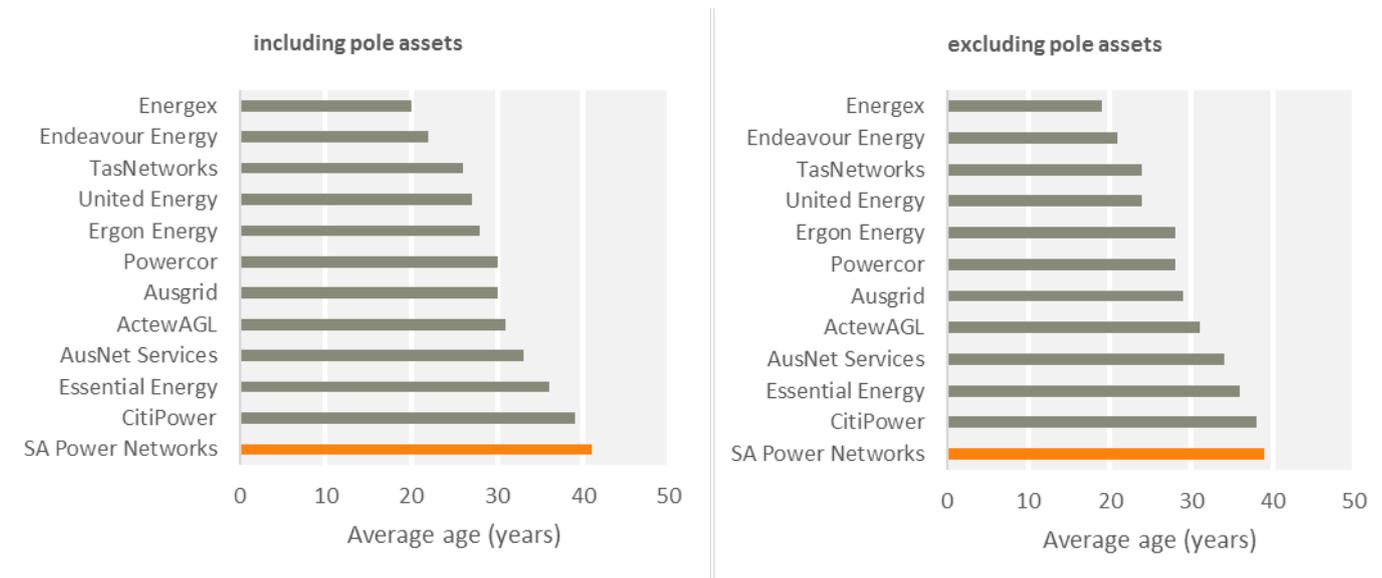
<sup>8</sup> Technical life: the typical expected life of an asset before it fails in service under normal operating conditions. The technical life may differ between businesses (due to different operation environment factors) and between asset classes. This should be referenced to typical industry values (AER, DRAFT Industry practice application note – Asset replacement planning, 2018).

Figure 12 shows a large proportion of the replacement cost within poles, pole top structures, underground cables and overhead conductors.

The majority of the value of assets in the 40-70 year age bracket fall within the overhead network category and consist of poles, pole top structures and conductors (this was the preferred and most economic construction method when the network was first constructed) and makes up approximately 80% of our network length.

Conversely, the value of assets with less than 40 years of age is dominated by underground cables. The majority of the underground cables are assets vested to SA Power Networks through greenfield real estate developments.

The combination of historical low repex (see Section 3.2) and declining augmentations and augex (see Section 3.5) have a compounding effect leading to an ageing asset base. Consequently, we have the oldest distribution network in the NEM as shown in Figure 13.



Source: AER Category Analysis Regulatory Information Notice data for DNSPs across the NEM (2016-2017 data)

**Figure 13: Average age of DNSPs' assets**

Figure 13 shows that even with the removal of pole assets (to account for SA Power Networks' long life Stobie poles), SA Power Networks still has the oldest asset base of the DNSPs in the NEM.

However, as the assets continue to age, replacements will be required when refurbishment is no longer a viable option due to the overall asset condition, cost, safety or equipment obsolescence. Expenditure on asset replacement will inevitably need to be increased to maintain the existing levels of service and to constrain the increasing risk across the distribution network as result of the deterioration of the ageing asset base. Failure to invest sufficiently in the network will ultimately lead to unacceptable safety and service level outcomes and higher expenditure and customer dissatisfaction in the future.

We aim to balance these risks while being mindful of the role SA Power Networks has in delivering better outcomes for customers at lower prices and also acknowledging the changing uses of our network.

### 3.7 Asset management practices

SA Power Networks has a systematic approach for managing network assets. Our SRMTMP links our regulatory obligations (see Section 4) to our internal management decision processes and documentation. The internal documentation comprises a suite of manuals, operational policies, processes and procedures (including technical standards) that are referenced through the SRMTMP.

Section 4 of the SRMTMP sets out the relevant documents associated with the safety and technical aspects of the maintenance of our network.

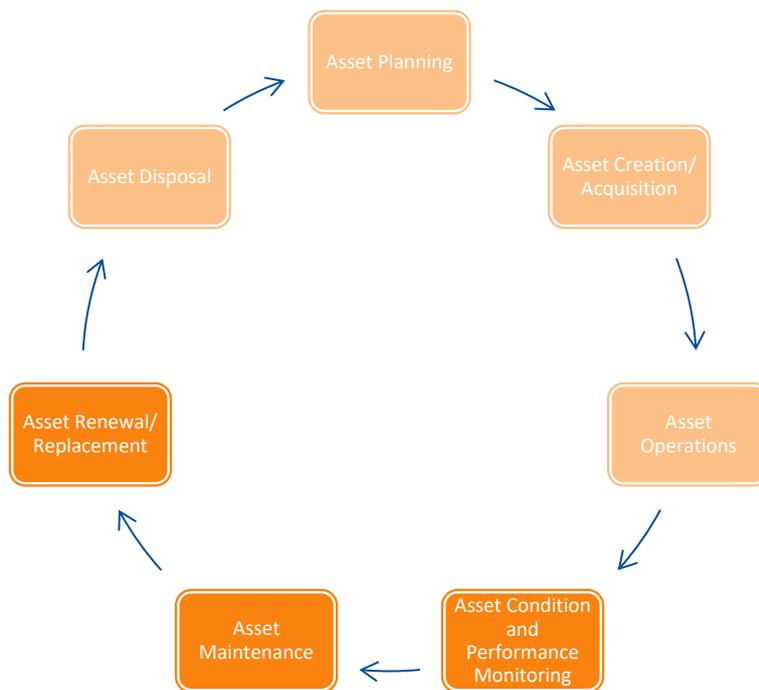
The documents (other than this document) most relevant to the preparation of our repex forecasts include:

- The Strategic Asset Management Plan Manual 15 (see Supporting Document 5.7 – Strategic Asset Management Plan (SAMP)), which outlines the operating environment and the challenges faced by SA Power Networks in delivering services now and into the future, and the overarching strategies implemented to deliver a valuable service to customers.
- The Power Asset Management Plan (Manual No. 16) (see Supporting Document 5.8 – Powerline Asset Management Plan (PAMP)) which outlines the strategies and plans SA Power Networks employs to effectively manage network assets to deliver value to customers.
- The Network Maintenance Manual (Manual No. 12), (document available on request) which details the strategies that govern SA Power Networks maintenance practices. The manual is designed for use by SA Power Networks employees, from executives to field personnel involved in the maintenance of network assets.
- The Line Inspection Manual (Manual No. 11), (document available on request) which provides a detailed guide in assessing the condition of the network assets (including high-resolution photographs of common defects and associated codes for each defect), the procedures for recording the data collected during the condition assessment and categorisation of defects. The manual embodies the knowledge, intent and experience of inspectors, coordinators and maintenance engineering specialists.

The documents listed above, in conjunction with Asset Plans developed for each asset class, provide a detailed explanation of the maintenance and replacement practices applied to our assets, covering:

- Inspections and inspections cycles - how and how often we inspect the condition of assets.
- Defect identification - how we measure the condition of assets and determine whether they are defective.
- Defect intervention – how we decide whether we need to repair, refurbish or replace an asset.
- Work selection – how we value the identified work.

These activities collectively focus on the asset condition and performance monitoring, maintenance and asset renewal phases of the asset lifecycle as shown in Figure 14.



**Figure 14: Typical asset life cycle stages as applied within SA Power Networks**

The general approach applied by SA Power Networks across its network assets for the asset life cycle stages highlighted is summarised in Table 1.

**Table 1: Power network asset life cycle stages – application within SA Power Networks**

Asset life cycle stage	Description
<b>Asset condition and performance monitoring</b>	<ul style="list-style-type: none"> <li>• The assessment of the asset to identify any defects and required corrective actions.</li> <li>• Comprehensive asset inspection and condition monitoring programs are undertaken across line and substation assets to identify defects that most commonly lead to asset failures<sup>9</sup>. The many assessment techniques used include visual inspections, thermography, partial discharge tests and other diagnostic techniques to determine the condition of the assets.</li> <li>• The line inspection and condition monitoring programs are as per the cycles nominated in the Network Maintenance Manual.</li> <li>• Regular monitoring of the network reliability and performance and emerging trends.</li> <li>• Investigating and monitoring equipment failures and emerging trends.</li> <li>• Ongoing trials with several emerging technologies towards cost-effective condition and asset assessments including the use of autonomous drones, fixed wing aircraft, specialised condition monitoring equipment and laser scanning technology referred to as light detection and ranging (<b>LIDAR</b>).</li> <li>• Optimisation of the frequency of inspection cycles across the network are ongoing.</li> <li>• Historical failure rates of assets inform the decision-making processes. Asset failure data provides a high-level indicator of the asset management practices and is used to determine the probability of failure in the condition-based risk management capital forecasting model.</li> </ul>
<b>Asset maintenance</b>	<ul style="list-style-type: none"> <li>• The process of undertaking planned minor work carried out to prevent more expensive work in the future and reactive maintenance where an asset defect or failure is fixed.</li> <li>• Maintenance work is prioritised based on the greatest return on investment.</li> </ul>
<b>Asset renewal/replacement</b>	<ul style="list-style-type: none"> <li>• The process of refurbishment or replacement of an asset to provide required functionality taking into consideration current and forecast network requirements to ensure it continues to deliver the required level of service.</li> <li>• Assets are replaced when they fail.</li> <li>• A risk-based approach is taken in renewing/replacing assets with condition defects prior to failure. Asset risks are assessed based on the probability of the asset failing and the consequence(s) of its failure.</li> <li>• Renewal work is prioritised and selected considering the risk that will be removed from the network relative to the cost of the work (ie return on investment).</li> <li>• The decision whether to repair, refurbish or replace is based on remaining whole of life-cycle costs. Refurbishment can significantly extend the expected life of the asset prior to requiring replacement but does not restore the asset to 'as new' condition.</li> </ul>

To optimise expenditure through the asset management lifecycle, we continually explore new ways to improve cost efficiency without adversely impacting the levels of service or risk or the benefits and outcomes of recent initiatives which are summarised in Table 2.

<sup>9</sup> Failure of an asset is defined as the asset being unable to perform its intended function safely and in compliance with jurisdictional regulations, and not because of external impacts such as extreme weather events, third party interference/damage, wildlife or vegetation interference and excludes planned interruptions (Australian Energy Regulator, 2014, *Better Regulation – Explanatory Statement – Final Regulatory Information Notices to Collect Information for Category Analysis*, March 2014).

**Table 2: Optimisation of expenditure across the asset management lifecycle**

Asset life cycle stage	Description of opportunity	Benefit or outcome
<b>Asset condition and performance monitoring</b>	<ul style="list-style-type: none"> <li>implementing the optimal level of condition monitoring</li> <li>predictive risk modelling on major asset classes</li> <li>introducing new low risk technologies to reduce whole of life cost (eg inspection drone trials)</li> </ul>	<ul style="list-style-type: none"> <li>focus resources on assessing condition of most critical assets</li> <li>focusing available capital on the highest risks in the network</li> <li>use of emerging technologies to undertake asset inspections to evaluate the suitability of pole top inspections and feeder patrols</li> </ul>
<b>Asset maintenance</b>	<ul style="list-style-type: none"> <li>utilising live line work practices</li> <li>greater reliance on condition and value-based maintenance programs</li> </ul>	<ul style="list-style-type: none"> <li>reducing number of planned outages</li> <li>optimising maintenance delivery</li> </ul>
<b>Asset renewal/replacement</b>	<ul style="list-style-type: none"> <li>development of a work valuing tool (see section 5.2.2)</li> <li>visibility map for planned work (see section 5.2.2)</li> <li>condition based risk modelling to undertake scenario modelling (see section 6.1)</li> <li>extending the expected life of assets through asset refurbishments</li> <li>deferring capital expenditure by implementing lower-cost short-term projects</li> <li>minimising the range and quantity of spare holdings</li> <li>maintaining strategic spares for high risk assets</li> </ul>	<ul style="list-style-type: none"> <li>ensures most important work selected considering the value that will be generated given the cost of the work; lower priority work delivered subject to resource capacity</li> <li>enables works in close proximity to be bundled to improve delivery efficiency</li> <li>maximising risk reduction for capital outlay</li> <li>more cost-effective refurbishment to defer asset replacement</li> <li>incorporation of most recent network design features and components in the eventual replacement or refurbishment program to integrate with the evolving network</li> <li>equipment standardisation and reduced risk of obsolescence</li> <li>less risk of prolonged interruptions through having critical spares readily available</li> </ul>

SA Power Networks has undertaken a comparison of unit rates to validate and demonstrate the effectiveness of our approaches in minimising repex (see Section 5.2.3). Our comparison of repex per unit of asset population from published category analysis RINs is discussed for AER repex modelled assets (see Section 7) and shows that we have a very efficient level of repex for most asset classes relative to other DNSPs. This is also discussed further in our PAMP.

## 4 Regulatory obligations and requirements

### 4.1 Overview

The need for asset renewal (refurbishment or replacement) activities allowed for in repex forecasts largely relate to our regulatory obligations governing the provision of standard control services and the maintenance of the reliability, security and safety of our distribution network.

These regulatory obligations derive from a number of sources. These sources include:

- section 60 of the *Electricity Act 1996 (SA)* (**Electricity Act**);
- the requirements of our Distribution Licence;
- the OTR approved SRMTMP;
- the various requirements relating to the maintenance of network assets referred to in the Electricity (General) Regulations 2012 (SA) (Electricity Regulations) (and section 12 of Schedules 1 – 4 in particular);
- the ESCoSA set service standards for reliability; and
- Chapter 5 of the National Electricity Rules (**NER**) (and clauses 5.2.1 and 5.2.3 in particular which require us to maintain and operate our facilities in accordance with relevant laws, the requirements of the Rules and good electricity industry practice, and the power system performance and quality of supply standards set out in Schedule 5.1 of the NER).
- SA Electricity Distribution Code; and
- ESCoSA and AER Guidelines. Our repex forecast has been developed to ensure that we are able to prudently and efficiently comply with all applicable regulatory obligations or requirements including those which are described in sections 4.2 to 4.8.

### 4.2 Meeting the National Energy Objective

As a DNSP operating in the NEM, SA Power Networks must aim to achieve the National Electricity Objective as stated in the National Electricity Law<sup>10</sup>, which is:

*‘...to promote efficient investment in, and efficient operation and use of, electricity services for the long-term interests of consumers of electricity with respect to:*

- *price, quality, safety and reliability and security of supply of electricity*
- *the reliability, safety and security of the national electricity system.’*

In order to achieve this objective, SA Power Networks needs to incur repex in relation to its distribution network.

### 4.3 Requirements under section 60 of the Electricity Act

Part 6 of the Electricity Act sets out our jurisdictional obligations in relation to safety and technical issues associated with the operation and maintenance of a safe electricity network in South Australia. In particular, section 60 of the Electricity Act sets out our responsibilities as an owner or operator of an electricity network:

*“(1) A person who owns or operates electricity infrastructure or an electrical installation must take reasonable steps to ensure that—*

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<sup>10</sup> Section 7 of the NEL.

- (a) *the infrastructure or installation complies with, and is operated in accordance with, technical and safety requirements imposed under the regulations; and*
  - (b) *the infrastructure or installation is safe and safely operated.*
- (1a) *A person who contravenes subsection (1) is guilty of an offence.*
- Maximum penalty:*
- (a) *if the person committed the offence intentionally or recklessly and with the knowledge that an immediate and material risk of harm to any person will or might result—*
    - (i) *if the offender is a body corporate—a penalty of \$250 000;'*

#### **4.4 Requirements of our Distribution Licence**

Clause 7 of our Distribution Licence requires SA Power Networks to comply with all applicable regulatory instruments, including any technical or safety requirements under the Electricity Act (including those obligations referred to in section 4.3 above).

The term 'applicable regulatory instruments' also includes any industry codes, industry rules, guidelines or other regulatory instruments made by ESCoSA (including, by way of example, the Distribution Code), the National Electricity Law (**NEL**) and National Energy Retail Law (**NERL**) or any statutory instruments made under the NEL or NERL which impose obligations on SA Power Networks in respect of the operations authorised by its Distribution Licence.

#### **4.5 Requirements under our OTR approved SRMTMP**

SA Power Networks is required under the conditions of its Distribution Licence and section 25 of the Electricity Act to comply with its OTR approved SRMTMP.

Clause 23(1)(c) of the Electricity and clause 8 of our Distribution Licence (as amended by section 23(1)(c) of the Electricity Act) imposes an obligation on SA Power Networks to prepare an SRMTMP:

'8.1 *The Licensee must:*

- (a) *prepare a safety, reliability, maintenance and technical management plan dealing with matters prescribed by regulation and submit the plan to the Technical Regulator for the approval; and*
- (b) *annually review and, if necessary, update the plan prepared in accordance with clause 8.1(a) and as updated from time to time in accordance with clause 8.1(b);*
- (c) *not amend the plan without the approval of the Technical Regulator; and*
- (d) *undertake annual audits of its compliance with its obligations under the plan and report the results to the Technical Regulator, in a manner approved by the Technical Regulator.*

Importantly, the SRMTMP must be approved by the OTR and we must comply with the approved SRMTMP. In accordance with these obligations, audits are routinely undertaken to assess our compliance with the SRMTMP (and therefore our compliance with the Electricity Regulations).

Regulation 72 of the Electricity Regulations prescribes what we must cover in these plans and includes in sub-regulation 72(2):

*'(a) the safe design, installation, commissioning, operation, maintenance and decommissioning of electricity infrastructure owned or operated by the person;'*

The SRMTMP also incorporates by reference a hierarchy of internal SA Power Network documents. These internal documents are considered and updated during the annual SRMTMP review and approval process as they form an integral part of our SRMTMP. The SA Power Networks' internal documents include the Network Maintenance Manual (No. 12) and the Line Inspection Manual (No. 11) which outline the:

- 'system of maintenance';
- 'predetermined processes'; and
- 'managed replacement programs',

instituted by SA Power Networks for the purposes of meeting (amongst other things) its obligations under Section 12 of Schedules 1 - 4 of the Electricity (General) Regulations (refer to section 4.6 below for further details in relation to these obligations).

Recognising the significance of these obligations to our asset renewal needs, the SRMTMP directly references (amongst other things) our internal processes and procedures that define how we undertake our line inspection practices. This includes how we assess and grade asset defects and the criteria associated with the remediation of these defects, including replacement and refurbishment activities. As such, we have a regulatory obligation to comply with these internal processes and procedures, via the approved SRMTMP.

## **4.6 Various requirements under the Electricity Regulations**

Division 1 of Part 10 of the Electricity Regulations set out the general safety requirements for electricity infrastructure. In particular, section 47 provides that:

- '(1) No circuit in electricity infrastructure may be allowed to remain in service unless every part of the circuit functions in a safe manner.'*
- '(2) Each active conductor of a high voltage powerline or other high voltage equipment must be protected by an automatic disconnecting device.'*
- '(3) Metal components of electricity infrastructure not normally conducting electricity that may become energised must be connected to earth.'*
- '(4) Electricity infrastructure must be adequately protected against earth faults.'*

The same Division also goes into more detail regarding the safety requirements for aerial lines (section 48), underground lines (section 49), powerlines (other than aerial or underground lines) (section 50), substations (section 51) and earthing and electrical protection systems (section 52). In general, those sections provide that these assets:

*'...must be designed, installed, operated and maintained to be safe for the electrical service conditions and the physical environment in which they will operate'.*

In addition, these sections also provide that for aerial lines (section 48), construction must be suitable for the level of hazard in the area while for earthing and electrical protection systems (section 52), the assets must be maintained to safely manage abnormal electricity network conditions likely to significantly increase the risk of personal injury or significant property damage.

Schedule 1 (aerial lines), Schedule 2 (underground lines and certain other powerlines), Schedule 3 (substations) and Schedule 4 (earthing and electrical protection systems) of the Electricity Regulations provide further requirements associated with the maintenance of our network assets but generally state:

*'...the assets and their components must be maintained to be in a safe operating condition.*

*A system of maintenance must be instituted including—*

- (a) predetermined processes to confirm the safe state of components;*
- (b) managed replacement programs for components approaching the end of their serviceable life.*

*Maintenance programs must be carried out in accordance with the listed standards.<sup>11</sup>*

#### **4.7 Requirements under our ESCoSA service standards for reliability**

The ESCoSA Service Standard Framework (**SSF**) prescribes the reliability and customer service levels that we must deliver to customers. The service levels that will apply for the 2020-25 RCP are based on the frequency and duration of unplanned interruptions in four broad feeder categories (CBD, Urban, Rural Short and Rural Long).

On 7 January 2019, ESCoSA finalised the SSF for the 2020-25 RCP which will set network reliability targets to maintain reliability at current levels. ESCoSA will decide whether to set performance targets as the average of five or ten years' performance in late 2019, at the same time it sets performance targets. These exclude network performance during severe or abnormal weather events using the Institute of Electrical and Electronics Engineers (**IEEE**) MED exclusion methodology.

#### **4.8 Requirements under Chapter 5 of the NER**

Clause 5.2.1 of the NER requires SA Power Networks to maintain and operate all equipment that is part of its facilities in accordance with:

- relevant laws;
- the requirements of the NER; and
- good electricity industry practice and relevant Australian Standards.

Further, clause 5.2.3 of the NER requires SA Power Networks to comply with the power system performance and quality of supply standards described in schedule 5.1 of the NER.

## 5 Regulatory treatment

### 5.1 Rule requirements

Clauses 6.8.2(c) and 6.5.7(a) of the NER require SA Power Networks to submit a building block proposal which includes the total forecast capex for the 2020-25 RCP, that SA Power Networks considers is necessary to achieve the capex objectives.

The capex objectives are to:

- '(1) meet or manage the expected demand for standard control services over that period;*
- (2) comply with all applicable regulatory obligations or requirements associated with the provision of standard control services;*
- (3) to the extent that there is no applicable regulatory obligation or requirement in relation to:
  - (i) the quality, reliability or security of supply of standard control services; or*
  - (ii) the reliability or security of the distribution system through the supply of standard control services,*to the relevant extent:
  - (iii) maintain the quality, reliability and security of supply of standard control services; and*
  - (iv) maintain the reliability and security of the distribution system through the supply of standard control services; and**
- (4) maintain the safety of the distribution system through the supply of standard control services.'*

The AER must accept SA Power Networks proposed capex forecast included in the building block proposal if the AER is satisfied that the forecast capex reasonably reflects the capex criteria.

The capex criteria are as follows:

- '(1) the efficient costs of achieving the capital expenditure objectives;*
- (2) the costs that a prudent operator would require to achieve the capital expenditure objectives; and*
- (3) a realistic expectation of the demand forecast and cost inputs required to achieve the capital expenditure objectives.'*

In making this assessment, the AER must have regard to the capex factors which are:

- '(4) the most recent annual benchmarking report that has been published under rule 6.27 and the benchmark capital expenditure that would be incurred by an efficient Distribution Network Service Provider over the relevant regulatory control period;*
- (5) the actual and expected capital expenditure of the Distribution Network Service Provider during any preceding regulatory control periods;*
- (5A) the extent to which the capital expenditure forecast includes expenditure to address the concerns of electricity consumers as identified by the Distribution Network Service Provider in the course of its engagement with electricity consumers;*
- (6) the relative prices of operating and capital inputs;*
- (7) the substitution possibilities between operating and capital expenditure;*

- (8) *whether the capital expenditure forecast is consistent with any incentive scheme or schemes that apply to the Distribution Network Service Provider under clauses 6.5.8A or 6.6.2 to 6.6.4;*
- (9) *the extent the capital expenditure forecast is referable to arrangements with a person other than the Distribution Network Service Provider that, in the opinion of the AER, do not reflect arm's length terms;*
- (9A) *whether the capital expenditure forecast includes an amount relating to a project that should more appropriately be included as a contingent project under clause 6.6A.1(b);*
- (10) *the extent the Distribution Network Service Provider has considered, and made provision for, efficient and prudent non-network options;*
- (11) *any relevant final project assessment report (as defined in clause 5.10.2) published under clause 5.17.4(o), (p) or (s); and*
- (12) *any other factor the AER considers relevant and which the AER has notified the Distribution Network Service Provider in writing, prior to the submission of its revised regulatory proposal under clause 6.10.3, is a capital expenditure factor.*

## 5.2 Why the AER should accept our forecast

The repex forecast proposed by SA Power Networks for the 2020-25 RCP is required in order to achieve the capex objectives and capex criteria, having regard to the capex factors. This is demonstrated in the following sections.

### 5.2.1 Capex objectives

We have a regulatory obligation to meet or manage the expected demand for standard control services.

The first capex objective (to meet or manage the expected demand for our services) is a key objective achieved by our forecast repex. If we do not appropriately manage the condition of our distribution network, and have appropriate plans in place to assess and rectify defects, we will not be able to supply standard control services to, and otherwise meet the needs of, our customers.

Our asset management plans, and the forecast repex we need to implement these plans, will enable us to meet and manage expected demand for our services during the 2020-25 RCP.

We have a regulatory obligation to identify and address defective assets on our network.

The second capex objective (to comply with applicable regulatory obligations or requirements) is the primary objective that our repex forecasts is required to achieve. That is, the level of intervention that is allowed for by this forecast is necessary to comply with the applicable regulatory obligations or requirements over the 2020-25 RCP.

As discussed in Section 4, we have a number of regulatory obligations relating to the provision of standard control services and the maintenance of the reliability, security and safety of our distribution network. As part of these obligations, we must prepare and comply with our SRMTMP, which was approved by the OTR. This plan sets out how we will maintain our network and how we will inspect our network assets, identify defects, and address these defects.

We have included references to these regulatory obligations, our approved SRMTMP, and our internal processes and procedures covered by the SRMTMP in this document.

We must maintain the reliability and security of the distribution system.

The third capex objective (to maintain the reliability and security of supply of standard control services to customers) is achieved in part through a continued increased rate of asset renewal and improved targeting of risk during the 2015-20 RCP. This is required even though we have an ageing asset base combined with reduced rate of asset renewal through augmentation works. To ensure reliability is maintained while balancing the need to constrain prices for customers, our risk-based modelling and forecasts of proposed repex ensure that we are maintaining the reliability of our network whilst acting in the long-term interests of customers in relation to the pricing of our services.

Our forecast is also aimed at maintaining risks within the distribution system.

The fourth capex objective (to maintain safety) is another objective achieved by our forecast repex. In this regard, the forecast volume of asset renewal is set to:

- maintain risk at an acceptable level applied through the assets modelled in CBRM;
- renew assets presenting unacceptable safety risks to staff, contractors and the public; and
- continue with a level of investment largely aligned with the 2015-20 RCP for assets not modelled in CBRM, including our safety capital programs of work.

Our value-based approach for prioritising work is based on risk removed per dollar spent to maximise the removal of identified network risk (including safety risks) from the network within the available budgets. Given this methodology was applied to prioritise repex in our 2015-20 RCP, and given the trend of identified network risk in the 2015-20 RCP (see Figure 18), we believe a continued level of investment is appropriate where CBRM models are not available to constrain network risk. This is discussed further in Section 5.2.2.

## 5.2.2 Capex criteria

Our forecasts are based on efficient costs.

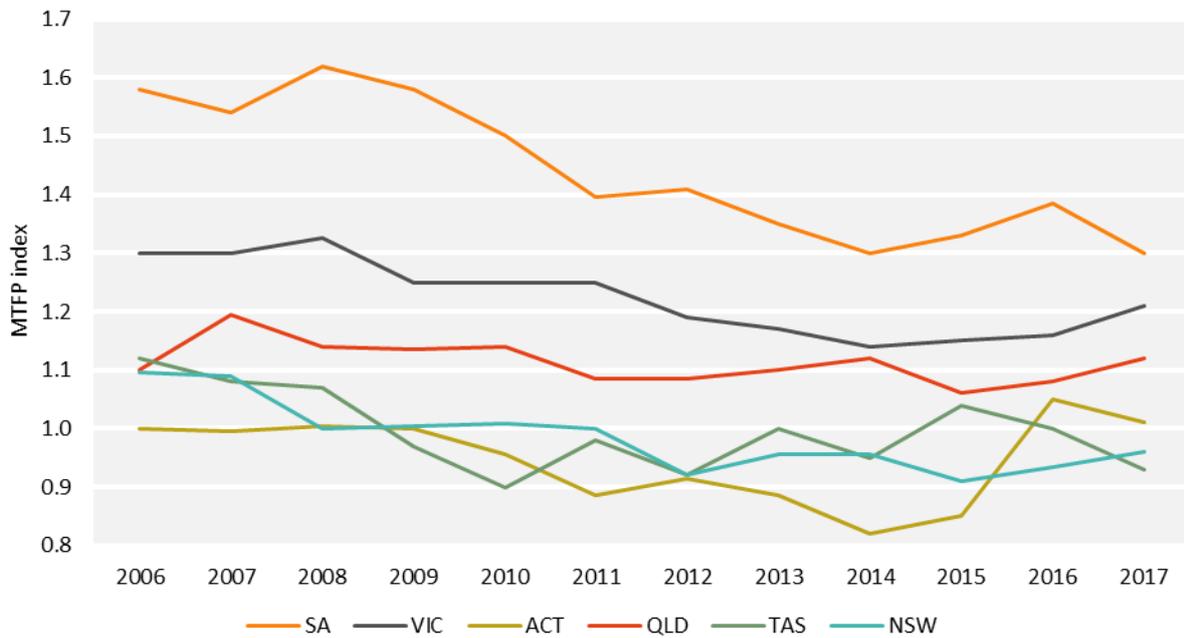
Our repex forecasts satisfy the first expenditure criteria (efficient costs).

The unit costs we have assumed in our models have been derived from our average historical costs for undertaking equivalent renewal activities (ie replacements and refurbishments / life extensions). Based on our current processes and system capabilities, this is reflective of efficient unit costs that would be anticipated, on average, over the 2020-25 RCP. Importantly, a significant portion of these historical costs reflect outsourced services that have resulted from competitive tender processes.

Each year, the AER undertakes annual benchmarking of DNSPs. Benchmarking provides the AER, consumers and other stakeholders with useful information about the relative efficiency of the networks they rely on, helping them to better understand the performance of these networks, the drivers of network productivity and the charges that make up around 30-40% of their electricity bills.<sup>12</sup> The multilateral total factor productivity (**MTFP**) is the primary technique used to measure and compare the relative productivity and efficiency of jurisdictions and individual DNSPs under the NEL and NER reporting requirement. It is a productivity index calculated using several reported DNSP input variables (including repex) and output variables - the higher the index, the better the performance of the DNSP.

<sup>12</sup> AER, 2018, Annual Benchmarking Report – Electricity Distribution Network Service Providers, November 2018.

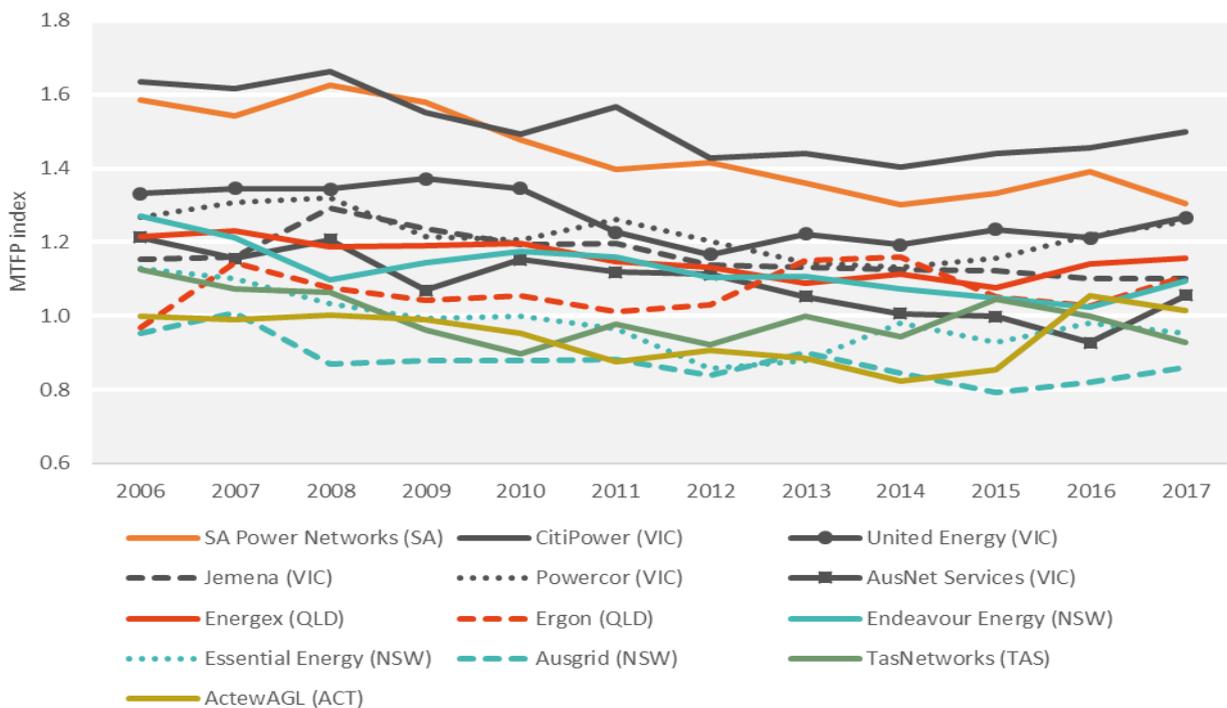
The results of this benchmarking by jurisdiction are shown in Figure 15.



Source: AER Annual Benchmarking Report - Electricity Distribution Network Service Providers, November 2018

**Figure 15: Multilateral total factor productivity (MTFP) by jurisdiction**

Figure 15 shows that South Australia's state-wide efficiency is consistently the best performing in the NEM. SA Power Networks MTFP declined slightly in 2017. This reduction in MTFP was due in part to a number of abnormal weather events that contributed to higher than normal emergency response costs and guaranteed service levels (GSL) payments to customers in 2017<sup>12</sup>. Our performance relative to other DNSPs is shown in Figure 16.

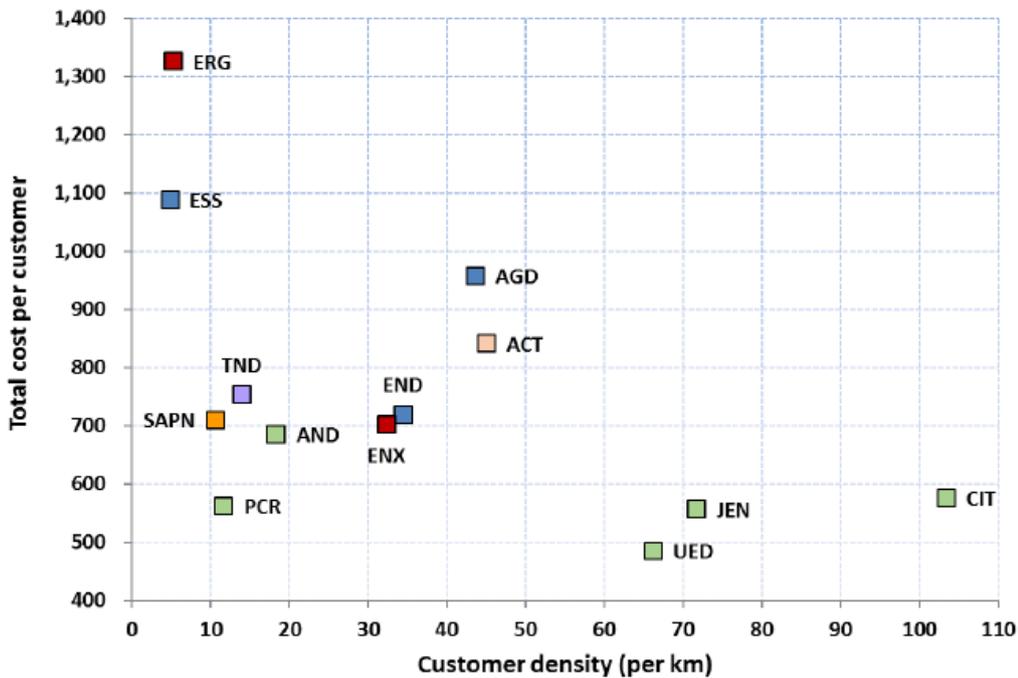


Source: AER Annual Benchmarking Report - Electricity Distribution Network Service Providers, November 2018

**Figure 16: Multilateral total factor productivity (MTFP) by DNSP**

Figure 16 shows that, even with a 6% decline in MTFP, we have consistently been one of the most efficient DNSPs in the NEM over the last 11 years.

The Partial Performance Indicator (PPI) of cost per customer is shown in Figure 17.



Source: AER Annual Benchmarking Report - Electricity Distribution Network Service Providers, November 2018

**Figure 17: Total cost per customer (\$2017)**

Figure 17 shows that our cost per customer (including in relation to repex) is lower than most other DNSPs with customer densities 2 to 5 times higher than our customer density.

Our own unit cost benchmarking (see Section 5.2.3) found our repex unit costs to be, for most asset classes, less than our peers which is a major contributing factor to the performance shown in Figure 17.

Furthermore, we have undertaken an analysis of the annual cost per unit of asset population across the major asset classes categorised in the AER’s publicly available RIN responses and found that, on average, our repex per asset population is consistently amongst the lowest of all DNSPs in the NEM across the majority of the categorised asset classes. This is largely due to our approach of repairing assets where possible ahead of renewal in order to minimise costs. This analysis is discussed further in our PAMP and in also in section 7.

Consequently, it is reasonable to accept that our unit costs assumptions and repex forecast reflect the efficient costs of achieving the capex objectives.

It is prudent to manage identified defects in the manner we have proposed.

Our repex forecast satisfies the second capex criteria (prudent expenditure) because the forecast is built up from risk based models or historic expenditure which consider both the risk reduction and cost per piece of work. These models identify which assets present the greatest network risk and lowest cost to renew, allowing us maintain acceptable levels of risk in a prudent manner.

For asset classes that have sufficient information to be modelled in CBRM, we adopt a risk-based approach to determine the optimum risk mitigation. This broadly means that the assets with highest risks and lowest renewal cost will be considered for renewal in priority to other assets. For asset classes not modelled in CBRM, we have adopted our 2015-20 RCP expenditure which incorporates our value-based approach

through which we value the risk of assets with identified defects and prioritise the renewal of those assets based on risk removed per dollar spent. Through this approach we continue to defer work with a low risk value and comparatively high cost to renew yet maintain efficiency and risk levels.

Our application of CBRM represents a conservative view of expenditure as it assumes a perfect allocation of resources. The targeting of risk removal is practical in low volume asset classes such as zone substation power transformers, but unlikely to be achieved in large volume assets such as poles. In addition, our models are based on available asset and condition information and therefore existing latent defects that likely exist within the network are not accounted for in the CBRM forecasts.

We have allowed for the prudent and efficient solutions to address the forecast need.

In support of both the first and second capex criteria (efficient and prudent expenditure), and as noted above, our repex forecast allows for the deferral of asset renewal where we consider the risks would not warrant action (ie there is an inherent assumption that there is a prudent and efficient level of 'do-nothing' occurring in our repex forecasts).

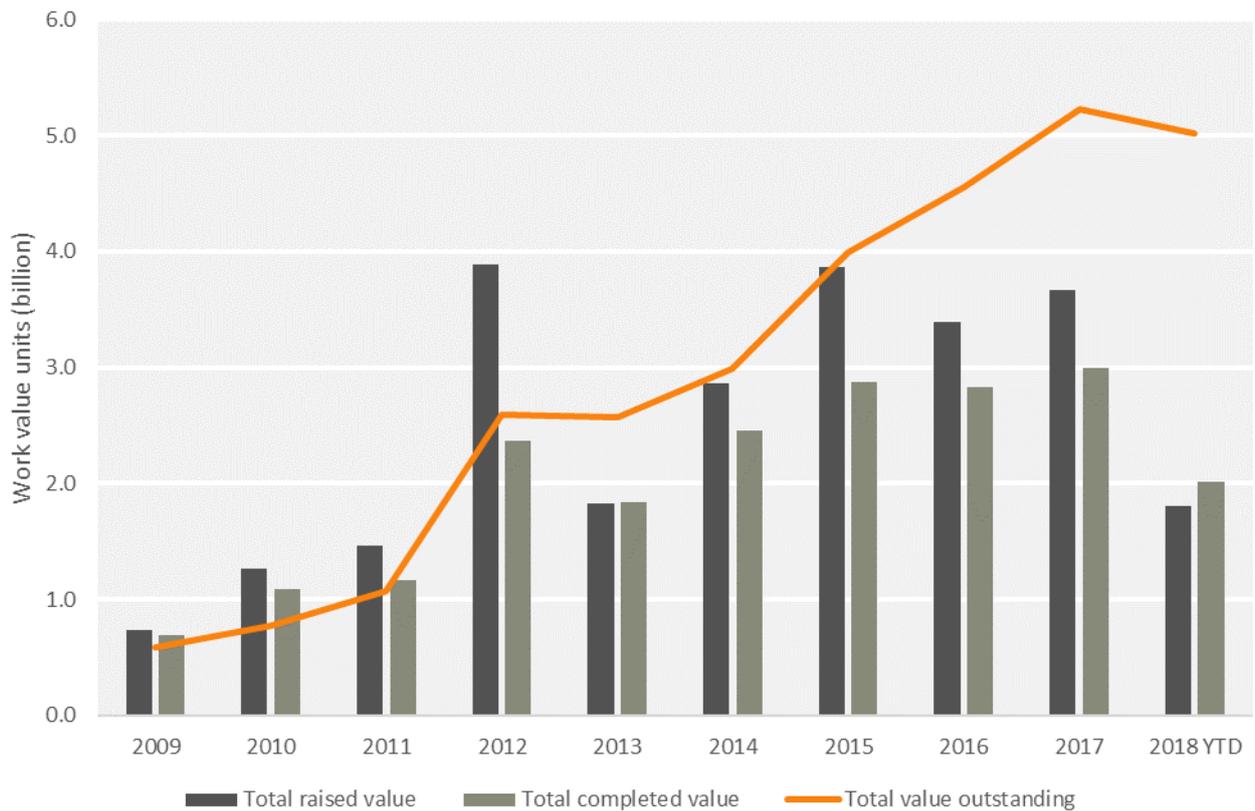
Since 2016, for all identified network defects, we have used our value-based approach to:

- more accurately identify and quantify the value of risk associated with an asset defect — to calculate the return on investment for rectifying a defect by assessing a wider range of risk parameters (eg bushfire risk, safety, environment, customer value, compliance risks, expenditures, probabilities and consequences of failures); and
- employ new work planning approaches using geographic information systems to make all work visible to work planners so that they can efficiently bundle work programs in similar geographic areas. This avoids excessive or unnecessary costs, such as increased truck visits and labour hours, and reduces the number of planned outages customers experience by bundling work.

As mentioned above in Section 3.1, we implemented our value-based approach to remove identified network risks more prudently and efficiently. Our value and visibility tool is the current operational tool used on line assets and it is being implemented on substation assets across 2018/19 to assess the level of risk present in the network arising from identified defects and other required works for small and medium repeatable jobs by:

- **having an agreed comparison of work value:** the sum of the reduction in risk and the benefits being gained by undertaking work whether it be capex or opex;
- **making work visible to everyone:** enables works in close geographic proximity to be visible for improved planning; and
- **enabling bundling:** grouping together other less urgent (secondary) work to augment the primary task ('anchor jobs').

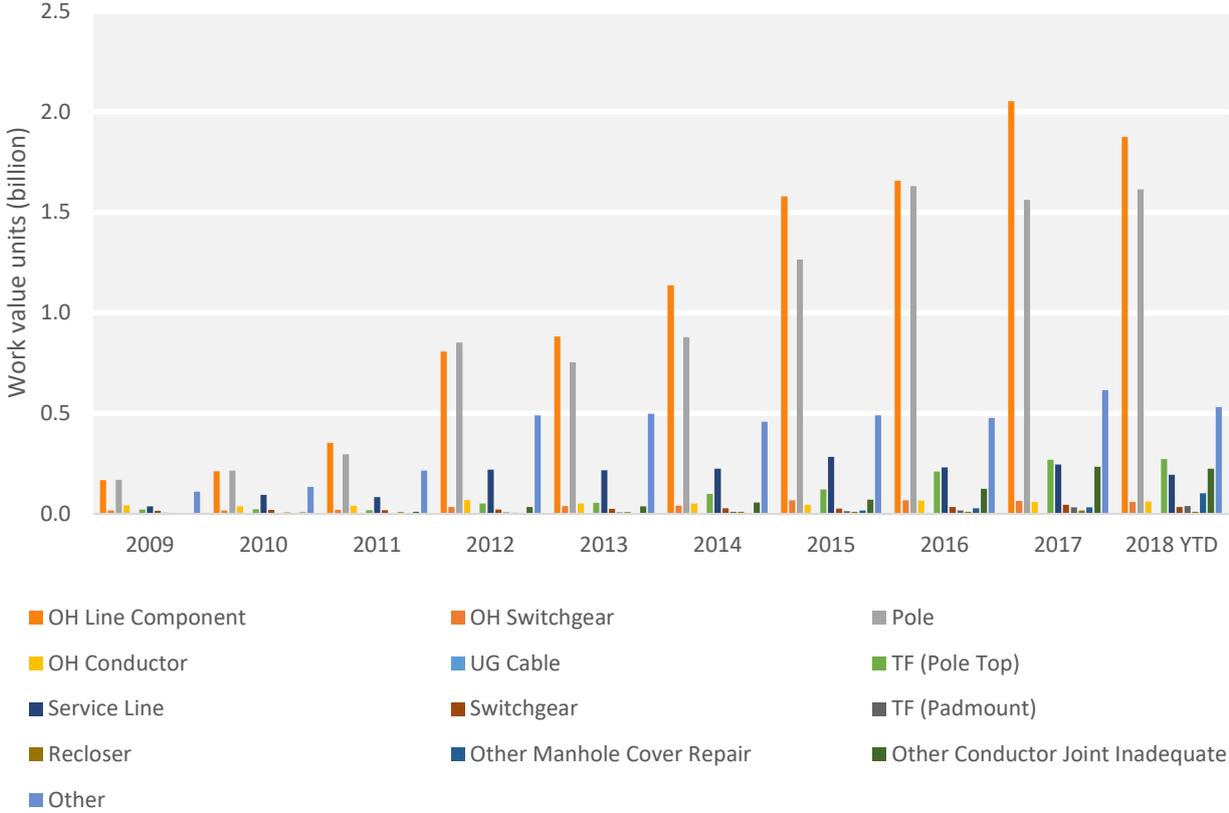
The trend of the identified network risks raised, completed and outstanding at the end of each regulatory year based on the application of this value-based approach is shown in Figure 18.



**Figure 18: Value of work outstanding, raised and completed at the end of each regulatory year through the value-based approach (2009 – July 2018)**

Figure 18 shows that the work value of raised and completed defects has plateaued since around 2015. However, the outstanding identified work value within the network at the end of each regulatory year has been steadily increasing since 2009, with the work value identified annually consistently exceeding the completed work value. In mid-2018, the completed work value was on track to exceed the work value of raised which will constrain the total outstanding work value if maintained. In other words, the rate at which we are identifying defects through our asset inspections and the total risk associated with these defects is exceeding the rate at which we have been completing works to remove the identified network risks.

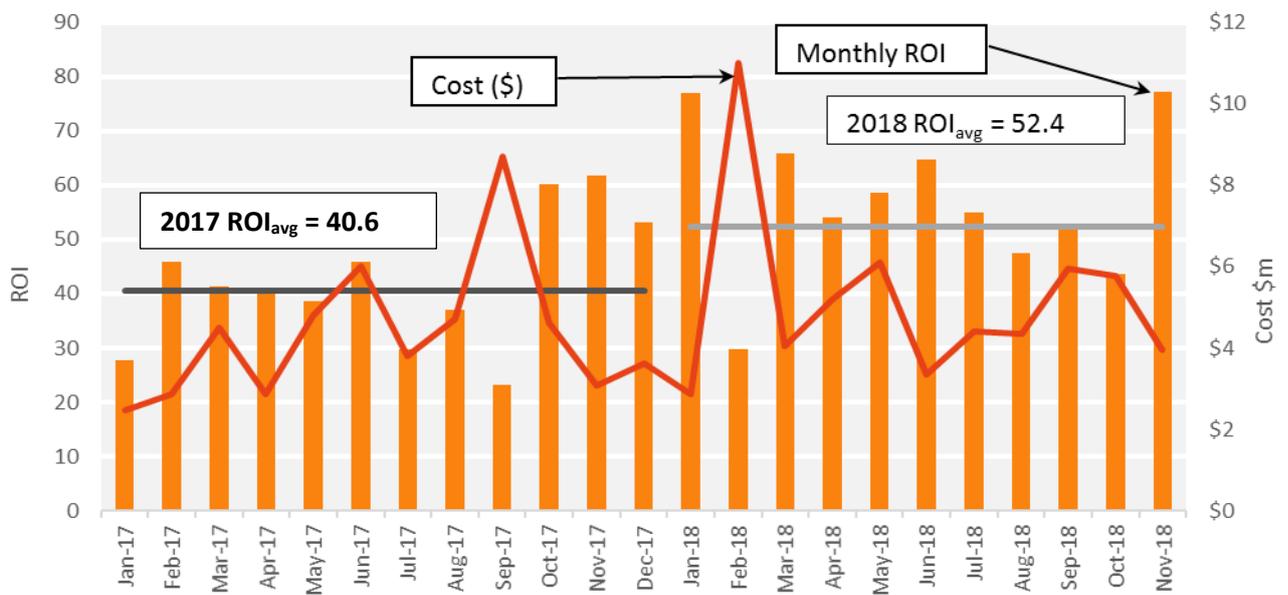
The distribution of the outstanding work value for identified defects (shown as an aggregate in Figure 18) is represented across the various asset types in Figure 19.



**Figure 19: Outstanding year end work value by asset class (2009 – July 2018)**

Figure 19 shows most of the risks identified through the cyclic inspection program that have not yet been addressed remain on overhead powerline components (pole top structures) and poles. Unsurprisingly, these two asset classes have seen the largest repex within the past three RCPs comprising an average combined 40% (approximately) of repex, which is a similar proportion of repex proposed for these asset classes in the 2020-25 RCP. The outstanding work value (risk) for pole top structures has continually increased since 2009, while the outstanding work value for poles has plateaued since around 2016.

Through the value-based approach, improved work selection and bundling has seen an improved return on investment (ROI; risk removed per dollar spent) as shown in Figure 20.



**Figure 20: SA Power Networks return on investment (ROI) through the value-based approach**

Figure 20 shows a 29% improvement on ROI for works delivered through the value-based approach from 2017 to 2018. Further process improvements for work selection are being pursued in order to optimise work selection and work delivery and to further improve ROI (eg reduced unit costs through increased delivery efficiency).

By using our value-based approach, we will be able to remove a larger amount of identified network risks as a result of our inspection and condition monitoring program through prioritising work on ROI.

Additionally, our forecasts allow for refurbishment for asset life extensions over asset replacements. Examples include our pole plating and replating program. Where feasible, extending the life of poles through plating is a significantly lower capital cost solution than pole replacement. Our forecast assumes that pole life extensions will be possible at similar proportions to that achieved over the 2015-20 RCP. This covers over two thirds of the forecast pole renewal volumes. Refurbishment programs are also undertaken on reclosers, circuit breakers, power transformers and electromechanical protection relays.

Taken together, we believe that this reasonably reflects a prudent and efficient solution to address our repex forecast needs.

We have used a reasonable approach to forecast the scale of the need to comply with these obligations.

The third capex criteria (realistic expectation of the demand forecast and cost inputs - eg the quantum of work) is also satisfied by our repex forecasts. The forecasting methodologies recommended provide a reasonable estimate of the volume of renewal activity that is likely to be required to comply with the approved SRMTMP.

As we have explained in section 5, we have used four forecasting methods that approach the forecasting problem in different ways. They are:

- **The CBRM forecasting models** – these models have been used widely in this country and others, including the United Kingdom, to produce forecasts for regulatory purposes. This modelling approach uses asset age and other asset information (such as asset condition) to make predictions about the state of assets in the future, and in turn, their risk of failure. This is discussed further in section 6.1.

- **The AER’s repex model** – This model has been used by the AER in recent years to produce repex forecasts for high volume, low cost asset classes. This modelling approach uses asset age, renewal volume and unit cost to make predictions of the renewals and funds required for the future regulatory years. We have considered the outcomes from using the AER’s repex scenario models and compared those outputs with our proposed forecasts and our proposed repex forecasts sit significantly lower than all scenario outputs for the AER modelled asset classes. This is discussed further in Section 6.2.2.
- **Our actual repex for the 2015-20 RCP and projected trend methods** – this approach is used for asset classes with minimum known asset information and/or where the quality of data required for CBRM models is not considered adequate to yield reliable results. This approach predicts the asset renewals and related expenditure that will be required for the 2020-25 RCP based on our actual repex in the 2015-20 RCP.
- **Assessing our actual repex for the 2015-20 RCP** is the methodology typically adopted in the absence of a CBRM model. Our actual repex for the 2015-20 RCP is typically much lower than the projected trend and substantially lower than the AER repex model outputs. In other words, the proposed renewal volumes and repex for those asset classes is similar to that being undertaken in the 2015-20 RCP.

As we have an ageing asset base, and a very low rate of asset renewal, the forecast scale of renewal for our network should not be reduced beyond that currently being undertaken in the 2015-20 RCP.

### 5.2.3 Capital expenditure factors

#### Benchmarking capital expenditure

The first capex factor (benchmarking) has been considered. Our analysis of the responses to the category analysis RINs of the NEM DNSPs suggests that we have a very low asset renewal rate (see Section 3.2) and one of the oldest networks in the NEM (see section 3.6). We believe that this analysis supports the view that our renewal volumes need to be maintained or increased above historical levels.

In addition, we also believe that our forecast volume is supported by the analysis we have performed using the four scenarios in the AER’s repex model; suggesting our proposed repex and volumes for the modelled asset classes is significantly lower than that determined through application of the AER’s repex model in determining repex thresholds (see Section 6.2.2).

Furthermore, the AER annual benchmarking of DNSPs demonstrates our costs (including repex) are contributing towards our efficiency ranking (see Section 5.2.2).

#### Expenditure over the 2010-15 RCP and forecast repex for the 2015-20 RCP

The second capex factor (comparison of expenditure in preceding RCPs) has been considered.

The forecasting methodologies we have used provide a reasonable estimate of the volume of renewal activity that is likely to be required to comply with the approved SRMTMP and associated regulatory obligations. The CBRM models provide a more robust assessment of required forward expenditure irrespective of the actual expenditure in the 2015-20 RCP which is notionally capped under the allowances determined by the AER’s repex model (for modelled assets) as part of the SA Power Networks distribution determination for the 2015-20 RCP (**2015-20 Determination**).

Notwithstanding the above, our actual expenditure in the 2015-20 RCP has been considered against the forecast CBRM model outputs when assessing our ability to deliver the quantum in the forward program of work. In the absence of CBRM models, we have generally proposed expenditure for asset categories in line with the 2015-20 RCP repex for the various RIN asset categories (eg historical expenditure reported in the

category analysis RINs for 2015/16 to 2017/18 inclusive plus application of the current business forecasts for 2018/19 and 2019/20 excluding overheads). This is discussed further in sections 6 and 7.

In addition, the downward trend of augmentation over the corresponding periods (see Section 3.5) has resulted in reduced asset replacements through augmentation works. Combined with our ageing asset base (see Section 3.6) and historical low rate of asset renewal (see Section 3.2), an increase in repex is expected as assets continue to deteriorate and more defects become evident through our inspection programs. This increase in repex has already been observed from the 2010-15 RCP into 2015-20 RCP.

A comparison of the proposed repex in contrast to the 2010-15 RCP and the 2015-20 RCP is shown previously in Figure 2. This includes CBRM model outputs for maintaining current levels of risk on poles, circuit breakers, power transformers and protection relays.

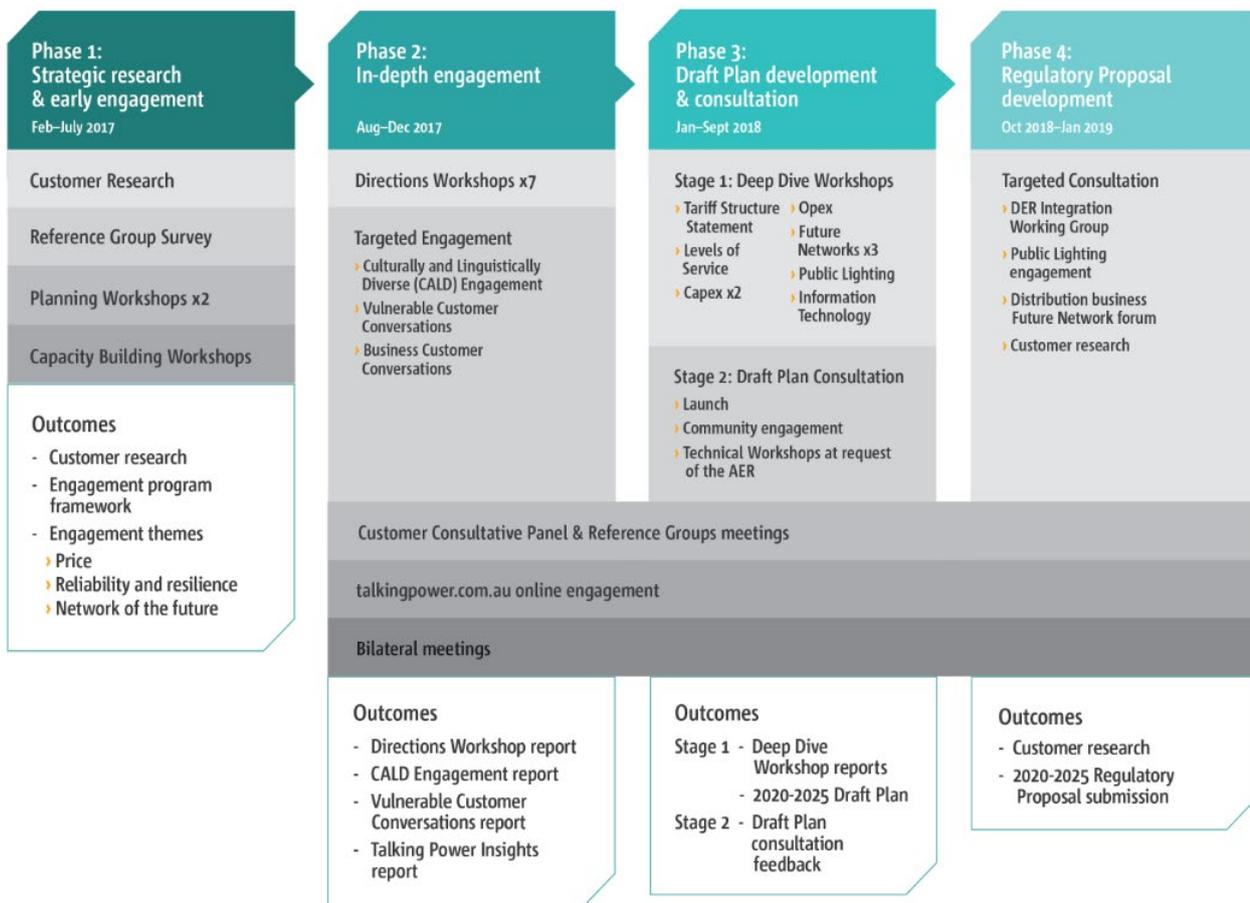
It shows a modest increase in forecast repex for 2020-2025 RCP over the 2015-2020 RCP forecast in real terms. It is reasonable to expect that the increase in works required can be delivered largely with existing resources given the 2017/18 repex exceeded the average of the repex proposed for the 2020-2025 RCP.

This comparison also demonstrates that our proposed repex forecast reflects a reasonable and relatively stable trend particularly given the significant decrease in augmentations compared to previous RCPs that will reduce the number of augmentation driven asset replacements.

#### Expenditure to address customer concerns

The third capex factor (address the concerns of electricity consumers) has been considered.

We strive to deliver outcomes for customers at the lowest sustainable cost and we are conscious that every dollar we spend is paid for by customers. We have undertaken an extensive customer and other stakeholder consultation program since early 2017. This consultation program has involved engaging with our Consumer Consultative Panel (**CCP**), four reference groups and customers and other stakeholders through a variety of forums via a staged approach as shown in Figure 21.



**Figure 21: Our customer and other stakeholder engagement program**

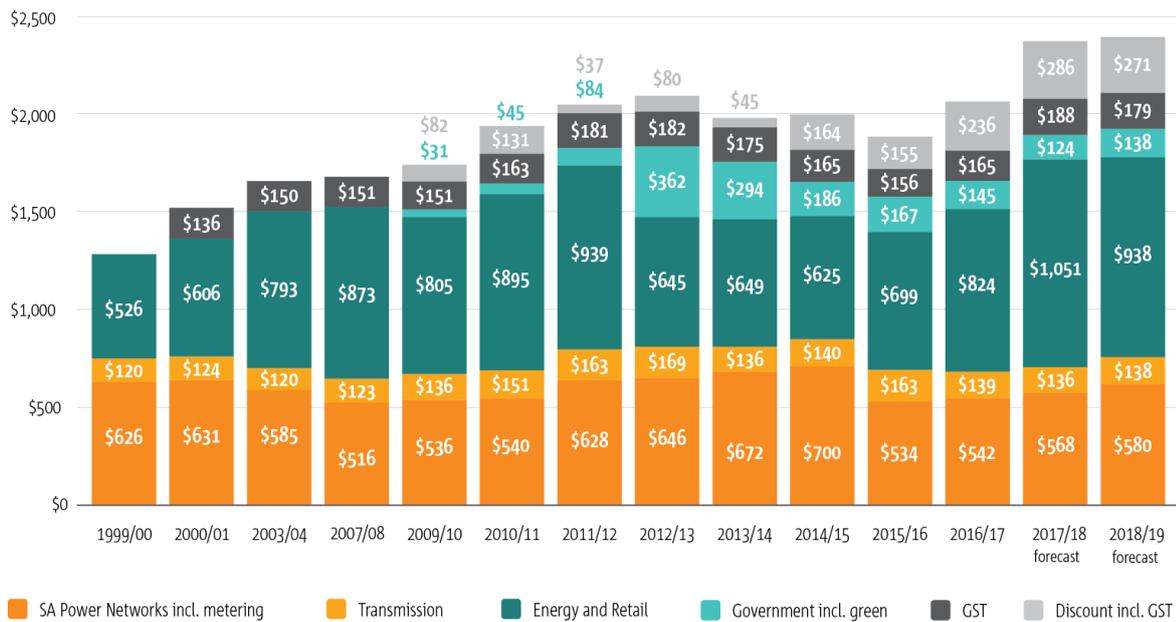
Throughout this engagement process the three key themes emerging have been:

- keeping prices down;
- maintaining a safe and reliable network; and
- transitioning us to a new energy future.

We have considered the impact on prices when determining our proposed level of repex. As with the second capex factor (comparison of expenditure in preceding RCPs) we have applied our actual repex for the 2015-20 RCP (actuals + forecasts, \$ real) for several major asset classes.

We believe that we will continue to achieve compliance with our SRMTMP through the proposed repex and continue the increasing trend of identified value of work through enhancements to our value-based approach to work selection relating to identified network defects.

The contribution of our network costs as a proportion of a typical residential bill is shown in Figure 22.



**Figure 22: Average SA residential electricity bills**

Figure 22 shows our network costs have reduced from around 50% to around 25% of the typical residential bill. Our forecast repex for the 2020-25 RCP will ensure that the contribution of network costs to a typical residential bill remain relatively stable.

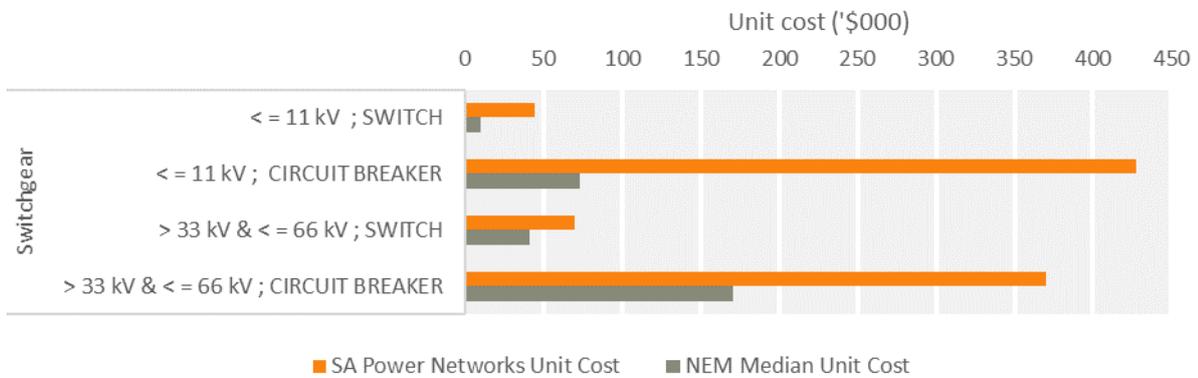
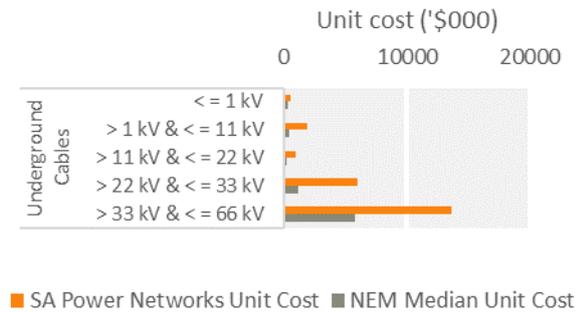
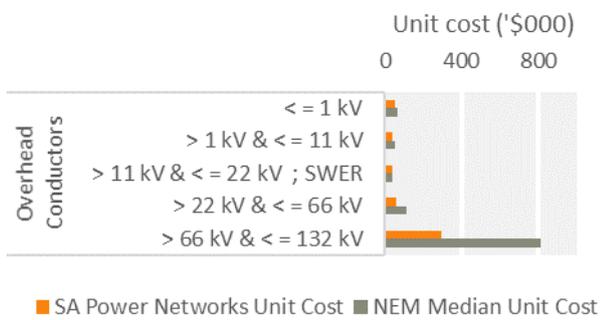
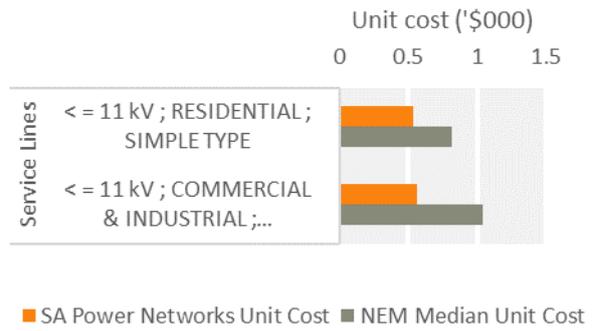
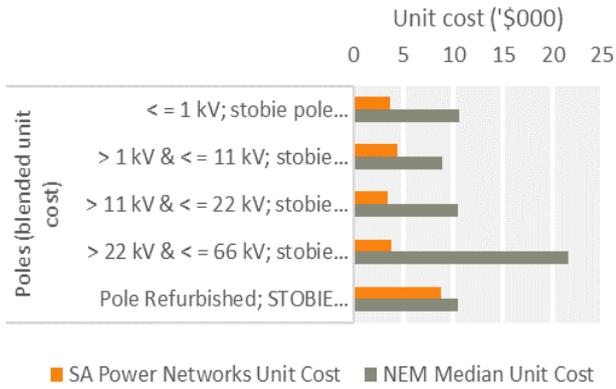
We therefore believe our forecast repex reflects the concerns of our customers to limit price increases for the network component of customers' electricity bills.

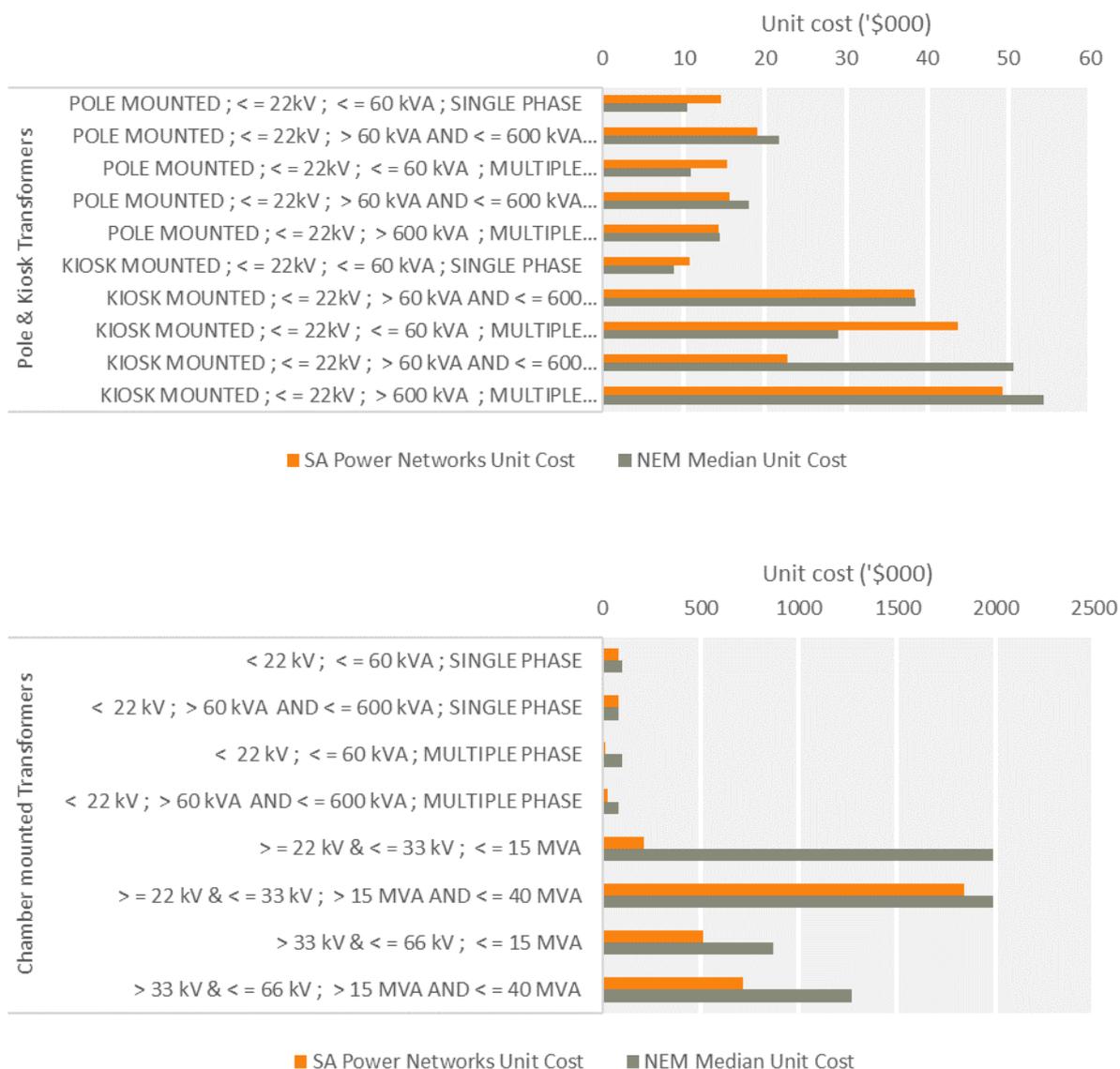
Relative prices of operating and capital inputs

The fourth capex factor (relative prices of capital inputs) has been considered.

For the CBRM and repex models, unit prices are derived from the total expenditure reported for each regulatory year divided by the number of asset renewals reported for the corresponding asset in the RIN response over a five-year period in real terms. We believe a five-year timeframe is appropriate to reflect any recent changes in asset management practices and to average out any annual variations in unit prices that can occur due to numerous factors including the extent of design work required, complexity of switching operations, standby power generation, open tender market prices, etc.

A comparison of our historical unit rates published in previous category analysis RINs compared to the NEM median unit rates as published by the AER in recent DNSP distribution determinations through application of the AER's repex scenario models is shown in Figure 23.





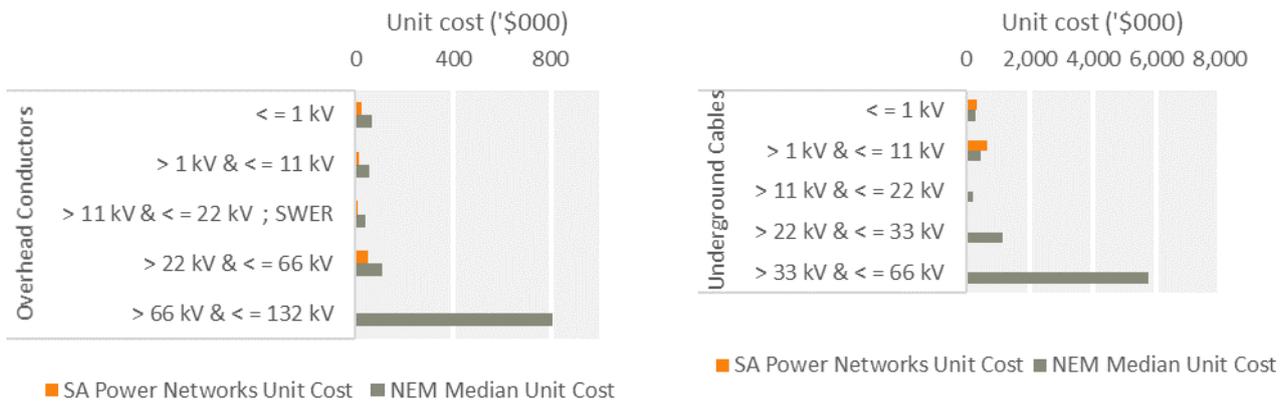
**Figure 23: SA Power Networks historical unit costs versus NEM median**

As can be seen in Figure 23, aside from cables and switchgear, our historical unit costs are lower than the median of the NEM DNSPs.

For cables, our higher unit costs (which for published category analysis RINs included minor repair work in response to failures or defects<sup>13</sup>) results in our higher unit costs relative to the NEM median for cables. Our analysis of other DNSPs RIN data indicates that we have a relatively high failure rate per length of cable which, in conjunction with the short patching lengths lead to a higher unit cost. Our back casting of category analysis RIN data for unit costs (real) to exclude minor repairs on defects or failures is shown in Figure 24. The revised conductor rates are included for completeness.

In contrast to the SA Power Networks conductor and cable unit cost in Figure 23 (which included the lengths and costs associated with minor repairs), the revised unit costs for conductors is much lower than the NEM median while our cable unit costs are closely aligned with the NEM median. Our repex unit costs for these linear assets is therefore considered efficient.

<sup>13</sup> The expenditure associated with cable minor repair work has been re-categorised as opex for the 2020-25 RCP (ie this expenditure was categorised as capex in the 2015-20 RCP).. This approach better reflects the nature of the work covered by this expenditure and is more consistent with the principles outlined in the AER's recent tax allowance decision. Further details in relation to this change in the categorisation of this expenditure and the resulting step change in opex are set out in Section 5.11 of **Attachment 5 – Capex** and 6.7.2.4 **Attachment 6 - Opex**.



**Figure 24: SA Power Networks historical unit cost vs NEM median (back casting of cables and conductors to remove minor repair work)**

For switchgear, we define some switchgear assets such as reclosers, sectionalisers and switching cubicles as DNSP defined assets within the category analysis RIN (ie we do not combine these asset quantities and repex together with circuit breaker assets). These assets have significantly lower unit costs for renewal than circuit breakers. Consequently, these lower cost switchgear assets are excluded from the switchgear category for SA Power Networks in the category analysis RIN. Conversely, other DNSPs appear to combine these assets with the more expensive circuit breaker assets with the comparison leading to a higher switchgear unit rate for SA Power Networks than the NEM median for switchgear.

Accordingly, a historical five-year basis for unit rates to develop our forecasts (2018 \$) is representative of efficient unit prices that would be anticipated over the 2020-25 RCP.

The fifth capex factor (substitution possibilities between capex and opex) and ninth capex factor (non-network options) have been considered.

Through our asset management practices (see Section 3.7), we typically undertake repairs in response to asset condition or defects identified where it is both possible and more cost effective than asset renewal. Examples of this include conductor and cable minor repairs (which are classified as opex) following failures or identification of localised defects. Assets that are unable to be repaired are considered for refurbishment (where possible) ahead of replacement (which are both classified as repex).

Our historical low rate of asset renewal (see section 3.2) and ageing asset base (see section 3.6) demonstrate that we have been investing in asset renewals at very low levels. As the assets continue to age and deteriorate, the ability to undertake, and the cost effectiveness of undertaking, repairs (as compared to refurbishment or replacement) will decline, as will the level of the associated repair opex.

We consider non-network options for augmentations where the driver for the investment is customer load. However for repex, investment is driven not only by maintaining reliability but also by significant safety risks (eg potential for injury, death and/or bushfire risk). The majority of our historical and forecast repex is on high volumes of relatively low cost, localised renewals scattered across our vast network the nature of which does not favour non-network solutions.

For example, a poor condition conductor of 1km in length on a 30km feeder in a rural high bushfire risk area with a history of failures may be selected for renewal. A non-network option such as a battery or embedded generator in the area being supplied by this conductor may address the reliability consequences in the event of further failures but would not remove the identified public safety and bushfire risks. Our approved SRMTMP requires us to maintain a safe and reliable network and a non-network option in this example would not achieve these outcomes as the identified safety risks would remain.

Another example is our pole renewal program. Poles with identified defects are selected for renewal based on our value-based approach (see section on 5.2.2). These can be scattered along a long length of feeder. Like the conductor example, non-network options may address the reliability consequences in the event of the poles ultimately falling to the ground but would not remove the identified public safety and bushfire risks. Again, our approved SRMTMP requires us to maintain a safe and reliable network and a non-network option in this example would not achieve these outcomes as the identified safety risks would remain.

Furthermore, changes to the NEL and NERL would be required to enable stand-alone power systems (**SAPS**), an electricity supply arrangement that is not physically connected to the national grid, to be considered as viable non-network options for large scale asset renewal projects. Subject to the outcome of the review, SAPS could then potentially form a viable non-network option as an alternative to large scale asset renewals. A review of the regulatory arrangement frameworks for SAPS is currently in progress<sup>14</sup>.

On this basis, non-network options are generally not currently considered appropriate for addressing the majority of the network renewal identified as being required for our network. Non-network options are, and will continue to be considered, for large-scale renewal programs or large projects in line with the requirements of the NER.

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<sup>14</sup> AEMC, 2019, Review of the regulatory frameworks for stand alone power systems, <https://www.aemc.gov.au/market-reviews-advice/review-regulatory-frameworks-stand-alone-power-systems>

## 6 Forecasting methods

Due to the unique nature of individual asset classes, the following four independent methods have been considered in forecasting our repex for the 2020-25 RCP for each asset class:

1. CBRM
2. AER replacement model (repex model)
3. Historical and future repex
4. Historical repex trend

The outputs of the four forecasting methods have been supplemented with the knowledge of our own subject matter experts to determine the required repex for each asset class.

### 6.1 CBRM forecasting method

CBRM is an asset renewal forecasting methodology that utilises asset information, engineering knowledge, historical performance and practical experience to quantify the condition of an asset and the associated risk it poses. The CBRM methodology uses a bottom-up assessment of an asset population, determining the individual condition of each asset, the consequences of its failure and the resulting risk it creates. By aggregating this information, CBRM provides the ability to granularly analyse the impacts of numerous intervention strategies to determine the optimal choice of action that achieves a desired asset management outcome.

Since it was first developed in 2002 by EA Technology Limited, the CBRM methodology has become widely used by utility operators and regulators throughout Australasia and the world to forecast repex for asset populations.

In 2013, CBRM was adopted by SA Power Networks and formed part of its methodology in forecasting repex during the 2015-20 RCP. SA Power Networks has continued to develop its understanding and utilisation of CBRM such that today its models are integrated with internal data sources and cover a greater portion of its asset base.

In 2016, SA Power Networks commenced transitioning its CBRM models to a new integrated platform that vastly improves its quality of data and modelling ability. Keeping the original CBRM methodology, the models have been reconstructed and refined using a platform software package called Asset Management Planning Suite provided by PowerPlan. The new software enables SA Power Networks to integrate CBRM models directly to its data sources such as its geographic information system (**GIS**), Systems, Applications & Products (**SAP**) and Outage Monitoring System (**OMS**). This connectivity will provide us with the ability to dynamically maintain relevant data on a real time basis. As such, any new condition information, or new assets forming part of the network are automatically included in the models and the subsequent outputs.

It is important to note that CBRM models generate ideal scenario outputs that are based on work selection with 100% efficiency (by assuming the renewal actions will be undertaken in the most optimal sequence), which are practical to adopt on small asset volumes (eg substation power transformers) but extremely difficult to achieve in very high asset volumes (eg poles).

Figure 25 and 26 show the system and model overview in which SA Power Networks utilises the CBRM method.

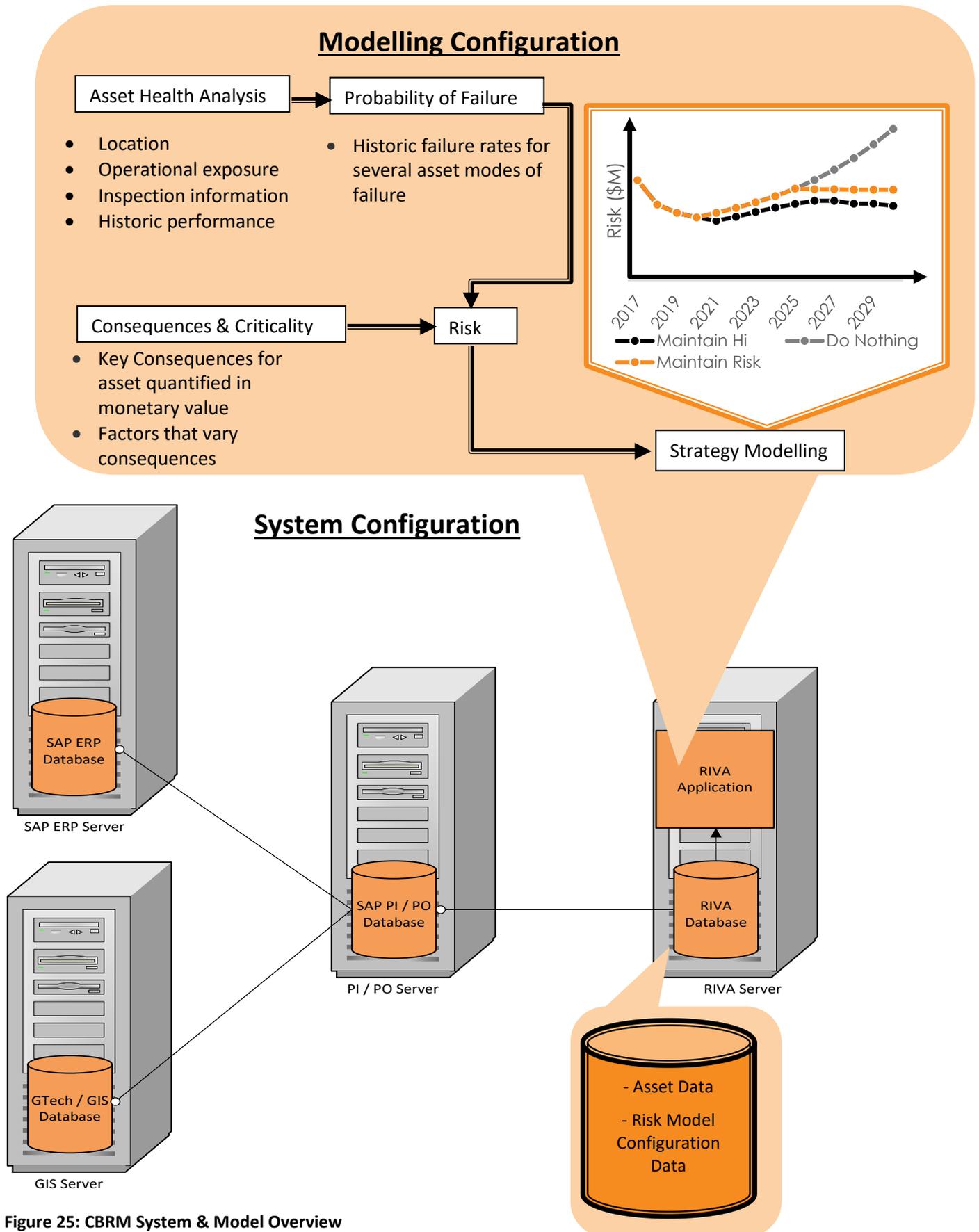


Figure 25: CBRM System & Model Overview

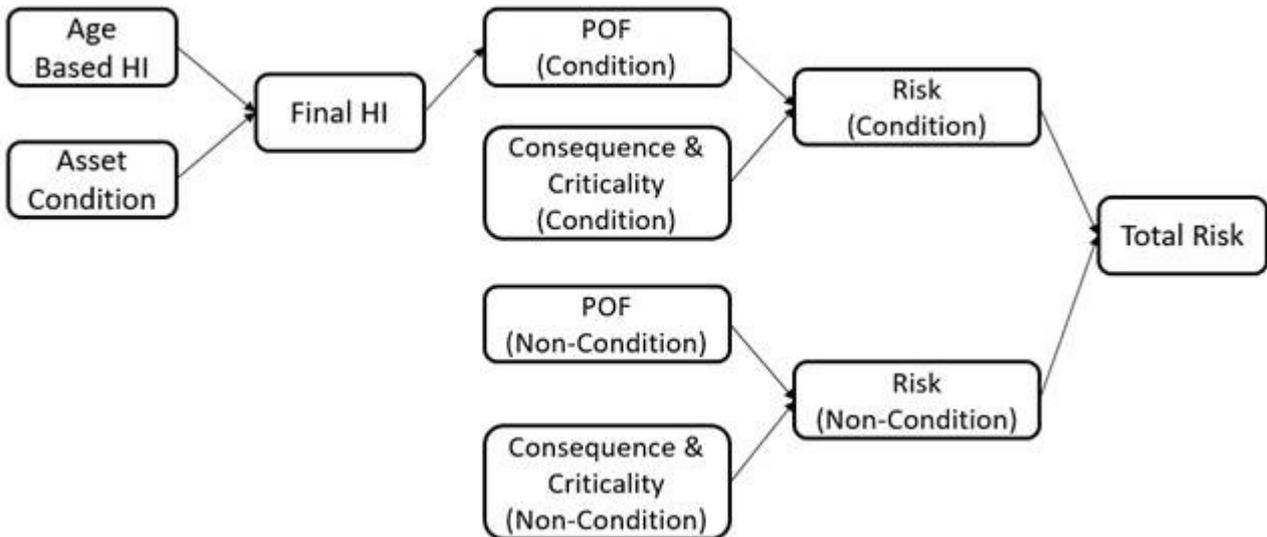


Figure 26: Overview of CBRM Model

The following sections detail the components of the CBRM model and system.

### 6.1.1 Asset health analysis

The Health Index (HI) aims to quantify the condition of an asset at a given point in time. The HI is a critical input into determining the probability of failure.

The HI is defined so that a score of 0.5 represents a new asset and a score of 5.5 represents an asset at the end of its life where the rate of failure begins to increase significantly. The CBRM model computes the Health Index in several stages.

The initial HI (HI1) is calculated based on the following factors:

- age;
- expected life as defined in the model;
- duty (mechanical loading); and
- environment (ground corrosion, air corrosion and pollution).

The initial HI1 is calculated using the formula:

$$HI_1 = 0.5e^{B*Age}$$

Where the ageing constant is defined by:

$$B = \ln\left(\frac{5.5}{0.5}\right) * \frac{env * duty}{life}$$

This formula assumes that the HI increases exponentially with age and uses assumed values for each of the duty factors and environment ratings.

An interim HI2 is created by multiplying the initial HI1 by a factor determined by the score of any detected defects, using a table of assumed values for each of the defect ratings. For example, if an asset were assigned a defect rating between 3 and 4 based on its last inspection, then its HI would be multiplied by a factor of 1.2.

The final HIY0 is determined by comparing the interim HI2 to either the condition score, corrosion value or problem code (whichever is available first). If the latter score is greater then it becomes the final HI, otherwise the value takes the average of the two scores. The scores are determined using a table of assumed values for each of the ratings.

## 6.1.2 Probability of failure analysis

Each asset type modelled within CBRM will have unique consequences for a condition-based failure for which the probability of occurrence has to be established. The probability of failure analysis used in CBRM is derived from experience and historical performance in terms of the number of occurrences per year. This number of occurrences is translated into a failure rate and then applied to each asset.

To apply this rate of failure as a probability to an asset, the HI is used to provide a weighted distribution of probability such that poor health assets receive a greater probability of failure. Acknowledging that a new asset can still present a chance to fail, a base level of probability exists for each asset, as represented by Lambda ( $\lambda$ ) in the general Reliability Bathtub curve depicted in Figure 27.

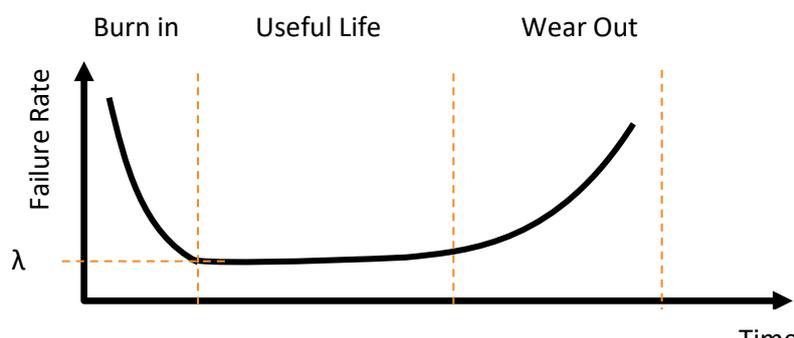


Figure 27: Generalised concept of Reliability Bathtub curve<sup>15</sup>

## 6.1.3 Consequences and criticality analysis

Consequence and criticality are analysed in CBRM to determine the overall risk level attributable to an asset. Consequences provide the model with an understanding of impact, whilst criticality presents factors that will vary the severity of each impact.

The consequences in CBRM attempt to capture the varying levels of effects caused by failure. These consequences may include minor, significant or major categorisation of a failure (severity based) or are directly related to specific consequences such as bushfires and fire starts, the need for repairs or an asset falling over. All consequences are broken down into the impacts they pose to the following five categories inferred from SA Power Networks' corporate risk matrix:

- **safety:** the impacts of causing a minor, significant or major injury to the community and employees;
- **network performance:** reliability impacts in the form of customer interruptions;
- **environment:** the damage incurred to an asset's localised environment and sensitive areas;
- **capex:** the capex required to rectify the failure; and
- **opex:** the opex required to rectify the failure.

Criticality factors then determine how the consequence may vary. As an example, assets in high public density areas will have higher safety consequences, and vegetation density will determine the harshness of a fire. Other factors used for criticality may include additional equipment attached to an asset (cost), environmentally sensitive areas, proximity to water sources, or high cost work sites (eg CBD).

Each consequence category is translated into monetary terms.

<sup>15</sup> Carchia, M., 1999, 18-849b *Dependable Embedded Systems*, Carnegie Mellon University.

### 6.1.4 Risk calculation

Generally, the risk level attributable to an asset is the product of probability and overall consequence. In CBRM, the risk posed by an asset is a summation of each modelled consequence multiplied by its criticality factor and associated probability of failure (**POF**), as summarised in the following equation:

$$Risk = \sum_{x=1}^y [POF_x \times (Consequence \times Criticality Factor)_x]$$

Hence, as each new asset has a base level of POF, all assets pose some form of risk to the network. Over time, as the condition of the asset worsens, the POF increases, and this risk exponentially grows, until the time that it fails, and the consequences are incurred. By intervening at the optimal time, the impacts of failure can be avoided whilst obtaining its longest use. The intervention will also improve the asset's condition, and hence reduce the risk posed.

#### **Asset Renewal Strategy Modelling**

After modelling and establishing health, probabilities, consequences and risk, CBRM calculates deterioration rates for each asset based on its condition and current age. This deterioration rate is used to forecast the growth in risk for each asset over time. By aggregating these values to an overall asset base level, CBRM provides the ability to model the impact of using various renewal strategies, demonstrating the outcomes in the form of required expenditure and the associated impacts to overall asset population risk and health. Importantly, risk reduction due to asset replacement undertaken as part of other programs (eg augex) is accounted for in CBRM.

We have modelled two main asset renewal strategies:

- **maintain risk:** this strategy aims to maintain a determined overall asset population risk level every year; and
- **maintain HI:** this strategy aims to maintain a determined overall asset population HI every year.

To achieve maximum efficiency, the intervention of assets should be based on return on investment (risk removed per dollar spent) instead of health condition. Therefore, the 'maintain risk' asset renewal strategy has been selected as the preferred strategy for all models.

## 6.2 AER repex model forecasting method

### 6.2.1 Overview

The AER's repex model is a statistical based model that forecasts repex for various asset categories based on their condition (using mean life<sup>16</sup> as a proxy) and unit costs. The AER uses the repex model to only assess forecast repex that can be modelled. This typically includes high-volume, low-value asset categories and generally represents a significant component of total forecast repex. In the AER's previous determinations for SA Power Networks, it has only modelled the following six asset classes in repex model: Poles, Underground Cables, Overhead conductors, Service Lines, Transformers and Switchgear.

SA Power Networks has not modelled switchgear because SA Power Networks reports assets relating to this asset class differently to other DNSPs (ie other DNSPs have reported reclosers, sectionalisers and circuit breakers under the "circuit breaker" categories, whereas SA Power Networks only reports circuit breakers under "circuit breaker" categories). The difference in classification makes the mean lives and unit costs incomparable and therefore this asset class is not recommended to be modelled.

The AER's repex modelling approach analyses four scenarios that consider both a DNSP's historical asset renewal practices and the asset renewal practices of other DNSPs in the NEM. In contrast to previous distribution determinations, the current AER approach considers intra-industry comparative analysis for unit costs and expected asset renewal lives<sup>17</sup>, rather than analysing inter-company historical performance. The four scenarios analysed are:

- historical unit costs and calibrated expected renewal lives;
- comparative unit costs and calibrated expected renewal lives;
- historical unit costs and comparative expected renewal lives; and
- comparative unit costs and comparative expected renewal lives.

SA Power Networks calibrates expected renewal lives using a two-step methodology advised by Nuttall Consulting, which is based on its 5-years historical renewal history and the age profile of network assets currently in commission. SA Power Networks defines historical unit costs as the 5 years average unit costs.

The AER defines comparative unit costs as the minimum of a DNSP's historical unit costs, its forecast unit costs and the median unit costs across the NEM. The AER defines comparative renewal lives as the maximum of a DNSP's calibrated expected renewal life and the median expected renewal life across the NEM.

For assets such as poles where we undertake both replacement and refurbishment, the unit costs are 'blended' costs which consider both types of renewal. The calibrated mean renewal lives also take refurbishment into consideration.

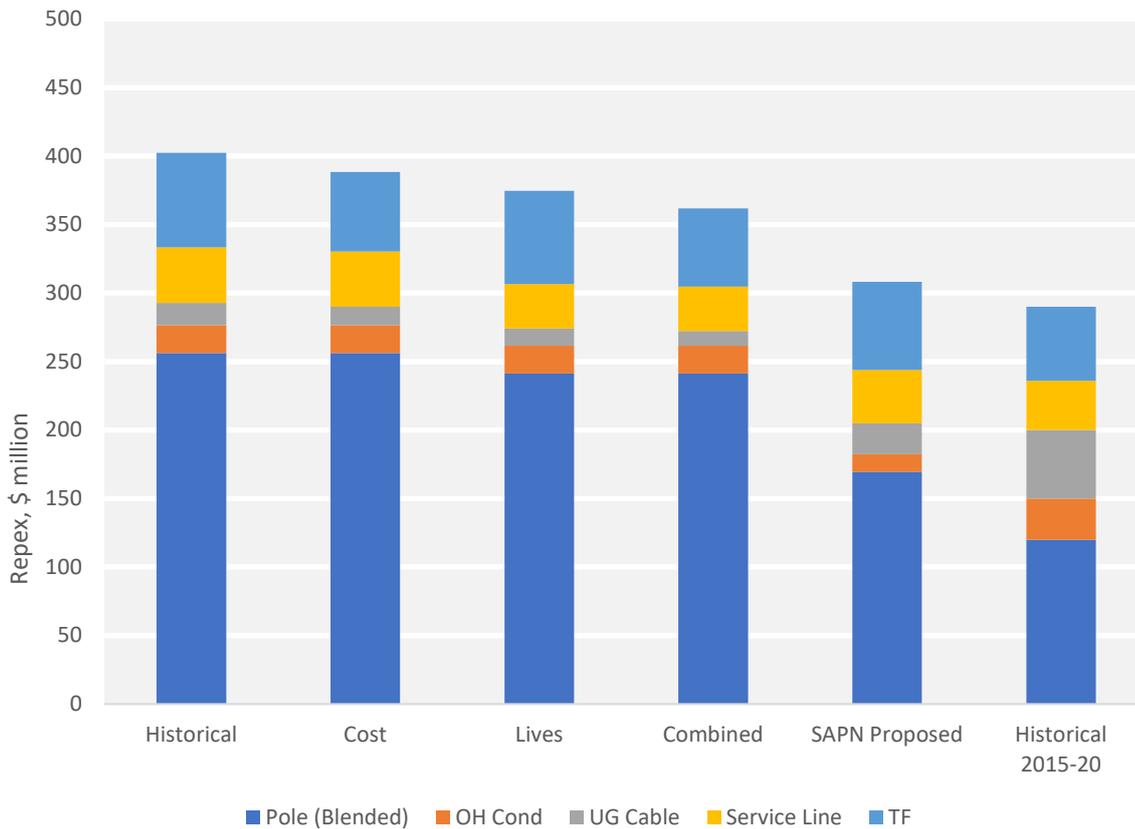
### 6.2.2 Repex model scenario analysis

By inserting benchmarking numbers into the repex model, the outputs of four scenario for modelled asset classes are shown below:

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<sup>16</sup> Mean life: The average expected life of an asset population based on a normal distribution (*Electricity network service providers replacement model handbook, AER, December 2011*).

<sup>17</sup> The AER's repex model spreadsheet has a heading "Replacement Life" however SA Power Networks treats this as the renewal life which is the blended mean life of replacements and refurbishments.



**Figure 28 Repex Output Comparison**

According to AER’s recent draft decisions for other DNSPs<sup>18,19,20</sup>, AER’s ‘replex model threshold’ is defined taking these results and other relevant factors into consideration. For the 2019–24 determinations, AER’s proposed approach is to set the replex model threshold equal to the highest result out of the ‘cost scenario’ and the ‘lives scenario’. This approach considers the inherent interrelationship between the unit cost and expected replacement life of network assets. For example, a distributor may have higher unit costs than other distributors for particular assets, but these assets may in turn have longer expected replacement lives. In contrast, a distributor may have lower unit costs than other distributors for particular assets, but these assets may have shorter expected replacement lives.’

This means, the 'Cost scenario', which generates higher output than the 'Lives scenario', is the preferred scenario for SA Power Networks. We will use the output from 'Costs scenario' for individual asset classes in Section 7 as the preferred output for the replex model.

### 6.3 Historical expenditure forecasting method

This method forecasts replex for the 2020-25 RCP for each asset class based on the actual replex for 2015/16 to 2017/18 and the SA Power Networks' forecast replex for the remaining two regulatory years of the 2015-20 RCP. Over the last few years our historical spend has been prioritised using an economic risk based system of management Value and Visibility (Section 2.2).

<sup>18</sup> Draft Decision - TasNetworks Distribution determination 2019-2024 Attachment 5 Capital Expenditure September 2018 (page 71)

<sup>19</sup> Draft Decision - Ausgrid Distribution determination 2019-2024 Attachment 5 Capital Expenditure November 2018 (page 5-26)

<sup>20</sup> Draft Decision – Endeavour Energy Distribution determination 2019-2024 Attachment 5 Capital Expenditure November 2018 (page 5-24)

### 6.4 Historical expenditure trend forecasting method

This method forecasts repex for the 2020-25 RCP for each asset class based on a projected trend for actual historical repex (2010/11 to 2017/2018) and projected spend for the last two regulatory years of the 2015-20 RCP.

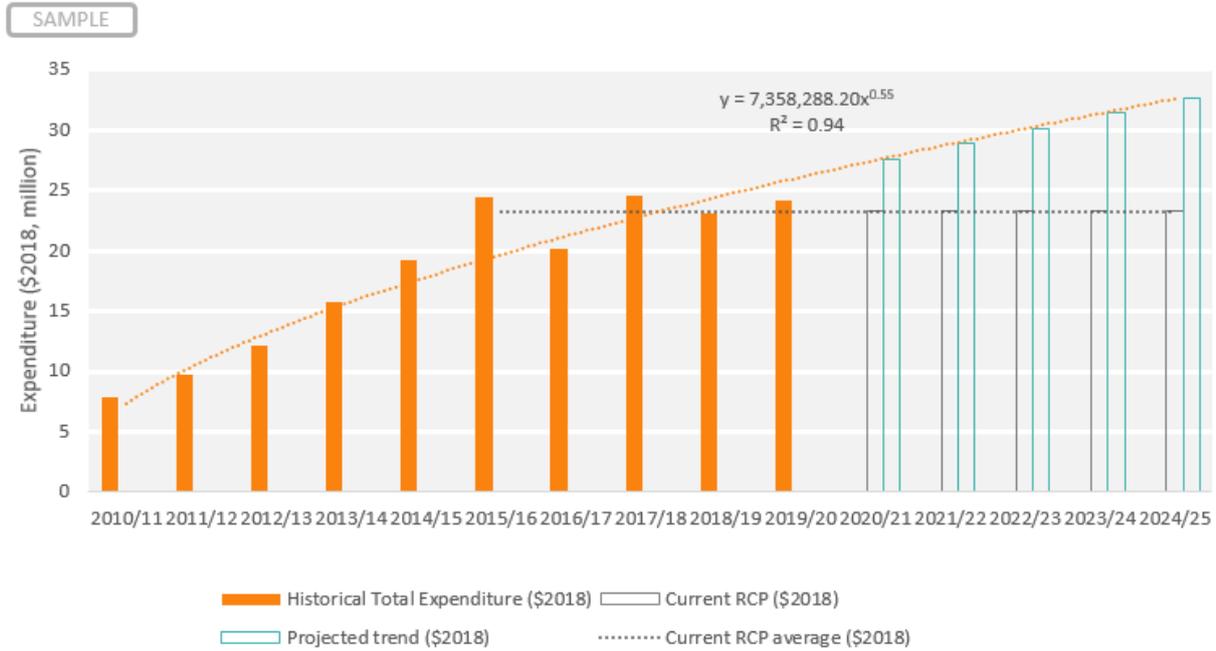


Figure 29: Example of how repex forecasts are derived based on historical expenditure and trend

### 6.5 Comparison of the four different forecasting approaches

A comparison of the four models considered across the asset classes is summarised in Table 3.

Table 3: Model comparison

Category	CBRM	Repex Model	Current RCP Expenditure	Projected Trend
<b>Asset information requirement</b>				
<b>Key input</b>				
• Historical failure rate	✓	✓	✓	✓
• Asset age profile	✓	✓	✗	✗
• Asset condition	✓	✗	✗	✗
• Consequence	✓	✗	✗	✗
<b>Risk quantification</b>				
<b>Model complexity</b>				

The forecasting methodologies considered for each major asset class are shown in Table 4.

**Table 4: Repex forecast models**

	Historic expenditure	Historic trend	CBRM	repex	Targeted
<b>Powerlines</b>					
Poles	○	○	●	○	
Pole top structures (incl. overhead line components)	●	○			
Reclosers	●	○			
Conductors	●	○	△	○	
Distribution transformers	●	○		○	
Service lines	●	○		○	●
Switchgear	●	○	△		
Underground cables	●	○	△	○	●
Other	○	○			●
<b>Substations</b>					
Protection relays	○	○	●		
Circuit breakers	○	○	●		
Power transformers	○	○	●	○	
Other	●	○			
Telecommunications	○	●			●
Safety	○	●			●

○ = other forecast models considered

● = proposed forecast method(s)

△ = under development

## 6.6 Impact of other programs on forecasts

In establishing our repex forecasts, we have considered the potential for overlap across our augex and repex where replacement of assets under an augmentation program provides a risk reduction (by replacing a poor condition asset with a new asset). We have implemented various processes to ensure that we are not double-counting asset replacements and/or upgrades between programs and not allowing for the effects that risk reduction in one program will have on other programs.

For example, we account for the removal of substation assets through augmentation in our substation asset CBRM risk models. We have forecast the replacement of some zone substation assets in our *Asset Plan 1.1.01 Distribution System Planning Report* to address forecast capacity constraints on the network. The replacement of these relatively old assets was specifically incorporated into the CBRM maintain risk scenario. If we did not replace these assets under our augmentation program, our substation asset repex would need to increase to maintain our current risk levels.

The renewal programs have been developed to maintain the safety and reliability risks associated with the condition deterioration of our assets over the 2020-25 RCP. These renewal programs are focused on maintaining risks over the 2020-25 RCP that are associated with asset condition.

The reliability program is largely related to non-asset condition failures (eg lightning strikes). Typically, this program targets small numbers of customers subject to repeated long-duration interruptions which do not represent a material portion of the total network reliability risk. Moreover, to develop these programs, we have specifically considered addressing the types of network outage that are not addressed through the replacement programs.

The bushfire mitigation program has been developed to reduce bushfire risk associated with powerline assets. This program addresses risk associated with both asset-condition and non-asset condition failures (eg

vegetation/animal or weather events). The only powerline asset we are forecasting expenditure using CBRM is poles and the bushfire mitigation programs do not include renewal of poles.

The majority of asset-condition related bushfire risk comes from other powerline assets (such as pole-top structures and conductors) which are in an asset class that is at this time not modelled.. The bushfire risk associated with these assets is increasing, however we are unable to reliably model these assets in CBRM and are therefore forecasting repex in line with historic repex rather than an increasing trend. Our historic repex in these un-modelled categories has occurred in parallel with our ongoing bushfire mitigation program. Ongoing bushfire mitigation investment is required to avoid an increase in risk that would otherwise occur with a flat repex profile in un-modelled categories such as pole-top structures and conductors.

## 7 Asset repex forecasts

### 7.1 Poles repex forecasts

#### 7.1.1 Summary

We have utilised four methods to forecast the required repex for poles, being CBRM, the AER's repex model, historical expenditure and historical expenditure projected trend. The modelling outputs have been supplemented with our own Subject Matter Experts (SME) knowledge to help build the required repex for poles for the 2020-25 RCP.

Figure 30 shows the forecast comparison of repex for poles.

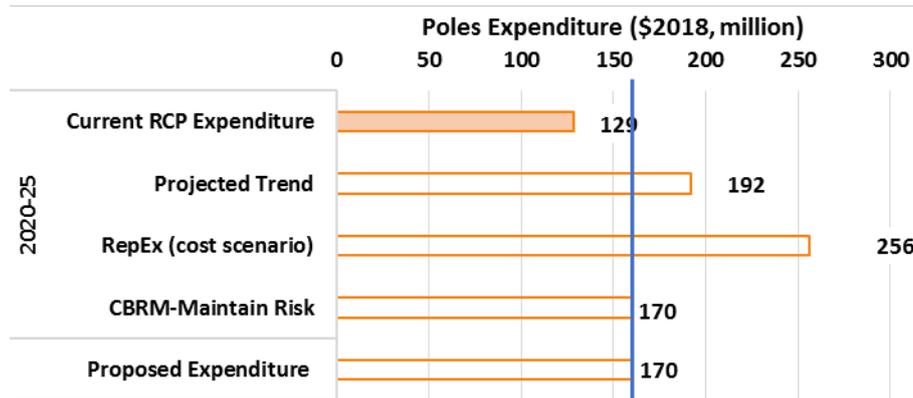


Figure 30: Poles forecast comparison

Figure 30 shows that our proposed repex of \$170 million is based on the CBRM model of poles to be replaced and plated (refurbished) that will maintain the risk due to poles in the network. In establishing our forecast repex we have targeted those assets that represent the highest ratio of risk against the cost to renew.

#### 7.1.2 Poles forecast repex profile

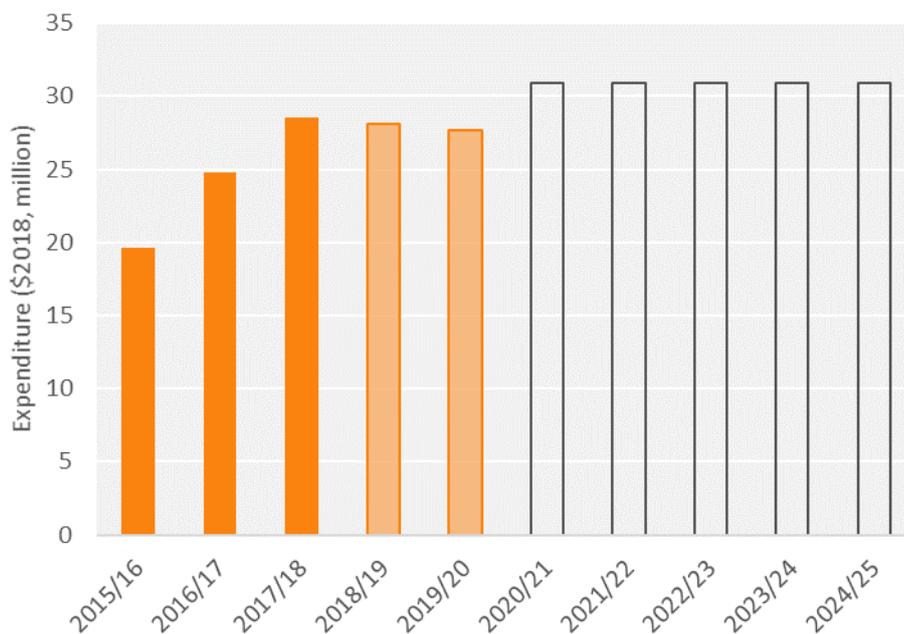
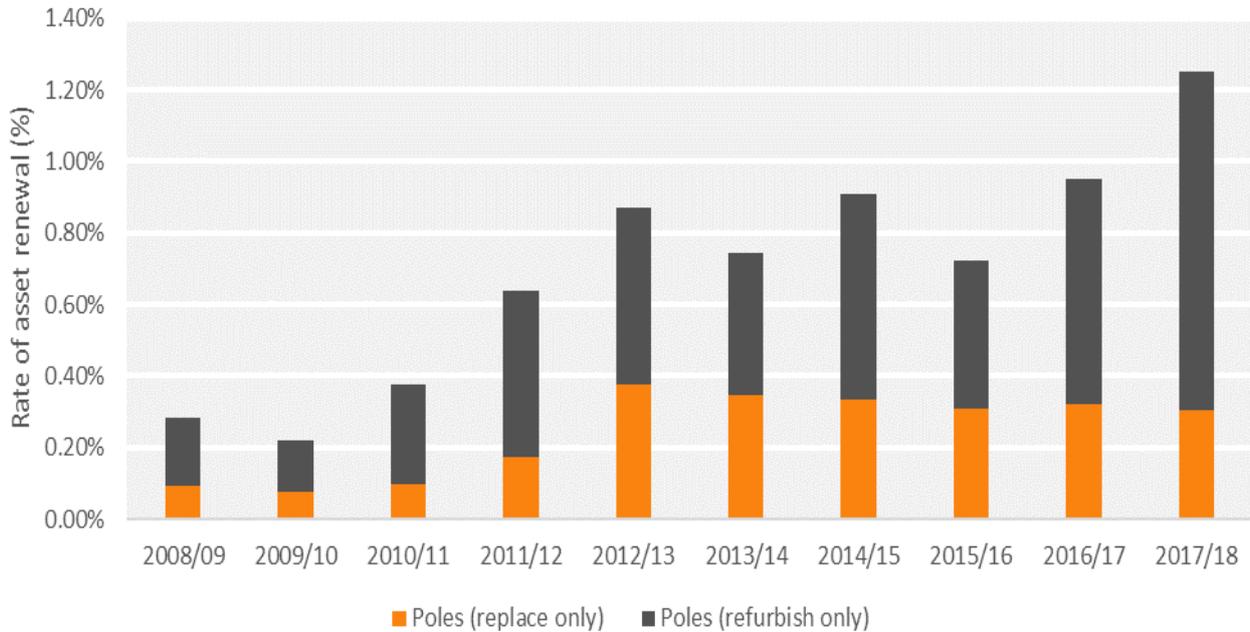


Figure 31: Poles historical and forecast repex (\$2018)

Figure 31 shows the historical and forecast repex and a yearly breakdown of the proposed \$170 million. The proposed \$170 million reflects a moderate increase on the expenditure in the 2015-20 RCP as the asset base ages and the level of risk to mitigate increases.

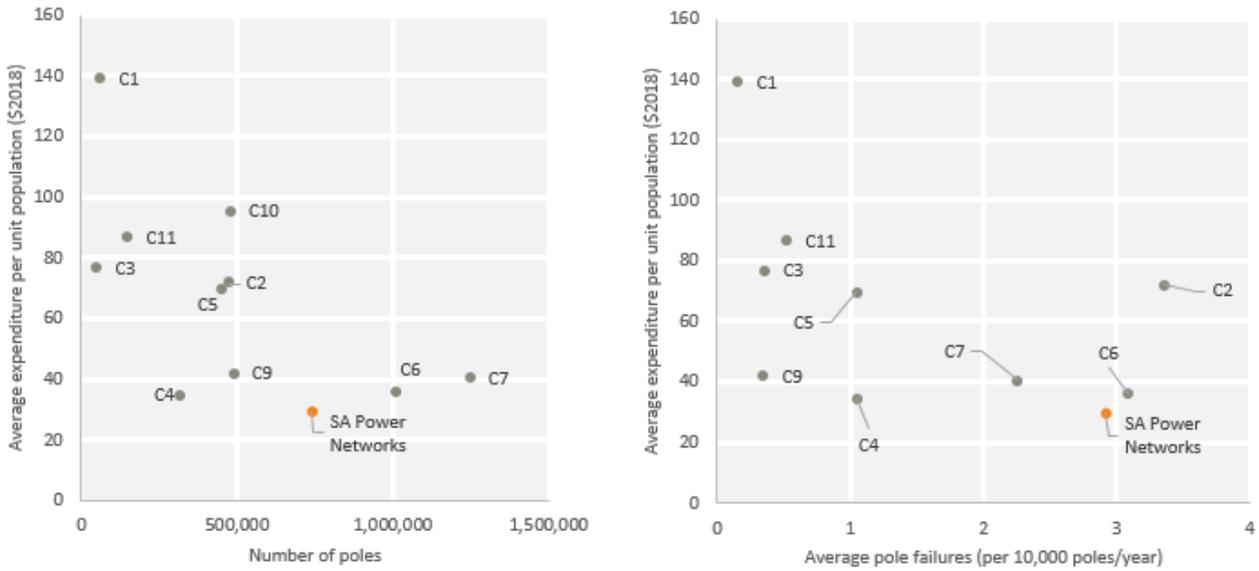
### 7.1.3 Poles rate of renewal



**Figure 32: Poles historic rate of renewal**

Figure 32 shows the historic renewal rate of poles. The proposed rate of renewal with proposed repex of \$170 million renews poles at a rate (for both plating (refurbishment) and replacing) of 1.3% per annum that is the minimum required to maintain an acceptable level of risk over the 2020-25 RCP in accordance with our SRMTMP and other regulatory obligations, while constraining our overall expenditure.

A comparison of pole performance in contrast to other DNSPs was undertaken analysing data from publicly available responses to Category RINs reported over the period from 2013/14 to 2016/17 inclusive (outliers excluded). A comparison of our average annual repex per unit population and failure rate is shown in Figure 33.



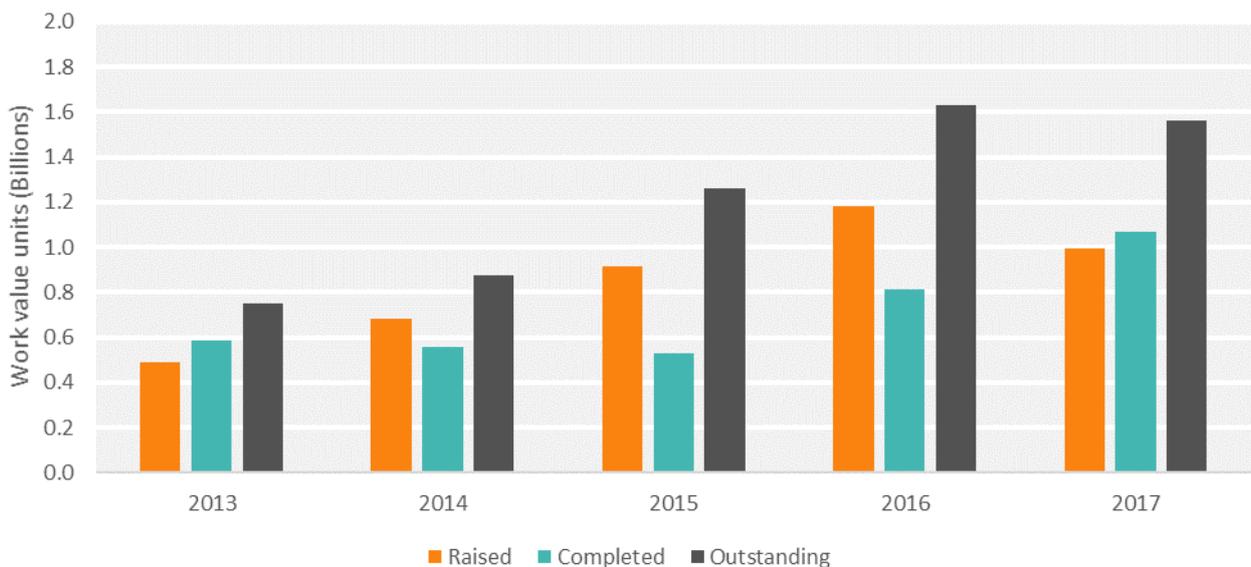
Notes: C8 excluded from both charts as no expenditure information available.

C10 excluded from failure rate chart as outlier due to very high failure rate relative to other DNSPs.

**Figure 33: Pole benchmarking of SA Power Networks vs other DNSPs (2013-2014 to 2016-2017 data)**

Figure 33 shows SA Power Networks currently has the lowest level of average annual repex per pole even with one of the higher reported failure rates amongst DNSPs. This shows SA Power Networks lifecycle management of poles is very efficient.

### 7.1.4 Pole identified risk value



**Figure 34: Poles value trend**

Figure 34 shows the trend in the value of known pole defects. The outstanding pole defects have high value in comparison to other assets. The total value of outstanding defects has increased over the last five years.

Our preferred forecast method for the repex on the pole population is therefore the risk-based CBRM approach. Considering our level of confidence with the poles CBRM model outputs and our desire to conduct risk-based decision making for our overall network, we consider the CBRM maintains risk output at an appropriate level, especially when compared to the AER's age-based repex model (which forecasts required repex of \$256 million under the ('cost scenario') and the historical trend forecast (which forecasts required repex of \$192 million).

Our forecast repex for poles for the 2020-25 RCP is therefore \$170 million applying the CBRM approach.

### 7.1.5 Pole asset information

In managing our pole assets, cost is balanced against levels of service and risk throughout each pole asset's life cycle.

Our cost efficiency largely stems from taking a risk-based life cycle management approach. This includes optimising the use of existing assets and undertaking cost effective refurbishments (plating) to extend asset life and defer the costs of asset replacement while maintaining service levels. Consequently, SA Power Networks operates one of the most efficient, but also one of the oldest, electricity distribution networks in Australia.

Our poles are unique in the NEM in that most of our poles are of a steel and concrete design, known as a Stobie pole. Stobie poles are more expensive than the wood poles more commonly used in other NEM jurisdictions. Typically, however, they last longer, and so we have found them to have lower life cycle costs.

Due to this longer expected life, historically, we were not seeing a significant number of pole failures. However, the ageing of the network means we are transitioning to a replacement cycle.

The expected life of poles varies but is typically in the order of 70 years. The main factors that influence expected life are corrosion zone, load capacity and atmospheric pollution. Based on the existing age profile, there are currently 5% of poles in our network that are more than 70 years old, and this will increase to 13% by 2025.

### 7.1.6 Pole renewal options and risk valuing

#### *Pole renewals*

There are two options which are covered by our repex forecast:

- **Pole refurbishment (plating)** - Our preferred option is to extend the life of the pole. For Stobie poles, which make up the majority of our poles, this involves welding additional steel plates to the pole to increase its structural strength. We call this process 'pole plating'. This is our preferred approach as it is a much lower cost solution than replacing the pole and can extend the life of a pole by as much 20 to 30 years. In recent years a new plating method has been implemented that improves on the strength of the plated pole compared to the previous plating design. This design also enables replating of previously plated poles that have been subject to additional corrosion.
- **Pole replacement** – Where pole plating is not feasible, we replace the pole. Our preferred pole replacement is the Stobie pole. We believe this type of pole provides the lowest lifecycle cost of available pole types in most circumstances. Due to the greater mechanical loading designed into our network through our existing use of Stobie poles, the like-for-like replacement of a Stobie pole with another Stobie pole is typically the most feasible. Importantly, due to these different loading requirements, the AER should not assume that cost of a wooden pole used in other NEM jurisdictions will be comparable to the wooden pole we would require for similar circumstances. By way of example, all our attachments are designed to fit to Stobie poles therefore the cost associated with redesign, sourcing and fitting these attachments to a replacement pole would need to be considered in addition to the cost of the pole.

The decision to plate or replat a pole considers the whole lifecycle of the pole by considering factors such as the overall condition of the pole (if not satisfactory the pole is replaced).

For poles with significant above ground damage, there are circumstances when our preferred option of pole plating is not considered the prudent or efficient solution. Plating is designed to restore strength to the region on the pole affected by ground level corrosion (typically from ground level to 150mm below the surface). If there is significant damage, such as corrosion of sections, missing concrete or significant impact damage, then the above ground structural strength will still not meet AS/NZS 7000 requirements if plating is undertaken.

As shown in Figure 31, the ratio of pole plating (refurbishment) to pole replacement has increased in recent years allowing us to remove more risk for the repex incurred.

### **Pole risk**

A pole identified from inspection as potentially requiring replacement or plating (based on its residual strength) has its likelihood of failure assessed on a case by case basis by considering:

- the loading on the pole;
- the poles environment; and
- the extent of the corroded section of steel at ground level.

The consequence of failure is calculated based upon the following:

- probability of failure, which is a qualitative measurement;
- defect severity;
- consequence of failure, covering environmental, safety, quality and reliability impacts;
- consequence of fire start; and
- number of customers affected.

Assessing the likelihood, consequence and cost of renewal, and the risk reduction, the renewal/replacement strategy for poles is based on maintaining the long-term risk and performance across the pole population and has been modelled using CBRM.

## **7.1.7 Poles CBRM model overview**

### **7.1.7.1 CBRM calibration**

The poles CBRM model was calibrated through an iterative process to ensure the model outputs were aligned with real world observations. The model was calibrated so that the failure rate matched the current number of failures. The poles CBRM inputs are tabled in Section 8.2 in the appendix. The inputs with the most impact on the results are discussed in this section.

#### **Poles expected life**

According to EA Technology's definition, *the Normal Expected Life depends on the Asset Register Category and its sub-category. It is defined as the time (in years) in an asset's life when the first significant signs of deterioration would be expected.*'

As SA Power Networks has only recently begun collection of data required for our CBRM model for Poles (in the 5 years since 2013), it has not collected sufficient data to determine the equivalent age. As a result, we have chosen to be consistent with the AER's repex model and used calibrated mean lives as an alternative. This approach is conservative (in terms of expenditure) as the calibrated mean life represents the point where there is a 50% chance of failure and survival. At this point, the POF is likely to be substantially higher than '*the first significant signs of deterioration*' defined by EA Technology.

## Health Index

The CBRM model limits the initial year HI based only on age information to a maximum value of 5.5.

## Atmospheric Corrosion Zone Corrosion Factor

The corrosion factor is assigned to the corresponding atmospheric corrosion zones. Corrosion factors determine the weighting of impact Atmospheric Corrosion zone has on the life expectancy of the asset.

Corrosion factors are based on the rate of corrosion per year in each corrosion zone as defined by AS/NZS 2312:2002.

## Asset Condition Weightings

Various asset inspection and defect information is used in the model to establish the condition and health of an asset. Asset Inspection information includes measurements of ground corrosion levels, concrete condition, bolt condition, bent/twisted condition and overall pole condition.

Model calibrations are such that each condition is given a weighting based on its associated influence on SA Power Networks' work practices for requiring refurbishment and has been established in consultation with Pole SMEs.

## Pole Plating

Plated poles underwent the same calibrations used for pole expected life, considering location and duty factors.

### ***7.1.7.2 Changes made in poles CBRM model since the regulatory proposal for the 2015-20 RCP***

We have improved the poles CBRM model significantly since we first built and used it to forecast our repex for the 2015-20 RCP. The key changes made to the model are as follows.

#### **Additional asset condition information**

Previously the CBRM Pole model included approximately 730,000 pole assets with limited condition information. This was due to a lack of available data and hence various assumptions being made to determine the population of poles and their associated condition.

We have since undertaken significant volumes of asset inspections and as such refined the volume of poles down to approximately 647,000 based on data present in our asset information systems, with approximately 70% of poles having inspected condition information.

#### **Refurbishment and replacement mix**

The volumes of poles that can be plated (refurbished) is based on their condition information. Only poles with defined ground line corrosion are considered for plating. The ratio of poles plated to poles replaced in the our repex forecast for the 2020-25 RCP is based on the ratio during the 2015-20 RCP.

### ***7.1.7.3 Poles renewal strategy modelling***

Two strategies were modelled for poles using the CBRM methodology to forecast the future repex requirements. These were:

- **replace due to health (avoid failures):** this strategy replaces any asset that reaches a HI of 7; and
- **maintain current risk:** this strategy replaces assets that provide the largest reduction in risk (delta risk) in each asset class relative to the cost of replacement, optimising the number of replacements required to maintain the network risk levels as at 1 July 2020 to 1 July 2030. The risk level at the end

of 2015-20 RCP has been used as a baseline due to the uneven level of expenditure between 2015 and 2020.

To support the assessment of the repex requirements for the two strategies we also modelled a 'Do Nothing' strategy. The 'Do Nothing' strategy assumes no renewals (both planned and unplanned) will occur during the 2020-25 RCP. This strategy only helps us to determine the baseline reference.

Do nothing (Baseline)

Figure 35 shows the forecast risk associated with pole assets in the absence of the proposed repex.

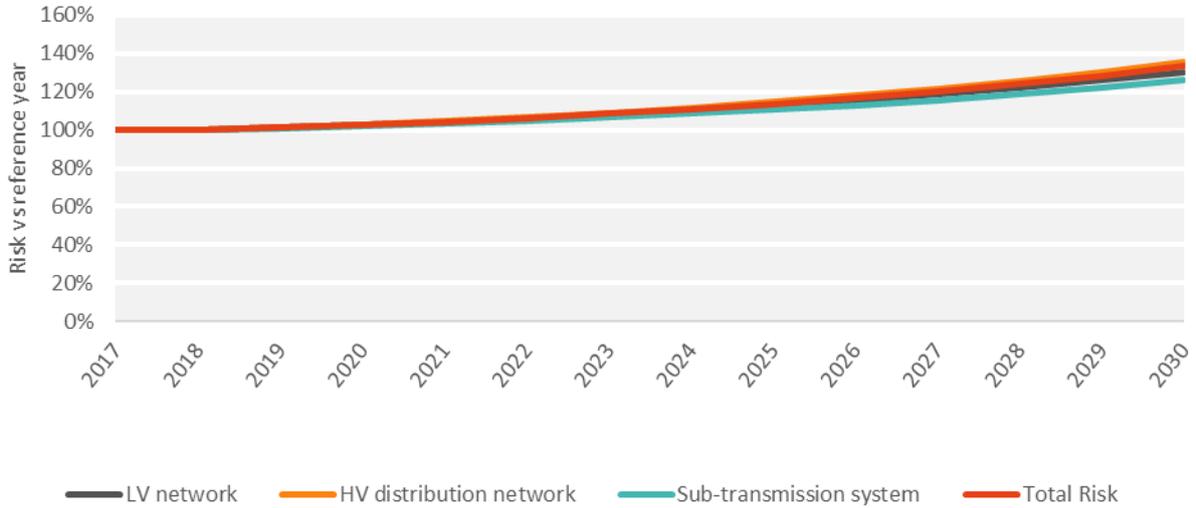


Figure 35: Poles Do Nothing (Baseline) Strategy -Risk Forecast

Figure 36 shows the forecast HI for this baseline strategy over the next two RCPs.

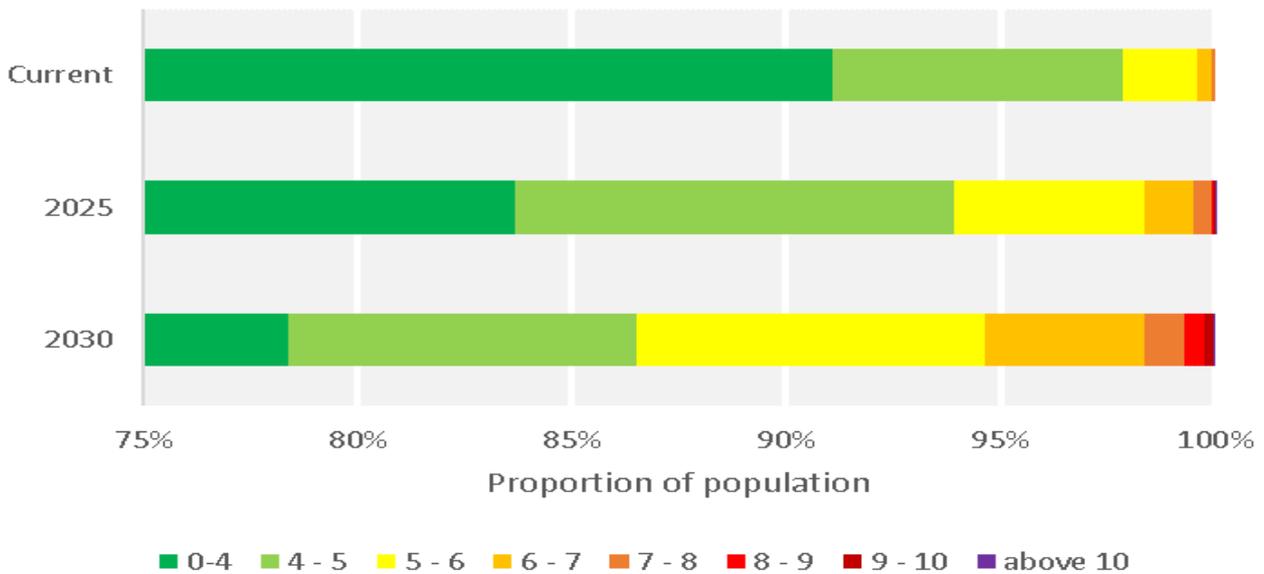
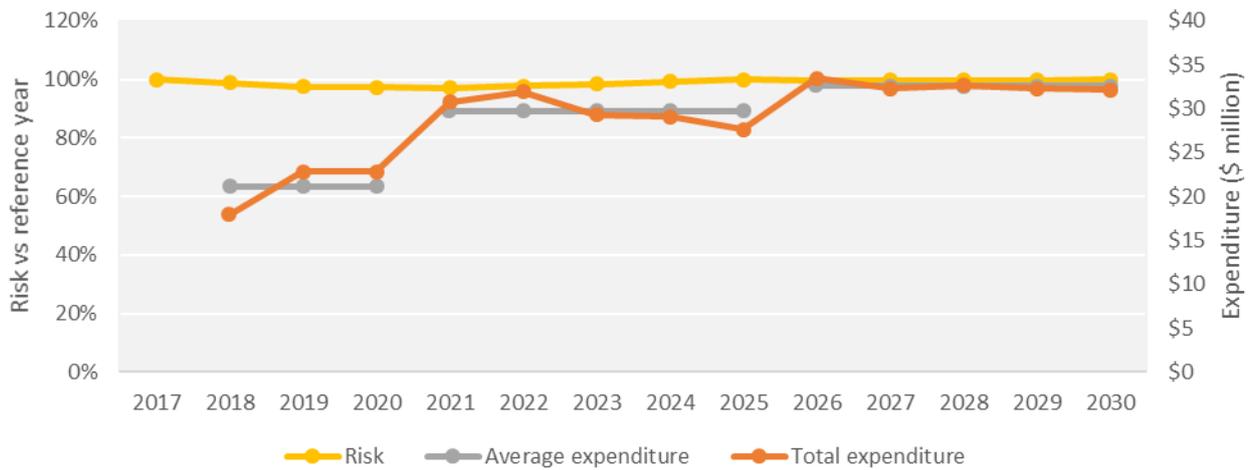


Figure 36: Poles Do Nothing Strategy - Health Index Forecast

#### 7.1.7.4 Maintain current risk renewal strategy

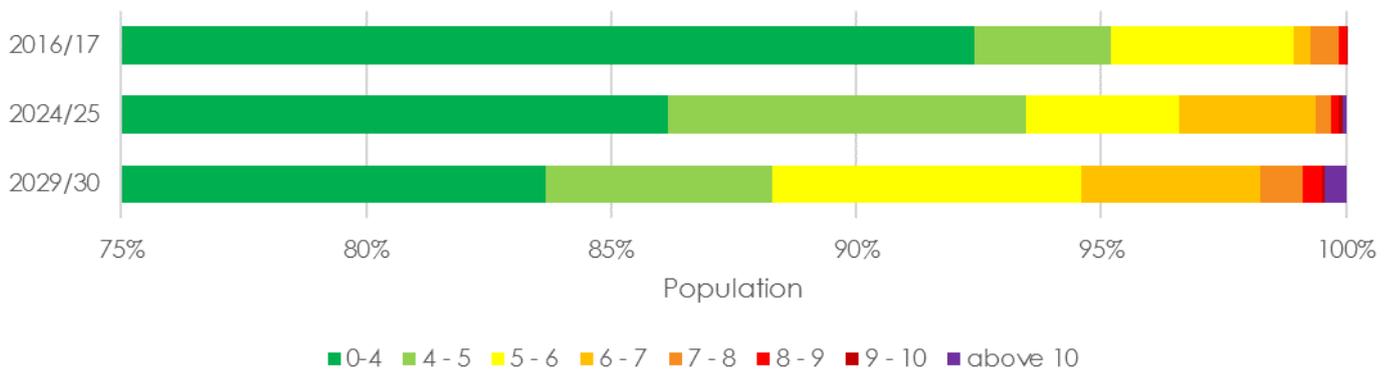
Figure 37 shows the forecast risk and repex in order to maintain our current risk renewal strategy for poles.



**Figure 37 – Maintain Risk - Risk & Expenditure Forecast**

Figure 37 shows the forecast repex for this strategy for the 2020-25 and 2025-30 RCPs.

Figure 38 shows the forecast health index for this strategy.



**Figure 38 – Poles Maintain Risk Strategy – Health Index Forecast**

Figure 38 shows that the percentage of poles with HI greater than 7 would decrease from the current 0.7% to 0.6% by 2025. However, this then increases again to 1.7% by 2030.

Based on this approach and on maintaining risk, our forecast repex for the 2020-25 RCP is \$170 million.

### 7.1.8 Poles - AER repex model inputs

Similar to the CBRM model, the AER repex model also utilises critical asset information to forecast the asset renewal volumes. The AER repex model has been used for comparison purposes with our CBRM model.

The repex scenarios for poles as described in section 6.2.2 were calculated using the inputs in Table 5

**Table 5: Unit costs and expected replacement mean lives derived from SAPN and AER's data**

Asset	Category	Unit Cost (\$k)			Mean Life
		SAPN	AER's BM	Comparative Unit Cost	
Pole (Unblended)	< = 1 kV ; Steel	7.0	10.6	7.0	76.8
	> 1 kV & < = 11 kV ; Steel	10.8	8.9	8.9	73.6
	> 11 kV & < = 22 kV ; Steel	8.4	10.4	8.4	71.9
	> 22 kV & < = 66 kV ; Steel	16.3	21.5	16.3	80.5
	Pole Refurb	1.2	10.5	1.2	20.0
Pole (Blended)	< = 1 kV ; Steel	3.6	10.6	3.6	71.2
	> 1 kV & < = 11 kV ; Steel	4.3	8.9	4.3	66.8
	> 11 kV & < = 22 kV ; Steel	3.4	10.4	3.4	66.4
	> 22 kV & < = 66 kV ; Steel	3.8	21.5	3.8	70.4
	Pole Refurb	8.8	10.5	8.8	20.0

Table 5 shows SAPNs mean lives and expected replacement unit costs derived from SA Power Networks' and AER's data<sup>21</sup>.

In line with current AER practise (see section 6.2.2), the costs scenario has been selected. This scenario yields a forecast of \$256 million for the 2020-25 RCP.

<sup>21</sup> The data for steel poles has been chosen as it is the closest to Stobie poles.

## 7.2 Pole top structures repex forecasts

### 7.2.1 Pole top structures forecast repex summary

We have utilised two methods to assess the required repex for pole top structures (which includes overhead line components and overhead switchgear), being historical expenditure and historical expenditure projected trend. The modelling outputs have been supplemented with our own SME knowledge to help build the required repex for pole top structures for the 2020-25 RCP.

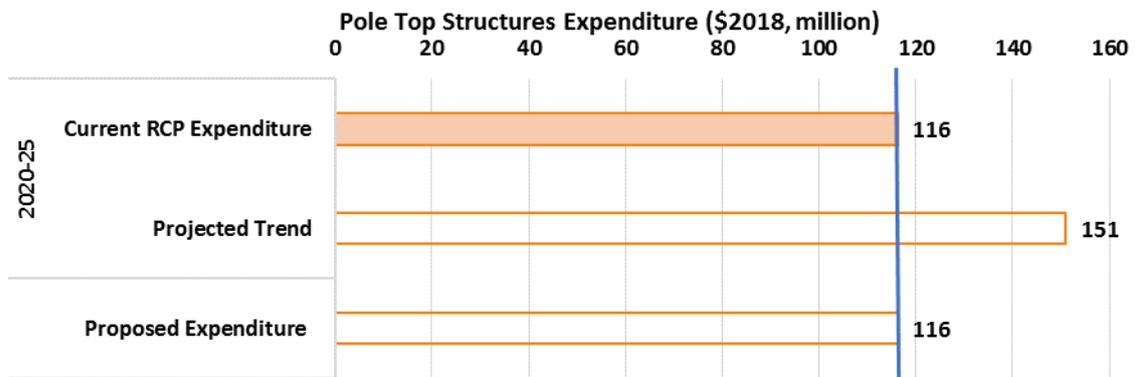


Figure 39: Pole Top Structures repex Summary

Figure 39 shows the repex summary for pole top structures. The proposed forecast repex of \$116 million is based on the 2015-20 RCP expenditure. Due to the nature of high volume of diverse assets with very little data, pole top structures cannot be modelled in CBRM or the AER's repex models. Based on historical failure trend, defect backlog and the ongoing implementation of our Asset & Works program, our proposed repex is based on the actual and planned expenditure for the 2015-20 RCP.

### 7.2.2 Pole top structures forecast repex profile

Figure 40 shows the historical and forecast repex and a yearly breakdown of our proposed repex of \$116 million for the 2020-25 RCP.

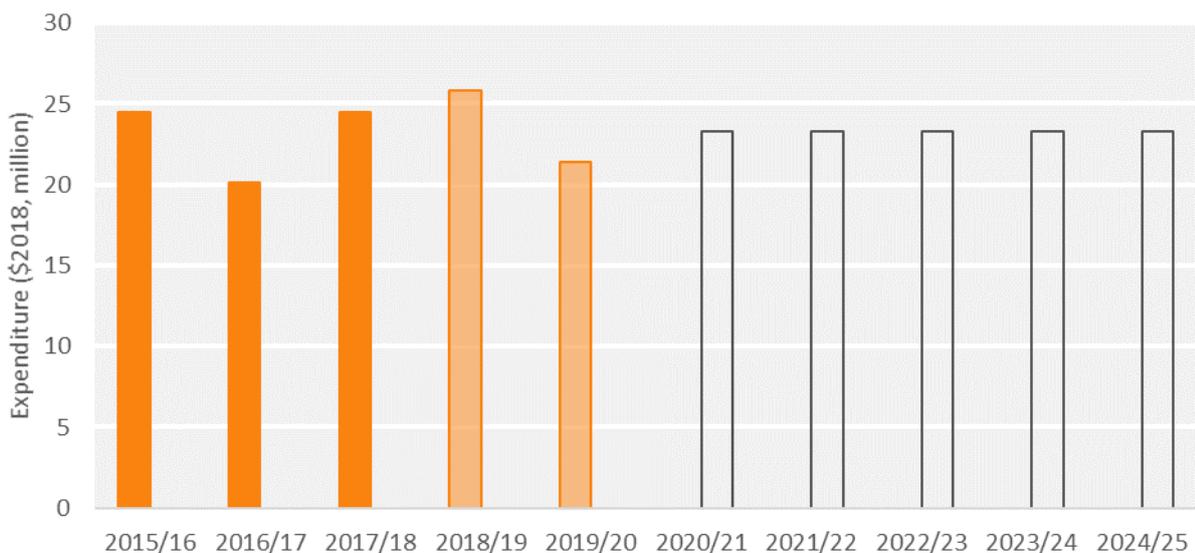


Figure 40 Historical and Proposed repex for the 2020-25 RCP for pole top structures

Figure 40 shows the proposed annual repex of \$23.2 million is consistent with the historical repex of \$20.1 to \$24.5 million.

### 7.2.3 Pole top structure identified defect risk value

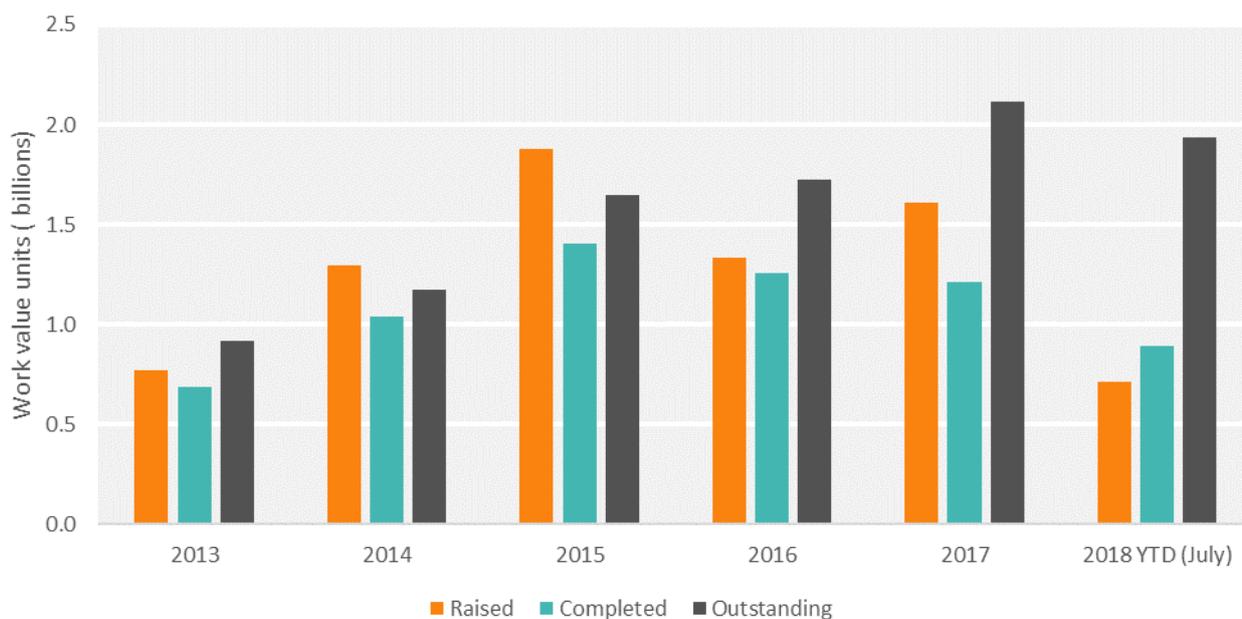


Figure 41 Pole Top Structures Value Trend

Figure 41 shows the risk value of known pole top structure defects and the high value of the known backlog of pole-top structure defects on the network.

### 7.2.4 Pole top structures asset description

The pole top structure category covers a variety of assets that enable overhead conductors to be securely attached to their support structures, support other pole mounted equipment and connect the overhead conductors to other equipment. Pole top structures include cross arms, insulators, overhead switchgear, joints and taps, and other components. Given the high proportion of renewal expenditure in this category and the wide variety of assets, some additional asset description is included below.



**Figure 42 A typical combination of pole top structures**

The number of failures of pole top structures has trended upward since 2011. The management of pole top structures is largely based on replacing any that have failed and identifying defects and subsequently valuing and prioritising proactive replacements.

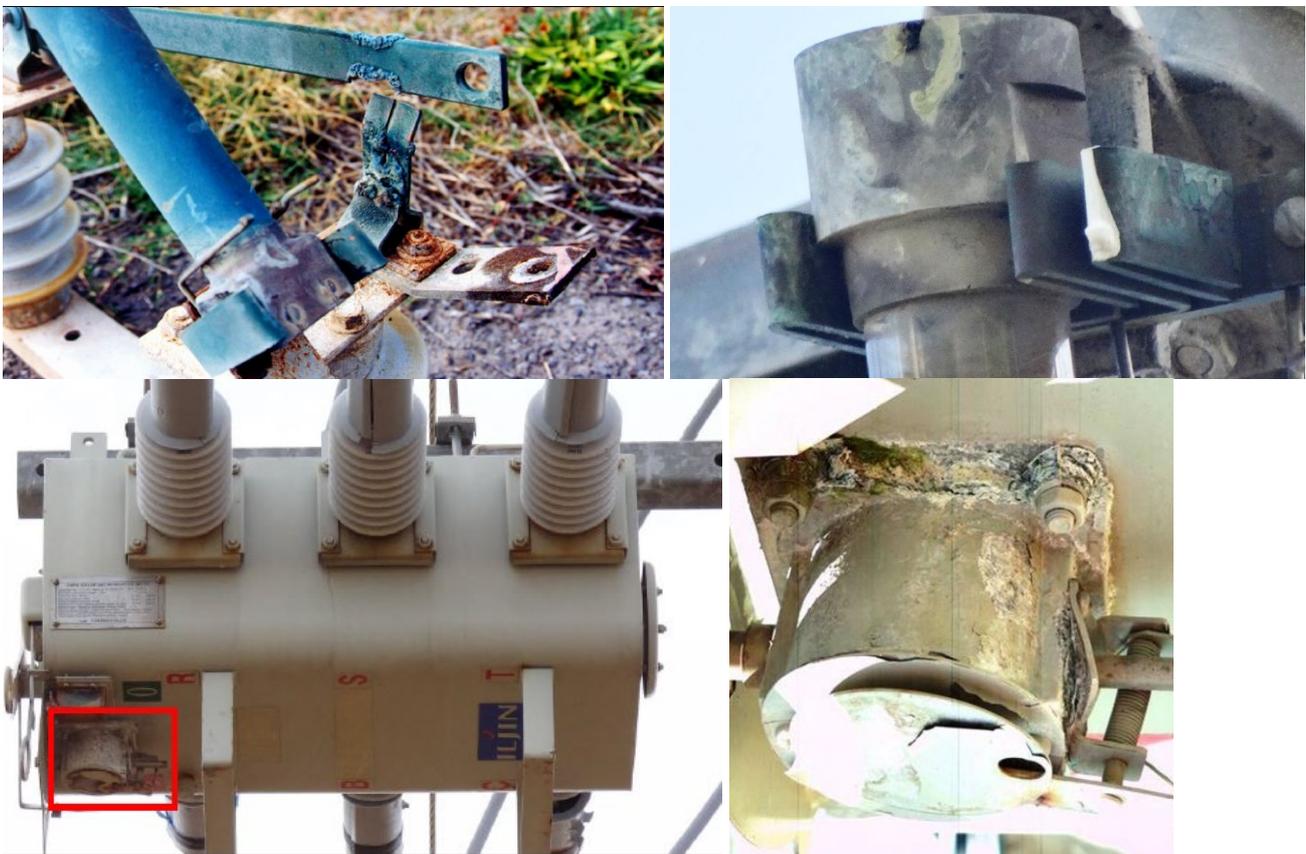
Pole top structures have not been modelled using CBRM to assess risk or asset health nor in AER's repex model because they are numerous and varied, and data is limited. The historical performance and expenditure of this asset class informs the required repex forecast to 2025.

The quantity of pole top structures and their distribution across each system is unknown but should be in proportion with pole quantity.

The expected life of pole top structures varies but is typically 40–50 years. The expected life of pole top structures is highly variable because they themselves are varied as is the environment in which they operate. The main factors that influence expected life are the materials used, corrosion zone, load capacity, atmospheric pollution and fatigue. Due to their wide variety and condition, and the uncertainty of the age profile, the proportion of these assets past their expected life cannot be determined. Having said that, we believe the average age of our pole top structures is greater than for most NEM DNSPs. The reason for this is that SA Power Networks uses stobie poles which tend to have a longer life span than any other materials, consequently, the replacement rate of our pole top structures should be lower than other DNSPs which have shorter living poles and replace pole top structures at the same time poles are replaced.



**Figure 43 Typical defects of crossarms and insulators**



**Figure 44 Typical defects of fuses and load switches**

Very little maintenance is undertaken on pole top structures with the components typically replaced on failure or when defects are identified.

Pole top structures cannot be refurbished and are replaced at the end of their expected life. The replacement strategy is based on managing risk either through identified failures or identification of defects. In addition, where the condition of pole top structures cannot reliably be detected through inspections, and the assets have a high likelihood and consequence of failure (eg in response to historical failures or known design deficiency), proactive replacement programs are planned.

#### **7.2.4.1 Other emerging issues**

While we continue to improve the work efficiency and defer as much risk as possible, it is important to understand and recognise the emerging risks we are facing.

##### **Wraplock issue on SWER Feeders (Ties)**

From 1970 to 2004 wraplocks were used in the HV SWER distribution network in the Eyre Peninsula and Mt Gambier to secure the conductor to the insulator. Wraplocks consisted of a length of steel wire with a rubber protective tube tied in a figure eight.



Wraplocks have a high likelihood of failure resulting in the conductor detaching from the insulator and falling to the ground. This has resulted in fire, outages and safety risks to the public.

In 2017/18, pre-bushfire inspections detected 43 high risk defects due to defective wraplock ties that needed an immediate fix due to their potential to start fires. The deterioration of all ties is not easily detected by inspection as the deterioration can be hidden behind the insulation until the tie fails and the conductor falls.

##### **Aluminium to steel Joint issue on the SWER Network**

SWER dropper bars and T-clamps are prone to corrosion. The aluminium to steel dissimilar metal joints corrode through galvanic action. The corrosion has led to fire starts and risk of electric shocks when the conductor falls. The corrosion of the dropper bars and T joints is difficult to see from inspection as the corrosion is inside the joint. Information from our Equipment Failure Investigation Database indicates these joints are exhibiting high failure rates. There were 36 failures on SWER feeders from 2008 to 2018 with 24 failures due to corrosion.



##### **Ball and socket suspension insulators wear on sub-transmission lines**

The ball and socket insulators are attached by inserting the ball into the socket and secured with a locking key. In this way insulators are connected to form an insulator string. This design allows some movement of the insulator when the conductor sways.

However, with movement over many years both the ball and the socket wear until, in some cases, the ball can escape from the socket dropping the conductor leading to serious consequences including fire and prolonged outages of sub-transmission lines.



Attempts have been made to determine the condition of the insulators by measuring the distance between insulator sheds. This method, while indicative, has not proven reliable as insulators assessed to be serviceable have been discovered to be highly worn. The reliable solution has been to replace all ball and socket insulators in areas where conductors have fallen and where evidence of wear has been observed. There have been 60 failures of ball and socket insulators on a total of 30 66kV and 33kV feeders since 2000.

### ***Brown insulator fuse base issue***

The ceramic brown insulators supporting fuse bases may shear off when being operated resulting in risks to field personnel from components falling and electric shocks. There have been six incidents since 2009 of fuse base breaks when the operator is switching.

The force applied to the insulators during operation contributes to their failure however fuses bases also break without being operated. There have been 103 broken fuse bases in 12 years highlighting the risks to the public from electric shocks and fire starts.

The repeated failures on operation and the multiple safety alerts in the past is evidence that it has been difficult to detect insulators that are about to break and the need for a replacement program.

### ***Glass housed liquid fuse issue***

Glass housed liquid fuses are widely used at over 10,000 locations in our network. They have the following issues which need to be addressed in a timely manner:

- break shattering glass and carcinogenic liquid which are causing safety issues and starting fires;
- do not always operate (“slow-blow”) before an upstream device;
- defects are difficult to be detected through inspection; and
- they will no longer be manufactured.



## 7.3 Underground cables repex forecast

### 7.3.1 Underground cable forecast repex summary

We have utilised three methods to assess the required repex for underground cables, being the AER's repex model, historical expenditure and historical expenditure trends<sup>22</sup>.

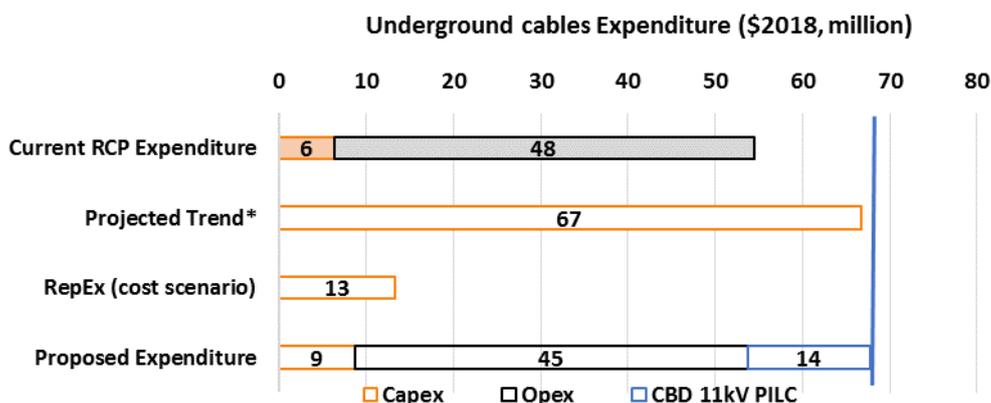


Figure 45 Underground cable Renewal Summary

Although our overall network strategy has been transitioning to condition-based risk management approach for forecasting repex for the 2020-25 RCP, the CBRM model requires asset information including installation dates, expected life, joint information and other condition information. We currently have limited asset data information for underground cables and further development is required to gain confidence in our CBRM modelling. In the absence of CBRM modelling, we have relied on historic expenditure along with a bottom up increase in CBD cable renewal to establish a forecast for the 2020-25 RCP.

Historically most conductor minor repair works comprise reactive patching or making repairs after a fault has occurred. However, a decision has been made to treat repex relating to cable minor repairs (i.e. work undertaken to patch/join a cable resulting from a defect or default) as opex rather than repex/capex. Cable minor repair work is more akin to repairs and maintenance rather than refurbishment and essentially only benefits current customers. For these reasons and other reasons set out in Section 5.11 of **Attachment 5 – Capex** and section 6.7.2.4 **Attachment 6 – Opex** to the Proposal, SA Power Networks is proposing to remove this type of expenditure from its repex forecast for the 2020-25 RCP and include a capex/opex trade off step change in its opex forecast for this type of expenditure. Works associated with projects that replace complete cable lengths will remain as capex.

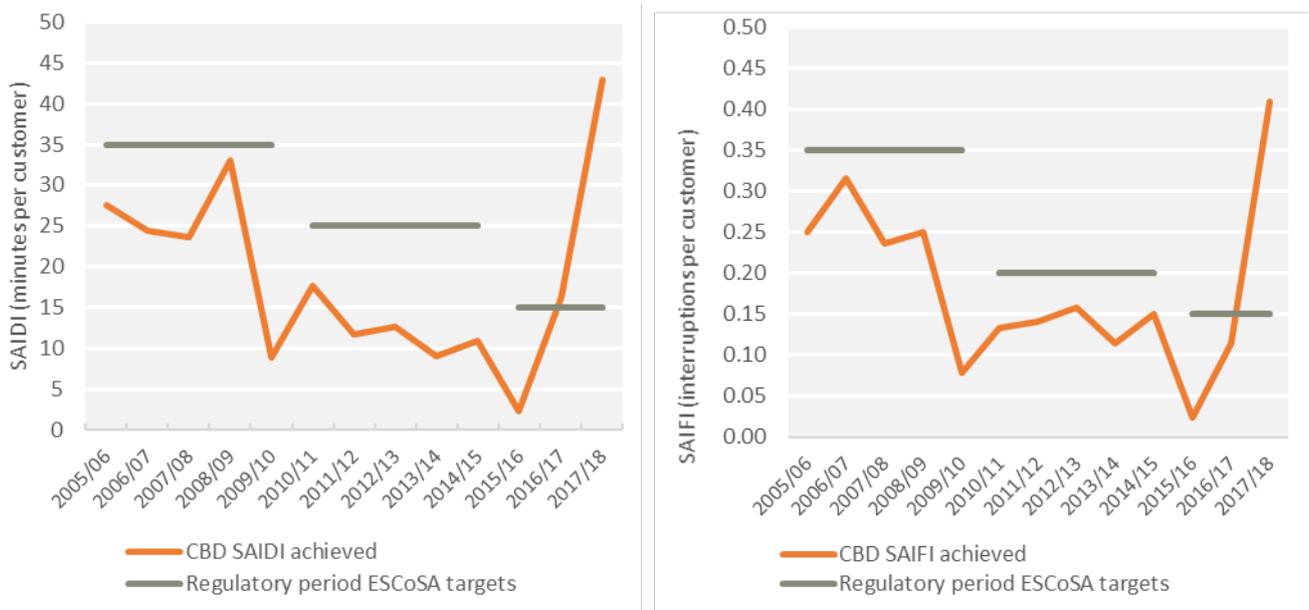
The underground cables repex forecast for the 2020-25 RCP comprises \$9 million in line with actual repex for the 2015-20 RCP and an additional \$14 million to replace bare Paper Insulated, Lead Covered (PILC) cable in the CBD (see section 7.3.2 below) making a total of \$23 million. As explained in section 7.3.2 below, in the absence of CBRM modelling we have relied on historic expenditure along with a bottom up increase in CBD cable renewal to establish a repex forecast for the 2020-25 RCP.

### 7.3.2 Replacement of bare PILC cables in the CBD

We failed to meet our reliability targets for the Adelaide Business Area (ABA) for the past two regulatory years as shown in Figure 46<sup>23</sup>.

<sup>22</sup> The Projected Trend is based on historic RIN submissions

<sup>23</sup> ESCoSA, SA Power Networks reliability standards review: Final decision, January 2019.



**Figure 46 Long-term CBD reliability standards vs actual performance<sup>24</sup>**

Figure 47 shows SA Power Networks’ analysis of faults on cables supplying the CBD. It was found the failure rate (# failures/100km/year) is 3-4 times higher on the PILC cables with bare lead on their outside (denoted by PLY-OTHER) than on PILC cables with insulation on their outside (denoted by PLY-HYDE) or XLPE cables.



**Figure 47 Long-term CBD HV cable failure rates by material type (2005-2017)**

In response to the increase in failures on the 11kV PILC cables in the CBD in 2017, SA Power Networks engaged an external consultant, Frazer-Nash, to undertake a detailed investigation of our 11kV bare PILC cables. This investigation concluded that the increased level of failures was caused by:

- thermal effects:** ambient temperature and cyclic loading; and
- ground conditions:** soil type and moisture.

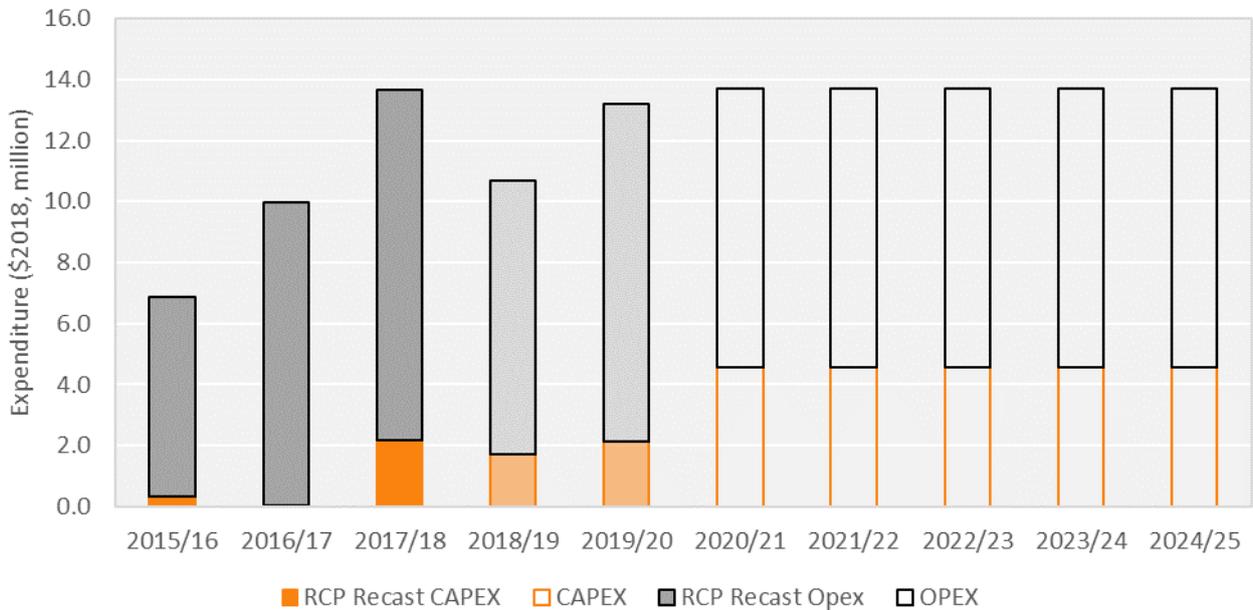
The investigation identified 20 x 11kV PILC cable sections with the highest probability of failure and these were located in the west of the CBD in areas of expansive clays, beneath parkland areas and operational high electrical loads.

<sup>24</sup> Reliability targets exclude SA Power Networks’ performance during severe or abnormal weather events through the application of the IEEE MED exclusion methodology. This approach allows the impact of MEDs to be studied separately from SA Power Networks’ daily operations and, in the process, better reveals trends in daily operation that would be hidden by the large statistical effect of major events.

Cable replex in the medium term is proposed to be increasingly focused on HV distribution cables (11kV) within the CBD and particularly the bare PILC due to their overall poorer condition and the impact on reliability service standards observed across 2016/17 and 2017/18 regulatory years. We will continue to undertake repairs on failure in relation to 11kV PILCs but will replace longer lengths of cable once the fault is isolated to enable phasing out of this problematic cable material type; noting the rate of replacement proposed will still take almost 50 years to phase out.

Based on the five year (2013-17) average failure rate for 11 kV PILC of 2.8 cable faults per annum, and a proactive replacement length of 500 metres per fault over and above the minimum length that would be currently be undertaken with the application of the replex unit rate for 11kV cables (see 7.3.5) and applying a 5% allowance for the complex switching arrangements required for CBD planned outages, we forecast replex of \$2.8 million per annum or \$14.01 million for the 2020-2025 RCP for this asset category. With over 70km of 11kV PILC cable in the CBD, this proposed rate of replacement will take four RCPs to phase out which is considered a very modest timeframe.

### 7.3.3 Underground cables forecast expenditure profile

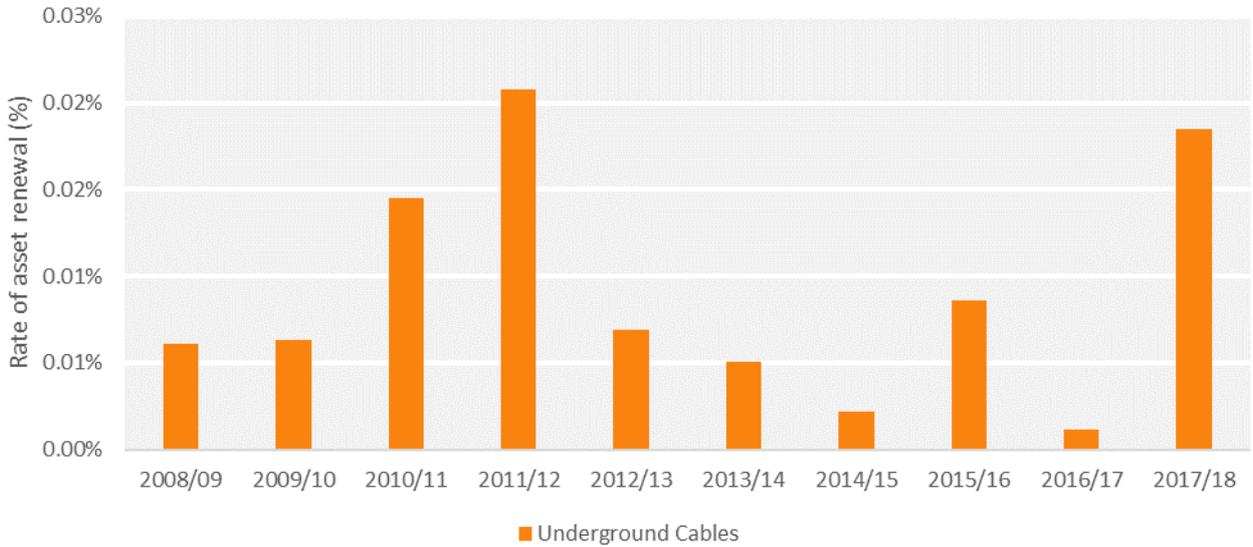


**Figure 48 Underground cables historical and proposed Expenditure for the 2015-20 and 2020-25 RCP**

Figure 48 shows the annual proposed replex for the 2020-25 RCP is an increase in contrast to recent regulatory years of the 2015-20 RCP. However, this is due to the proposed CBD 11kV PILC replacements project commencing over the 2020-25 RCP period. The proposed expenditure is otherwise comparable to the actual 2017/18 regulatory year cable expenditure and the forecast for the remainder of the 2015-20 RCP.

### 7.3.4 Underground cables rate of replacement

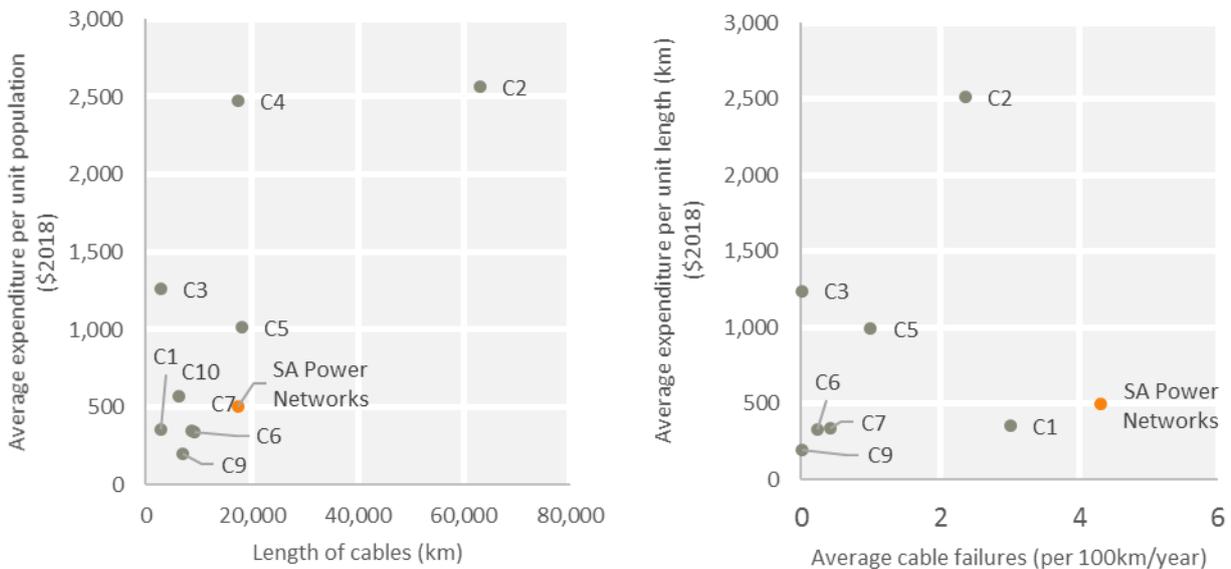
Figure 49 shows the historic rate of replacement of underground cables.



**Figure 49 Underground Cables Rate of Replacement**

Figure 49 shows that historically cables have been replaced at low rates and the requested replacement expenditure equates to a replacement rate of < 0.1 %. Continued replacement at this rate will require some cables to last 1000 years before they are replaced. This is unsustainable and the renewal rate will need to be increased in the future.

A comparison of cable performance in contrast to other NEM DNSPs was undertaken analysing data from publicly available responses to Category RINs reported over the period from the 2013/14 regulatory year to the 2016/17 regulatory year inclusive (outliers excluded). A comparison of average annual repex per unit length and failure rate is shown in Figure 50.



**Figure 50 Cable benchmarking of SA Power Networks as compared to other NEM DNSPs (based on 2013/14 to 2016/17 data)**

Figure 50 shows SA Power Networks currently has a mid-range level of average annual repex per length of cable even with one of the higher reported failure rates amongst DNSPs. Many other DNSPs with large proportions of their cable assets within CBD districts are contained within ducts leading to a lower failure rate due to the mechanical protection ducts provide. Whereas the majority of SA Power Networks cable population outside of the CBD is directly buried. SA Power Networks experienced a period of real estate developments where developers installed the cheapest cable material able to comply with specifications at the time. Minor repairs (or patching) of these cables has typically been undertaken in response to failures in lieu of cable replacement due to most faults occurring on cable sections that have previously not had any recorded faults with around 70% of faults occurring within the LV network. This shows SA Power Networks lifecycle management of cables is very efficient.

### 7.3.5 Underground cables AER repex method inputs

#### 7.3.5.1 Underground cables repex key input information

Table 6 gives details of the key input information for the underground cables AER’s repex model.

**Table 6 : Underground Cables repex Key Input Information**

		Unit Cost (\$k)			Mean Life
Asset	Category	SAPN	AER's BM	Comparative Unit Cost	SAPN Mean Life
Underground Cables	< = 1 kV	310.4	304.5	304.5	73
	> 1 kV & < = 11 kV	639.0	457.3	457.3	68
	> 11 kV & < = 22 kV		215.7		81
	> 22 kV & < = 33 kV		1149.4		101
	> 33 kV & < = 66 kV		5767.0		88

In line with current AER practise (see section 6.2.2), the costs scenario has been selected. This scenario yields a forecast of \$13 million for the 2020-25 RCP.

#### 7.3.5.2 Underground cables AER repex model calibrations

##### Age Profile

The accuracy of the age profile of our underground cables provided in the RIN and used for AER repex modelling has been significantly improved in 2018. Previously, cable ages were based on the ‘feeder age’ based on the age of the oldest pole on a specific feeder. Results from calibrations based on this age profile and installed asset quantities over the years yielded outputs that were significantly higher than realistic and outside our expected range.

We have refined the high voltage underground cables age based on a mix of the install dates of the transformers, switching cubicles, poles, feeders, voltage levels and material types. The logical sequence we have followed in this refinement is to assign an age starting with the feeder average transformer age. If this information is not available then feeder average switching cubicle age, feeder average pole age or feeder

start-up date is used. Where none of this information was available, we defaulted to installation date by voltage and material type.

The table below shows the percentages of high voltage underground cable sets ages that have been estimated from various assumptions.

**Table 7 : High Voltage Underground Cables Installation Dates Estimation summary**

Assumption	Percentage of Cable sets
Feeder ground transformer/switching cubicle/pole average install date/Feeder start-up	92.5%
Default installation date by voltage and material type	7.5%

We have also refined the install dates for low voltage underground cables based on installation dates of transformers that they are supplied from.

Table 8 shows the percentages of low voltage underground cable sets ages that have been estimated from various assumptions.

**Table 8 : Low Voltage Underground Cables Installation Dates Estimation summary**

Assumption	Percentage of Cable sets
Ground transformer install date	94.9%
Default installation date by voltage and material type	5.1%

**Unit Costs**

The unit costs have also been revised in line with advice provided by the Network Project Officers responsible for designing and estimating underground cable designs.

## 7.4 Conductors repex forecast

### 7.4.1 Conductors forecast repex summary

We have utilised three methods to assess the required repex for conductors, being the AER's repex model, historical expenditure and historical expenditure trends<sup>25</sup>.

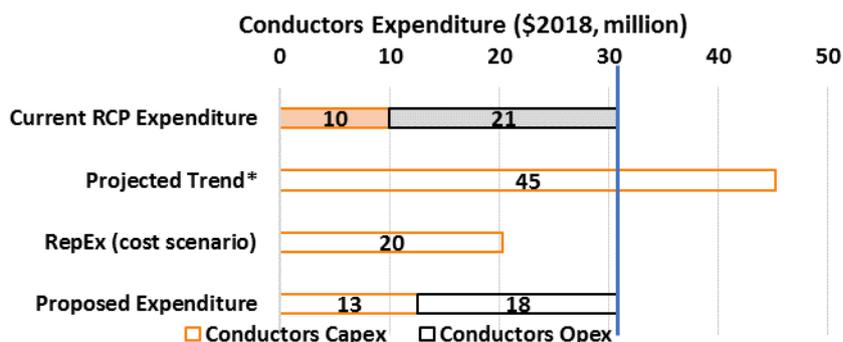


Figure 51 Conductors Expenditure Summary

Although our overall network strategy has been transitioning to a condition-based risk management approach for forecasting repex for the 2020-25 RCP, the CBRM model requires asset information including installation dates, mean life, number of joints and other condition information. We currently have limited asset data information for conductors and further development is required to gain confidence in our CBRM modelling.

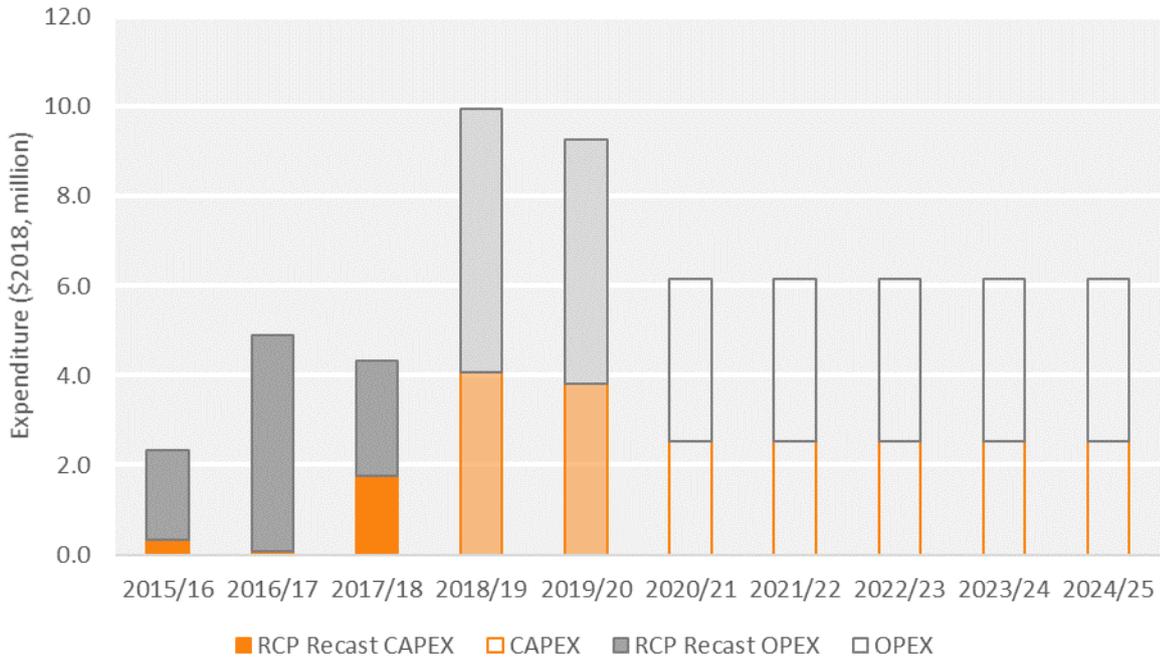
In the absence of CBRM modelling, we have relied on historic repex to establish a forecast repex for the 2020-25 RCP of \$31 million.

Historically most conductor minor repair works comprise reactive patching or making repairs after a fault has occurred. However, a decision has been made to treat repex relating to conductor minor repairs (i.e. work undertaken to patch/join a conductor resulting from a defect or default) as opex rather than repex. Conductor minor repair work is more akin to repairs and maintenance rather than refurbishment and essentially only benefits current customers. For these reasons and other reasons set out in Section 5.11 of Attachment 5 – Capex and Attachment 6 – Opex to the Proposal, SA Power Networks is proposing to remove this type of expenditure from its repex forecast for conductors for the 2020-25 RCP and include a capex/opex trade off step change in its opex forecast for this type of expenditure. Works associated with projects that replace complete conductor lengths will remain as capex.

Our proposed forecast repex for conductors of \$13 million is based on the historical expenditure over the last 5 years with the breakdown between capex and opex matching the 2017/18 capex/opex ratio.

<sup>25</sup> The Projected Trend and the is based on historic RIN submissions

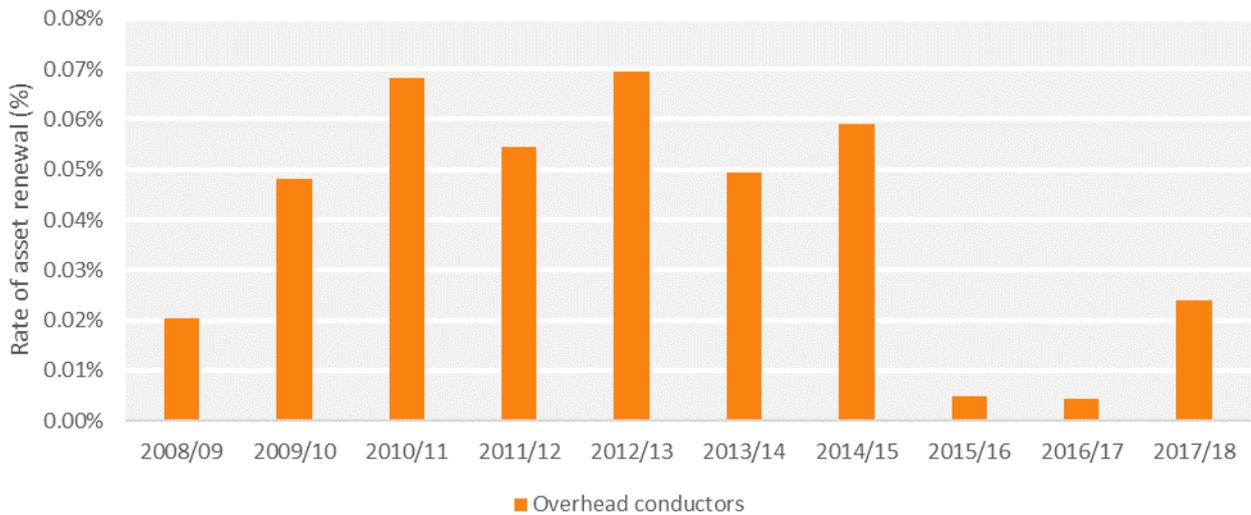
### 7.4.2 Conductors forecast repex profile



**Figure 52 Conductors Historical and Proposed repex for the 2015-2020 and 2020-25 RCPs**

Figure 52 shows a significant increase in forecast repex over the next two regulatory years. This forecast is based on planned projects to address poor condition conductors. The proposed repex per regulatory year is less than the next two regulatory years forecast as it is based on the previous 5-year average. This forecast relies on better condition assessment to more prudently manage conductors.

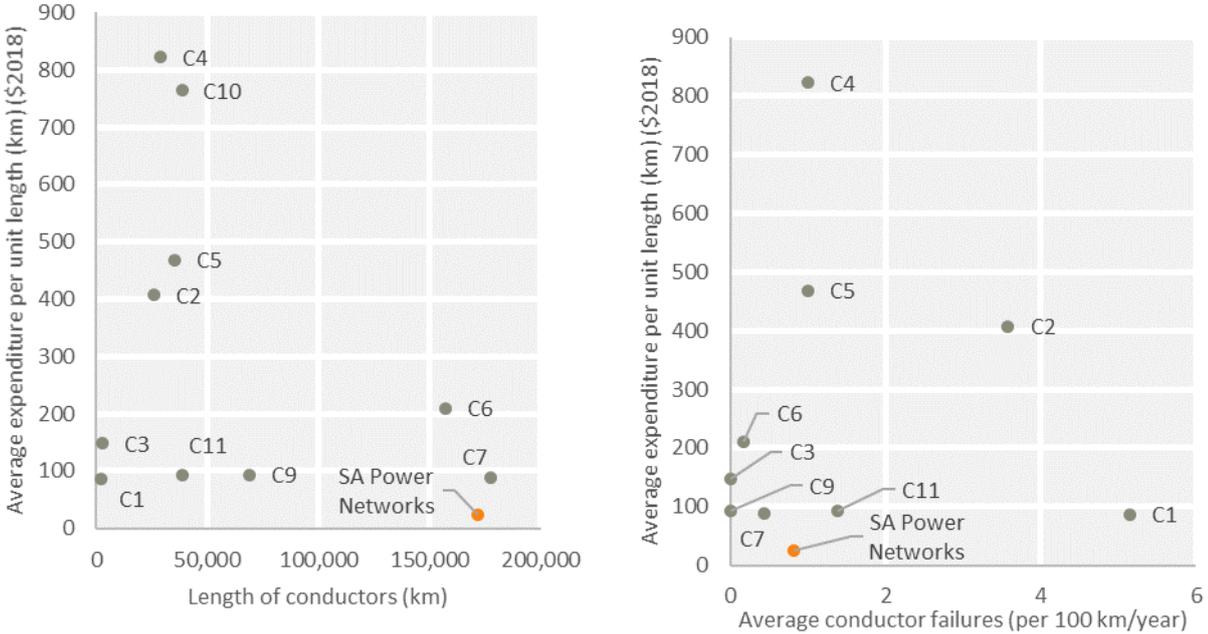
### 7.4.3 Conductors rate of replacement



**Figure 53: Overhead conductor replacement**

Figure 53 shows we have historically undertaken minimal proactive conductor replacements and instead focused on reactive minor works (or patching). Over the 2020-25 RCP, we plan to continue this historical practice while we also focus on improving the conductor asset information that will support our plan to transition to condition-based risk management for this asset class. The proposed repex yields a replacement rate of <0.1% per year. This rate will almost certainly need to be increased in the future.

A comparison of conductor performance in contrast to other NEM DNSPs was undertaken analysing data from publicly available responses to Category RINs reported over the period from 2013/14 to 2016/17 inclusive (outliers excluded). A comparison of average annual repex per unit length and failure rate is shown in Figure 54.



Notes: C8 excluded from both charts as no expenditure information available.  
C10 excluded from failure rate chart as outlier due to very high failure rate relative to other DNSPs.

**Figure 54 Conductor benchmarking of SA Power Networks versus other DNSPs (2013-14 to 2016-17 data)**

Figure 54 shows SA Power Networks currently has the lowest level of average annual repex per conductor length with a mid-range failure rate amongst DNSPs. This demonstrates the efficiency of SA Power Networks' lifecycle management of conductors.

## 7.4.4 Conductors AER repex model inputs

### 7.4.4.1 Conductors AER repex key input information

Table 9 gives details of the key input information for the conductors AER repex model.

**Table 9 : Conductors repex key input information**

Asset	Category	SAPN	Unit Cost (\$k)		Mean Life
			AER's BM	Comparative Unit Cost	SAPN Mean Life
Underground Cables	< = 1 kV	23.2	67.0	23.2	110
	> 1 kV & < = 11 kV	15.4	55.2	15.4	85
	> 11 kV & < = 22 kV ; SWER	7.4	40.0	7.4	81
	> 11 kV & < = 22 kV ; Multiple-Phase		86.4		
	> 22 kV & < = 66 kV	51.2	111.7	51.2	88
	> 66 kV & < = 132 kV		809.8		85

In line with current AER practise (see section 6.2.2), the costs scenario has been selected. This scenario yields a forecast of \$20 million for the 2020-25 RCP.

### 7.4.4.2 Conductors AER repex model calibrations

#### Age Profile

The accuracy of the age profile of our overhead conductors provided in the RIN and used for AER repex modelling has been significantly improved in 2018. Previously, conductor ages were based on the 'feeder age' that were estimated based on the age of the oldest pole on a specific feeder. Results from calibrations based on this age profile and installed asset quantities over the years yielded outputs that were significantly higher than expected.

We have refined the high voltage overhead conductor age based on a mix of the install dates of the transformers, switching cubicles, poles and feeders. The logical sequence we have followed in this refinement is to assign an age starting with the older date of two adjacent poles, feeder average pole age, feeder average transformer age and feeder average switching cubicle date. If this information is not available then feeder start-up date is used. Where none of this information is available, we then evenly distribute them to the remaining population.

**Table 10 : High Voltage Overhead conductors Installation Dates Estimation Summary**

Assumption	Percentage of overhead conductors
Adjacent poles/Feeder ground transformer/switching cubicle/pole average install date/Feeder start-up	98.5%
Overhead conductors with no information available and evenly distributed to the remaining population	1.5%

We have also refined the low voltage overhead conductor age based on a mix of the install dates of the transformers, switching cubicles, poles and feeders. The logical sequence we have followed in this refinement is to assign an age starting with age of supplying transformer date, feeder average transformer age, feeder average pole age and feeder average switching cubicle date. If this information is not available, then feeder start-up date is used. Where none of this information is available, we then evenly distribute them to the remaining population.

The table below shows the percentages of low voltage overhead conductor ages that have been estimated from various assumptions.

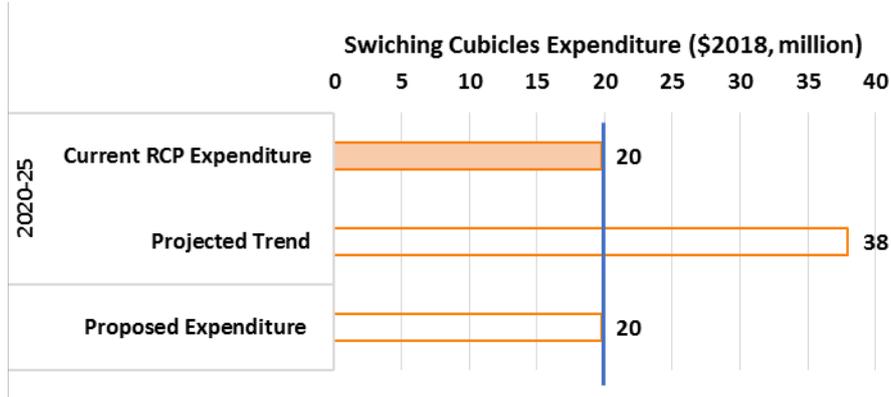
**Table 11 Low Voltage Conductor Assumptions**

Assumption	Percentage of overhead conductors
Supplying transformer/Feeder ground transformer/switching cubicle/pole average install date/Feeder start up	99.7%
Overhead conductors with no information available and evenly distributed to the remaining population	0.3%

## 7.5 Switching cubicles repex forecasts

### 7.5.1 Switching cubicles forecast repex summary

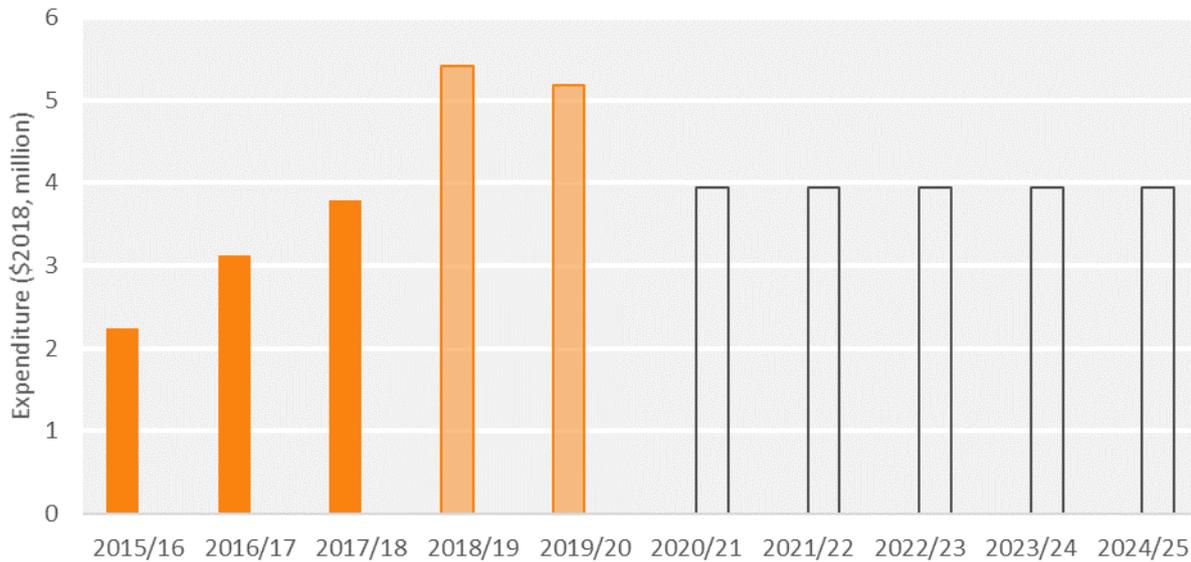
We have utilised two methods to assess the required repex for switching cubicles, being historical expenditure and historical expenditure trends. The modelling outputs have been supplemented with our own SME knowledge to help build the required repex for switching cubicles for the 2020-25 RCP.



**Figure 55 Switching Cubicles Repex Summary**

Figure 55 shows the switching cubicles repex forecast for the 2020-25 RCP is based on the actual repex for the 2015-20 RCP of \$20 million. A CBRM model for switching cubicles is under development with further refinement in data quality required to provide reliable outputs.

### 7.5.2 Switching cubicles forecast repex profile

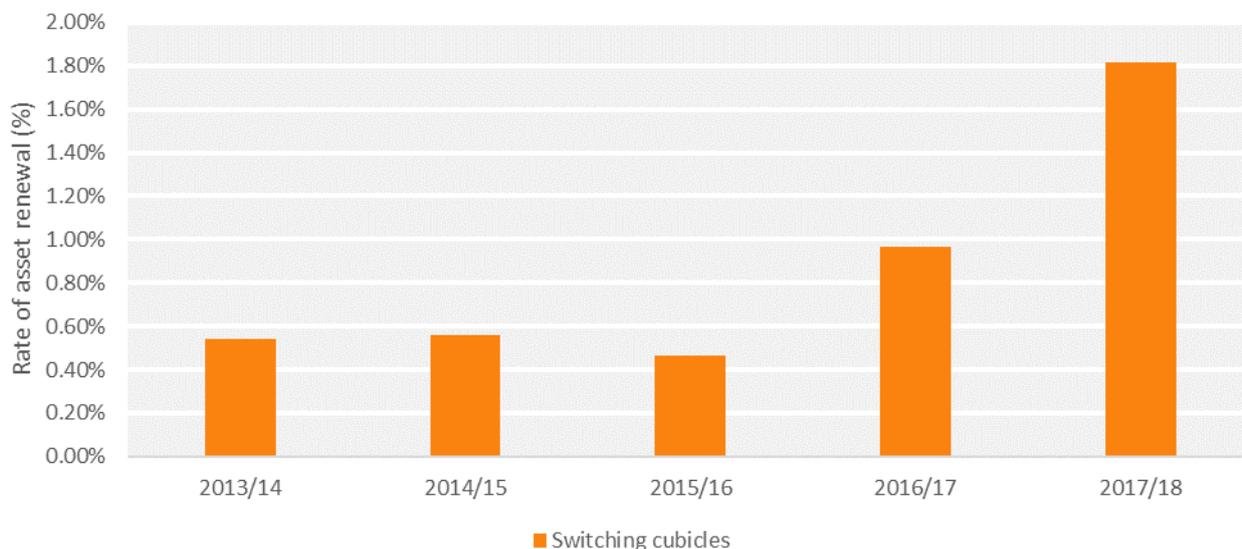


**Figure 56 Switching Cubicles Historical and Proposed repex for the 2015-20 and 2020-25 RCPs**

Figure 56 shows that repex has been increasing due to planned projects to address poor condition switching cubicles. The proposed repex for the 2020-25 RCP per regulatory year is less than the forecast repex over the next two regulatory years as it is based on the previous 5-year average and the knowledge that the backlog of poor condition switching cubicles will be reduced over the 2020-25 RCP.

### 7.5.3 Switching cubicles rate of renewal

Figure 57 shows the historical rate of renewal for switching cubicles.



**Figure 57 Switching cubicles rate of renewal**

Figure 57 shows we have historically undertaken very minimal switching cubicle replacements with an increase having occurred across 2016 to 18 in contrast to earlier years due to a large proportion of out of service units across the network that cannot be operated safely while energised. Over the 2020-25 RCP we plan to continue the average rate of replacement being undertaken in the 2015-20 RCP while we also focus on improving the switching cubicle asset information that will support our plan to transition to condition-based risk management for this asset class. The proposed repex yields an average replacement rate of 1.3% per year. This rate will need to be increased in the future as the switching cubicle asset class continues to age and deteriorate and the number of identified out of service units increases.

## 7.6 Distribution transformers repex forecast

### 7.6.1 Distribution transformer forecast repex summary

We have utilised three methods to assess the required repex for distribution transformers, being AER’s repex model, historical expenditure and historical expenditure trend. The modelling outputs have been supplemented with our own SME knowledge to help build the required repex for the 2020-25 RCP.

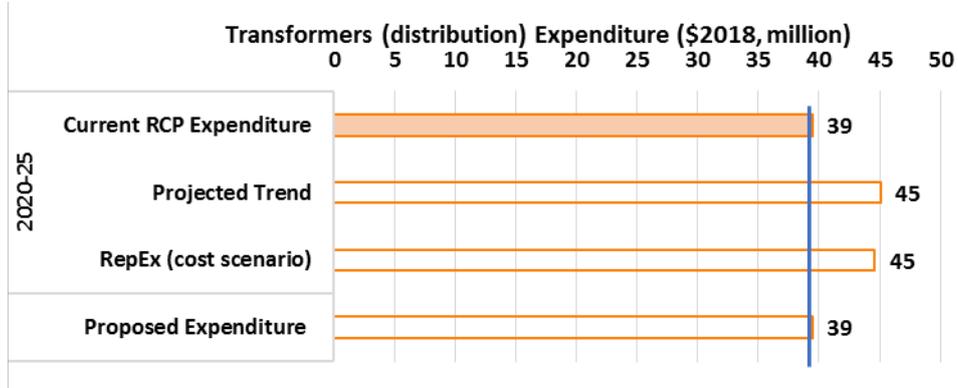


Figure 58 Distribution Transformer Repex Summary

Although our overall network strategy has been transitioning to a condition-based risk management approach for repex forecasts for the 2020-25 RCP, the CBRM model requires asset condition data. We currently have limited asset data information for distribution transformers (unlike substation power transformers which undergo Dissolved Gas Analysis). In the absence of a CBRM model, the repex forecast for the 2020-25 RCP is based on the actual repex for the 2015-20 RCP of \$39 million.

### 7.6.2 Distribution transformers forecast repex profile

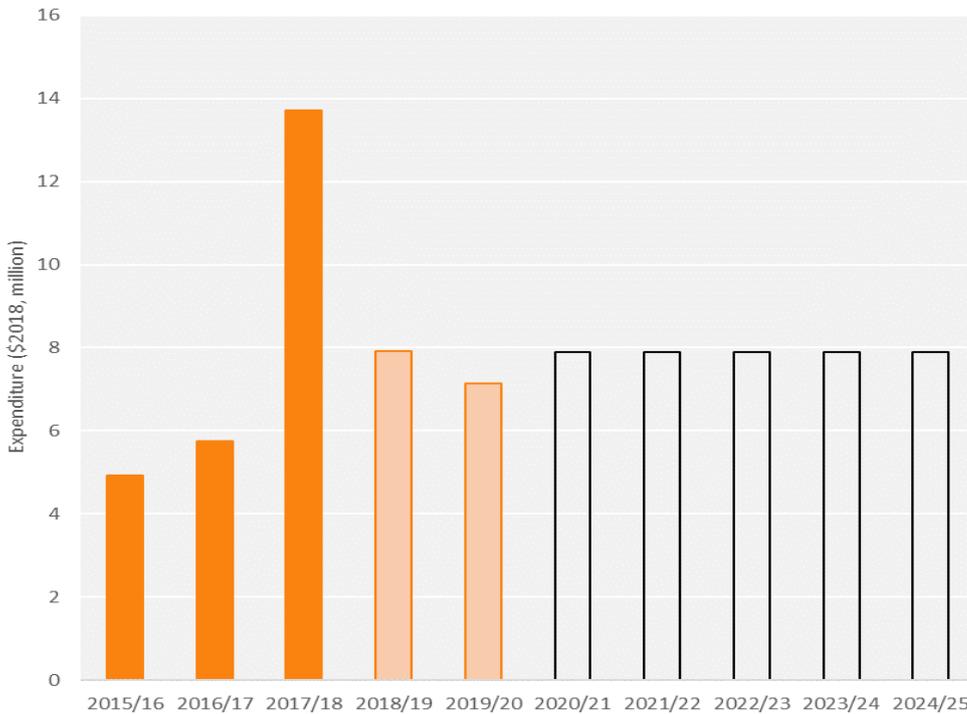
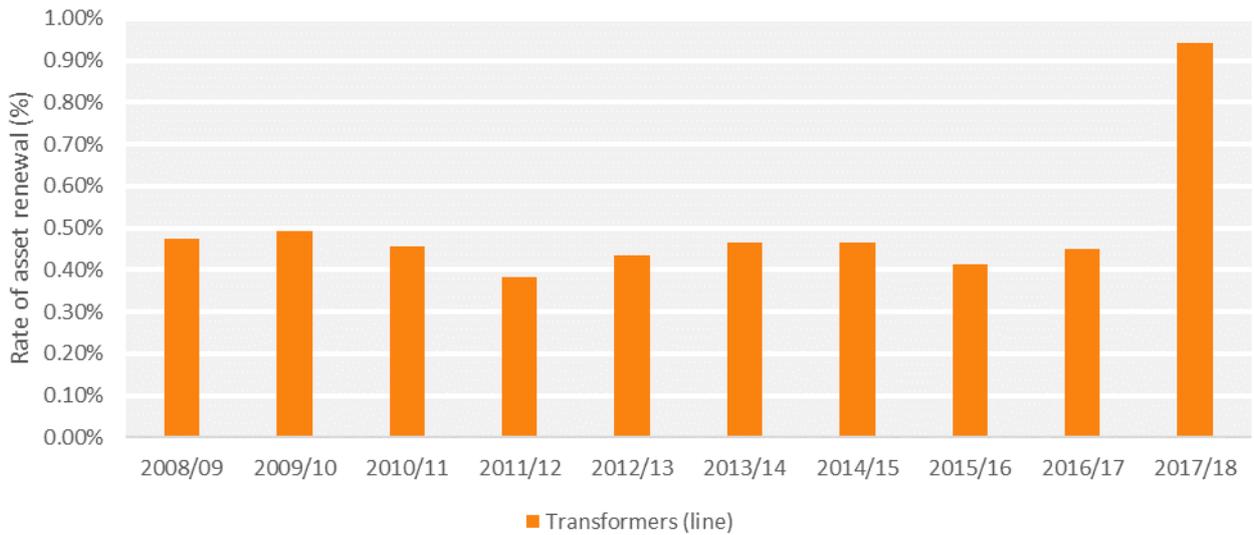


Figure 59 Distribution Transformer Historical and Proposed Repex

Figure 59 shows that repex has increased over the 2017/18 regulatory year due to a conscious effort to reduce the backlog of poor condition transformers and to address the associated risk which had grown in recent years. The proposed repex per regulatory year is less than the repex incurred in the 2017/18 regulatory year as improvements in our value-based approach will ensure a smoother year by year spend.

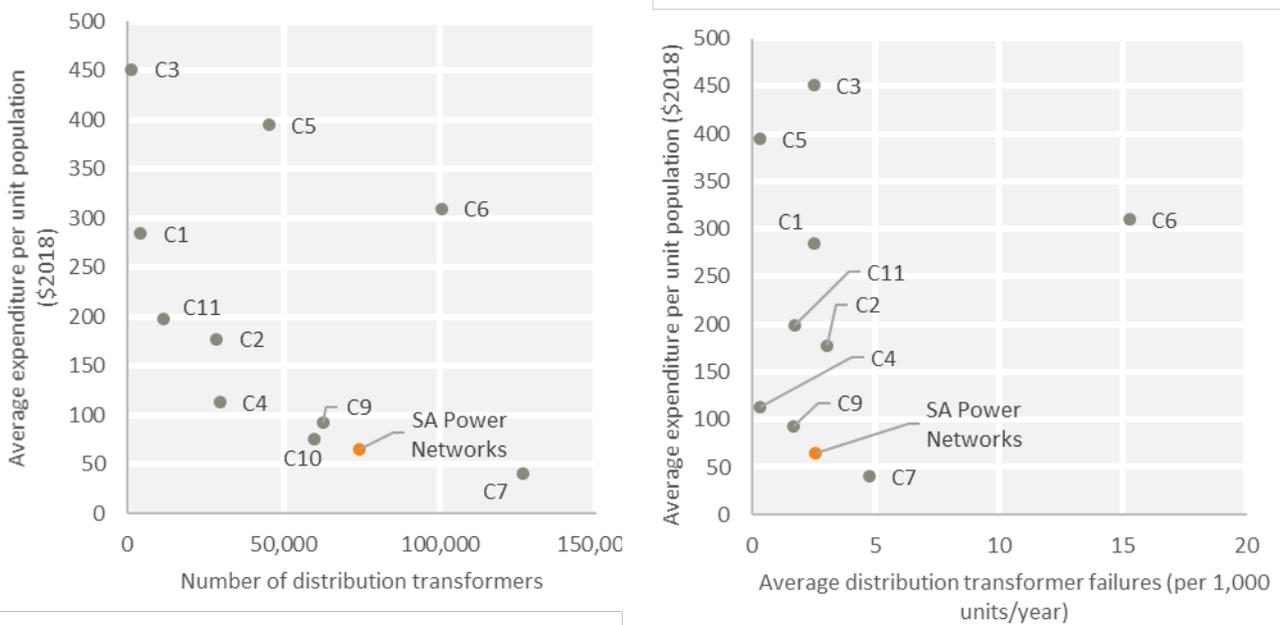
### 7.6.3 Distribution transformers rate of renewal



**Figure 60 Distribution Transformers Rate of Renewal**

Apart from 2017/18 regulatory year, the historical rate of renewal has been < 0.5%. The proposed repex yields a renewal rate of 0.6 % per regulatory year. If this low rate were maintained into the future some transformers would be required to last 166 years. It is expected the renewal rate will need to increase in future.

A comparison of distribution transformer performance in contrast to other NEM DNSPs was undertaken analysing data from publicly available responses to Category RINs reported over the period 2013/14 to 2016/17 inclusive (outliers excluded). A comparison of average annual repex per unit population and failure rate is shown in Figure 61.



Notes: C8 excluded from both charts as no expenditure information available.  
 C10 excluded from failure rate chart as outlier due to very high failure rate relative to other DNSPs.

**Figure 61 Distribution transformer benchmarking of SA Power Networks as compared to other DNSPs (2013/14 to 2016/17 data)**

Figure 61 shows SA Power Networks currently has the lowest level of average annual repex per distribution transformer even with a failure rate comparable with the majority of other DNSPs. Typically, SA Power

Networks replaces distribution transformers when they no longer function or in response to significant defects. Refurbished like for like transformers replace failed ground mounted units when replacing with a standard padmount is expensive and a spare is available. Replaced ground mounts are refurbished spares for this purpose. This demonstrates the efficiency of SA Power Networks' lifecycle management of distribution transformers.

### 7.6.4 Distribution transformer AER repex model inputs

Table 12 gives details of the key input information for the distribution transformers AER repex model.

**Table 12 : Distribution Transformers AER repex Key Input Information**

Asset	Category	Unit Cost (\$k)		SAPN Mean Life
		SAPN	AER's BM	
Distribution Transformers	pole mounted ; < = 22 kv ; < = 60 kva ; single phase	14.6	10.4	63
	pole mounted ; < = 22 kv ; > 60 kVA and < = 600 kVA ; Single Phase	19.1	21.7	72
	pole mounted ; < = 22 kv ; > 600 kVA ; Single Phase			103
	pole mounted ; < = 22 kv ; < = 60 kVA ; Multiple Phase	15.3	10.9	56
	pole mounted ; < = 22 kv ; > 60 kVA and < = 600 kVA ; Multiple Phase	15.6	18.0	53
	pole mounted ; < = 22 kv ; > 600 kVA ; Multiple Phase	14.2	14.4	60
	kiosk mounted ; < = 22 kv ; < = 60 kVA ; Single Phase	10.7	8.8	71
	kiosk mounted ; < = 22 kv ; > 60 kVA and < = 600 kVA ; Single Phase	38.5	38.6	73
	kiosk mounted ; < = 22 kv ; < = 60 kVA ; Multiple Phase	43.8	29.0	57
	kiosk mounted ; < = 22 kv ; > 60 kVA and < = 600 kVA ; Multiple Phase	22.7	50.6	54
	kiosk mounted ; < = 22 kv ; > 600 kVA ; Multiple Phase	49.3	54.4	55

## 7.7 Reclosers and sectionalisers repex forecasts

### 7.7.1 Reclosers and sectionalisers forecast repex summary

We have utilised two methods to assess the required repex for reclosers and sectionalisers, being historical expenditure and historical expenditure trends. The modelling outputs have been supplemented with our own SME knowledge to help build the required repex for the 2020-25 RCP.

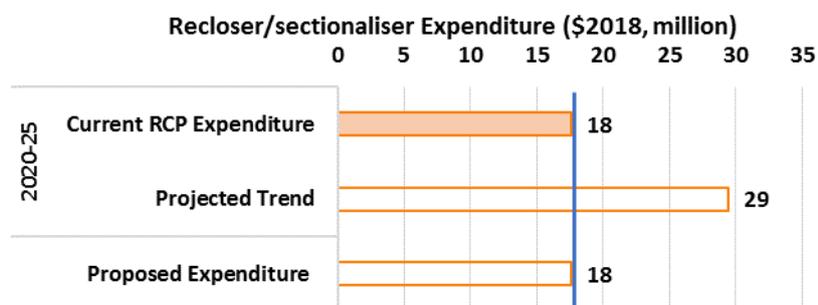


Figure 62 Recloser/Sectionalisher repex Summary

Although our overall network strategy has been transitioning to a condition-based risk management approach, for forecast repex for the 2020-25 RCP we prioritised CBRM application to the critical network assets. Figure 62 shows the proposed repex is based on actual repex in the 2015-20 RCP.

### 7.7.2 Reclosers and sectionalisers forecast repex profile

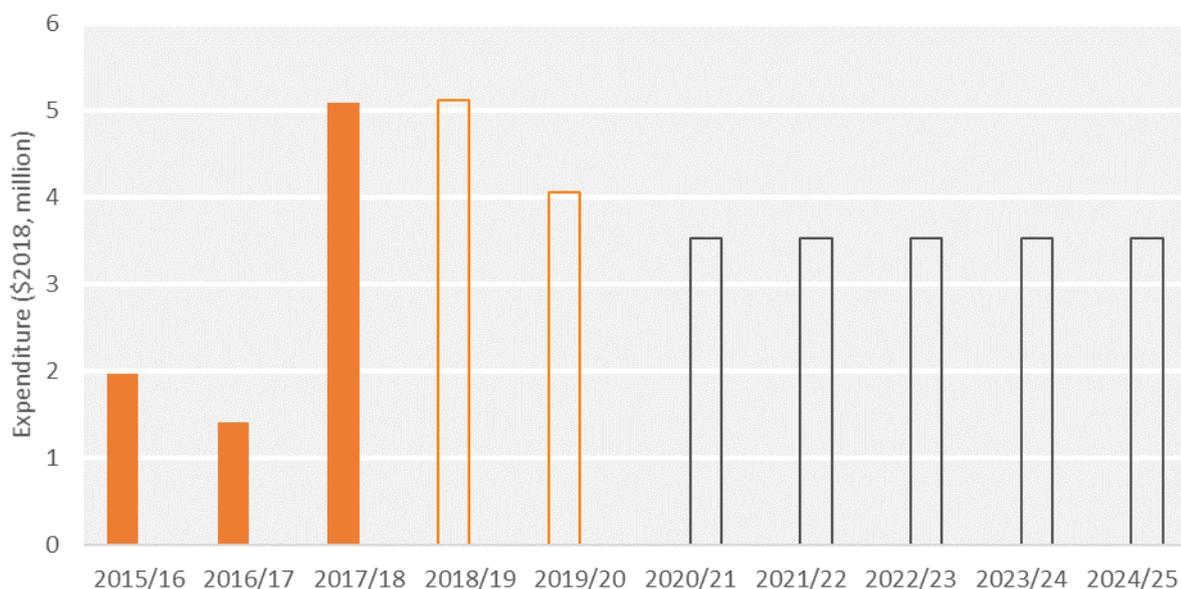


Figure 63 Recloser/Sectionalisher Historical and Proposed repex for the 2015-20 and 2020-25 RCPs

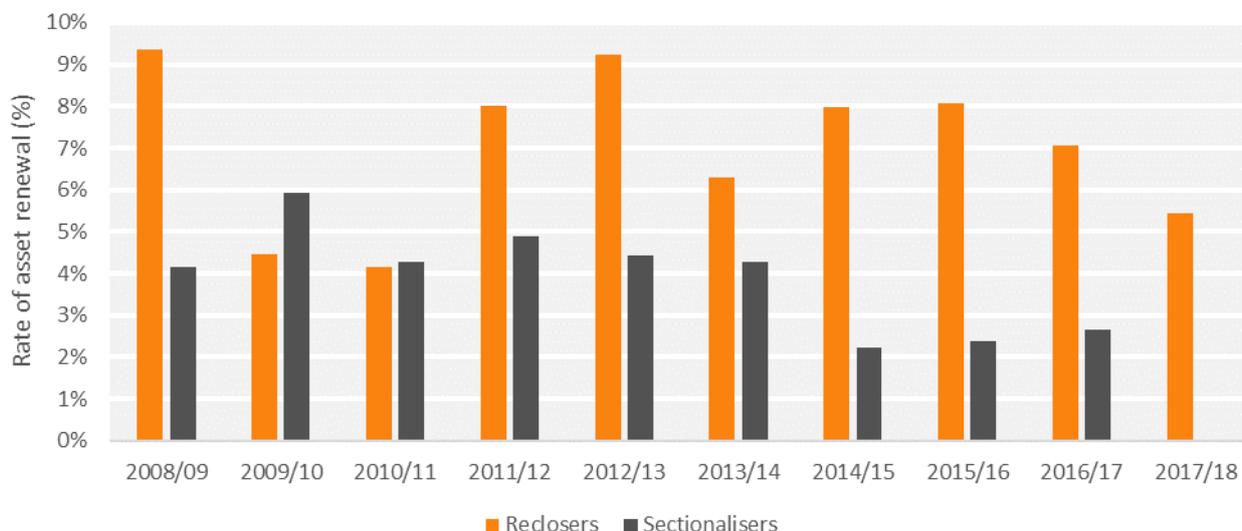
Figure 63 shows that repex has increased over the 2017/18 regulatory year. The volumes of reclosers refurbishment has increased in recent regulatory years as refurbishment is much cheaper than replacement. The proposed repex per regulatory year is less than the actual repex incurred in the 2017/18 regulatory year due to a reduction in backlog of poor condition assets.

#### Analysis of Historical Replacements

During the 2015-20 RCP, we have focussed on replacing old hydraulic reclosers that have reached the end of their life. These old hydraulic reclosers are no longer being manufactured, have no spares support and pose increased risks to our network in both reliability and safety. The historic expenditure excludes replacements undertaken as part of bushfire mitigation or reliability programs.

### 7.7.3 Reclosers and sectionalisers rate of renewal

Figure 64 shows the historical rate of renewal for reclosers and sectionalisers.



**Figure 64 Recloser and sectionaliser rate of renewal**

Figure 64 was calculated by considering the recloser and its associated controller as one device. In the past it was common for only the recloser or its controller to be replaced. In future the controllers will be considered as a recloser unit increasing the population by 60%.

Figure 64 shows we have had a relatively stable rate of recloser renewal particularly since the 2011/12 regulatory year in which we undertook a significant number of recloser refurbishments to extend the life of recloser assets. Historically refurbishment has been cheaper than replacement. In future the renewal rate will be < 8% for reclosers.

The recloser renewal program is made up of planned and unplanned repex. The planned repex of \$7.7 million consists of E type refurbishments and OYT type replacements (with electronic units) as the OYTs have reached their end of expected life. The unplanned repex of \$6.1 million is the average unplanned repex over the last 5 years. The sectionaliser repex comprises the renewal of sectionalisers that have failed or are predicted to fail of \$4.5 million.

## 7.8 Service lines repex forecasts

### 7.8.1 Service lines forecast repex summary

We have utilised three methods to assess the required repex for service lines, being the AER's repex model, historical expenditure and historical expenditure trends. The modelling outputs have been supplemented with our own SME knowledge to help build the required repex for the 2020-25 RCP.

Figure 65 shows the forecast comparison for service lines.

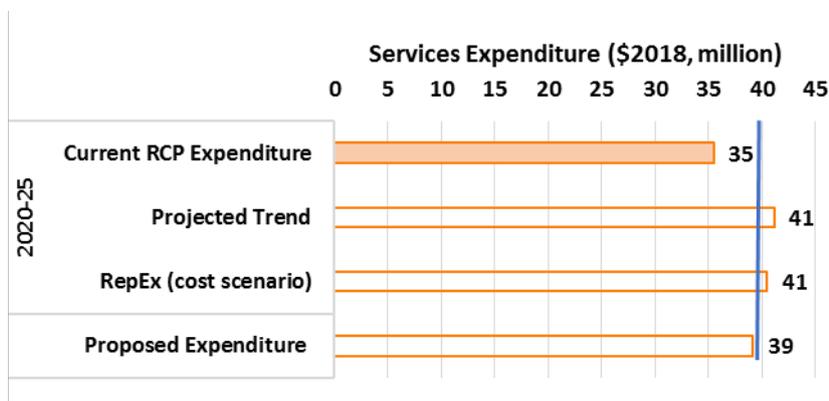


Figure 65: Service Line repex Summary

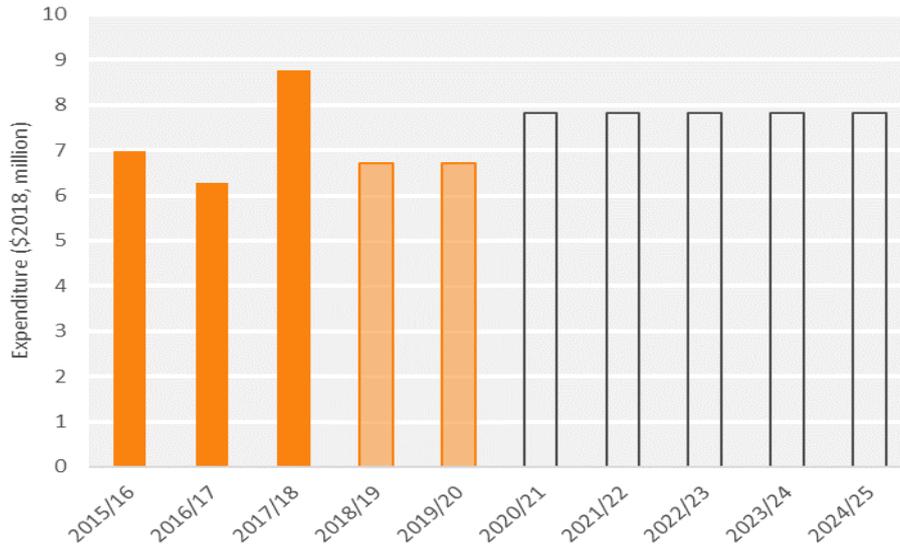
Figure 65 shows our proposed repex is based on a build-up of the actual repex for the 2015-20 RCP of \$35 million with an additional \$3.7 million for targeted replacements. These targeted replacements are for a planned phase out of aluminium neutral screen service lines which we believe is the population of service lines contributing to the increasing trend in network related low voltage shocks to customers.

There are currently an estimated 210,000 aluminium neutral screens services installed across the network. While some of these aluminium neutral screens services will be phased out through asset failures and customer driven service line alterations/modifications through business as usual activities, a proactive replacement program is proposed to reduce the known safety risk associated with these services. A bottom up forecast has been developed of \$3.7 million per RCP for the next six RCPs to address this risk with priority to be given to the areas where shock reports have been more concentrated.

Accordingly, the service line repex forecast for the 2020-25 RCP is \$39 million.

The historical and forecast repex profile for service line repex is shown in Figure 66.

Figure 66 shows the actual repex for the 2015-20 RCP and the forecast repex for the 2020-25 RCP.

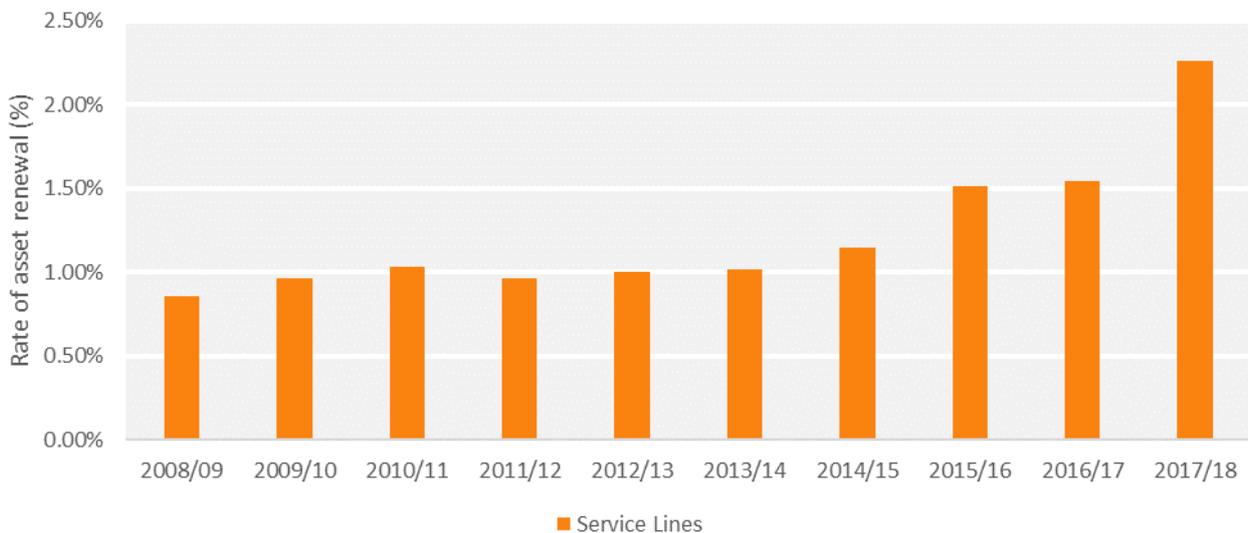


**Figure 66 Service Line Historical and Proposed repex for the 2015-20 and 2020-25 RCPs**

Figure 66 shows a spike in expenditure during 2017/18 as a result of low cost/high risk defects identified and being prioritised through our value-based approach with forecast repex lower out to the 2019/20 regulatory year and then increasing to an annual repex moderately higher than the annual average of the 2015-20 RCP for service lines.

### 7.8.2 Service lines rate of renewal

Figure 67 shows the rate at which service lines (or replacement of components of individual service lines) are being renewed through our repex program.

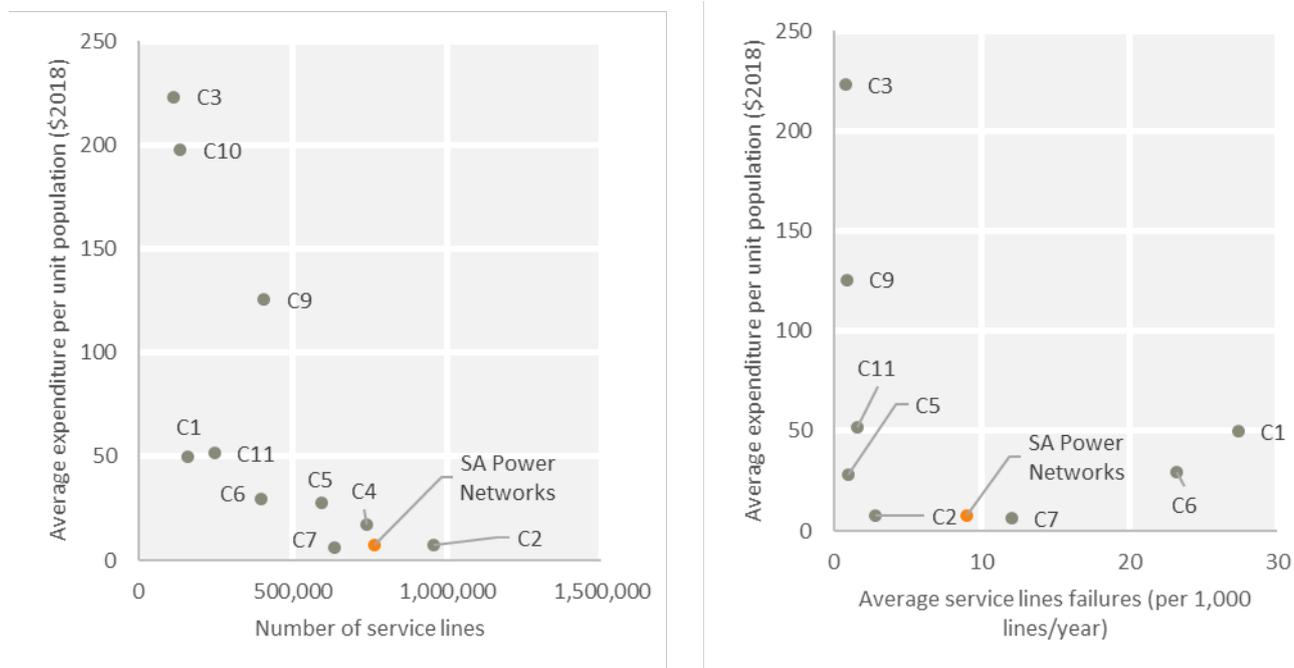


**Figure 67 Service Line Rate of Renewal**

Figure 67 shows the rate of service line renewals (or replacement of components of individual service lines) has doubled from 2013/14 to 2017/18 mainly driven through replacements arising from defect identification and with the relatively low unit cost and high safety risk. The return on investment tends to be high and therefore such works are given a high priority for work selection and replacement. The trend of replacements is reflective of the increase in expenditure from 2016/17 to 2017/18.

A comparison of service line performance in contrast to other DNSPs was undertaken analysing data from publicly available responses to Category RINs reported over the period 2013/14 to 2016/17 inclusive (outliers

excluded). A comparison of our average annual repex per unit population and failure rate is shown in Figure 68.



Notes: C8 excluded from both charts as no expenditure information available.  
 C4 excluded from failure rate chart as no failure information available.  
 C10 excluded from failure rate chart as outlier due to very high failure rate relative to other DNSPs.

**Figure 68: Service line benchmarking of SA Power Networks as compared to other DNSPs (2013/14 to 2016/17 data)**

Figure 68 shows SA Power Networks currently has one of the lowest level of average annual repex per service line (even with a mid-range reported failure rates) amongst NEM DNSPs. This is largely due to the fix on failure approach adopted by SA Power Networks. This demonstrates the efficiency of SA Power Networks lifecycle management of service lines.

### 7.8.3 Service lines AER repex model inputs

Table 13 gives details of the key input information for the service lines AER repex model.

**Table 13 : Service Lines AER repex Key Input Information**

Asset	Category	SAPN	Unit Cost (\$k)		Mean Life
			AER's BM	Comparative Unit Cost	SAPN Mean Life
Service lines	< = 11 kV ; Residential ; Simple Type	0.5	0.8	0.5	54
	< = 11 kV ; Commercial and Industrial ; Simple Type	0.6	1.0	0.6	51

In line with current AER practise (see section 6.2.2), the costs scenario has been selected. This scenario yields a forecast of \$41 million for the 2020-25 RCP.

## 7.9 Substation power transformer repex forecast

### 7.9.1 Substation power transformer repex summary

Four approaches have been considered to forecast the repex requirements for substation power transformers to 2030, being CBRM modelling, AER repex modelling, historical expenditure and historical expenditure trends.



Figure 69 Substation Transformer repex Summary

Our preferred forecast method for the repex on the substation power transformer is the risk-based CBRM approach. Considering our level of confidence with the substation power transformer condition data and CBRM model, we consider the CBRM maintain risk output of forecast repex of \$25 million to be appropriate.

### 7.9.2 Substation power transformers forecast repex profile

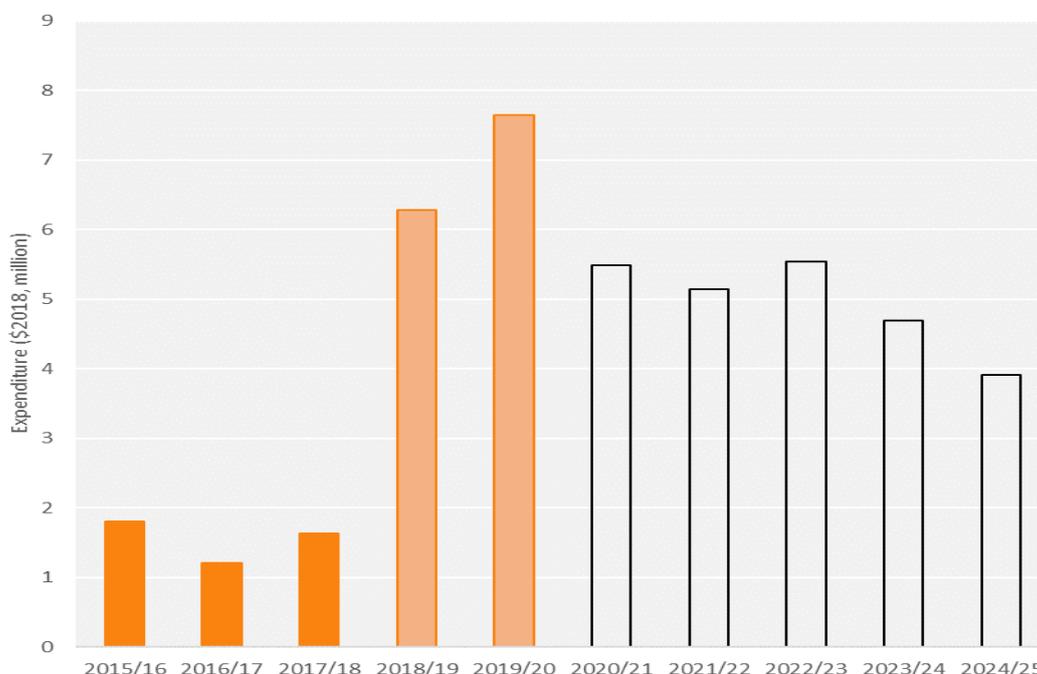
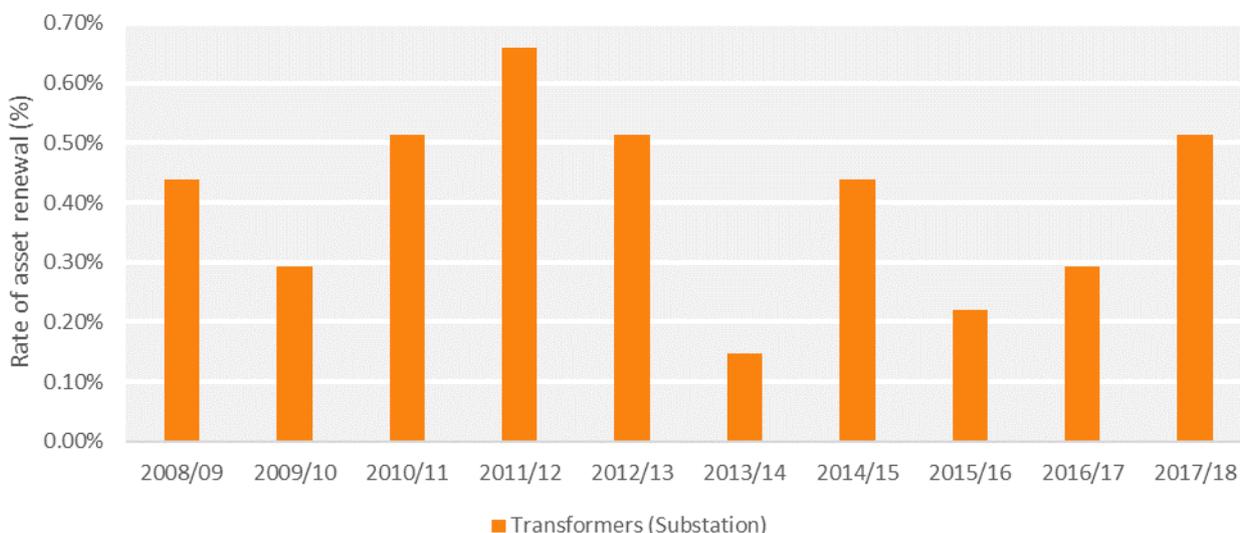


Figure 70 Substation Power Transformer Historical and Proposed repex for the 2015-20 and 2020-25 RCPs

The repex forecast for the 2020-25 RCP incorporates replacement modelling supplemented with targeted programs to address specific asset risks. Assets managed by these targeted programs are treated separately (as outliers to the general population or non-modelled asset types) to address risks related to specific design flaws or performance issues beyond age related degradation that would otherwise make them prone to early

failure. Targeted intervention programs are managed through refurbishment or (sometimes) replacement and based on engineering analysis.

### 7.9.3 Substation power transformers rate of renewal

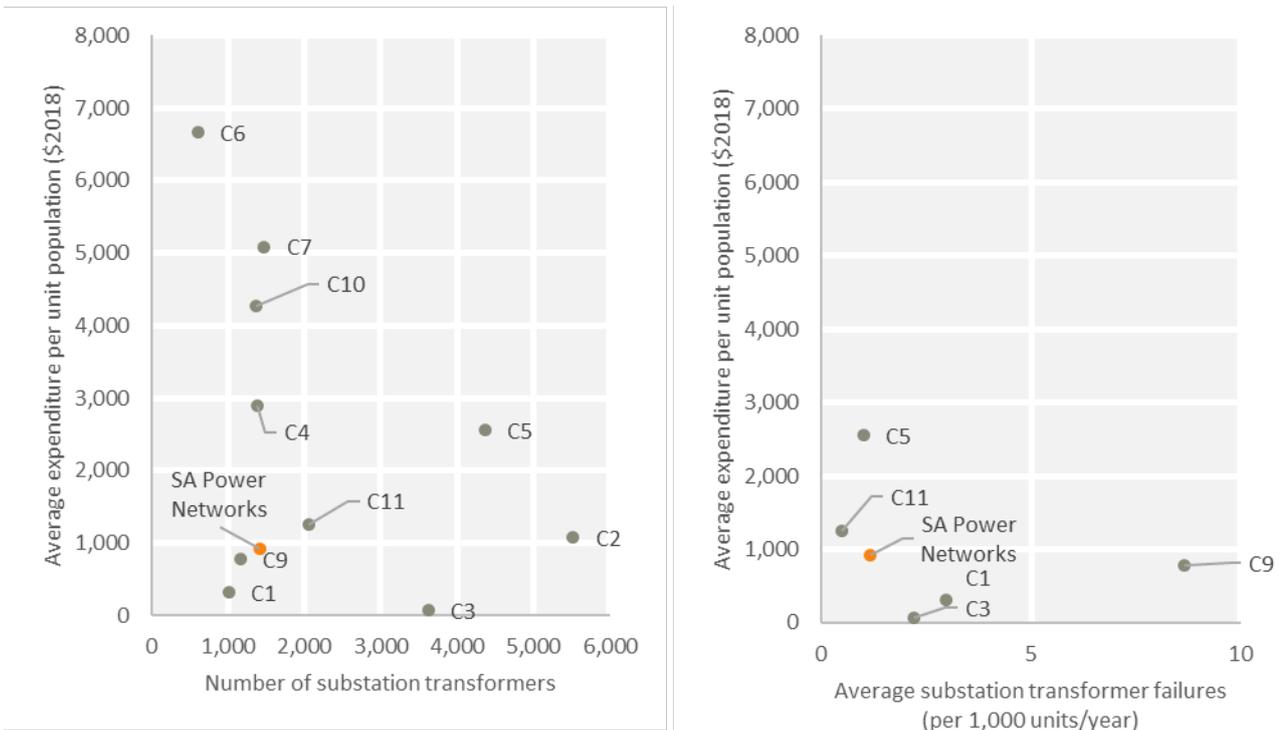


**Figure 71 Substation Transformers Rate of Renewal**

Figure 71 shows historically the rate of renewal is < 0.7% of the population. With the proposed repex, the rate of renewal will continue to be < 0.7%.

A comparison<sup>26</sup> of ground outdoor / indoor chamber mounted transformers of all types (includes both substation and distribution substation transformers) in contrast to other NEM DNSPs was undertaken analysing data from publicly available responses to Category RINs reported over the period 2013/14 to 2016/17 inclusive (outliers excluded). The comparison of average annual repex per unit population and failure rate is shown in Figure 70.

<sup>26</sup> The AER RIN reporting does not separately categorise ground outdoor / indoor chamber mounted transformers between substations and HV distribution networks for certain transformer capacity and voltages; this would be applicable to all DNSPs.



Notes: C8 excluded from both charts as no expenditure information available.  
 C4 excluded from failure rate chart as no failure information available.  
 C6, C7, C10 excluded from failure rate chart as outliers due to very high failure rate relative to other DNSPs.

**Figure 72 Substation power transformer benchmarking of SA Power Networks as compared to other DNSPs (2013/14 to 2016/17 data)**

Figure 72 shows SA Power Networks currently has one of the lowest level of average annual repex for the ground outdoor/indoor chamber mounted transformers even with a mid-range reported failure rates amongst DNSPs. This is largely due to the asset management practices and targeted refurbishment programs to extend the expected life of these major assets where possible. While the data used for this asset class comparison is highly variable across the DNSPs it generally demonstrates SA Power Networks lifecycle management of substation power transformers is efficient.

### 7.9.4 Substation power transformer CBRM model overview

CBRM modelling of substation power transformers incorporates information on both current condition and the observed performance of the transformer fleet over the last 10 years to calculate current risks and deterioration rates for individual assets. Future risk is forecast at a point in the future for each asset to determine relative changes in risk across the asset fleet and to show the effects of different intervention strategies on future risk and asset performance.

#### 7.9.4.1 Substation power transformers CBRM model calibration

The Power Transformer CBRM model has been reconstructed using the RIVA platform provided by Powerplan, allowing integration of the CBRM model with other key SAPN asset information systems including SAP, GIS, SAP works manager and other corporate systems in order to provide up to date information of new and decommissioned assets and updated condition data as becomes available.

The transformer CBRM inputs are tabled in Section 8.3 in the appendix.

The transformer CBRM model in the RIVA platform is substantially the same model as was initially developed with EA Technology in 2011 and used to support our 2015-20 RCP repex proposal. Key changes made in the transition to the current modelling platform include:

- Updated asset, condition and performance to reflect current (10 year historical) data.
- Updated equipment specific engineering reliability and obsolescence modifiers to reflect current understanding of equipment make/type performance issues.
- Alignment of standard model calibrations (eg equipment condition modifiers, POF curve parameters) with Version 1.1. of the Ofgem DNO Common Network Asset Indices Methodology (**CNAIM**).

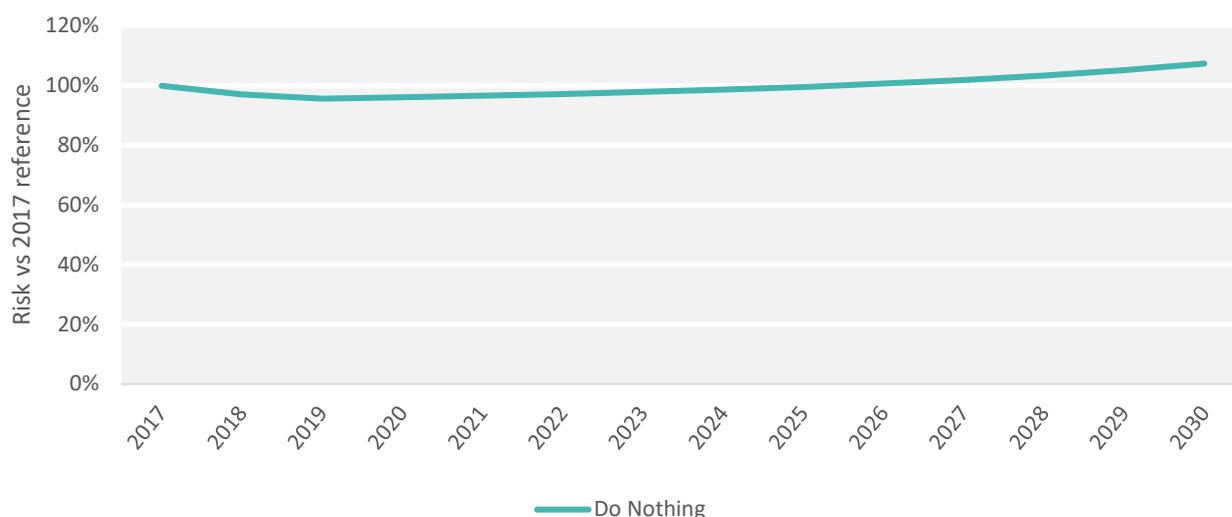
#### 7.9.4.2 Substation transformers renewal strategy modelling

Two strategies were modelled for circuit breakers using the CBRM methodology in order to forecast the future repex requirements. These were:

- **replace on condition:** this strategy plans asset for replacement as they reach a Health Index of 7.27; and
- **maintain risk:** this approach considers the relative changes in risk over the planning period (current condition, observed performance, rate of deterioration and relative consequence of failure for each asset) and relative replacement costs to construct a program that efficiently maintains the long term operational performance of the asset population.

Each of these strategies consider the effect of other asset renewal works (including load-driven and strategic asset renewal works) and the delivery of targeted asset refurbishment and replacement plans to 2030.

To provide a comparative baseline for modelling renewal strategies a 'Do Nothing' investment scenario was initially modelled in CBRM to illustrate the risk/performance impacts of performing no proactive intervention from 2020 (only intervening to fix equipment as failures occur). Figure 73 shows the forecast risk profiles for the Substation Power Transformer model under the 'Do Nothing' investment scenario.



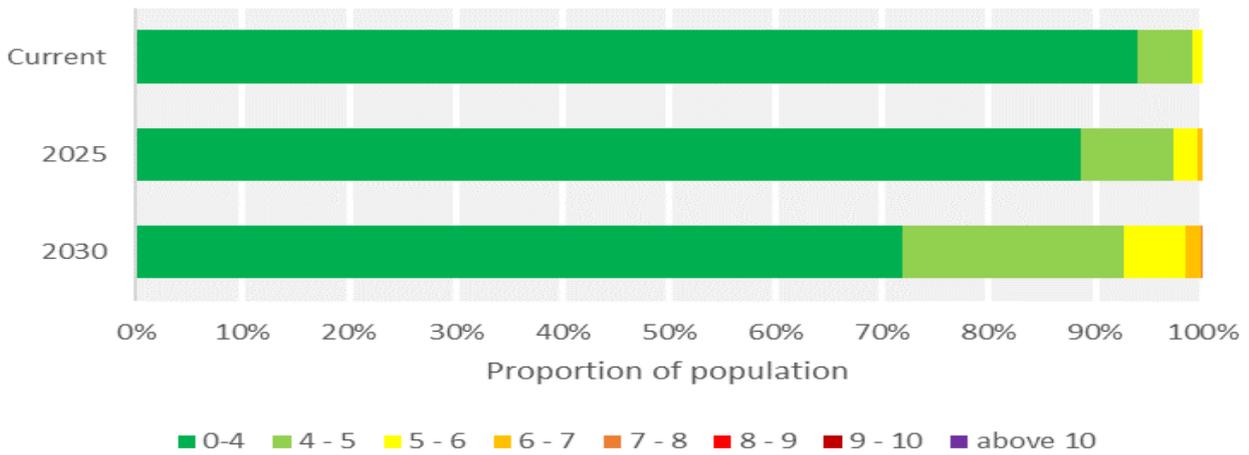
**Figure 73: Substation Power Transformers Do Nothing (Baseline) - Risk Forecast**

For the Substation Power Transformer model, completion of planned investment during the second half of the 2015-20 RCP is forecast to see an increase in 2014-15 risk levels by approximately 4% by 2020. From 2020 onwards, risk levels are forecast to increase further without investment as current assets age and deteriorate in service.

For Substation Power Transformers, equipment risk is forecast to increase by approximately 108% from 2015 levels by 2025 and to 115% by 2030 without investment as large populations of aged 'Medium' and 'Small' transformers continue to age and deteriorate in service.

Figure 74 shows the current and forecast health distribution of the substation power transformer population with no intervention over the next two RCPs. Over time, the proportion of assets with significant deterioration will grow over the next two RCPs.

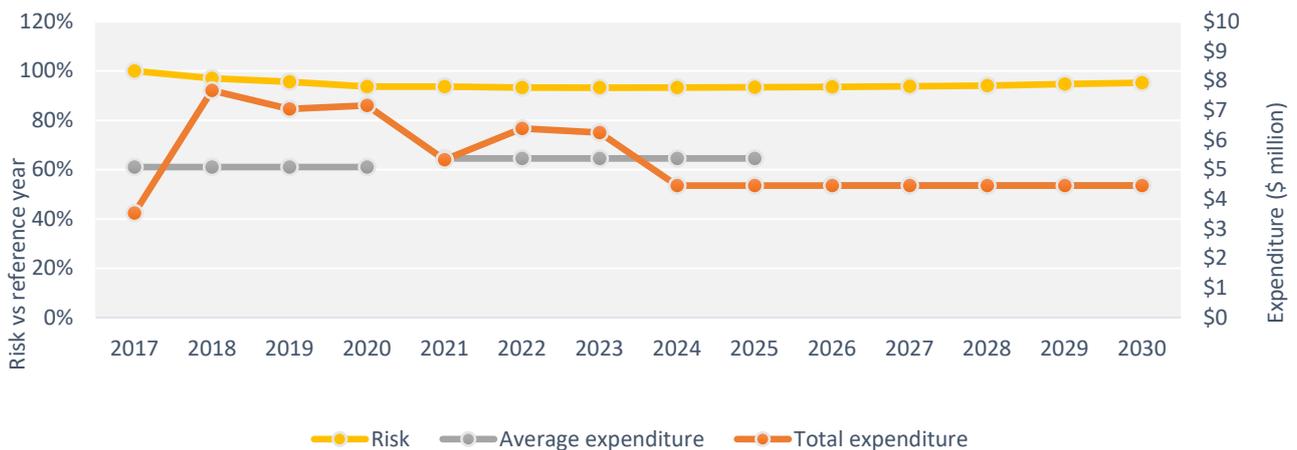
<sup>27</sup> An equipment HI of 7 is the point at which assets are considered to have a high and significantly increasing POF (end of reliable service life) and should be planned for replacement.



**Figure 74: Substation Power Transformers Do Nothing Baseline- Health Index Forecast**

### Maintain Current Risk Levels Renewal Strategy

Figure 75 shows the forecast risk and repex to maintain current levels of risk for substation power transformers.

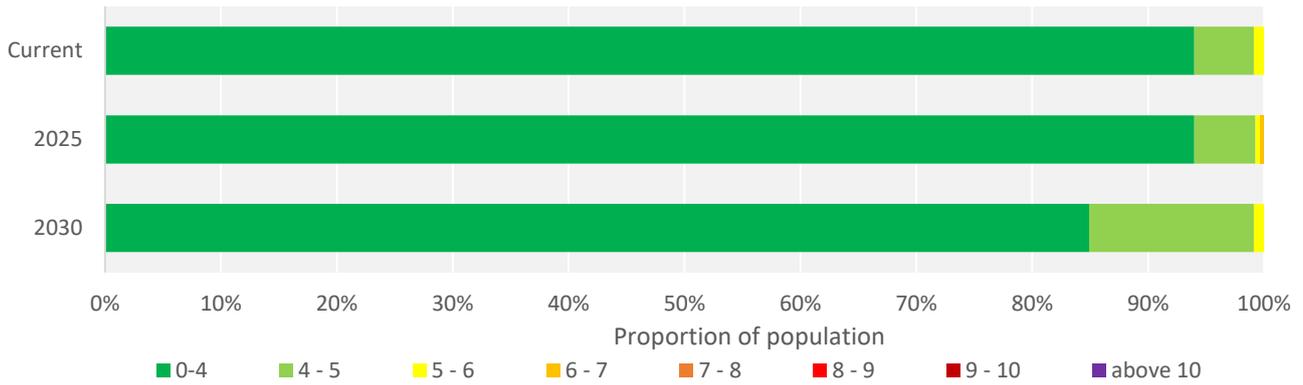


**Figure 75: Substation Power Transformers Maintaining Risk - Risk & Repex Forecast**

The strategy represented by Figure 75 accounts for the cumulative effects of other planned investment programs such as substation upgrades, unplanned (on failure) asset replacement, other transformer replacement plans, the completion of planned works in 2018/19 and targeted refurbishment / replacement programs to 2030. The completion of all proposed investment programs over the planning period is forecast to maintain (2015) levels of safety, reliability and network performance across the asset class to 2030.

Figure 75 shows that the effect of this renewal strategy is as annual average repex of \$5.4 million over the 2020-25 RCP and \$4.5 million over the 2025-30 RCP. To address the increased risk remaining at the end of the 2015-20 RCP, additional expenditure over the 2020-25 RCP will target areas of identified risk through existing programs of renewal for Tyree design Spec E465 transformers, 66kV SRBP bushings and 11kV compound filled cable boxes.

Figure 76 shows that the HI profile for the population would degrade over the 2020-25 RCP by selectively deferring renewal of less critical assets.



**Figure 76: Transformers Maintaining Risk - Health Index Forecast**

In addition to CBRM modelling, the total repex forecast for the 2020-25 RCP incorporates targeted refurbishment/replacement programs to address asset specific risks (as outliers to the general population) that would otherwise make them prone to early failure. The effects of completing these programs have been assumed within CBRM modelling outputs and the total repex required is \$28.2 million in the 2020-25 RCP and \$22.3 million in the 2025-30 RCP.

## 7.9.5 Substation power transformers AER repex model inputs

### 7.9.5.1 Substation Transformers AER repex Key Input Information

Table 14 gives details of the key input information for the substation power transformers AER repex model.

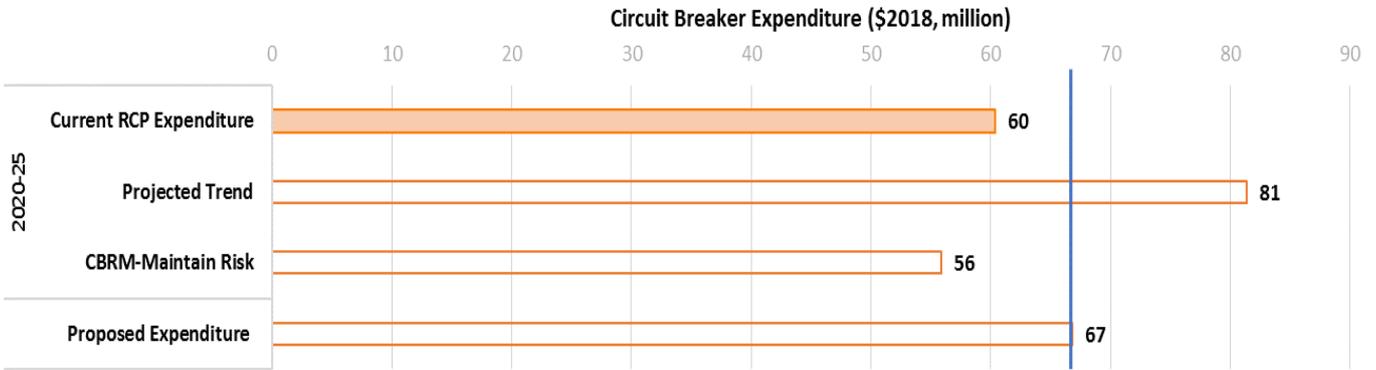
**Table 14 : Substation Power Transformers AER repex Key Input Information**

Asset	Category	SAPN	Unit Cost (\$k)		Mean Life
			AER's BM	Comparative Unit Cost	SAPN Mean Life
Substation Transformers	ground outdoor / indoor chamber mounted ; < 22 kv ; > 60 kva and < = 600 kva ; multiple phase	15.8	102.4	15.8	63
	ground outdoor / indoor chamber mounted ; < 22 kv ; > 600 kva ; multiple phase	27.9	79.5	27.9	96
	ground outdoor / indoor chamber mounted ; > = 22 kv & < = 33 kv ; < = 15 mva	210.6	1987.4	210.6	64
	ground outdoor / indoor chamber mounted ; > 33 kv & < = 66 kv ; < = 15 mva	515.9	871.5	515.9	74
	ground outdoor / indoor chamber mounted ; > 33 kv & < = 66 kv ; > 15 mva and < = 40 mva	714.8	1266.5	714.8	64
	ground outdoor / indoor chamber mounted ; > 66 kv & < = 132 kv ; < = 100 mva		2986.7		
	ground outdoor / indoor chamber mounted ; > 132 kv ; < = 100 mva				

## 7.10 Substation circuit breakers repex forecast

### 7.10.1 Substation circuit breakers forecast repex summary

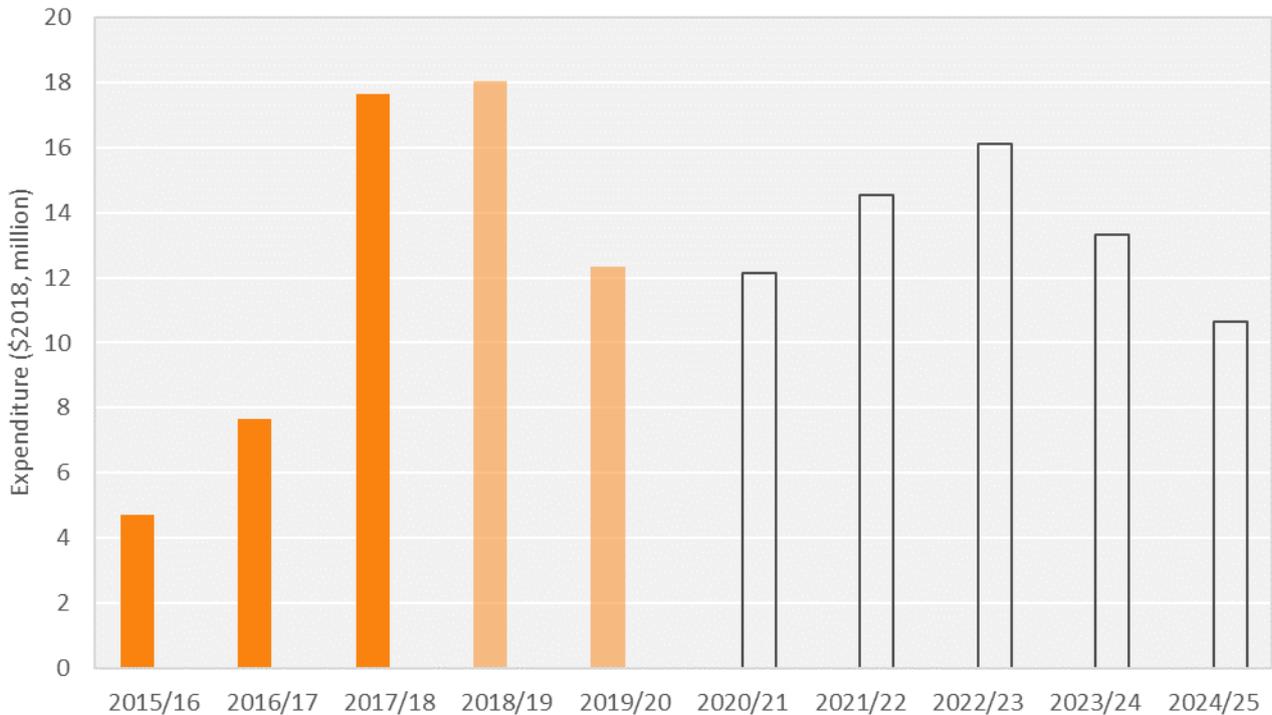
Three approaches have been considered to forecast the repex requirements for Substation Circuit Breakers to 2030, being CBRM modelling, historical expenditure and historical expenditure trends.



**Figure 77 Substation Circuit Breaker repex Summary**

Our proposed repex is based on CBRM risk analysis to maintain risk along with additional repex to remove risks related to specific design flaws or performance issues that are not captured by CBRM modelling. Our estimate for this additional repex for the 2020-25 RCP is \$10.8 million, resulting in a forecast repex of \$67 million.

### 7.10.2 Substation circuit breakers forecast repex profile

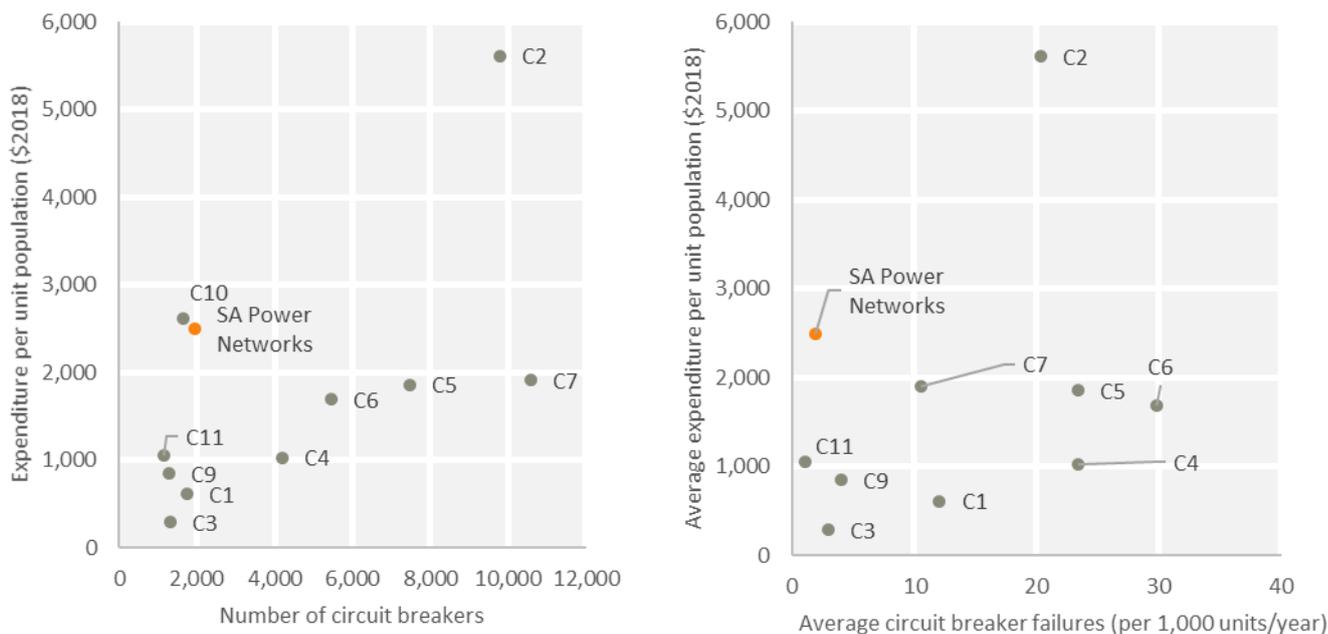


**Figure 78 Substation Circuit Breaker Historical and Proposed repex for the 2015-20 and 2020-25 RCPs**

Figure 78 shows that each repex forecasts for the 2020-25 RCP are less than the actual repex incurred in the 2017/18 regulatory year.

The repex forecast for the 2020-25 RCP incorporates replacement modelling supplemented with targeted programs to address specific asset risks. Assets managed by these targeted programs are treated separately (as outliers to the general population or non-modelled asset types) to address risks related to specific design flaws or performance issues beyond age related degradation that would otherwise make them prone to early failure. Targeted intervention programs are managed through refurbishment or (sometimes) replacement and based on engineering analysis.

A comparison of circuit breaker performance in contrast to other NEM DNSPs was undertaken analysing data from publicly available responses to Category RINs reported over the period from 2013/14 to 2016/17 inclusive (outliers excluded). A comparison of average annual repex per unit population and failure rate is shown in Figure 79.



Notes: C8 excluded from both charts as no expenditure information available.  
C10 excluded from failure rate chart due to very high failure rate relative to other DNSPs.

**Figure 79 Circuit breaker benchmarking of SA Power Networks as compared to other DNSPs (2013/14 to 2016/17 data)**

Figure 79 shows SA Power Networks currently has one of the highest level of average annual repex per circuit breaker coinciding with one of the lowest reported failure rates amongst DNSPs.

SA Power Networks’ benchmark volumes and expenditures in Figure 79 also exclude the effects of (low value, high volume) renewal programs for distribution recloser circuit breaker asset types. These benchmark results also come as a consequence of SA Power Networks’ investment focus from 2010/11 on the renewal of aged (1950s era) high voltage indoor switchboard assets, which provide the replacement of many other asset types (eg civil works, high voltage cables and auxiliaries systems) that have not had their repex separately reported in category analysis RINs.

While the data used for this asset class comparison is highly variable across the DNSPs it generally demonstrates SA Power Networks lifecycle management of circuit breakers is otherwise efficient and failure rates are comparatively low.

### 7.10.3 Substation circuit breaker CBRM overview

CBRM modelling of circuit breakers incorporates information on both current condition and the observed performance of the circuit breaker fleet over the last 10 years to calculate current risks and deterioration rates for individual assets. Future risk is forecast at a point in the future for each circuit breaker to determine

relative changes in risk across the asset fleet and to show the effects of different intervention strategies on future risk and asset performance.

The circuit breakers CBRM inputs are tabled in Section 8.4 in the appendix.

The circuit breaker CBRM model has been reconstructed using the RIVA platform provided by Powerplan, allowing integration of the CBRM model with other key SAPN asset information systems including SAP, GIS, SAP works manager and other corporate systems in order to provide up to date information of new and decommissioned assets and updated condition data as becomes available.

The circuit breaker CBRM models in the RIVA platform are substantially the same models initially developed with EA Technology in 2011 and used to support our 2015-20 RCP repex proposals. Key changes made in the transition to the current modelling platform include:

- Updated asset, condition and performance to reflect current (10 year historical) data.
- Updated equipment specific engineering reliability and obsolescence modifiers to reflect current understanding of equipment make/type performance issues.
- Alignment of standard model calibrations (eg equipment condition modifiers, POF curve parameters) with Version 1.1. of the Ofgem DNO Common Network Asset Indices Methodology (**CNAIM**).

### **7.10.3.1 Circuit breakers renewal strategy modelling**

Two strategies were modelled for circuit breakers using the CBRM methodology in order to forecast the future repex requirements. These were:

- **replace on Condition:** this strategy plans asset for replacement as they reach a Health Index of 728; and
- **maintain Risk:** this approach considers the relative changes in risk over the planning period (current condition, observed performance, rate of deterioration and relative consequence of failure for each asset) and relative replacement costs to construct a program that efficiently maintains the long term operational performance of the asset population.

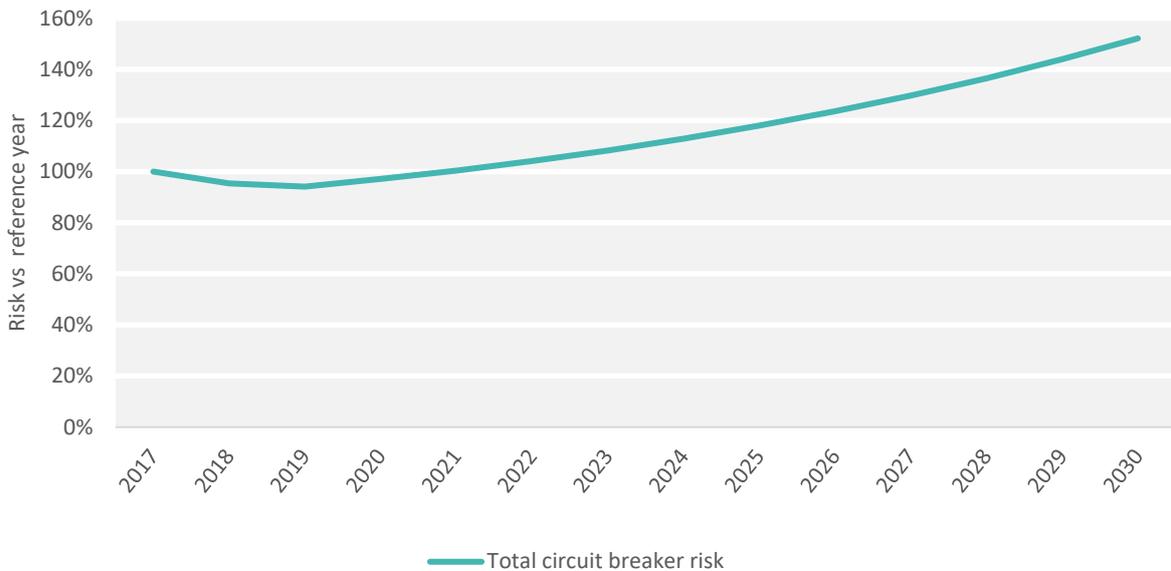
Each of these strategies consider the effect of other asset renewal works (including load-driven and strategic asset renewal works) and the delivery of targeted asset refurbishment and replacement plans to 2030.

To provide a comparative baseline for modelling renewal strategies a 'Do Nothing' investment scenario was initially modelled in CBRM to illustrate the risk/performance impacts of performing no proactive intervention from 2020 (only intervening to fix equipment as failures occur).

Figure 80 shows the forecast risk profiles for the Sub-Transmission and Distribution circuit breaker models under the 'Do Nothing' investment scenario.

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<sup>28</sup> An equipment HI of 7 is the point at which assets are considered to have a high and significantly increasing POF (end of reliable service life) and should be planned for replacement.



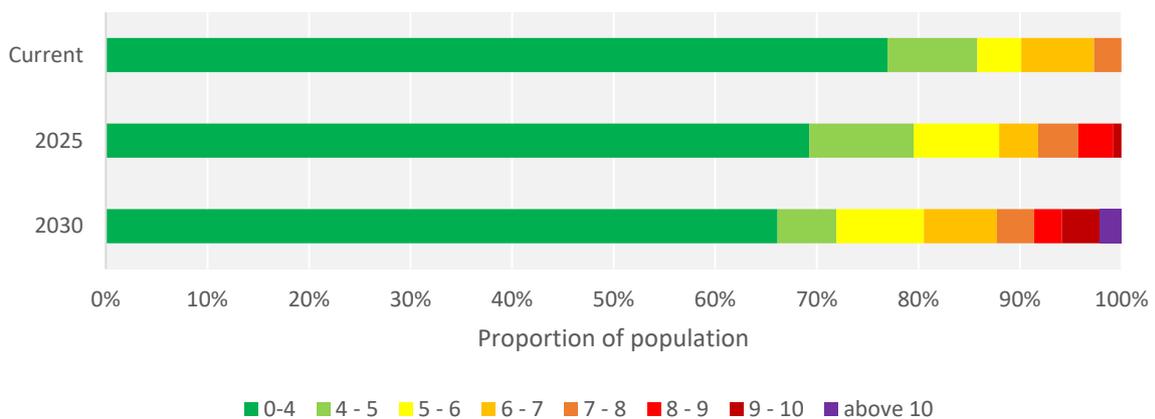
**Figure 80: Circuit Breakers Do Nothing (Baseline) - Risk Forecast**

For each circuit breaker model, completion of planned investment during the second half of the 2015-20 RCP is forecast to maintain (2015) risk levels by 2020. From 2020 onwards, risk levels are forecast to increase without investment as current assets further age and deteriorate.

For distribution circuit breakers, population risk is forecast to increase by approximately 20% from 2020 levels by 2025 and to 55% by 2030 without investment as large populations of aged indoor small bulk oil switchgear continue to age and deteriorate in service.

For sub-transmission circuit breakers, population risk is forecast to increase by approximately 19% from 2020 levels by 2025 and to 49% by 2030 without investment as significantly aged (>60 yrs) outdoor bulk oil circuit breakers continue to age and deteriorate in service

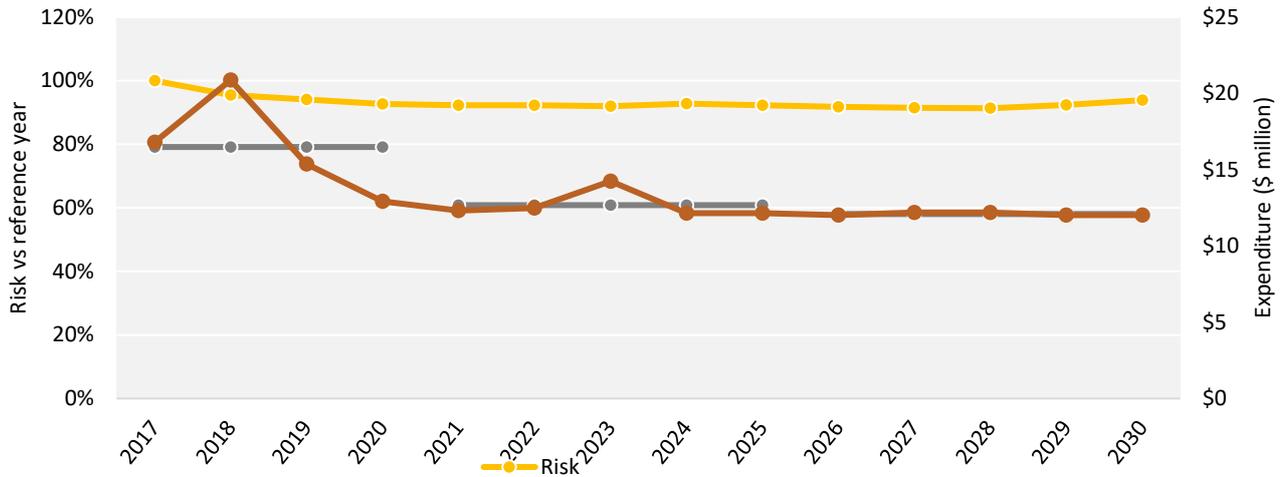
Figure 81 shows the current and forecast health distribution of the circuit breaker population with no intervention over the next two RCPs. Over time, the proportion of assets with significant deterioration will grow considerably over the next two RCPs. The percentage of circuit breakers with a HI above 7 will increase from the current 3% to 8% by 2025 and 14% by 2030.



**Figure 81 - Circuit Breakers Do Nothing Baseline- Health Index Forecast**

### Maintain Risk Renewal/Replacement Strategy

Figure 82 shows the forecast risk and repex to maintain current levels of risk for circuit breakers.

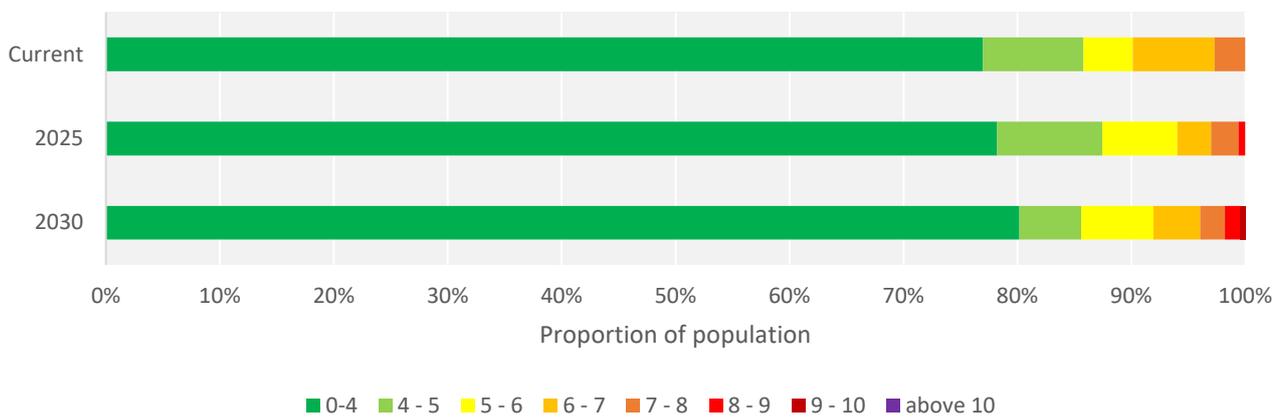


**Figure 82 - Circuit Breakers Maintaining Risk Strategy - Risk & Repex Forecast**

The strategy represented by Figure 82 accounts for the cumulative effects of other planned investment programs such as substation upgrades, unplanned (on failure) asset replacement, other replacement plans, the completion of planned works in 2018/19 and targeted refurbishment / replacement programs to 2030.

Delivery of this strategy efficiently maintain the long-term performance of the circuit breaker fleet through targeted interventions in areas of risk that provide the greatest return on investment, prioritising poor condition, critical assets that are approaching the end of their economic service life. The combined effect of all planned replacement and refurbishment plans is to maintain levels of safety, reliability and network performance for the asset class to 2030.

Figure 83 shows that the HI profile for the population would degrade over the 2020-25 RCP by selectively deferring renewal of less critical assets.



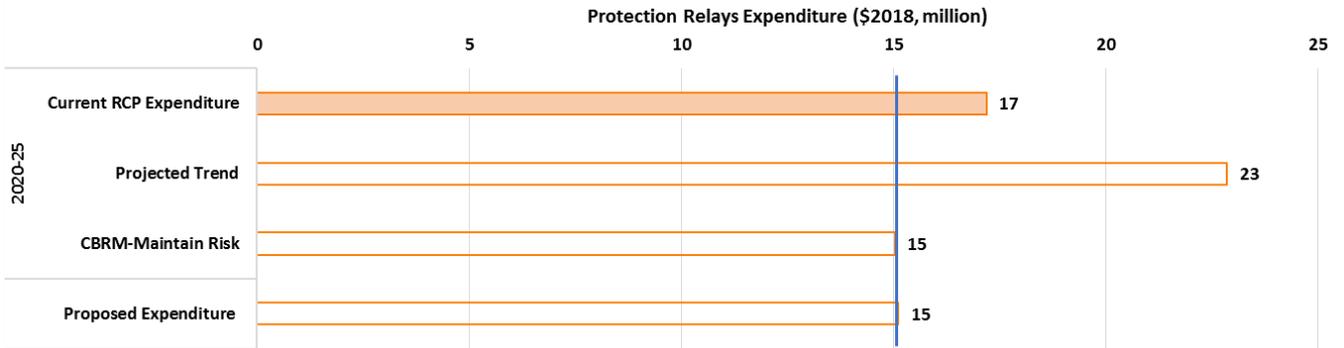
**Figure 83 - Circuit Breakers Maintaining Risk Strategy– Health Index Forecast**

In addition to CBRM modelling, the repex forecast for the 2020-25 RCP incorporates targeted refurbishment/replacement programs to address asset specific risks (as outliers to the general population) that would otherwise make them prone to early failure. The effects of completing these programs have been assumed within CBRM modelling outputs and the forecast repex required over the next two RCPs to deliver this strategy is \$63.8 million in 2020-25 RCP and \$60.6 million in the 2025-30 RCP. This compares with a repex forecast of \$93.6 million in the 2020-25 RCP and \$107.2 million in 2025-30 RCP had a maintain health strategy been adopted.

## 7.11 Protection relay repex forecast

### 7.11.1 Protection relay forecast repex summary

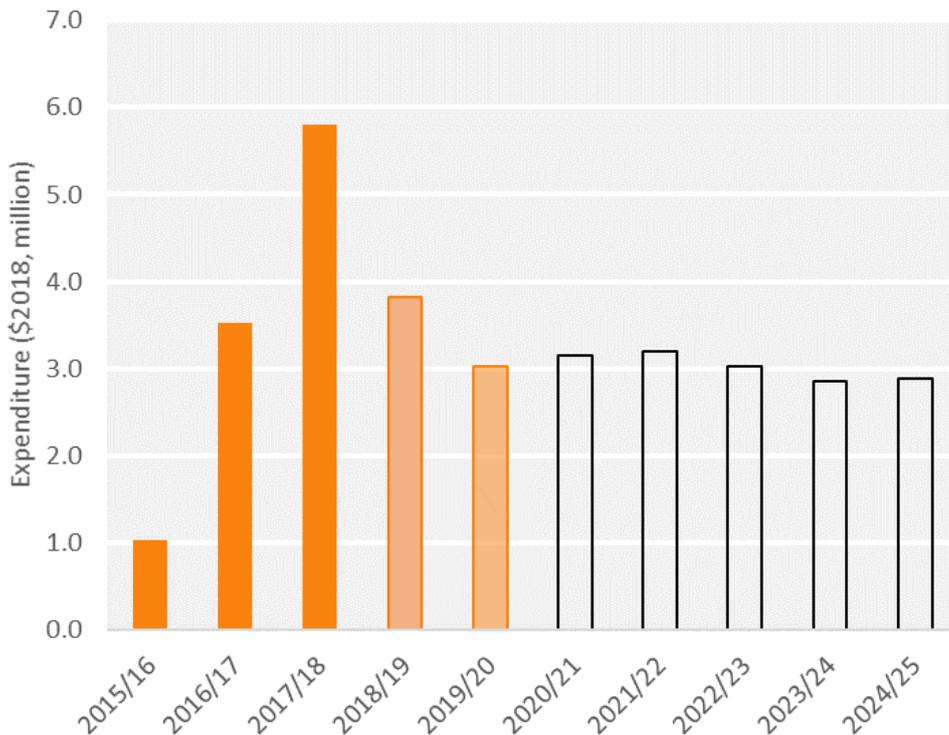
We have utilised three methods to assess the required repex for protection relays, being CBRM model, historical expenditure and historical expenditure trends. The modelling outputs have been supplemented with our own SME knowledge to help build the required repex for protection relays for the 2020-25 RCP.



**Figure 84 Protection Relay repex Summary**

In Figure 84 the proposed expenditure of \$15 million is based on CBRM risk analysis to maintain current levels of risk.

### 7.11.2 Protection relay forecast repex profile



**Figure 85 Protection Relay Historical and Proposed repex for the 2015-20 and 2020-25 RCPs**

Figure 85 shows that the proposed annual repex for the 2020-25 RCP based on maintaining current levels of risk is less than the repex incurred in the 2016/17 and 2017/18 regulatory years.

### 7.11.3 Protection relay CBRM model overview

CBRM modelling of protection relays uses asset information, engineering knowledge and failure data to determine the probability and consequence of failure for each asset. While condition data for protection relays is of limited use compared to primary assets, the CBRM methodology is able to determine the likelihood of a relay failure resulting in adverse consequences. Using the CBRM model, it is possible to quantitatively determine the reduction in risk when replacing aging protection schemes with their modern equivalent and in turn ensure that asset replacements are carried out efficiently.

Figure 86: Protection Relays Do Nothing (Baseline) -Risk Forecast below shows the forecast risk of Protection Relays for the 'Do Nothing' baseline.

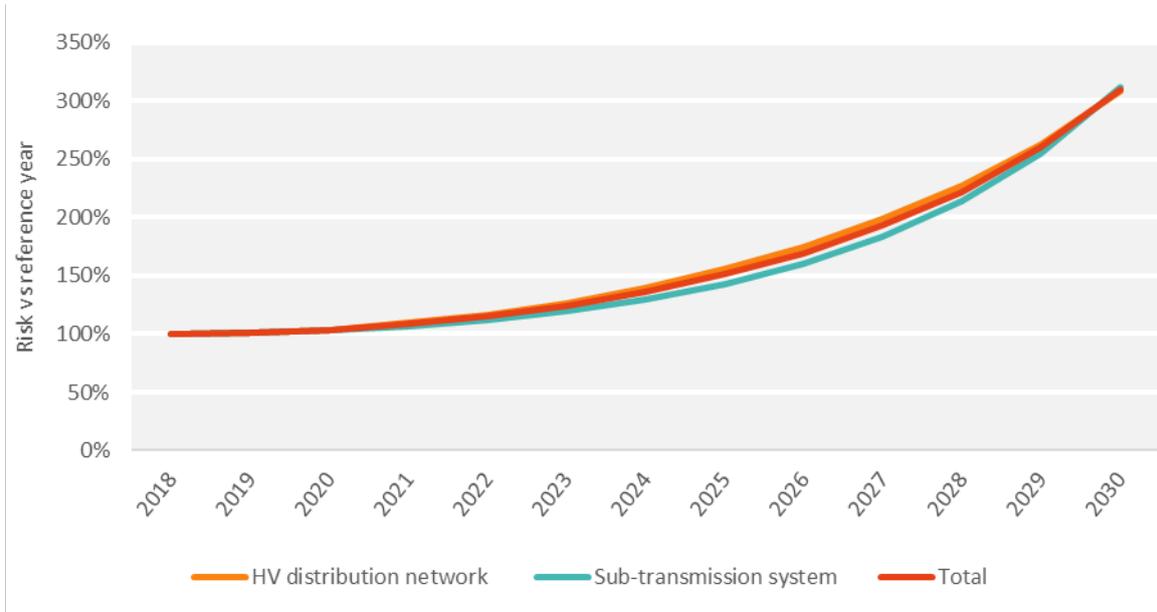


Figure 86: Protection Relays Do Nothing (Baseline) -Risk Forecast

Figure 86 shows that the overall Protection Relays population risk would increase from the current levels of risk by 51% by 2025 and 202% by 2030.

Figure 87 shows the forecast health index for this strategy.

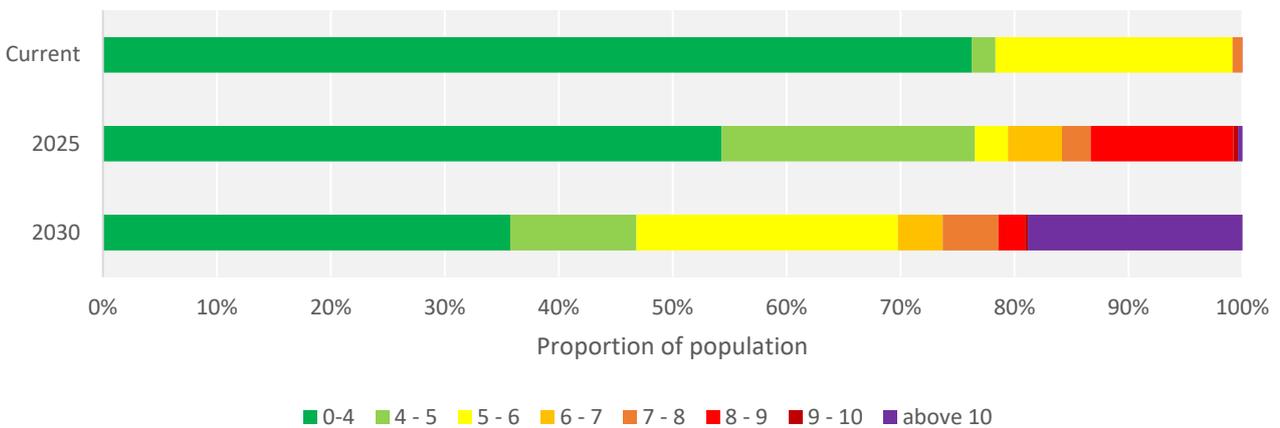
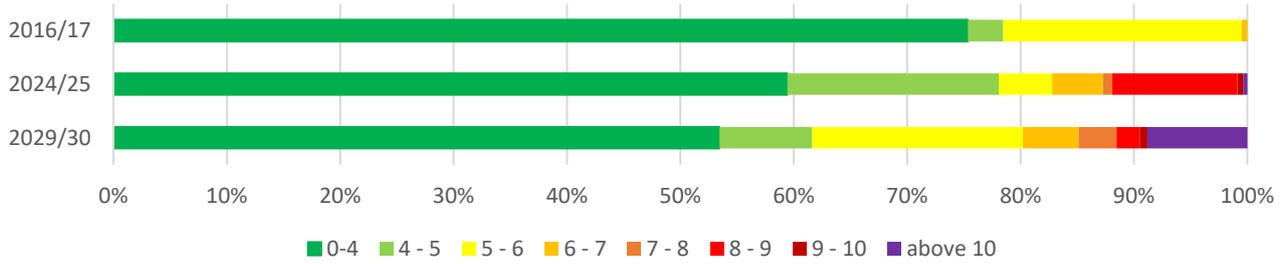


Figure 87 – Protection Relays Do Nothing Baseline - Health Index Forecast

Figure 87 shows that over time, the percentage of assets with HI above 7 would grow from the current 1% to 16% by 2025 and to 26% by 2030.

Figure 88 shows the health index forecast for this strategy



**Figure 88 – Protection Relays Maintain Risk Strategy – Health Index Forecast**

Figure 88 shows that the percentage of Protection Relays with HI greater than 7 would increase from the current 0% to 13% by 2025 and to 15% by 2030. While the HI is forecast to increase, this does not necessarily result in an increase in risk. Modern digital relays are capable of self-reporting failures and provided these failures can be addressed in a timely fashion, they can be ‘run to fail’ without increasing risk.

The required repex over the next two RCPs for the maintain risk strategy is \$15 million in each RCP compared with forecast repex of \$43.5 million in the 2020-25 RCP and \$23.3 million in the 2025-30 RCP under a maintain health strategy.

## 7.12 Other un-modelled network repex

This section discusses the forecasting methodologies applied to un-modelled assets. Note that repex may not match proposed units multiplied by quantities listed due to rounding.

### 7.12.1 Other line assets renewal

As mentioned in section 1.2, other un-modelled line assets include line voltage regulators and capacitors, cable ducts, manholes, earthing systems, ancillary equipment (line fault indicators, access roads, locks) and other safety programs required to meet current safety standards. The basis of the proposed repex for these asset classes is discussed below.

The unit rates are from historical costs for the various relevant work types for the asset captured within our SAP system.

#### 7.12.1.1 Line voltage regulators and capacitors

Voltage regulators are designed to maintain a constant voltage level in an active conductor while capacitors connect 'imaginary' electrical load to the active conductors. There is no planned work for capacitors and so the forecast is for voltage regulators only. The forecast quantity of units required for replacement is based on the average number of units replaced over the last five years and the number of units currently in the backlog to be addressed. It is assumed that we will still have the same number of backlog units in mid-2020 based on the current rate at which we are completing the work.

The unit cost varies depending if the tank or controller requires replacement (like for like) or if both the tank and controller need replacing (modern day equivalent). Historically, we have approximately 40% of units that require only the tank or controller to be replaced and 60% where both the tank and controller require replacement.

The need to remove the backlog of failed voltage regulator units via planned works is increasing due to the uptake of PV systems and the increasing rate of customer complaints concerning being unable to export into the network, leading to fault finding and identification of defective voltage regulators. It is far more cost effective to replace existing failed voltage regulators installed within the distribution network rather than to undertake alternative measures (eg line upgrades) to improve local quality of supply issues. In addition, there are defective units that are not operating as required which require planned replacement to restore their required functionality.

Table 15 shows the proposed quantities and unit costs of line regulators planned for replacement. The number of replacement units is based on the average number of replacement units completed over the last five years (from 2013 to 2018) while also addressing the current identified backlog of work within the 2020-25 RCP.

**Table 15: Line voltage regulators quantities and unit costs**

Asset Type	Avg. no units pa	Unit cost <sup>29</sup>	Proposed repex 2020-25 RCP
<b>Unplanned</b>			
<b>Tank or controller only</b>	13.2	\$17,531	\$1,157,078
<b>Tank and controller</b>	19.9	\$39,445	\$3,928,806
<b>Planned</b>			
<b>Backlog units</b>	3.4	\$39,445	\$670,579
<b>TOTALS</b>			
<b>All units</b>	36.5	\$31,524 (weighted average)	\$5,756,463

#### **7.12.1.2 Cable ducts and manholes**

Ducts are used throughout the distribution network for enabling the installation and planned replacements of underground cables. Our cables and ducts are most prevalent within the CBD where underground cables form most of the distribution network. Where cable joints fail within manholes, typically the cable can be repaired/patched. However, where the cable fault is located between manholes, this can require spare ducts to be used to install replacement cable lengths (when the failed cable is unable to be removed due to displaced duct joints). As a result, we now have six high priority locations where there is little to no spare duct capacity. These locations and estimated cost for each are outlined in our CBD Asset Plan and summarised in Table 16. The unit rate for duct installation can be as little as \$1,000/m but site specifics such as new manhole installations, major service relocations and providing alternate supply during any outages can add significant cost to the works.

Ducts are grouped together connected by manholes typically used for joining HV and LV cables. New manholes are built by pre-casting and assembling on site with costs from \$85,000 to \$250,000 while manhole lids and cable supports refurbishment can range between \$2,000 to \$20,000; the average being \$10,000.

With approximately 55% of CBD manholes inspected to September 2018 (i.e, 670 out of approximately 1,200), 38 have been identified as having structural defects. Applying this proportion to the entire manhole population equates to 70 manholes requiring structural remediation. Given the high vehicular loading and pedestrian traffic within the CBD, we propose to address these manholes within the 2020-25 RCP to address these defects which present safety risks to the public.

<sup>29</sup> Excluding overheads

**Table 16: Ducts and manholes quantities and unit costs**

Asset Type	Length or quantity	Unit cost <sup>30</sup>	Proposed repex 2020-25 RCP
<b>Ducts</b>			
<b>Six duct lengths within CBD</b>	1,790	\$6,953 <sup>31</sup>	\$12,447,355
<b>Manholes</b>			
<b>Manholes with structural defects</b>	70 (estimated)	\$8,766	\$613,602
<b>Total</b>			
			\$13,060,957

Table 16 shows most ducts and manhole repex is required for ducts. Not having spare ducts available in the event of cable faults would result in prolonged customer outages as new ducts would need to be installed after the fault has occurred. Having ducts installed and available ready for use ensures that cable faults can be rectified quickly.

### 7.12.1.3 Earthing systems

Earthing is the intentional connection of the neutral conductor and metallic structures to the ground. It is an integral part of the electricity distribution network to enable the network to be operated safely and minimise risks to staff, contractors and the public as well as protecting network assets.

As mentioned in section 4.6 we have legislated obligation in relation to safety and technical issues arising from our electricity distribution network (ie *Electricity infrastructure must be adequately protected against earth faults*). Therefore, when earthing system defects are identified they must be remedied. The forecast is based on the average number of defects completed per annum since 2010 multiplied by the unit rate considered typical for these work types which is a conservative approach given the low number of defects raised and addressed during the 2010/-11 regulatory year. The proposed quantities and typical unit rates for distribution earthing systems is summarised in Table 17.

<sup>30</sup> Excluding overheads

<sup>31</sup> Based on the aggregate of all projects proposed

**Table 17: Distribution earthing forecast quantities and unit costs**

Asset Type	Avg. no defects raised pa (2010/-18)	Avg. no defects completed pa (2010-18)	Unit cost <sup>32</sup>	Proposed repex 2020-25 RCP
<b>Distribution earthing systems</b>				
Earth CMEN missing	174	82	\$530	\$217,985
Earth MEN missing	206	50	\$858	\$216,285
Earth pole high reading	1	1	\$350	\$1,749
Earth stake damaged	2	2	\$762	\$5,718
Earth SWER transformer pole	1	1	\$1,642	\$8,210
Earthing equipment fault	30	30	\$511	\$77,153
<b>Total</b>				<b>\$527,099</b>

Table 17 shows a proposed repex of approximately \$527,000 with the majority to address the large number of defects identified with missing bonds on earthing systems.

**7.12.1.4 Ancillary equipment**

Ancillary assets include line fault indicators, fences, gates, locks, signs, access roads and cable barriers. The proposed expenditure is based on maintaining the historical level of identified risk across these assets. As outlined in the ancillary assets asset plan, the rate at which work has been completed on ancillary assets over the last six years has maintained the level of identified risks across the ancillary assets. The forecast is based on continuing to address the average number of defects completed per year since 2010 multiplied by the unit rate considered typical for these work types which is a conservative approach given the low number of defects raised and addressed during the 2010/11 regulatory year. The proposed quantities and typical unit rates for ancillary assets is summarised in Table 18.

<sup>32</sup> Based on average estimated costs for work against notifications in SAP; excludes corporate overheads

**Table 18: Ancillary asset forecast quantities and unit costs**

Asset Type	Avg. no defects raised pa (2010-18)	Avg. no defects completed pa (2010-18)	Unit cost <sup>33</sup>	Proposed repex 2020-25 RCP (\$)
<b>Line fault indicators (LFIs)</b>				
Line fault indicators (LFIs)	0	0	Not applicable	\$0
<b>Fences, gates and locks</b>				
Access fences	28	4.6	\$4,625	\$105,347
Access gates damaged	15	6.8	\$698	\$23,650
Access locks damaged	18	4.7	\$351	\$8,178
Access locks missing	6	3.3	\$390	\$6,504
Barriers	191	85.3	\$1,006	\$429,519
<b>Sub-total</b>	<b>257</b>	<b>105</b>		<b>\$573,196</b>
<b>Signs</b>				
Number device missing	908	701	\$78	\$273,710
Number structure	279	184	\$72	\$66,190
Warning sign missing	874	444	\$181	\$403,132
<b>Sub-total</b>	<b>2,061</b>	<b>1,329</b>		<b>\$743,033</b>
<b>Access roads</b>				
Access roads	428	220	\$1,079	\$1,186,509
<b>TOTALS</b>				
<b>All ancillary assets</b>	<b>2,746</b>	<b>1,654</b>		<b>\$2,502,742</b>

<sup>33</sup> Based on average estimated costs for work against notifications in SAP; excludes corporate overheads

Table 18 shows a proposed repex of approximately \$500,000 per annum with approximately half of this for maintaining access roads required to access network assets safely.

### 7.12.1.5 CBD safety program

In line with our requirements under our SRMTMP and related regulatory obligations, we are nearing completion of safety audits of 670 operational sites within the CBD. This audit process commenced in 2012 with 100 high priority sites used to develop the audit process and methodology. All identified safety defects arising from the safety audits are entered into our SAP works management system and the work value determined, the works are then prioritised based on return on investment (risk removed per dollar spent) as per our value-based approach described previously (see section 5.2.2). This enables the progressive removal of identified safety risks that exist within the network and to meet regulatory safety requirements through delivering our SRMTMP.

We are proposing to address the identified safety issues arising from these audits to ensure the safety risks to staff and contractors is minimised. Our current focus to the end of the 2015-20 RCP is to address minor works associated with 200 sites. Our proposed repex does not allow for additional identified defects that are identified to 2025 as our focus is to address the current identified backlog of work. Notwithstanding, any additional defects identified will be valued and where viable incorporated with other planned safety works for delivery efficiency.

The build-up of work is comprised of:

- **minor works:** addressing missing or inadequate general and exit/emergency lighting, AS3000 & RCD compliance, signage and, fire extinguishers and presence of debris; and
- **moderate works:** restricted access/egress typically vertical access ladders. These hazards ranged from difficulty in access to or egress from the ladder, lack of guarding at ladder entry points, unstable landings, loose or damaged ladders/cages, obstructions whilst using the ladder and undersize rungs as well as lack of, or insufficient, guardrails on raised walkways or rooftop sites.

**Table 19: CBD safety program of works**

Asset Type	Number of sites	Unit cost <sup>34</sup>	Proposed repex 2020-25 RCP
<b>Minor works</b>			
Lighting, electrical, environment, ventilation	470	\$1,578	\$741,582
<b>Moderate works</b>			
Replacement ladders, platforms, fall arrest systems	26	\$42,649	\$1,108,866
<b>Total</b>			
<b>Minor/moderate works</b>			<b>\$1,850,448</b>

<sup>34</sup> Estimated average cost per site; excluding overheads

Table 19 shows a large number of sites requiring relatively minor works to improve worker safety while a smaller number of identified sites require more substantial works, the majority of which require improved access ladders to achieve compliance with safety standards and to rectify identified safety hazards.

### 7.12.2 Other substation assets

Other substation asset renewal programs include substation Auxiliaries: DC & AC supplies, substation Insurance Spares, substation infrastructure -Civil (incl. buildings, structures), surge arresters, instrument transformers, substation disconnectors, Pipework Bus' Switchyards, substation Cables and Terminations

The majority of these works are planned and prioritised based on risk. Forecast repex is largely based on historical repex except for substation Auxiliary AC/DC Supplies and substation civil works.

We have allowed a small step increase in our allowance for substation auxiliary AC & DC supplies to improve network security by allowing effective recovery of the network in the event of a large scale, prolonged loss of AC mains (system black scenario). This plan followed the review of network recovery performance following the SA state wide blackout in September 2016 due to multiple transmission line failures. Further details are included in *Asset Plan 3.2.08 Substation DC Auxiliaries*.

We have also allowed for a step increase in substation civil works to manage the condition of substation control/switchrooms, further details are included in *Asset Plan 3.2.16 Substation Civil Buildings and Structures*.

We have forecast repex of \$41 million in the 'Other substation assets' category for the 2020-25 RCP.

### 7.13 Telecommunication assets

Telecommunication asset renewal programs include 48 V DC systems, UPAX/Business telephone network, data network, microwave radio, telecommunication, Misc. radio systems, optical fibre network, pilot cable network, TNOc management systems and OT cyber security.

The majority of works are planned and prioritised based on risk. Forecast repex is largely based on historical expenditure along with bottom-up forecasts outlined in the *Telecommunication Asset Plans* which include:

- Once off step increase in UPAX/Business Telephone Network in 2020 for a complete system replacement.

This project will replace the full system which is nearing its end of life. The replacement has the added benefit that the system will become more secure.

- Once off step increase in Radio Systems in 2020.

The micro wave system is nearing the end of its life. Not replacing this system runs the risk that the manufacturer will cease to support the old system.

- Once off step increase in TNOc Management Systems and OT Cyber Security in 2022.

The hardware of the TNOc System will be replaced as it nears the end of its life. An added benefit to this replacement is an improved software system. The Cyber Security system needs to be replaced as it reaches its end of life.

- Replacement of Mobile Radio

SA Power Networks has been warned that the current system is using outdated technology that is nearing the end of its life. If the system is not replaced we risk losing support from the vendor

We have forecast repex of \$38 million (repex and non-network repex) for these and other business as usual telecommunication renewals for the 2020-25 RCP.

Note that there is no duplication with IT non-network repex as the assets covered by the telecommunication asset plans are explicitly listed.

## 8 APPENDIX CBRM constants

### 8.1 CBRM Consequence values used in Multiple Models

#### Safety Consequences

Consequence Rating	Consequence Monetary Value
Minor	\$ 100,000 per person
Major	\$ 1,000,000 per person
Fatality	\$ 10,000,000 per person

#### Network performance Consequences

Consequence Rating	CBD	Urban	Rural Short	Rural Long
<b>Average Restoration Time (Minutes)</b>	Asset Class Specific	Asset Class Specific	Asset Class Specific	Asset Class Specific
SAIDI (\$/customer minute)	\$4.77	\$0.49	\$0.46	\$0.42
SAIFI (\$/customer outage)	\$406	\$45	\$60	\$71

#### Environment Consequences

CAPEX Average Cost of Failure	
Settings	CBD
Loss Fire	\$1000
Loss Per Oil Litre	\$100
LossPerSF6kG	\$400

#### Opex and Capex Consequences

OPEX Average Cost of Failure				
Consequence Rating	CBD	Urban	Rural Short	Rural Long
<b>Avg. Cost of Fault</b>	Asset Class Specific	Asset Class Specific	Asset Class Specific	Asset Class Specific

## 8.2 CBRM pole constants

Table 20: Poles Probability of Failure Key Input Information

Key Input Information	Value	Information Source	Comments	
<b>Average life</b>	<b>Pole Categories</b>			
	Category 1	69 Years	RIN	Pole categories based on pole width and height and matched to RIN categories.
	Category 2	69 Years	RIN	
	Category 3	66.4 Years	RIN	
	Category 4	70.4 Years	RIN	
	Category 5	70.4 Years	RIN	
	Category 6	70.4 Years	RIN	
	Category 7	70.4 Years	RIN	
	Wooden	35 Years	SAPN SME	
	Rail	70 Years	SAPN SME	
	Steel	70 Years	SAPN SME	
	Tower	70 Years	SAPN SME	
	H-Iron	70 Years	SAPN SME	
<b>Replacement costs</b>	<b>Voltage</b>		Based on RIN Unit Replacement Costs	
	LV	\$7,003		SAPN-SAP
	7.6kV	\$10,839		SAPN-SAP
	11kV	\$10,839		SAPN-SAP
	19kV	\$8,372		SAPN-SAP
	33kV	\$16,325		SAPN-SAP
	66Kv	\$16,325		SAPN-SAP
	132kV	N/A		
<b>Asset installation year</b>	Varies for every asset		SAPN-SAP	
<b>Atmospheric corrosion zone</b>	1,2,3 and 4		SAPN-SAP	
<b>Asset condition</b>	Varies for every asset		SAPN-SAP	
<b>Asset historical defects</b>	Varies for every asset		SAPN-SAP	

**Table 21 - Pole Size Categorisation**

Width(mm)	Height(m)		
	<=18	>18 <=21	>21
<=155	1	1	1
>155 <205	2	2	2
>=205 <207	3	3	3
207	2	2	2
>207<=256	4	3	2
256	2	2	2
>=256<=307	5	5	4
307	3	3	2
>=307<=320	6	6	5
>320	7	7	6

**Table 22: Poles Consequence of Failure Key Input Information**

Consequence Factor	Consequence Category	Value	Information Source	Comments	
Network Performance		SCONER Category			
	System Average Duration Index (SAIDI)	CBD	\$4.77/Customer Minute	SAPN/AER	
		Urban	\$0.49/Customer Minute	SAPN/AER	
		Rural Short	\$0.46/Customer Minute	SAPN/AER	
		Rural Long	\$0.42/Customer Minute	SAPN/AER	
	System Average Frequency Index (SAIFI)	CBD	\$406/Customer Outage	SAPN/AER	
		Urban	\$45/Customer Outage	SAPN/AER	
		Rural Short	\$60/Customer Outage	SAPN/AER	
		Rural Long	\$71/Customer Outage	SAPN/AER	
	Value of Customer Reliability	CBD	\$44,856	SAPN/AEMO	
		Urban	\$38,566	SAPN/AEMO	
		Rural Short	\$38,566	SAPN/AEMO	
		Rural Long	\$38,566	SAPN/AEMO	
	Safety	Minor injury	\$100,000 per person	SAPN/ EA Technology	
		Major injury	\$1,000,000 per person	SAPN/ EA Technology	
		Fatality	\$10,000,000 per person	SAPN/ EA Technology	

Consequence Factor	Consequence Category	Value	Information Source	Comments
	Average Consequence of Failure	\$1,614	SAPN/ EA Technology	
	Average Consequence of fire start	\$1,600,000	SAPN/ EA Technology	
	Average Consequence of bush fire	\$260,000,000	SAPN/ EA Technology	
	Average Consequence of replacement	\$0	SAPN/ EA Technology	
	Average Consequence of repair	\$0	SAPN/ EA Technology	
Environment	Loss fire	\$10,000	SAPN/ EA Technology	
	Loss per waste per tonne	\$475	SAPN/ EA Technology	
	Loss per disturbance	\$300	SAPN/ EA Technology	
	Average Consequence of failure	\$1,250	SAPN/ EA Technology	
	Average Consequence of fire start	\$2,025	SAPN/ EA Technology	
	Average Consequence of bush fire	\$5,034,750	SAPN/ EA Technology	
	Average Consequence of replacement	\$0	SAPN/ EA Technology	
	Average Consequence of repair	\$0	SAPN/ EA Technology	

Consequence Factor	Consequence Category	Value		Information Source	Comments
OPEX		<b>Low Voltage</b>	<b>11kV</b>	<b>33/66kV</b>	
	Condition Fire Start	\$2,000,000	\$2,000,000	\$2,000,000	SAPN
	Condition bush fire	\$250,000,000	\$250,000,000	\$250,000,000	SAPN
	Non condition fire start	\$2,000,000	\$2,000,000	\$2,000,000	SAPN
	Non condition bush fire	\$250,000,000	\$250,000,000	\$250,000,000	SAPN
CAPEX	Condition Pole Break	\$7,003	\$10,839	\$16,325	SAPN
	Condition Replacement	\$7,003	\$10,839	\$16,325	SAPN
	Condition Plated	\$1,230	\$1,230	\$1,230	SAPN
	Non condition pole break	\$7,003	\$10,839	\$16,325	SAPN

### 8.3 CBRM substation power transformer constants

The tables below give a summary of key input information for the power transformer CBRM model.

**Table 23 : Substation Transformers Probability of Failure Key Input Information**

Key Input Information	Value	Information Source	Comments
Expected life	65 years	Ofgem CNAIM, SME assessment	
Asset installation year	Varies for every asset	SAP Asset Register, Equipment Nameplate Data	
Asset condition	Varies for every asset	SAP (Inspection, maintenance & condition monitoring)	
Asset historical defects	Varies for every asset	SAP (Inspection, maintenance & condition monitoring)	
Installation Environment	Varies for every asset	SAP (corrosion zone, indoor/outdoor installation type)	
Operating Duty	Varies for every asset	SAP (TF load, OLTC switching duty)	
Reliability Rating	Varies for every asset	SME Engineering assessment of historical make/model reliability and performance	
Historical Asset Performance	Varies by Failure Scenario	SME Knowledge/Failure reporting	Minor, Significant, Major, & Condition Replacement Failure Scenarios – from 10 year fleet performance history

**Table 24 : Substation Transformers Consequence of Failure Key Input Information**

Consequence Factor	Consequence Category	Value	Information Source	Comments
Network Performance	SCONRRR Category			
	CBD	\$4.77/ Customer Minute	SAPN/AER	

Consequence Factor	Consequence Category		Value	Information Source	Comments	
	System Average Duration Index (SAIDI)	Urban	\$0.49/ Customer Minute	SAPN/AER		
		Rural Short	\$0.46/ Customer Minute	SAPN/AER		
	System Average Frequency Index (SAIFI)	Rural Long	\$0.42/ Customer Minute	SAPN/AER		
		CBD	\$406/ Customer Outage	SAPN/AER		
		Urban	\$45/ Customer Outage	SAPN/AER		
		Rural Short	\$60/ Customer Outage	SAPN/AER		
	Value of Customer Reliability	Rural Long	\$71/ Customer Outage	SAPN/AER		
		CBD	\$44,856	SAPN/AEMO		
		Urban	\$38,566	SAPN/AEMO		
		Rural Short	\$38,566	SAPN/AEMO		
	Safety		Rural Long	\$38,566	SAPN/AEMO	
		Minor injury		\$100,000 per event	SAPN/ EA Technology	
Major injury			\$1,000,000 per event	SAPN/ EA Technology		
Fatality			\$10,000,000 per event	SAPN/ EA Technology		
Average consequence of Minor Failure			\$500	SAPN/ EA Technology		
Average consequence of Significant Failure			\$26,000	SAPN/ EA Technology		
Average consequence of Major Failure			\$130,000	SAPN/ EA Technology		
Average consequence of Failure to Trip			\$26,000	SAPN/ EA Technology		
Average cost of Condition Replacement			\$1,200	SAPN/ EA Technology		
Environment	Loss Oil		\$100/litre	SAPN/ EA Technology		
	Loss per waste per tonne		\$300	SAPN/ EA Technology		
	Loss per disturbance		\$475	SAPN/ EA Technology		

Consequence Factor	Consequence Category	Value	Information Source	Comments
	Loss Fire	\$1,000	SAPN/ EA Technology	
OPEX	Average cost of fault restoration	Varies for each asset/failure scenario	SAPN	Considers substation location, TF Type construction, installation location and OLTC obsolescence
CAPEX	Average cost of fault restoration	Varies for each asset/failure scenario	SAPN	Considers substation location, TF rating, installation location and obsolescence

## 8.4 CBRM substation circuit breaker constants

Table 25 and Table 26 give a summary of key input information for the circuit breaker CBRM models.

**Table 25 : Circuit Breakers Probability of Failure Key Input Information**

Consequence Factor	Consequence Category		Value	Information Source	Comments
Network Performance		SCONRRR Category			
	System Average Duration Index (SAIDI)	CBD	\$4.77/Customer Minute	SAPN/AER	
		Urban	\$0.49/Customer Minute	SAPN/AER	
		Rural Short	\$0.46/Customer Minute	SAPN/AER	
		Rural Long	\$0.42/Customer Minute	SAPN/AER	
	System Average Frequency Index (SAIFI)	CBD	\$406/Customer Outage	SAPN/AER	
		Urban	\$45/Customer Outage	SAPN/AER	
		Rural Short	\$60/Customer Outage	SAPN/AER	
		Rural Long	\$71/Customer Outage	SAPN/AER	
	Value of Customer Reliability	CBD	\$44,856	SAPN/AEMO	
		Urban	\$38,566	SAPN/AEMO	
		Rural Short	\$38,566	SAPN/AEMO	
Rural Long		\$38,566	SAPN/AEMO		
Safety	Minor injury		\$100,000 per event	SAPN/ EA Technology	
	Major injury		\$1,000,000 per event	SAPN/ EA Technology	
	Fatality		\$1,000,000,000 per event	SAPN/ EA Technology	

Consequence Factor	Consequence Category	Value	Information Source	Comments
	Average consequence of Minor Failure	\$500	SAPN/ EA Technology	
	Average consequence of Significant Failure	\$26,000	SAPN/ EA Technology	
	Average consequence of Major Failure	\$130,000	SAPN/ EA Technology	
	Average consequence of Failure to Trip	\$26,000	SAPN/ EA Technology	
	Average cost of Condition Replacement	\$1,200	SAPN/ EA Technology	
Environment	Loss Oil	\$100/litre	SAPN/ EA Technology	
	Loss per waste per tonne	\$300	SAPN/ EA Technology	
	Loss per disturbance	\$475	SAPN/ EA Technology	
	Loss Fire	\$10,000	SAPN/ EA Technology	
	Loss SF6	\$550/kg	SAPN/ EA Technology	
OPEX	Average cost of fault restoration	Varies for each asset/failure scenario	SAPN	Considers substation location, CB construction , installation and obsolescence
CAPEX	Average cost of fault restoration	Varies for each asset/failure scenario	SAPN	Considers substation location, CB construction , installation and obsolescence

**Table 26 : Circuit Breakers Consequence of Failure Key Input Information**

Consequence Factor	Consequence Category		Value	Information Source	Comments	
Network Performance		SCONRRR Category				
	System Average Duration Index (SAIDI)	CBD		\$4.77/Customer Minute	SAPN/AER	
		Urban		\$0.49/Customer Minute	SAPN/AER	
		Rural Short		\$0.46/Customer Minute	SAPN/AER	
		Rural Long		\$0.42/Customer Minute	SAPN/AER	
	System Average Frequency Index (SAIFI)	CBD		\$406/Customer Outage	SAPN/AER	
		Urban		\$45/Customer Outage	SAPN/AER	
		Rural Short		\$60/Customer Outage	SAPN/AER	
		Rural Long		\$71/Customer Outage	SAPN/AER	
	Value of Customer Reliability	CBD		\$44,856	SAPN/AEMO	
		Urban		\$38,566	SAPN/AEMO	
		Rural Short		\$38,566	SAPN/AEMO	
Rural Long			\$38,566	SAPN/AEMO		
Safety	Minor injury		\$100,000 per event	SAPN/ EA Technology		
	Major injury		\$1,000,000 per event	SAPN/ EA Technology		
	Fatality		\$10,000,000 per event	SAPN/ EA Technology		
	Average consequence of Minor Failure		\$500	SAPN/ EA Technology		

Consequence Factor	Consequence Category	Value	Information Source	Comments
	Average consequence of Significant Failure	\$26,000	SAPN/ EA Technology	
	Average consequence of Major Failure	\$130,000	SAPN/ EA Technology	
	Average consequence of Failure to Trip	\$26,000	SAPN/ EA Technology	
	Average cost of Condition Replacement	\$1,200	SAPN/ EA Technology	
Environment	Loss Oil	\$100/litre	SAPN/ EA Technology	
	Loss per waste per tonne	\$300	SAPN/ EA Technology	
	Loss per disturbance	\$475	SAPN/ EA Technology	
	Loss Fire	\$10,000	SAPN/ EA Technology	
	Loss SF6	\$550/kg	SAPN/ EA Technology	
OPEX	Average cost of fault restoration	Varies for each asset/failure scenario	SAPN	Considers substation location, CB construction , installation and obsolescence
CAPEX	Average cost of fault restoration	Varies for each asset/failure scenario	SAPN	Considers substation location, CB construction , installation and obsolescence

## 8.5 CBRM protection relay constants

### 8.5.1.1 Protection relays CBRM key input information

The tables below gives a summary of key input information for the Protection Relay CBRM models.

**Table 27 : Protection Relays Probability of Failure Key Input Information**

Key Input Information	Value	Information Source	Comments
Expected life	Varies for every asset type	SME assessment, Vendor warranty, failure reporting	
Asset installation year	Varies for every asset	SAP Asset Register	
Local Environment	Varies for every asset	SME Knowledge (Indoor/outdoor/other installation)	Overwhelming majority of relays are installed indoors.
Air Conditioned	Varies for every asset	SAP Asset Register	
Operational History	Varies for every asset	SME Engineering assessment of historical performance of the relay. Failure reporting	Unused. Built in the model to capture cases where an individual relay has maloperated, but not been replaced.
Pilot/Comms condition Factor	Varies for every asset	SME knowledge/failure reporting	Used to capture failures of telco equipment for communications-dependent protection schemes.
Generic Reliability Factor	Varies for every asset type	SME Engineering assessment of make/model reliability	
Susceptible to Spurious operation	Varies for every asset type	SME knowledge, failure reporting	Determines whether the failure mode of a relay tripping inadvertently is considered
Increased maintenance required	Varies for every asset type	SME/field knowledge	Captures relays that frequently require calibration during maintenance
Abnormal Failure Rate Factor	Varies for every asset type	Failure reporting	Used when the failure rate does not align with expected life, eg early failures due to manufacturer quality control
Fault Duty	Varies for every asset	SAP (associated circuit breaker fault duty)	Used to determine the probability of a relay failure coinciding with a fault (demand event)

Inspection Period	Varies for every asset type	SAP (maintenance schedule)	Used to determine the probability of a relay failure coinciding with a fault (demand event). Set to 1 day for a modern self-reporting relay
Redundancy	Varies for every asset	SAP (asset data)	Removes consequence of failing to trip for assets with redundancy

**Table 28 : Protection Relays Consequence of Failure Key Input Information**

Consequence Factor	Consequence Category	Value	Information Source	Comments
Network Performance		SCONRRR Category		
	System Average Duration Index (SAIDI)	CBD	\$4.77/Customer Minute	SAPN/AER
		Urban	\$0.49/Customer Minute	SAPN/AER
		Rural Short	\$0.46/Customer Minute	SAPN/AER
		Rural Long	\$0.42/Customer Minute	SAPN/AER
	System Average Frequency Index (SAIFI)	CBD	\$406/Customer Outage	SAPN/AER
		Urban	\$45/Customer Outage	SAPN/AER
		Rural Short	\$60/Customer Outage	SAPN/AER
		Rural Long	\$71/Customer Outage	SAPN/AER
	Value of Customer Reliability	CBD	\$44,856	SAPN/AEMO
		Urban	\$38,566	SAPN/AEMO
		Rural Short	\$38,566	SAPN/AEMO
Rural Long		\$38,566	SAPN/AEMO	
Safety	Minor injury	\$100,000 per event	SAPN/ EA Technology	
	Major injury	\$1,000,000 per event	SAPN/ EA Technology	
	Fatality	\$10,000,000 per event	SAPN/ EA Technology	

Consequence Factor	Consequence Category	Value	Information Source	Comments
	Average consequence of Minor Failure	\$500		SAPN/ EA Technology
	Average consequence of Significant Failure	\$26,000		SAPN/ EA Technology
	Average consequence of Major Failure	\$130,000		SAPN/ EA Technology
	Average consequence of Failure to Trip	\$26,000		SAPN/ EA Technology
	Average cost of Condition Replacement	\$1,200		SAPN/ EA Technology
Environment	Loss Oil	\$100/litre		SAPN/ EA Technology
	Loss per waste per tonne	\$300		SAPN/ EA Technology
	Loss per disturbance	\$475		SAPN/ EA Technology
	Loss Fire	\$10,000		SAPN/ EA Technology
	Loss SF6	\$550/kg		SAPN/ EA Technology
OPEX	Average cost of fault restoration	Varies for each asset/failure scenario	SAPN	Considers substation location, Relay type, complexity of isolation/replacement
CAPEX	Average cost of fault restoration	Varies for each asset/failure scenario	SAPN	Considers substation location, Relay type,