Business Case: Network asset replacement expenditure

2025-30 Regulatory Proposal

Supporting document 5.3.1

January 2024

SA Power Networks

Empowering South Australia

Contents

Glossary

Acronym / term	Definition
A&W	Assets and Work
AER	Australian Energy Regulator
AMS	Asset Management System
AMTP	Asset Management Transformation Program
ARP note	Asset Replacement Planning note
BCR	Benefit Cost Ratio
Capex	Capital expenditure
CBD	Central Business District
CBRM	Condition Based Risk Management
CER	Customer Energy Resources
DUFLS	Dynamic Under Frequency Load Shedding
EDC	Electricity Distribution Code
GIS	Gas Insulated Switchgear
IP MPLS	Internet Protocol Multi-Protocol Label Switching
LV	Low Voltage
MED	Major Event Days
NER	National Electricity Rules
NPV	Net Present Value
PDH	Plesiochronous Digital Hierarchy
RCP	Regulatory Control Period
Repex	Replacement expenditure
SDH	Synchronous Digital Hierarchy
SF6	Sulphur hexafluoride
SPS	Service Performance Scheme
TEAM	Transport Engineering and Management
TNC	Telecommunications Network Control
VCR	Value of Customer Reliability
WACC	Weighted Average Cost of Capital

1. About this document

1.1 Purpose

This document outlines the justification for our forecast network asset replacement expenditure for the 2025-30 Regulatory Control Period (**RCP**).[1] The expenditure recommended is required to meet our regulatory obligations to operate a safe and reliable network and to otherwise comply with the requirements of the National Electricity Rules (**NER**).

1.2 Expenditure category

The expenditure forecasts outlined in this document are expressed in June $2022 (excluding overheads) and comprise our overall capital expenditure on network asset replacement and refurbishment (**repex**).

1.3 Related documents

This document should be read together with the following documents that specifically relate to repex, and together form a suite of supporting documents to our Regulatory Proposal for this expenditure category:

- 5.3.3 Value Framework document — describes how we value investment benefits;
- 5.3.2 Repex Forecasting Approach document — provides a structural overview of the approaches used to prepare the forecasts for the repex, included in this business case; and
- 5.3.4 Repex Model Framework document — details the repex modelling used to develop the forecasts (where modelled), including the input assumptions and their basis.

In addition, the larger programs / individual projects described in section 8, have their own detailed business cases as listed below.

This document describes our current approach to asset management (in section 3) and repex forecasting. 5.12.15 - Assets and Work (phase 3, P3) details our planned improvements to our asset management systems.

Table 1: Related documents

Title
Industry practice application note – Asset replacement planning
5.3.2 - Repex Forecasting structure
5.3.3 - Repex value framework
5.3.4 - Repex model framework
5.3.10 - Hindley Street Substation 66kV Replacement
5.3.11 - Mobile substation replacement
5.9.4 - CBD Reliability Improvement to meet EDC Targets
5.2.5 - Resourcing plan for delivering the network program
5.12.15 - Assets and Work P3

[1] This is also more correctly termed assets renewal expenditure, covering both asset refurbishment and asset replacement.

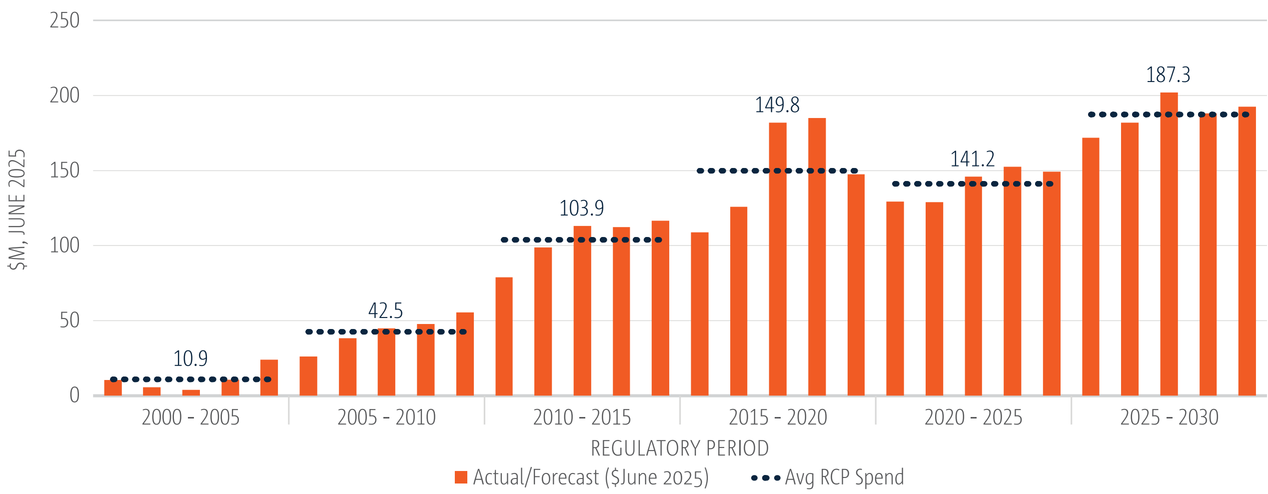
2. Executive summary

This business case recommends $810 million in capital expenditure (**capex**), to replace or refurbish network assets to maintain safety (including minimising bushfire risk), and reliability outcomes for our customers and the community.[2] This expenditure is expected to generate substantial benefits for customers, with a calculated **Net Present Value (NPV) of $314 million over a 20-year period**.[3]

The risk that deteriorating asset condition is posing to safety and reliability is manifesting more significantly now as the product of our unique network asset age profile. We have one of the oldest electricity distribution networks in Australia with a large proportion of our network constructed in the 1950's and 1960's. We also have one of the lowest replacement rates in the National Electricity Market (**NEM**).

As a function of this unique age profile, acting prudently and efficiently, we replaced relatively little network in past periods when the age profile was lower. Over time, as the age profile has increased and asset condition deteriorated causing escalating service risk, acting prudently and efficiently, our repex levels have followed a consistent upward trend, increasing from an average of circa $11 million per annum in the 2000-05 period, to $141 million per annum in the current 2020-25 period.[4]

Figure 1: Long term replacement expenditure profile[5]



Our forecast expenditure for 2025-30 RCP was developed by applying risk modelling aligned to the Australian Energy Regulators (**AERs**) *AER industry practice application note for asset replacement planning 2019*, for a selection of asset classes that have sufficient data. This modelling enables us to quantify the service outcomes for customers and the community resulting from varying rates of replacement. It also leverages detailed bushfire risk quantification developed by the Commonwealth Scientific and Industrial Research Organisation (**CSIRO**) as well as expert engineering assessment of the probability of failure of our assets.

Our modelling shows that our current replacement rates for some modelled asset classes would lead to an increase in failure of in-service assets, resulting in increased safety risk (including bushfire related risk) and a deterioration in reliability outcomes for customers in the 2025-30 RCP.

We engaged with our customers on the need apparent with respect to the risk that asset condition is posing for service performance, and considered multiple scenarios in terms of what we could do and spend on the

2 All figures are in June $2022 excluding network and corporate overheads.

3 This NPV estimate is intentionally conservative, encompassing all costs associated with modelled and unmodelled assets, yet it does not encompass the entirety of the benefits.

4 These figures are in June $2025 terms.

5 Expenditure here is shown in June $2025 terms.

network. Our customers were clear in their recommendations, and our total repex forecast has been developed to achieve the target service level outcomes that our customers recommended, including:

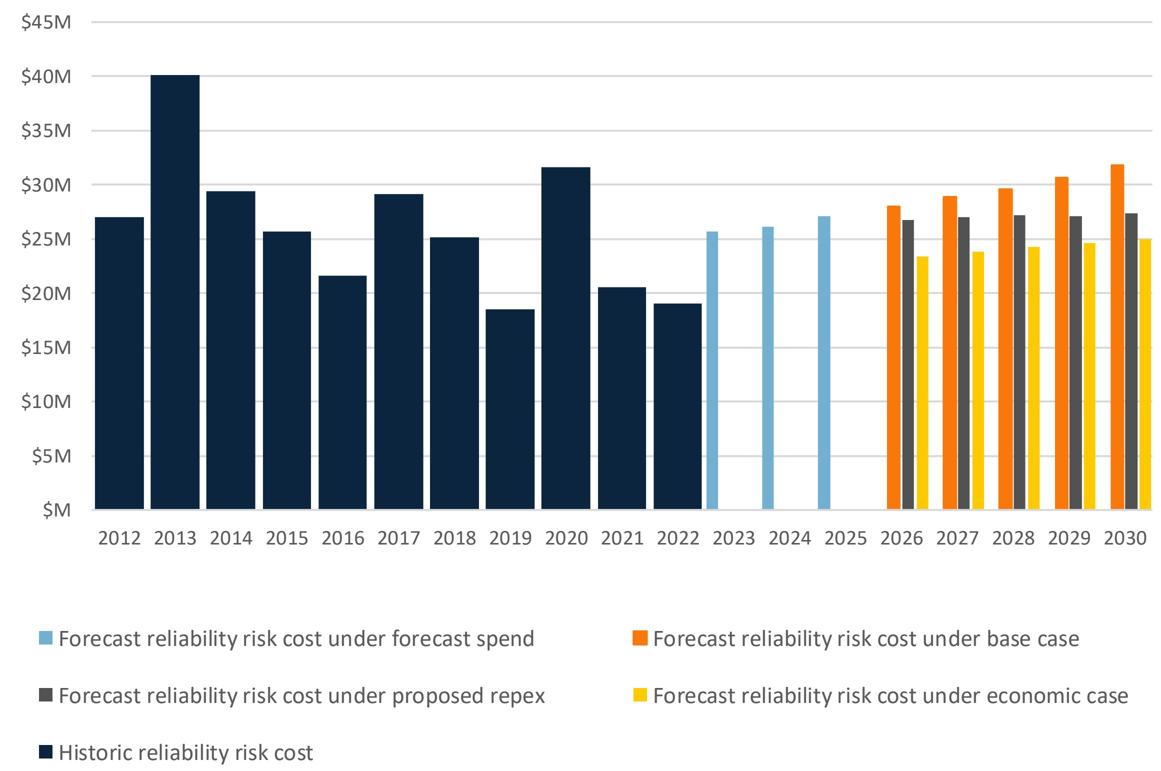
- meeting our obligation to **maintain safety** on the network (including bushfire related risk);
- **improving the reliability of the central business district (CBD)** to bring it into line with our jurisdictional reliability targets determined by the Essential Services Commission of South Australia (**ESCoSA**); and
- **maintain service reliability for customers at a geographic regional level**.

Our forecast repex ($810 million) continues our long-term upward trend in repex, to continue to counter escalating customer service risk posed by deteriorating asset condition. This forecast scenario was preferred to alternatives that we considered on the basis that:

- the 'base case' ($646 million) of maintaining current replacement rates, would degrade reliability and safety (for modelled asset classes), as shown in Figure 2 and Figure 3, an outcome that was not supported by our customers; and
- the 'economic case' ($830 million) of only undertaking replacements where there is a net benefit, would not maintain reliability at a geographic region level (despite improving overall service performance for modelled asset classes relative to other options) – this would be inconsistent with our customers' recommendation that we maintain service by geographic region, to not drive further inequity in service between customers in regional versus metropolitan areas. This option would also impose higher costs than other options, adding further to the energy affordability concerns that our customers have told us to be mindful of.

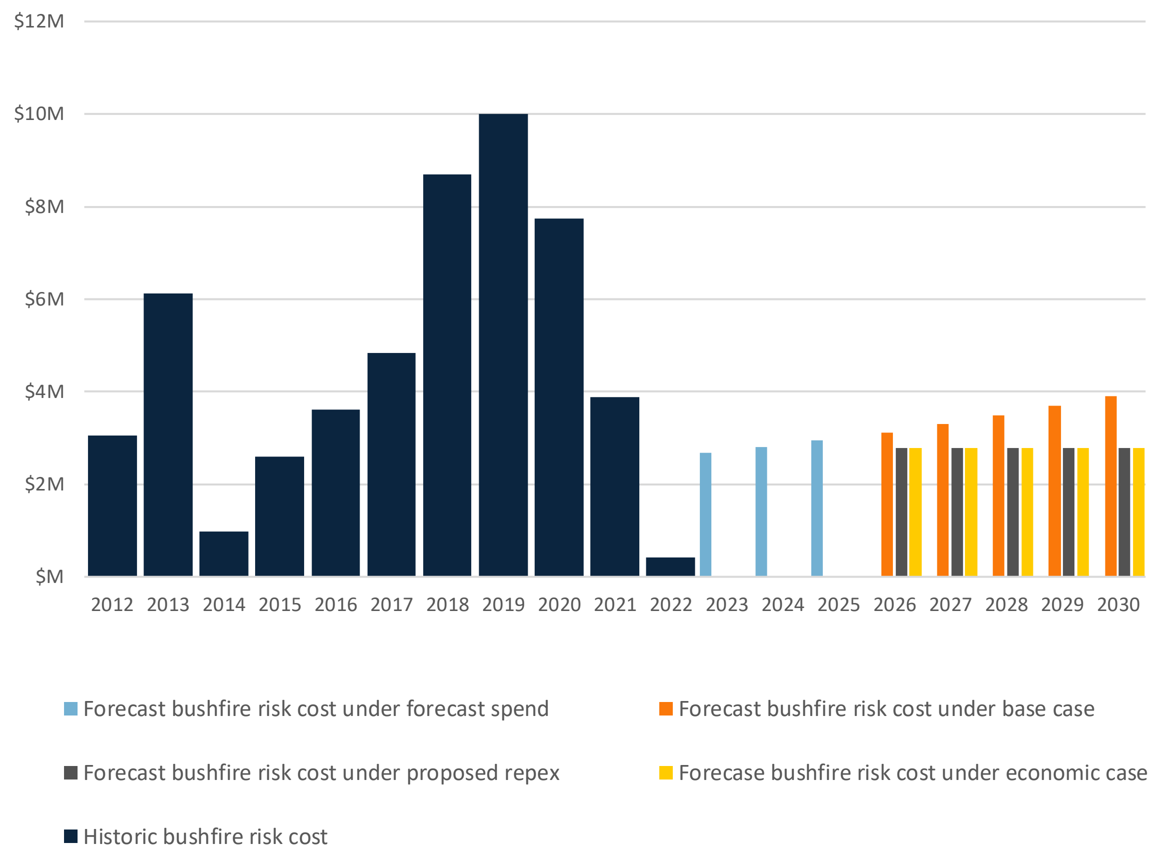
Figure 2 and Figure 3 display the results of our repex forecast and the service outcome that it achieves, relative to our counterfactual ('base case') and to an alternative scenario ('economic').

Figure 2: Impacts on reliability service outcomes[6]



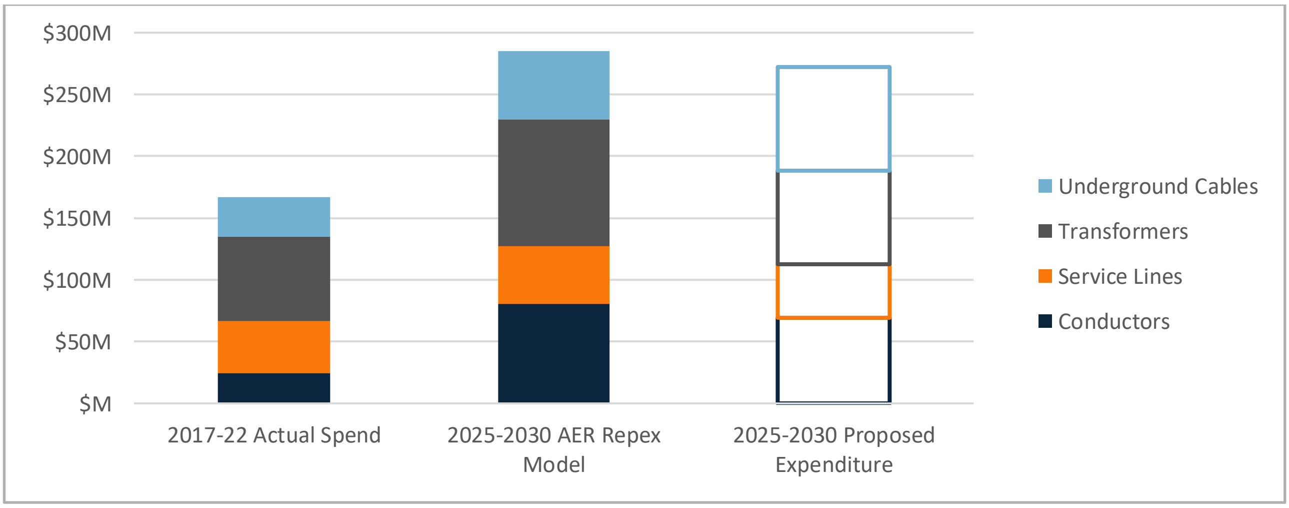
[6] For modelled assets only. Unmodelled assets, which have proposed expenditure reliant on historic spend, have not had risk quantified in this manner. Risk for modelled zone substation assets has been quantified but are not yet included in this aggregate risk figure.

Figure 3: Impacts on bushfire safety service outcomes[7]



As part of our top-down challenge, our repex forecast was compared to and shown to be lower than the results of the AER's repex model in aggregate (for asset classes included in the AER repex model), as displayed in Figure 4. This was also the case at the asset category level, except for underground cables where additional expenditure is needed to improve CBD reliability to meet jurisdictional reliability service standard targets – as the least cost means of achieving compliance.

Figure 4: Comparison of expenditures with AER's repex model



[7] For modelled assets only. Unmodelled assets, which have proposed expenditure reliant on historic spend, have not had risk quantified in this manner.

3. Background

3.1. The scope of this document

This document covers the repex for our distribution network assets used in the provision of Standard Control Services (**SCS**), and which collectively form the:

- sub-transmission system;
- zone sub-stations;
- distribution network including the high and low voltage network and service lines;
- mobile plant; and
- telecommunications and their associated facilities.

The asset classes covered by this document are set out in table 2 below.

Table 2: Asset classes and description

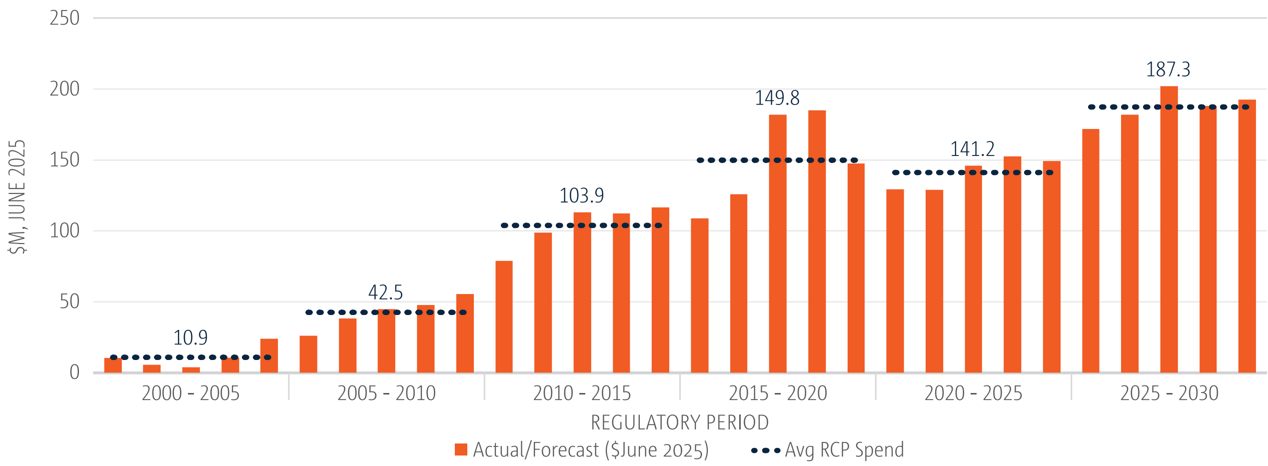
Asset class	Description
Poles	The support structure for overhead conductors at a height above ground level and at a distance from all other objects that exceeds prescribed safety clearances.
Pole top structures	Enable overhead conductors to be securely attached to their support structures, support other pole mounted equipment and connect the overhead conductors to other equipment. They include cross arms, insulators, overhead switchgear, joints and taps, and other components.
Underground cables	Transmits electricity between substations and from substations to customers.
Overhead conductors	Supported by poles and pole top structures, 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.
Distribution transformers	Progressively change the voltage of electricity to a level such that it can be used by customers. Also includes line voltage regulators and capacitors used in line regulation.
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 load switches.
Service lines:	Connect the distribution network to customers.
Zone substation power transformers	Provide voltage transformation and regulation of electricity in the HV network (sub-transmission system and HV distribution network).
Zone substation circuit breakers	Act as controlled switching devices within zone substations and control the energisation of electricity distribution equipment.
Protection relays:	Automatically protect personnel and the network in the event of fault conditions, by activating primary plant (such as circuit breakers or reclosers).
Other line assets	Assets include cable ducts, manholes, earthing systems, ancillary equipment (line fault indicators, access roads, locks) and other safety programs required to meet current safety standards.
Other substation assets	Assets include HV instrument transformers, surge arrestors, capacitor banks, AC and DC auxiliaries, disconnectors, buildings, buswork and support structures, substation cables and terminations, secondary wiring and ancillary asset types.
Telecommunication assets	• **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.

While this document justifies all expenditure, more specific business cases were developed for discrete large projects or new discrete programs. These business cases are summarised in Section 8.

3.2. Our expenditure to date

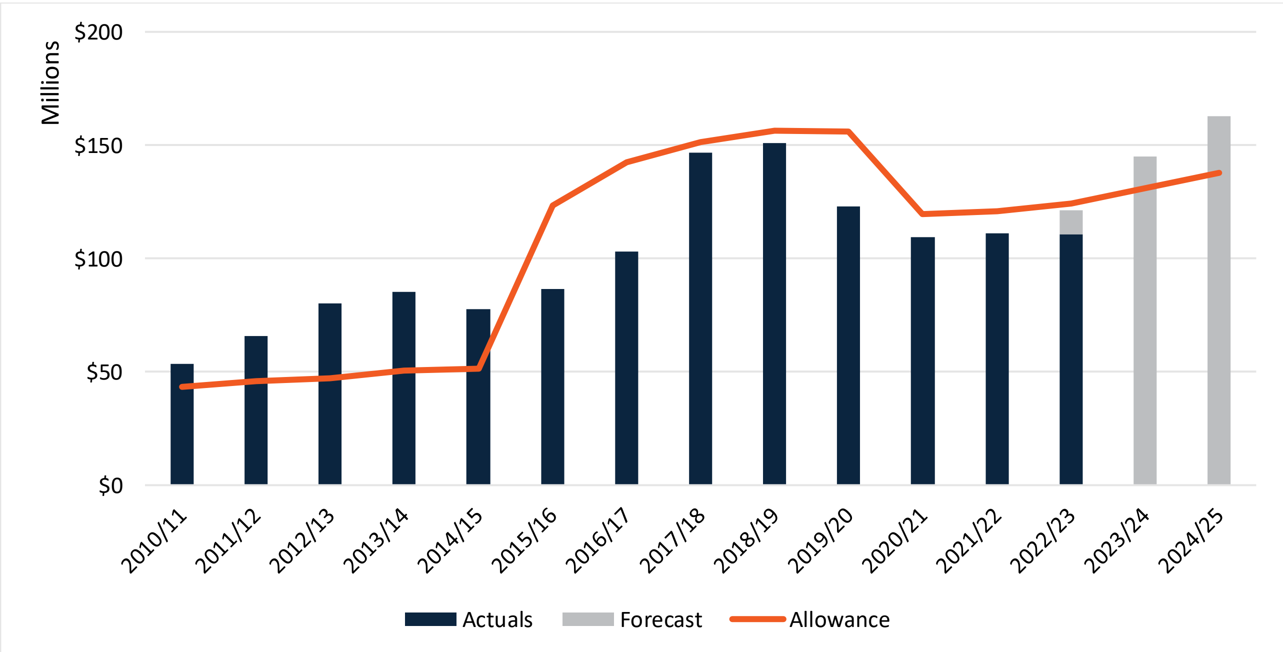
We have one of the oldest distribution networks in Australia, with a large proportion constructed in a confined period in the 1950s and 1960s. This gives our asset profile a unique shape. Consequently, acting prudently and efficiently, we replaced relatively little network in past regulatory periods when the age profile was lower. Over time, as the age profile has increased and asset condition deteriorated causing escalating service risk, acting prudently and efficiently, our repex levels have followed a consistent upward trend, as Figure 5. This long-term increase in repex, combined with increasing augex on reliability and bushfire mitigation, have been crucial in keeping long-term service performance steady despite escalating risk.

Figure 5 Long term replacement expenditure profile



In the 2020-25 period, our repex levels continued this long-term trend, and we forecast spending slightly higher than the AER forecast for this period. Despite this increase in repex (and augex), overall distribution system reliability has declined over this more recent period.

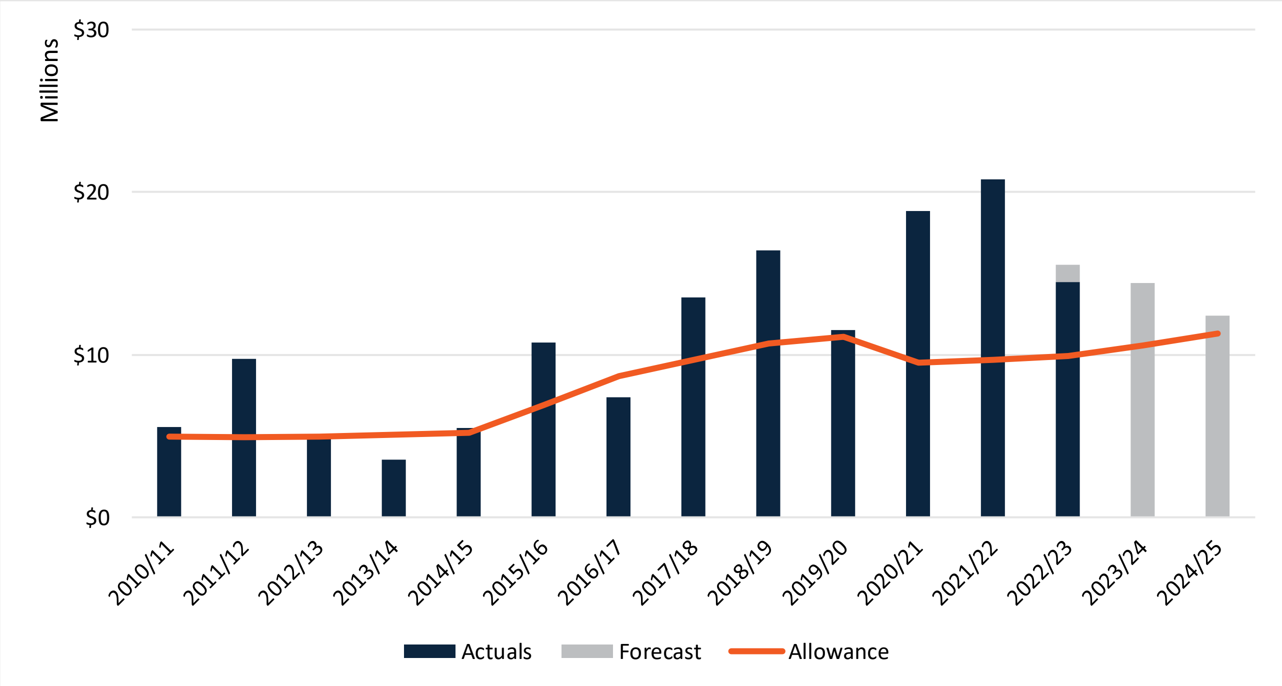
Figure 6 – Repex expenditure relative to allowance



Our visibility of risk in 2020-25 vastly improved through analytics in quantifying in monetary terms, customer service risk posed by our assets, capitalising on enabling investments such as our Assets and Work program from our 2020-25 Regulatory Proposal. With this information, we reprioritised expenditure within the asset classes of our overall repex, to reasonably endeavour to manage overall service performance within our capex allowance.

We also re-prioritised our overall network capex program, with an increase in reliability augmentation expenditure (**augex**), see Figure 7. In 2016 we began implementing a feeder automation program, segmenting our network into smaller segments such that a fault impacts a smaller number of customers. In this way we can mitigate the reliability risk of asset failures by reducing the reliability *consequence* of a failure rather than addressing the *probability* an asset will fail (e.g. by replacing it).

Figure 7 – Long term Augex (Reliability) expenditure profile



Our analysis has shown this program is cost effective at managing reliability risk where there are large customer numbers on a single segment of network. We reprioritised expenditure from repex to reliability augmentation expenditure as shown above. This has allowed us to achieve a moderate improvement in reliability in 2016/17 through to 2022/23 particularly in the urban and rural short categories where there are larger numbers of customers per feeder and the feeders are more often meshed.

3.3. Our performance to date

Reliability service performance

Key observations on our reliability service performance, measured on the basis of the duration of supply interruptions (**USAIDI**) [8] and frequency of supply interruptions (**USAIFI**)[9] are that:

- at an overall network level as displayed in Figure 8, our reliability performance has generally been sound, but we have seen a gradual deterioration since the start of the 2020-25 RCP;

8 Unplanned System Average Interruption Duration Index (USAIDI).

9 Unplanned System Average Interruption Frequency Index (USAIFI).

- at a feeder category level, performance in the Adelaide Central Business District (CBD) feeder category, as displayed in Figure 9, has been declining since the start of the 2020-25 RCP with respect to interruption frequency. This is mainly due to poor network asset condition driving failures in high voltage cables. Given this performance, we are unlikely to achieve our jurisdictional network reliability service standard target for CBD feeders in the 2020-25 RCP.

Figure 8 – Distribution System Reliability (excluding MEDs) - Normalised

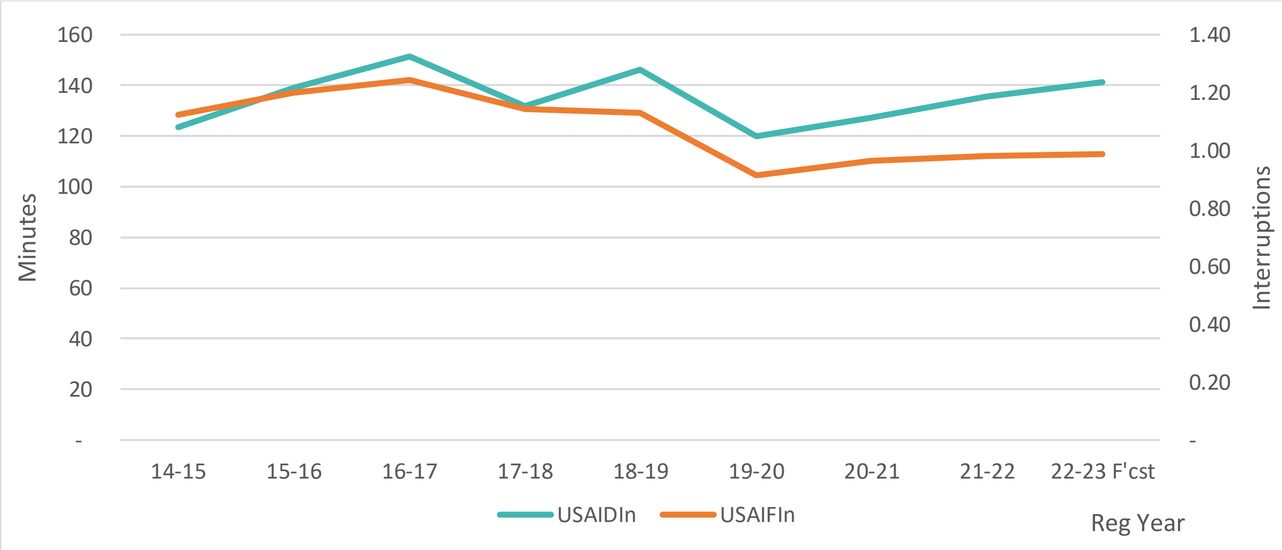
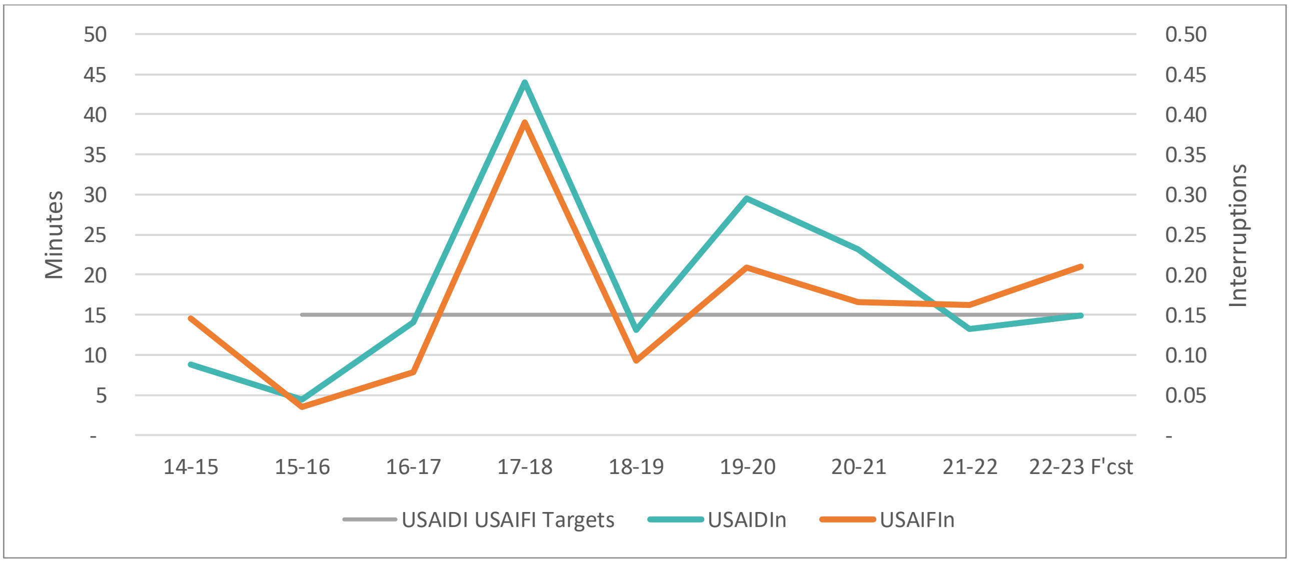


Figure 9 - CBD feeders reliability performance (excluding MEDs)

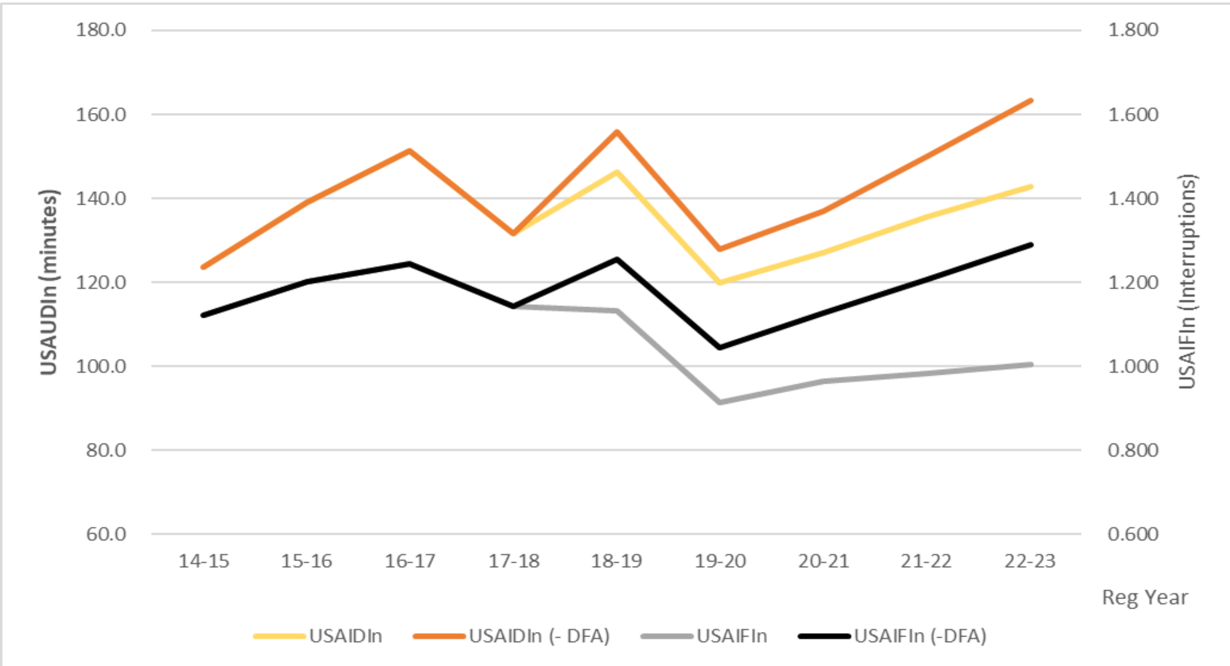


The extent of the concern that network asset condition is posing for reliability performance is being masked in the observed reliability trend data, noting that:

- we have been implementing a program included in our AER capex forecast for 2020-25 RCP called 'Assets and Work', which has been allowing us to better target the network asset replacements that have the greatest impact on reliability outcomes; and
- since 2016 we have been implementing a program of network feeder automation which has been allowing us to mitigate consequences of an asset failure, rather than mitigating the risk that an asset will fail (i.e. by replacing it):

- this program involves us sectionalising our network into smaller segments so that a network asset failure / fault impacts a smaller number of customers, mitigating the duration and frequency of supply interruptions, and has so far been deployed on 245 of our 1,722 feeders;
- this program is cost effective in managing reliability risk where we have large customer numbers on a single network segment, particularly urban and rural short feeders;
- our analysis indicates, as shown in Figure 10 which displays our reliability performance with and without feeder automation, that if we had not undertaken feeder automation, our reliability service performance would have been materially worse, in terms of both customer experienced outage frequency and outage durations;
- however, while there will continue to be a role for network augex by way of feeder automation in response to underlying and non-asset condition causes of reliability impacts, there will be limits to what further network automation / segmentation can achieve noting:
    - these programs cannot address non-reliability consequences of asset failures such as safety and bushfire risks (i.e. risks to persons and property);
    - automation tends to be uneconomic on feeders with lower customer density; and
    - there is a point where even for reliability management, it becomes more efficient to address the underlying cause of an outage (i.e. the risk of an asset failure) due to diminishing returns presented by continued network segmentation via feeder automation.

Figure 10 Distribution system reliability - with and without distribution feeder automation (DFA)



Safety service performance

Key observations on our safety performance, particularly in relation our network assets causing electric shocks or fire starts are that:

- the number of reports of our low voltage (LV) distribution network assets causing shocks, as displayed in Figure 11, has been relatively stable over the long term, noting that in recent years we increased our proactive renewal expenditure for service lines which are the assets contributing to increases in electric shocks, and introduced systems to leverage smart meter data to detect faults before resulting in a shock; and
- the trend in fire starts has also been fluctuating long term, as displayed in Figure 12, and declining in recent years driven by a number of factors including: our operational controls; increasing of repex; the increasing sophistication of our targeting of asset replacement based on risk; and our ongoing 'Bushfire Risk Mitigation Program' involving network upgrades (augex). La Niña conditions present across regions on our network over the past three years has meant unusually wet and cool summers and decreased fire start risk. As these conditions subside, fire start risk will increase in coming years.

Figure 11 - Electric shock reports

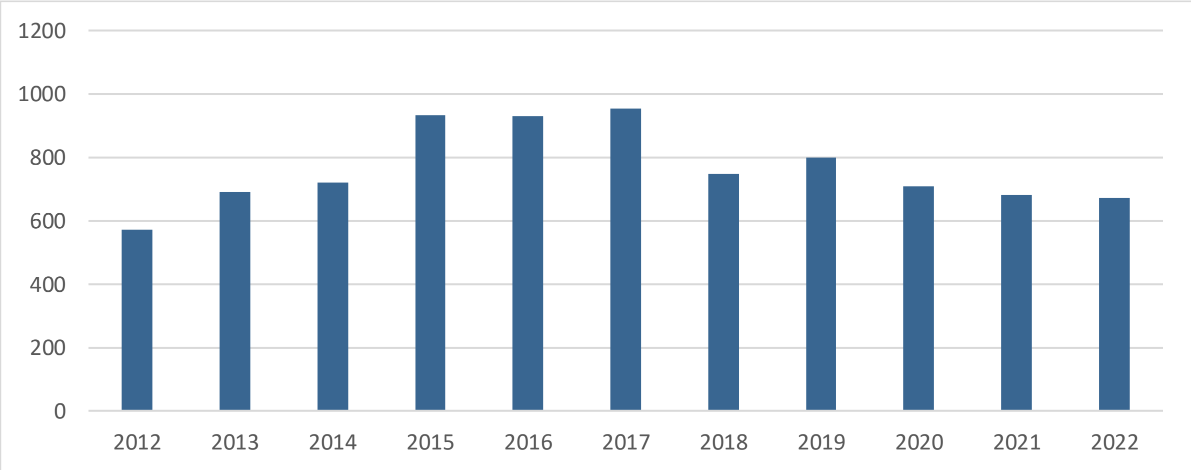
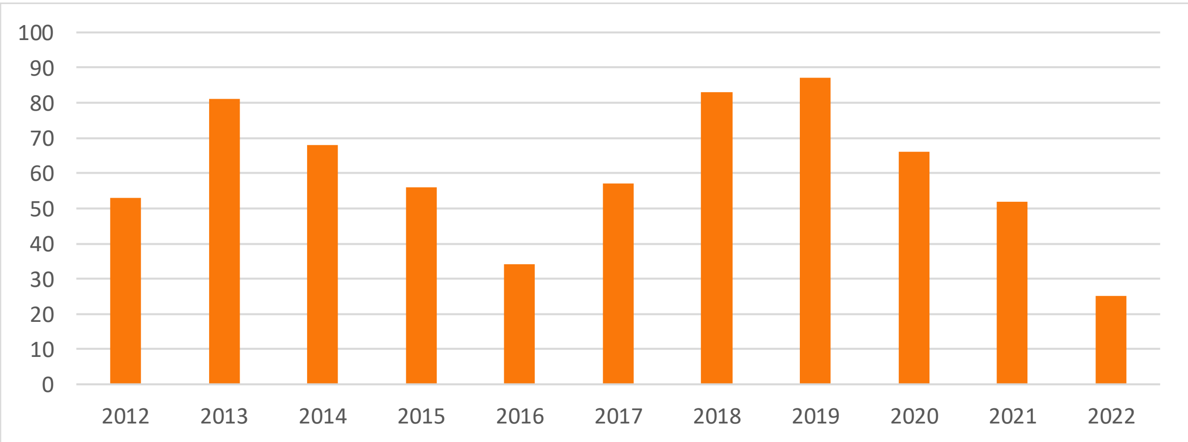


Figure 12 - Network fire starts



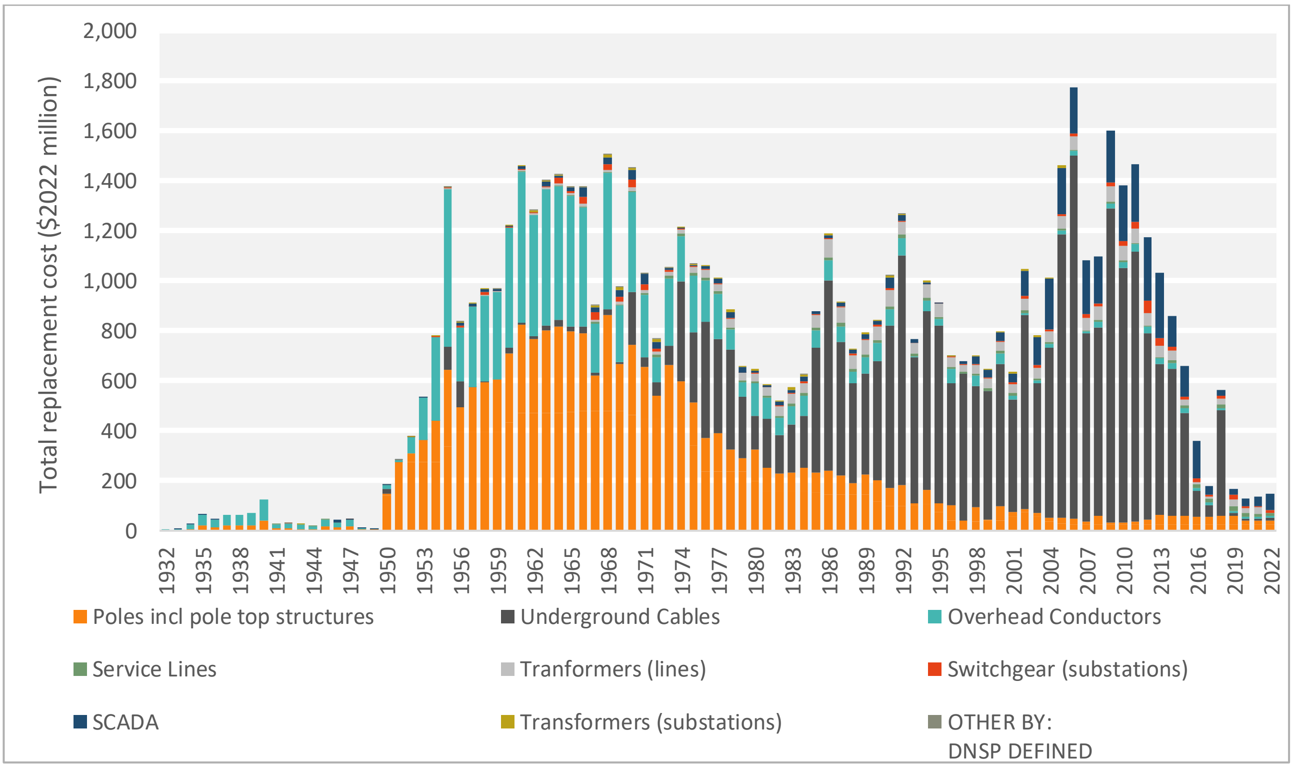
As with the case for reliability, with respect to safety, we have deferred repex by addressing the consequence of asset failures via network upgrades to mitigate bushfire risk. These strategies can be used to defer replacements in the short term but do not eliminate the need for asset replacement, and many of these upgrade programs have finite scope. For example, once we have installed fire danger protection settings on all feeders to reduce bushfire risk, the risk on these assets continues to increase over time due to asset condition deterioration, eventually requiring asset replacement as an intervention.

3.4. Drivers for change

The condition of our network is deteriorating

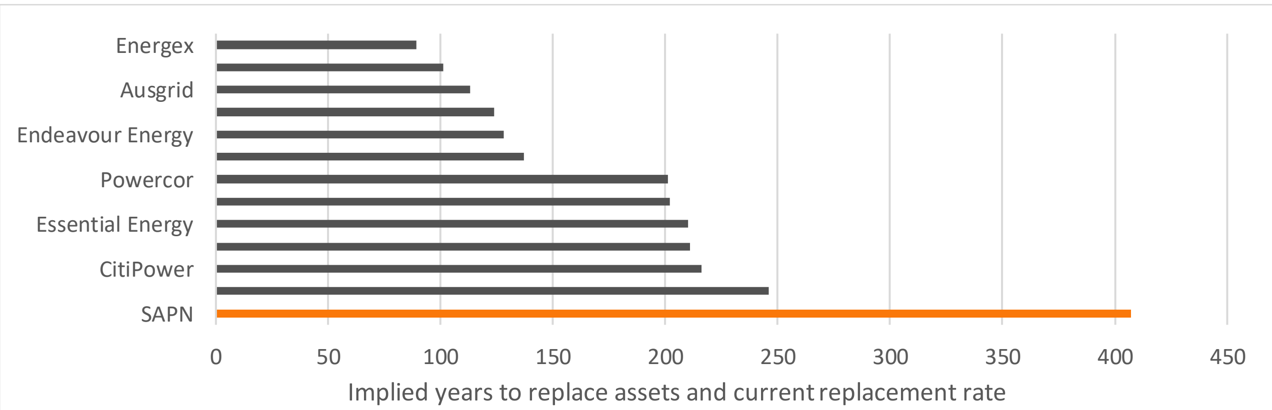
We have one of the oldest electricity distribution networks in Australia with a large proportion of our network constructed in the 1950's and 1960's when major electrification of the state commenced under the Playford Government involving a rapid expansion of the network across metropolitan areas and to major regional centres. Much of this network will reach the end of its life in the coming decades. Figure 13 shows the age profile of some of our highest volume network asset categories.

Figure 13 - SAPN Asset age profile



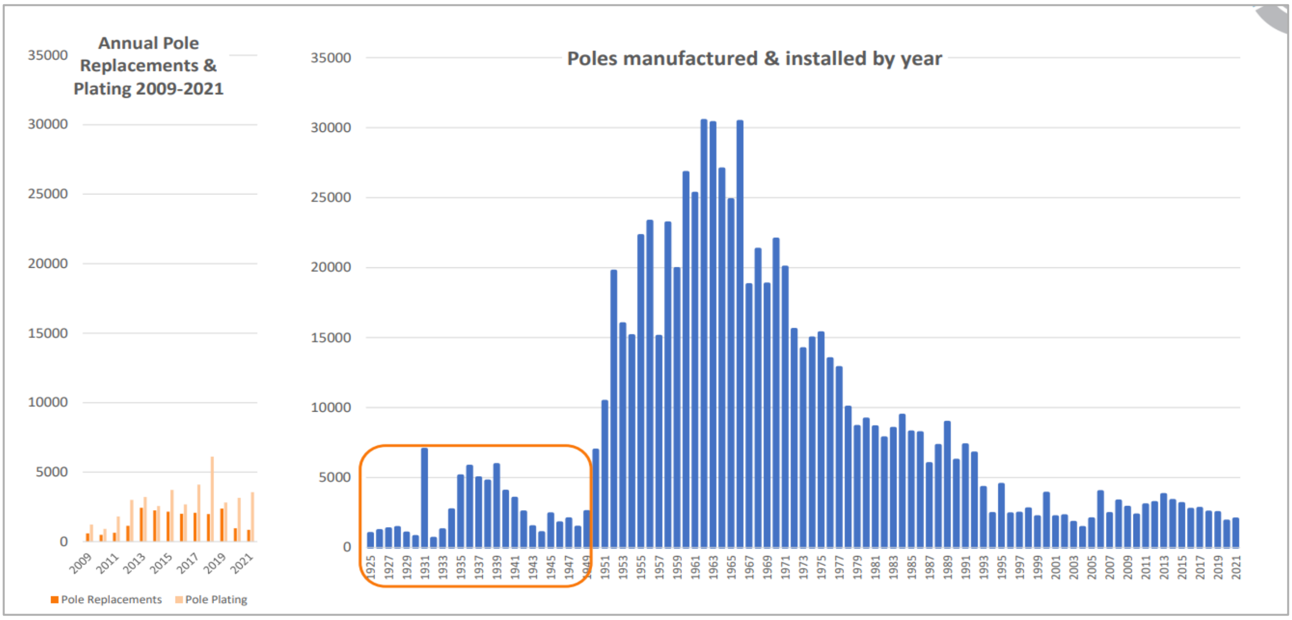
In past RCPs as the asset base was younger, acting prudently and efficiently, we replaced relatively little of the network constructed to date, maintaining the safety and reliability of our network with the lowest repex rate in the NEM. Figure 14 below shows the result of analysis from Dynamic Analysis determining implied asset lives from the replacement rates of various Distribution Network Service Providers (DNSPs).

Figure 14 - Implied asset lives



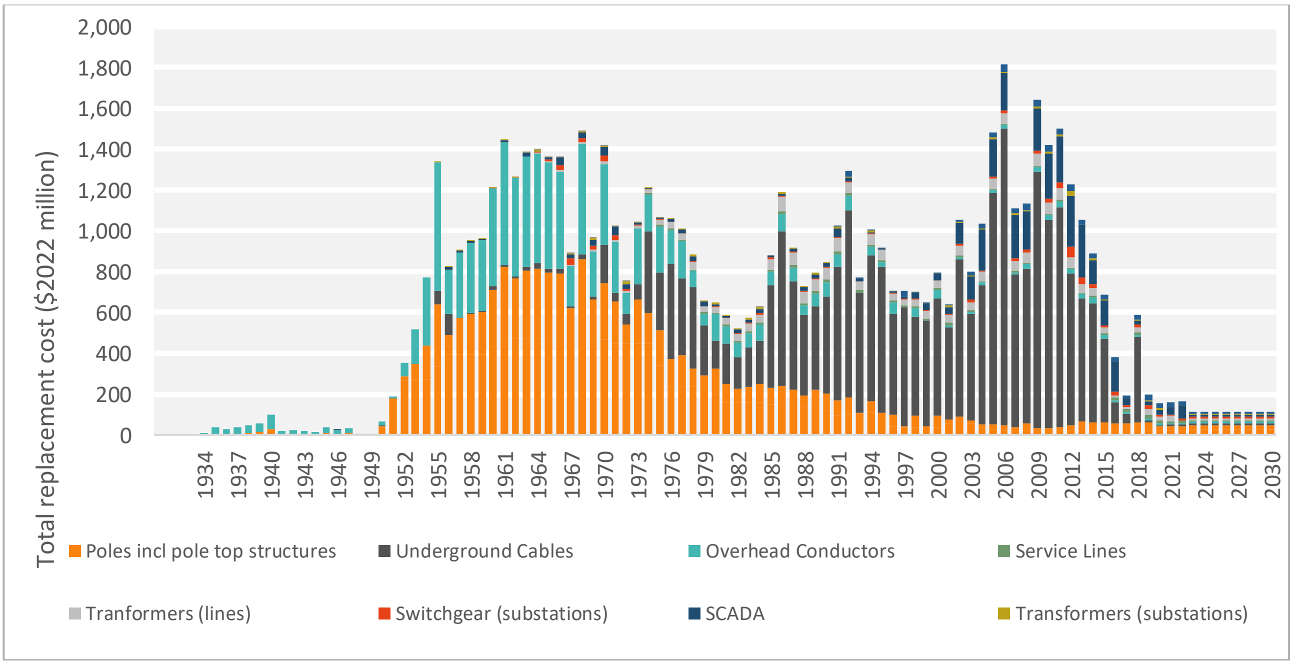
While a low replacement rate of long-lived assets was prudent and efficient when the assets were relatively new, as our age profile has increased so to has our level of repex. Our pole replacement program and age profile illustrate this concept – see Figure 15. Our current pole replacement rate looks reasonable when compared to the rate of construction in the oldest parts of the network (1920's to 1940's). However, the rate at which the network was constructed is not constant – during the widescale electrification of the state in the 1950's and 1960's considerably more poles were installed. As this cohort of poles age and deteriorate the current rate of replacement is unlikely to maintain the current failure rate (and therefore current service outcomes).

Figure 15 – Pole replacements vs pole construction



Without a continuation of an increase in repex, the number of assets reaching end of life will increase, leading to more failures in service, deteriorating reliability and increasing safety risk to customers and the community. Forecasting the age profile of our existing assets at our current replacement rate, the cohort of assets reaching the end of their technical life will grow.

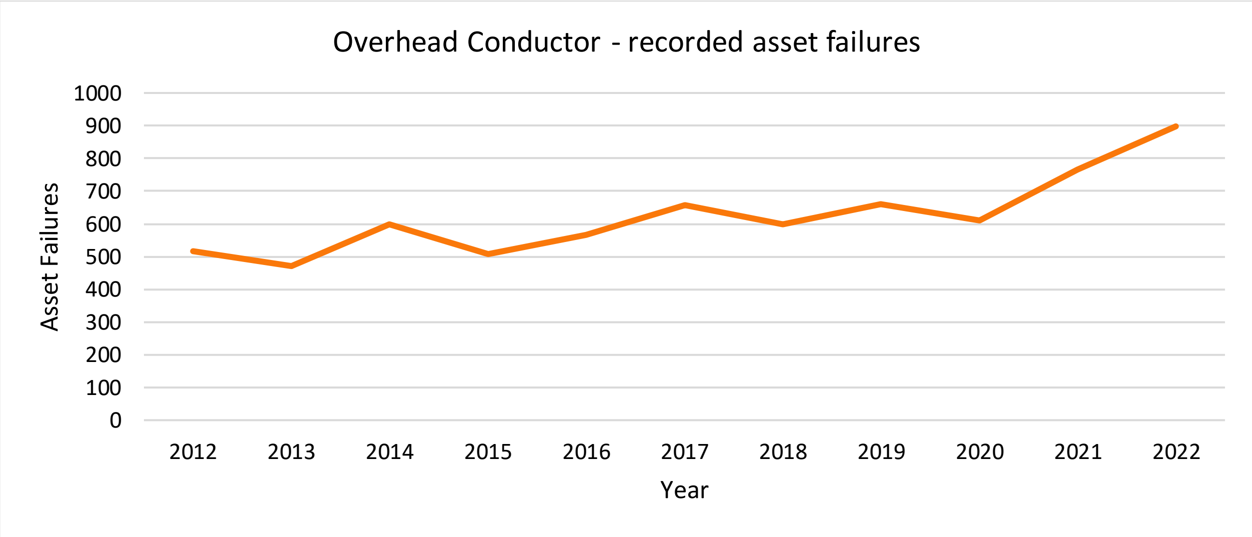
Figure 16 - Projected age profile (of existing assets) at 2030



We are seeing an increase in the failure rate of our assets

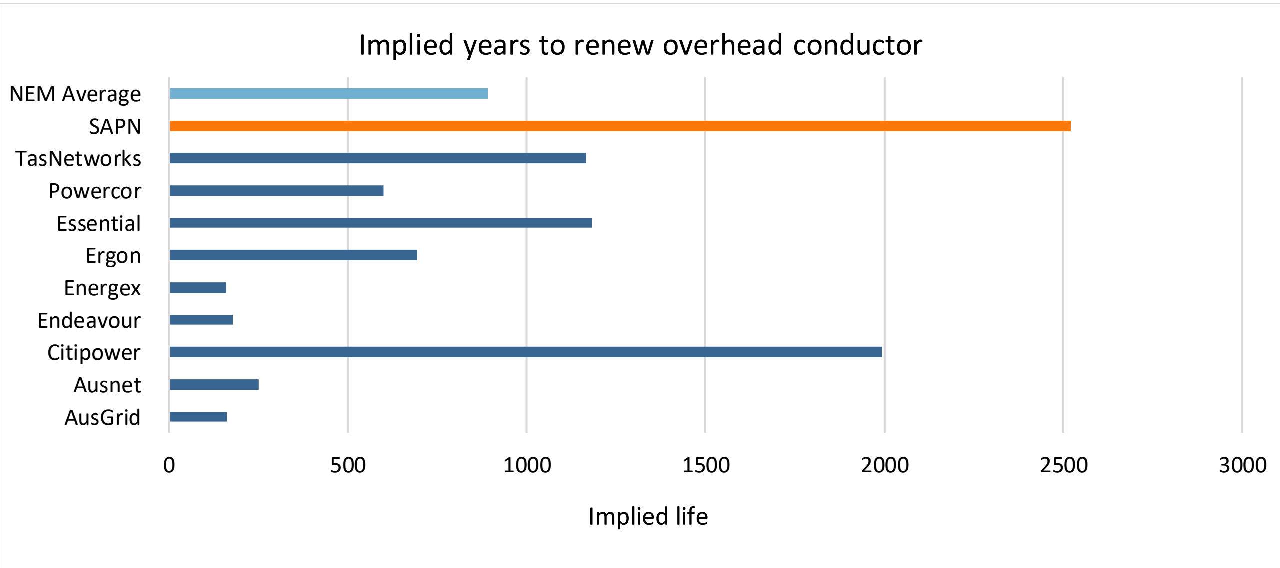
While our proactive pole replacement program (targeting poles most likely to fail) has maintained the performance of our pole population, we have not maintained the performance of some of our other asset classes. For example, overhead (**OH**) conductors have seen increasing in-service failures over the last decade, resulting in increasing outages and safety risks to the community, see Figure 17. These failures are those attributable to deteriorating condition (i.e. not caused by extreme weather events, vegetation, third party damage, etc).

Figure 17 - Overhead conductor – recorded asset failures



This asset class has been essentially 'run to fail' with minimal proactive investment, our replacement rate for OH conductor assets is by far the lowest in the NEM, refer Figure 18. At our current rate of replacement our OH conductor assets would need to last approximately 2,500 years. While this replacement rate may be appropriate when the assets are relatively young, this rate is no longer sustainable. Given the current replacement rate, we are seeing an increasing trend in failures and the associated outages and safety risks.

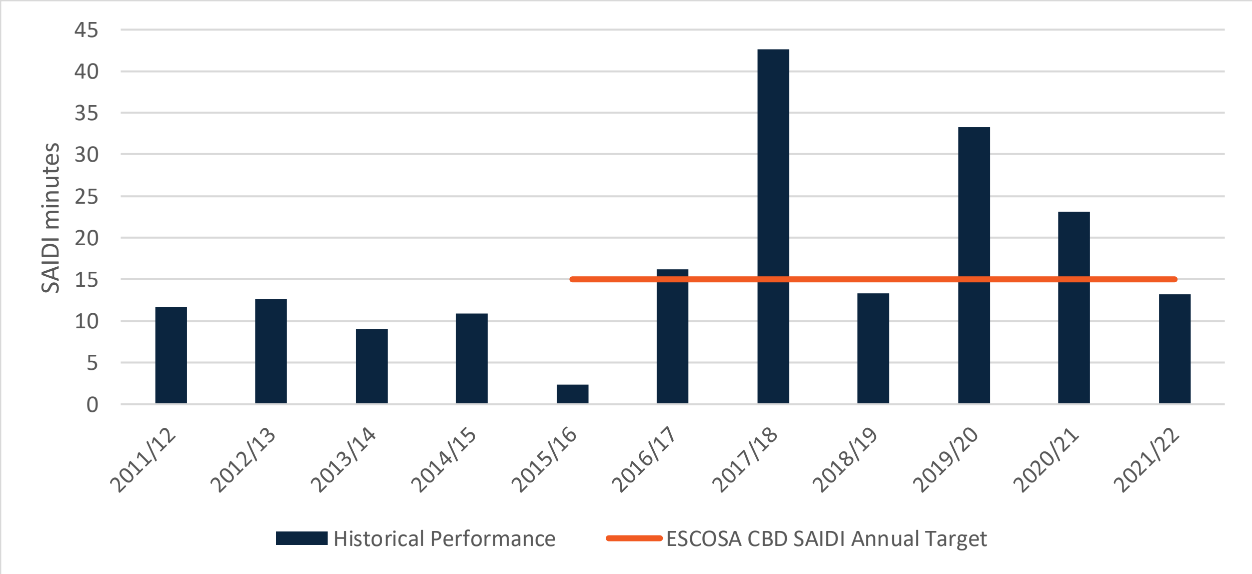
Figure 18 - Implied overhead conductor life



Our reliability in the Adelaide CBD has failed to meet targets

As with OH conductors, we historically run our underground cable network to failure with minimal proactive investment. In the current RCP we began proactively replacing underground cable in the CBD in response to increasing failures. Our low historic replacement rate (and the fact that our oldest underground cable network is in the CBD) is impacting reliability with evidence of increased in cable failures in the CBD.

Figure 19 - CBD reliability performance



Our reliability targets are set by ESCoSA and SAIDI has been set at 15 minutes. As can be seen in Figure 19 we have not been meeting the target, predominantly because of underground cable failures.

3.5. Asset management practice

This section sets out our asset management approach and how we are responding to these drivers for change. It outlines the overarching asset management policy, objectives and core strategies.

Asset management policy

Our policy is aligned with the Corporate Strategic Plan, applies to all of our assets and associated activities and supports excellence in asset management and delivery of essential services. The asset management policy states that we will employ good asset management practices that:

- provide a safe environment for employees, contractors and the community;
- are guided by the Corporate Strategic Plan;
- are driven by the levels of service that customers value;
- ensure we comply with our regulatory obligations;
- deliver a prudent risk based approach; and
- foster continuous improvement.

The asset management policy practices are integrated into the asset management objectives and strategies applied to our network assets.

Asset management objectives

We developed asset management objectives underpinning our asset management core strategies. The asset management objectives are outlined in our Strategic Asset Management Plan (**SAMP**). These objectives are as follows:

1. keep the public, staff and contractors **safe;**
2. develop service levels supported by comprehensive **customer and key stakeholder engagement**;
3. achieve agreed current and future **levels of service** while complying with legislative requirements;
4. deliver sustainable network investments and performance that are **cost efficient** and consistent with prudent risk management approaches;
5. maintain an asset management system that satisfies the criteria and evidentiary needs of **regulators**; and
6. promote clarity and transparency to build **stakeholder confidence**.

Asset management core strategies

The features of our asset management approach, include:

- development and delivery of service levels supported by comprehensive customer and key stakeholder engagement;
- translation of service levels and risk into operational asset management decision making processes;
- development and maintenance of the asset information systems and standards to ensure compliance with regulations, industry standards and to enable effective asset management decision making;
- determining optimum spares holdings to deliver regulated standards and customer expectations;
- integration with augmentation projects (such as customer connections), including optimal scheduling and bundling of inspection, maintenance and replacement of assets;
- long-term planning for managing each asset class, allowing for factors such as the age profile and expected end of life, performance history, condition information, and industry experience; and
- achievement of continuous improvement.

We continually improve our asset management practices and systems to provide a balanced outcome that meets shareholder, risk, compliance, and customer objectives. A major part of that improvement has been continuing to transition to a risk-based replacement approach for assets. This transition requires good asset condition data combined with improved analytical techniques to enable asset risks to be quantified.

Asset management system

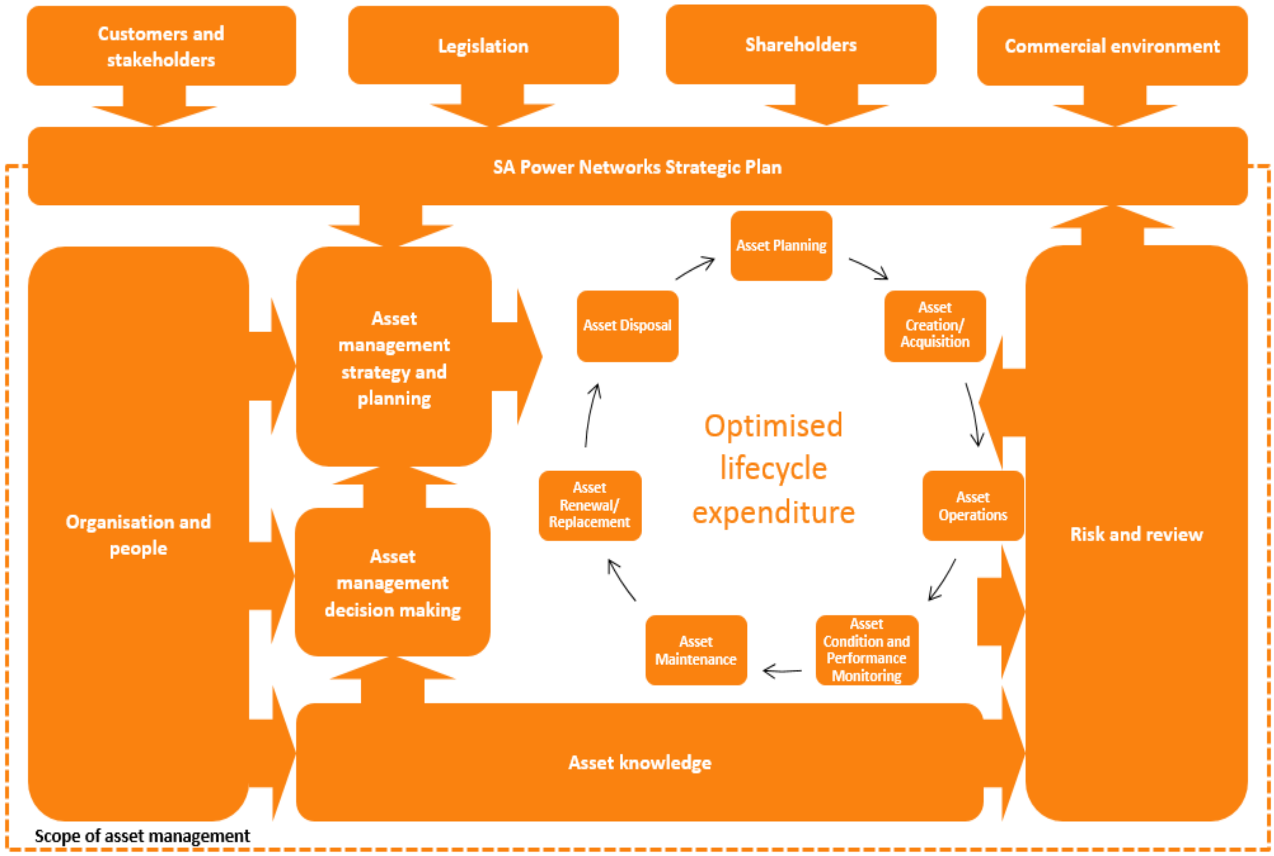
To deliver effective asset management, we evolved and continue to develop an Asset Management System (**AMS**). The AMS ensures the many aspects of asset management are addressed, risks are identified and managed, asset management activities are integrated with other business planning functions and reviews and improvements are organised and ongoing. Our AMS includes but is not limited to:

- strategic asset management documentation including the SAMP and supporting detailed strategies, asset plans, manuals, processes and procedures with line of sight to the Corporate Strategic Plan;
- comprehensive, centralised management of asset information and standards;
- specific strategies for managing all classes of assets and all operating environment issues;
- a risk management process;

- systemised relationship management to ensure asset management activity integrates fully with other departments;
- effective management of life-cycle delivery mechanisms; and
- work process documentation including provision for review and improvement.

Like many other utilities our AMS is based on the conceptual model shown in Figure 20 – which shows hat the elements of the AMS are integrated and reliant on each other, with the performance of any one element affecting other elements.

Figure 20- Asset management system structure



Source: Institute of Asset Management, 2015

Asset management improvement

We have been investing in our asset management systems via a long-term strategic program, Assets and Work (**A&W**), delivering on a roadmap first established in 2014 in consultation with the global asset management specialist firm, Vesta aligning with ISO55000:2014:

- the first stage of the A&W program was included in the AER's 2015-20 Distribution Determination – development in this period focused on foundational elements including asset data as well as an initial move to a value versus cost approach to network investment; and
- the second stage of the A&W program was included in the AER's 2020-25 Distribution Determination - this stage has focused on improving our approach to economic valuation of network investment and ensuring network expenditure aligns with this approach.

Investment in our asset management systems via the A&W program underpinned our ability to continue to deliver sound service outcomes to customers despite a growing number of assets reaching end of economic service life. This has largely been achieved by better understanding the risk our assets pose to service outcomes and where best to invest our network repex.

Recognising the need to refresh the roadmap first developed in 2014, we comprehensively assessed our asset management practices and systems in 2023 with asset management specialist AMCL. This assessment formed the foundation of a revised roadmap to 2030 to be delivered via our Assets and Work Phase 3 (Asset Management Transformation Program – **AMTP**), which effectively continues the A&W program, delivering on a revised roadmap and ensuring that all business activities support effective asset management.

Asset replacement planning

Asset renewal / replacement decisions form a fundamental part of the asset management lifecycle. We take a value-based approach when considering whether to renew or replace an asset. This decision on timing is made by comparing the cost (including risk costs) of retaining the asset in service against the cost of renewal or replacement (or the cost of investing in an alternative solution).

When determining if to replace (or renew) the asset we consider the *benefit* of replacing the asset which is typically the risk removed. On failure, an asset may pose a risk to the public, network workers, the network itself or any other stakeholder in the electricity system. This is summarised by the Risk Cost, which is a measure of the expected monetised value of the risk event. The high-level formula for calculating the Risk Cost is depicted in Section 6.3. At its highest level, the Risk Cost is made up of three components as follows:

- **Probability of Failure (PoF)**: the probability an asset experiences a functional failure in a given year;
- **Likelihood of Consequences (LoC)**: the probability any given functional asset failure results in a consequence occurring; and
- **Cost of Consequences (CoC)**: the average cost of a consequence that results from the asset failure.

During this RCP, as part of our A&W program, we developed Risk Cost Modelling, allowing us to quantify risk costs at an individual asset level. This quantification enables us to forecast risks to service outcomes at an individual asset, asset class or asset portfolio level under various scenarios as well as forecast the investment required to manage these risks to achieve certain service outcomes.

Our approach to quantifying risk and forecasting repex has been developed to align with the AER ARP note.

4. The identified need

This document justifies the total sum of our forecast repex for 2025-30. This repex comprises several asset classes, projects and programs, that each have their own specific contexts as to asset condition and the need for an asset retirement decision. However, we configured and optimised all of this activity to achieving an overall target service level outcome for customers, drawing on our analysis and modelling of quantified risk costs (or avoidance benefits) where feasible and by maintaining spend as a proxy for maintaining service where data does not permit detailed modelling. This combination has allowed us to decide which asset classes to spend more or less in, based on their expected effect on forecast risk and service performance.

The underlying driver for investment to be considered in this business case is that a significant proportion of our network assets are ageing to a point of significant deterioration of condition, triggering consideration of the need to retire assets. We identify that these factors will drive rising network asset failures, which will pose risks to the maintenance of service performance (reliability and safety) to customers – that is, there are risks of increasing: service outages; direct physical harm to persons; and physical harm to persons, property and building damage to customers and the community from network asset failures starting fires.

In considering potential responses to this driver, we engaged with our customers on their desired service level outcomes balanced against price outcomes, and considered our regulatory requirements under the

National Electricity Rules (**NER**), National Electricity Law (**NEL**) and jurisdictional regulations. As a result of these considerations, the identified need for the total sum of our replacement is as follows:

a. to respond to customers' concerns[10], identified through our consumer and stakeholder engagement process, regarding their explicit service level recommendations that we:
    - maintain reliability service performance by geographic region – driven by a desire to not see further inequity in service performance between regions;
    - maintain safety service performance in aggregate – driven by a desire to not see deterioration in the safety risk posed by the network;

b. to comply with applicable regulatory obligations / requirements[11], in this case with specific reference to the network reliability service standard target set by ESCoSA in the South Australia Electricity Distribution Code (**EDC**) in relation to the Adelaide CBD;[12]

c. outside of the Adelaide CBD, to maintain the reliability service performance of our network[13] –we have been guided by consumers as to how reliability should be maintained, in this case, by geographic region - highlighting the importance of considering equity between regions and customers when investing in the reliability of the network;[14] and

d. to maintain the safety of our distribution network and system, in relation to the risks of harm to workers, consumers and community, and property and buildings of consumers and the community.[15]

4.1. Our forecast of service outcomes

The drivers for change outlined in section 3.4 mean that without changing our current approach (i.e. current replacement rates), we expect to be unable to maintain safety and reliability on our network.

To confirm this, we modelled a Base-Case (business-as-usual) counterfactual to forecast the outcome for customers in terms of the quantitative / monetised service risk cost that would result if we continued with our current replacement rates. As shown in Figure 21, the base case would see increasing failures with increasing safety risks and a deterioration in reliability.

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

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

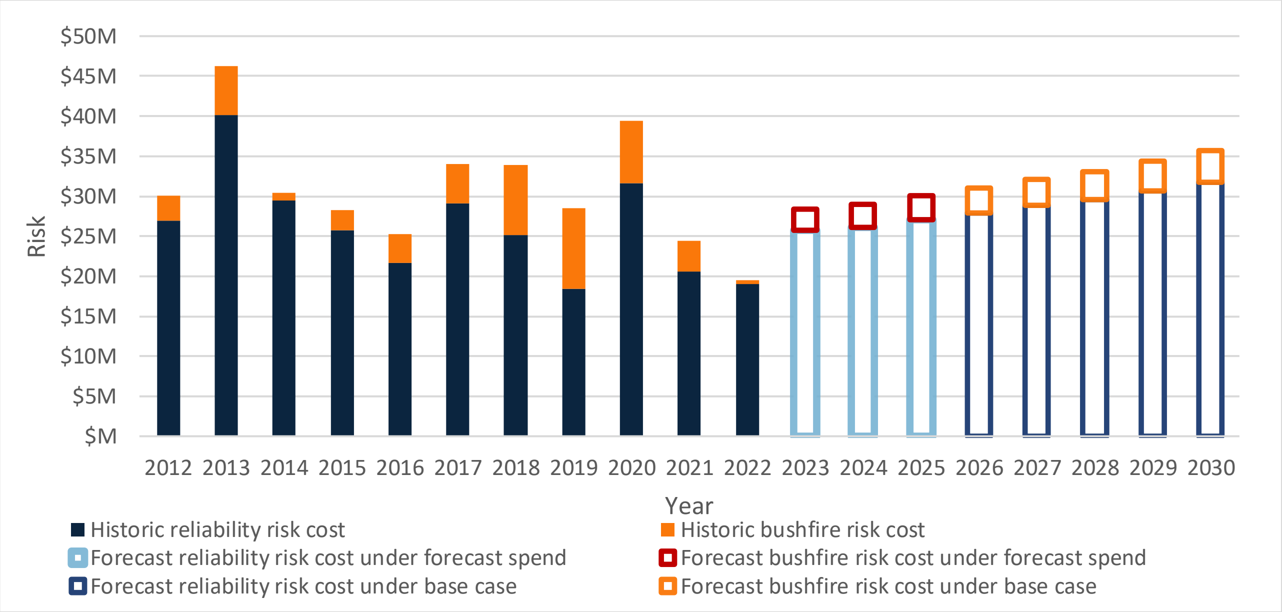
12 SA Power Networks is required by the EDC to use its best endeavours to achieve minimum network reliability targets during each and every regulatory year. For the Adelaide CBD feeders, the target has been set at 15 minutes (average minutes off supply per customer per annum) in relation to the duration of unplanned supply interruptions (excluding Major Event Days). ESCOSA, *Electricity Distribution Code (EDC), Version EDC/14*, 1 July 2025, p.8.

13 This is pursuant to Clause 6.5.7(a)(3) of the NER, which requires that, where there is no applicable regulatory obligation or requirement in relation to reliability of supply of standard control services, the required expenditure is limited to expenditure to enable the distributor to maintain the reliability of standard control services.

14 The NER do not mandate the basis upon which reliability service performance should be maintained.

15 This is pursuant to Clause 6.5.7(a)(4) of the NER, which requires that safety of the distribution system through the supply of standard control services be maintained.

Figure 21 – Total risk due to condition of all modelled assets[16]



5. The target outcome recommended by our customers

The sum total of the forecast repex proposed in this document, is aligned to achieve outcomes that were directly supported by our customers, as ultimately reflected in the recommendations of the People's Panel:

- the topic of service reliability and safety was a key focus of our consumer and stakeholder engagement program. One of the four key themes that framed our engagement under a desire to 'focus on what matters' to our customers has been the theme of 'a reliable, resilient, and safe electricity network';
- in engaging on this theme, and under the specific topic of 'reliability and bushfire safety' we undertook a series of deep-dive workshops called 'Focused Conversations' with a broad range of consumer, industry, and government and regulatory body representatives. In these Focused Conversations we sought recommendations on the service outcomes customers prefer and expect;[17]
- with particular regard to the management of reliability and bushfire safety through network asset replacement, we engaged on the identified need by outlining:
    1. information on what impacts on the safety and reliability of our network and how these drivers have been evolving over time and how this can be managed through either asset replacement or asset upgrades;
    2. our service outcomes and expenditure performance over time in asset replacement;

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16 For modelled assets only. Unmodelled assets, which have proposed expenditure reliant on historic spend, have not had risk quantified in this manner. Risk for modelled zone substation assets has been quantified but are not yet included in this aggregate risk figure.

17 This was covered in workshops (1) scene setting / rationale – providing stakeholders with an overview of the factors impacting service outcomes including ageing assets, (2) delivering service outcomes through asset replacement – providing stakeholders with an understanding of the challenges and drivers associated with managing ageing infrastructure and what this means for customers in terms of service levels) , (4) optimising asset investment – summary of Focused Conversations outcomes and discuss proposed investment levels) for the 'Reliability and bushfire safety' Focused Conversation. Materials presented at the Focused Conversations are available on our TalkingPower website under 'focused conversations'. [https://www.talkingpower.com.au].

3. information on the ageing and deteriorating condition of our network assets;
4. our approach to forecasting service performance risks for customers; and
5. our assessment of current versus forecast risk for service performance outcomes to customers;

- in the Focused Conversations we then posed three scenarios of how we could respond to the needs, and expected outcomes for customers in relation to service, expenditure and price, these included:
  1. 'Basic' – a base-case counterfactual of BAU, where we do nothing materially different and maintain our current level of replacement expenditure, showing the resulting decline in service performance outcomes for customers (monetised) from forecast asset failures;
  2. 'maintain' – a scenario where we undertake expenditure to maintain the current level of reliability and safety in the network in aggregate; and
  3. 'new value' – a scenario where we undertake expenditure to maintain the current level of reliability and safety in the network by geographic region.
- as the Focused Conversations progressed, these three scenarios evolved, as we sought to integrate choices for customers on outcomes through network upgrades and network replacements;
- while our customers and stakeholders were consistently mindful of energy affordability concerns, the Focused Conversations arrived at a clear consensus recommendation to the People's Panel, as the next stage in our engagement program, that we should invest sufficiently in network asset replacement in order to achieve the following:
  6. **maintain reliability by geographic region** – highlighting the importance of considering equity between regions and customers when investing in the reliability of the network;
  7. **improve reliability of the Adelaide CBD to comply with the jurisdictional service standard target** - given the importance of complying with standards and of the Adelaide CBD to the economic prosperity of South Australia and to customers in this region; and
  8. **to maintain safety in aggregate across our network** – given the desire of our customers to not see rising risks of harm to persons and damage to property and assets, particularly in the face of rising climate change risks;[18]
- ultimately, the People's Panel deliberated on and affirmed the results of the Focused Conversations in their formal recommendation, and we committed to taking this recommendation forward as reflected in the overall recommendation reflected in this justification document for forecast repex.

Since conducting the People's Panel, we published a Draft Proposal to play back how we gave effect to customer recommendations and to confirm that those recommendations remain valid given continued cost of living pressures and to obtain further input to refine our Regulatory Proposal. Submissions received on our Draft Proposal suggest that the recommendations of the People's Panel remain valid with respect to this repex forecast and the service levels it seeks to achieve for reliability and safety, noting that:

- members of the People's Panel affirmed that their recommendations, including in respect of repex outlined in this document, remain current;[19]

[18] The recommendations of the Focused Conversation are contained in documents published on our TalkingPower website under the page titled 'focused conversations'. SAPN, *final outputs and recommendations to the People's Panel for Reliability and Bushfire Safety*, October, 2022. Accessible on: [https://www.talkingpower.com.au].

[19] DemocracyCo, *Submission: SA Power Networks Draft Regulatory Proposal 2025-30*, 30 August 2023.

- some parties such as SACOSS[20] and the SA Government Department of Energy and Mining (**DEM**) [21] generally urged further consideraiton of the overall magnitude of our forecat capex in totality. These parties also provided qualified comments in relation to repex:
  - SACOSS noted it supports maintaining current reliability levels (urging us to propose no more reliablity expenditue than necessary to maintain current levels), and expenditure required to comply with regulatory obligations – our repex forecast seeks only to maintain current reliability and safety risk;
  - DEM noted that it supports investment to maintain reliability, while also urging us to consider the timing of our repex forecast and whether some of it can be pushed out beyond the next RCP – our justification document now responds by providing the analysis to demonstrate why it would be imprudent and inefficient to not undertake our forcast repex (by quantifying reliability and safety risk to customers) and also by us having removed our substation disconnector program from our Draft Plans having assessed that this project could not be supported as efficient in 2025-30;[22]
- The Asset Condition and Risk Sub-Committee of our Community Advisory Board (CAB) who has been engaging with us over the long term on the need for repex, noted it supports our repex forecast and the service outcomes it achieves. It commented that our forecasting methodology has been rigorous and meets industry standards, and that the given the rigour of our process and science applied, that it supports our forecast, but encourages the AER to assess if the forecast achieves the best economic outcome – this document now confirms the economic efficiency now of our forecast;[23]
- the Small Business Commissioner of South Australia supported the repex forecast, noting the importance of network asset replacement which correlates with reliable service and safety outcomes for small businesses and their customers;[24] and
- the Energy and Water Ombudsman of South Australia supported our proposed service levels and expenditure to support a reliability, resilience and safe distribution network, which include this repex forecast, as being in the best interests of the South Australian community.[25]

5.1. How we have integrated asset replacement and augmentation

As outlined, our forecast expenditure is configured to achieve target service outcomes for customers. Two of the main drivers for our repex are reliability and bushfire risk service outcomes, both of which are also targeted in our separate augex programs (‘5.9.3: maintaining underlying reliability performance program’; ‘5.9.5: worst served customers reliability improvement programs’) and bushfire management programs ‘5.6.1:Bushfire Risk Management Programs’).

While these augex programs target the same outcomes, they have differing underlying drivers to our repex. Our forecasts have been developed on the basis that:

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20 SACOSS, *South Australian Council of Social Service Submission on SA Power Networks’ 2025-30 Draft Regulatory Proposal*, September 2023.

21 DEM, *South Australian Department of Energy and Mining* – Submission, October 2023.

22 DEM, *South Australian Department of Energy and Mining – Submission*, October 2023.

23 SCRSC, Submission from the Asset Condition and Risk Sub-Committee of the CAB – Draft Regulatory Proposal 2025-30, 17 August, 2023.

24 SMCSA, Small Business Commissioner of South Australia – Consultation on SA Power Networks 2025-30 Draft Regulatory Proposal, 1 September 2023.

25 EWOSA, Energy and Water Ombudsman of South Australia – Submission to SA Power Networks: Draft Regulatory Proposal 2025-30, 29 August 2023.

- repex responds to deteriorating **network asset condition**, undertaking sufficient renewal investment to maintain reliability (except for the CBD where an improvement is required) and maintain bushfire risk across the **population of all modelled assets** (*not* at an asset class level); and
- augex responds to other drivers of performance (eg. addressing reliability impacts not related to asset condition such as lightning strikes and other weather events, and third party interference (e.g. animals) or seeks to improve performance where economically justified.

Where our augex is expected to deliver a material reduction in risk associated with network asset condition - for instance our bushfire mitigation program installing devices that reduce the likelihood of ignition from an asset failure – we have accounted for this risk reduction in our repex forecasting.

We have also cross-checked our repex plans with our capacity augex plans to ensure that any asset being replaced as part of a capacity upgrade is not included in our repex program forecasts.

6. Our approach to forecasting replacement expenditure

6.1. The forecasting structure

Our repex forecasting approach is detailed in 'document 5.3.2 - **Repex Forecasting Approach**'. Our approach is categorised according to the repex program, and asset value / volume, as covered in Table 3 below.

Table 3: Forecast approach by asset type and program

Replacement program / Asset type	Conditional	Reactive	Planned
High volume assets - sufficient data for modelling	Volumetric risk-based model	Historic	Individual business case
High volume assets - insufficient data for modelling	Historic	Historic	Historic
High value asset	Individual business case	Historic	Individual business case

Where sufficient data is available, forecasts are underpinned by detailed modelling and value assumptions as covered in our 'document 5.3.4: **Model Framework'**, and consistent with the expectations set in the AER ARP Note. This detailed modelling may be in the form of high-volume asset class forecasts (i.e. for asset classes with large populations consisting of similar assets) or individual asset renewal business cases – both of which are guided by the Model Framework.

High volume asset class forecasts rely on a large population of similar assets, for instance Overhead Conductors. These forecasts are derived via bottom-up modelling of each individual asset, relying on statistical modelling to determine expected lives using large populations of data (e.g. population age profile, failure rates). For this statistical analysis to be valid, the population must have similar physical traits. For this reason, an asset class may be separated into sub-populations - for instance in the Distribution Transformer population, statistical lives of pole-top transformers are considered separately from ground level.

Where an individual asset within an asset class is unique or of significant value - for example a single instance of outdoor Gas Insulated Switchgear (**GIS**) in a population of predominantly indoor Oil Insulated Switchgear, or where a project solution is significantly different or higher cost to 'business as usual' treatment, this individual asset may be considered separately from the population through an individual business case. The same economic principles outlined in the **Model Framework** are applied in an individual business case.

Where insufficient data is available to support an asset risk (benefit) modelling approach, historical expenditure is generally used. This forecasting approach is likely to be conservative as it assumes a homogeneous age/condition profile across the asset population which is often not the case. Using the historical expenditure approach, only a single case is considered – a continuation of the current rate of expenditure.

Table 4 - Forecast approach by asset class and program

Asset Class	Population Risk/Cost Modelling	Historical Expenditure	AER repex Model	Targeted/ Individual Business Case
Poles	●			
Pole Top Structures		●		
Underground Cables (Excl CBD)	●		○	
Underground Cables: Adelaide CBD				●
Overhead Conductors	●		○	
Switching Cubicles	●		○	
Distribution Transformers	●		○	
Reclosers/Sectionalisers	●			
Services	●	●		
Zone Substation Power Transformers	●		○	
Zone Substation Switchgear (Excl Hindley Street)	●		○	
Zone Substation Switchgear: Hindley Street				●
Zone Substation Switchgear: Northfield GIS Replacement				●
Protection Relays	●			
Other unmodelled powerline assets		●		
Other unmodelled zone substation assets		●		
Telecommunication assets		●		
Mobile Plant				●

6.2. Alignment with SA Power Networks' risk framework

There are significant risks inherently associated with all electricity networks. They have the potential to start fires, cause widespread property damage, and injure or kill staff or members of the public.

We adopted an enterprise risk management approach to managing risk as covered in our Risk Management Framework. The framework includes instructions and templates for risk assessments. The Asset Management Policy requires asset managers to manage assets to satisfy customer service needs, meet licence and regulatory obligations, and provide a safe environment for employees, contractors and the community. Key components of our risk management system include:

- **Risk Management Policy**: outlines the risk management approach to all business activities to ensure the organisation maximises opportunities without exposing the business to unacceptable risk levels.
- **Risk Appetite Statement**: provides guidance in decision making around strategic risks such as safety, bushfire, asset management, unregulated business and workforce capability.
- **Risk Management and Compliance Committee**: oversees and makes recommendations to the Board on the risk profile of the business and ensures that appropriate policies and procedures are adopted for timely and accurate identification, reporting and management of significant risks to the business.
- **Risk Management Framework:** outlines how risk management information should be used and reported within the business as a basis for decision making and accountability; includes risk assessment templates and guidance of application.
- **Corporate risk register**: identifies key whole-of-business risks that have the potential to impact the achievement of the business strategic objectives. They are not a reflection of the 'top ranked' risks for the business (by risk rating), but are risks that all workers should be aware of. Dedicated cross-departmental effort is required to manage these risks.

- **Departmental risk registers**: department specific risks that require controls to be in place. While there is crossover between departments for certain risks, they will only be elevated to the corporate risk register where there is a potential impact a large cross section of the organisation.

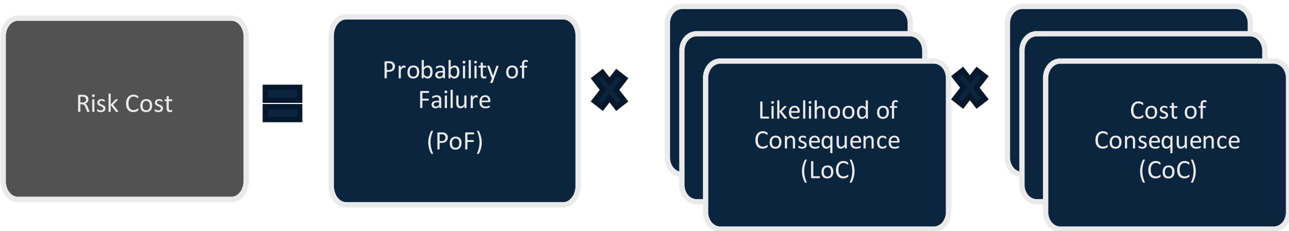
Asset related risks are assessed in line with the risk management framework. The model framework and value framework underpinning our repex forecasting were developed to align to the risk management framework.

6.3. The forecasting model framework

Repex forecasts are based on a combination of actual historical expenditure for some asset classes, modelled forecasts for other asset classes where sufficient data is available and business cases for targeted / individual projects. The Model Framework describes our forecasting approach for modelled asset classes. Risk is assessed and evaluated to enable selection of the optimal set of investments to support long term asset replacement planning. Forecast modelling does this by calculating risk in monetary terms and optimising the set of investments applied to the asset base to meet specific scenario outcomes (eg. maintaining reliability). The Model Framework is guided by alignment with regulatory rules, guidelines and expectations, and supports development of an efficient and prudent investment portfolio that maximises consumer benefits. The AER ARP note is the key source of regulatory requirements for asset risk (benefit) modelling.

The most common driver of the replacement of network assets is condition deterioration leading to the asset failure. On failure, an asset may pose a risk to members of the public, network workers, the network itself or any other stakeholder in the electricity system. This is summarised by the Risk Cost, which is a measure of the expected monetised value of the risk event. The high-level formula for calculating the Risk Cost is depicted in Figure 22.

Figure 22 - Risk Cost quantification



At its highest level, the Risk Cost is made up of three components defined as follows:

- PoF: the probability that an asset experiences a functional failure during a given year;
- LoC: the probability that any given functional failure of an asset results in a consequence occurring; and
- CoC: the average cost of a consequence that results from the asset failure.

The approach to valuing the cost of consequences is outlined in our **'5.1.5 Value Framework'**.

The benefit of replacing an asset before it fails is the reduction in risk cost that can be achieved by replacing the deteriorated asset with a new asset, along with any reduction in opex that may be achieved.

Replacements are prioritised using a benefit cost ratio (BCR) which uses annualised investment cost as the denominator. The BCR will be greater than 1.0 if the benefit during the year after replacement is greater than the cost of the investment over the next year. If this holds, then the lost benefit of waiting another year to invest is greater than the cost of the investment over the same year.

$$Benefit\ Cost\ Ratio = \frac{Investment\ Value}{Annualised\ Investment\ Cost}$$

The annualised investment cost is calculated using the following formula:

$$Annualised\ Investment\ Cost = \frac{Investment \times WACC}{1-(1+WACC)^{-Investment\ Lifetime}}$$

The model can implement various constraints that influence investments that will make up the annual investment portfolio. This includes the major constraints, such as budget limits and requirements for investments to be benefit cost positive.

The model is configured to produce results for (at least) the following scenarios:

- minimise risk at a portfolio level within a total budget (eg. current replacement expenditure);
- minimise risk within each asset class within asset class specific budgets;
- maintain risks at a portfolio level at least cost; and
- maintain risks within each asset class at least cost.

The investment plan selects investments from highest BCR to lowest, except where a constraint is enforced e.g. to maintain the reliability outcomes for each geographic region. Further detail on the approach to modelling risk and forecasting expenditure is included in 5.3.4 - Repex model framework.

An important aspect of the Risk Cost Modelling is that it is calibrated to real world observations – in terms of failure numbers and observed risk outcomes (such as outages).

6.4. The Value Framework

The Value Framework[26] provides the means of translating our Strategic Focus Areas, and the consequences and benefits identified in our Risk Management Framework into value dimensions and metrics to determine the economic value of the consequences and benefits, as displayed in Figure 23.

Figure 23 - Mapping Strategic Objectives, Enterprise Risks and Value Dimensions

26 We engaged with our Community Advisory Board (CAB) in developing our Value Framework, who endorsed the framework.

In forecasting repex, our risk valuation uses the value framework to determine the consequences of an asset failure and how those consequences are quantified. The Value Framework defines twelve Value Dimensions reflecting broad categories into which economic value can be allocated. Each Value Dimension contains several Value Metrics to which dollar values are assigned. Table 5 summarises the Value Dimensions and their intended scope, with the first five corresponding to the categories outlined in the AER's ARP note.

Table 5 - Value Dimensions and associated scope

Value Dimension	Scope
OHandS	Costs to workers, the public and the business associated with physical injuries sustained by persons because of network assets or network activities.
Bushfire	Costs associated with bushfires including loss of life, property, environment, and network assets.
Reliability	Costs incurred by customers for the network failing to provide them with electricity, such as via the failure of an asset or insufficient capacity being available.
Environment	Costs associated with damage to the environment caused by network assets or network activities. This excludes the costs associated with network-initiated bushfires.
Energy Conservation	The value OF the reduction of appliance energy consumption due to a reduction in network voltage.
Asset	Direct financial costs to the network that occur as a result of an asset failure that are not included within any other value dimension (such as costs associated with unplanned response).
Investment benefits	Avoidable costs associated with replacing a degraded asset with a new equivalent or other benefits resulting from undertaking the investment (such as avoided maintenance) and time saved from assets being unavailable.
Investment costs	Actual expected costs associated with undertaking investments. These costs could be funded under network capex or opex. This category also considers avoided (current) and reduced (future) expenditures.
Customer value of exports	Value of exports from customer energy resources (CER), as per the AER methodology. This dimension only considers the value of customer energy exports that are permitted by the AER CECV methodology.
Compliance	Costs incurred for not complying with legal and/or regulatory obligations.
Cybersecurity	Costs associated with a cyber breach of our systems that relate to detection, notification and response to a breach, as well as direct business impacts in time lost without system access, and penalties imposed.
Customer time value	The value of the time that customers spend accessing, or using, information regarding our services.

For each Value Dimension, one or more Value Metrics are identified against which dollar values are assigned. When the framework is applied, each applicable value metric is summated to determine total value of a consequence/benefit under each dimension. Table 6 summarises the Value Dimensions and Metrics.

Table 6 - Value Dimensions and their Value Metrics

Value Dimension	Value Metrics				
OHandS	Disability Weighted Value of Life / WHS Cost (including disproportionality factor)	Investigation costs	Litigation costs		
Bushfire	Direct economic losses (property, livestock, agriculture)				
Reliability	Unserved energy	Lost Embedded Generation	Investigation costs	Litigation costs	
Environment (non-bushfire)	Remediation Costs	Greenhouse Gas Emissions	Penalties	Investigation costs	Litigation costs
Energy Conservation	Avoided energy consumption				
Customer time value	Customer productivity				

Asset	Reactive Replacement Premium	Asset Repairs	Investigation Costs		
Investment Benefits	Avoided Opex	Opex reduction	Capex Avoidance	Capex reduction	Other benefits
Investment Costs	Activity Cost	Financing Rate	Investment Lifetime	Capex	Opex
Customer export curtailment	Avoided distribution losses	Generator SRMC	Generator LRMC		
Compliance	Penalties				
Cybersecurity	Business Cyber recovery	Penalties	Business productivity loss		

Further detail on the approaching to valuing investments is included in document 5.1.5 - Value framework.

6.5. Risk-Based Model scenario analysis

For assets modelled, which quantified investment value of asset renewals as defined by the Value Framework, we compare varying repex scenarios. For each scenario, reliability and safety outcomes were quantified for our modelled assets. Bushfire risk was considered as a single system wide value, while reliability was considered both at a system and regional level. This regional analysis was included as stakeholders in Focused Conversations voiced concerns over maintaining reliability at a system wide level while some regions suffered a decline in performance (offset by an improvement elsewhere).

Multiple scenarios were compared (i.e. an options analysis) to determine a proposed approach to repex, for modelled assets, these included:

- **Scenario 1 (base case)** where we maintain our current level of repex. This scenario does not align with outcomes desired by customers as both reliability and bushfire service outcomes deteriorate.
- **Scenario 2 (proposed)** includes additional repex to arrest any decline in performance associated with asset failures. Reliability performance is maintained for each geographic region. Our repex program maintains fire start risk at its current level and our augex program delivers a net reduction in fire start risk in targeted locations (where economic). This scenario aligns with the outcomes recommended by customers, via Focussed Conversation and the People's Panel.
- **Scenario 3 (economic)** includes repex required to arrest any decline in safety outcomes, in addition to any other repex evaluated on a strictly economic basis with no consideration of overall service outcomes. This scenario included additional repex (beyond what is required to maintain service levels) where investment could be shown to have a positive net benefit. This scenario would improve service levels (specifically reliability), at an overall level, at additional cost to customers. However, it fails to maintain reliability at a geographic level.

Our **Peoples Panel recommended Scenario 2** which our proposed expenditure is aligned to achieve.

7. Expenditure programs

This section outlines the forecast replacement expenditure and programs for each major asset class as listed in Figure 24.

Figure 24 - Asset class overview

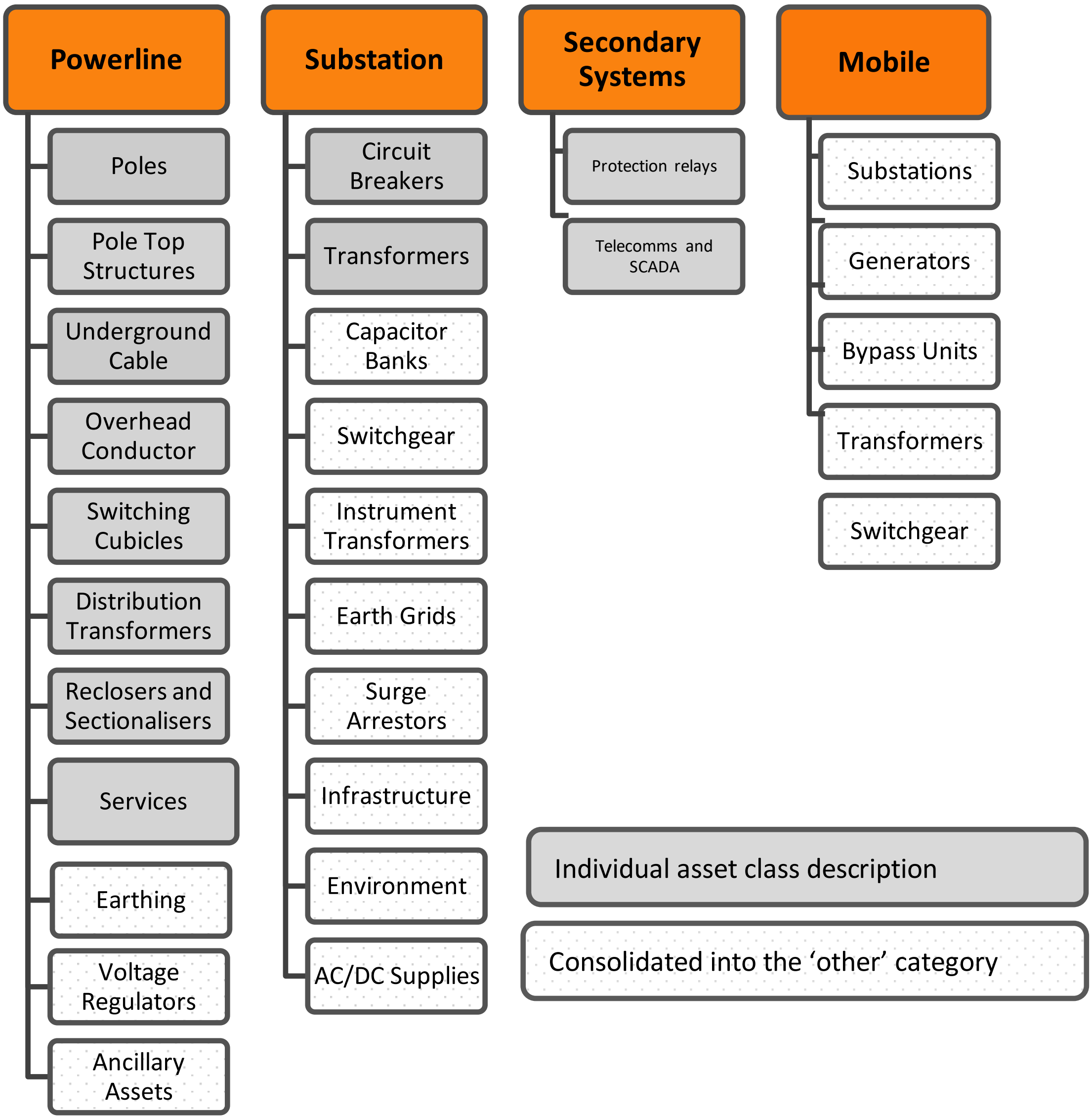


Table 7 actual versus forecast expenditure by asset class

Asset Class	Actual Expenditure (2017-22) $m ($2022)	Proposed Forecast (2025-30) $m ($2022)	AER repex Model $m ($2022)
Poles	$123.5	$134.9	-
Pole Top Structures	$143.5	$139.9	-
Underground Cables (including CBD)	$31.0	$83.8	$54.8
Overhead Conductors	$24.0	$69.3	$80.5
Switching Cubicles	$19.8	$18.2	-
Distribution Transformers	$40.6	$46.0	$74.7[27]
Reclosers/Sectionalisers	$15.6	$20.6	-
Services	$40.5	$43.3	$46.4
Zone Substation Power Transformers	$29.2	$29.8	$28.5

[27] Distribution and zone substation transformers are grouped within the AER repex model format.

Zone Substation Circuit Breakers (Excl Hindley Street)	$67.0	$72.1	-
Zone Substation Circuit Breakers: Hindley Street	-	$28.0	-
Zone Substation Circuit Breakers: Northfield GIS Switchboard Replacement	-	$11.8	-
Protection Relays	$25.0	$28.8	-
Other unmodelled powerline assets	$5.6	$4.9	-
Other unmodelled zone substation assets	$34.6	$37.8	-
Telecommunication assets	$30.8	$31.2	-
Mobile Plant	-	$9.5	-
Repex Total		$810.4	-

7.1. Modelled expenditure program outcomes

For modelled asset expenditure programs, the effects of proposed expenditure levels on service outcomes can be assessed. Figure 25 and Figure 26 show the impacts on service outcomes, for modelled assets, under the scenarios presented in Section 6.5. The proposed scenario, as preferred by our customers, maintains bushfire safety outcomes at a statewide level, and maintains reliability outcomes at a geographic region level. The contribution of each modelled assets' proposed expenditure program to the outcomes preferred by customers is detailed throughout Section 7.

Figure 25 - Impacts on reliability service outcomes

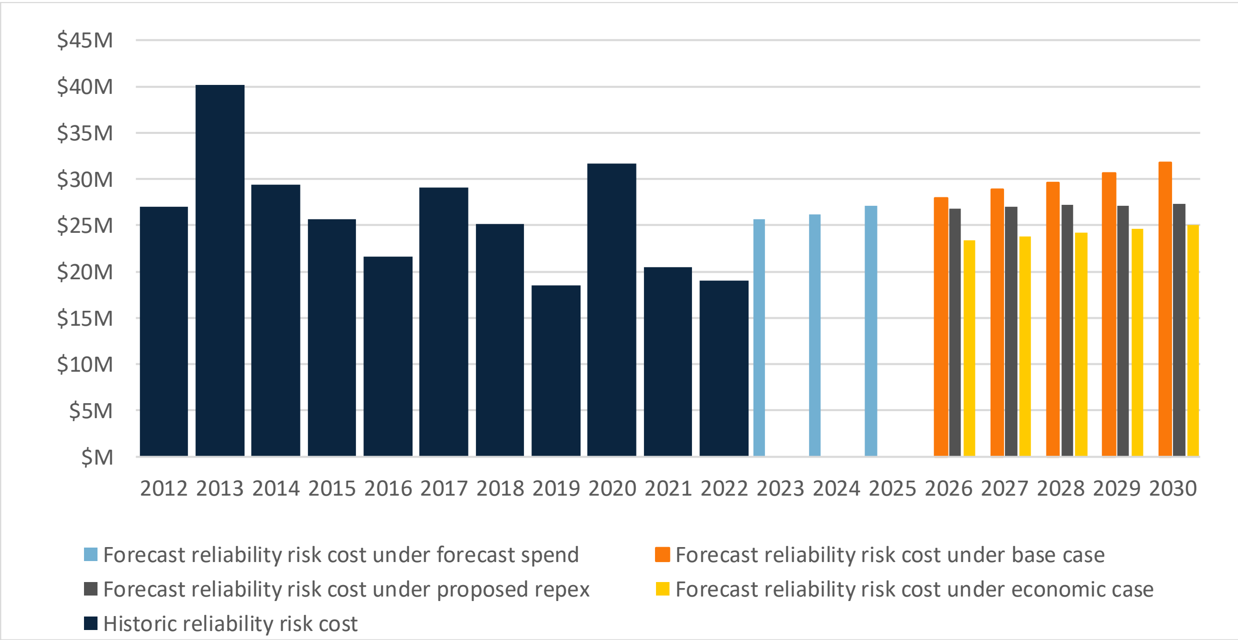
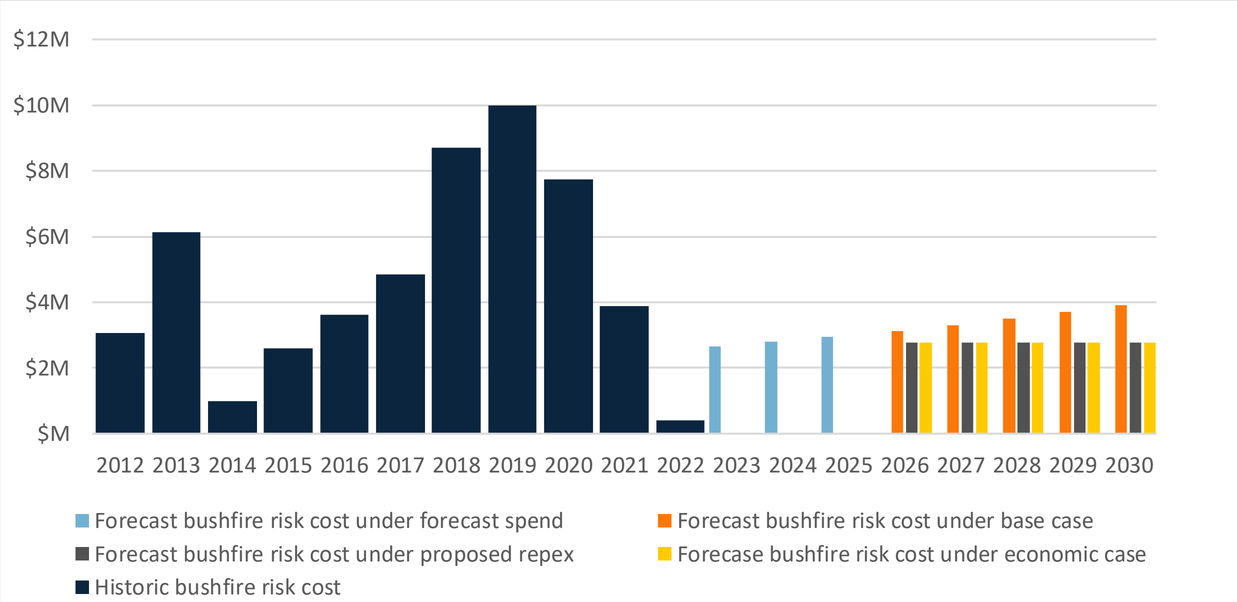


Figure 26 - Impacts on bushfire safety



7.2. Poles

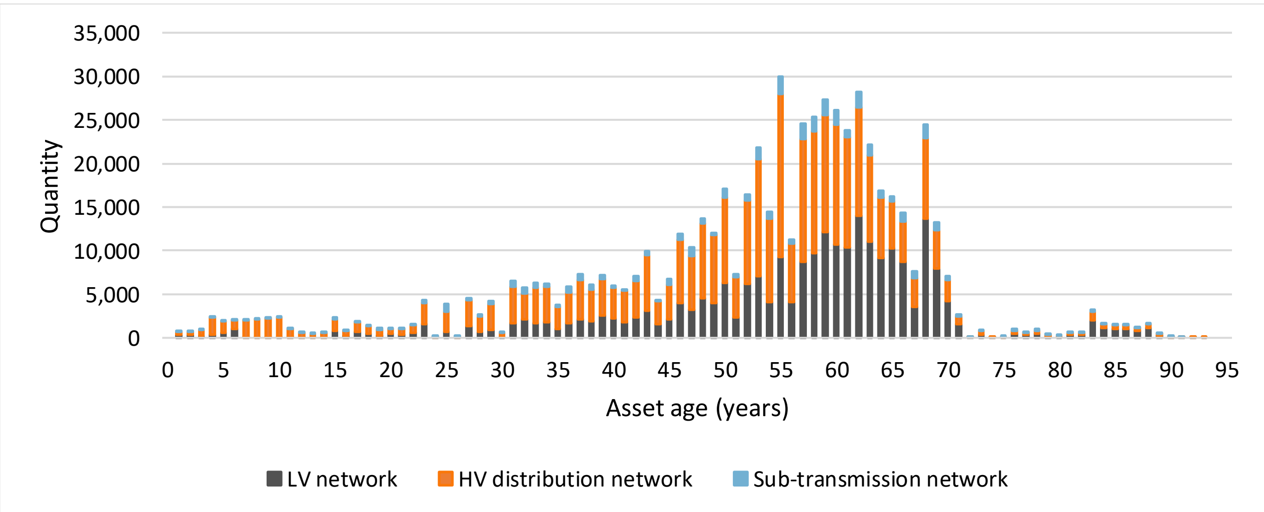
Pole asset class description

Poles provide 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. They also support other network equipment such as pole top structures, transformers, reclosers, and voltage regulators. Stobie poles are used almost exclusively across our network and consist of a concrete core with two outer steel beams connected by bolts to ensure strength. This asset class includes a small number of municipal tramway poles (mainly within the LV network) and wooden poles (former Telstra poles with only our assets attached).

When a pole reaches the end of its technical life it may be possible to refurbish ('plate') by welding steel plates at ground level where corrosion typically occurs. This refurbishment is only possible for some poles (where pole condition makes it suitable to plate). Where possible, plating is the preferred renewal method.

Figure 27 below shows the age profile of our pole population. Of the approximately 611,000 poles across the network, a significant proportion are over 65 years of age.

Figure 27 - Pole age profile



Pole asset performance (2012-2022)

The main risks associated with pole failures include:

- potential injury/death of SA Power Networks staff, contractors or the public due to:
  - electric shock via any current transmitted through the steel pole or live conductors falling to the ground, and
  - physical contact through a pole falling to the ground;
- fire start resulting from pole defects and live conductors falling to the ground;
- potential third-party property damage due to pole corrosion and collapse; and
- impact on reliability due to outages associated with pole failures and unplanned pole replacements.

Figure 28 shows the annual number of asset failures for pole remains relatively stable and far lower than most other asset classes, reflecting our condition monitoring and proactive replacement program.

Figure 28 – Observed pole failures

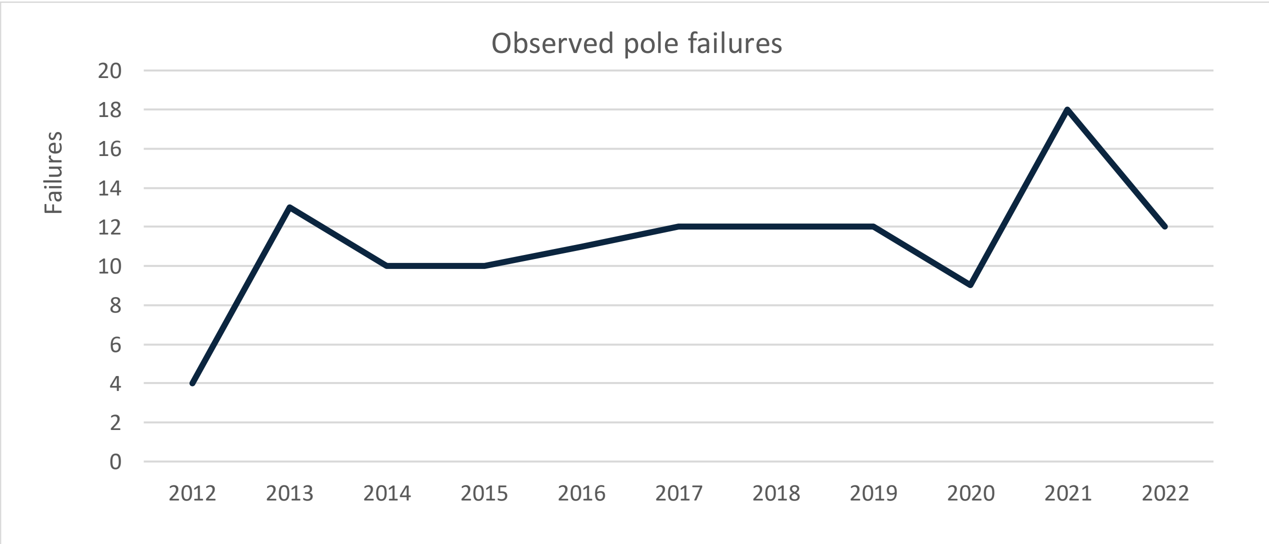
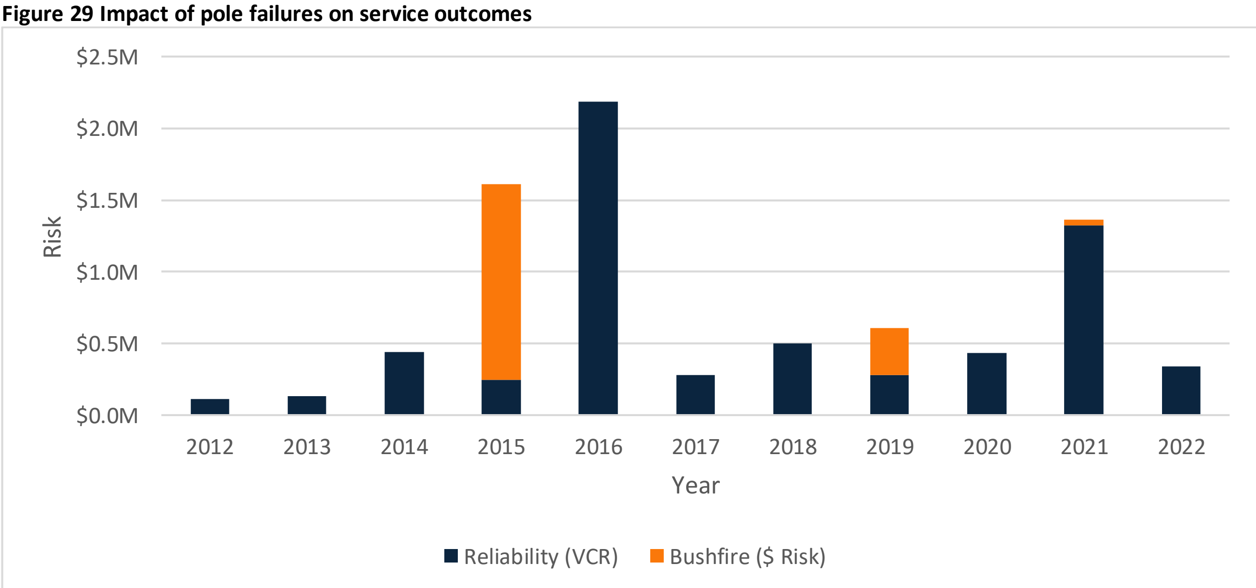


Figure 29 shows that pole failures have had relatively little impact on service outcomes as compared to other asset classes e.g. overhead conductors and underground cables due to our proactive replacement program and higher replacement rate.

Figure 29 Impact of pole failures on service outcomes



Pole replacement rate (2012-2022)

Figure 30 - Pole actual replacement rate

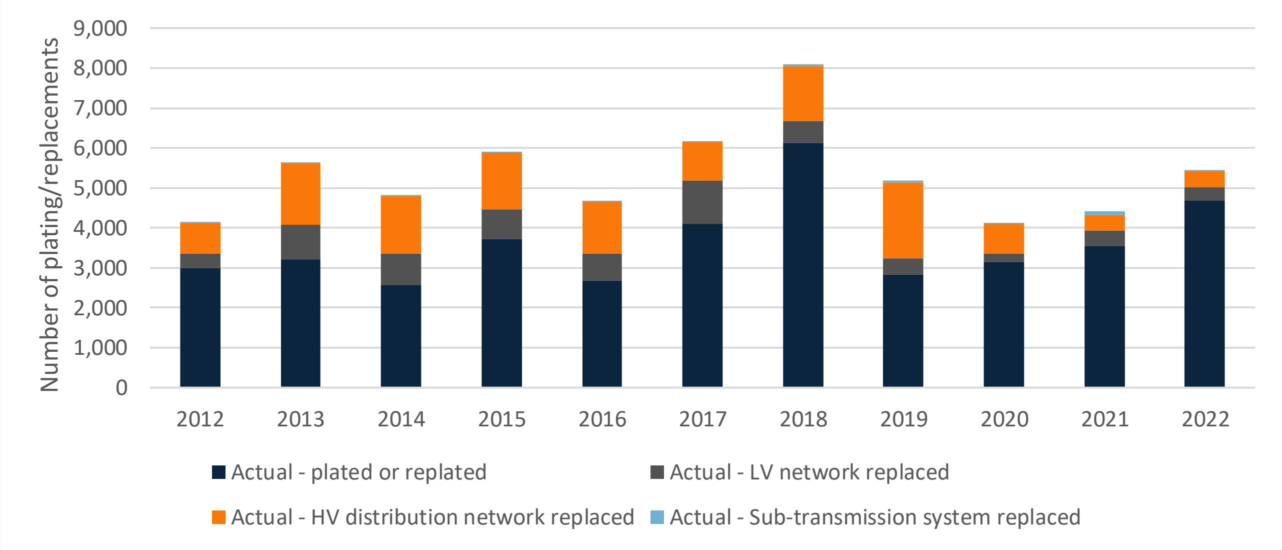


Figure 30 - Pole actual replacement rate

We recently been replacing on average less than 1000 poles per year under our replacement program and deferred 3000-4000 replacements via plating. With this replacement rate it would take approximately 600 years to replace the entire pole population. Given the mean life of poles is expected to be under 100 years this would suggest this replacement rate is now below a sustainable rate. However, the recent performance of our pole assets does not suggest an increase in replacement rates is necessary for this asset class in the near term.

Pole forecast risk to service outcomes (base case)

Figure 31 shows our forecast pole failure rate based on our current replacement rate. This failure rate has been forecast using probability of failure modelling for each individual pole asset considering its known condition, estimated mechanical load and remaining strength, and forecast degradation.

Figure 31 – Historic and forecast pole failures

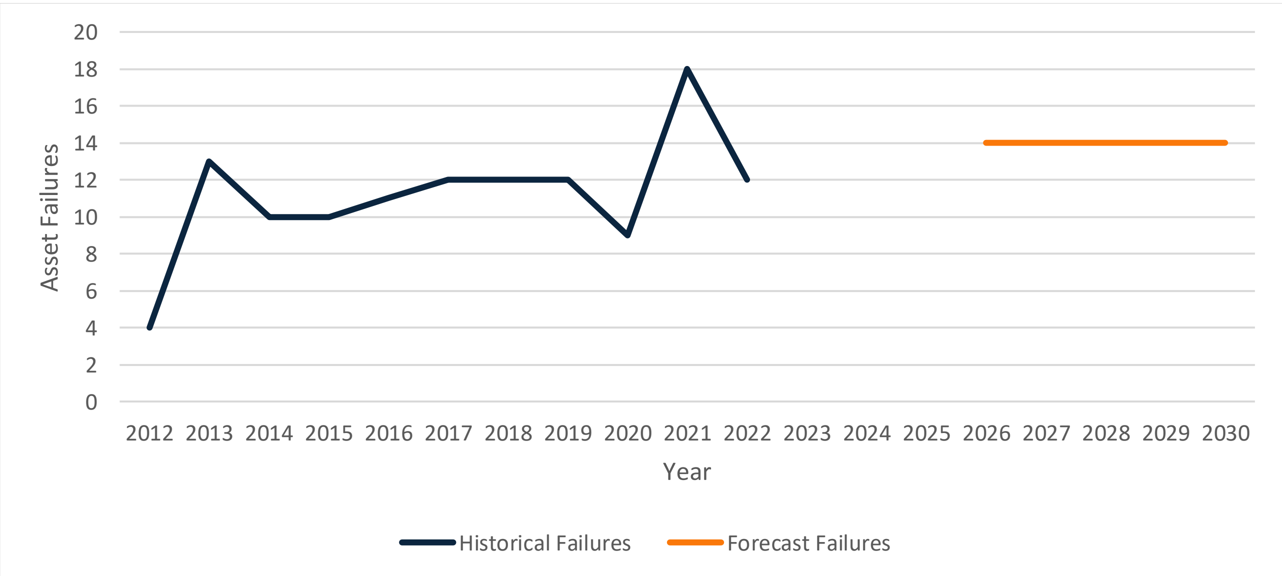
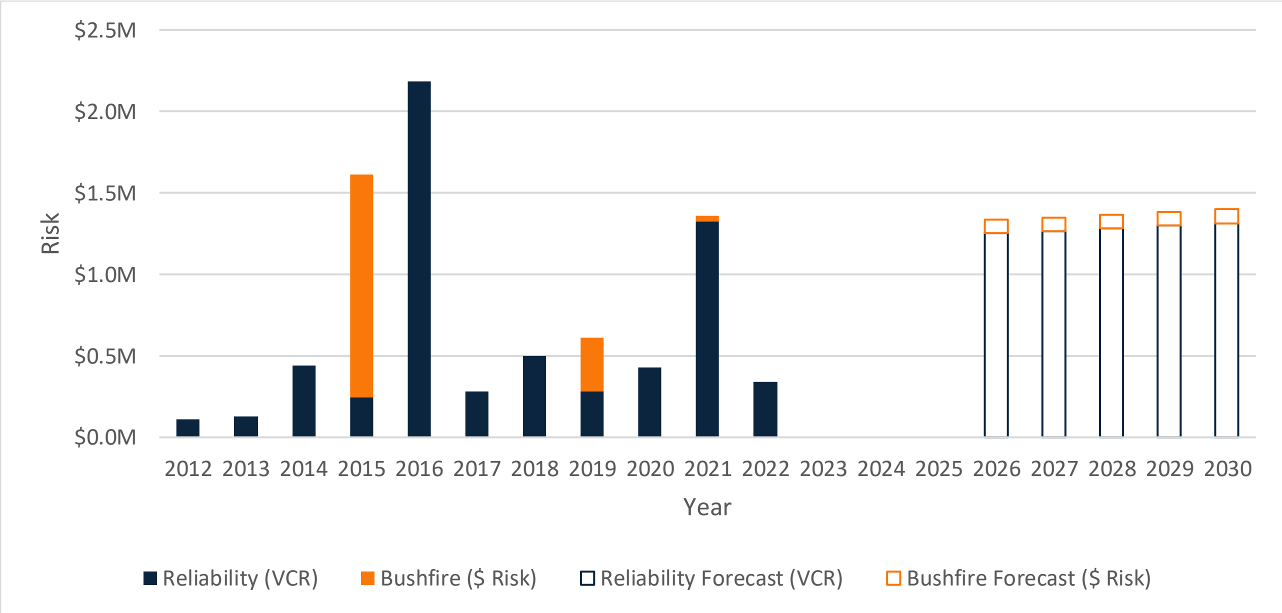


Figure 32 shows the observed performance impact from pole assets along with the forecast impact on service outcomes if we continue our current replacement rate. Our risk modelling shows that a continuation of our current rate of replacement would maintain the current impact on customer reliability and safety risk (including bushfire risk) from our pole assets.

Figure 32 – Historic and forecast pole risk (base case)



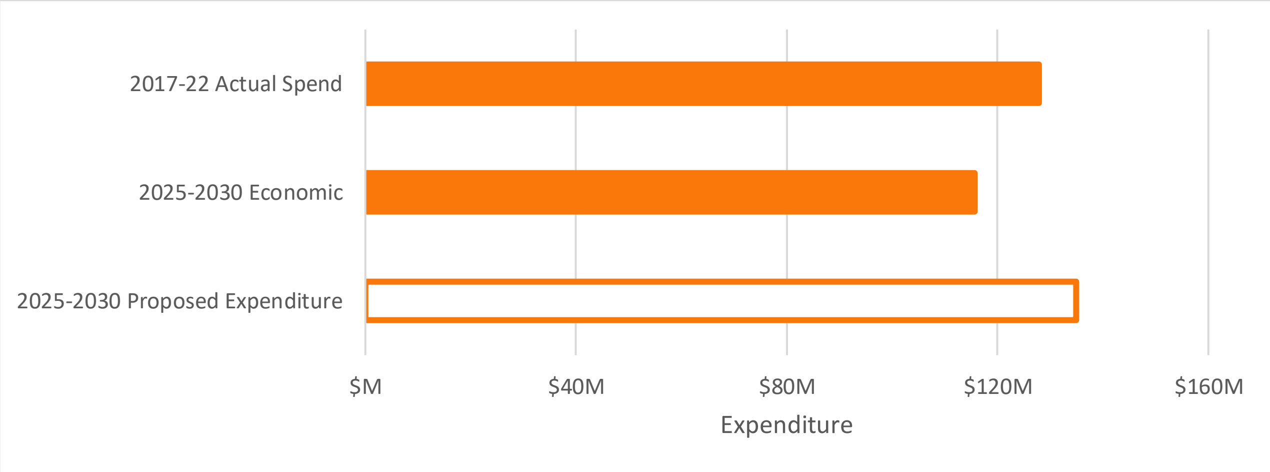
Pole expenditure forecast

Poles that have failed resulting in supply interruption are replaced immediately. Any defected poles identified via routine inspection, and determined to no longer perform its function as a support structure are also replaced immediately, to meet legal obligations of safely operating the network. Remaining defects have their value assessed to remove as much risk from the network in the most cost-efficient manner. Where efficient and feasible, poles are plated to reinforce the base instead of being completely replaced. Pole plating significantly extends the life of the asset at a much lower cost than complete replacement.

Pole forecast renewal expenditure summary (2025-30)

We considered three scenarios (i.e. options) in developing our required expenditure for poles, being a **base case** (using actual spend), **economic scenario** and a **proposed scenario** meeting target outcomes presented in section 5. The proposed scenario for pole expenditure included an additional safety constraint, due to our requirement to maintain them safely as support structures.

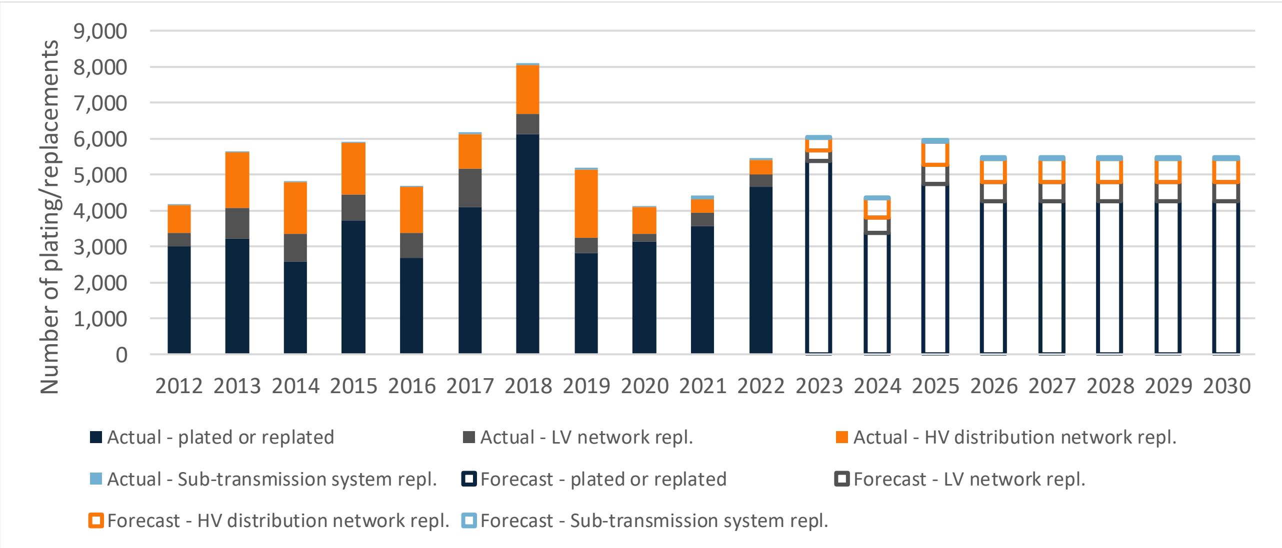
Figure 33 – Pole expenditure comparison



Pole forecast rate of renewal (2012-30)

Figure 34 shows the historic renewal rate of poles. The proposed rate of renewal with an expenditure of $129 million results in an average refurbishment rate of less than 1% and a replacement rate of less than 0.2% resulting in less than 1% of our poles replaced over the 2025-30 period.

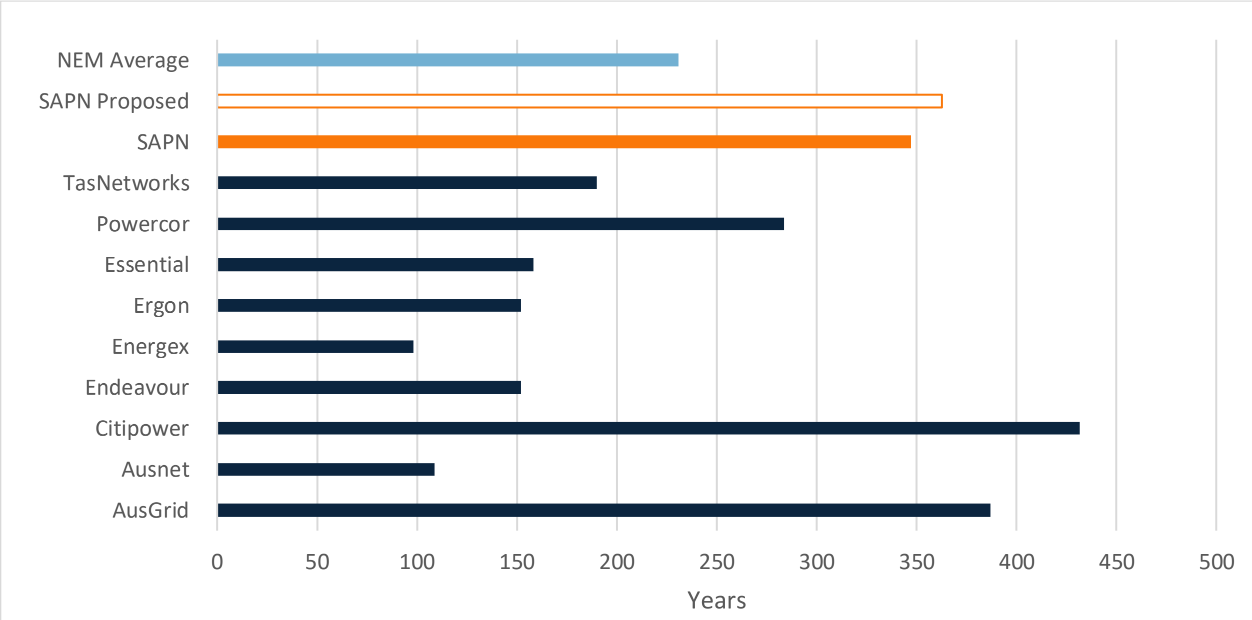
Figure 34 - Pole actual and forecasted replacement rate



We compared our proposed pole replacement rates with those of other DNSPs to cross-check our forecasts.[28] The current and proposed renewal rate puts our replacement program at the lower end of DNSPs, noting that our Stobie poles have a longer expected life, as displayed in Figure 35.

28 This uses data from publicly available Category Regulatory Information Notices (RIN) reported over the period 2015/16 to 2019/20.

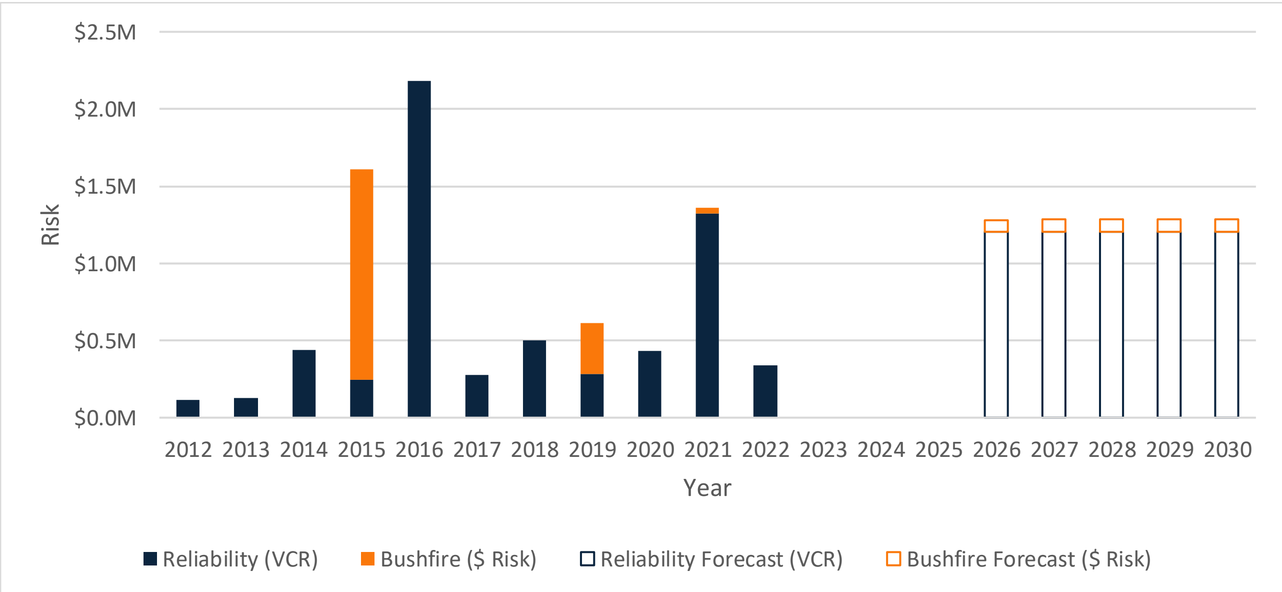
Figure 35 – DNSP pole replacement rate comparison



Pole forecast risk to service outcomes (proposed)

Figure 36 shows the observed performance impact from pole assets along with the forecast impact on service outcomes given the proposed investment above. Our risk modelling shows that reliability and bushfire safety outcomes can be maintained, given the proposed expenditure.

Figure 36 - Historic and forecast pole risk (proposed expenditure)



7.3. Pole top structures

Pole top structure class description

Pole top structures 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. As this asset class comprises a very large number of small assets, we have limited data on this asset population.

The quantity of pole top structures and distribution across the network is unknown and due to their wide variety and condition and the uncertainty of the age profile, detailed forecasting models for this asset class were not produced.

Pole top structure asset performance

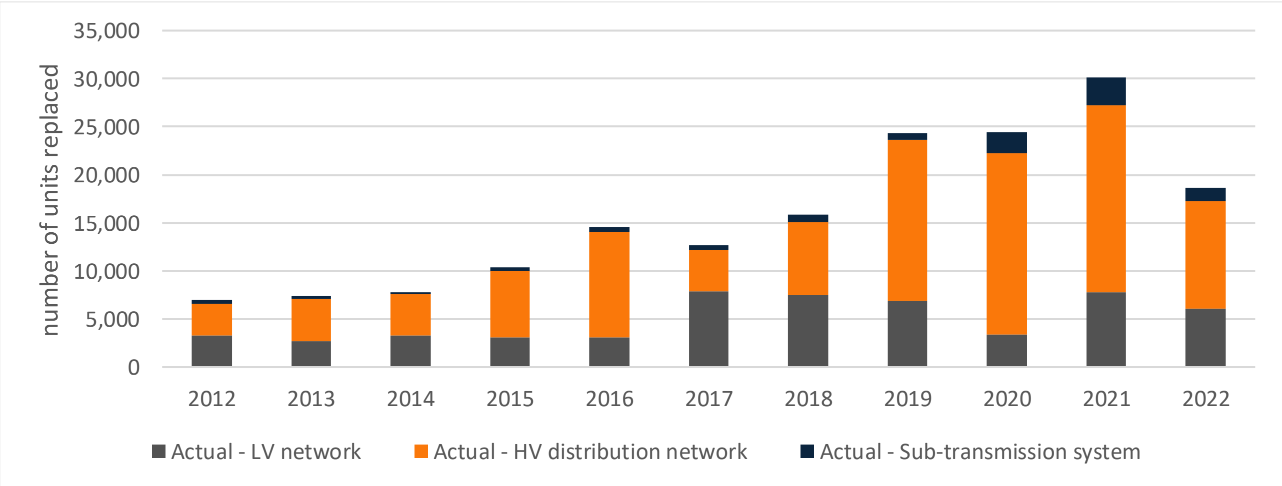
The main risks associated with pole top structures include potential:

- injury/death of SA Power Networks staff, contractors or the public due to:
  - electric shock from current transmitted through the pole or live conductors falling to the ground when a pole top structure fails;
  - physical contact with pole top structure, or the conductor it is supporting, falling to the ground when a pole top structure fails; or
- fire start because of pole top structure failure, including hot joints, or through component design (e.g. flashover from animal contact with rod air gaps and current limiting arcing horns); and
- impact on reliability due to outages from pole top structure failures.

Pole top structure replacement rate (2012-22)

We have recently been replacing an average of approximately 25,000 pole top structures each year.

Figure 37 – Pole top structure actual replacement rate



Pole top structure forecast risk to service outcomes (base case)

Detailed historical analysis and forecasting models have not been produced for this asset category due to data limitations.

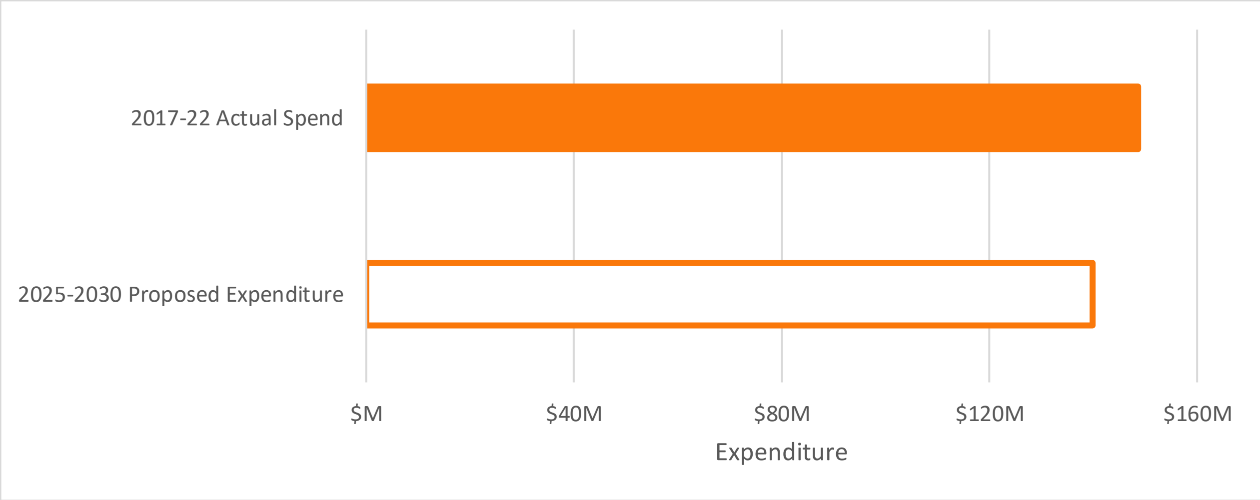
Pole top structure expenditure forecast

Pole top structures that fail resulting in a supply interruption are replaced immediately. Defects identified via routine inspection have their risk value assessed to remove as much risk as possible from the network in the most cost-efficient manner. Given the lack of data on this asset class and mixture of asset types within the class we have not developed a forecast model, with forecast expenditure based on historic expenditure.

Pole top structure forecast renewal expenditure summary (2025-30)

We have used only one method to forecast expenditure for pole top structures, being historic expenditure.

Figure 38 – Pole top structure expenditure comparison



Pole forecast rate of renewal (2012-30)

Detailed historical analysis and forecasting models were produced for this asset category due to data limitations.

Pole forecast risk to service outcomes (proposed)

Detailed historical analysis and forecasting models were not produced for this asset category due to data limitations.

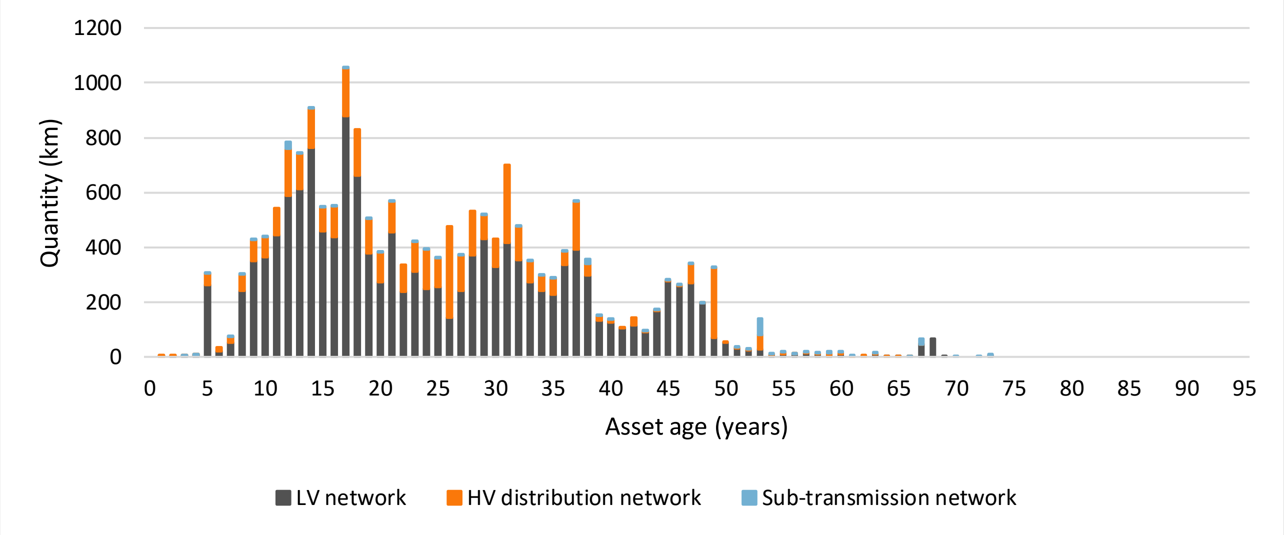
7.4. Underground cables

Underground cable asset class description

The underground cable network, which transmits electricity between substations and from substations to customers, extends for approximately 18,000km.

The significant and sustained 200-400km per annum of cable installed beginning in the 1970's aligns with large scale real estate developments in areas such as West Lakes (1970's) and Golden Grove (1980's and 1990s) extending to outer suburbs and infill developments that require undergrounding of the distribution network since then. A small proportion (~1%) of cables are more than 50 years of age, refer Figure 39. These older cables are predominantly located in the Adelaide CBD where their deteriorating condition has resulted in increasing failures and reliability not meeting jurisdictional service standard targets.

Figure 39 - Underground cable age profile



Underground cable asset performance (2012-22)

The main risks associated with underground cables include:

- potential injury/death of SA Power Networks staff, contractors or the public due to:
  - accessing failed/faulty cable terminations for operational purposes,
  - a cable fault causing a localised explosion, and
  - failed neutrals on cables resulting in potential electric shocks;
- impact on reliability service standards due to the time associated with locating and repairing cable faults; and
- potential environmental damage from oil filled cable failures.

Figure 40 shows the total number of cable failures across the entire population (LV and HV) has been gradually increasing over the last decade, with increasing failures in the CBD impacting on reliability performance. Underground cable failures have had a significant impact on reliability outcomes as compared to other asset classes, particularly in the Adelaide CBD.

Figure 40 – Observed cable failures

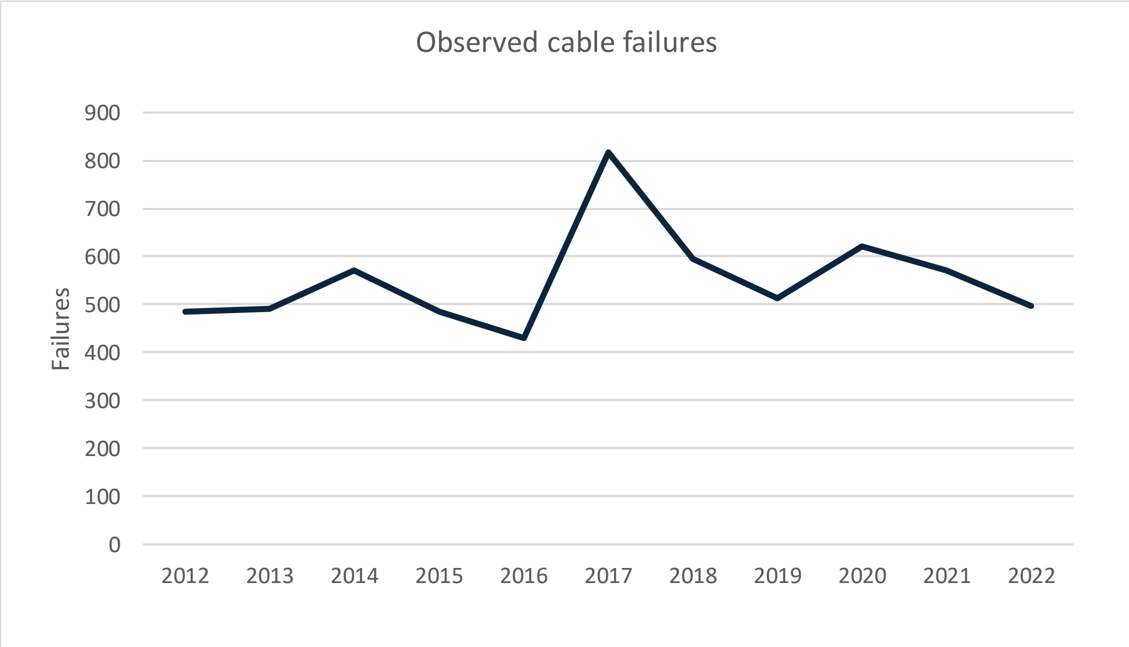
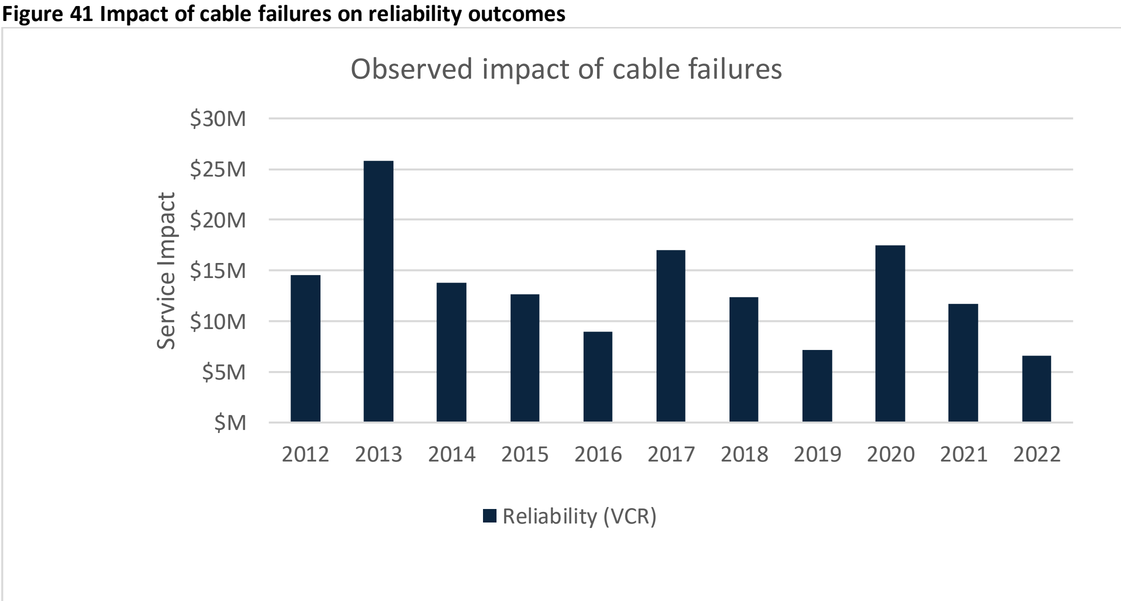


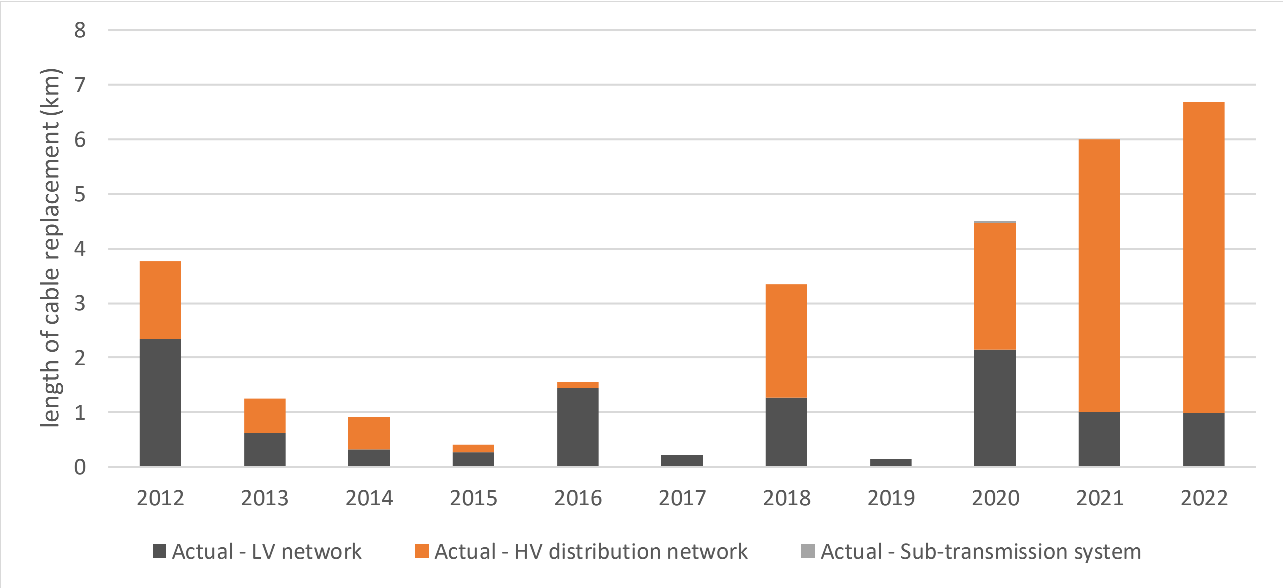
Figure 41 Impact of cable failures on reliability outcomes



Underground cable replacement rate (2012-22)

We recently been replacing on average approximately 6km of underground cable per year in the current RCP, under our replacement program out of a total population of more than 18,000km. This results in a total effective annual volume of 0.03% of the underground cable population. With this replacement rate it would take 3,000 years to replace the entire underground cable population. Given the mean life of cables is expected to be less than 80 years this would suggest this replacement rate is clearly now not sustainable. We are now seeing an increase in failures in the CBD (our oldest population of cables) impacting on reliability.

Figure 42 - Underground cable actual replacement rate



Underground cable forecast risk to service outcomes (base case)

Figure 43 shows our forecast cable failure rate based on our current replacement rate. This failure rate has been forecast using probability of failure modelling for each individual cable asset using a statistical approach considering various factors including age, soil type, cable type, and other factors. This approach has been developed based on 10 years of recorded asset failures in collaboration with engineering consultants, Frazer Nash. The probability of failure modelling has been validated by 'back casting' within the model to compare the number of failures predicted with the number of failures we have observed.

Figure 43 – Historic and forecast underground cable failures

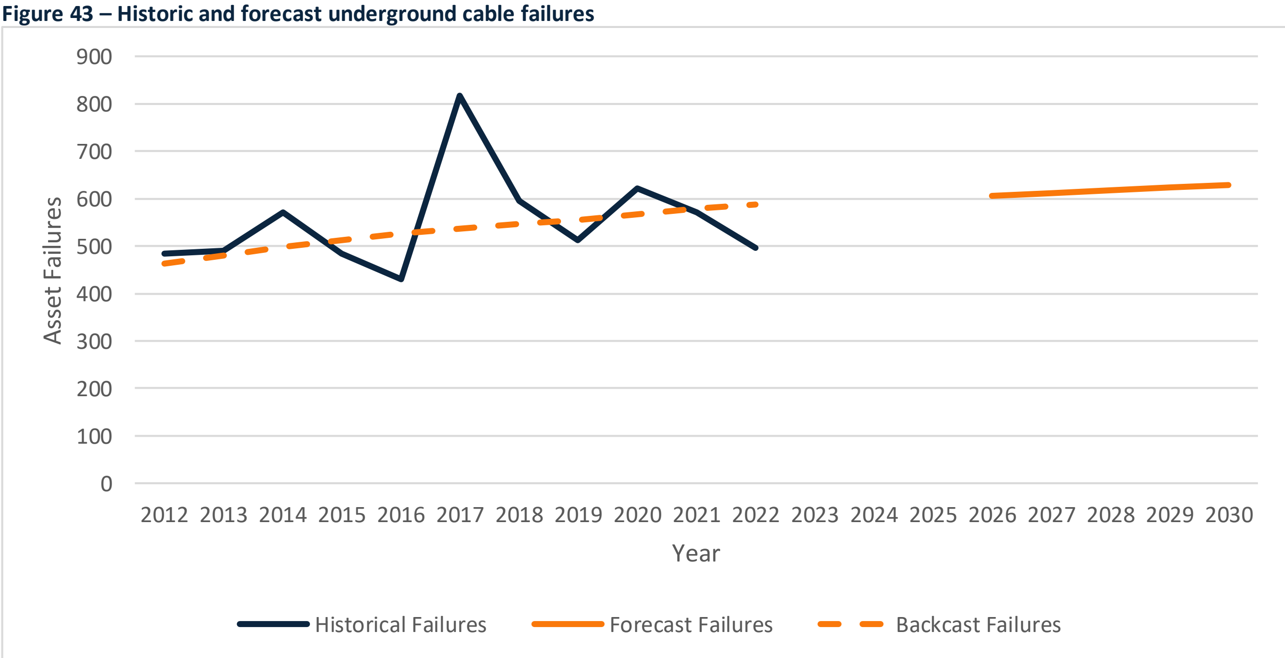
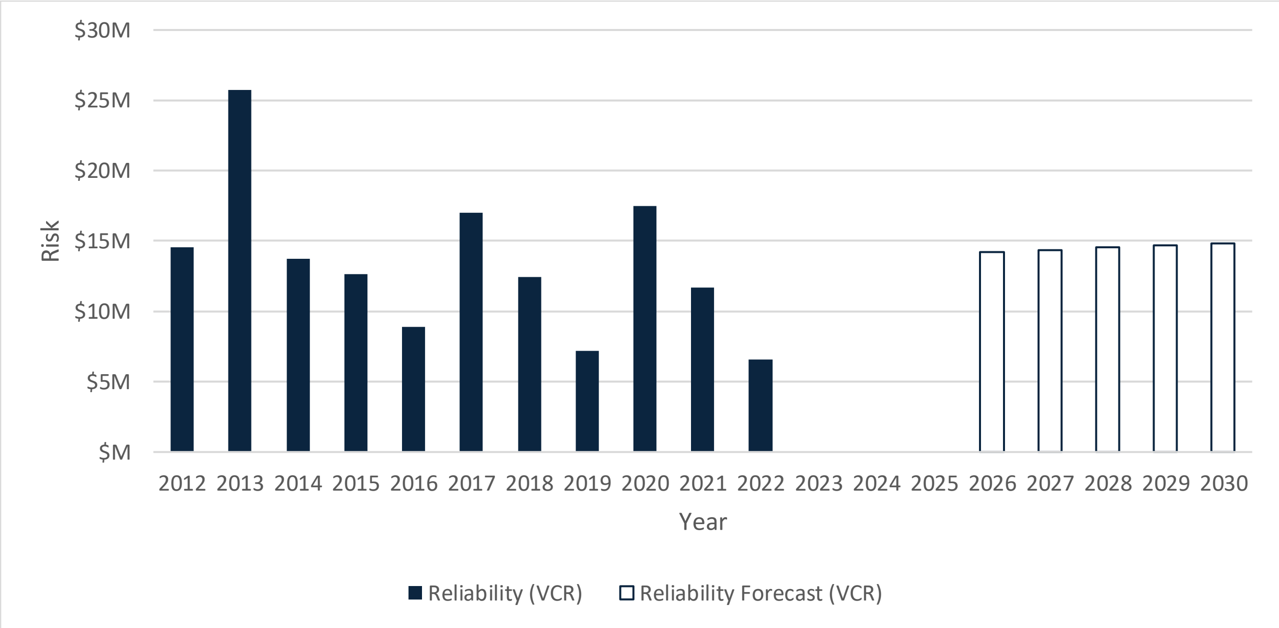


Figure 44 shows the observed performance impact from cable assets along with the forecast impact on service outcomes if we continue our current replacement rate.

Our risk modelling shows that a continuation of our current replacement rate would deteriorate customer reliability. While the deterioration across the entire population is gradual, we are already failing to meet our jurisdictional service standard target for reliability in the Adelaide CBD and expect the CBD to see most of this deterioration.

Figure 44 – Historic and forecast underground cable risk



Underground cable expenditure forecast

Cables that have failed, resulting in a supply interruption, are typically repaired but not replaced. These repairs often consist of a short section of new cable jointed to the original cable. Unlike most other asset classes (eg. poles, transformers) asset failures therefore do not result in a replacement.

The cables renewal/replacement strategy aims to achieve the service level outcomes described in section 5. The majority of proactive cable replacement is forecast in the Adelaide CBD region to meet the jurisdictional service standard reliability target for the CBD. This cable replacement forecast has been optimised together with augmentation solutions to meet the target at lowest overall (repex plus augex) cost. Further details are available in section 8.1 of this document and the separate '*5.3.12: CBD reliability business case'.*

Underground cable renewal expenditure summary (2025-30)

We considered three scenarios (i.e. options) in developing our required expenditure for underground cables, being a **base case** (using actual spend), **economic scenario** and a **proposed scenario** meeting targeted outcomes presented in section 5. We provided an additional comparison with the AER repex model output, which shows we propose to spend more than the repex model indicates for this asset class. Our proposed scenario modelling shows that additional expenditure is required to improve cable reliability in the CBD, to meet jurisdictional reliability targets, compared to the age based repex model approach.

Figure 45 – Underground cable expenditure comparison

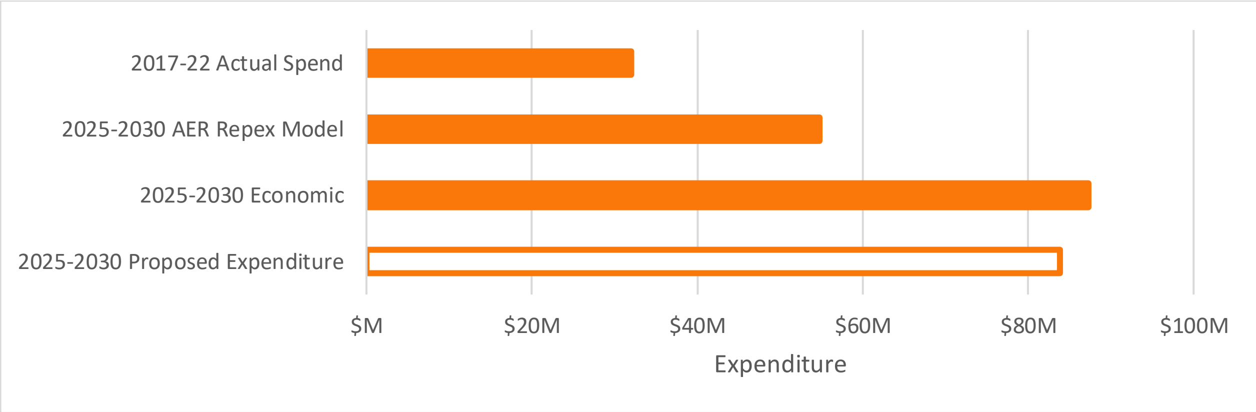
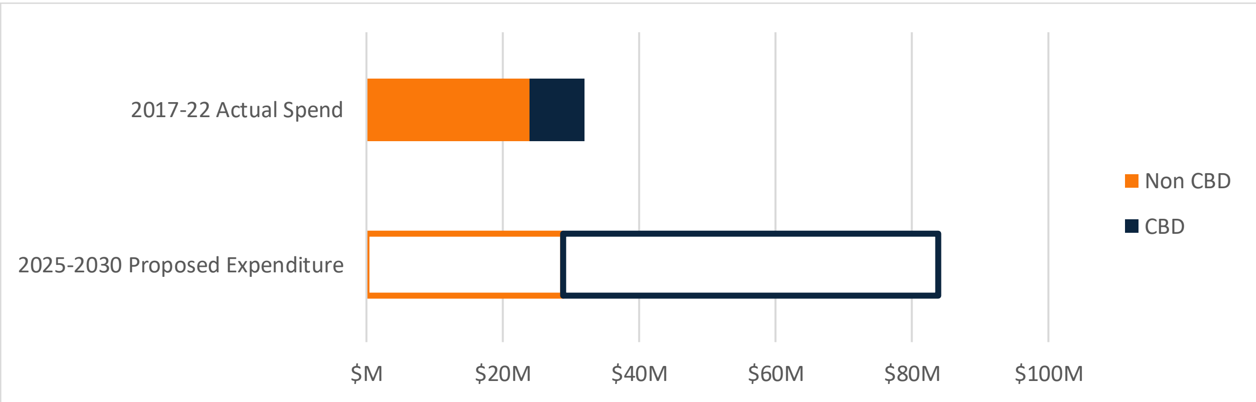


Figure 46 shows the breakdown of the actual and proposed underground cable expenditure by CBD and Non CBD spend.

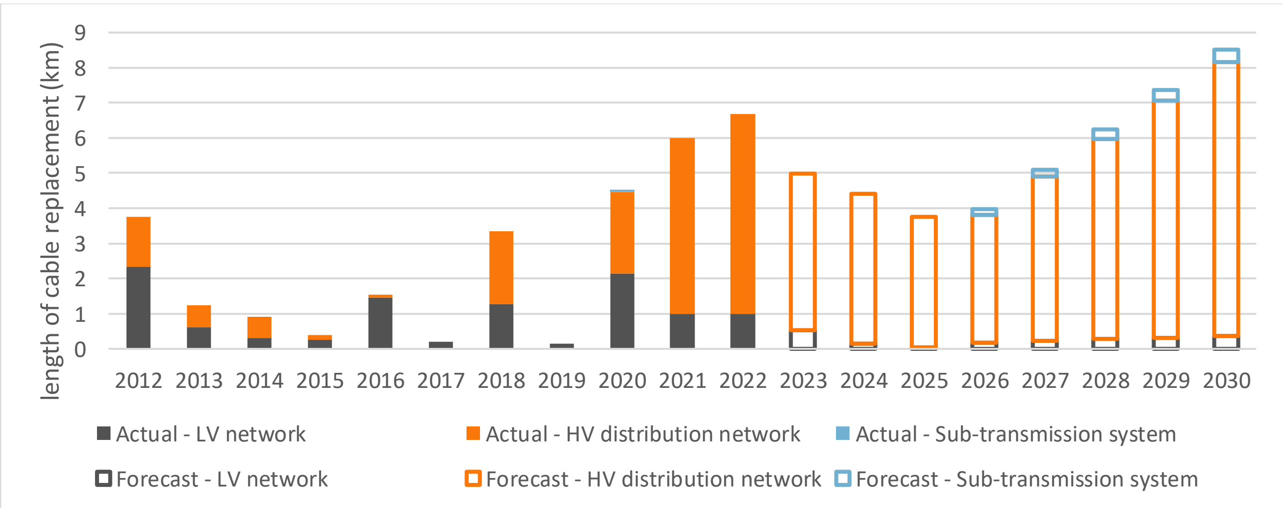
Figure 46 – Underground cable expenditure CBD/ Non CBD



Underground cable rate of renewal (2012-30)

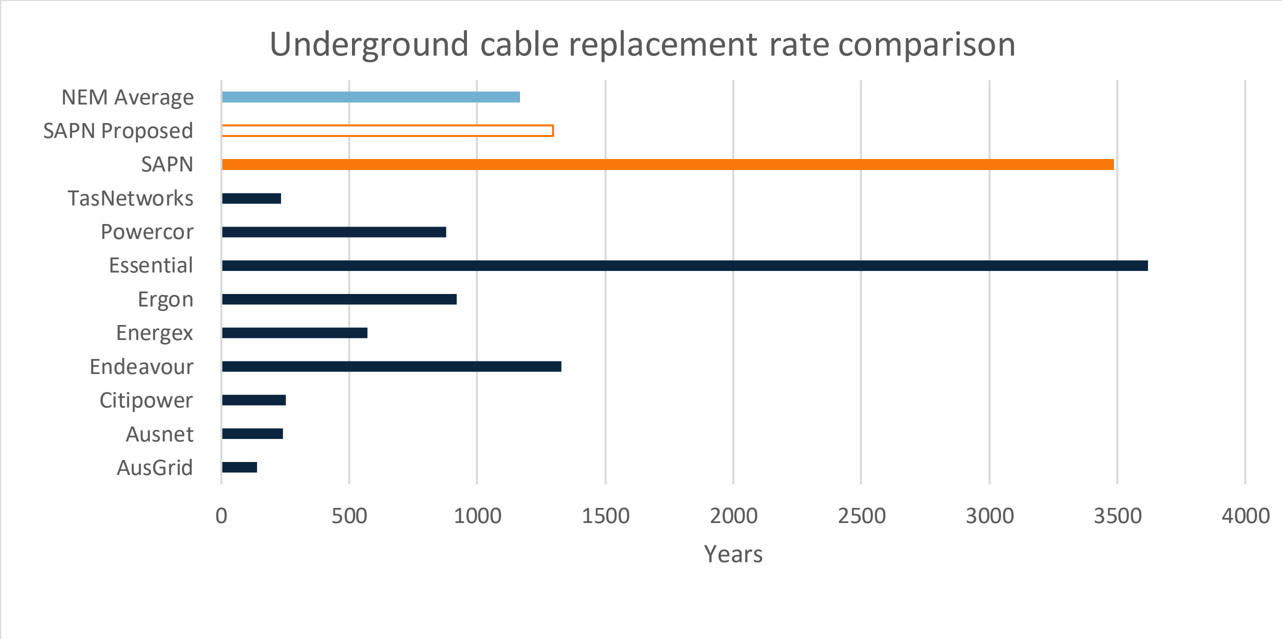
Figure 47 shows the historic and proposed renewal rate for cables. The proposed rate of renewal results in less than 0.4% of our cable population replaced over the 2025-30 period.

Figure 47 - Underground cable actual and forecasted replacement rate



We compared our proposed cable replacement rates to those of other DNSPs analysing data from publicly available Category RINs reported over the period 2015-2016 to 2019-2020. The proposed increase in expenditure results in an implied renewal rate closer to the NEM average.

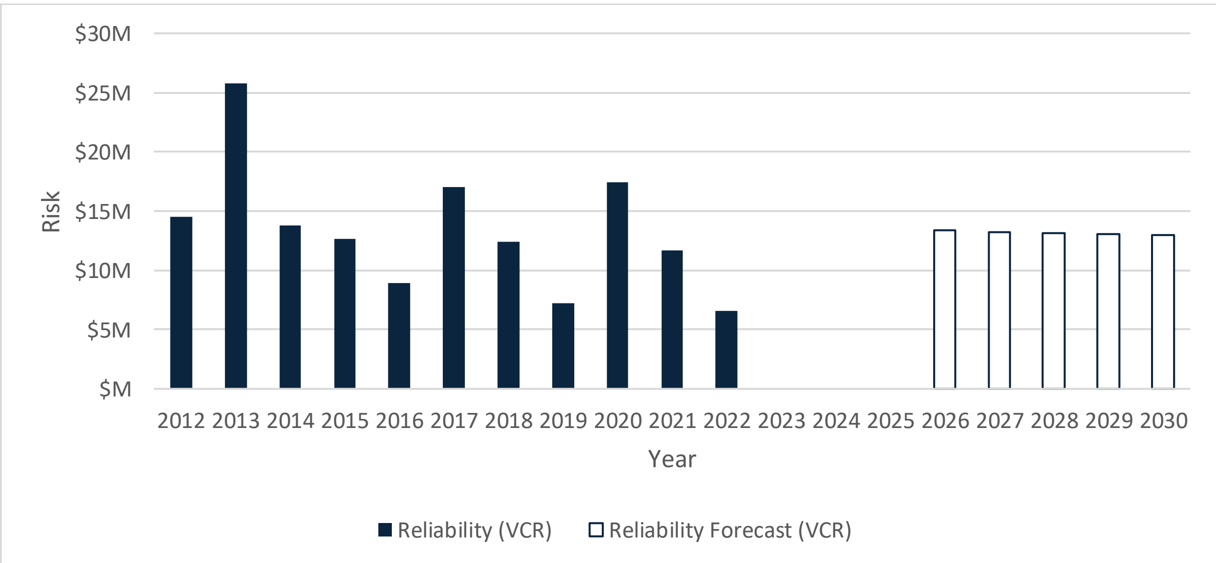
Figure 48 – DNSP cable replacement rate comparison



Underground cable forecast risk to service outcomes (proposed)

Figure 49 shows the observed performance impact from underground conductor assets along with the forecast impact on service outcomes given the proposed investment above. Our risk modelling shows that reliability service outcomes can be improved in the CBD to target levels, given the proposed expenditure.

Figure 49 - Historic and forecast underground cable risk (proposed expenditure)



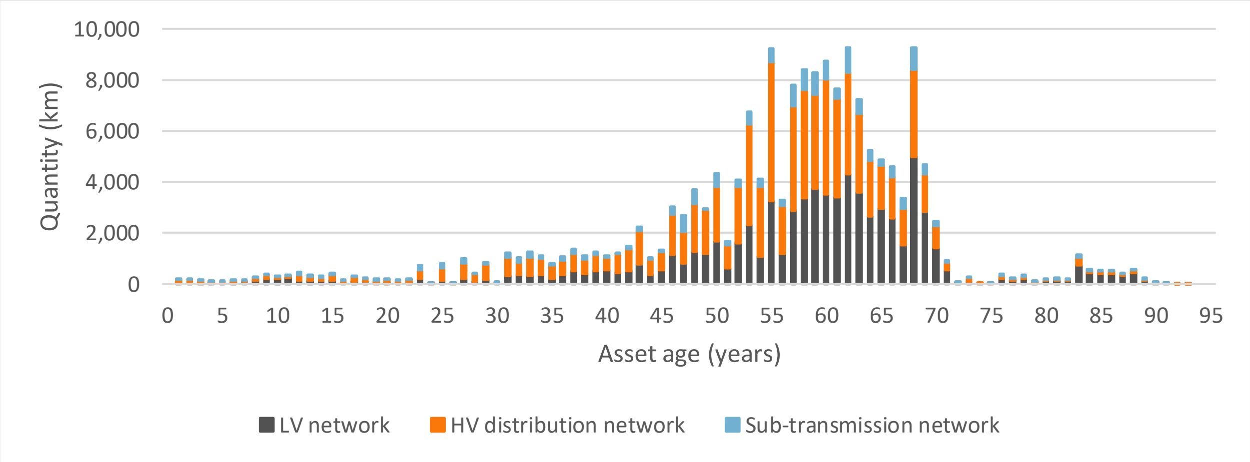
7.5. Overhead conductors

Overhead conductor asset class description

Overhead conductors transmit electricity between substations and from substations to customers. Of the approximately 175,000km of conductors across our network (over a route length of approximately 70,000km), a significant proportion (~80%) are 40–65 years old. Since the 1980's all new residential development has been supplied with underground cables rather than overhead conductor.

Figure 50 below shows the age profile of the overhead conductor population. The life expectancy of conductors varies, but is typically 65–95 years. The main factors that influence expected life are distance to coast, material type and diameter.

Figure 50 - Overhead conductor age profile



Overhead conductor asset performance (2012-22)

The main risks associated with conductors include:

- potential injury/death of SA Power Networks staff, contractors or the public due to:
  - electric shock through any current transmitted through the pole or live conductors falling to the ground,
  - electric shock through physical contact of vehicles, machinery and other equipment primarily in rural areas,
  - electric shock or fire starts due to breaches of conductor clearances to ground, buildings, structures or vegetation,
  - physical contact through conductor falling to the ground because of the pole, pole top structure or conductor condition, or
- fire start due to conductor defects or failures; and
- impact on reliability due to outages resulting from conductor failures.

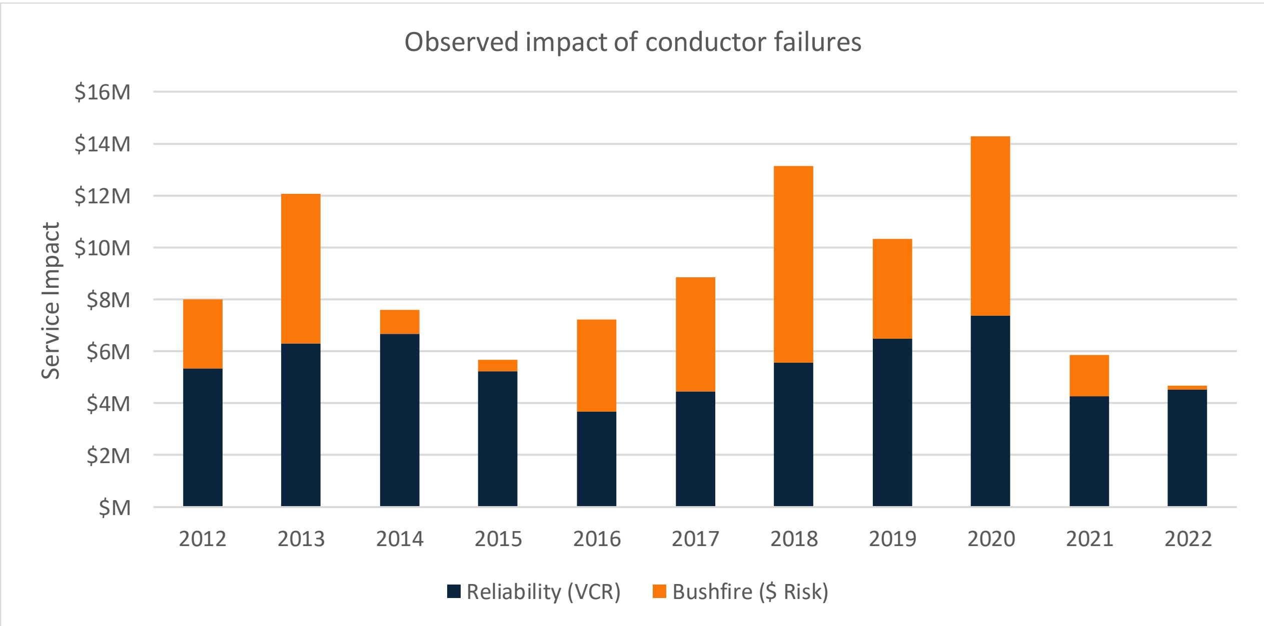
Figure 51 shows that the historical number of conductor failures has increased over the last decade. Given our extremely low replacement rate with a class of assets approaching the end of their technical life this is expected.

Figure 51 – Observed conductor failures

The lower bushfire risk in 2021 and 2022 reflects the fact that fire starts from conductor failures can vary (for instance fire starts may be lower during wetter years). In addition to risks from failures, a severely deteriorated conductor which has lost its strength poses a risk to our employees when undertaking work on the network.

Conductor failures have been the largest contributor to bushfire risk (based on actual fire starts) within our modelled asset classes.

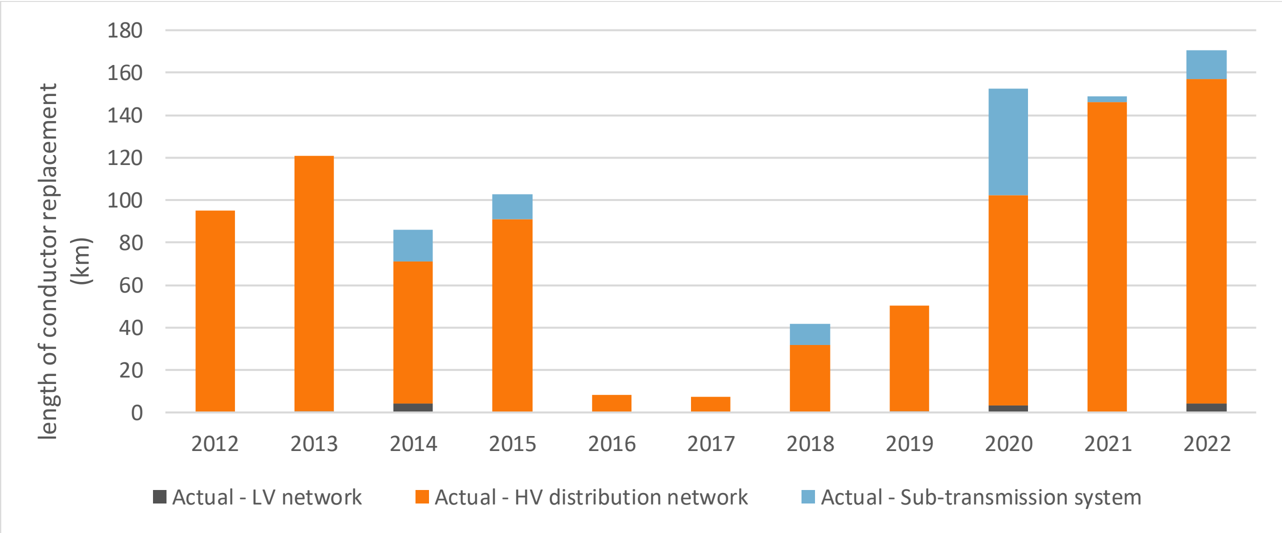
Figure 52 - Impact of overhead conductor failures



Overhead conductor replacement rate (2012-22)

We have recently been replacing on average less than 150km of overhead conductor per year under our replacement program. This results in a total effective annual volume of less than 0.1% of the population (175,000km) replaced each year. With this replacement rate it would take well over 1,000 years to replace the entire conductor population. This replacement rate may be appropriate, efficient and prudent, when the assets are relatively young but is clearly unsustainable in the long term and is now resulting in increased failures. Further, this replacement rate is at odds with other DNSPs in the NEM see Figure 53.

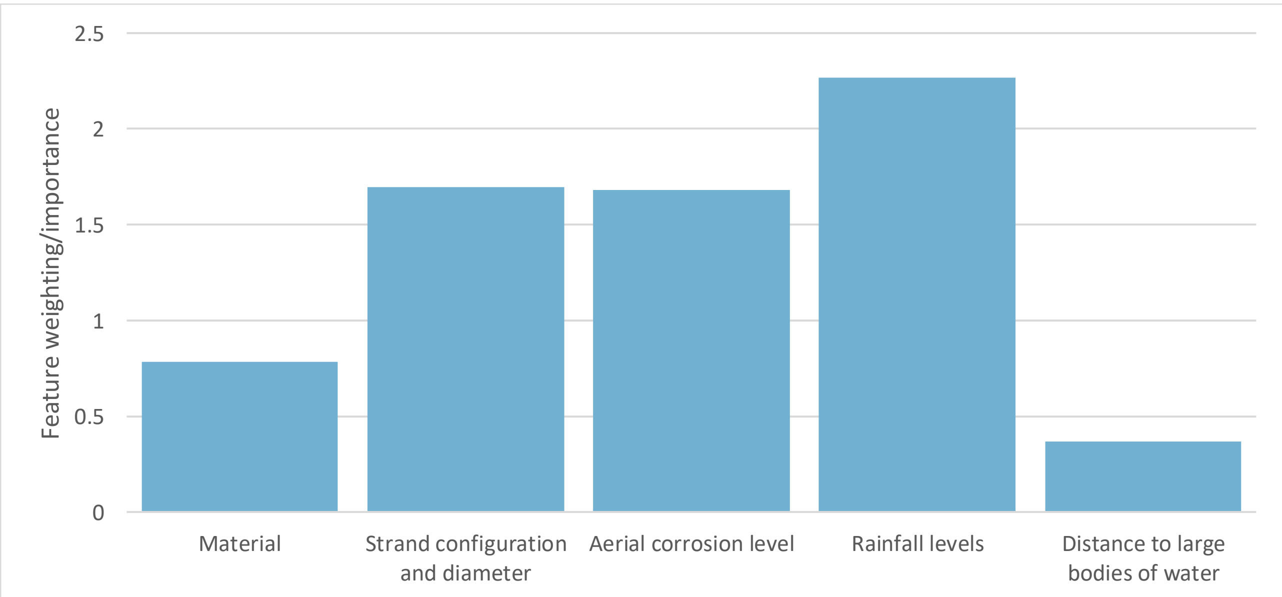
Figure 53 - Overhead conductor actual replacement rate



Overhead conductor forecast risk to service outcomes (base case)

Figure 54 shows our forecast conductor failure rate based on our current replacement rate. The conductor forecast uses a probability of failure model developed in collaboration with Frazer Nash, building on the ENA conductor health index approach. This model uses machine learning analysis to identify the relationship between recorded asset failures, asset characteristics and operating environment (Figure 54). This relationship is used to determine the current health/conditional age of each asset and using a statistical approach, the derivation of a survival function to forecast probability of failure.

Figure 54 - Feature weighting for conductor probability of failure model



Using the above method, the failure for each individual conductor asset was forecast using a model calibrated against observed failures and considers various factors such as age, distance to coast, material type and conductor diameter. The probability of failure modelling was validated by 'back casting' in the model to compare the number of failures predicted with the number of failures observed over the last decade.

Figure 55 – Historical and forecast overhead conductor failures

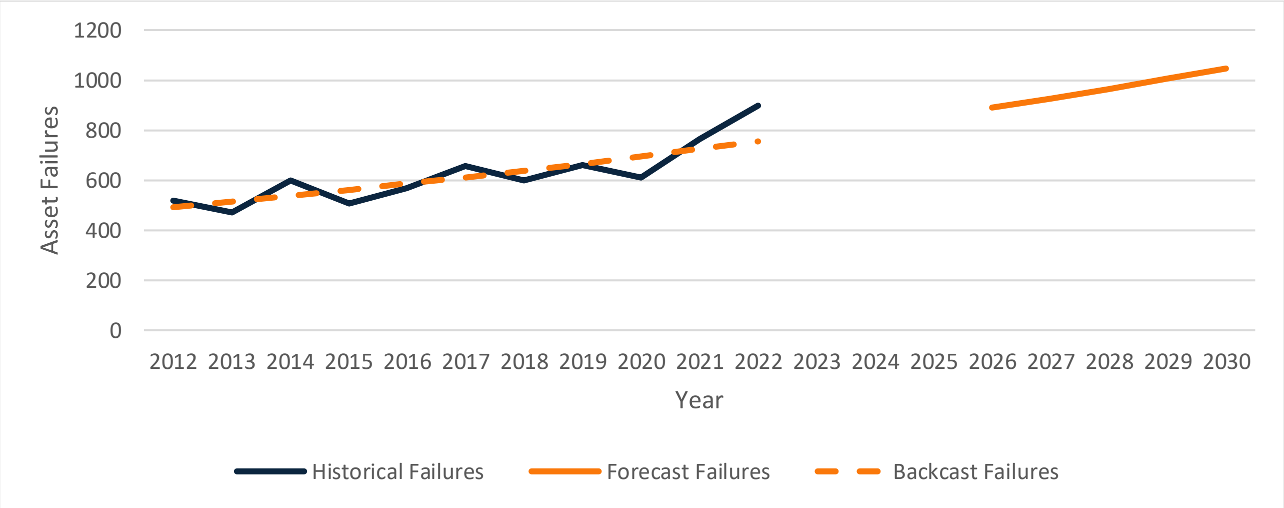
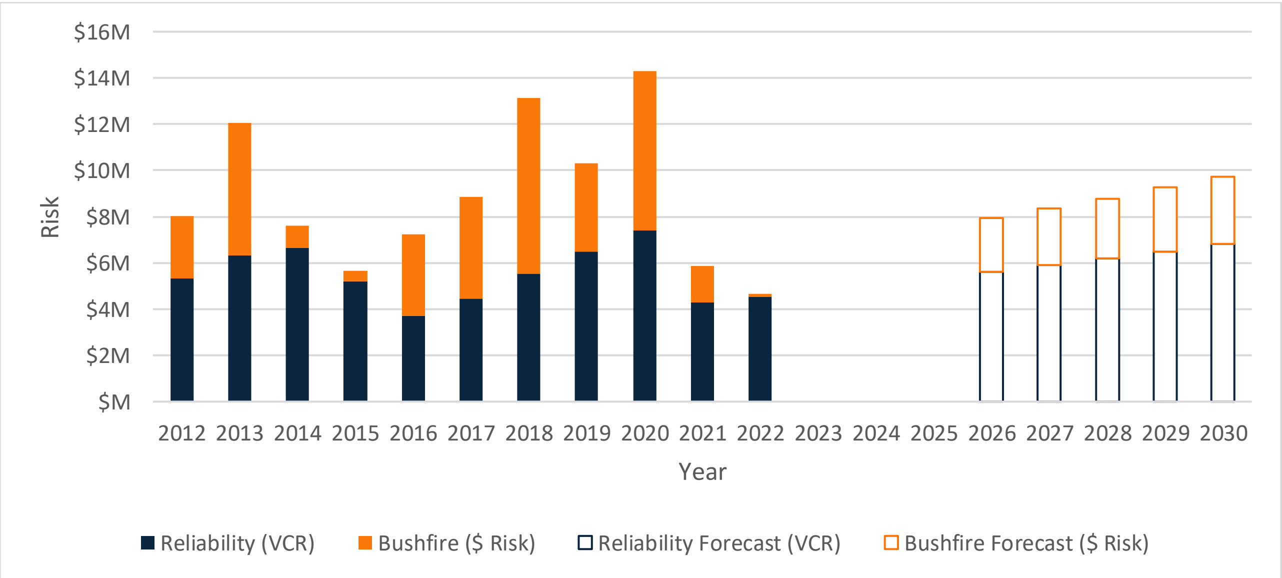


Figure 56 shows the observed performance impact from conductor assets along with the forecast impact on service outcomes if we continue our current replacement rate. Our risk modelling shows that continuing our current replacement rate would result deteriorating customer reliability and increase safety risk (including bushfire risk).

Figure 56 – Historical and forecast overhead conductor risk



Overhead conductor expenditure forecast

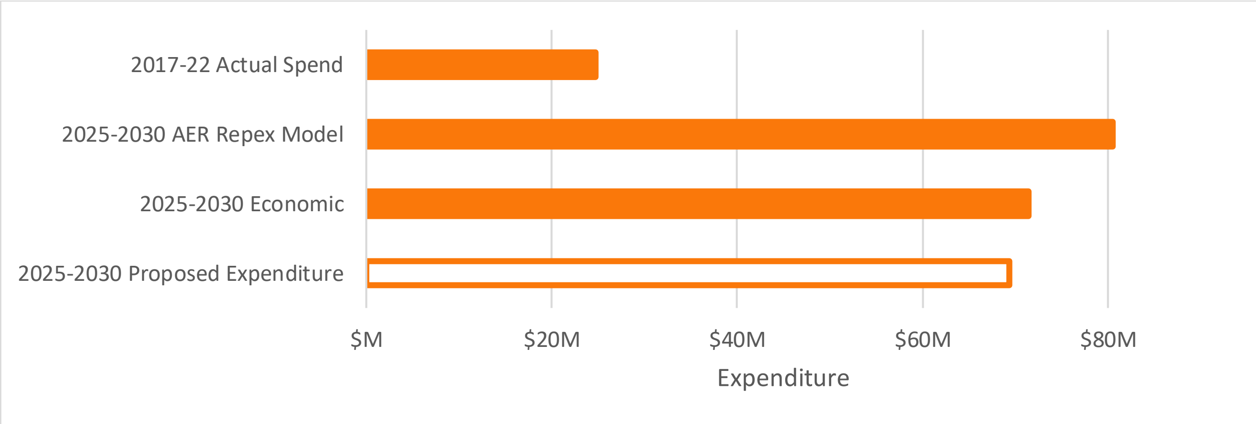
A conductor that has failed resulting in a supply interruption is generally repaired and placed back into service. Unlike most other asset classes (eg. poles, transformers) asset failures therefore do not result in an immediate replacement.

Addressing the increase in forecast risk outlined above, we developed a proposed scenario for conductors aimed at achieving the service level outcomes described in section 5.

Overhead conductor forecast renewal expenditure summary (2025-230)

We considered three scenarios (i.e. options) in developing our required expenditure for overhead conductors, being a **base case** (using actual spend), **economic scenario** and a **proposed scenario** meeting targeted outcomes presented in section 5. We provided an additional comparison with the AER repex model.

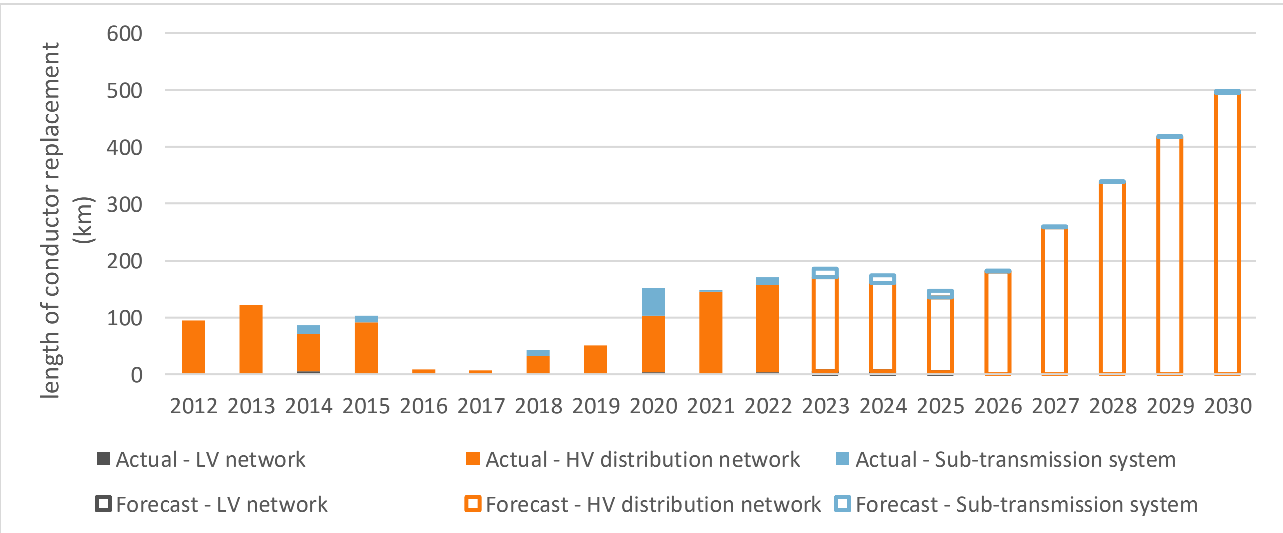
Figure 57 – Overhead conductor expenditure comparison



Overhead conductor rate of renewal (2012-30)

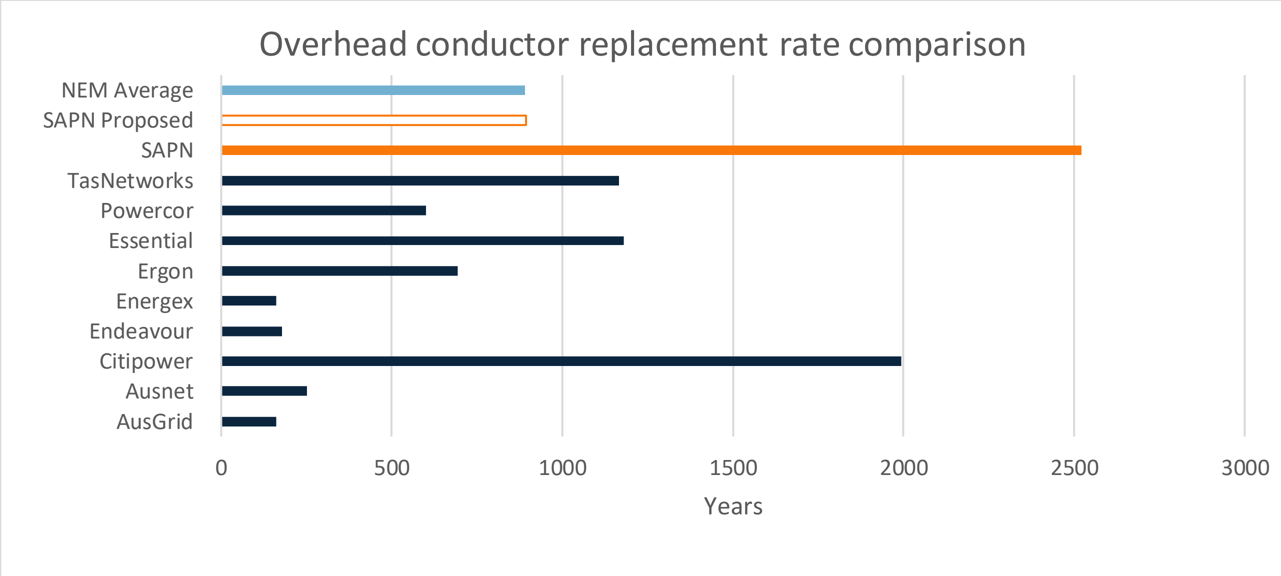
Figure 58 shows the proposed renewal rate with an expenditure of $69.3 million. The average proposed replacement rate over the 2025-30 RCP is 340km of replacement out of a population of 175,000km, resulting in less than 1% of our conductor population replaced over the 2025-30 period. Further increases in replacement rates will be required in future periods.

Figure 58 - Overhead conductor actual and forecasted replacements



We compared our proposed conductor replacement rates with those of other DNSPs analysing data from publicly available Category RINs reported from 2015-2016 to 2019-2020 as a cross-check of our forecasts. The proposed renewal rate increase puts our replacement program more in line with other distributors.

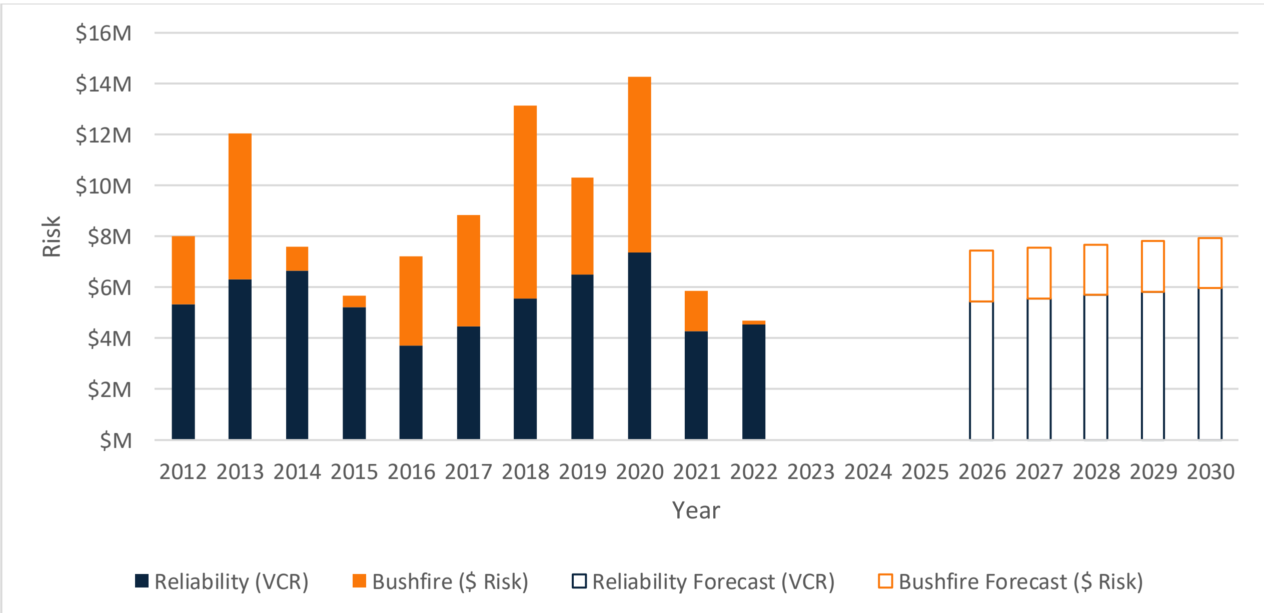
Figure 59 – DNSP Overhead conductor replacement rates



Overhead conductor forecast risk to service outcomes (proposed)

Figure 60 shows the observed performance impact from overhead conductor assets along with the forecast impact on service outcomes given the proposed investment above. Our risk modelling shows that reliability and bushfire safety outcomes can be improved relative to the base case, given the proposed expenditure.

Figure 60 - Historic and forecast overhead conductor risk (proposed expenditure)

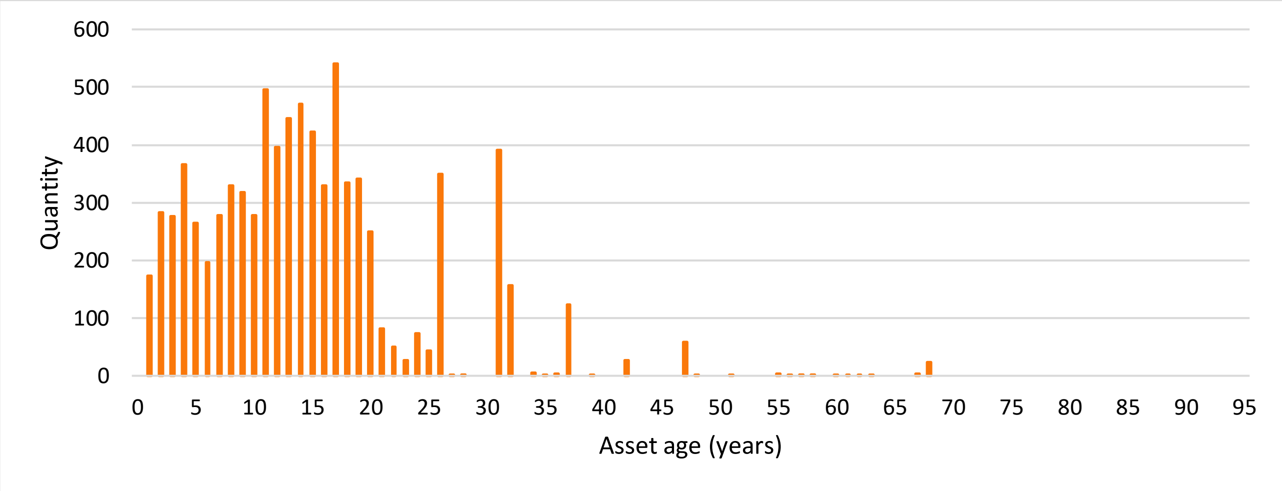


7.6. Switching cubicles

Switching cubicle asset class description

Switching cubicles are devices mounted on ground that connect components of the underground cable network. These devices enable safe connection and disconnection (ie. switching) of cables and transformers for operational and maintenance purposes. The age profile of this asset class is shown in Figure 61.

Figure 61 - Switching cubicle age profile



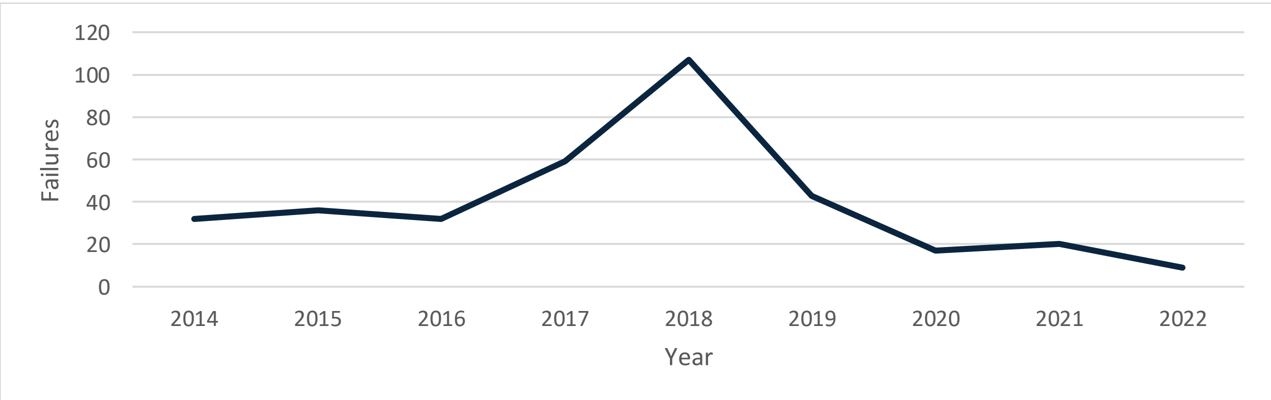
Switching cubicle asset performance (2014-22)

The main risks associated with switching cubicles include:

- potential injury/death of SA Power Networks staff, contractors or the public due to switches failing:
    - during switching operations, or
    - when not being operated;
- impact on reliability with outages caused by switching cubicle failures or delays in restoring power during other outages because of an inability to switch using inoperable switches; and
- environmental impacts of greenhouse gas emissions (SF6) from asset condition or failure.

Figure 62 shows historical switching cubicle failures increased to 2018. Replacement rates were increased to address this deterioration in performance (see Figure 63) and since then failures have stabilised.

Figure 62 – Observed switching cubicles failures

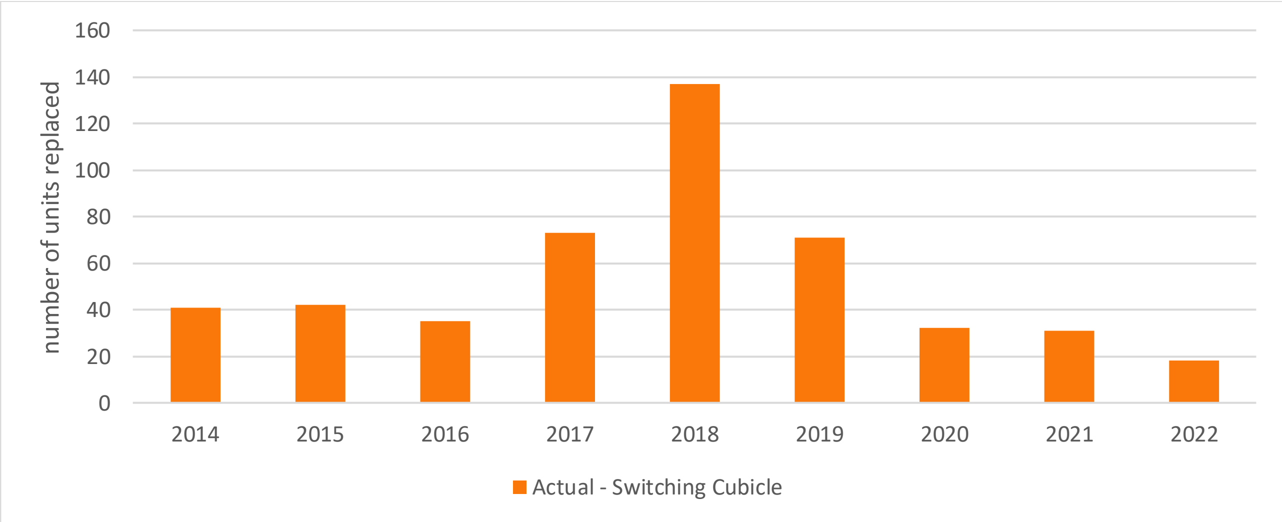


Switching cubicles have little impact on service outcomes as compared to other asset classes as catastrophic failures are rare and failures typically do not cause outages or present safety hazards but rather impact on operation of the network (ie inability to switch).

Switching cubicle replacement rate (2014-22)

We have recently been replacing an annual average of 20-30 switching cubicles under our replacement program. This results in a total effective annual volume of 0.36% of the switching cubicle population (8,227) replaced annually. With this replacement rate it would take 274 years to replace the entire switching cubicle population. Given the mean life of switching cubicles is 68 years this would suggest this replacement rate is not sustainable.

Figure 63 - Switching cubicle replacement rate



Switching cubicle forecast risk to service outcomes (base case)

Figure 64 shows our forecast of switching cubicle failures. We do not expect an increase in failures given our current replacement rate and in fact forecast a reduction.

Figure 64 – Historical and forecast switching cubicle failures

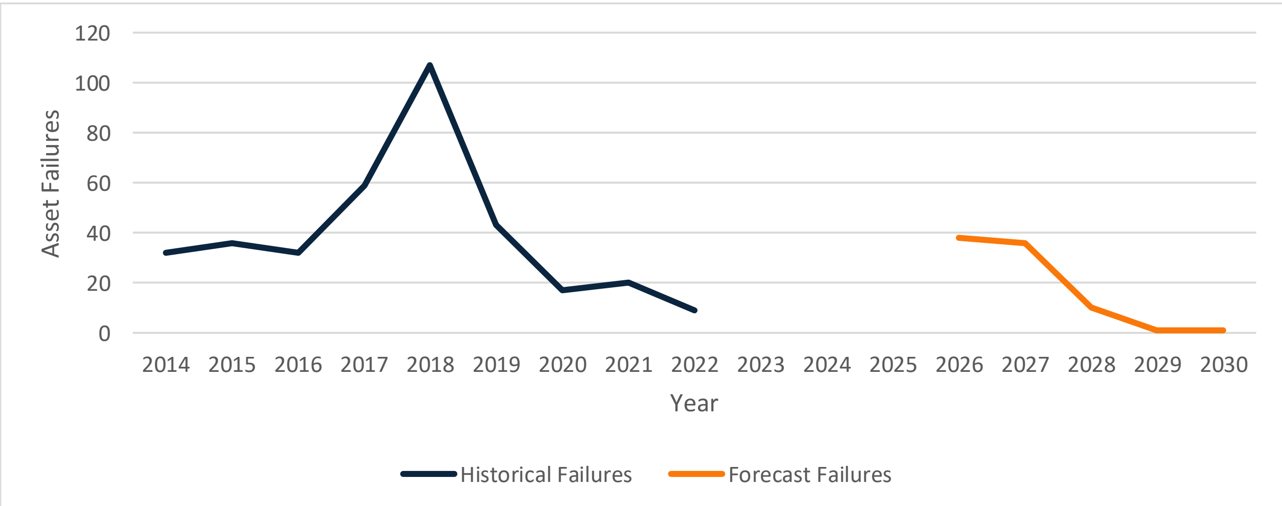
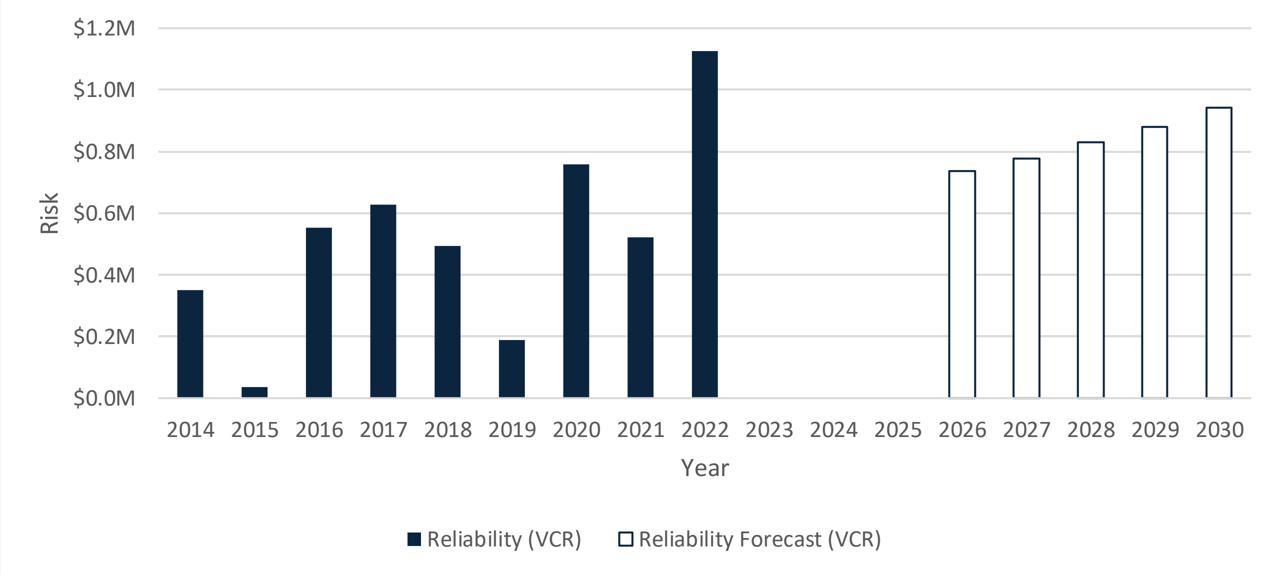


Figure 65 shows the observed performance impact from switching cubicles along with the forecast impact on service outcomes if we continue our current replacement rate. Our risk modelling shows that a continuation of our current rate of replacement would result in a deterioration in customer reliability.

Figure 65 – Historical and forecast switching cubicle risk



Switching cubicle expenditure forecast

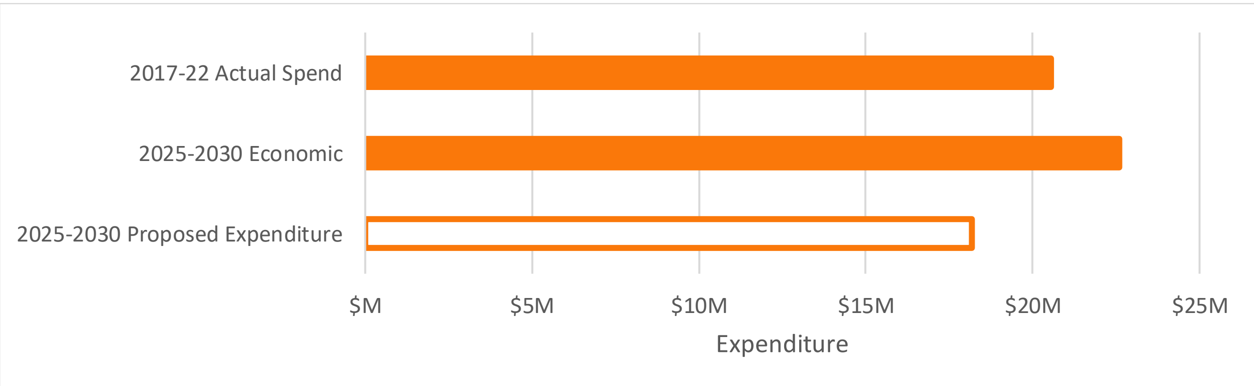
Switching cubicles may be replaced or refurbished. They rarely fail catastrophically (resulting in an outage) but instead fail to operate. Most of the repex is aimed at switching cubicles in the network that cannot be safely operated while energised. Limited refurbishment of switching cubicles is undertaken, with most makes/models replaced.

The renewal/replacement strategy for switching cubicles is based on achieving the service level outcomes described in section 5. While the current replacement rate is not sustainable, replacement of other asset classes presents better value in the overall replacement expenditure forecast.

Switching cubicle renewal expenditure summary (2025-30)

We considered three scenarios (i.e. options) in developing our required expenditure for switching cubicles, being a **base case** (using actual spend), **economic scenario** and a **proposed scenario** meeting targeted outcomes presented in section 5.

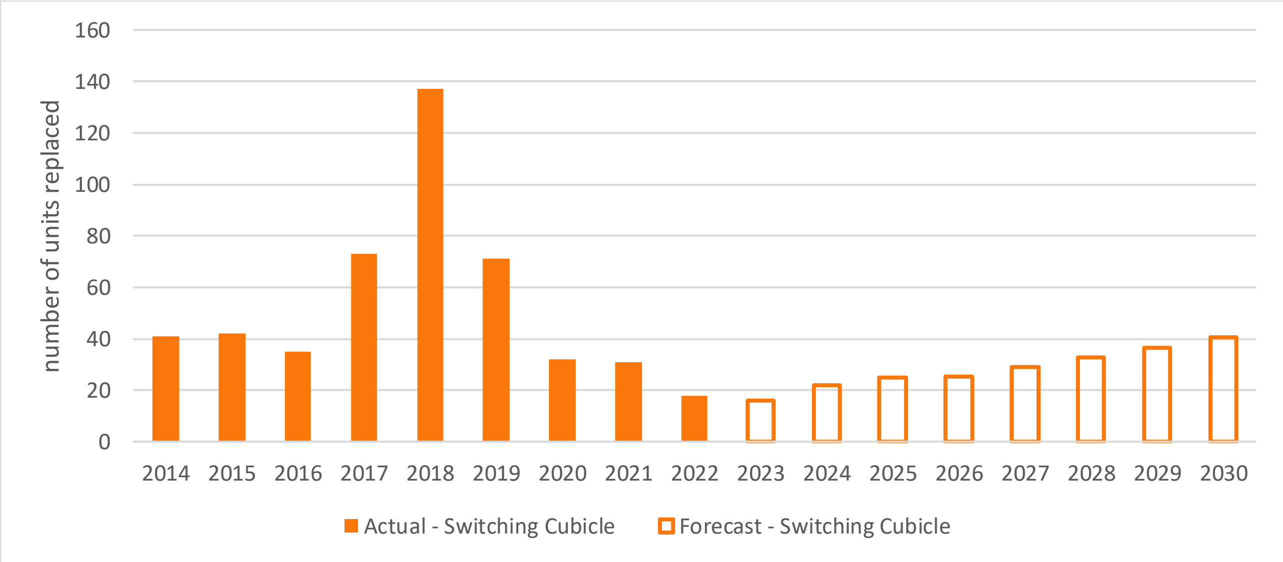
Figure 66 – Switching cubicle expenditure comparison



Switching cubicle rate of renewal (2012-30)

Figure 67 shows the historic and forecast renewal of switching cubicles. The proposed rate of renewal with an expenditure of $18.2 million provides an average replacement rate of 0.4%, resulting in less than 2% of our switching cubicle population replaced over 2025-30.

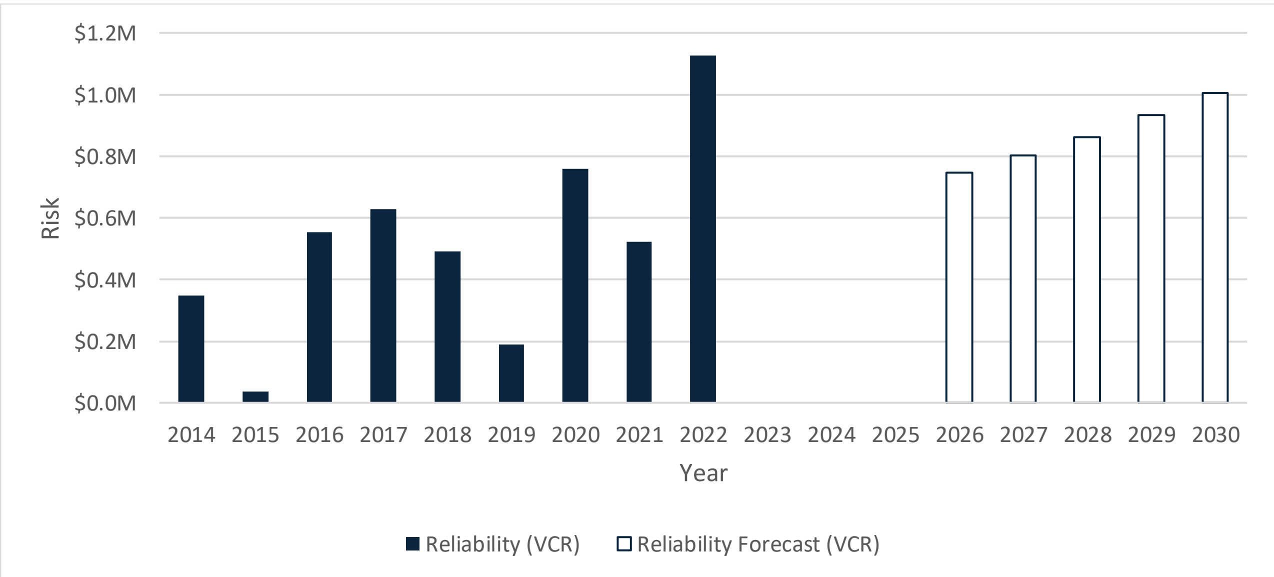
Figure 67 - Switching cubicle actual and forecasted replacements



Switching cubicles forecast risk to service outcomes (proposed)

Figure 68 shows observed performance impacts from switching cubicle assets along with the forecast impact on service outcomes given the proposed investment above. Our risk modelling shows that reliability outcomes can be allowed to deteriorate slightly, relative to the base case, via a reduction in switching cubicle expenditure, at the benefit of higher value investment in other asset categories.

Figure 68 - Historic and forecast switching cubicle risk (proposed expenditure)



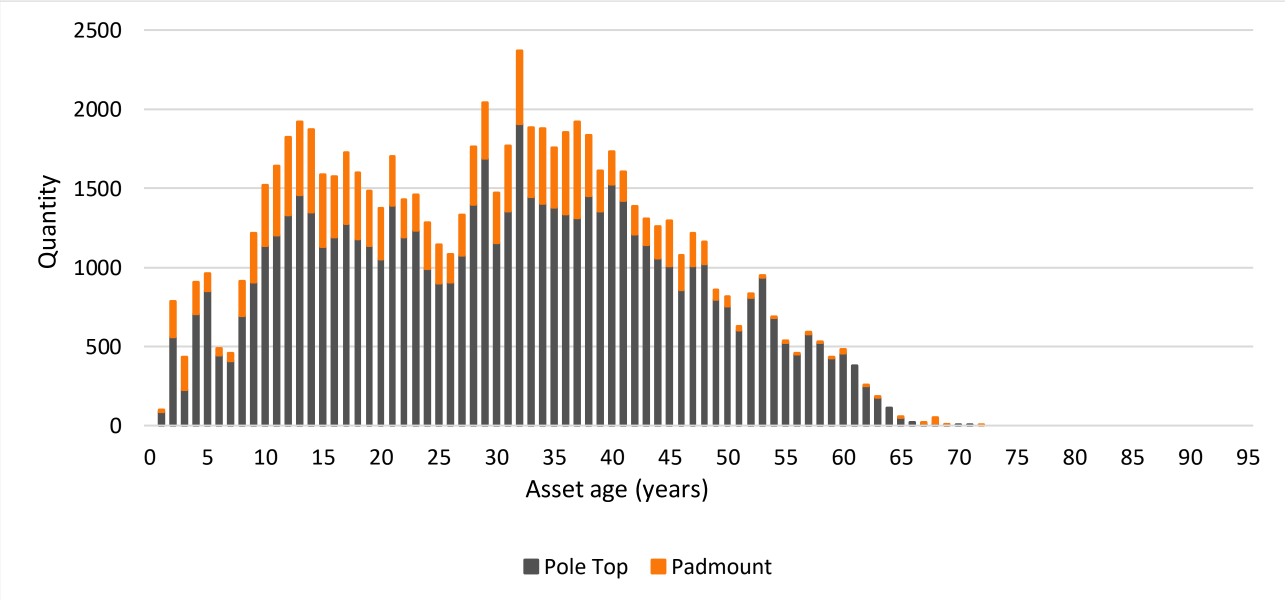
7.7. Distribution transformers

Distribution transformer asset class description

Distribution transformers change (transform) the voltage of electricity. Electricity is transported across the network at higher voltages to reduce losses and the approximately 76,000 distribution transformers installed across the network reduce voltage to a level that can be used by customers. They are installed overhead and mounted on poles (pole top) or installed at ground level inside a cabinet/cubicle (padmount) or in enclosed chambers (ground level station).

Figure 69 shows the age profile for the distribution transformer population. The expected life of distribution transformers varies but is typically 50–70 years. The main factors that influence expected life are corrosion zone, overloading of capacity and atmospheric pollution.

Figure 69 - Distribution transformer age profile



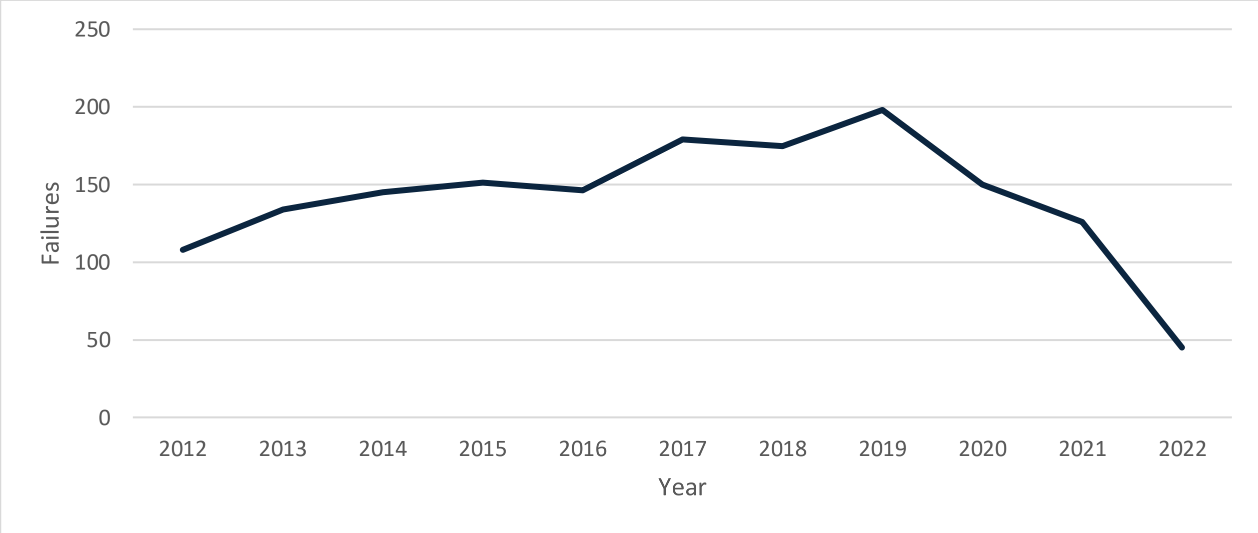
Distribution transformer asset performance (2012-22)

The main risks associated with distribution transformers include:

- potential injury/death of SA Power Networks staff, contractors or the public due to debris from catastrophic transformer failures that:
    - make physical contact through distribution transformers
    - falling to the ground because of the pole, pole top structure or distribution transformer condition, or
    - cause a fire start because of distribution pole top transformer exploding or overheating;
    - impact on reliability service standards due to the time associated with unplanned distribution transformer failures; and
- environmental impacts due to oil spills because of asset condition or failure.

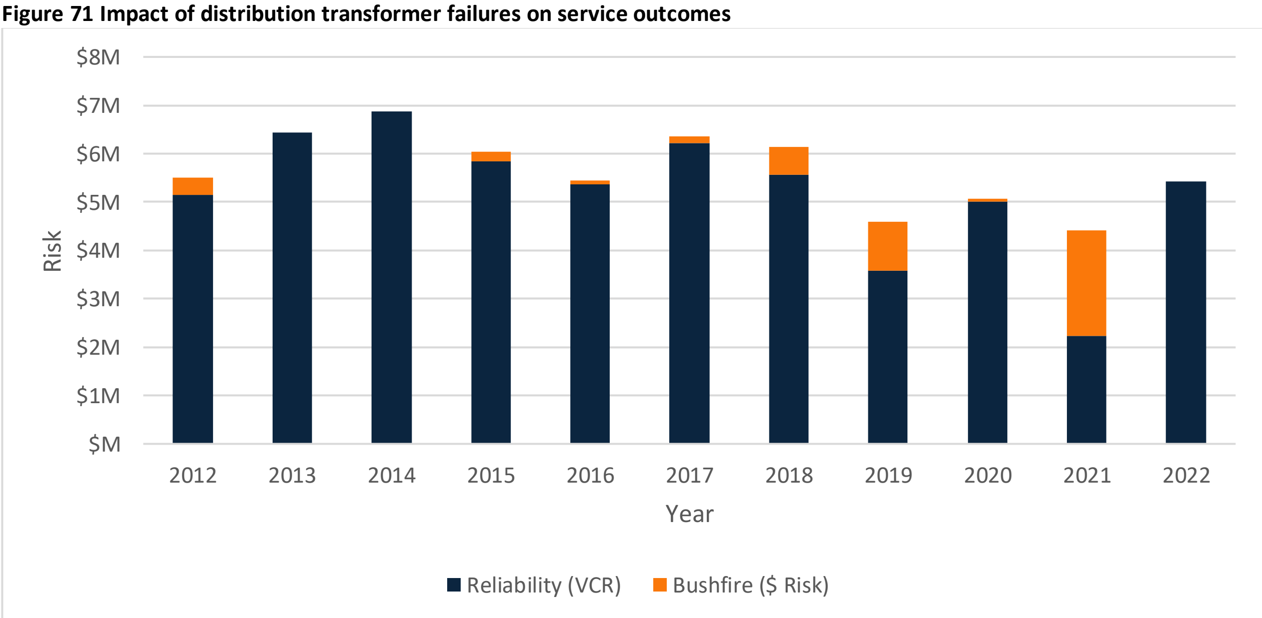
Figure 70 shows the historical number of transformer failures. The number of failures was on an upward trend to 2018 with a backlog of poor condition transformers. This backlog was addressed in 2018 (see Figure 72) which has since improved performance of this asset class.

Figure 70 – Observed distribution TF failures



Distribution transformer failures have had a moderate impact on service outcomes as compared to other asset classes and remains relatively stable

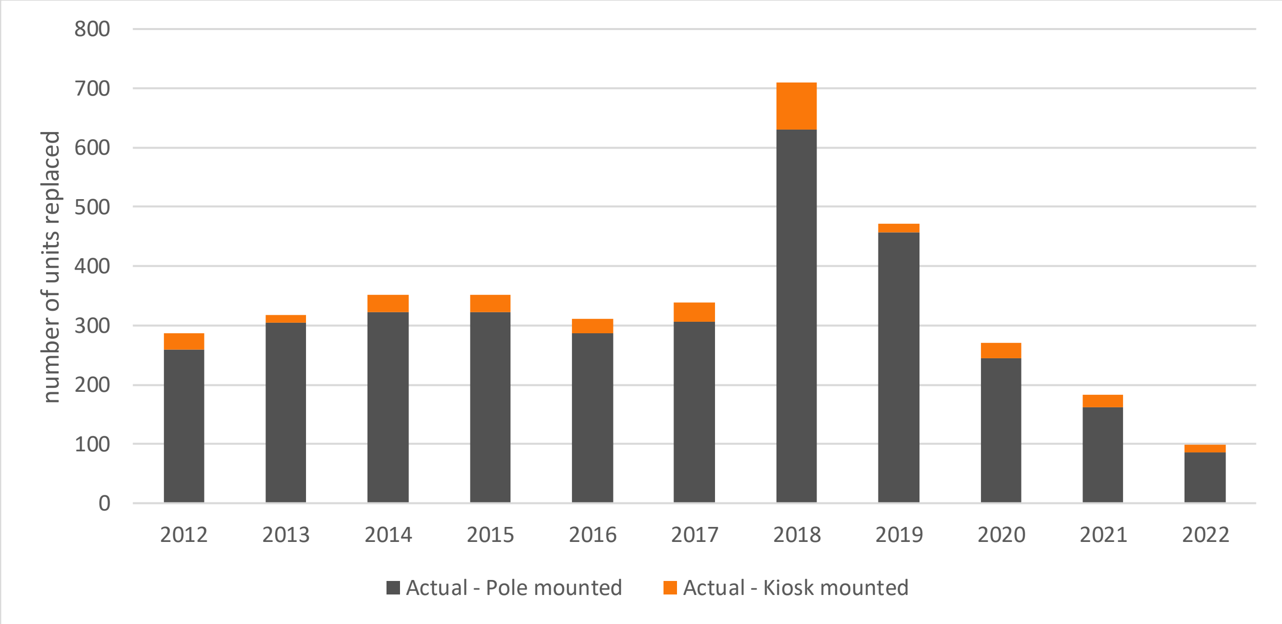
Figure 71 Impact of distribution transformer failures on service outcomes



Distribution transformer replacement rate (2012-22)

We have recently been replacing an average of 200-300 distribution transformers per year. This results in a total effective annual volume of 0.32% of the distribution transformer population (76,857) replaced annually. With this replacement rate it would take 307 years to replace the entire pole population. Given the mean life of distribution transformers is approximately 60 years, this would suggest this replacement rate is not sustainable

Figure 72 - Distribution transformer actual replacement rate



Distribution transformer forecast risk to service outcomes (base case)

Figure 73 shows our forecast distribution transformer failure rate based on our current replacement rate. This failure rate was forecast using probability of failure modelling for each individual distribution transformer asset using a statistical approach considering various factors including age, distance to coast, manufacturer, and electrical load. This approach was developed based on 10 years of recorded asset failures in collaboration with engineering consultants, Frazer Nash using a health index approach. The probability of failure modelling has been validated by 'back casting' in the model to compare the number of failures predicted with the number of failures we have observed over the last decade.

Figure 73 – Historical and forecast distribution transformer failures

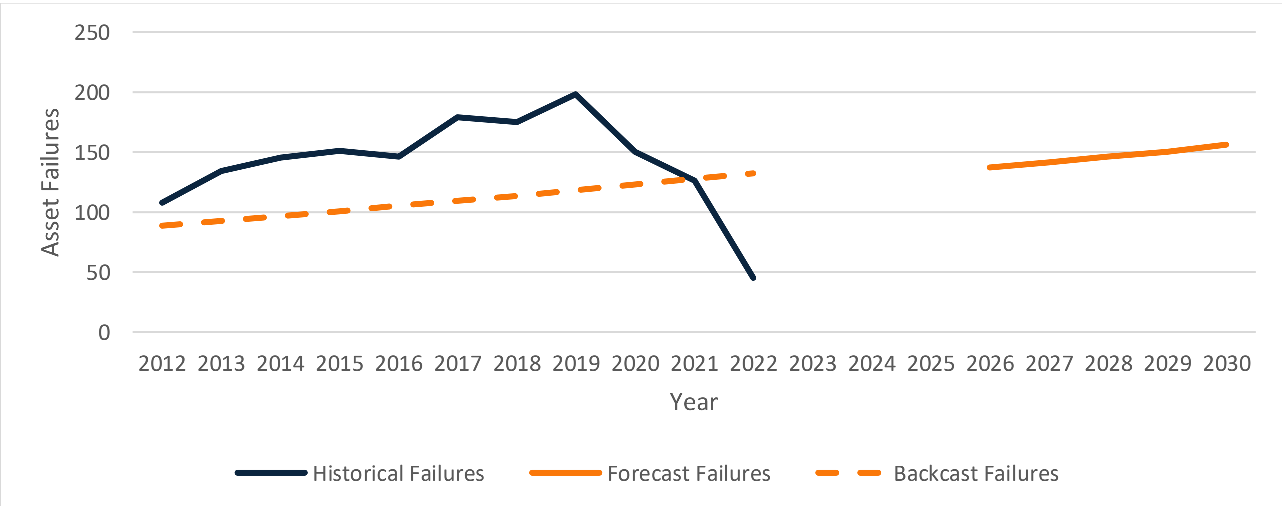
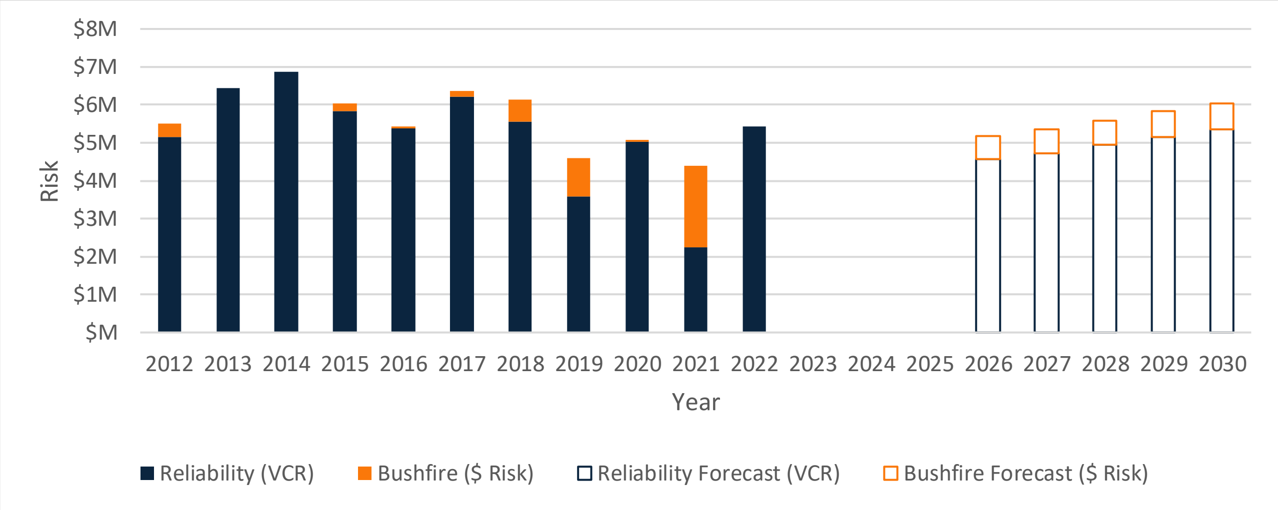


Figure 74 shows the observed performance impact from distribution transformer assets along with the forecast impact on service outcomes if we continue our current replacement rate. Our risk modelling shows that a continuation of our current rate of replacement would result in a gradual deterioration in customer reliability and an increase in safety risk (including bushfire risk).

Figure 74 – Historical and forecast distribution transformer risk



Distribution transformer expenditure forecast

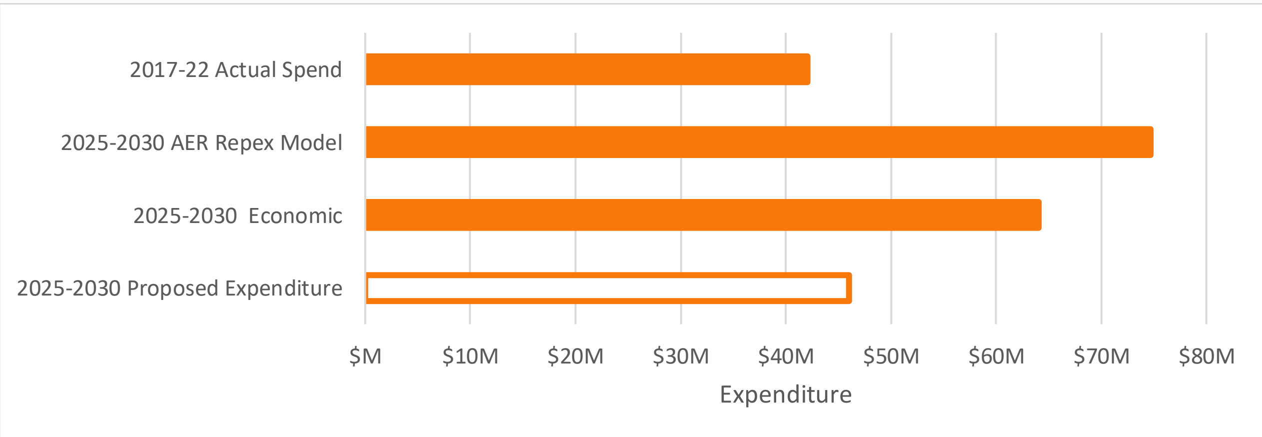
Distribution transformers that have failed resulting in a supply interruption are replaced immediately. Any distribution transformer defects identified via routine inspection have their value assessed to remove as much risk from the network as possible in the most cost-efficient manner. While customer connection alterations or augmentation can also involve transformer replacements the level of replacements are not material in the context of the entire population. Most of the risk removed via deteriorating transformers is funded through the planned replacement program.

The renewal/replacement strategy for distribution transformers is based on achieving the service level outcomes described in section 5.

Distribution transformer forecast renewal expenditure summary (2025-30)

We considered three scenarios (i.e. options) in developing required expenditure for distribution transformers, being a **base case** (using actual spend), **economic scenario** and a **proposed scenario** meeting targeted outcomes presented in section 5. We provided an additional comparison with the AER repex model output. Proposed expenditure for distribution transformers is lower than current actual expenditure as modelling suggests there are greater Benefit/ Cost investments to be made in other asset categories, to achieve the service outcomes presented in section 5.

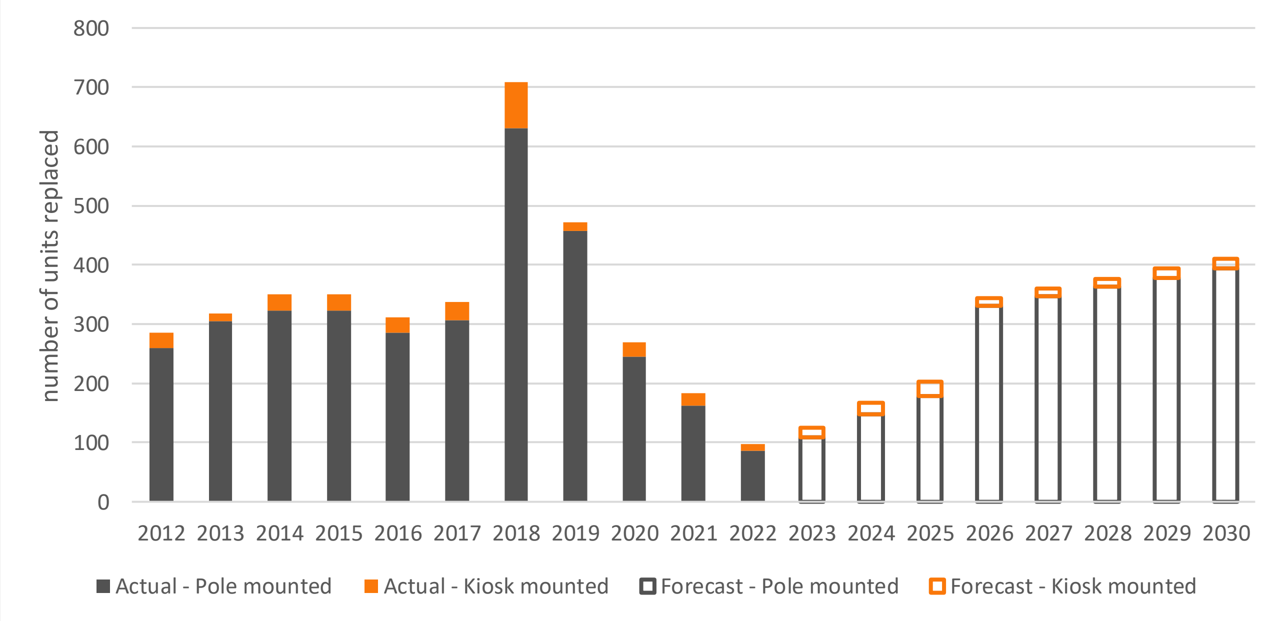
Figure 75 – Distribution transformer expenditure comparison



Distribution transformer rate of renewal (2012-30)

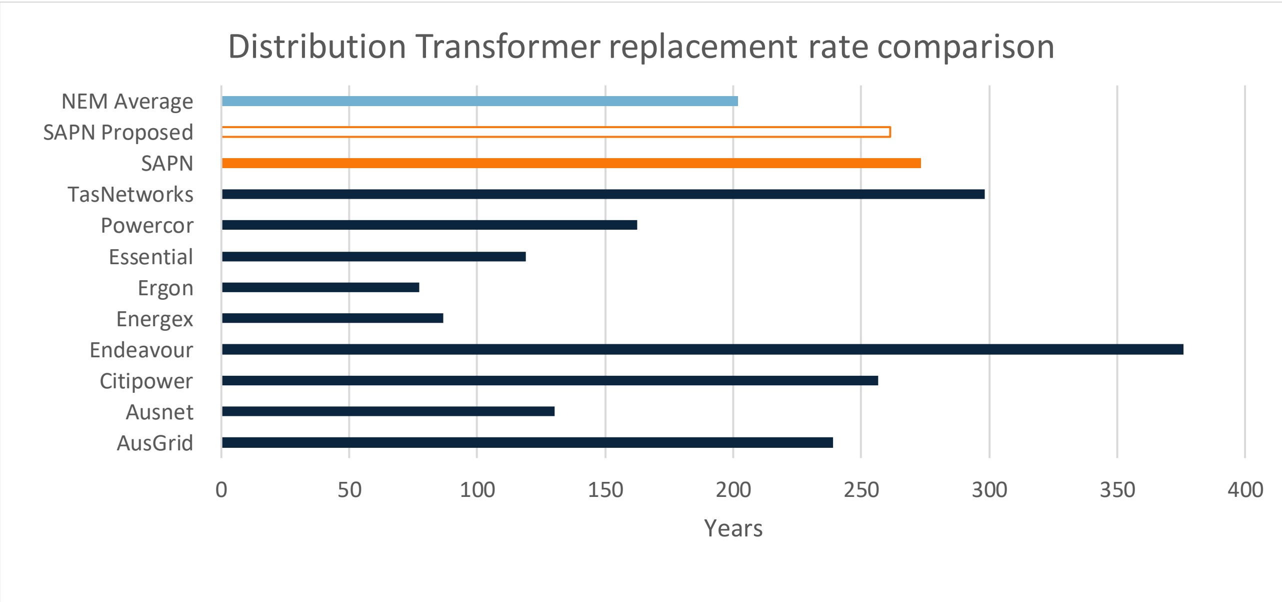
Figure 76 shows the proposed replacement rate with an expenditure of $46.0 million. The average proposed replacement rate over the 2025-30 RCP is approximately 400 transformers per year out of the population of 77,000 transformers with 2.7% of the population replaced over 2025-30.

Figure 76 - Distribution transformer actual and forecasted replacement rate



We compared our proposed distribution transformer replacement rates with those of other DNSPs using data from Category RIN covering 2015-2016 to 2019-2020 as a cross-check of our forecasts.

Figure 77 - DNSP distribution transformer replacement rates

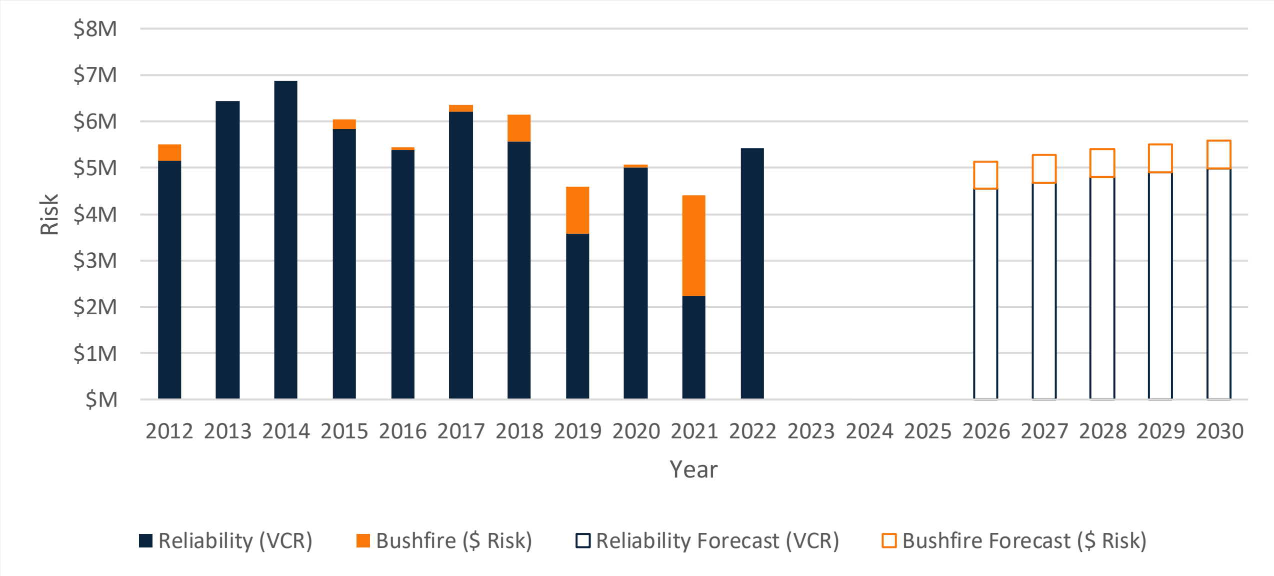


It should be noted that by optimising across multiple asset classes, the proposed expenditure forecast would result in a deterioration in performance in our distribution transformer fleet offset by an increase in other asset class expenditure/performance.

Distribution transformer forecast risk to service outcomes (proposed)

Figure 78 shows the observed performance impact from distribution transformer assets along with the forecast impact on service outcomes given the proposed investment above. Our risk modelling shows that reliability and bushfire safety outcomes can be improved relative to the base case and contribute to meeting the outcomes supported by customers.

Figure 78 - Historic and forecast distribution transformer risk (proposed expenditure)



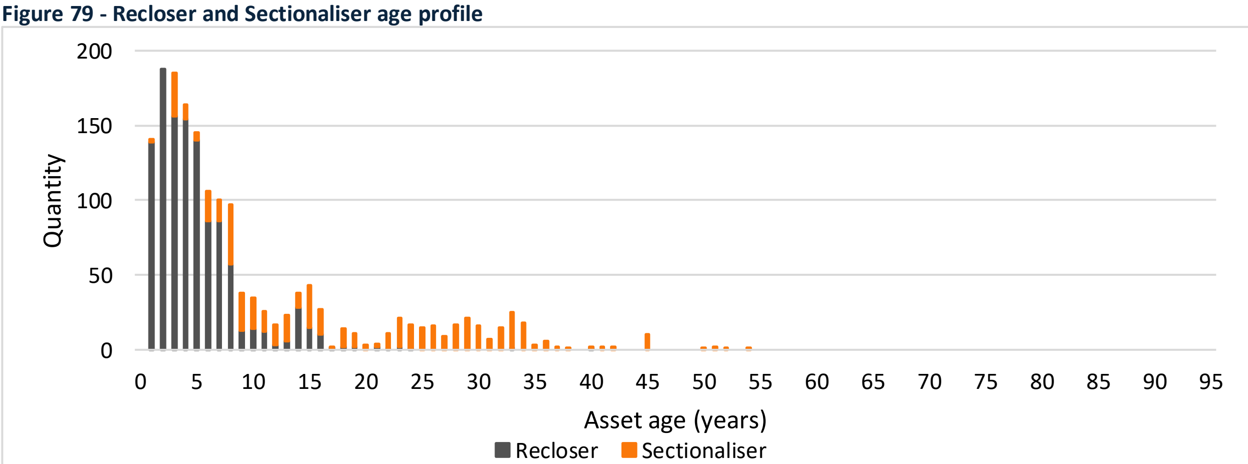
7.8. Reclosers and sectionalisers

Recloser and Sectionaliser asset class description

Reclosers and sectionalisers are specialised switchgear located on the overhead network. A recloser is like a circuit breaker connected to adjacent sections of overhead conductors in an electrical circuit. A sectionaliser is a switch always used in conjunction with an associated recloser. They are positioned in the network to reduce the risk of damage from electrical faults and to improve the reliability of supply to customers.

Figure 79 shows the age profile of our recloser and sectionaliser population. The majority of reclosers are electronic with an expected lifespan of 10-15 years while many sectionalisers are electro-mechanical with an expected lifespan of greater than 15 years.

Figure 79 - Recloser and Sectionaliser age profile



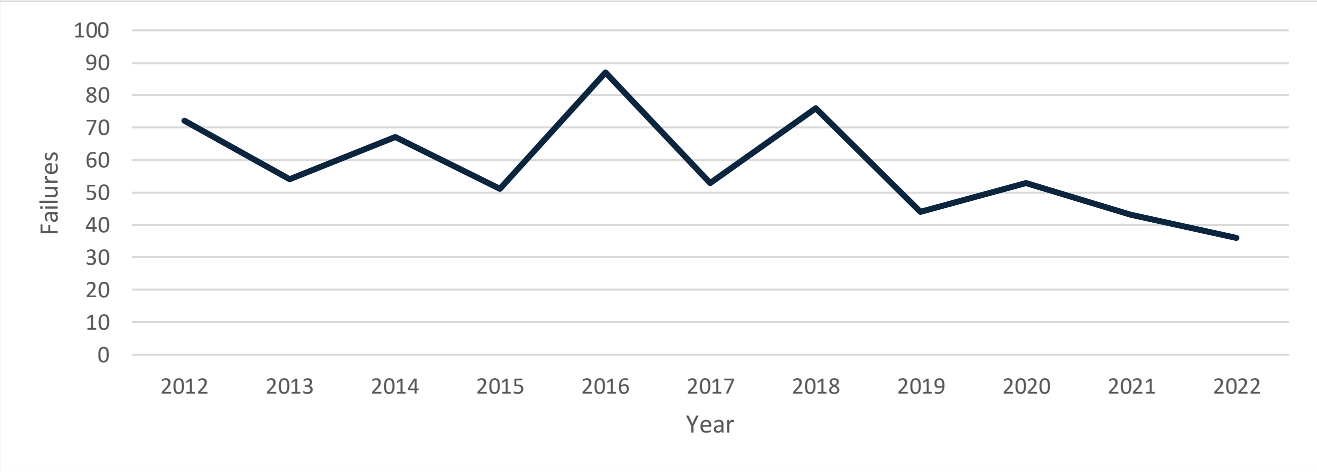
Recloser and sectionaliser asset performance (2012-2022)

The main risks associated with reclosers and sectionalisers include:

- potential injury/death of SA Power Networks staff, contractors or the public from inadequate protection due to the inability to detect faults or clear faults within required timeframes; and
- impact on reliability due to unplanned recloser or sectionaliser failures.

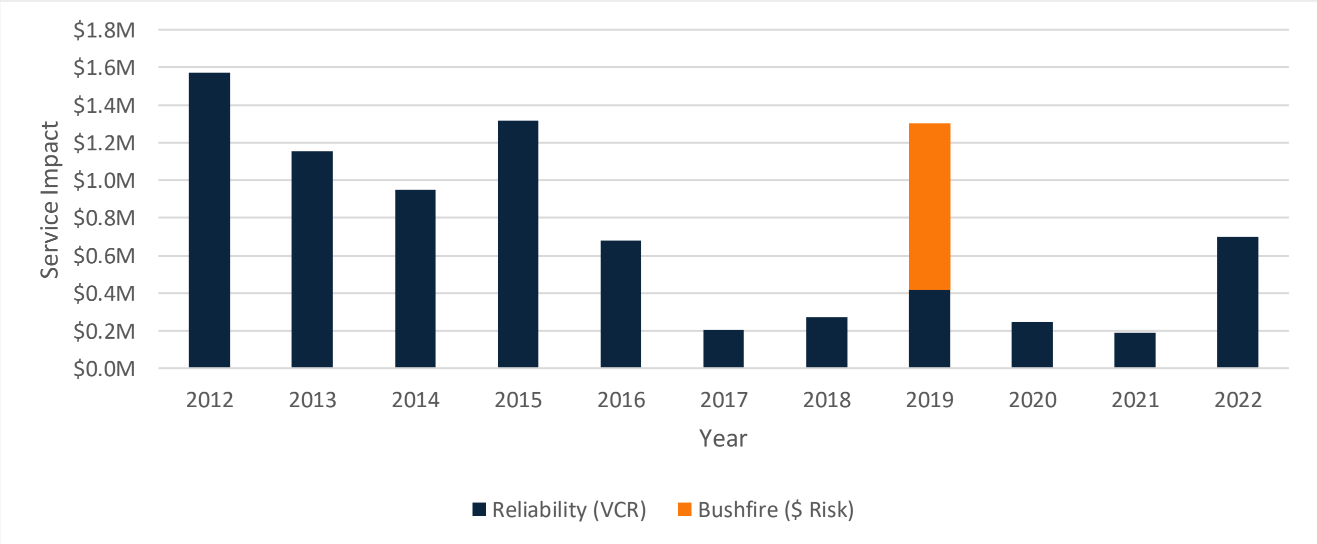
Figure 80 shows the historical number of recloser and sectionaliser failures gradually decreased over the last decade.

Figure 80 – Observed recloser/sectionaliser failures



Recloser and sectionaliser failures have had relatively little impact on service outcomes as compared to other asset classes eg overhead conductors and underground cables.

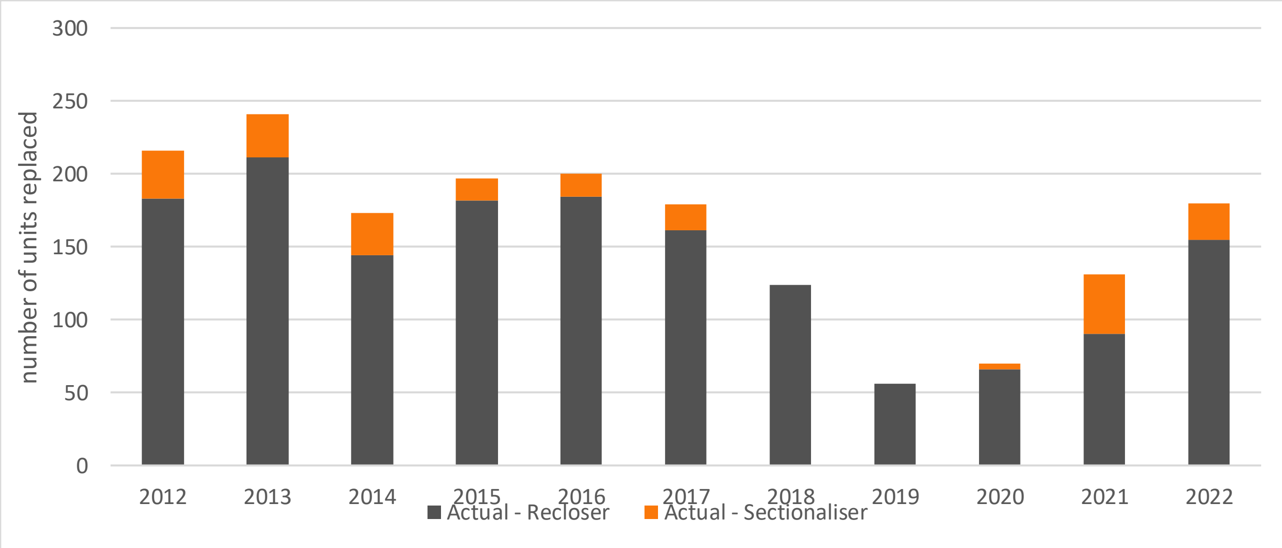
Figure 81 Impacts of recloser/sectionalisers on service outcomes



Recloser and sectionaliser replacement rate (2012-22)

We have been replacing an annual average of 56 reclosers and sectionalisers. This results in a total effective annual volume of 3.4% of the population replaced each year. With this replacement rate it would take approximately 30 years to replace the entire population.

Figure 82 - Recloser and sectionaliser actual replacement rate



Recloser and sectionaliser forecast risk to service outcomes (base case)

Figure 83 shows our forecast recloser and sectionalise failure rate based on our current replacement rate. This failure rate was forecast using probability of failure modelling for each individual recloser and sectionaliser asset using a statistical approach considering age and observed failures.

Figure 83 – Historical and forecast recloser and sectionalisers failures

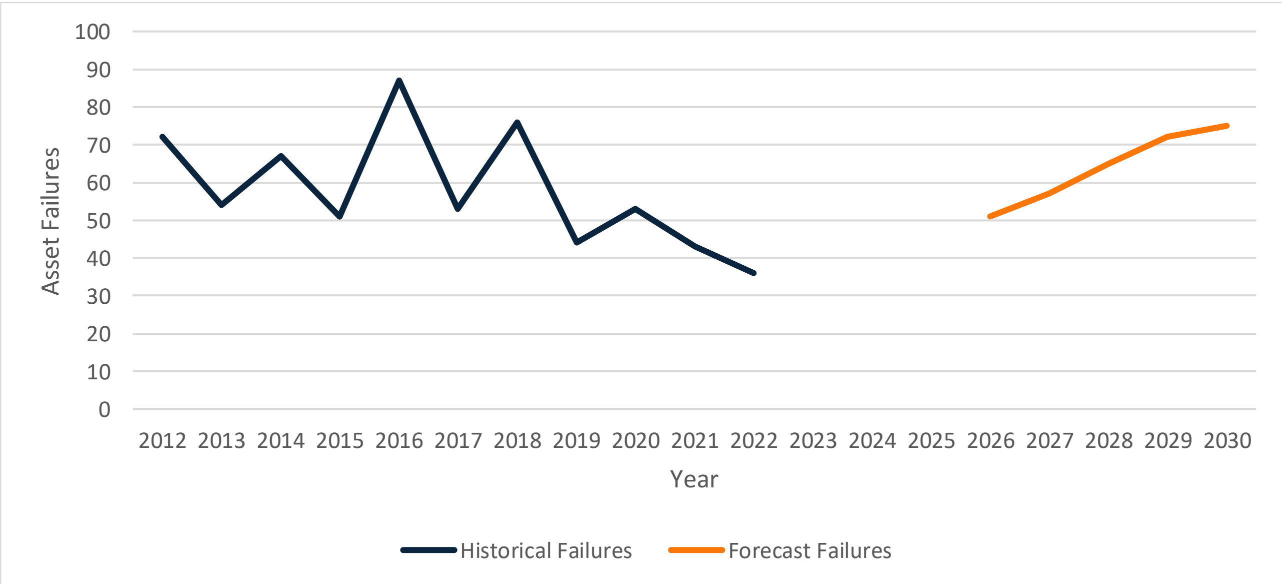
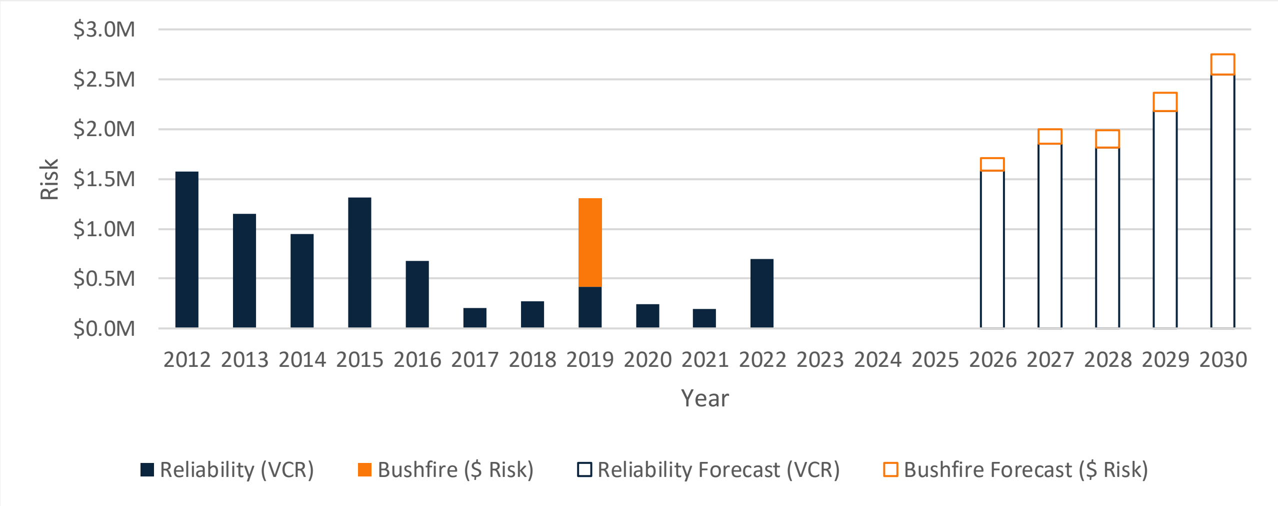


Figure 84 shows the observed performance impact from distribution transformer assets along with the forecast impact on service outcomes if we continue our current replacement rate. Our risk modelling shows that continuing our current rate of replacement would result in a gradual deterioration in customer reliability and an increase in safety risk (including bushfire risk).

Figure 84 – Historical and forecast recloser and sectionalisers risk



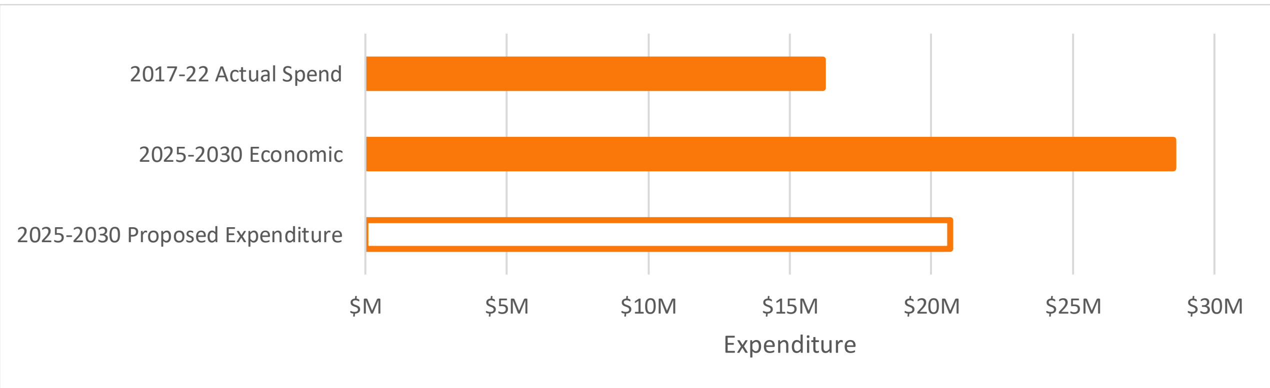
Recloser and sectionaliser expenditure forecast

The replacement strategy for reclosers and sectionalisers is based on information obtained from the asset condition assessment along with the number of operations and the identification of reclosers or sectionalisers that have failed to operate during network outages. Reclosers that fail to operate during a network outage have their protection settings investigated to determine if protection settings or equipment failure was the underlying cause of failure to operate. The renewal/replacement strategy for reclosers and sectionalisers is based on achieving the service level outcomes described in section 5.

Recloser and sectionaliser forecast renewal expenditure summary

We considered three scenarios (i.e. options) in developing our required expenditure for reclosers and sectionalisers, being a **base case** (using actual spend), **economic scenario** and a **proposed scenario** meeting targeted outcomes presented in section 5. We provided an additional comparison with the AER repex model output.

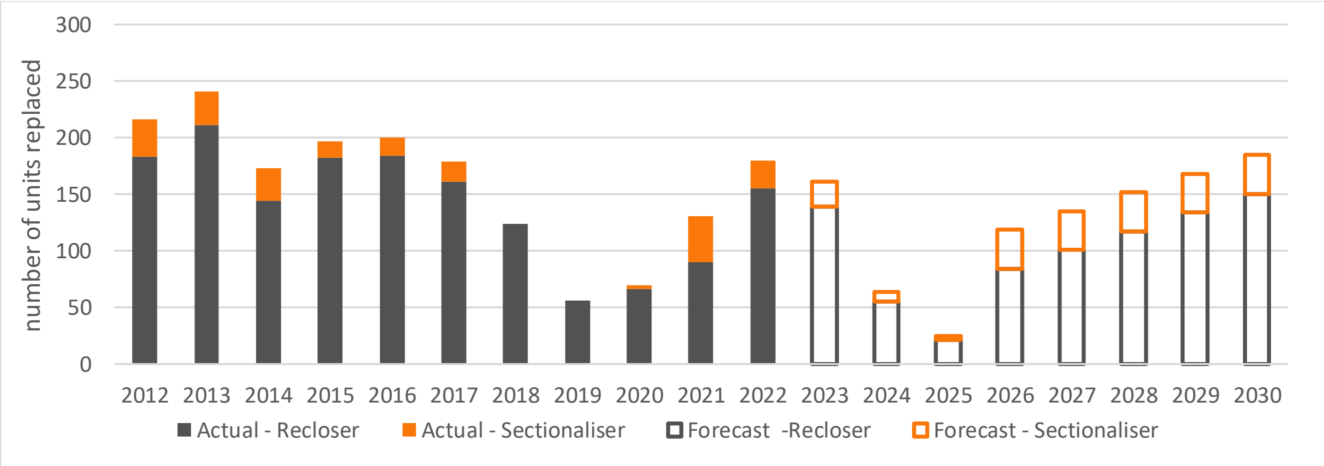
Figure 85 – Recloser and sectionalisers expenditure comparisons



Recloser and sectionaliser rate of renewal (2015-2030)

Figure 86 shows the forecast renewal rate of reclosers and sectionalisers. The proposed rate of renewal with an expenditure of $20.7 million results in an average replacement rate of 8.5% per year, with 42.5% of the population replaced over 2025-30.

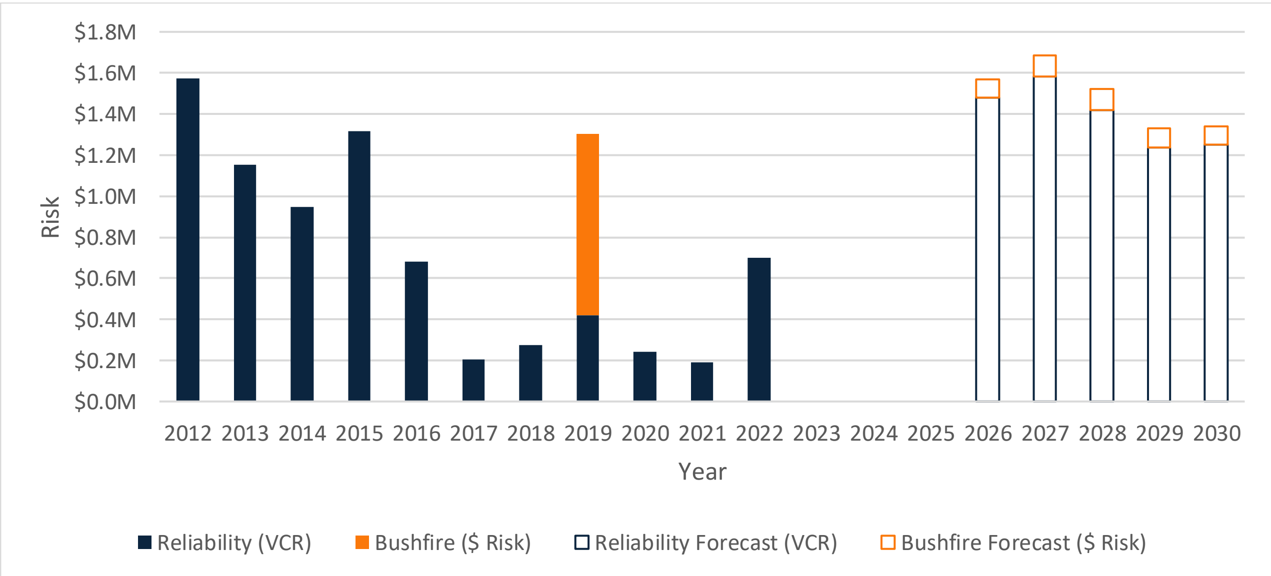
Figure 86 - Recloser and sectionaliser actual and forecasted replacements



Recloser and sectionaliser forecast risk to service outcomes (proposed)

Figure 87 shows the observed performance impact from recloser and sectionaliser assets along with the forecast impact on service outcomes given the proposed investment above. Our risk modelling shows that reliability and bushfire safety outcomes can be improved, given the proposed expenditure.

Figure 87 - Historic and forecast recloser and sectionaliser risk (proposed expenditure)



7.9. Services

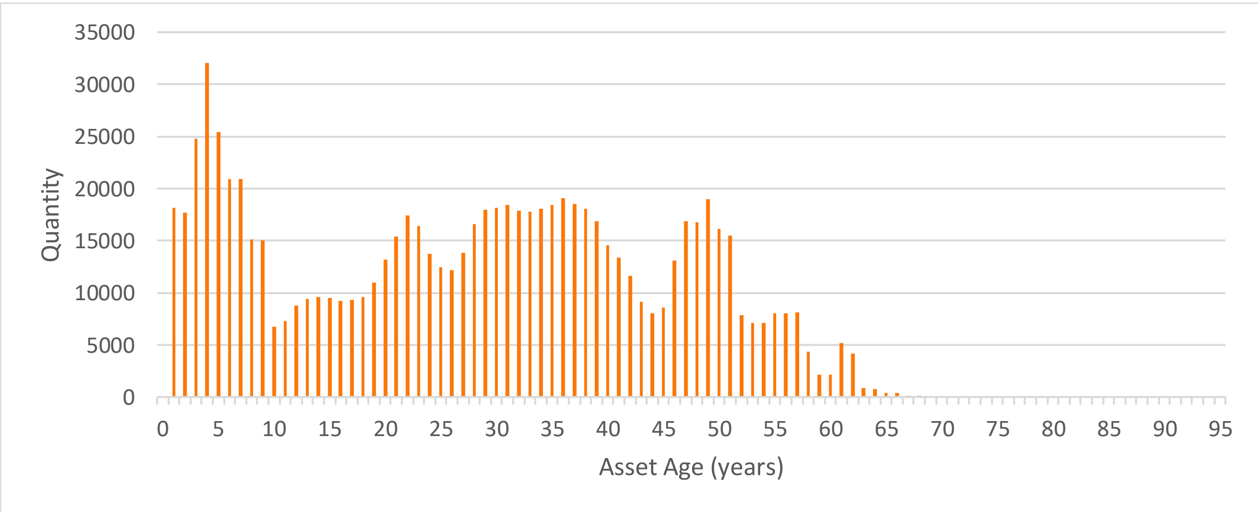
Services asset class description

Services are specific assets for the sole purpose of connecting the distribution network to customers. This system includes various pieces of electrical equipment designed to supply customer loads from the distribution system nominally at 230V (for single phase connections) or at 400V (for 3 phase connections). Customers are normally provided with one primary service line. The service generally include all assets associated with the connection point including:

- overhead conductor (overhead connections);
- service pit for underground connections;
- fuses in the service pit (below ground connections) or mounted on pole (overhead connections); and;
- other infrastructure for commercial connections that can include connection directly to the HV network or connection to a distribution transformer.

The value asset risk was modelled for only the service line component (overhead conductor) of the service asset class, with a historical expenditure approach used for the remaining service components, where asset data is insufficient. Figure 88 below shows the age profile of the service line population.

Figure 88 - Services age profile



Services asset performance (2012-22)

The main risks associated with services include:

- potential injury/death of SA Power Networks staff, contractors or the public due to:
  - electric shock via any current transmitted via the service to the customer because of the service condition,
  - physical contact through an overhead service because of service location and/or condition,
  - fire starts due to overhead service lines clashing, service box failure and/or falling to ground,
  - potential injury/death from contact of vehicles, machinery and other equipment mainly in rural areas, or

  - potential injury/death or fire starts from failure of aluminum neutral screens and Nilcrom 660F services;
- impact on reliability due to the time associated with unplanned service failures.

Figure 89 shows the number of service failures has decreased in recent years, while the impact to service outcomes has remained relatively stable, Figure 90.

Figure 89 – Observed service failures

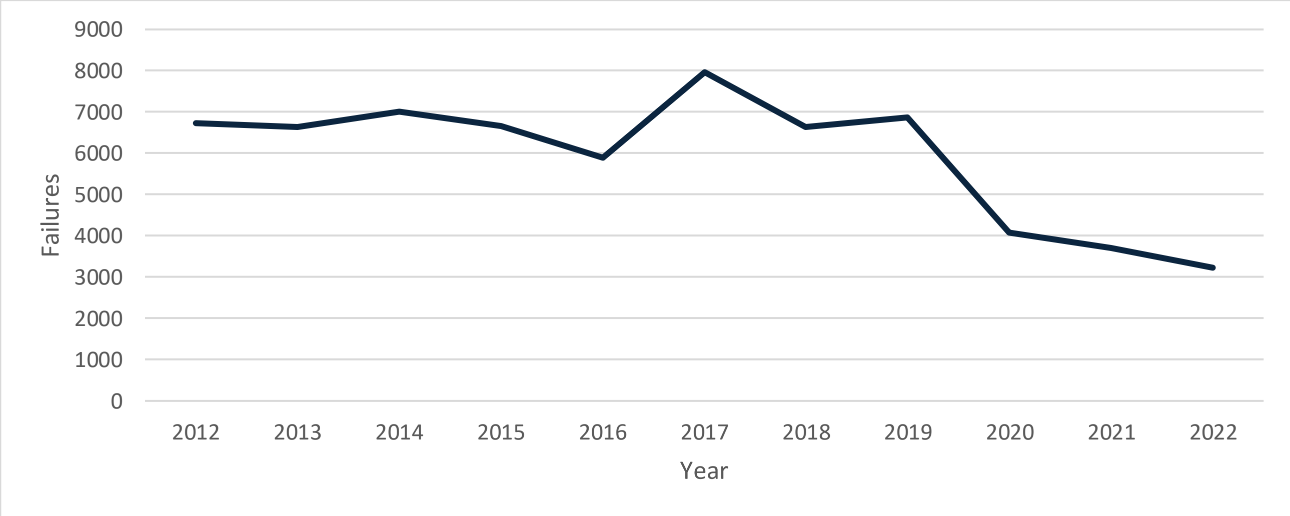
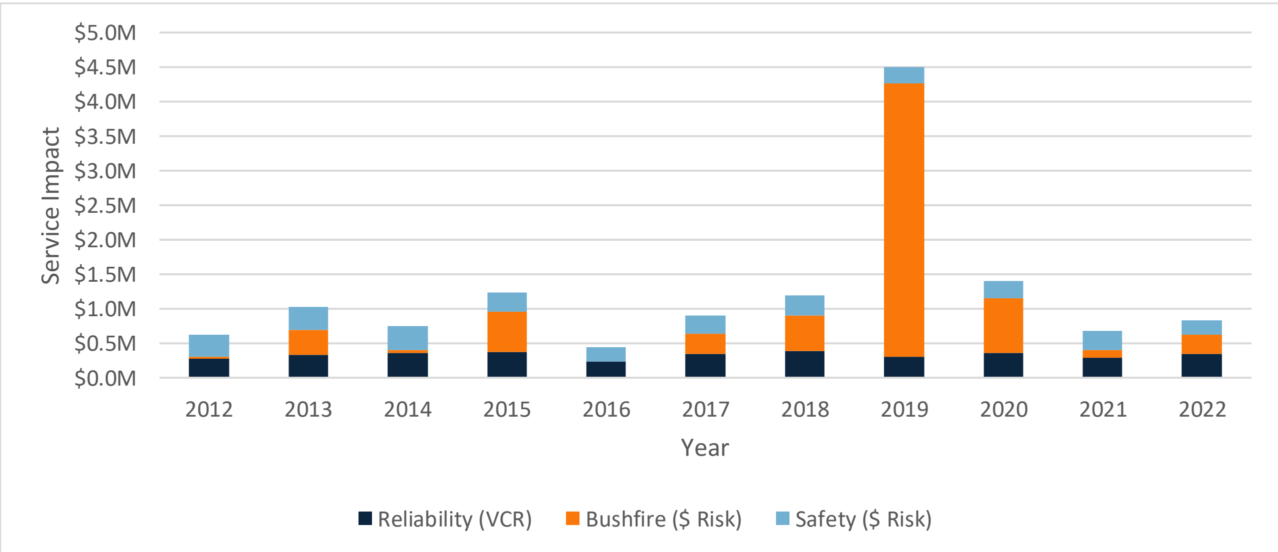


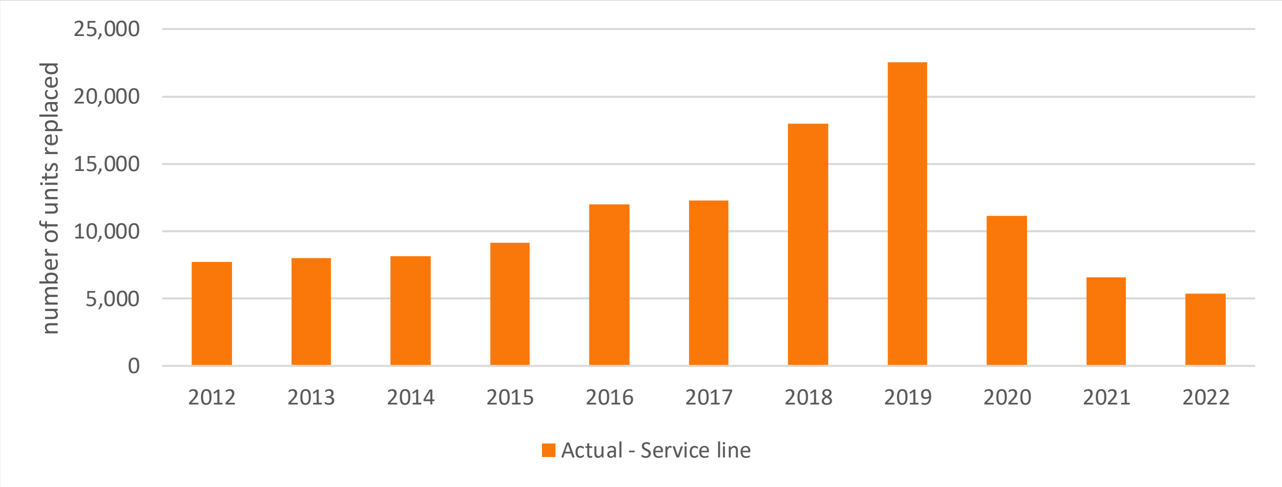
Figure 90 Impact of service failures on service outcomes



Service replacement rate (2012-22)

We have recently been replacing an average of 5,000 to 10,000 service components per year. This results in a total effective annual volume of 0.6% of the service component population (~840,000 connections x 2 service components per connection) replaced each year. With this replacement rate it would take 168 years to replace the entire service population.

Figure 91 - Services actual replacement rate



Services forecast risk to service outcomes (base case)

Figure 92 – Historical and forecast service failures

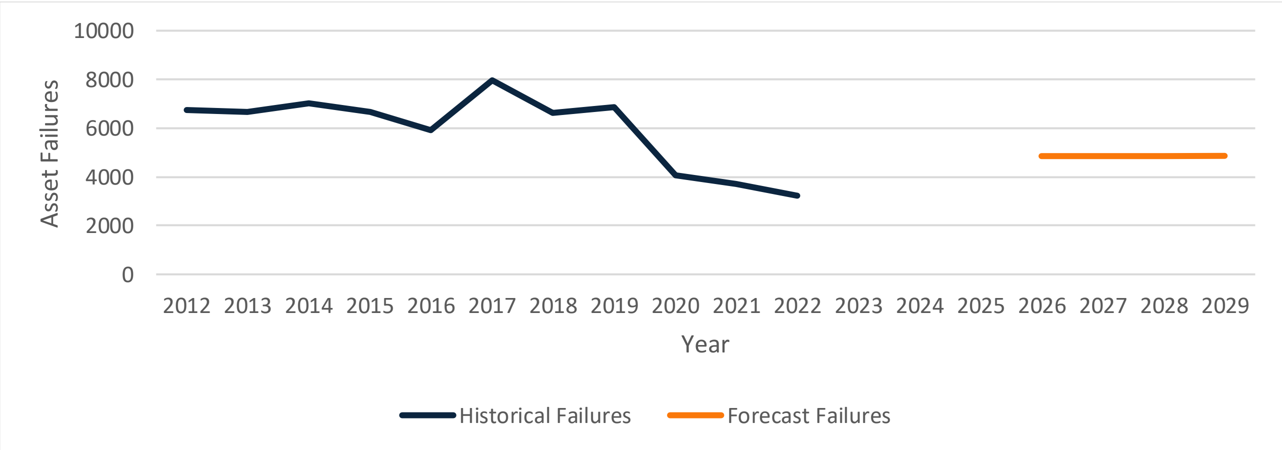
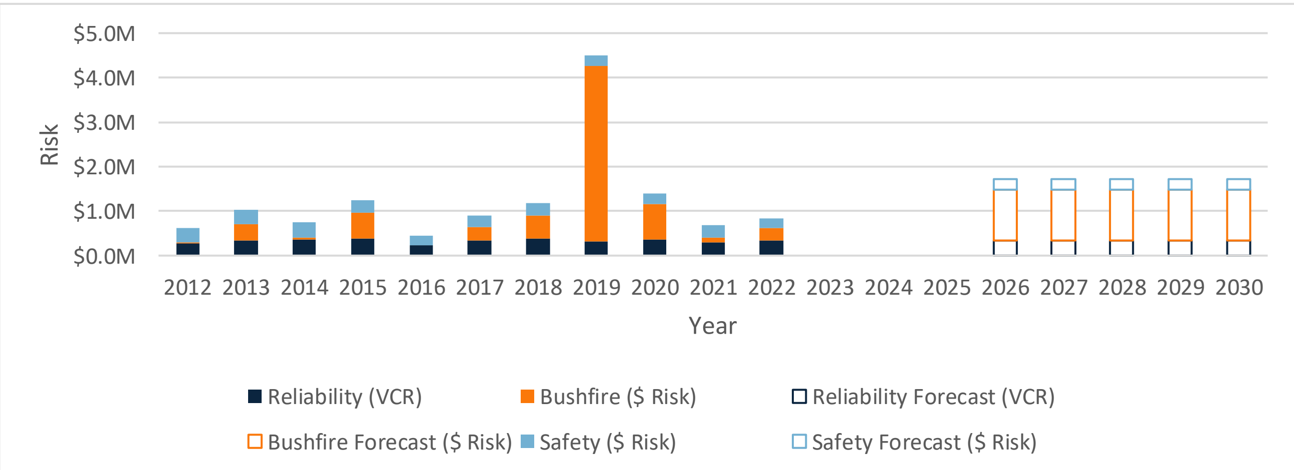


Figure 93 shows the current risk to service outcomes for services and how this would grow if we continue our current replacement rate.

Figure 93 – Historical and forecast services risk (base case)



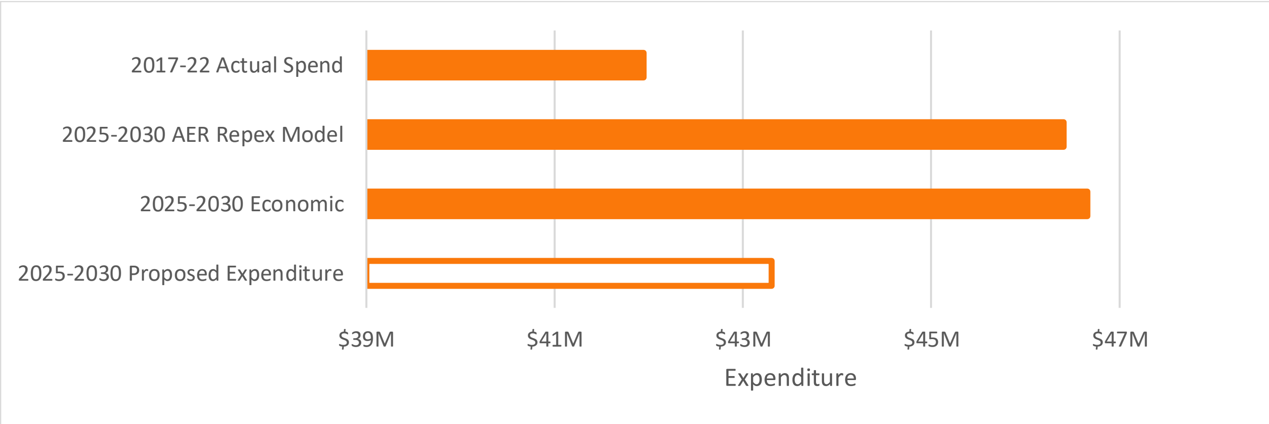
Services expenditure forecast

Services that have failed resulting in a supply interruption are replaced immediately. The model assumes replacement after a failure is like-for-like with a brand-new modern equivalent of the failed asset, with no change in our network configuration. Any service defects identified via routine inspection have their value assessed to remove as much risk from the network in the most cost-efficient manner. Service replacements may also occur as the result of electric shocks reported by the public or via proactive assessment of smart meter data indicating a service may be faulty. The renewal/replacement strategy for services is based on achieving the service level outcomes described in section 5.

Services forecast renewal expenditure summary (2025-30)

We considered three scenarios (i.e. options) in developing required expenditure for services, being a **base case** (using actual spend), **economic scenario** and a **proposed scenario** meeting targeted outcomes presented in section 5. We have provided an additional comparison with the AER repex model output.

Figure 94 – Services expenditure comparison



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Services rate of renewal (2022-30)

Figure 95 shows the forecast renewal rate for services. The proposed rate of renewal with an expenditure of $43.3 million results in an average replacement rate of 2%.

Figure 95 - Services actual and forecasted replacement rate

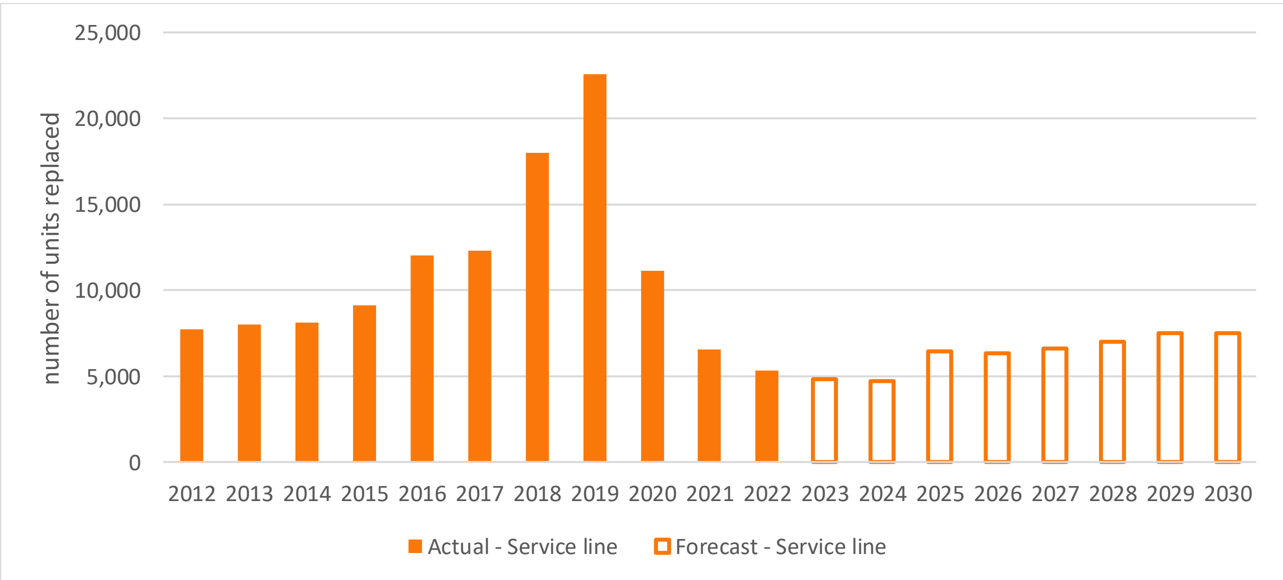
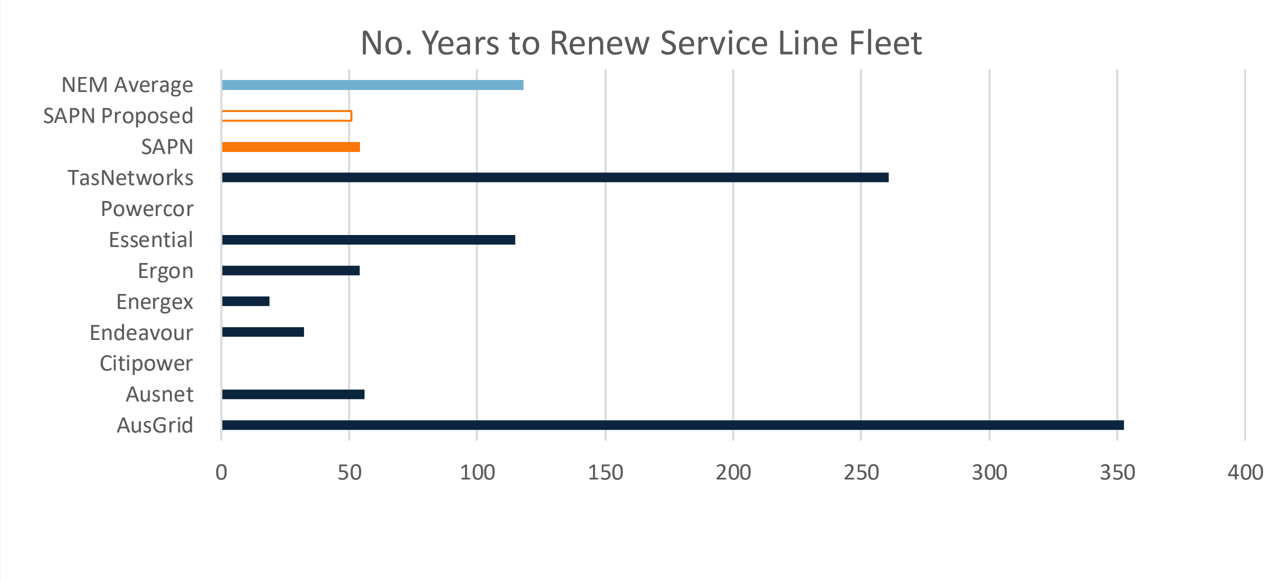


Figure 96 compares our proposed service replacement rates to those of other DNSPs analysing data from publicly available Category RINs reported over the period 2015-2016 to 2019-2020. The varied definition of service replacement between DNSPs gives this comparison limited value for this asset category.

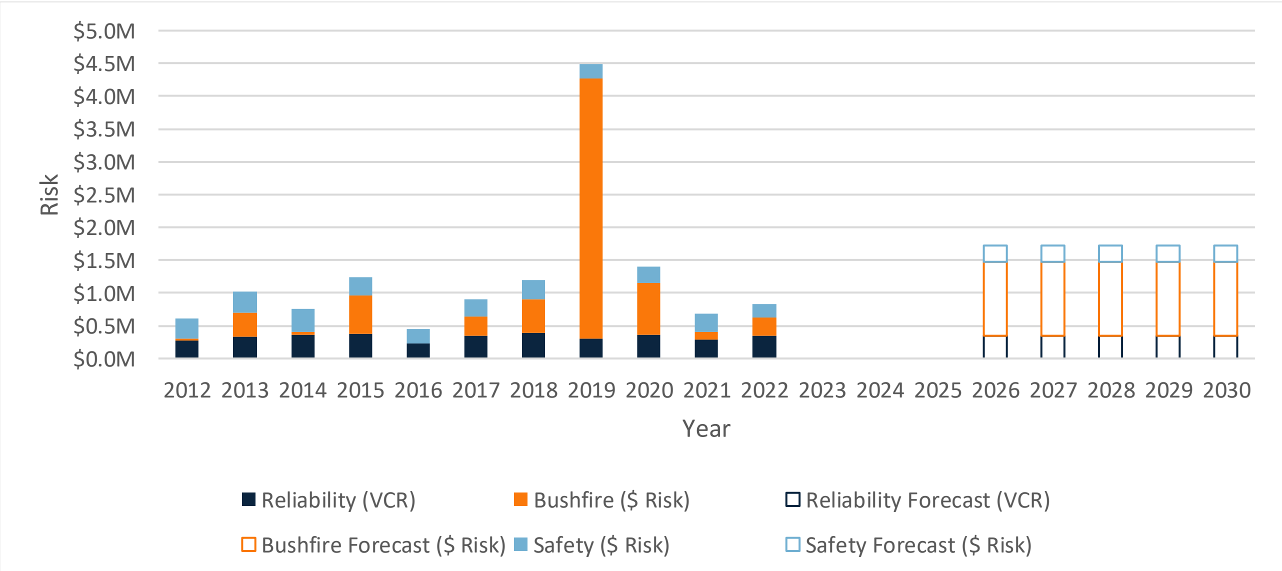
Figure 96 - DNSP service replacement rates



Services forecast risk to service outcomes (proposed)

Figure 97 shows the observed performance impact from service assets along with the forecast impact on service outcomes given the proposed investment above. Our risk modelling of service lines, combined with unmodeled projections of service component risk, shows that reliability, bushfire safety and people safety outcomes can be maintained, given the proposed expenditure.

Figure 97 - Historic and forecast services risk (proposed expenditure)



7.10. Powerline – other

Powerline 'other' assets description

This section provides an overview of other powerline assets. Due to their relatively low expenditure and variety of assets compared to the asset classes previously discussed, the overview is limited to key points:

- 'other' powerline assets include earthing systems and ancillary assets.
- earthing: ensure current is directed to earth rather than through the asset to minimise risks to staff, contractors and the public; and
- ancillary assets: prevent unauthorised access, enable staff and contractors access to our assets (fences and security to assets), and assist network operations staff with locating faults (line fault indicators).

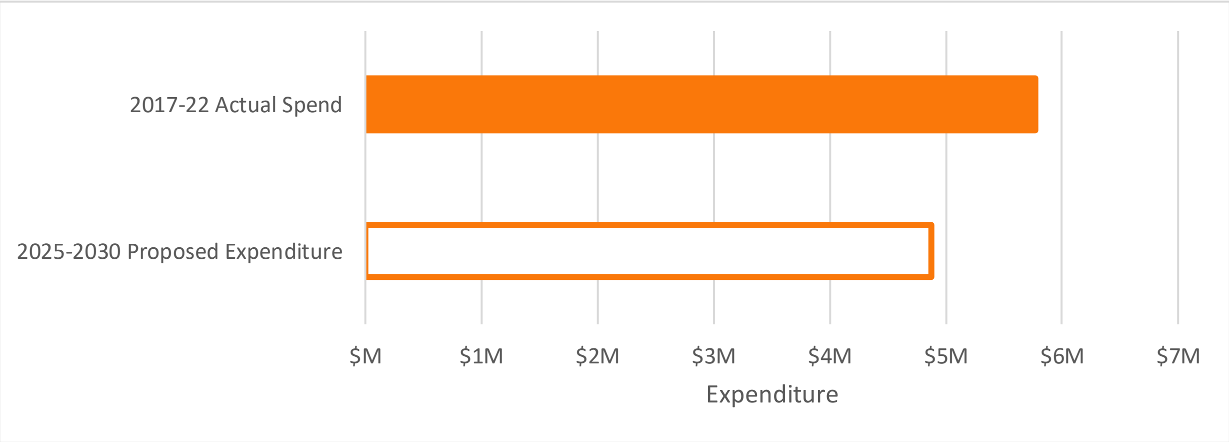
Powerline 'other' expenditure forecast

Given the lack of data on this asset class and mixture of asset types within the class we have not developed a forecast model. Our forecast expenditure is based on historic expenditure.

Powerline 'other' renewal expenditure summary

We used only one method to forecast expenditure for other powerline assets, historic expenditure see below.

Figure 98 – Other powerline expenditure comparison



Pole forecast rate of renewal (2012-30)

Detailed historical analysis and forecasting models have not been produced for this asset category due to data limitations.

Pole forecast risk to service outcomes (proposed)

Detailed historical analysis and forecasting models have not been produced for this asset category due to data limitations.

7.11. Zone substation circuit breakers

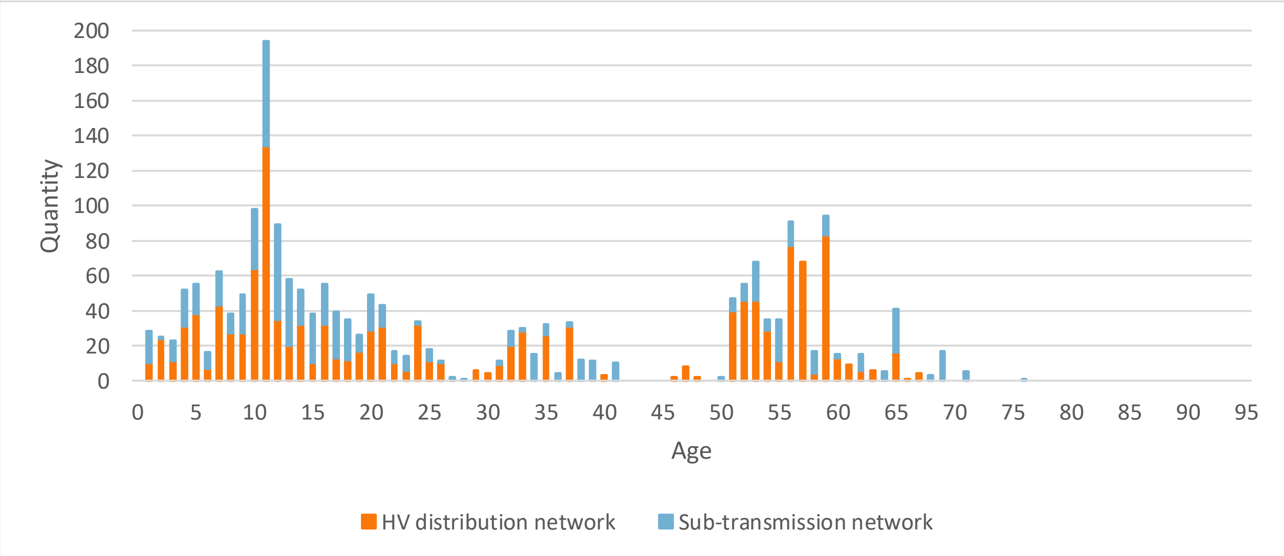
Circuit breaker asset class description

Circuit breakers are controlled switching devices used within zone substations to control the energisation of the high voltage network. The safe and reliable operation of these assets is critical to providing a safe, reliable and resilient network as they deliver the essential control and protection functionality necessary to maintain public safety and the ongoing reliable supply of electricity to our customers.

Circuit breakers on our network consist of a fleet of 2,073 individual circuit breakers operating at voltages of 66kV, 33kV, 11kV and 400V across a network of 400 substations. The existing network has developed over many years with circuit breakers that cover a variety of technologies and arrangements that date back to the early 1950s.

The expected service life of a circuit breaker varies but for the current population it is typically in the range of 55–65 years. The average age of assets within this asset class is 29 years, increasing from 28 years over the last five years, with a median age of 19 years, a maximum age of 77 years and approximately 25% of the population in service for greater than 53 years, refer Figure 99.

Figure 99 - Zone Substation Circuit breaker age profile

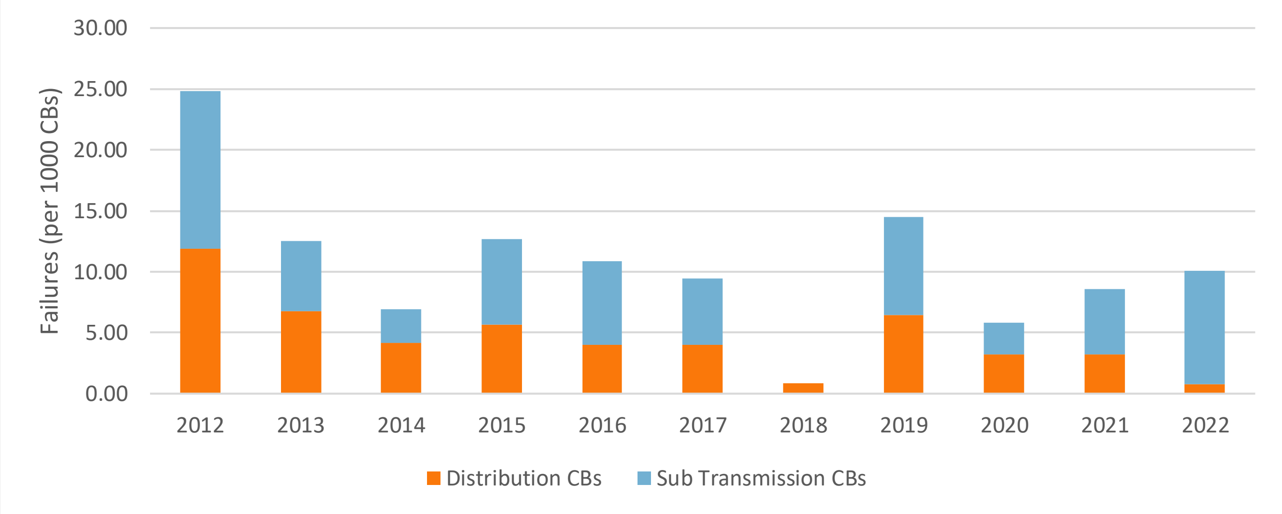


The large population of switchgear within the 10 to 15-year and 50 to 65-year age brackets represent periods of strong network growth, with a large volume of aged switchgear the result of substantial network investment in the 1960s. A significant proportion of this aged, legacy indoor oil filled switchgear continues to supply major metropolitan areas and the Adelaide CBD.

Circuit breaker asset performance (2012-22)

A high level of performance is required of substation switchgear, which provides the control and protection functionality essential for public safety and reliable energy supply for customers. The historic occurrence of circuit breaker functional failures (per 1,000 assets) over the last 10 years is shown in Figure 100.

Figure 100 - Circuit breaker functional failures



These functional failures encompass a combination of different failure types that prevent essential functionality and are managed via reactive maintenance, refurbishment or 'like for like' replacement. Failure rates for substation circuit breakers have been held stable under our current asset management approach, although their infrequent occurrence and large asset population results in considerable volatility year on year.

The completion of substantial programs of remedial works across Email/Westinghouse 11kV oil circuit breakers and HSS Horizon 33kV outdoor circuit breakers (delivered in previous RCPs) have addressed significant developing areas of circuit breaker risk, including poor mechanical (slow operation) and electrical (HV bushing) condition. However, we are now seeing new areas of maintenance burden amongst our remaining indoor oil insulated switchboards with the onset of systematic unreliability from wear out issues across shutters, racking mechanisms and insulating components that cannot be effectively mitigated by further refurbishment.

For this asset class to date, major incidents have been relatively low probability events, however their past occurrence and experience of other utilities has shown the potential for considerable consequences such as:

- safety hazards (including potential injury/death) for oour staff, contractors and the public exposure to arcing faults, catastrophic (explosive) failure, building damage and switchroom fires;
- loss of supply to customers, including widespread and long duration outages depending on the type of equipment, load(s) served and location of the circuit breaker within the network;
- financial impacts (direct and indirect) from consequences of equipment failure including supply restoration activities, investigation, clean up and repair/replacement of damaged equipment and operational restrictions where unreliable operation can lead to hazardous situations; and
- environmental damage where failures result in a loss of contaminated oil, SF_6 (and its byproducts) or asbestos into the environment and the potential for secondary fire damage from catastrophic equipment failure.

While there is close correlation between asset age and performance, degradation and risk growth over time depends on many factors. A key part of our asset management approach is the application of Condition Based Risk Management (**CBRM**) modelling tools initially developed with EA Technology in 2011.

CBRM modelling incorporates information on current condition and observed performance to calculate current risks and deterioration rates of individual assets and models the effects of different intervention strategies on future risk. An important output of this modelling is the calculation of individual asset Health

Index scores on a 1 to 10 scale as described in Table 8 to give a common measure of condition and likelihood of failure calibrated against observed failure rates.

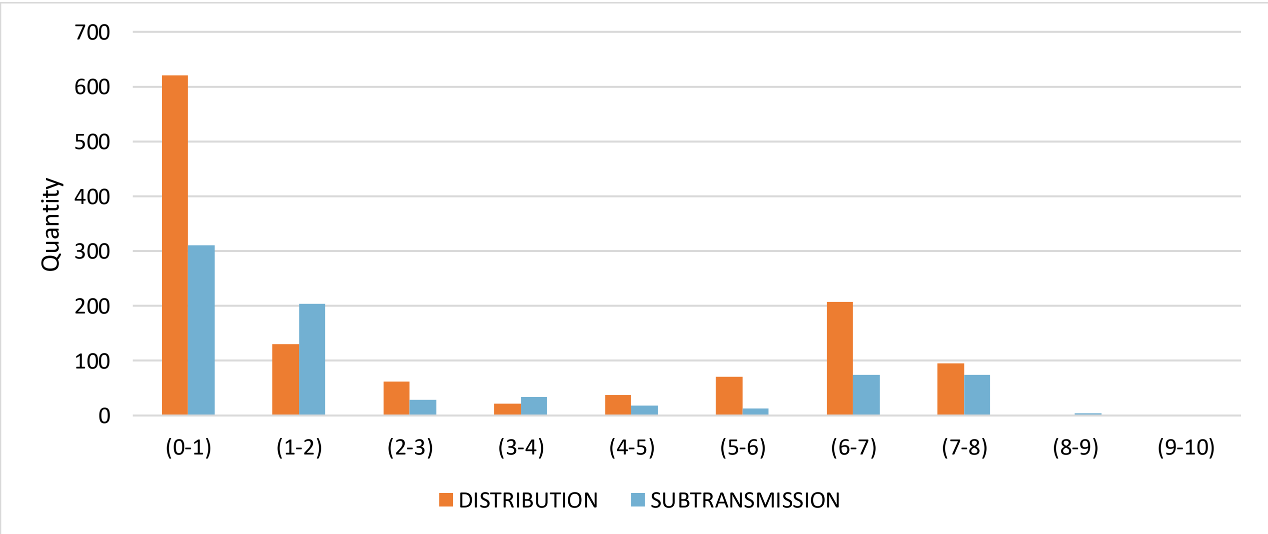
The current assessment of the asset class is shown in Figure 101 and, reflecting the age profile, is dominated by two distinct sub populations of assets:

- young assets in good condition (Health Index between 0.5 and 5); and
- aged (oil insulated) assets approaching the end of reliable service (Health Index between 6 and 8).

Table 8: Circuit breaker Health Index Interpretation

Health Index	Probability of Failure (p.o.f)	Qualitative Description of Condition
0 - 4	Very Low	'As new' condition – normal ageing
4 – 5	Low	Some observable degradation
5 – 6	Medium	Material deterioration: requires assessment and monitoring
6 – 8	High	Advanced degradation: intervention requires consideration
8 - 10	Very High	End of reliable service life: intervention required

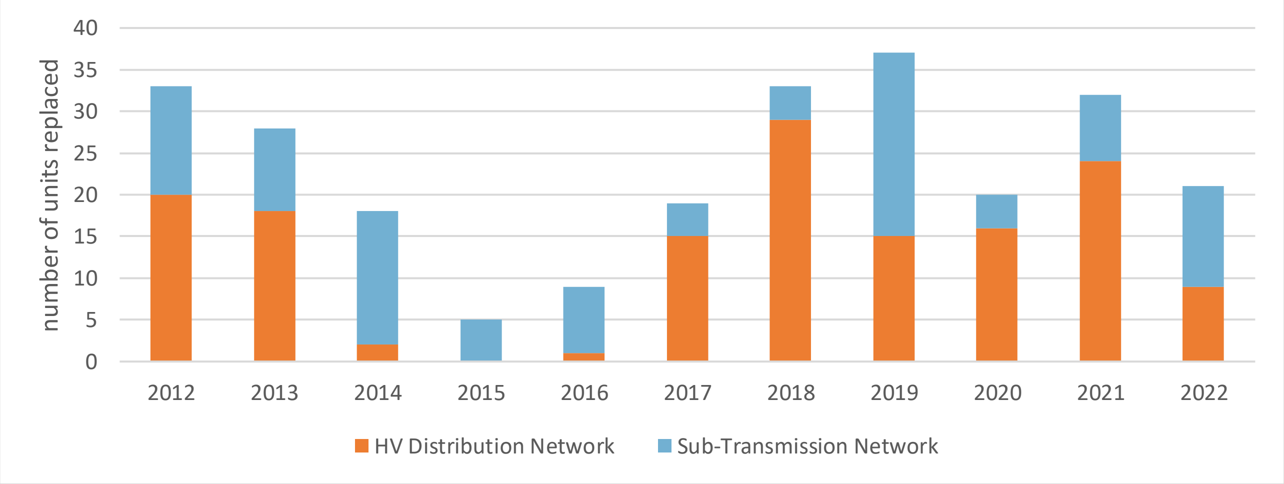
Figure 101 - Circuit breaker current asset health



Circuit breaker replacement rate (2012 – 22)

Annual replacement volumes in Figure 102 illustrate the continuation of substation circuit breaker asset renewal programs across the 2015-20 and 2020-25 RCPs. The need for more significant ongoing investment in distribution circuit breakers was identified in the 2010-15 RCP to manage enduring risks of large populations of aged, legacy and poor condition indoor switchboards approaching end of life.

Figure 102 – Circuit breaker actual replacements

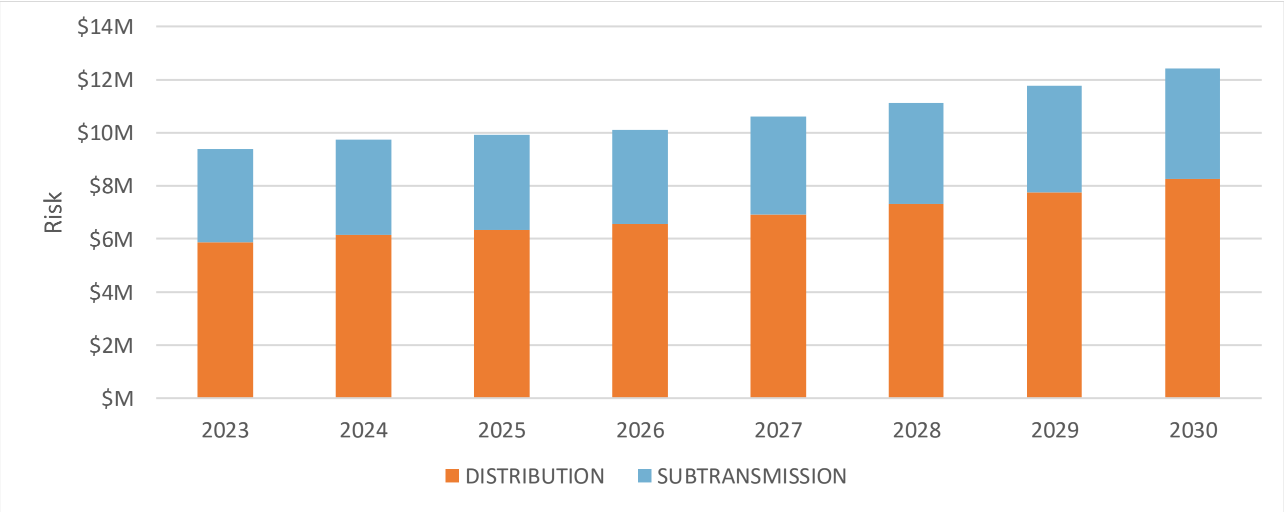


Over the last 5 years, sustained investment programs across the asset class have been replacing on average 29 circuit breakers per year, which represents an annual renewal rate of approximately 1.4% of the circuit breaker population. At this replacement rate, we can expect to remove the last oil filled indoor switchboard from service by 2045 (after 72 years in service).

Circuit breaker forecast risk to service outcomes (base case)

Figure 103 shows the forecast impact on service outcomes (risk growth) across the asset class in the absence of continued proactive intervention beyond 2025.

Figure 103 – Circuit breaker condition based risk forecast



This forecast models the risk mitigation effects of completing in progress and approved projects until 2025 and the delivery of other forecast programs of work, including substation upgrades (Augex) and other renewal programs over the 2025 – 30 RCP.

The risk forecast in Figure represents a 'Run to Failure' scenario for the 2025-30 RCP (ie. the risk/performance impacts of not performing proactive interventions to arrest deterioration – only intervening to fix equipment as it fails). Service levels across the sub-transmission and distribution systems under this approach are expected to deteriorate by approximately 33% over the 2025-30 RCP, driven principally by service deterioration of indoor oil switchboards.

Circuit breaker expenditure forecast

The high-level renewal/replacement strategy for the circuit breaker asset class is to maintain long-term risk and performance levels of the asset class as assets age and deteriorate in service (maintain risk). Evaluation of current risk and future performance is modelled using CBRM.

The investment program for the asset class continues our current programs and approach to maintain sustainable performance, safety and reliability across the asset fleet by risk prioritised proactive investment in poor condition, critical assets relative to the cost of intervention.

Intervention options for the asset class include enhanced maintenance, condition monitoring, network reconfiguration or operational restrictions to manage risk exposure of individual assets, with consideration of:

- whether the asset can be decommissioned and either not replaced or replaced with a more efficient arrangement without negatively affecting network reliability and performance;
- the cost of repair/refurbishment vs cost of new equipment;
- confidence in the effectiveness of the refurbishment process considering historical asset condition/ performance and future requirements;
- the circuit breaker make/type considering the remaining populations of identical units in service. Unique and small populations are typically prioritised for replacement with a more commonly used make/model;
- known long-term capital plans for assets (e.g. asset augmentation and/or redundancy); and
- current or future operational requirements (e.g. safety or environmental risks to be mitigated).

Where more efficient means of risk mitigation (typically decommissioning, asset refurbishment or non-network options) are not considered credible or effective, replacement is used to manage risk.

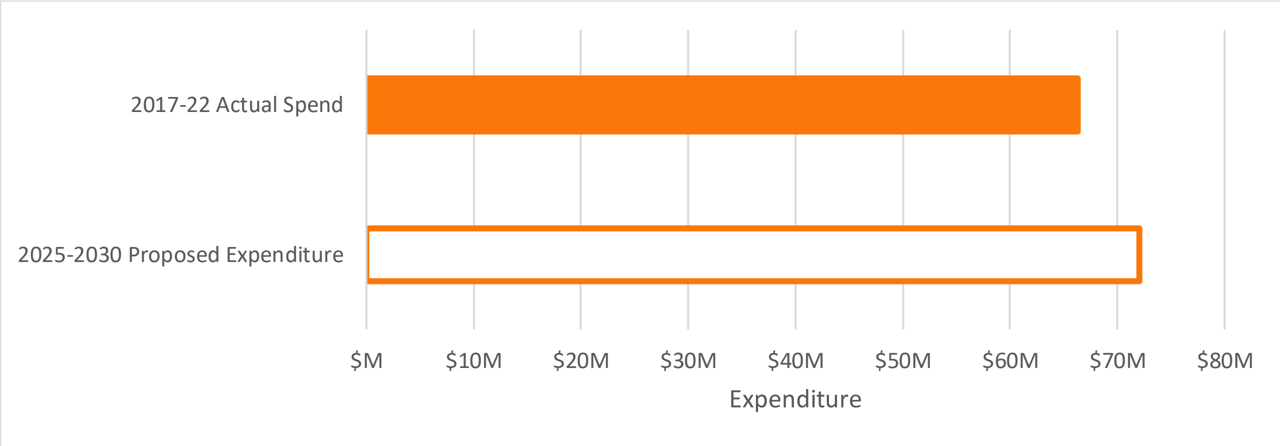
Expenditure plans for 2020-30 RCP continue to focus on the large volumes of aged, oil-insulated switchgear expected to reach the end of safe and reliable service by 2030, prioritising circuit breaker replacements by their contribution to risk and estimated intervention cost. Additional targeted investment aims to address the current population of aged, legacy and poor condition oil-insulated switchboards, Ring Main Units and Low Voltage basement substations in Adelaide's CBD that no longer meet safety and reliability expectations.

Circuit breaker renewal expenditure summary (2025-30)

We used population risk/cost modelling to forecast expenditure for substation circuit breakers, using a 'Maintain Risk' strategy within CBRM as the most appropriate match to our strategic objectives, stakeholder feedback, information confidence within the models and our ability to efficiently manage risk. This approach continues from the current RCP and seeks to efficiently maintain long-term performance of the asset fleet via prioritised interventions on critical assets providing the greatest return on investment.

Through CBRM modelling, we considered the relative changes in risk over the planning period arising from current condition, observed performance, rates of deterioration and the effects of parallel programs of work and the necessity to deliver substantiative performance improvements in the CBD. A description of this approach is outlined in section 6.

Figure 104 – Circuit breaker expenditure comparison

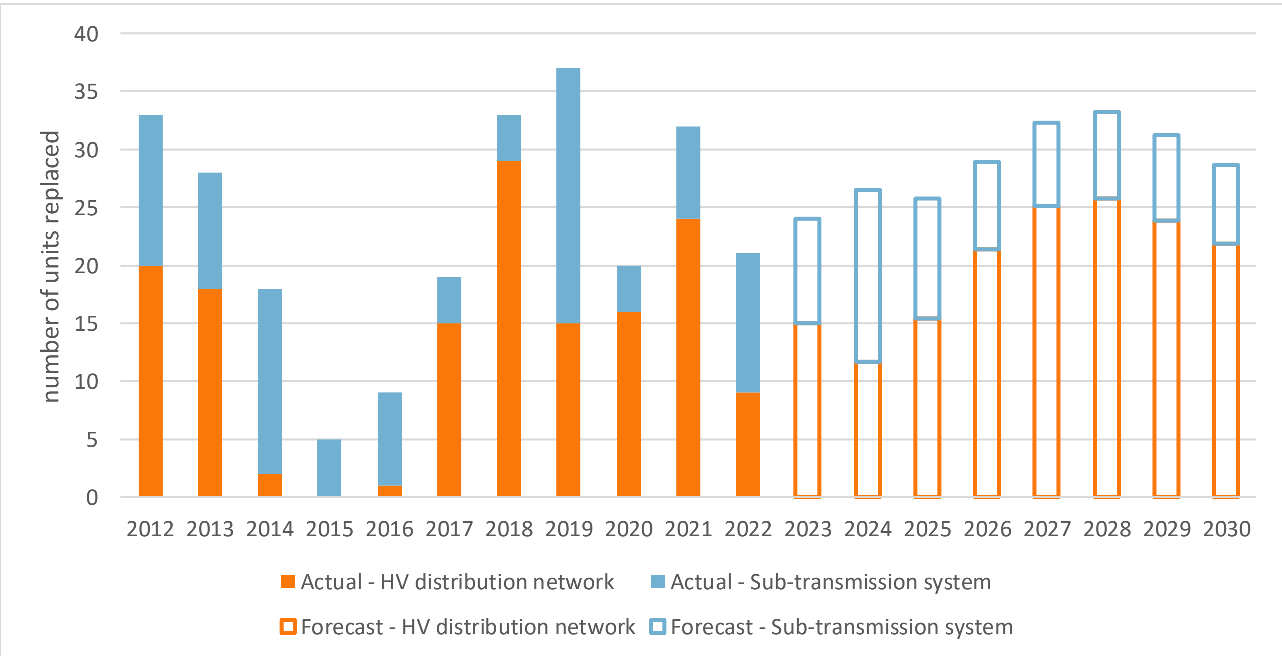


This forecast presents a moderate increase on actual spend in the last 5 years, driven principally by targeted investment in poor condition and unmodelled assets in the CBD network and unit cost increases (significantly above CPI) from price escalation in long term supply contracts for major plant.

Circuit breaker rate of renewal (2012-2030)

The planned (2023 and 2024) and forecast (2025-30) replacement volumes required to maintain performance of the circuit breaker fleet over the planning period is shown in Figure 105. Delivery of this plan employs investment in refurbishment and replacement intervention types and will renew approximately 1.5% of the population annually, with 7.5% of the population renewed over the 2025-30 period.

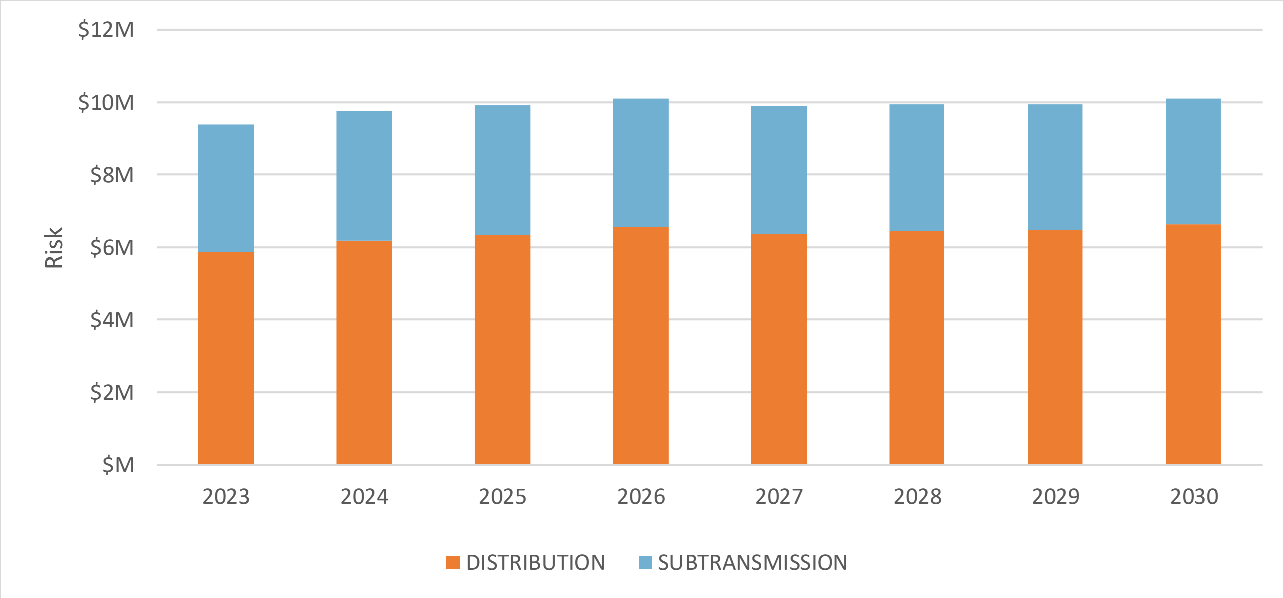
Figure 105 - Circuit breaker actual and forecasted replacements



Service outcomes delivered through forecast replacement expenditure

The residual risk delivered by the forecast investment program is shown in Figure 106. The combined effect of all programs of planned replacement over the forecast period (inclusive of augex and other repex initiatives) is to maintain levels of safety, reliability and network performance across the asset class to 2030.

Figure 106 - Circuit breaker forecast risk profile



7.12. Zone substation power transformers

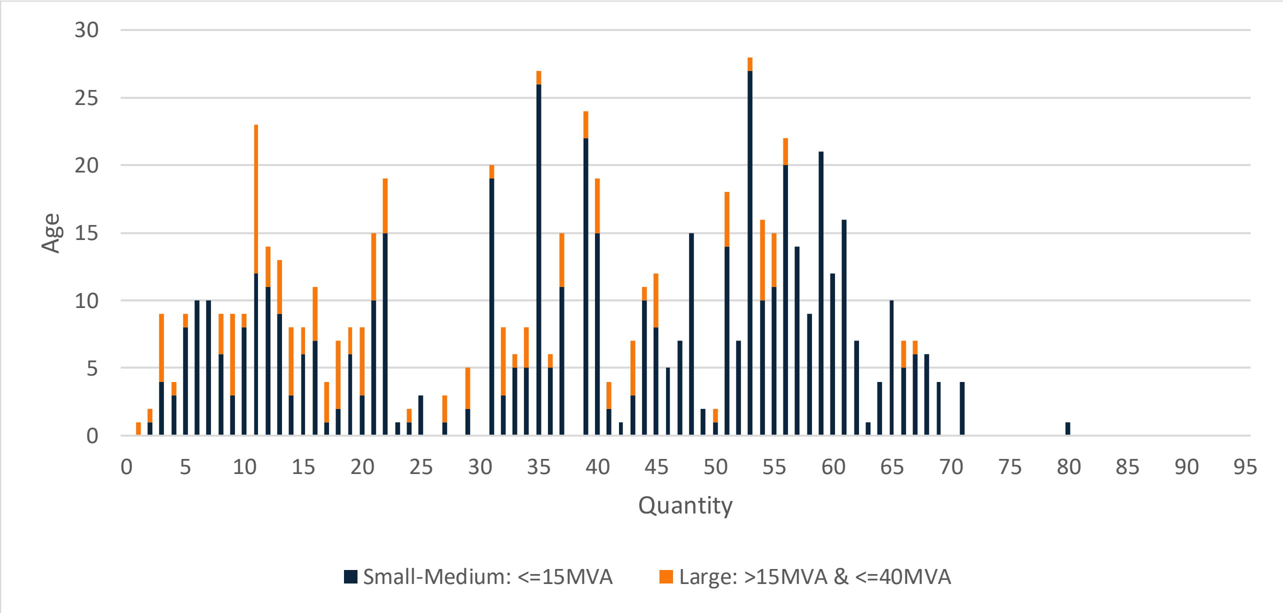
Power transformer asset class description

Substation Power Transformers and regulators fulfill an essential role in our distribution network, providing power flows between different voltage levels across the sub transmission and distribution systems and regulating the quality of supply voltages to customers.

The safe and reliable operation of these assets is integral to providing a safe, reliable and resilient network, with service failures incurring consequences including wide scale supply interruptions, hazards to public safety, the environment and collateral damage to neighboring property and electrical assets.

There are 646 multi-phase power transformers and regulators currently in service with rated voltages of 66kV, 33kV and 11kV across a network of 400 substations. The core technology of the asset fleet remains largely unchanged from the 1950s, with the majority of installed assets being oil insulated and, more recently, small populations of natural ester and resin insulated (dry type) transformers.

Figure 107 - Power transformer age profile



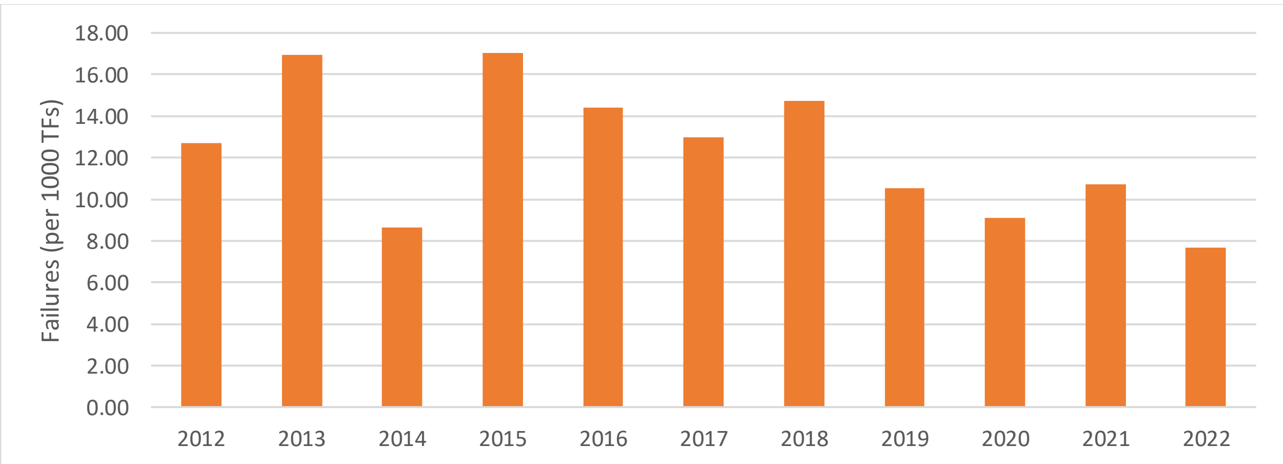
The expected service life of these assets varies but for the current population it is typically in the range of 60–65 years. The average age of assets within this asset class is 37 years, increasing from 35 over the last 5 years, with a median age of 40 years, a maximum of 81 years and more than 25% of the population in service for greater than 55 years. Refer Figure 107 - Power transformer age profile.

Power transformer asset performance (2012-22)

Power Transformers deteriorate with age with the cumulative effects of day-to-day electrical, thermal and environmental stresses and abnormal (severe) stresses from lightning over-voltages, system faults and heatwave overloading. Over time these effects reduce the asset's ability to withstand service stress and increases the likelihood of an in-service failure.

There are a range of different failure types that can prevent essential functionality, and many can be effectively monitored and managed via condition monitoring, reactive maintenance or asset refurbishment prior to catastrophic in-service failure. The historic occurrence of these failures (expressed per 1000 assets) over the last 10 years is shown in Figure 108.

Figure 108 - Power transformer functional failures



The performance of the transformer fleet was steady during the first half of the current RCP, with delivery of targeted replacement and refurbishment programs from previous RCPs and successive mild summer seasons significant contributing factors to recent performance. The need for intervention across the transformer fleet is typically reactive and driven by condition, performance and type risks identified through routine condition monitoring, maintenance and analysis of historic failures.

The long-term reliable performance of power transformers in general depends on the original quality of equipment design and manufacturing alongside operational and service conditions and so type issues often bear greater consequences than a single asset failure. For this asset class to date, major failure incidents have been relatively low probability events, however their recent past occurrence and the experience of other utilities has shown the potential for considerable consequences such as:

- safety hazards (including potential injury/death) for our staff, contractors and the public due to catastrophic failure of the power transformer, bushings and subsequent fires;
- loss of supply to customers including long duration outages and quality of supply issues depending on the depth of distributed generation, loads served, location of the transformer within the network and availability of mobile bypass equipment;
- financial impacts (direct and indirect) from equipment failures including supply restoration activities, investigation, clean up and repair/replacement of damaged equipment and operational restrictions where unreliable operation can lead to hazardous situations; and
- environmental damage where failures result in a loss of contaminated oil into the environment and the potential for secondary fire damage from catastrophic equipment failure.

While there is close correlation between asset age and performance, degradation and risk growth over time depends on many factors. A key part of our asset management approach is the application of CBRM modelling tools initially developed with EA Technology in 2011.

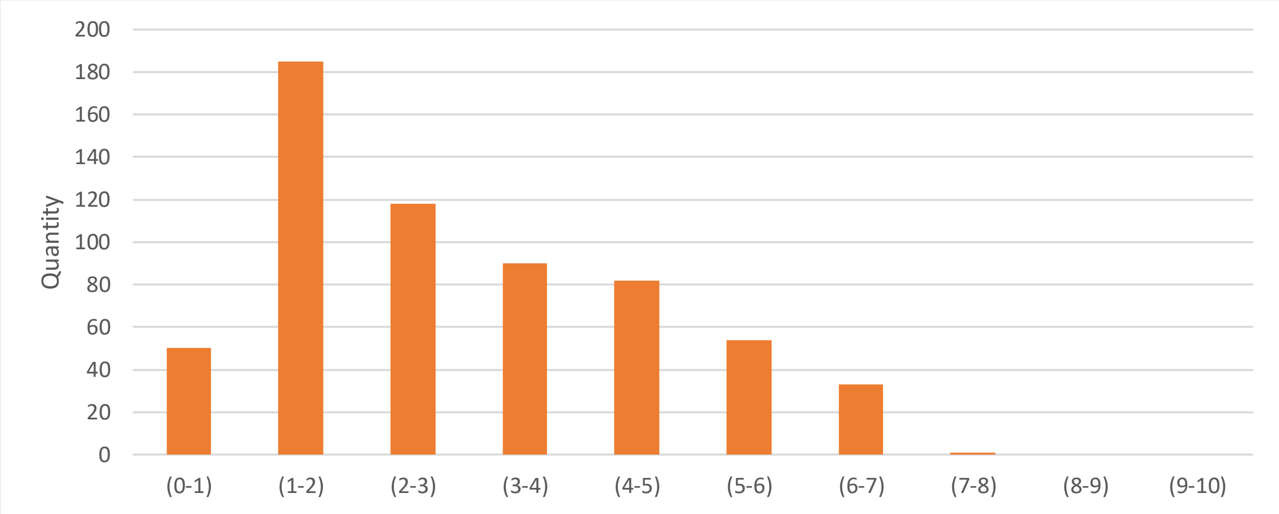
CBRM modelling incorporates information on current condition and observed performance to calculate current risks and deterioration rates of individual assets and to model the effects of different intervention strategies on future risk. An important output of this modelling is the calculation of individual asset Health Index scores on a 1 to 10 scale as described in Table 9 to give a common measure of condition and likelihood of failure calibrated against observed failure rates.

Our current assessment of the transformer fleet is shown in Figure 109. The distribution of asset health scores illustrates the diversity of age and condition across the asset fleet, with most installed assets in good condition and smaller numbers of aged but serviceable transformers (Health Index between 6 and 8) nearing the end of reliable service.

Table 9: Transformer Health Index Interpretation

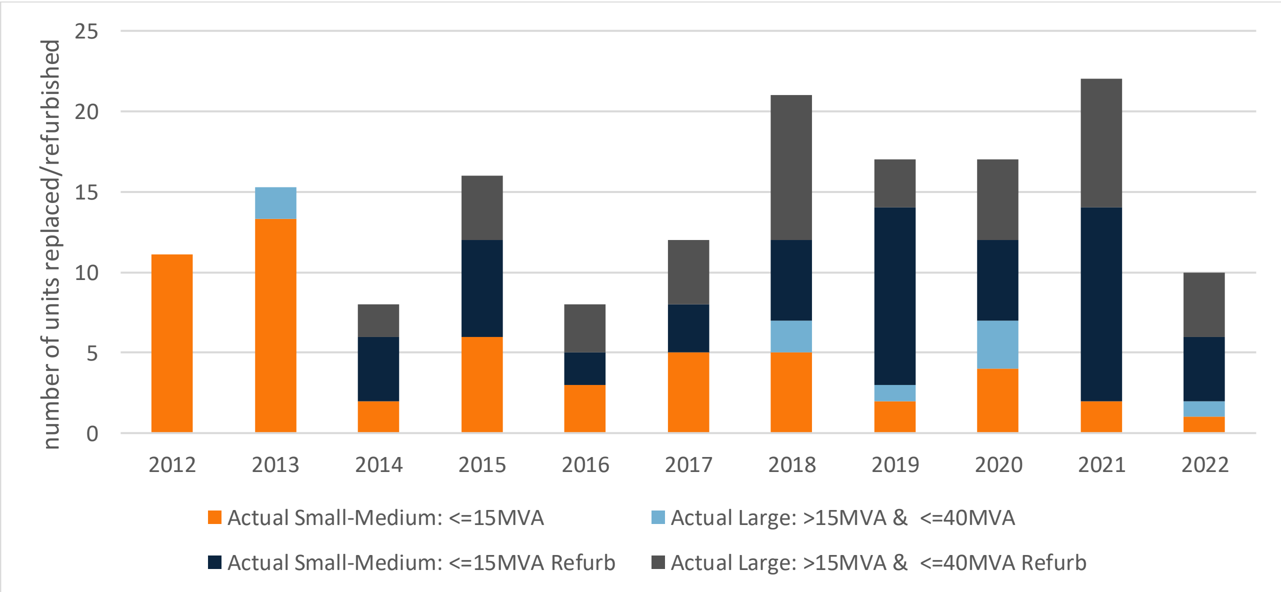
Health Index	Probability of Failure (p.o.f)	Qualitative Description of Condition
0 - 4	Very Low	‘As new’ condition – normal ageing
4 – 5	Low	Some observable degradation
5 – 6	Medium	Material deterioration: requires assessment and monitoring
6 – 8	High	Advanced degradation: intervention requires consideration
8 - 10	Very High	End of reliable service life: intervention required

Figure 109 – Transformer current asset health



Power transformer replacement rate (2012 – 22)

Figure 110 - Power transformer actual replacements

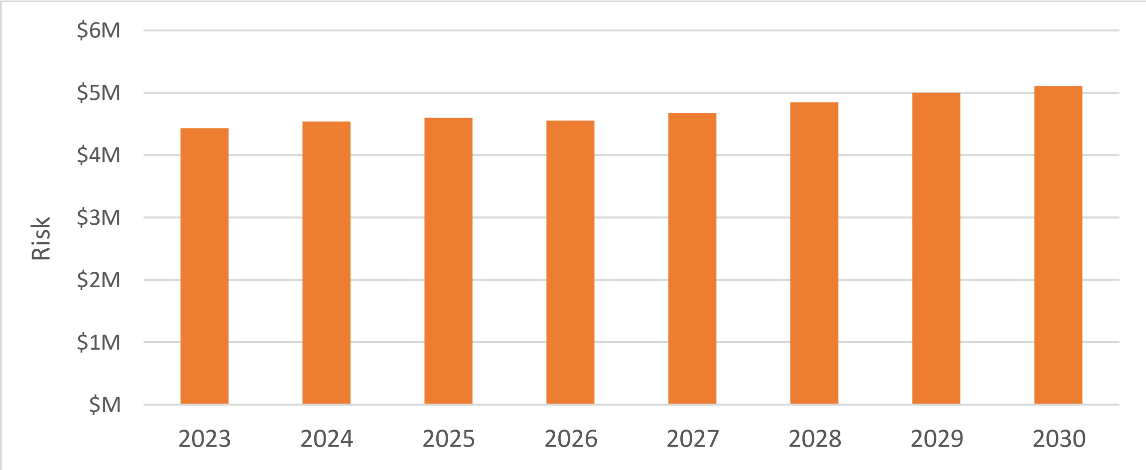


Annual replacement volumes in Figure 110 illustrate the continuation of enduring programs of investment in this asset class across the 2015-20 and 2020-25 RCPs. As a condition driven program, intervention volumes vary significantly year on year, but on average over the last 5 years we have been replacing approximately 3-4 transformers per year, with ongoing reactive and targeted replacement and refurbishment of high-risk transformers across approximately 2-3% of the population annually.

Power transformer forecast risk to service outcomes (base case)

Figure 111 shows the forecast impact on service outcomes (risk growth) across the asset class in the absence of continued investment beyond the completion of planned project delivery up until 2025. Under this 'Run to Failure' scenario, service levels are forecast to deteriorate by approximately 20% over the 2025-2030 RCP as the current population of significant aged, poor condition assets continues to grow.

Figure 111 – Power transformer condition based risk forecast



Power transformer expenditure forecast

The high-level renewal/replacement strategy for the substation power transformers asset class is to maintain long-term risk and performance of the asset class as assets age and deteriorate in service (maintain risk). Evaluation of current risk and future performance is modelled using CBRM.

The investment program for the asset class continues our current programs and approach of intervention to maintain sustainable performance, safety and reliability across the asset fleet via a mixture of proactive refurbishment and replacement types, addressing critical assets in poor condition and likely to suffer major failure.

Intervention options for the asset class include enhanced maintenance, condition monitoring, network reconfiguration or operational restrictions to manage risk exposure of individual assets, with consideration of:

- whether the asset can be decommissioned and either not replaced or replaced with a more efficient arrangement without negatively affecting network reliability and performance;
- the cost of repair/refurbishment vs cost of new equipment;
- confidence in the effectiveness of the refurbishment process considering historical asset condition/ performance and future requirements;
- transformer make/type issues, considering the remaining populations of identical units in service;
- known long-term capital plans for assets (e.g. asset augmentation and/or redundancy); and
- current or future operational requirements (e.g. safety or environmental risks to be mitigated).

Where more efficient means of risk mitigation (typically decommissioning, refurbishment or non-network options) are not considered credible or effective, replacement is used to manage risk.

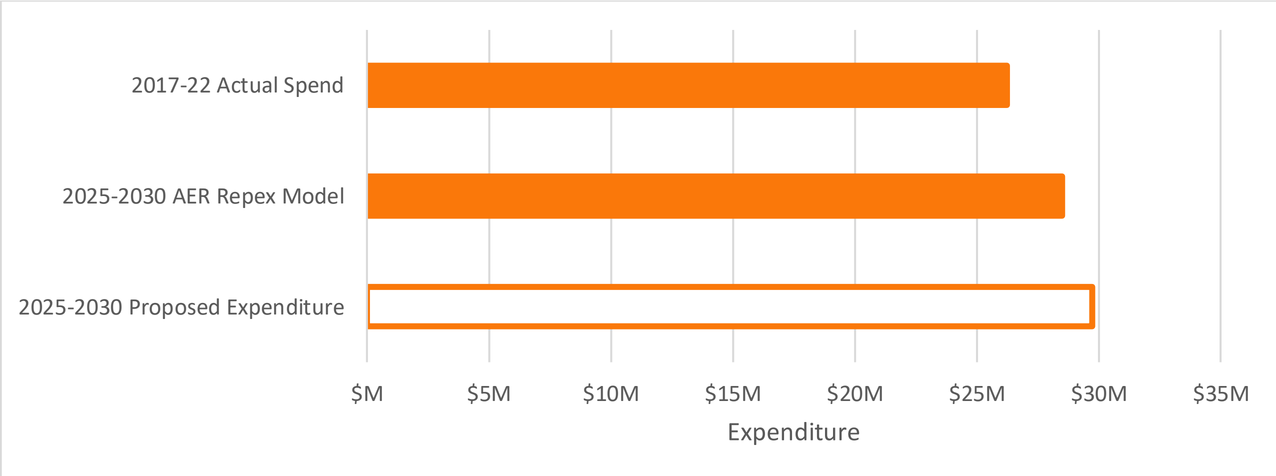
Expenditure plans for 2025-30 continue to deliver current replacement and refurbishment programs targeting critical assets in poorest condition and intervening prior to it impacting customer service and network performance outcomes. While principally a strategy of reactive intervention, areas of targeted proactive investment will address small populations of (unmodelled) ground level regulators and oil-insulated transformers installed in basement distribution substations in Adelaide's CBD.

Power transformer renewal expenditure summary (2025-30)

Our investment approach for substation transformers is to intervene on assets at or approaching end of life, based on condition assessment or in response to in-service failure, using CBRM modelling of expected degradation and risk profile changes the over the forecast RCP. This approach continues from the current RCP as the most appropriate match to strategic objectives, stakeholder feedback, information confidence within the model and our ability to efficiently manage risk and potential peaks in future workloads.

Through CBRM modelling, we consider the relative changes in condition and risk of individual assets over the planning period arising from current condition, observed performance and rates of deterioration, along with the effects of parallel programs of work and the necessity to deliver substantiative performance improvements in the CBD. A description of this approach is outlined in section 6.

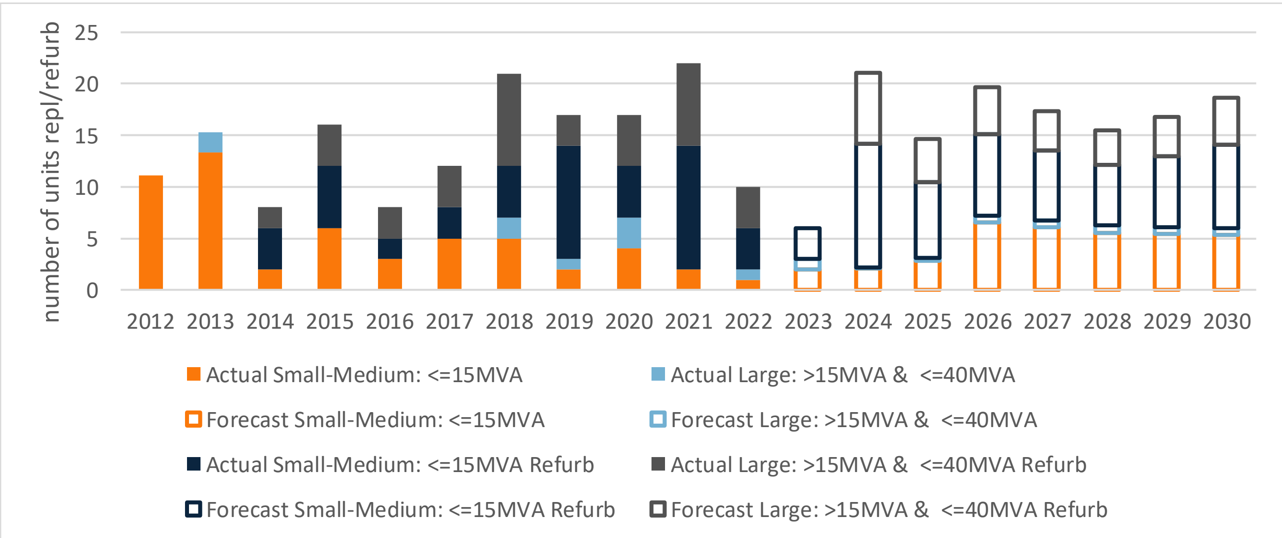
Figure 112 – Power transformer expenditure comparison



This forecast substantially represents the ongoing (reactive) expenditure requirements to manage substation transformer failure over the 2025-30 RCP, with a modest increase on expenditure in over the last 5 years driven principally by unit cost increases (significantly above CPI) from price escalation in long term supply contracts for major plant and incidence of significantly aged, poor condition Medium sized OLTC transformers expected to reach the end of reliable service over the 2025-30 RCP.

Power transformer rate of renewal (2012-2030)

Figure 113 - Power transformer actual and forecasted replacements

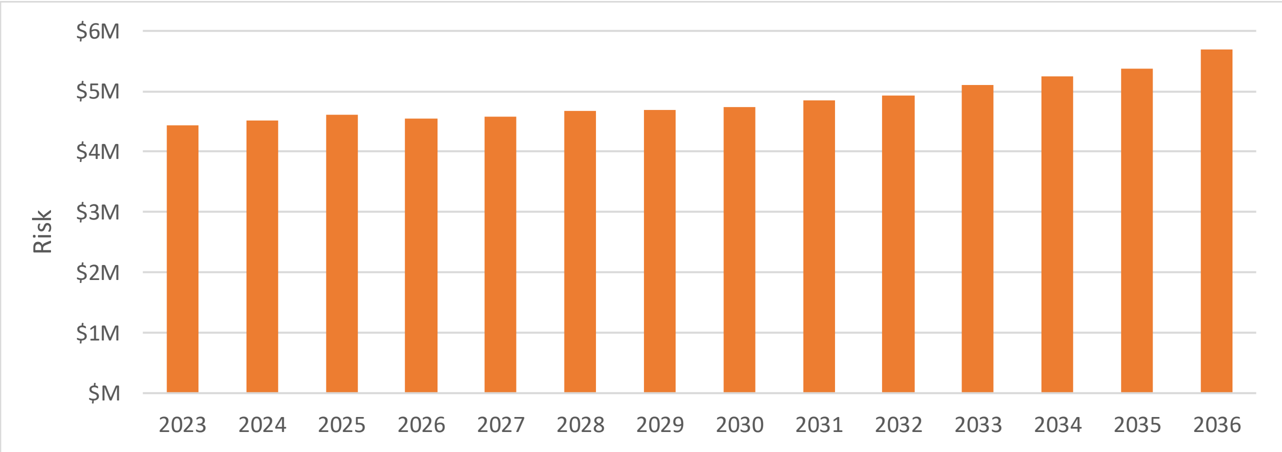


The planned (2023 and 2024) and forecast (2025 - 2030) interventions volumes across the power transformer asset class are shown in Figure 113. Delivery of this program maintains an efficient mix of refurbishment and replacement investment types, with an intervention rate of 2.7% of the population annually, resulting in approximately 13.5% of our population refurbished or replaced in 2025-30.

Service outcomes delivered through forecast replacement expenditure

The residual risk delivered by the forecast investment program is shown in Figure 114. The combined effect of all programs of planned and reactive replacement over the forecast period (inclusive of augex and other repex initiatives) is to maintain levels of safety, reliability and network performance across the asset class to 2030.

Figure 114 - Substation Transformer forecast risk profile



7.13. Zone substation – other

Zone substation 'other' assets description

Substation 'other' expenditure comprises enduring programs of (planned and reactive) capital investment in minor, unmodelled substation asset types. This includes renewal of high voltage bus work and insulators, instrument transformers, surge arrestors, substation cables and terminations, disconnectors, capacitor banks, station DC and AC auxiliaries, civil structures and and other ancillary assets and infrastructure that support service delivery from our zone substations. Assets in this category comprise a diverse range of asset types and functionalities, with programs of investment designed to address risk and maintain service reliability, safety and operational resilience of our zone substations.

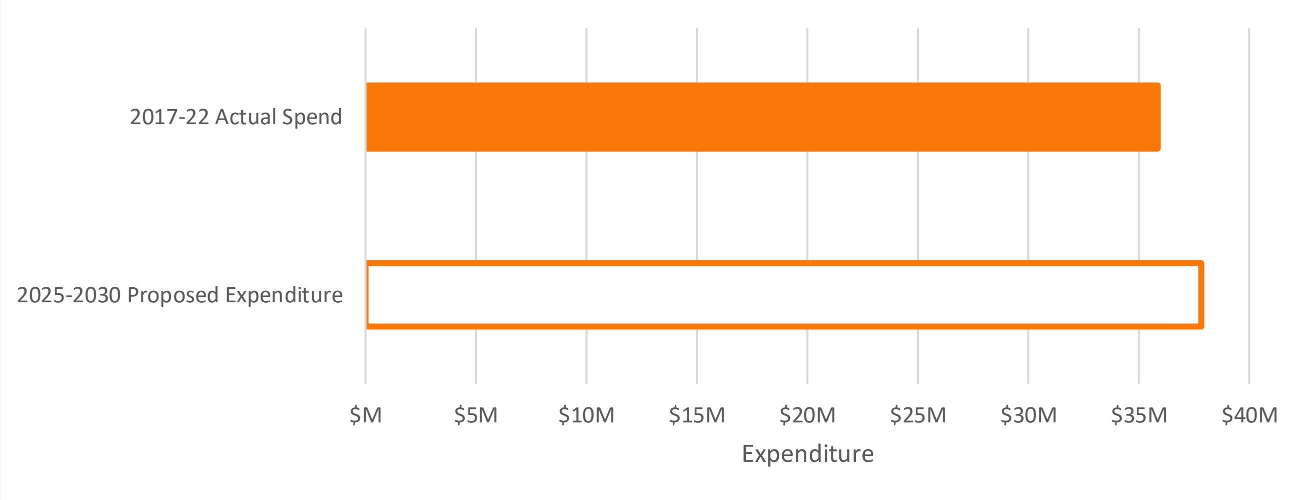
Zone substation 'other' expenditure forecast (asset class only)

Expenditure forecasts for this category are driven by historical expenditures and the expected requirements forecast by asset condition, age demographics, performance, identified risks and intervention cost. No significant change from our historical requirements are forecast to manage this asset group.

Zone substation 'other' renewal expenditure summary

We use only one method to forecast expenditure for 'zone substation - other', which is an allowance for continuation of existing programs of refurbishment and replacement in line with current work delivery.

Figure 115 – Other substation expenditure comparison



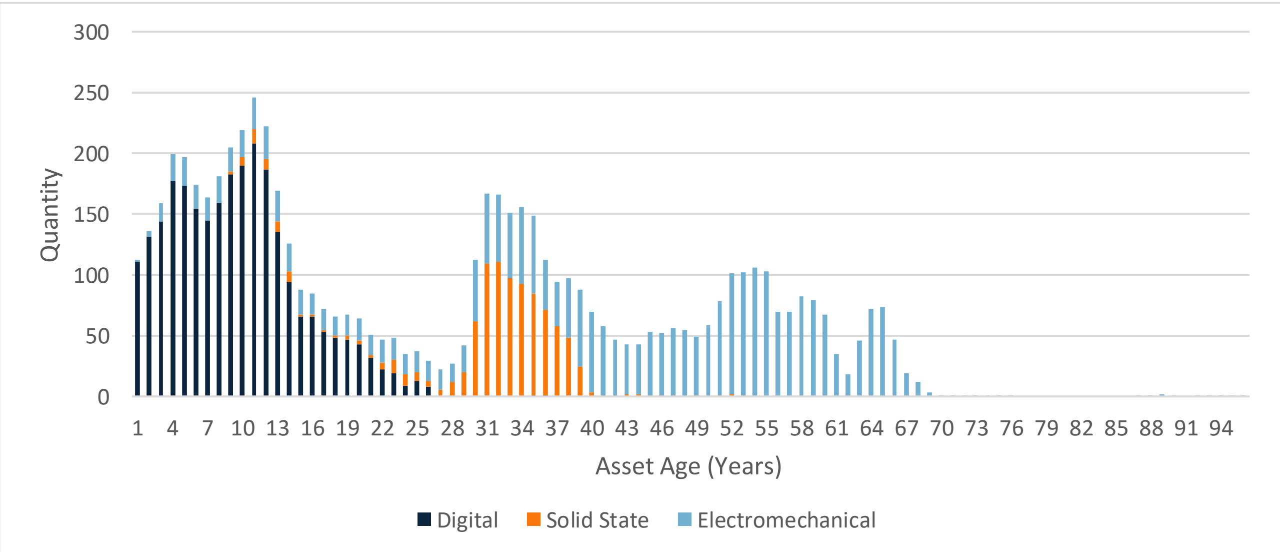
7.14. Protection relays

Protection relay asset class description

Protection relays and control assets in the HV network automatically protect personnel and the network in the event of fault conditions. Of the approximately 6,000 protection relays installed in substations, a significant proportion (~63%) are over 25 years of age, refer Figure 116.

The number of protection relay failures has steadied in recent years, which can be attributed to better asset management of existing relays, targeted replacement of poor performing models and more robust digital relays coming to market. Their management is based on the outcomes of inspections and diagnostic tests, in addition to responding to any identified faults reported through SCADA or network outages where protection relays failed to operate. Protection relays may be subdivided into three different types; Electromechanical, Solid State and Digital with each representing a different generation of relay technology, visible in the below.

Figure 116 - Protection relay age profile



The expected lifespan of each type of relay also varies, with electromechanical relays having expected lifespans of more than 60 years, while more recent digital relays having lifespans within the 10-20 year range.

Protection relay asset performance

Protection relays provide critical safety and system security functionality, and therefore a high level of performance is required for these assets.

Figure 117 - Protection Relay Historic Failures

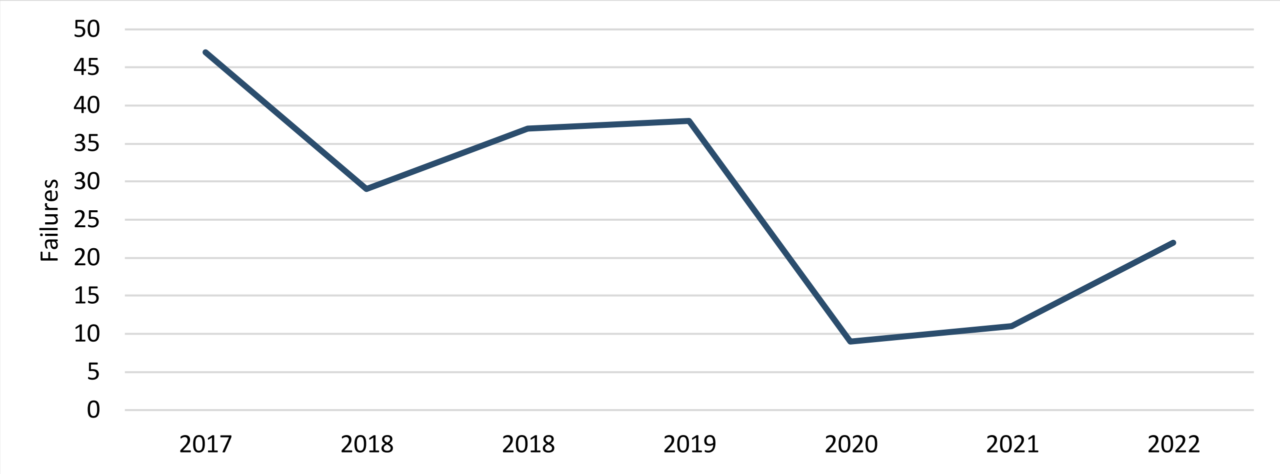


Figure 117 shows historical numbers of failures has decreased in recent years. Programs in prior RCPs to improve reliability resulted in steady failure rate performance despite increases in the population of shorter-lived digital relays. The improvement can be mostly attributed to the roll out of air conditioning into control buildings and improvements in design practices after reviewing any systemic failure issues.

As the population of digital relays expands, a transition to replacing upon failure, rather than proactively will occur as the modern relays reliably notify of a failure without consequence. However, those observed not to give warnings accurately or have spuriously operated will still require proactive replacement to maintain network risk. The existing fleet of solid state and electromechanical relays may fail silently, and an issue will not be known about until it fails to operate for a fault, so also will require the current maintenance and replacement programs to continue. At this time, no significant increase in asset failures has occurred in these categories so modelled asset specific lifespans have been reviewed and extended to reflect this.

For each type of protection relay, the main risks associated with mal-operation or failing to operate are:

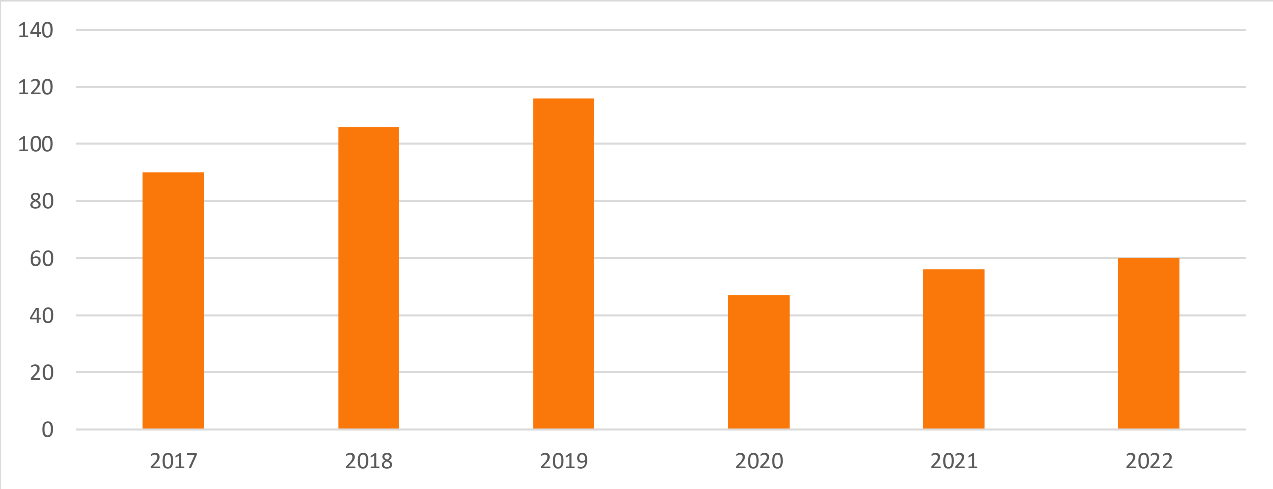
- potential injury/death of our staff, contractors or the public due to:
    - insufficient protection to ensure all HV plant is protected should any single component of the protection scheme fail,
    - failure of protection relays to provide the critical clearing times, or
    - fire start because of a protection relay scheme failing to operate in the event of a fault;
- impact on reliability outcomes due to:
    - protection relays operating when no network fault exists, or
    - protection relay interrupting a larger supply area than intended due to its design or commissioning faults, settings or relay failure; and
- potential environmental risks through knock on effects to other assets because of protection relays failing to clear a fault resulting in catastrophic failure of:
    - power transformers leading to oil spills, or
    - circuit breaker assets leading to SF6 discharge into the environment.

Any protection relays that fail to operate when required during a network fault are investigated reactively with audits and compliance checks undertaken to ensure protection relays are installed and configured with the correct settings.

Protection relay replacement rate (2017-22)

In Figure 118 below, the number of relays replaced from 2017 to 2022 is shown. Prior to 2017, the number of protection schemes was reported, rather than the number of relays so has been omitted.

Figure 118 - Protection relay repex replacements 2017 - 2022



In many cases relay replacements are completed in conjunction with other primary plant asset replacements, so replacement trends will generally reflect those in other substation repex categories. This is because existing protection would need to be reconfigured and recommissioned if retained and typically the protection relays themselves are also near end of life.

Significant asset renewal has occurred due to non-repex programs in recent years, such as the roll out of Dynamic Under Frequency Load Shedding (DUFLS) at zone substations across the state, which required the replacement of existing feeder protection relays to meet the new requirements (Refer Emergency Standards Cost Pass through). It is expected this program will be complete by the end of the current RCP and will result in significant shift in the age profile of protection relays. These programs have been factored into repex forecasts but are not reflected in the number of relays replaced in Figure .

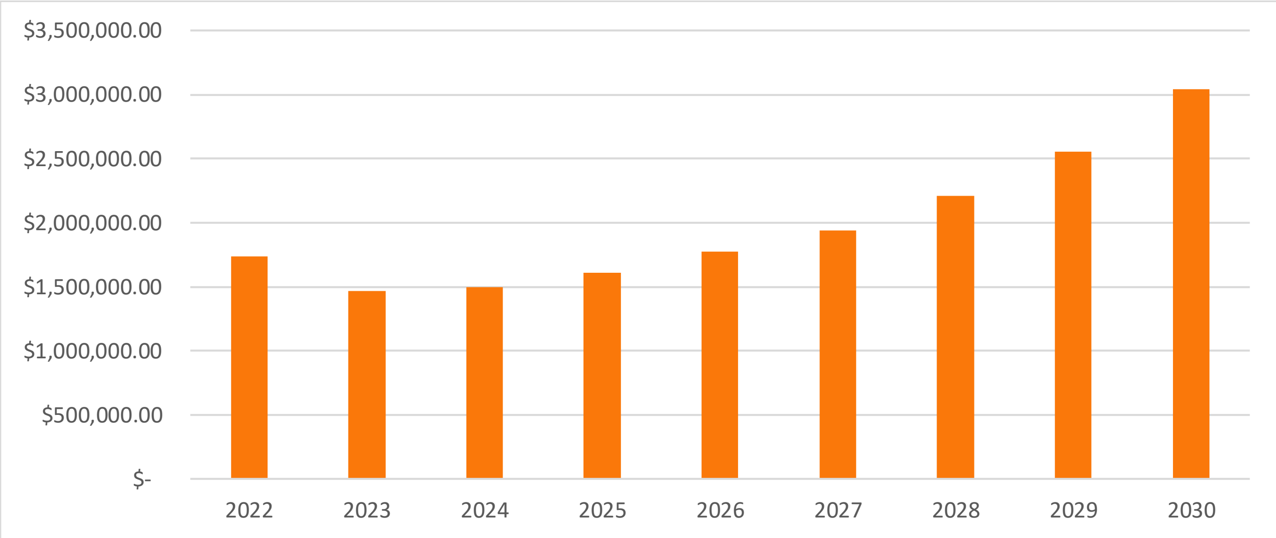
Specific protection relay replacement programs are created where a type of relay, or protection scheme has been found to be no longer fit for purpose, lack required redundancy, no spares and parts availability or, at an elevated risk of maloperation. Examples of these programs include the removal of 66kV pilot differential line protection schemes and transformer protection without Circuit Breaker Failure (CBF) detection.

We are observing an increasing rate of functional failures of certain early digital relays, mostly attributed to a few specific failure modes, which is reflected in the modelled growth in risk in this asset class.

Protection relay forecast risk to service outcomes (base case)

Figure 119 shows the growth of risk in the protection relay asset class without continued investment beyond the completion of planned investment, up to 2025. Under this 'Run to Failure' scenario, up to 2025 planned works will mitigate a significant amount of risk, with DUFLS and several switchboard replacements removing significant numbers of ageing protection relays. Beyond 2025, it is predicted the condition of some assets will deteriorate significantly, and therefore the risk posed by these assets will increase significantly.

Figure 119 - Protection Relay Base Case Risk



The bulk observed increase in risk post 2025 can be attributed to continued deterioration of certain models of digital relays which have already shown propensity to fail without any warning when called to operate for a fault, often resulting in 11kV switchboard outages. These relays were installed with new 11kV switchboards up to 2014 and will be reaching end of life in the 2025-30 RCP. Other aging protection schemes which contribute to the significant increase in risk post 2025 include pilot differential schemes, outdoor frame leakage protection and legacy relays can no longer be economically maintained and serviced due to spare part availability.

Protection relay expenditure forecast

The renewal/replacement strategy for protection relays is based on maintaining the long-term risk and performance across the protection relay population.

Electromechanical protection relays are refurbished where possible using purchased components or spares from previously replaced units. Refurbishment of electromechanical protection relays significantly extends their life at a much lower cost than complete replacement. Where spares are no longer available it is necessary to replace some relays with modern relays to create spares. Most new protection relays installed are digital relays with the capability to alarm on failure, and thus reduce the probability of a consequence occurring. Where possible these will be done like-for-like when the relay or a close modern equivalent is available. Removed relays are typically not used as spares due to their short asset life. We expect that as these relays become more prolific, more repex expenditure will fall under the unplanned rather than planned category.

Other relay replacement expenditure includes:

- line protection upgrades to facilitate the decommissioning of pilot protection schemes, where the pilot cables are end of life; and
- protection schemes where no redundancy exists in the event of a circuit breaker failure to operate. These protection schemes are also at the end of their expected lifespans.

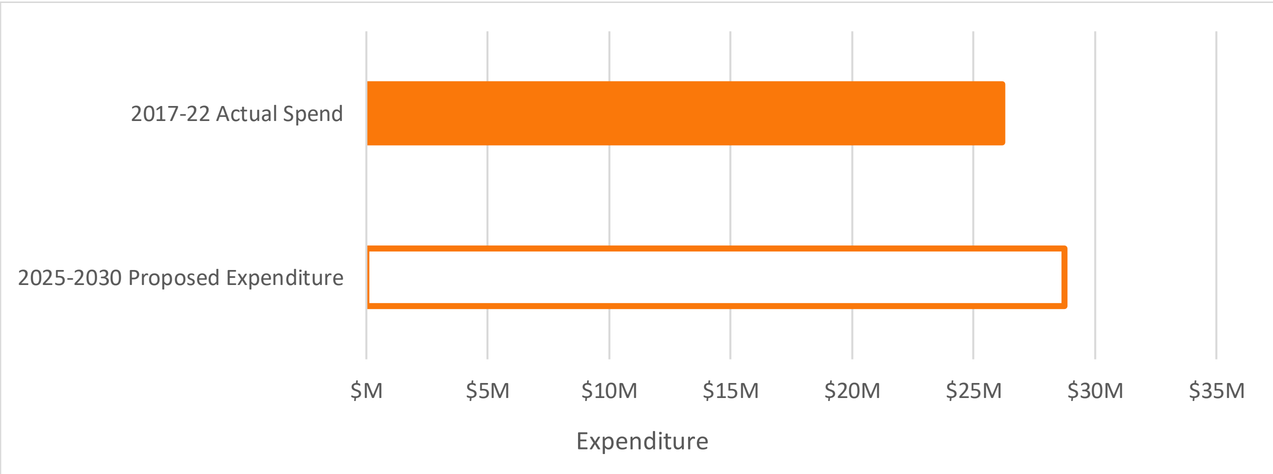
Wherever possible, these protection relays are replaced in conjunction with planned circuit breaker refurbishments/replacements, transformer replacements or other significant works which require the protection relay system to be recommissioned.

The renewal/replacement strategy for protection relays is based on achieving the service level outcomes described in section 5.

Protection relay renewal expenditure summary (2025-30)

Through Risk/ Cost modelling we considered two scenarios (i.e. options) in developing our required expenditure for protection relays, being a **base case** (using actual spend) and a **proposed scenario** meeting targeted outcomes presented in section 5.

Figure 120 – Protection relay expenditure comparison

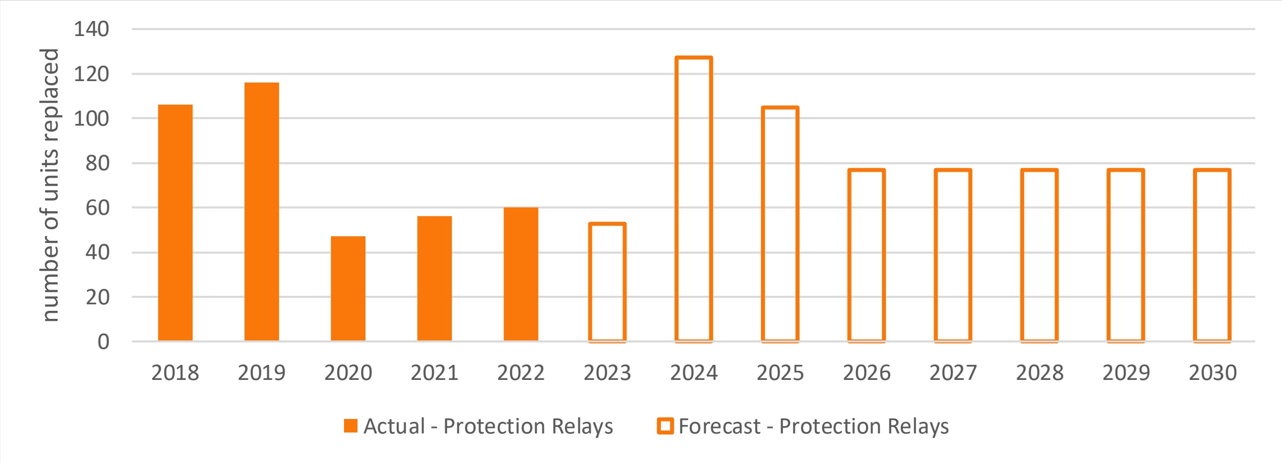


It is not anticipated that any significant change in expenditure will be required to maintain the performance of the protection relay asset category. The proposed $25 million expenditure has been modelled to be sufficient to meet future repex requirements to maintain a reliable and safe network

Protection relay rate of renewal (2017-30)

Figure 121 shows the historic and forecast renewal rate of protection relays. The proposed rate of renewal with an expenditure of $25 million will allow for about approximately 77 relays to be replaced per year, which equates to approximately 1.3% of assets per year.

Figure 121 - Protection relay actual replacement rate (repex only)



7.15. Telecommunications

Telecommunication asset class description(s)

We have an extensive telecommunications network used for the provisioning of SCADA, Tele-Protection, operational telephony, equipment management and monitoring of operational and telecommunications equipment in substations. The telecommunications network is critical for the support of the electrical distribution network and if unavailable results in the loss of communications for critical services that may worsen reliability outcomes. The telecommunications assets are broadly classified as:

- linear communication assets: copper and fiber optic cables that provide a physical communication line between network assets;
- other communication assets: microwave radio, 48V DC power systems, radio systems, GRN 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.

As most communication assets are electronic, they are monitored continuously via their connection to the TNC. In addition, annual inspections on above-ground telecommunication assets, and more detailed condition monitoring on selected below-ground linear communication assets and on structural assets supporting telecommunications equipment, are undertaken. Any failures of telecommunication assets that can impact supply are attended to immediately; other identified defects are prioritised based on risk.

The linear communication assets are a mix of older copper networks and more modern fibre optic networks. Much of the copper network is reaching the end of its technical life. The age profile of the linear telecommunication assets is shown in Figure 122. The age profile of the assets is shown in Figure 123.

Figure 122 - Telco linear asset age profile

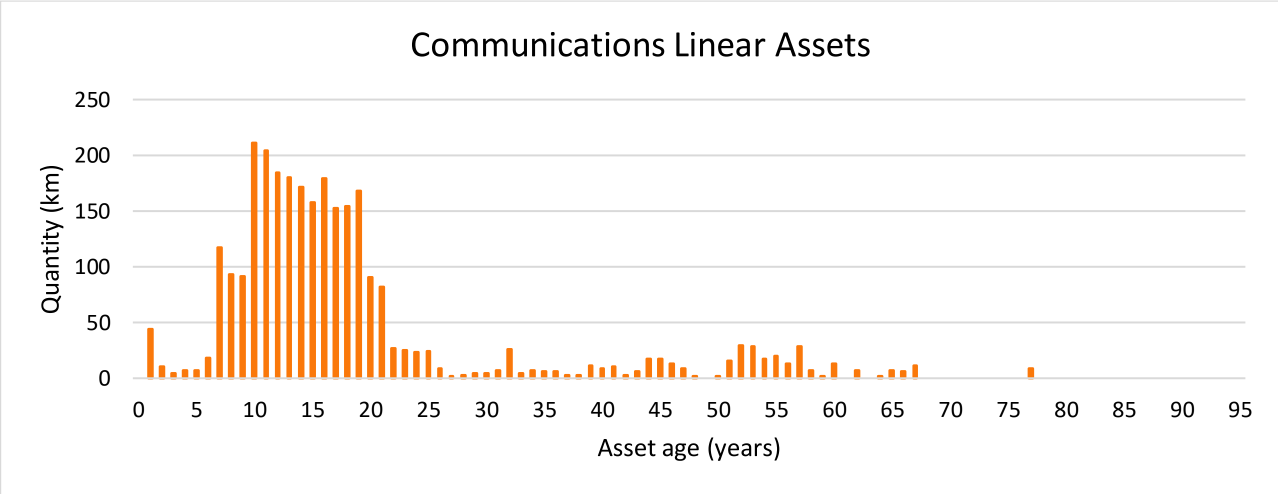
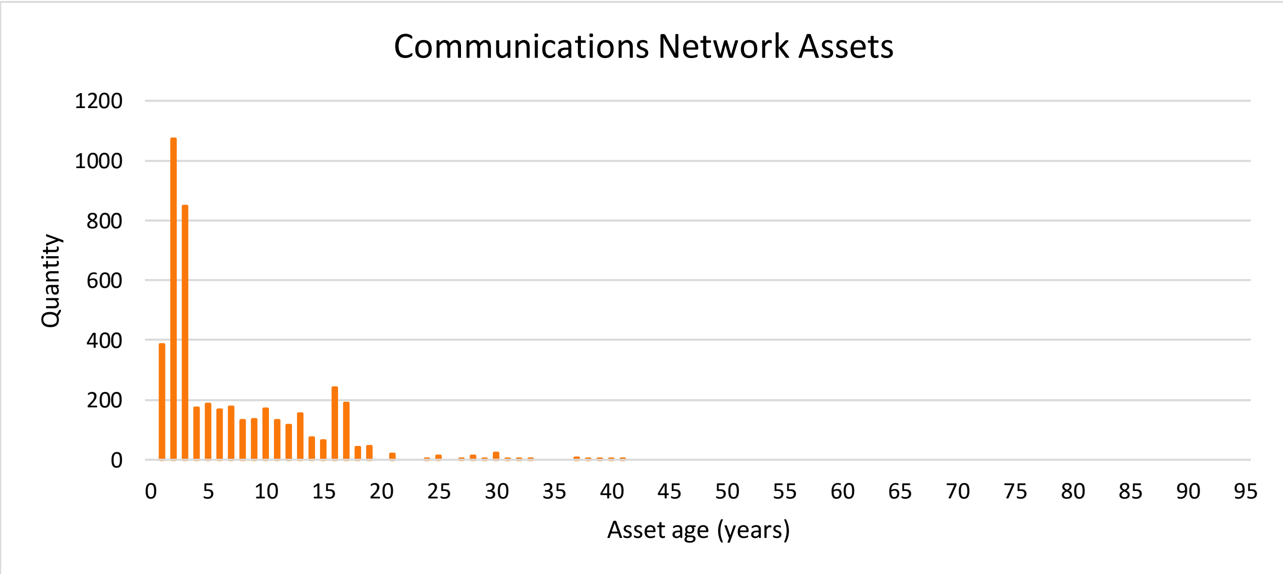


Figure 123 - Telco network assets age profile



Telecommunication asset performance

Condition information on telecommunication assets is limited. Generally, assets in each class are considered fit for purpose and/or good condition with performance criteria being met. Any identified condition defects are prioritised based on risk. The main risks associated with telecommunications assets include:

- potential injury/death of our staff, contractors or the public due to:
  - aerial fibre being installed near conductors and fibre optic and pilot cables being installed near underground cables,
  - physical failure of a tower or monopole in poor condition,
  - unauthorised access to a tower or monopole,
  - exposure to laser or radio frequency radiation, and
  - exposure to chemicals from battery systems; and
- potential interruption to electricity supply; considered generally to be very low as the telecommunications network design caters for redundancy across critical network assets in the event

of a fault or third-party damage. There is however an increase in this risk associated with the existing PDH/SDH technologies that is detailed further in the section below.

The risks for the telecommunications assets are largely addressed via existing operational controls.

Only authorised personnel are permitted to work on linear communication assets due to their proximity to overhead conductors and underground cables. All fibre cables are labelled with laser radiation warning signs on the cable at user accessible locations (pits, cabinets, patch panels) and similar for locations with radio communication infrastructure warning of radio frequency zones. Sites containing 48V DC systems have eye wash stations or bottles and warning signs relating to battery spillage or contamination, and most towers and poles in urban areas or within substation sites with safety climbing devices are secured, inspected and certified annually.

Telecommunication asset forecast risk to service outcomes (base case)

Detailed historical analysis and forecasting models were not produced due to data limitations.

Telecommunication expenditure forecast

The replacement strategy for linear communication assets is based on managing risks. Electronic communication assets are replaced to maintain an acceptable level of safety and reliability; battery systems and TNC hardware are typically replaced based on age with condition monitoring used to prioritise replacements. Site infrastructure is renewed/replaced based on condition with an assessment determining the viability and most cost-effective solution of renewal, upgrading or replacement of the structure.

Since 2018, following lengthy proof of concept and trials, we invested in operational Data Networks to replace legacy PDH/SDH technologies that became end of life in 2013 and 2016 respectively with the current telecommunications technology IP/MPLS. This replacement has been a targeted approach that will accelerate from 2023 onwards to maintain the reliability of the network.

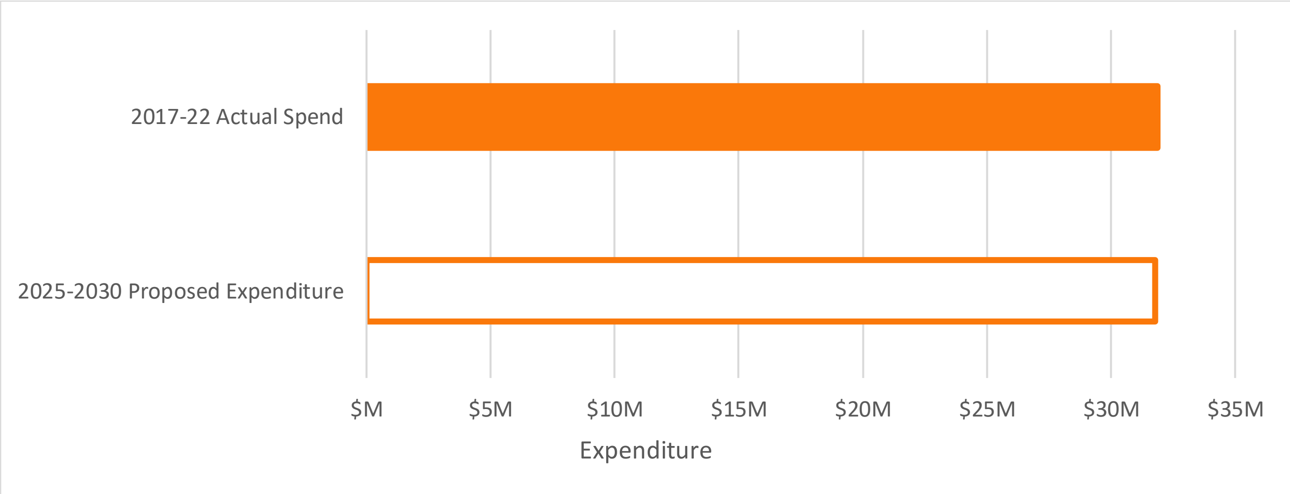
We aim to complete full migration to the IP/MPLS network in the 2025-30 RCP, with a proposed increase in forecast of $4.8 million over the period when compared to historical spend. This acceleration is required to reduce the risks posed from the aging and unsupported SDH/PDH network including:

- potential significant increase in failures causing widespread outages across the telecommunications network resulting in loss of communications for critical services that may impact reliability;
- prolonged telecommunications network outages due to inadequate skills and knowledge of today's workforce to troubleshoot the legacy SDH/PDH networks; and
- increase in cyber security risk due to the legacy management platforms and firmware required to operate the legacy network, with no vulnerability management or patching of applications or the underlying operating systems.

Telecommunication renewal expenditure summary

Forecast expenditure for telecommunications was mostly based on historical expenditure. An increase in IP/MPLS Data Network migration spend (as highlighted in the previous section), has been largely offset by reductions in other categories of telecommunications expenditure, relative to historical expenditure.

Figure 124 – Telecommunications expenditure comparison



Telecommunication forecast rate of renewal (2012-30)

Detailed historical analysis and forecasting models were not produced due to data limitations.

Telecommunication forecast risk to service outcomes (proposed)

Detailed historical analysis and forecasting models have not been produced for this asset category due to data limitations.

8. Major projects and targeted programs

8.1. CBD Reliability

The business case for the 2025-30 RCP for the Adelaide CBD reliability improvement program recommends an optimised investment of $25 million in augmentation capital expenditure (augex) and $55 million in repex capex. This is a new program that will improve current reliability of supply to our CBD customers to bring performance in line with jurisdictional CBD reliability standards over the next RCP.

We have CBD supply reliability targets and thresholds set under our jurisdictional reliability obligations, defined in the South Australian EDC. The SAIDI target is currently set at 15 minutes, with a reporting threshold set at 20 minutes. The reliability of the CBD network has been degrading historically such that we have exceeded the CBD targets and thresholds over the last four years (2018/19 to 2021/22), averaging 24 minutes of SAIDI p.a. over this period.

Without suitable investment it is highly likely that we will continue to not comply with the jurisdictional CBD reliability standards in the next RCP.

The recent decline in the CBD performance has been driven by the condition of the CBD cable network, with much of the cable network entering its end-of-life phase, resulting in escalating cable faults. Our modelling has demonstrated that the current rate of cable replacement (in the 2020-25 RCP) is insufficient to arrest the declining rate of the CBD reliability. A significant uplift in cable replacement expenditure is required to bring the reliability of the CBD to 15 minutes by the end of 2030.

We strive to manage the distribution network efficiently by maximising the life of assets and deferring repex where it is possible without jeopardising reliability or safety outcomes. We believe that the installation of automated switches in key CBD locations will allow us to defer the replacement of some cable sections while maintaining reliability. These automated switches will rapidly switch supply around a faulted cable section to reduce the number of customers who will experience a sustained interruption due to the cable fault. The installation of automated switches will allow a smaller uplift in cable expenditure to meet the reliability target than would be possible with cable replacements alone.

CBD reliability is also contingent on continued expenditure on other asset classes and maintenance activities including, distribution equipment, substation equipment, inspection, maintenance, and augmentation. These replacements are justified separately to the CBD reliability improvement business case but the expenditure proposed is included in this document for context.

Further detail is available in '*document 5.3.12: CBD reliability business case*'

8.2. Hindley Street Switchboard

Hindley Street substation is one of four critical zone substations supplying the Adelaide CBD and is part of the meshed 66kV metropolitan east network. It is supplied via two 66kV cables, one from Whitmore Square, and one from North Adelaide /Croydon. The existing outdoor 66kV yard at Hindley Street is extremely congested, with overhead pipework structures, string bus and three aged bulk oil CBs manufactured in 1954. These are the only three of this type of circuit breaker remaining in the network.

The age and condition of existing switchgear poses a significant reliability and safety risk, with thousands of pedestrians passing every day within a few metres of deteriorated bushings and terminations. Catastrophic failure of a circuit breaker is likely to result in an extended substation outage with approximately 43MW of CBD load at risk. Only 21MW of the 11kV load can be tied away to other CBD feeders.

Most of the disconnectors are defective or inoperable and no longer provide safe points of isolation. The configuration of the existing bus structures does not allow for piecemeal replacement of equipment with modern equivalent and any major plant failure, even if not catastrophic, would incur a lengthy replacement period. The existing congested layout also cannot accommodate any additional line or transformer bays, noting a future connection to the proposed City Central - Eliza Street substation will be required.

We propose to replace the 66kV equipment and bus with a new indoor GIS switchboard. The switchboard would be in a new multi-story building and the site expanded to occupy adjoining SAPN property that is currently leased to a third party. The upgrade will address all reliability and safety risks associated with the existing outdoor equipment and structures and will provide additional spare bays for future lines and transformers. All existing outdoor 66kV switchgear and structures will be removed, providing space for future projects. The upgrade will also allow all 66kV protection and transformer relay panels to be removed from the existing control building which is also extremely congested.

We consider the proposed solution to be the only viable option as the new building and switchgear can be fully constructed while the substation remains in service, followed by a staged cutover of the incoming 66kV lines and transformers. It is not possible to offload the entire substation.

The recommendation is to invest $30.8.5 million to replace the aged outdoor 66kV equipment at Hindley Street substation with a modern GIS indoor switchboard. Construction is planned to commence in 2026. Through a combination of improved reliability and elimination of specific safety risks to both the public and our employees, the project has benefits that outweigh costs with a positive net present value result.

Further detail is available in *'document 5.3.10: Hindley Street Substation 66kV Replacement business case'.*

8.3. Mobile Substation Replacement

Mobile bypass equipment, such as mobile substations and mobile switchboards, provide the ability for rapid restoration of supply after catastrophic network asset failure. We own two 66-33/11kV 10MVA Mobile Substations built in 2000, and one 11kV Mobile Switchboard built in 2012. The Mobile Switchboard has been permanently in service at Port Pirie since 2013.

Mobile bypass equipment is a very cost-effective way to increase asset utilisation. We design the network with up to 3MVA of load at risk at a substation after transfers, of which there are currently 150 substations at risk. These require mobile bypass equipment to restore supply in the event of asset failure. To reinforce these substations would be orders of magnitude more costly than managing a small number of mobile substations.

Mobile bypass equipment also provides access to substations for asset maintenance, replacement and augmentation. The alternatives of generation or lengthy planned interruptions are far more costly to both us and the community.

Both mobile substation trailers were inspected by Transport Engineering and Management (**TEAM**) in 2023. TEAM identified levels of corrosion which the South Australian Police would likely defect as unroadworthy. Furthermore, both trailers are already 8 years past business and industry standard practice of 15-year asset life and have travelled thousands of kilometers in harsh conditions across South Australia. TEAM state that to complete a full repair and assessment of the trailers, the substation plant would require complete disassembly and reassembly from the trailer. The cost to do so is estimated at 42% of the total Capex to replace and would only increase asset life by an estimated 7 years.

The mobile switchboard is unavailable for planned and emergency use due to being permanently deployed at Port Pirie. This switchboard will remain in service for the foreseeable future, and as a consequence, a new mobile switchboard is required to cover this reliability and project risk.

The recommended option is to replace the two large mobile substations for $3.5 million each and the mobile switchboard for $2.5 million in 2027-29 for a total of $10.5 million, including $1 million of historical expenditure for management of the whole mobile bypass fleet. This option has a positive NPV, addresses all reliability and operational issues identified with the mobile bypass equipment and is the least cost option.

Further detail is available in *'document 5.3.11: Mobile Substation Replacement business case'.*

8.4. Northfield GIS Switchboard Replacement

The Northfield 275/66/11 kilovolt (**kV**) Connection Point Substation is a key link in the 66kV interconnected network that supplies approximately 115,000 customers in Adelaide's eastern suburbs. It was installed in the late 1980s and components of its infrastructure are now reaching the end of their service lives and are in poor condition. In particular, the gas insulated switchgear (**GIS**) that forms part of the substation is in poor mechanical condition and subject to accelerated ageing. These condition issues are principally a result of significant external corrosion – specifically on the flanges and O-rings in the GIS – caused by 35 years of continuous service in an outdoor environment.

Reflecting its age, the condition of the Northfield GIS has deteriorated to the extent that there is a material risk of asset failure. Failure of the GIS installation has the potential to lead to significant levels of unserved energy to customers in Adelaide's eastern suburbs.

We undertook a Regulatory Investment Test for Distribution (**RIT-D**) to determine the most efficient means of ensuring reliable supply for Adelaide's eastern suburbs. Further, we expect there to be significant market benefits associated with ensuring reliable supply for Adelaide's eastern suburbs – principally in the form of avoided involuntary load shedding – and considers the identified need for this RIT-D to be delivering market benefits. In addition to market benefits, we expect there will be significant environmental benefits from avoided leakage of the gas used to insulate the Northfield GIS.

We prepared a Final Project Assessment Report (**FPAR**)[29], published in December 2022, in accordance with the requirements of clause 5.17.4 of the NER. It was the third and final stage of the formal consultation process set out in the NER in relation to applying the RIT-D.

The FPAR follows our publication of the options screening notice and the Draft Project Assessment Report (**DPAR**), including the associated consultation periods. We concluded that there will not be a non-network option, or stand-alone power system (**SAPS**) option, that could form a potential credible option on a standalone basis, or that could form a significant part of a potential credible option for this RIT-D.

We proposed Option 1, to construct a new Northfield 66kV air insulated switchgear (**AIS**), as the preferred option which satisfies the RIT-D. This option involves constructing a new 66kV outdoor AIS immediately south of the existing Northfield substation with three 66kV bus sections supplying all existing seven 66kV lines as well as supplying the two 66/11kV transformers at the existing Northfield substation.

The Northfield GIS Replacement RIT-D FPAR stated, 'Construction of the new AIS would commence in 2023 with commissioning by H1 2025'. Since publication, detailed design has been undertaken and engagement with ElectraNet, our transmission partner. This process has revealed several critical technical issues that had to be resolved. This is typical for implementation of a project of this size as the FPAR was based on a concept design.

The revised timeline is for construction of the AIS to commence December 2023 with practical completion in H2 2025. As the ElectraNet 275/66kV connections to the AIS must be staged to ensure security of network supply, cutover and final connection works will be completed in Q4 2026. We currently estimate a total project expenditure of approximately $25.1 million, of which $3 million has been spent to date, $10.4 million forecast during the current RCP, and $11.7 million required for project completion during the next RCP.

29 https://www.sapowernetworks.com.au/data/314233/ensuring-reliable-supply-for-adelaide-s-eastern-suburbs-northfield-gis-final-project-assessment-report-fpar-/

9. Cross-checking the reasonableness of our forecasts

9.1. Comparison with AER repex model

Overview

The AER repex model is a statistical based model that forecasts repex for various asset categories based on their age profile, condition (using mean life 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 previous determinations for SA Power Networks, the AER has only modelled five asset classes in the AER repex model, with Poles excluded in the 2020-25 Determination on the basis that Stobie poles are unique to South Australia and cannot be compared with wooden poles used in other states. These are: (1) Underground Cables (2) Overhead conductors (3) Service Lines (4) Transformers, and (5) Switchgear.

We have not modelled switchgear because we report 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 we only report 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.

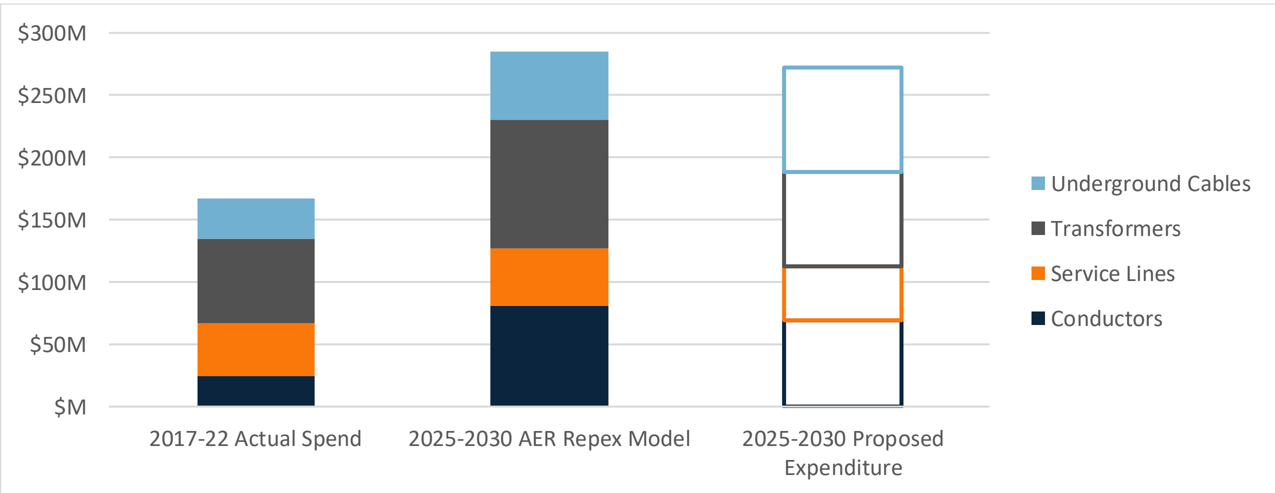
The AER repex modelling approach analyses four scenarios that consider both a DNSP's historical asset renewal practices and the asset renewal practices of other DNSPs in the NEM:

1. historical unit costs and calibrated expected renewal lives;
2. comparative unit costs and calibrated expected renewal lives;
3. historical unit costs and comparative expected renewal lives; and
4. comparative unit costs and comparative expected renewal lives.

We calibrate expected renewal lives using a two-step methodology advised by Nuttall Consulting, which is based on its 5-year historical renewal history and the age profile of network assets currently in commission. We define historical unit costs as the 5 year 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.

Figure 125 – Comparison of expenditures with AER's repex model



According to AER Draft Decisions for other DNSPs, the “AER’s ‘repex model threshold’ is defined by taking these results and other relevant factors into consideration. For these draft decisions, the AER’s proposed approach is to set the repex 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 "Lives scenario", which generates a higher output relative to the "Cost scenario", is our preferred scenario. We have used the output from the "Lives scenario" for individual asset classes in Section 7 as preferred output for repex model.

For assets modelled within both the AER repex model and our modelling, our overall expenditure is less than the sum of the “Lives scenario”. The underground cable expenditure increase is driven by the need to meet jurisdictional reliability targets in the CBD and the additional expense of replacing CBD cables as compared with other cables in the network which would not be captured by the AER repex model.

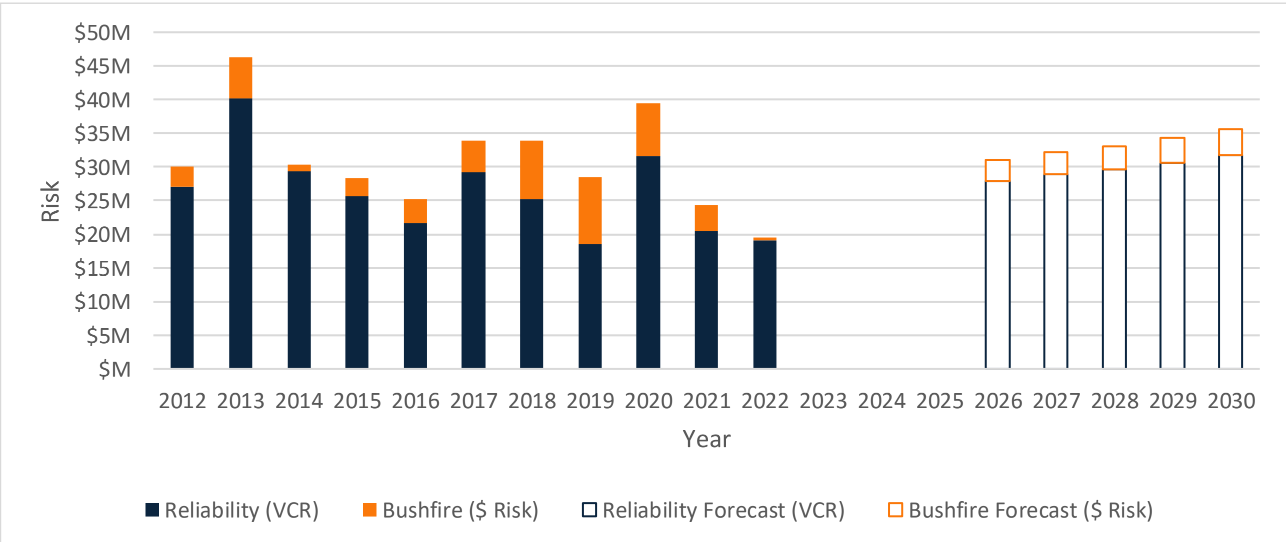
9.2. Scenario comparison

In addition to comparing to the AER repex model we considered several alternate scenarios (i.e. options analysis) in developing our repex forecast. For each scenario, reliability and safety outcomes were quantified for our modelled assets. Bushfire risk was considered as a single system wide value, while reliability was considered both at a system level but also at a regional level. This additional regional analysis was included as stakeholders in our Focused Conversations voiced concerns over maintaining reliability at a system wide level while some regions suffered a decline in performance (offset by an improvement elsewhere). The expenditure and outcomes from each of the scenarios considered is included below.

Scenario 1 (base case) in which we maintain our current level of replacement expenditure.

Replacement expenditure 2025-30: $646M million

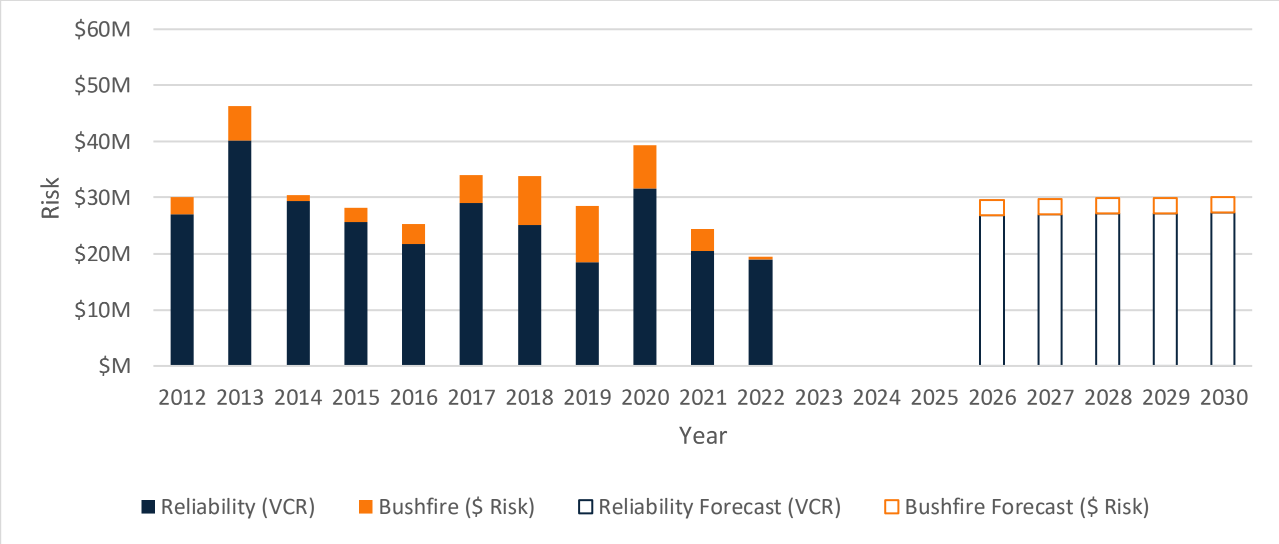
Figure 126 – Scenario 1 historical and forecast risk for all modelled assets



Scenario 2 (proposed) includes additional replacement to arrest any decline in performance associated with asset failures. Reliability performance is maintained for each geographic region. Our replacement program maintains bushfire safety risk at its current level and our augmentation program delivers a net reduction in bushfire safety risk in targeted locations (where economic).

Replacement expenditure 2025-30: $810 million

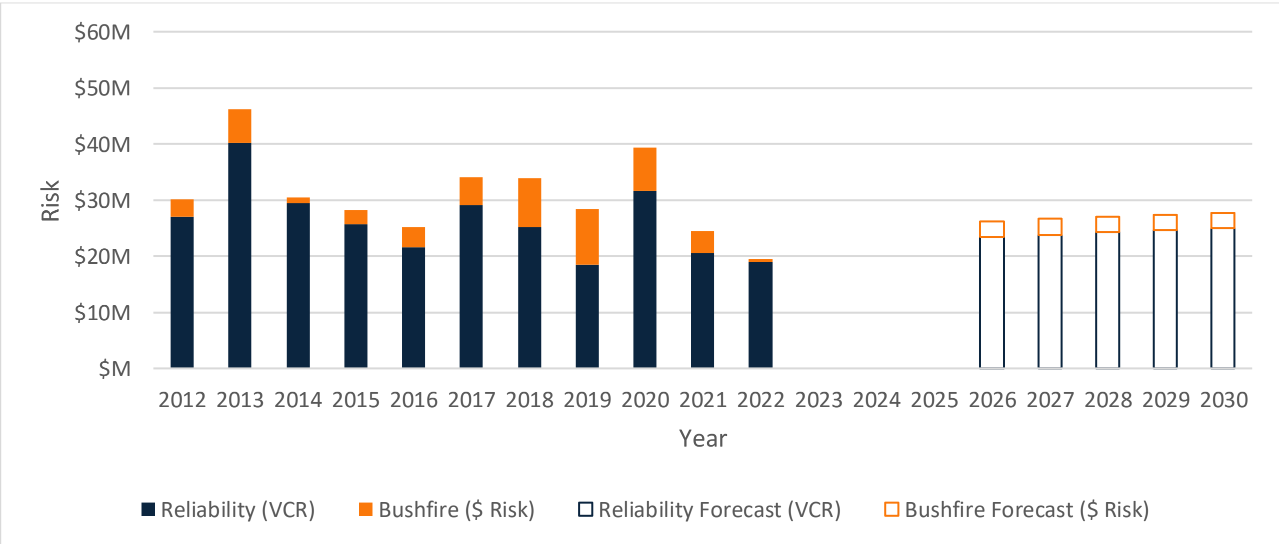
Figure 127 - Scenario 2 historical and forecast risk for all modelled assets



Scenario 3 (economic) includes repex on a strictly economic basis with no consideration of overall service outcomes. This scenario included additional repex (beyond what is required to maintain service levels) where investment could be shown to have a positive net benefit. This scenario would improve service levels (specifically reliability), at an overall level, at additional cost to customers. However, it fails to maintain reliability at a geographic level.

Replacement expenditure 2025-30M: $830 million

Figure 128 - Scenario 3 historical and forecast risk for all modelled assets



Our Peoples Panel recommended Scenario 2 which our proposed expenditure is aligned to achieve.

9.3. Sensitivity testing

To validate our repex forecast modelling and understand the influence of inflation on our model outputs, a set of model outputs were prepared with varying discount rate inputs. Note that the proposed scenario expenditure presented in this document, and other compared scenarios (including base case and economic) use a WACC input of 4.05%. Table 10 summarises the results of this sensitivity testing.

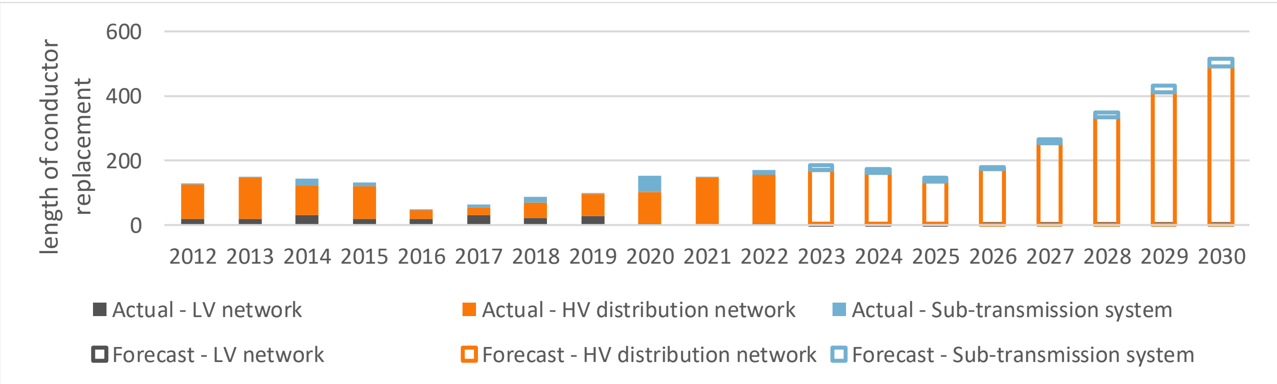
Table 10 - WACC sensitivity test of proposed scenario forecast modelling

WACC	Proposed Scenario Expenditure ($m)
3.73%	$811.1
4.05%	$810.4
4.50%	$809.8
5.00%	$809.5

9.4. Comparison with other DNSPs

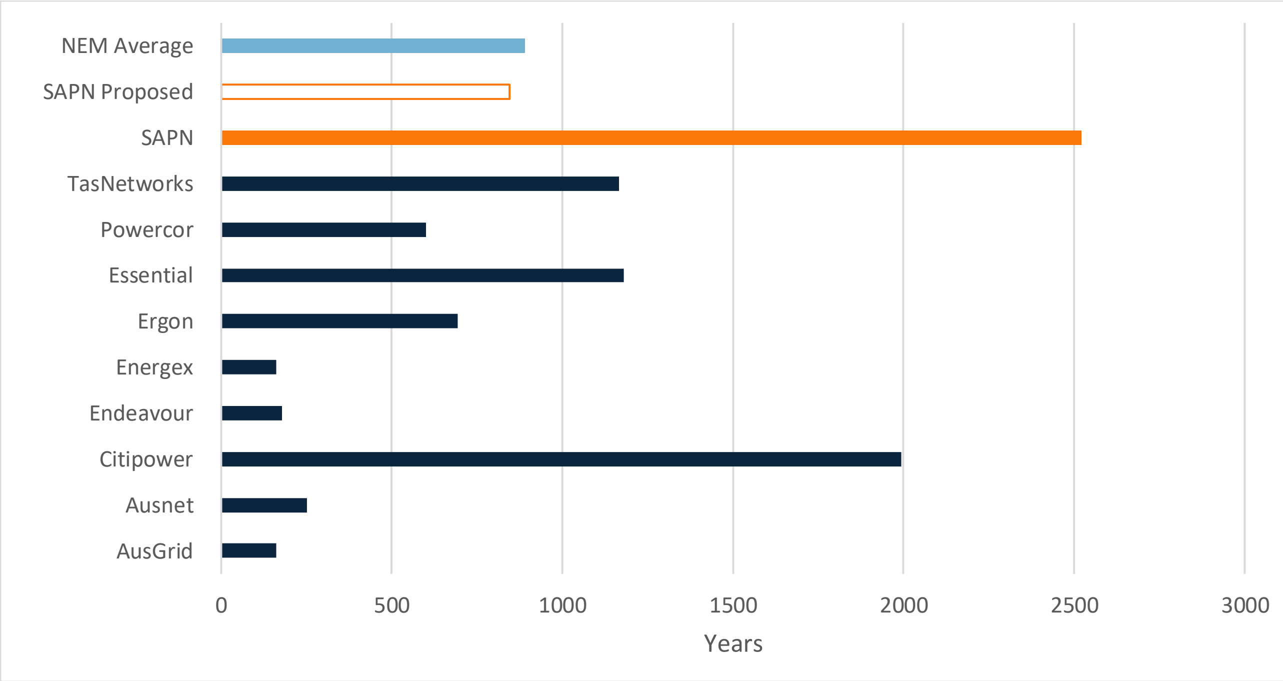
In developing the asset class forecasts and overall expenditure forecast, we compared historic and forecast replacement rates with other NEM DNSPs, using category analysis RIN data from 2015 to 2020. Considering the number of units replaced and total population, an 'implied life' was determined for each asset class (and the entire asset base). This comparison was useful where analysis suggested a required step increase, for instance in overhead conductor expenditure.

Figure 129 - Overhead conductor renewal rate



The increase in renewal rates appears large in the context of historic conductor repex (which has been minimal given we have typically 'run to fail'). However, when viewed in the context of other DNSP practices this forecast appears reasonable putting us in line with our NEM counterparts.

Figure 130 - DNSP comparison of overhead conductor renewal rates



10. Approaches we used to mitigate expenditure levels

10.1. How we optimised within each asset class

In our expenditure forecast modelling we consider the benefit and cost of each individual asset that may be replaced (see section 6.3). Individual assets are then ranked from highest to lowest benefit cost ratio (BCR) and sufficient replacements undertaken to meet the scenario service outcome objectives (eg. maintain reliability and bushfire safety risk). This forecasts the **minimum** number of replacements to meet the objectives.

This approach implies that we can undertake a perfectly allocated replacement program with no consideration of asset location with respect to our resources. In reality, we have depots across the state with resources (eg powerline workers) undertaking a variety of work. While the highest BCR asset replacement may be in Mount Gambier, our resources in Mt Gambier may be undertaking customer connection work while we have resources available at Ceduna that can undertake asset replacement work with a lower BCR.

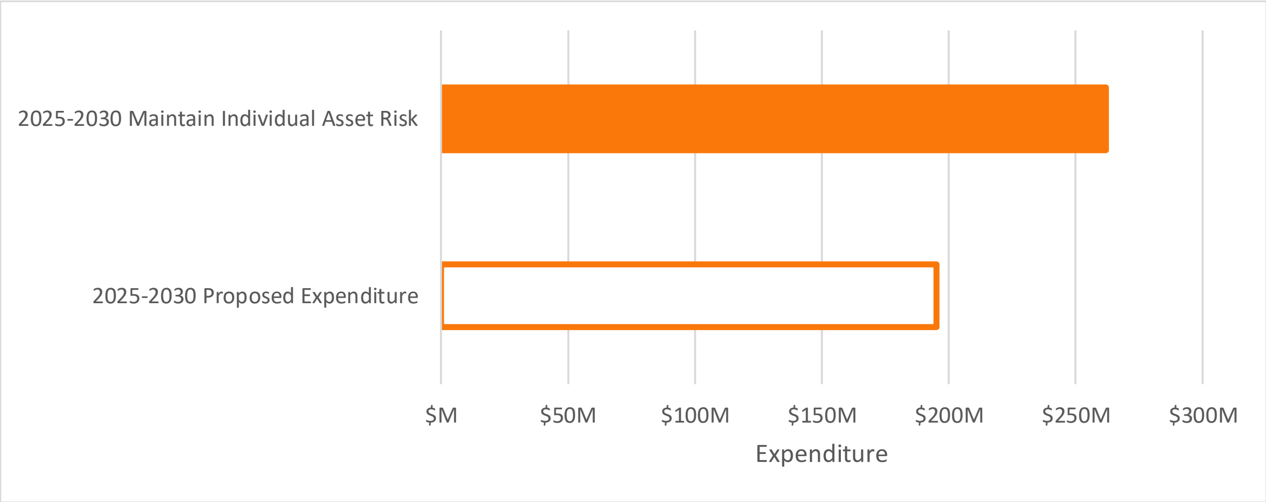
We have not attempted to quantify the real-world effect of resource allocation on our expenditure forecast and instead assumed that we can perfectly allocate investment based on BCR. In practice, we will need to identify efficiency gains to offset our inability to perfectly select work.

10.2. How we optimised across our portfolio of asset replacement

In the past we considered each asset class in isolation, forecasting expenditure based on maintaining the risk to performance at an asset class level. While the asset replacements within each asset class were ranked by BCR, the relative benefit of investments *between* asset classes had not been considered. We have now adopted an approach where most of our modelled assets are considered in a single portfolio. This increases the effectiveness of the overall portfolio by replacing those assets that have the highest BCR regardless of which asset class they belong to.

This portfolio optimisation has resulted in a forecast expenditure reduction of $66 million over the 2025-30 RCP while achieving the same service level outcomes, see Figure 131.

Figure 131 – Proposed expenditure and unoptimized maintain asset risk expenditure for modelled assets



10.3. How we optimised between network asset replacement and augmentation

Where practical we sought to develop optimum investment solutions to achieve identified needs. For instance, to address the poor reliability performance in the CBD we developed a program of work that combines both repex (mainly underground cable replacement) and augex (reliability). Further details on our approach to optimising this investment are in document *'5.3.12: CBD Reliability business case'*.

10.4. The alternatives to network asset replacement that we considered

While our expenditure forecasts are based on removing risk through replacement, we considered if parts of our network should be replaced at all. With the recent improvements in distributed energy resource technologies, there is potential for parts of our network to be decommissioned with customers instead supplied by SAPS.

To assess the viability of this potential option, we partnered with ITP renewables in 2021 to undertake a systematic analysis of the entire Eyre Peninsula region of the network (the most sparsely populated and therefore most likely to contain sections of the network that are economic to *not* replace).

This analysis utilised much of the data underpinning the Risk Cost Model used in forecasting our replacement expenditure – including the quantification of risk costs. The analysis showed that there were very few locations where SAPS were an economically viable alternative to maintaining an ongoing connection to the network.

We believe that SAPS represent a viable solution in unique parts of the network (very long sections supplying a single customer) but that this non-network alternative does not represent a material impact on our forecast expenditure.

The full report and analysis are available in the *Microgrid Feasibility and Screening Study – South Australian Eyre Peninsula*[30]

[30] ITP Renewables, *Microgrid Feasibility and Screening Study – South Australian Eyre Peninsula*, May, 2023. Accessible on: [https://itpau.com.au/projects/eyre-peninsula-microgrid-feasibility-studies-and-screening-tool/].

10.5. Our proposal to improve asset management cost efficiency

As described in section 3.5, we have been investing in its asset management systems via a long-term strategic program, Assets and Work (A&W). This program aims to improve the effectiveness (doing the 'right' work) and efficiency (reducing the cost of doing the 'right' work) of our network investment.

We comprehensively assessed asset management practices and systems in 2023. This assessment formed the foundation of a revised roadmap to 2030 to be delivered via our Assets and Works Phase 3 program. This program effectively continues the A&W program, delivering on a revised roadmap and ensuring that all business activities supporting effective asset management.

Where the A&W program has largely focused to date on achieving benefits through doing the 'right' work, the Assets and Works Phase 3 program for 2025-30 is forecast to achieve efficiency benefits. This efficiency benefit / cost reduction has not been incorporated into the forecast expenditure within this business case but is instead applied as a separate specific efficiency adjustment to our total capex forecast in our Regulatory Proposal.

Further details are set out in our separate business case, *'document 5.12.15 - Assets and Work P3'.*

11. Resourcing implications and deliverability

We have developed a plan to ensure that we can deliver the recommended project in this business case together among all of the increased volume of work reflected in the programs that comprise our total network expenditure forecast in our Regulatory Proposal. This plan considers the detailed implications of our proposed overall uplift in total network expenditure for our required workforce and supporting internal services of information technology, feet, property and human resources.

We consider that our plan is realistic and achievable over the 2025-30 RCP. The details of our approach are set out in our accompanying document, *'5.2.5: Resourcing Plan for Delivering the Network Program'*.