Repex - Business case addendum

2025-30 Regulatory Proposal

Supporting document 5.3.1 - Network Asset Replacement expenditure - Business case addendum

December 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 is an addendum to our original business case '*5.9.3: Business case – Network asset replacement expenditure*' included in our Regulatory Proposal (submitted to the AER on 31 January 2024). Our original business case should be read for further background detail including with respect to the overall forecasting method, the identified need, target outcome recommended by our customers via engagement, the approaches used to mitigate the expenditure forecast, and how we examined resourcing and deliverability.

This document now responds to the AER Draft Decision (the Draft Decision) having not accepted and therefore revised our forecast capex on network asset replacement and refurbishment (repex) for 2025-30 to a lower expenditure level than we had forecast in our Regulatory Proposal, by submitting:

- our responses to concerns raised by the AER in its Draft Decision regarding various aspects of our risk cost modelling that led the AER to adjust our proposed expenditure to 15% less than we forecast;
- detail on the recalibration of our risk cost model to reflect corrected asset data, updated modelling assumptions and observed network risks; and
- a revised expenditure forecast for the program.

1.2 Expenditure category

This expenditure comprises our overall capital expenditure (capex) on network asset replacement and refurbishment (repex). All expenditure outlined in this document is expressed in June $2022 (excluding overheads), and excludes the efficiency adjustment arising from our separate 'Assets and Works' business case (approved in the Draft Decision) – this adjustment is made to forecast repex in our capex model.

1.3 Related documents

This document should be read together with the following documents:

- 5.3.1 Business case – network asset replacement expenditure Jan 2024
- 5.3.12 - CBD Reliability - Business case addendum Dec 2024 – which details the repex for CBD cables.

2 Executive summary

This document recommends a revised repex forecast of **$784.7m** in capex, to replace or refurbish network assets to maintain safety (including with respect to bushfire risk) and reliability outcomes for our customers and the community in the 2025-30 Regulatory Control Period (RCP).[1]

The original business case in our Regulatory Proposal had forecast $810.4m in repex. It was forecast by applying risk modelling aligned to the *AER industry practice application note for asset replacement planning 2019*, for a selection of asset classes that have sufficient data. This modelling enabled us to quantify service outcomes for customers and the community resulting from various counterfactual rates of repex. Our original forecast sought to achieve an overall identified need, consistent with the service outcomes preferences of our customers as expressed via our engagement, of:

- maintaining safety (including with respect to bushfire risk) consistent with regulatory obligations;
- improving the reliability of the Adelaide CBD to align it with jurisdictional reliability targets; and
- maintaining service reliability for customers at a geographic region level.

We do not accept the AER's Draft Decision, which reduced forecast repex to $692.1m, on the basis that:

- our modelling indicates that this level of expenditure would cause a deterioration in customer service outcomes, through failure of in-service assets, degrading reliability (via increased outages) and increasing safety risks to customers and the community; and
- our additional analysis and updated data set out in this addendum, addresses all the concerns the AER identified with our modelling assumptions and calibrations by:
    - consistently using the most recent five years of actual data to calibrate our modelling;
    - recalibrating our probability of failure models to align with recent failure history;
    - increasing the sophistication of our estimates of reliability risk from asset failures by considering asset voltage levels and network types; and
    - translating service outcomes of forecast expenditure into service levels measured as the System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) metrics.

The further analysis and modelling improvements that we made to address the Draft Decision have resulted in our revised repex forecast being $25.7m lower than the original forecast from our Regulatory Proposal. This addendum demonstrates that our revised repex forecast of $784.7m represents the most prudent and efficient forecast to achieve the overall identified need on the basis that this forecast provides that:

- **service outcomes are aligned to customer preferences** - achieves a target service outcome (maintaining safety, improving CBD, maintaining reliability by region) aligned to the preferences of our customers as expressed consistently throughout all stages of our consumer engagement and which have remained unchanged;
- **value of service outcomes to customers is maintained** - achieves a target monetised service outcome that our analysis has shown will maintain customer service outcomes in the 2025-30 period to current levels, in monetised risk terms, that is, quantifying the risk posed by network asset condition to reliability and safety to customers in dollar impact terms – in contrast, a counterfactual of maintaining only to our current rates of replacement would deteriorate reliability and increase safety risk;
- **service level outcomes are maintained for customers** - achieves a target service outcome that our analysis has shown will maintain customer service outcomes in terms of actual service levels by way of

[1] All figures are in June $2022 excluding network and corporate overheads.

SAIDI and SAIFI – that is, we have shown that our forecast repex will only maintain current / historic service rather than improve; and

- **expenditure to achieve these service outcomes is efficient for customers** - the repex forecast in order to achieve these target service outcomes is efficient for customers as evidenced by:
    - the expenditure generating significant monetary savings to customers (relative to the base case counterfactual of maintaining current repex rates), with benefits to customers exceeding costs and a Net Present Value result of **$147 million over a 20-year period**;[2] and
    - as a top-down comparative efficiency test, the expenditure forecast is shown to be lower (for applicable asset classes) than the AER's own repex model as displayed in Figure 1.

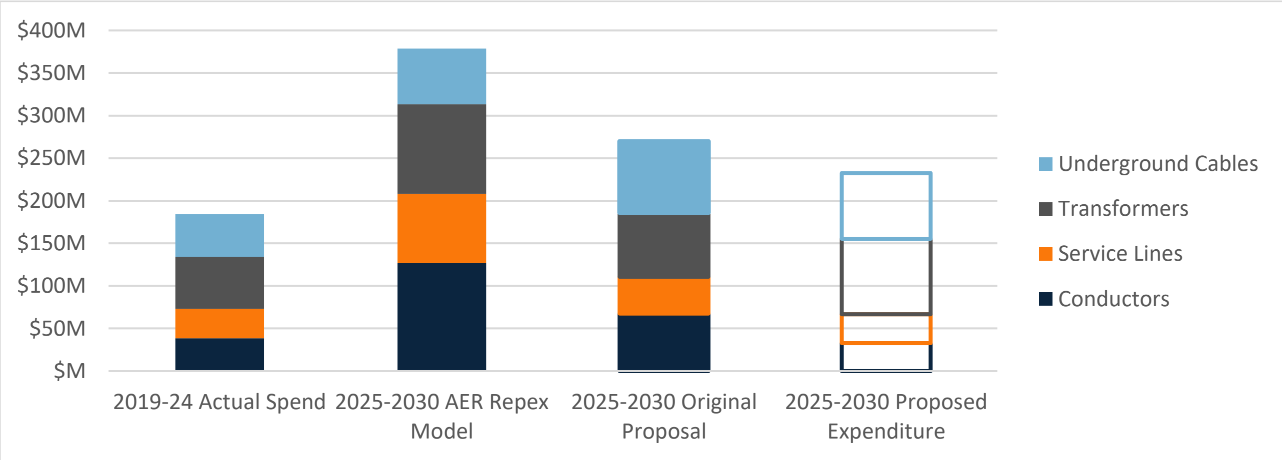

Figure 1 – Comparison of expenditures with AER's repex model

2 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.

3 Background

3.1 Our original proposal

In our Regulatory Proposal, we originally forecast **$810.4m** for repex in the 2025-30 RCP. This expenditure aimed to address the need to retire distribution network assets that are, or will be, in poor condition with a view to maintaining reliability service performance and safety (including bushfire risk), across our network.

We had forecast expenditure using three different approaches:

1. a risk-cost model quantifying the level of service risk in monetary terms (representing 67% of the proposal);
2. using historic expenditure for those asset categories where insufficient data is available to rely on detailed modelling (representing 28% of the proposal); and
3. independent business cases for specific programs of work that are not BAU (CBD reliability, Hindley Street upgrade and Northfield switchgear replacement),

Our repex forecast aimed to achieve a target service outcome that was aligned to the preferences of our customers, as expressed through all stages of our engagement including our Focused Conversations, People's Panel and in submissions to our Draft Proposal of:

- maintaining reliability by geographic region – highlighting the need to consider equity between regions;
- improve reliability of the Adelaide CBD – given the importance of complying with jurisdictional service standards, and of the CBD to economic / customers' prosperity; and
- maintain safety in aggregate across our network – given a desire to not see rising risks of harm to persons and damage to property and assets, particularly in the face of rising climate change risks.[3]

Our forecast met these service level objectives at lowest cost, and was shown to be efficient overall, with benefits exceeding costs with an NPV result of $364.6m over a 20-year period, and with expenditure being comparatively lower than the AER repex model for those asset classes modelled by the AER repex model.

3.2 Summary of how we have revised our approach

This addendum responds to the Draft Decision having included an alternative repex forecast of $692.1m, which was $118.3m lower than the forecast we proposed, and which resulted from it having:

- accepted the forecast expenditure for the two individual business cases (Northfield and Hindley Street) and forecast expenditure for asset types for which expenditure was forecast on the basis of historic expenditure; and
- not accepting and therefore adjusting forecast expenditure for asset types for which expenditure was forecast on the basis of our risk-cost model, citing various concerns with the assumptions, inputs and settings of our modelling – this expenditure was substituted with historical expenditure.

The table below outlines each key concern raised in the Draft decision and summarises how we have responded in order to address each concern – these points are detailed throughout this addendum.

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3 Further detail on the views expressed by our customers can be found in our Regulatory Proposal. SAPN, *Attachment 5 – capital expenditure: 2025-30 Regulatory Proposal, January 2024*, p.33; and SAPN, 5.*3.1 business case: network asset replacement expenditure - 2025-30 Regulatory Proposal*, January 2024, pp.22-23.

Table 1 AER considerations and our response

	AER DRAFT DECISION CONSIDERATIONS	HOW WE RESPONDED
Modelling input assumptions	**Outage duration**	
	• Using a 12 year average likely overstates risk as it doesn't consider changes in asset condition or response practices that may impact frequency or duration of events. • Calculating an entire asset population's outage duration by just voltage level is not reflective of the actual restoration experience for urban and rural customers. • Potential that large weather events may be skewing outage duration data adjacent to these events (in last 2 years).	• Updated our average outage duration to reflect a 5-year average. This is reflected in our revised repex forecast. • Updated our average outage duration to account for network characteristics using feeder type (urban, rural long, rural short and CBD). This is reflected in our revised repex forecast. • Undertook analysis of the impact of large weather events on average restoration times. This analysis demonstrated a negligible difference and therefore we have not adjusted our modelling.
	Likelihood of consequence	
	• Assumption of 100% chance of outage in the event of a failure likely overstates risk and is not supported by actual data.	• Updated our likelihood of consequence to reflect actual observed likelihoods based on our failure data.
Model calibration	**Probability of failure**	
	• Predicted increasing failure trends are inconsistent with actual failure data for HV and LV conductors. • Calibration of failure model should better reflect observed overall network risk values.	• Recalibrated our probability of failure models for cables and conductors to align with actual failures over a 5-year average. • Undertook an audit of our asset failure data which identified a systemic issue that had resulted in under-reporting of failures in some asset classes while overreporting in others. Corrected failure data has now been used to calibrate our model as well as in revised Regulatory Information Notice (RIN) reporting. This error only affected powerline asset types.
Target service level	**Baseline service level**	
	• An average of 3 to 5 years should be used to set the baseline service level that the proposal seeks to maintain, rather than a single year (2021-22).	• Clarified an AER misinterpretation. Our service outcome forecasting approach calibrates the model using historical observations (over a period) and uses this as the target service level. The baseline service level maintained is therefore not 2021/22 but the average service level of the 5 years used to calibrate the model.

	AER DRAFT DECISION CONSIDERATIONS	HOW WE RESPONDED
	Link between expenditure forecast and target service level	
	• Better demonstrate the effect of the proposed expenditure (and counterfactuals) on service level outcomes by way of SAIDI and SAIFI.	• Updated our modelling to also reflect reliability service performance in SAIDI and SAIFI performance metrics rather than just Value of Customer Reliability (VCR).
Substitute Forecast	**Unplanned Expenditure**	
	• The substitute forecast provided for several unplanned replacement programs that are unmodelled, was lower than historical expenditure	• Reviewed the substitute forecast and potential impact on delivering service outcomes. The reduction is not practical. Given these lines are not modelled, it is expected that the same level of expenditure will be required to maintain current performance.

Additionally, two errors were identified in the forecasts presented in our original proposal, found in the course of addressing the AER's Information Requests and its Draft Decision – these have been remediated in our Revised Proposal. These are outlined in Table 2 below.

Table 2 Errors from original proposal and remediations

	ERROR IDENTIFIED	REMEDIATION OF ERROR
	Car hit pole provision	
	• We unintentionally omitted our forecast repex to replace poles damaged by third parties (e.g. vehicle damage), also known as 'car hit pole' expenditure.	• Included a forecast of $23.4m for 'car hit pole' that is reasonably required over the 2025-30 RCP, in line with historic expenditure.
	Underground cables	
	• Expenditure proposed for REP001 did not correctly aggregate the appropriate components of the risk cost model expenditure forecast for non-CBD cables and the expenditure forecast proposed in the CBD reliability business case	• Updated modelling approach to clearly split CBD and non CBD cables forecasts.

4 The context to the identified need for investment

4.1 Out-turn service performance trends continue to indicate underlying concerns

In forecasting repex, we use observed actual asset failure rates and performance in order to calibrate our modelling and identify any jurisdictional reliability service standard targets that are unlikely to be met.

Reliability service performance

The Draft Decision referenced the AER's view that reliability service performance was not deteriorating and had been improving over the long term. We disagree with this view on the basis that:

- while it is true that SAIDI and SAIFI levels are currently lower than they were during one of the worst performing periods (2005-2010), there is evidence of a worsening trend;
- with the benefit of an additional year (2023/24) of actual performance data relative to what we showed in our Regulatory Proposal, we observe a trend of deteriorating reliability (both SAIDI and SAIFI) over a long term period from 2014/15, which is most pronounced in the period since 2019/20;
- these observed actual trends in SAIDI and SAIFI are masking the underlying concern that we consider is posed by asset condition, on the basis that we have been undertaking a widespread roll-out of Distribution Feeder Automation (DFA, or automation) which has masked the apparent concern by significantly reducing the number of customers interrupted when a fault occurs Figure 2 and Figure 3 therefore show what SAIDI and SAIFI trends would have been without DFA; and
- while DFA will remain a suitable investment option in some meshed parts of our network (particularly the CBD as set out in our separate business case addendum), these upgrades have reached a point of diminishing returns and are unlikely to provide the same reliability benefit in 2025-30 as we have achieved in 2020-25; and
- our revised forecast now uses the most recent 5-years (19/20 to 23/24) of observed actual performance to calibrate our models and forecasts.

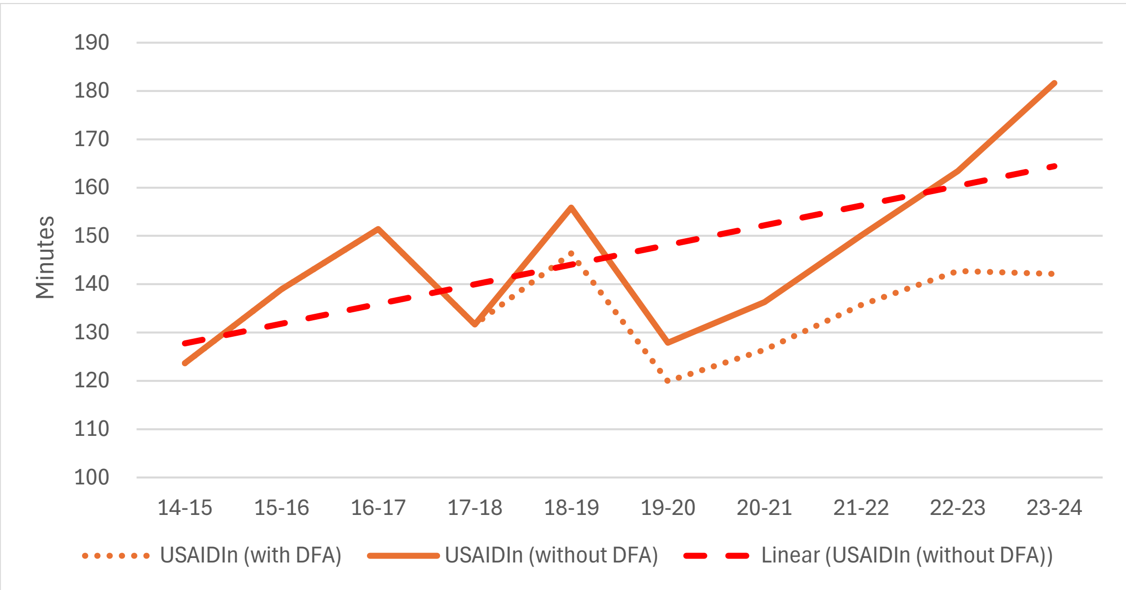

Figure 2 – Distribution Network USAIDI with & without DFA (excluding MEDs)

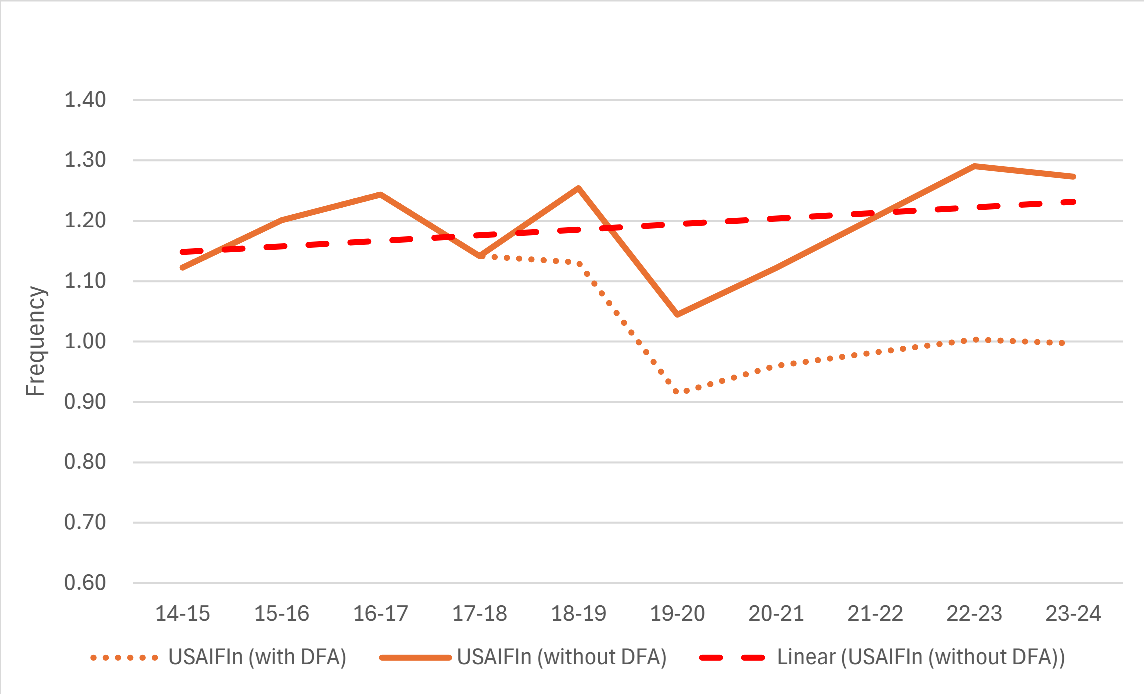

Figure 3 – Distribution Network USAIFI with & without DFA

Safety performance

While the Draft Decision appeared to focus predominantly on reliability trends, the need for appropriate levels of repex is also driven by the need to maintain safety performance, that is, to not see an increase in safety risks to customers and the community arising from network asset failures. Again, with the benefit of an additional observed actual performance data relative to our Regulatory Proposal we have observed continuing trends of concern, including:

- **electric shocks** associated with our network continue to trend upwards with more shocks reported **to date** (October) in 2024 than in **full years** over the period 2018-2024 and are forecast[4] to exceed any year of reporting; and
- **fire starts** associated with our network are relatively flat driven by several 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). Further, the period since 2019/20 has seen weather conditions (dominantly La Nina) that are not conducive to fire starts.

[4] The forecast of shocks in 2024 presented is a simple annual pro-rata of the shocks recorded to date in 2024.

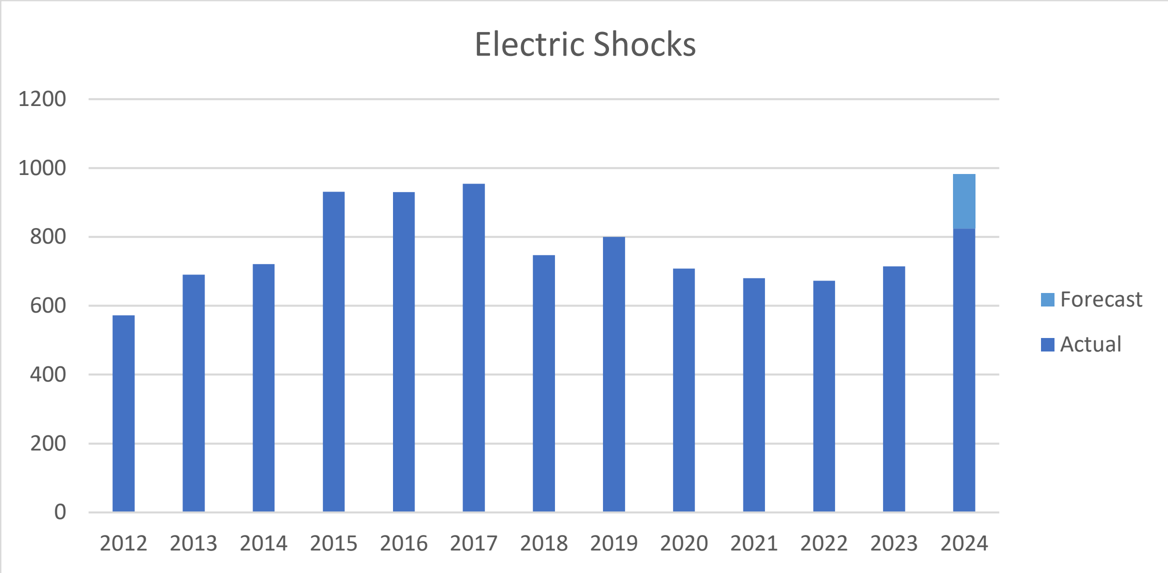

Figure 4 - Electric shock reports

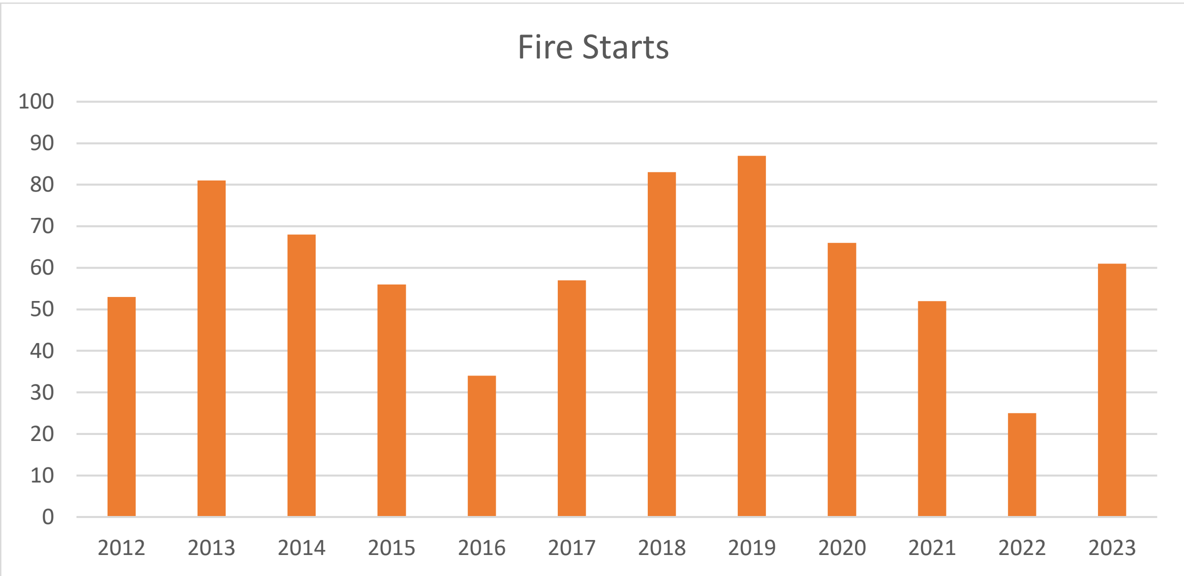

Figure 5 - Fire start reports

4.2 The identified need remains unchanged

The identified need for our forecast repex for 2025-30 remains unchanged from the original business case in our Regulatory Proposal. In summary:

- the risk that deteriorating asset condition is posing (via asset failures) to safety and reliability is manifesting more significantly now due to our unique network asset age profile – we have one of the oldest distribution networks in Australia as Figure 6 shows, with a large proportion of assets constructed in a confined period in the 1950s and 1960s as Figure 7 shows, and much of this network will reach end of life in coming decades;
- 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, as Figure 8. This Long term repex increase, combined with increasing augex on reliability and bushfire mitigation, has been crucial to keeping long-term service performance steady despite escalating risk;
- our modelling indicates that a significant proportion of our network assets are ageing to the point of significant deterioration of condition, triggering consideration of the need to retire assets – to avoid rising asset failures that would pose risk to the maintenance of service performance (reliability and safety) to customers through service outages, direct physical harm to persons, and physical harm to property and building damage to customers and the community (including from fire starts);
- as a response to this driver, and informed by the service outcome preferences of our customers, and our regulatory requirements under the National Electricity Rules (NER) and National Electricity Law (NEL) and jurisdictional regulations, the total sum of our repex seeks to:
    a. respond to customers' concerns[5], identified through our consumer and stakeholder engagement process and which have remained unchanged, 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. comply with applicable regulatory obligations / requirements[6], 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;[7]
    c. outside of the Adelaide CBD, to maintain the reliability service performance of our network[8] – we have been guided by consumers as to how reliability should be maintained, in this case, by geographic region.

[5] 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.

[6] 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 (SCS).

[7] 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.

[8] 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 SCS, the required expenditure is limited to expenditure to enable the distributor to maintain the reliability of standard control services.

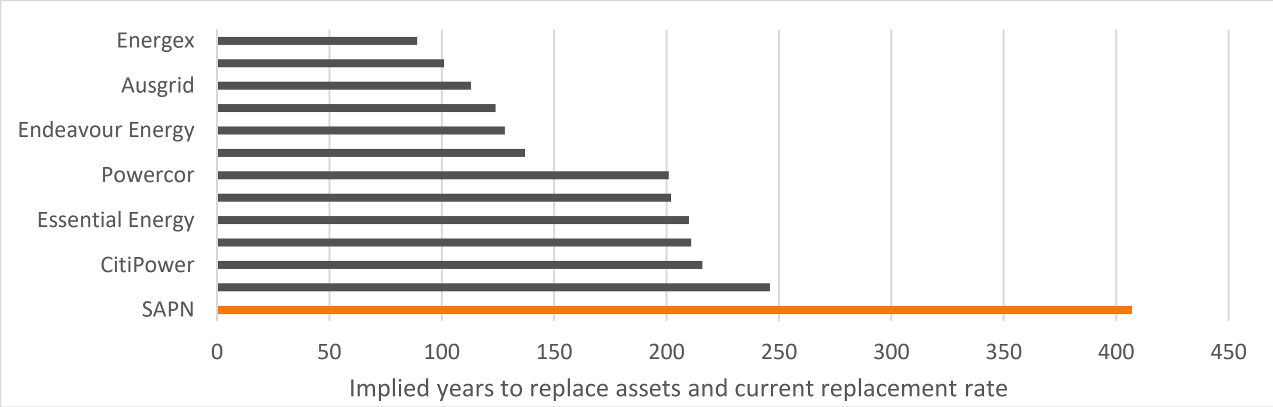

Figure 6 - Implied asset lives

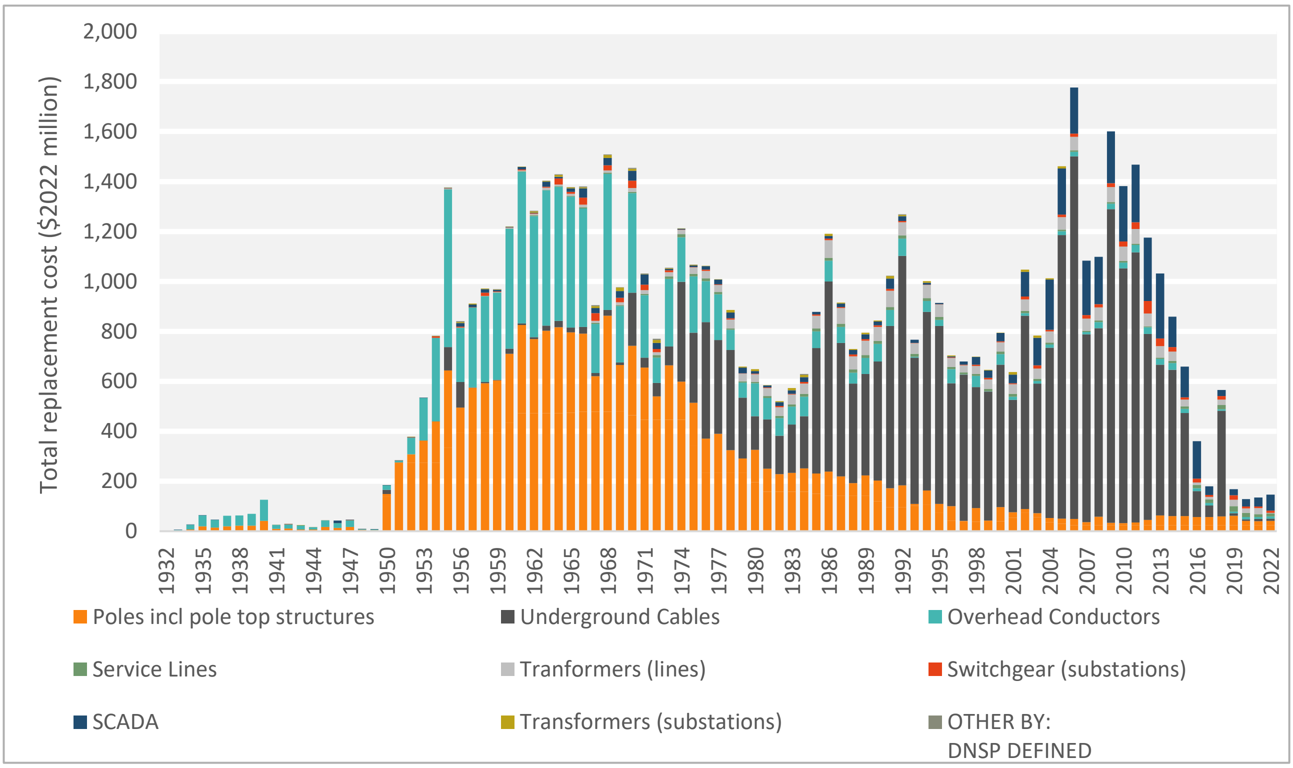

Figure 7 - SAPN Asset age profile

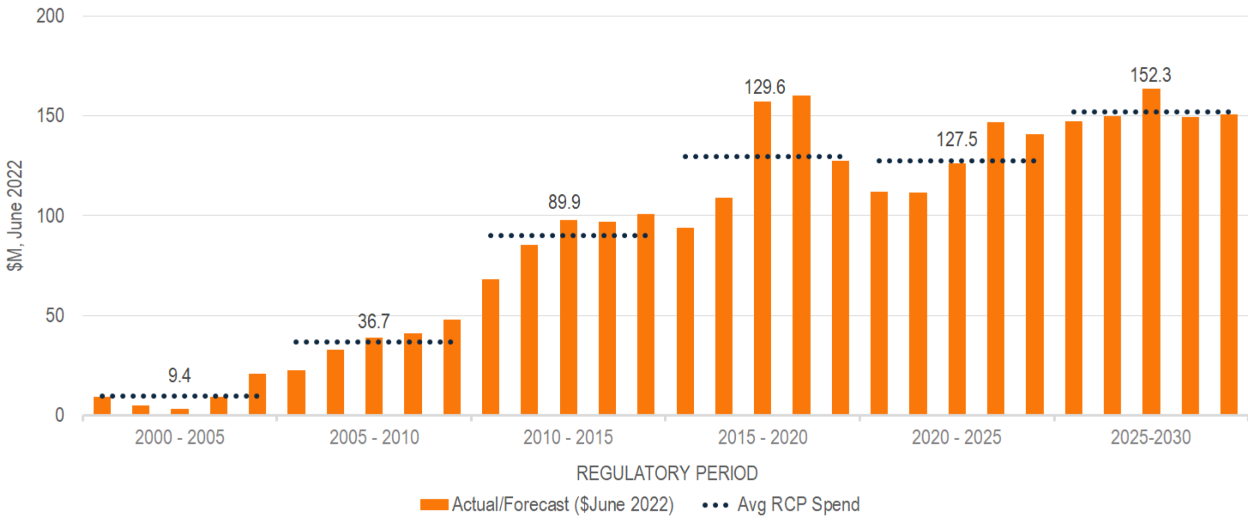

Figure 8 Long-term repex profile ($2022)

5 Revised proposal

5.1 Overview of our forecasting method

The overall method by which we forecast repex has not changed since our Regulatory Proposal, and was detailed in our original business case[9] and as summarised in Figure 9[10] below, this involved a combination of:

- detailed bottom-up modelling; and
- top-down trend analysis for some asset classes where condition information is difficult to obtain.

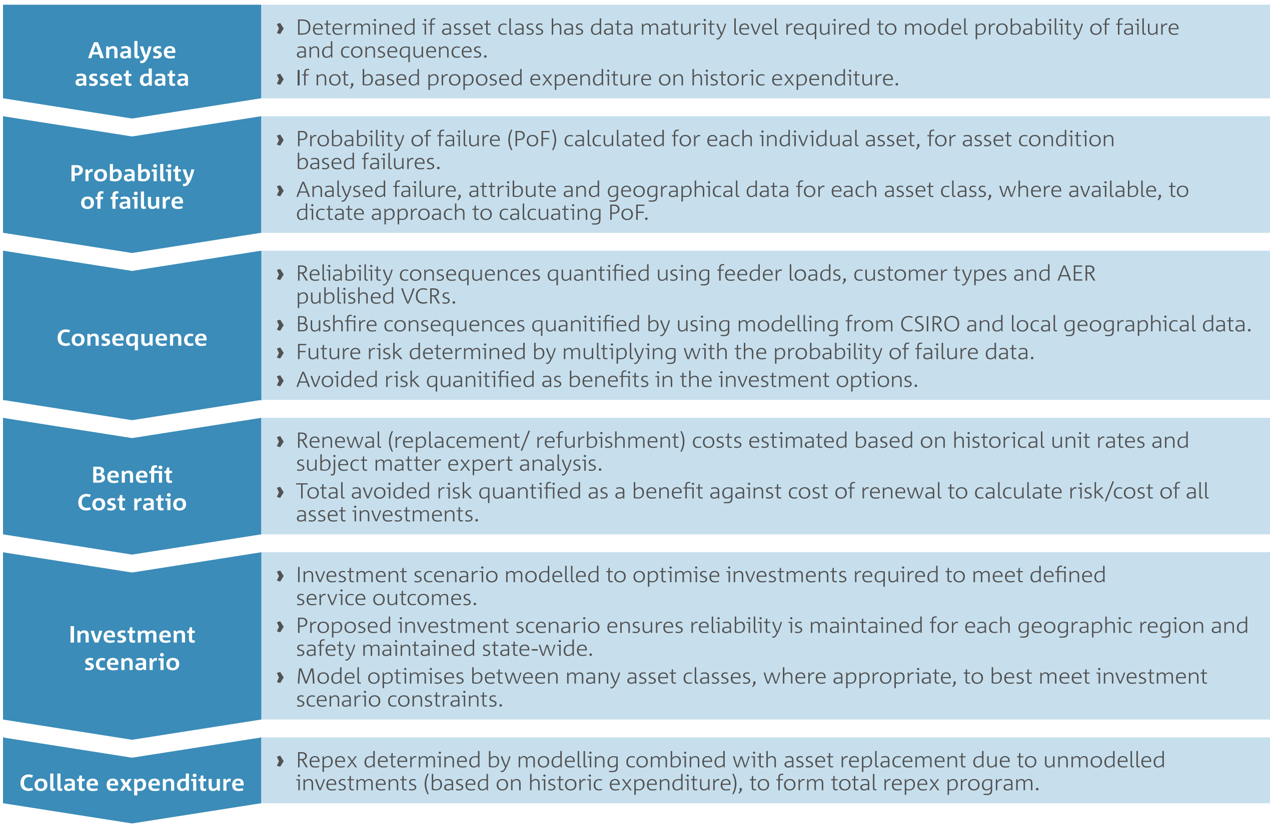

Figure 9 - Repex forecasting methodology

5.2 Investment options considered in our original business case remain relevant

In our original business case, we developed a set of counterfactual scenarios for assets modelled via our risk cost model, to quantify the monetised effect of alternative investment options (differing levels of repex) in terms of reliability and safety outcomes to customers.[11] These counterfactuals were designed via our engagement so that customers could make informed preference decisions on service outcomes, and served to indicate to the AER the relative efficiency of our repex forecast and its alignment to customer preferences.

We have not identified any new information to suggest that these counterfactuals are no longer relevant for assessing the prudency efficiency of our Revised Proposal. Therefore, the investment scenarios / options that we have compared in this addendum remain the same in structure. These are as follows:

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9 Section 6 of our original business case outlines the forecasting approach used for each asset category of repex. SAPN, *5.3.1 business case: network asset replacement expenditure - 2025-30 Regulatory Proposal*, January 2024, pp.25-30.

10 SAPN, *Attachment 5 – capital expenditure: 2025-30 Regulatory Proposal, January 2024*, p.30;

11 There were other scenarios that were explored during our engagement, that were no longer retained in our original business case as they did not meet the needs of our customers (e.g. we originally considered a scenario that maintained reliability in aggregate but which did not maintain reliability by region, which our customers did not prefer).

- **scenario 1: the base case counterfactual** – whereby we maintain to our current level of repex, with both reliability deteriorating and safety risk increasing as a result (including bushfire risk);
- **scenario 2: our Revised Proposal** – whereby we maintain reliability by geographic region, maintain safety in aggregate. The forecast repex maintains fire start risk at current levels (with our augex bushfire risk mitigation program, already approved in the Draft Decision, delivering a net reduction in fire start risk in targeted locations where it is efficient). This scenario is also economically efficient with benefits greater than costs in NPV terms); and
- **Scenario 3: economic replacements only** - includes repex 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 includes 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.

5.3 Our revised repex forecast is evidenced to be in customers' interests

This addendum recommends $784.7m in forecast repex, as the prudent and efficient level of repex to meet the identified customer service need over the 2025-30 RCP. In recommending this level of expenditure, we sought to ensure that we had regard to multiple indicators and sources of information to satisfy ourselves that this expenditure forecast is indeed in customers interests, as detailed in the section below.

5.3.1 The revised forecast achieves a target service outcome aligned to customer preferences

As demonstrated by the analysis outlined below, our repex forecast (i.e. scenario 2) is the only investment scenario / option that achieves the service outcomes preferences recommended by our customers and which remain unchanged throughout our engagement. Our Revised Proposal for scenario 2, maintains reliability by geographic region and maintains safety in aggregate as recommended by our customers. This is preferred to other scenarios / options considered which in contrast:

- scenario 1 ($629m) will not maintain reliability nor safety, inconsistent with our customers preferences that service not be degraded; and
- scenario 3 ($826.7m) will not maintain reliability by geographic region and lead to more regional inequity in service and higher expenditure, inconsistent with our customers preferences to not see further regional service degradation and to minimise expenditure given affordability pressures.

5.3.2 The revised forecast achieves a target of maintaining customer service outcomes in monetary terms

Our risk cost modelling allows us to quantify in monetary terms the impacts on customers arising from the risk of asset failures (i.e. the cost of outages, the cost of damage to property and buildings and physical harm to individuals including from bushfire starts).

Applying this modelling, we can evidence that our revised repex forecast (scenario 2) will, and in contrast to the counterfactuals considered, maintain customer service outcomes in the 2025-30 to their current levels. Put another way, this evidence indicates that not allowing our revised repex forecast, would impose higher costs to customers in terms of service outcomes relative to the performance they currently experience.

5.3.3 The revised forecast maintains customer service levels on outage duration and frequency

As outlined earlier, a key concern identified in the Draft Decision was its inability to see a clear link between the repex we had forecast and our target service level outcomes in terms of SAIDI and SAIFI metrics. This affected the AER's ability to verify our claim that our repex forecast would only maintain service levels, rather than improve these levels.[12]

We recognise that our original business case, while demonstrating that service outcomes would be maintained in economic / monetary terms, did not evidence a service level outcome. Therefore, to address this concern, we updated our modelling to also calculate the SAIDI and SAIFI outcomes of our revised repex forecast and the counterfactuals we have assessed in this addendum. This analysis, as displayed in Figure 10 and Figure 11 below, evidences our assertion, that our revised repex forecast will in fact maintain service levels in both SAIDI and SAIFI metrics, consistent with current / historic performance.[13]

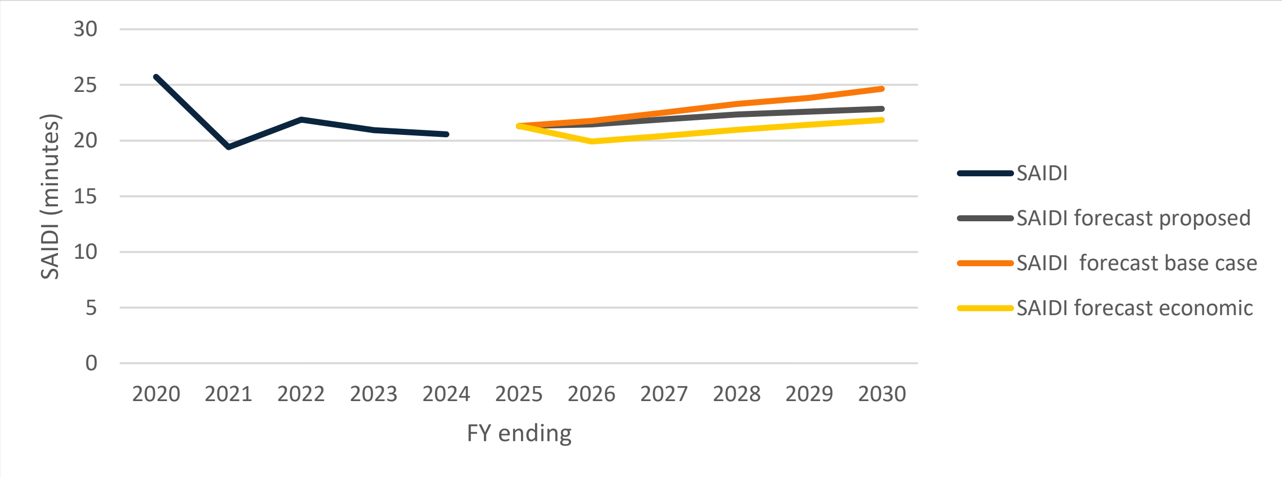


Figure 10 – Impacts on SAIDI outcomes

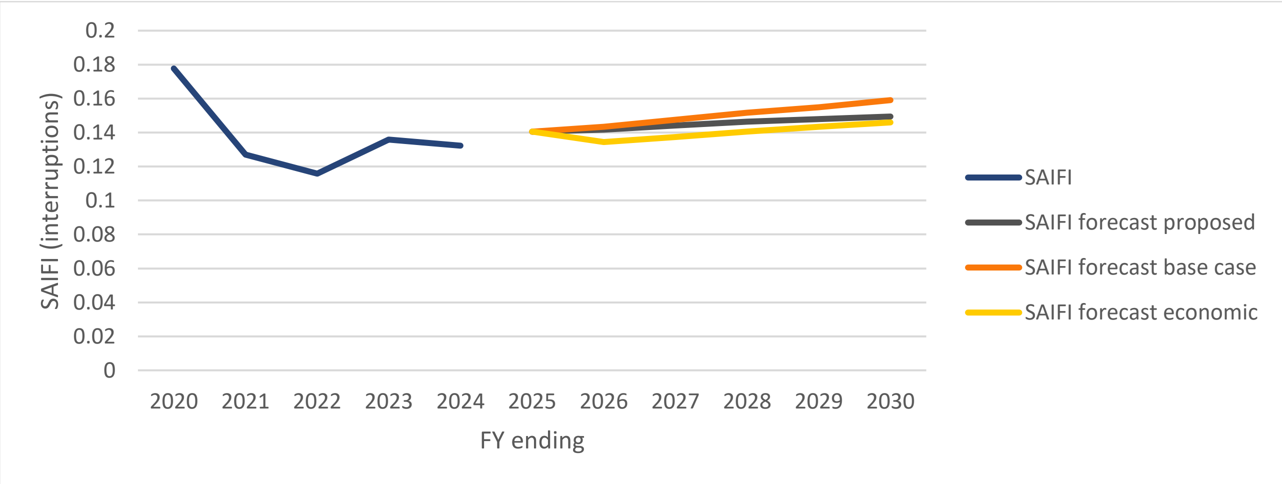


Figure 11 – Impacts on SAIFI outcomes

12 The AER contended that SA Power Networks had assumed a linear relationship between reliability risk and SAIDI without empirical support.

13 This analysis considers modelled asset failures, and does not include the SAIDI and SAIFI of repex for the CBD reliability program (actual or forecast), as reliability performance of the CBD is addressed via a separate business case addendum (5.3.12 - CBD Reliability - Business case addendum).

5.3.4 The revised forecast to achieve the target service outcomes is economically efficient for customers

Finally, our modelling also shows that the revised repex we have forecast in order to achieve the target service outcomes aligned to our customers' preferences, is evidenced as being efficient, with key indicators evidencing that our forecast:

- will result in customer benefits that are greater than the costs of repex, with a calculated NPV of **$147 million over a 20-year period**;[14] and
- is lower cost than the top-down comparator of the AER's own repex model, for applicable asset classes, as displayed in Figure 12 – this is also true at the asset category level, except for cables, where failure to meet reliability service standards in the CBD has resulted in the need to increase expenditure in this asset class as a compliance need (considered in our separate business case addendum).

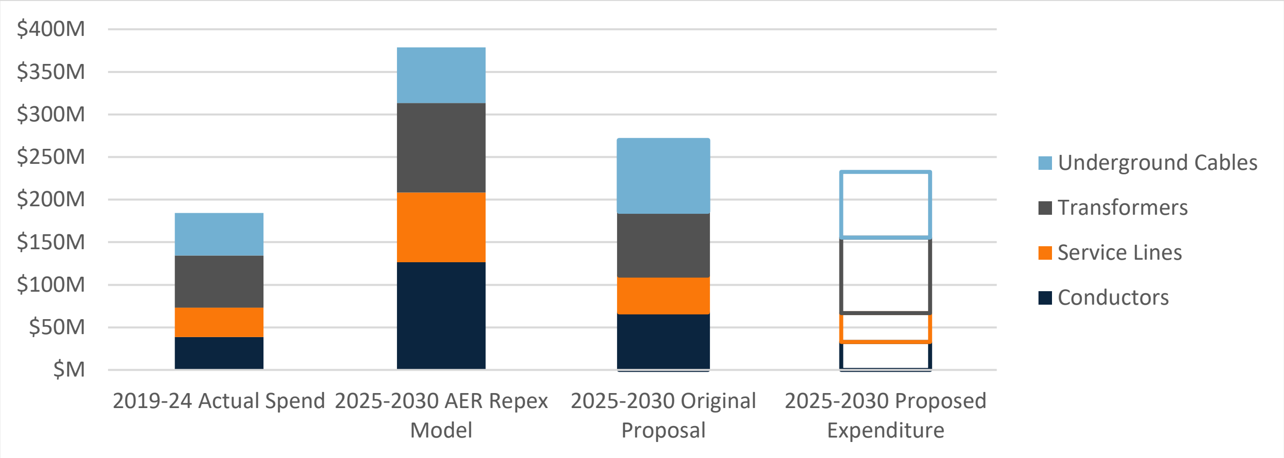


Figure 12 - Comparison of expenditures with AER's repex model

[14] 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.

5.4 The revisions to our risk cost modelling address AER concerns and are reasonably based

5.4.1 Calculation of the baseline service level in the model

The Draft Decision outlined a concern, based on its interpretation that we had used a single year (2021–22) to set the baseline service level that our forecast seeks to maintain (i.e. the target service level). The AER recommended that a 3 to 5 year average would mitigate the risk of under or over-estimating the underlying performance and align to the AER's approach to setting targets reflecting expected performance, namely with respect to the STPIS.[15]

We disagree with the concern but acknowledge that our original business case may have caused the AER to misinterpret our approach. For the avoidance of doubt, we outline that our revised repex forecast uses a baseline service level that is based on 5 years of performance, and that this is consistent with the AER's expectation, noting that:

- the risk modelling that we used to forecast repex has been calibrated using actual historic performance data **up to** the year 2023-24. This means that the first year of our modelling and target service level was not based on a single year but in fact based on a service level calibrated using historical observed performance over the period 2019-20 to 2023-24 which mitigates the risk of under or over estimating service needs due to annual performance variations; and
- for our Revised Proposal, we have applied a consistent 5 year period of performance data (2019/20-2023/24) to recalibrate our model – this 5 year period aligns consistently with the same measurement period that is used to determine the STPIS targets for the 2025-30 RCP, aligns to the AER's intent, and aligns regulatory network performance measures with our forecast modeling for the 2025-30 RCP.

5.4.2 Outage duration

The Draft decision outlined concerns that several of our assumptions on outage duration overstate risk, including by using a 12 year average of outage data, the lack of consideration of network characteristics (in addition to voltage), and the potential that large weather events may have skewed outage duration data adjacent to these events.[16]

We agree with the concerns identified by the AER, with the exception of the effect of weather events, and have revised our modelling accordingly, as follows:

- while the modelling in our original business case used an average outage duration based on observed durations differentiated by voltage of the asset failure, we have now also had regard to network type (e.g. urban, rural long, rural short, or CBD) as we agree that this more sophisticated approach produces a more robust basis for estimating the reliability risk of an asset failure by better identifying the potential reliability impact of asset failures that can be avoided through proactive repex; and
- applying this change together with a revision to the data averaging period from our original 12 year average to an average of the most recent five years of historical outage data, we have estimated the median restoration times following an asset failure based on both voltage and network type as outlined in Table 3 below. These revised median restoration times have been incorporated into our risk modelling used to derive our revised repex forecast

[15] AER, Draft Decision, *SA Power Networks Electricity Distribution Determination 2025 to 2030: Attachment 5 Capital Expenditure*, September 2024, p.19.

[16] AER, Draft Decision, *SA Power Networks Electricity Distribution Determination 2025 to 2030: Attachment 5 Capital Expenditure*, September 2024, pp.19-20.

	Duration (Original Proposal)	Durations (Revised Proposal)			
SCONRRR Category	State-wide	CBD	Rural Long	Rural Short	Urban
Cable; <=1kV	290	324	280	210	261
Cable; >11kV & <=22kV	609	N/A	143	143	N/A
Cable; >1kV & <=11kV	297	99	155	209	137
Cable; >22kV & <= 33kV	499	90	342	122	184
Conductor; <=1kV	233	160	234	193	160
Conductor; >11kV & <=22kV	344	N/A	287	184	312
Conductor; >1kV & <=11kV	235	124	169	138	124
Conductor; >22kV & <=66kV	390	N/A	153	145	173
Distribution Transformer; Kiosk Mounted	406	41	851	636	273
Distribution Transformer; Pole Mounted	358	51	232	207	217
Recloser	252	N/A	259	210	309
Sectionaliser	132	71	71	71	71
Service Line	229	129	233	187	187
Switching Cubicle	183	198	125	286	198
Pole; <=1kV	348	96	179	103	96
Pole; >11kV & <=22kV	441	422	422	422	422
Pole; >1kV & <=11kV	351	310	199	223	310
Pole; >22kV & <=66kV	461	360	576	360	360

Table 3 – Comparison of duration parameters between original and revised proposals

However, we disagree that the weather events noted by the AER will have any material effect on our risk cost modelling, and therefore we have not adjusted our modelling on this basis. This is noting that:

- analysis of duration figures calibrated by removing data from outages the day following an MED, in addition to outages from the MED itself showed no significant systematic variance, as per Appendix A; and
- two Identical model runs using each version of duration inputs, gave expenditure output with no significant variance.
  - Proposed expenditure: **$784.7m**
  - Expenditure with day following MED removed from duration parameters: **$785.2m**

5.4.3 Likelihood of consequence

The Draft Decision identified a concern with our assumption that cables within the CBD would have a 100% chance of causing an outage was overstating risk and that actual data for the CBD suggested 64% was reasonable when considering both 11kV and 33kV cables.[17]

We agree with the concern, and have updated our modelling to make use of the most recent five years of historical data to update our likelihood of consequence estimates as follows:

[17] AER, Draft Decision, *SA Power Networks Electricity Distribution Determination 2025 to 2030: Attachment 5 Capital Expenditure*, September 2024, p.21.

- we have had regard to most recently available data for all assets, covering the period 2019-20 to 2023-24 – using both observed failures and observed consequences including outages and fire starts;
- we consider that a 5 year average used to derive the estimates is appropriate on the basis that it reflects a consistent approach to the use of actual data over a period that is long enough to reflect current performance but not too long that it may cause the concerns identified above that the AER had with longer term observations that may not capture recent network practices; and
- having regard to this actual data set, we have revised our original 11kV cable 100% assumption down to 98% outside the CBD. For the CBD, we have recalibrated our probability of failure (PoF) for cables based solely on failures that led to an outage in our historical STPIS performance data thereby embedding the likelihood of consequence (i.e outages) within a lower PoF assigned to the cables.

5.4.4 Probability of failure assumptions

The Draft Decision identified a concern that our probability of failure estimates were overstated and misaligned to actual observed failures in recent years.

We agree with the concern and have revised our approach by having corrected a systemic error that we identified in how our actual failure data was being reported, as follows:

- in the course of answering the AER's Information Requests, we identified a systemic error in our asset failure data resulting from a new data capture tool that we introduced in 2020/21 – these data issues were not apparent when we commenced the process of our repex risk cost modelling circa 2021;
- following a thorough investigation, we are now clear of the causes of the issues and are developing solutions to fix the issues in our systems – there were two main issues that were impacting the historical failure data stored in our systems and reported in the AER's RINs, and were resulting in asset failures being attributed to either the wrong asset class or the wrong voltage within an asset class;
- the systemic error only applied to powerline assets and did not affect data relating to zone substation or secondary systems assets;
- we have corrected the historical failure data for 2019/20 to 2022/23 and audited this corrected data via the RIN process - our Category Analysis RIN (2.2 Repex) failure data for year 2019/20 through 2022/23 has been recast and audited for the 2023/24 RIN submission. A detailed report outlining the cause of the errors, and the amendments has been provided to the AER as part of the October 2024 RIN submission; and
- finally, we have also recalibrated our probability of failure models to reflect the corrected data:
    - Figure 13 and Figure 14 illustrate the incorrect attribution of LV and HV conductors in our original data along with the corrected data that we have now used to recalibrate our models for the revised repex forecast; and
    - Figure 15 demonstrates, for the probability of failure of conductors, that this recalibration now better reflects our real world observations and eliminates any upward basis from our forecasts, that were the source of the AER's concern.

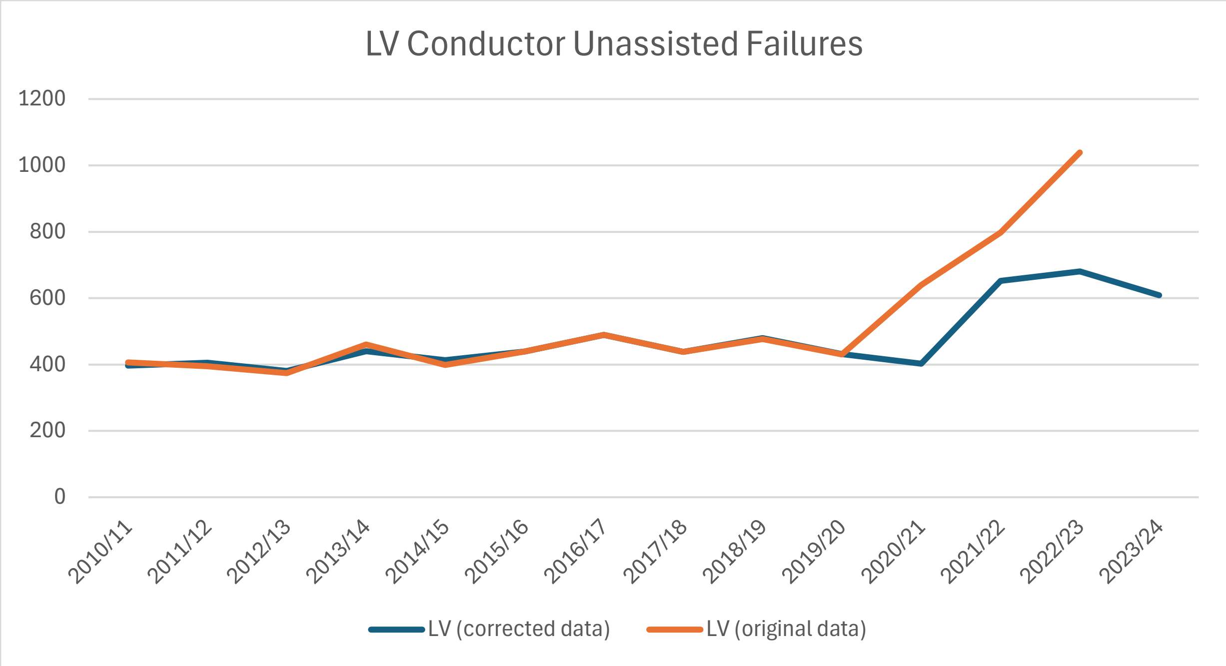


Figure 13 - Unassisted LV conductor failure data showing data error

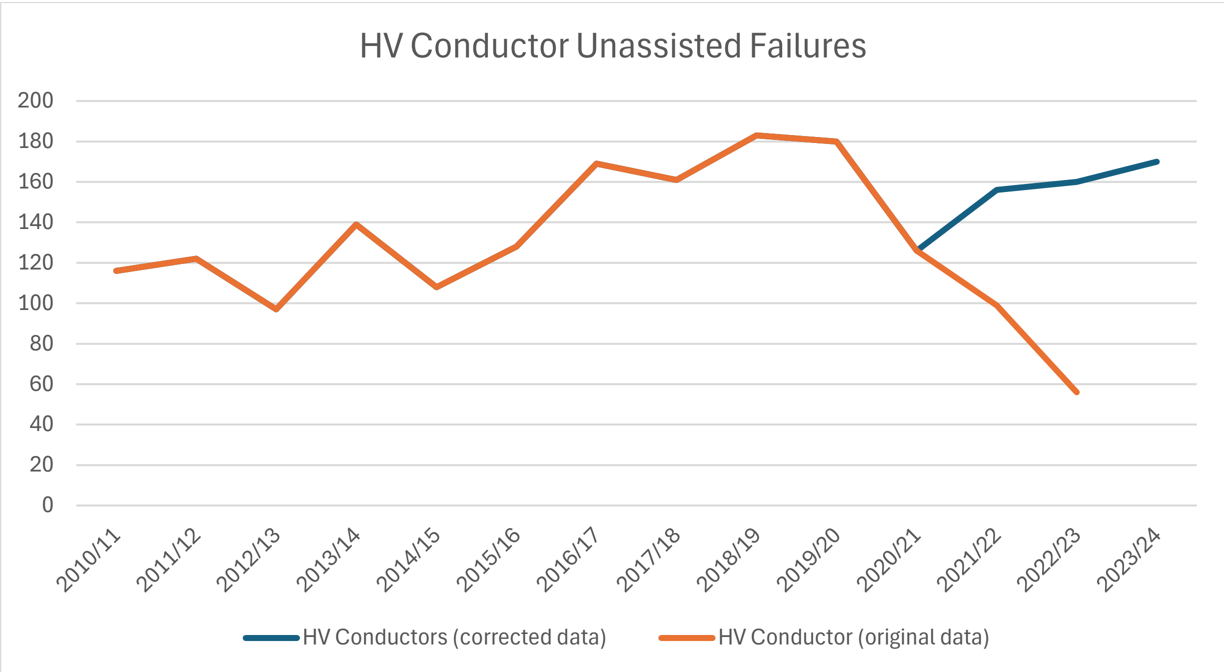


Figure 14 – Unassisted HV conductor failure data showing data error

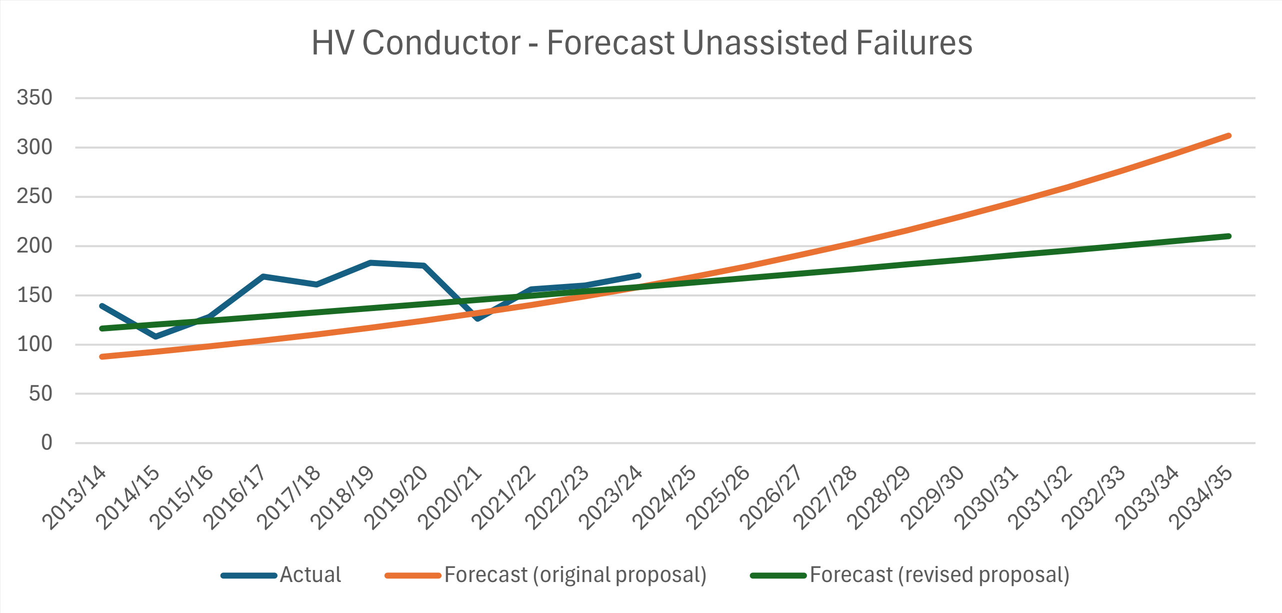


Figure 15 - Revised Probability of Failure model for Conductors

5.5 Other issues

The Draft Decision applied a substitute forecast to several unmodelled repex programs, alongside substitute forecasts to modelled programs within underground cable and distribution transformer asset classes (REP001, REP013, REP016, REP017, REP050). The original proposal's forecast for these unmodelled programs were based on historical expenditure, and the substitute forecasts are significantly below these historical levels.

We have reviewed the AER's substitute forecast and potential impact on delivering service outcomes and consider that the reduction is not practical. Given these lines are not modelled, it is expected that the same level of expenditure will be required to maintain current performance, and have therefore maintained our position on the need for this expenditure.

In addition, we identified two errors in our original business case and repex forecast.

1. we identified an error in our original business case and repex forecast, whereby we had omitted our forecast repex to replace poles damaged by third parties (e.g. vehicle damage), also known as 'car hit pole' expenditure. Our revised repex forecast therefore now corrects for this error by including a forecast of **$23.4m** for 'car hit pole' that is reasonably required over the 2025-30 RCP, noting that:
    - this is an ongoing driver of expenditure for SA Power Networks; and
    - the forecast is based on historic expenditure over the last five years, which we consider to serve as a reasonable basis for forecasting expenditure over the 2025-30 RCP, as this level of expenditure reflects more recent driving practices and there is no indications that incidents of 'car hit pole' are likely to decline in coming years.
2. through the AER Information Request process on our original proposal, an error was found in our proposed underground cable replacement expenditure. The expenditure proposed for REP001 did not correctly aggregate the appropriate components of the risk cost model expenditure forecast for non-CBD cables and the expenditure forecast proposed in the CBD reliability business case. This resulted in an omission of approximately **$13m** of forecast expenditure. This is issue has now been corrected. Further, the approach used for modelling both CBD and non CBD underground cables has been updated to allow clear distinction between the expenditure required to meet service outcomes as reflected in both this document and '5.3.12 - CBD Reliability - Business case addendum '.

5.6 We actively explored practices to lower the costs of the challenge that repex responds to

In examining the magnitude of the identified need for network repex in coming years, and in seeing that this will be a challenge that will span multiple RCPs, we have sought to ensure that

1. we were forecasting repex to achieve a target service level aligned to customer preferences and which is efficient;
2. our forecasting methods were reasonable, having applied multiple tiers of internal and external challenge, and engaging both external technical consultants as well as inviting AER scrutiny including via the Early Signal Pathway and post-lodgement engagement with the AER and its external engineering consultants, EMCA; and
3. we also explored means of mitigating the cost of the challenge that repex responds to, as follows:
    a. **reducing the cost of repex** - the key initiative we identified recognised that there were improvements that we could make to our asset management and work delivery practices which could serve to reduce the costs of repex – therefore, our Regulatory Proposal included a program (approved in the Draft Decision) 'Assets and Works Phase 3', that will drive material reductions in costs that we have preemptively included in our overall forecast capex for 2025-30; and

    b. **non-network alternatives** - we have also explored the potential for alternatives to repex, principally in the form of Stand Alone Power Systems (SAPS). In partnership with ITP renewables in 2021 we undertook 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). However, the analysis showed that there were very few locations where SAPS were an economically viable alternative to maintaining an ongoing connection to the network. SAPS represent a viable solution in unique parts of the network (very long sections supplying a single customer) but this alternative does not represent a material impact on our forecast expenditure at this time. We intend to continue to look for non-network solutions to defer or avoid capex during the RCP, as evidenced by our community battery at Robe.[18]

[18] This large-scale battery will reduce demand on the sub-transmission line supplying robe and defer significant investment including in our original 2025-30 proposal (Augex Capacity) in upgrading the line to meet peak demand.

6 Modelled risk and expenditure by program

Applying the abovementioned revisions and responses to the concerns raised in the Draft Decision, this section now outlines the revised forecast repex and programs for each major asset class listed in Figure 16.

Note on data interpretation:

It should be noted in the sections below, for some areas of repex, that the forecast risk may appear to be slightly misaligned with historic service outcomes. This occurs for two key reasons:

1. Because the model optimises across all asset classes, it can be more efficient to allow risk in some classes to deteriorate, whereas in other classes it improves. Overall risk is maintained, and cost minimised, but the risk in individual asset classes shifts. This is desirable.
2. The expenditure forecasts seek to maintain the *modelled* risk and therefore some misalignment between historical observation and our model outputs can occur, but does not affect the integrity of the modelled outcomes.

The misalignments referred to in point 2 generally occur as a result of modelled risk *understating* actual risk, as a result of assumptions, for example, that feeder automation is 100% effective, reducing the impact of asset failures, whereas in the real world, this is not the case.

Nonetheless, we have provided historic observed outcomes of reliability and bushfire risk as comparators, to confirm reasonableness of the forecasts.

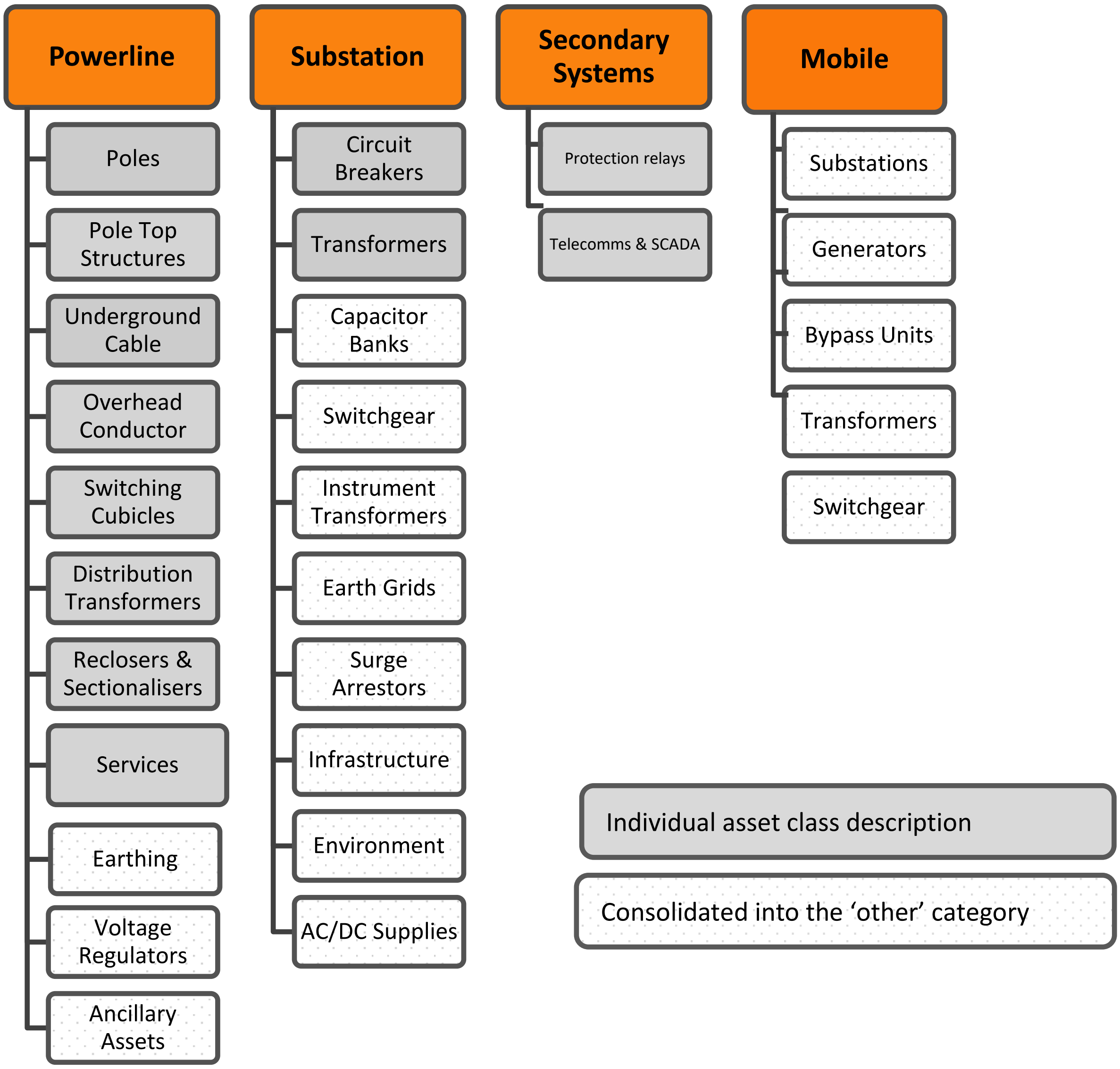


Figure 16 – Asset class overview

Table 4 – Summary of expenditures

Asset Class	Actual Expenditure (2019-24) $m ($2022)	Original Proposal Forecast (2025-30) $m ($2022)	AER Draft Decision (2025-30) $m ($2022)	Revised Proposal Forecast (2025-30) $m ($2022)	AER Repex Model $m ($2022)
Poles	$114.0	$134.9	$134.9	$152.8	-
Pole Top Structures	$130.9	$139.9	$139.9	$139.9	-
Underground Cables (non CBD)	$50.0	$28.8	$52.4	$46.5	$65.6
Underground Cables (CBD)		$55.0		$30.7	
Overhead Conductors	$38.6	$69.3	$37.3	$32.8	$126.6
Switching Cubicles	$16.2	$18.2	$16.2	$15.4	-
Distribution Transformers	$36.3	$46.0	$28.2	$58.9	$69.9[19]
Reclosers/Sectionalisers	$15.4	$20.6	$16.1	$19.5	-

19 Distribution and zone substation transformers are grouped within the AER repex model format.

Asset Class	Actual Expenditure (2019-24) $m ($2022)	Original Proposal Forecast (2025-30) $m ($2022)	AER Draft Decision (2025-30) $m ($2022)	Revised Proposal Forecast (2025-30) $m ($2022)	AER Repex Model $m ($2022)
Services	$34.6	$43.3	$33.4	$33.9	$81.6
Zone Substation Power Transformers	$24.9	$29.8	$24.6	$29.8	$35.2[19]
Zone Substation Circuit Breakers (Excl Hindley Street)	$66.7	$72.1	$60.4	$72.1	-
Zone Substation Circuit Breakers: Hindley Street	-	$27.9	$27.9	$27.9	-
Zone Substation Circuit Breakers: Northfield GIS Switchboard Replacement	-	$11.8	$11.8	$11.8	-
Protection Relays	$28.3	$28.8	$25.0	$28.8	-
Other unmodelled powerline assets	$6.6	$4.9	$4.9	$4.9	-
Other unmodelled zone substation assets	$31.9	$37.8	$37.8	$37.8	-
Telecommunication assets	$35.0	$31.8	$31.8	$31.8	-
Mobile Plant	-	$9.5	$9.5	$9.5	-
Repex Total		$810.4		$784.7	-

6.1 Poles

Pole asset performance (2019-2024)

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;
- pole corrosion and collapse resulting in potential third-party property damage; and
- impact on reliability due to outages associated with pole failures and unplanned pole replacements.

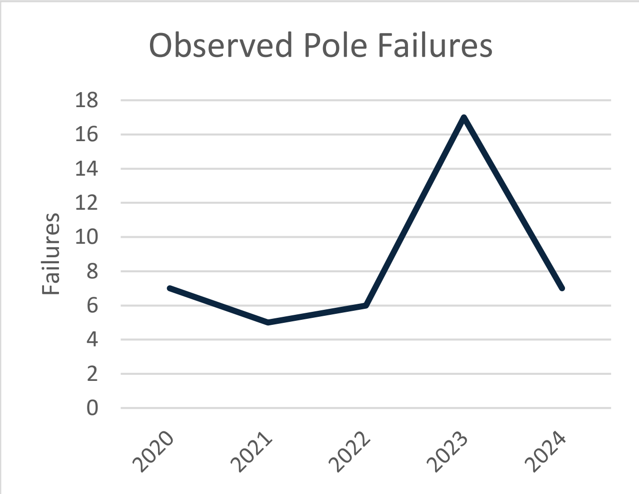


Figure 17 – Observed pole failures

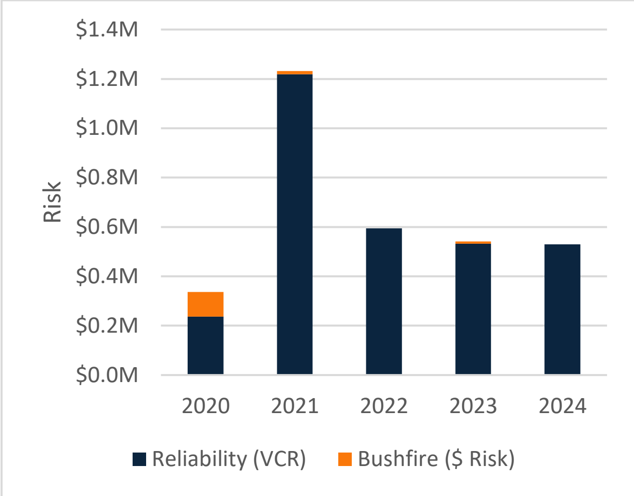


Figure 18 – Impact of pole failures on service outcomes

Figure 17 shows the annual number of asset failures for pole remains relatively stable at less than 0.01% of the population – with some variation year on year, and far lower than most other asset classes, reflecting our condition monitoring and proactive replacement program. Figure 18 shows that pole failures have had relatively little impact on service outcomes as compared to other asset classes e.g. overhead conductors & underground cables due to our proactive replacement program and higher replacement rate.

Pole replacement rate (2019-2024)

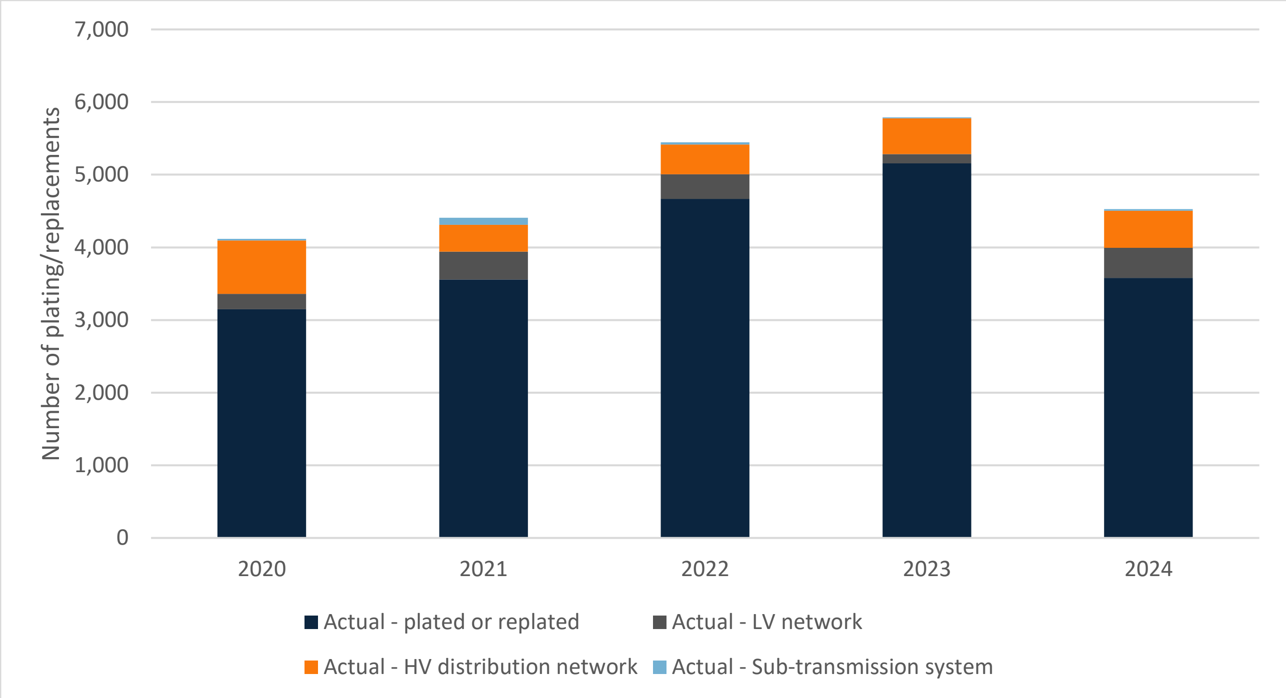


Figure 19 - Pole actual replacement rate

We have recently been replacing on average less than 1000 poles per year under our replacement program and deferred 3000-5000 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 20 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.

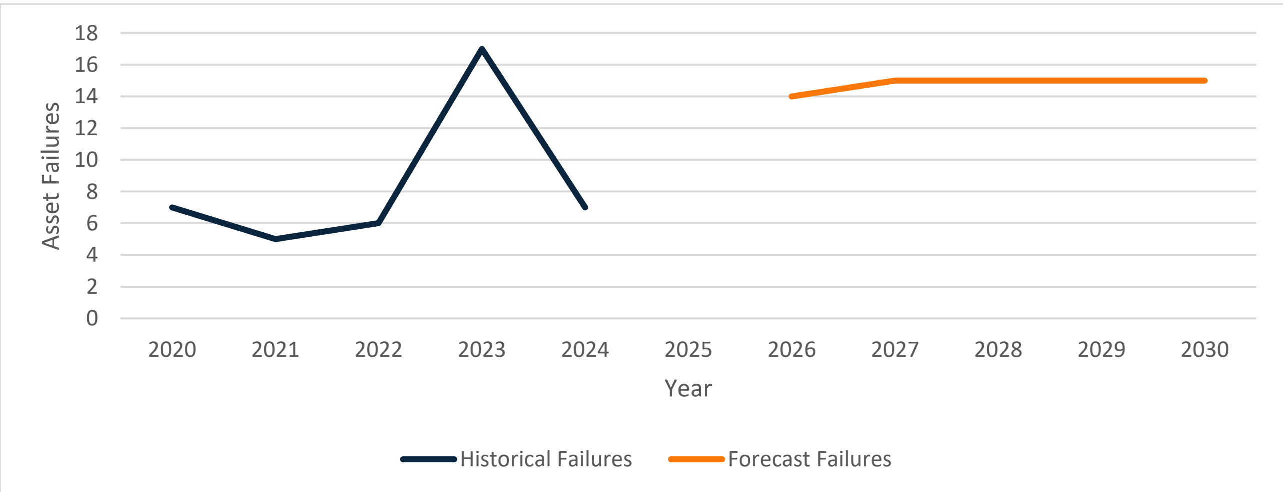


Figure 20 – Historic and forecast pole failures

Figure 21 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 result in a gradual deterioration in customer reliability and increase in safety risk (including bushfire risk) from our pole assets.

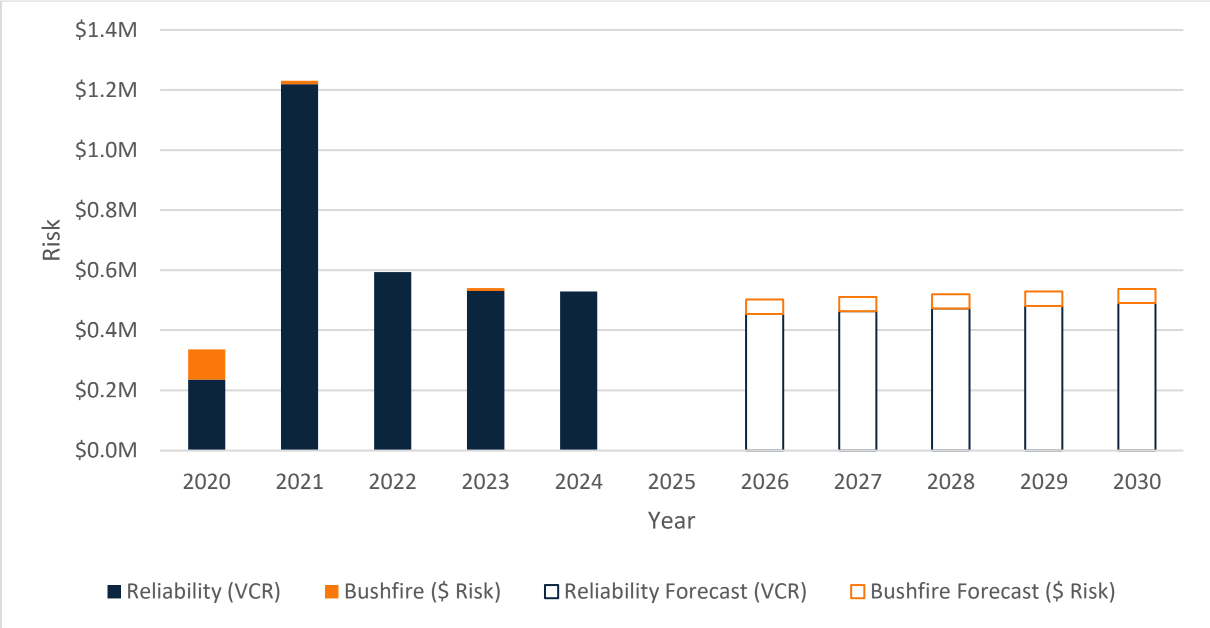


Figure 21 – Historic and forecast pole risk (base case)

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 (2025-2030)

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

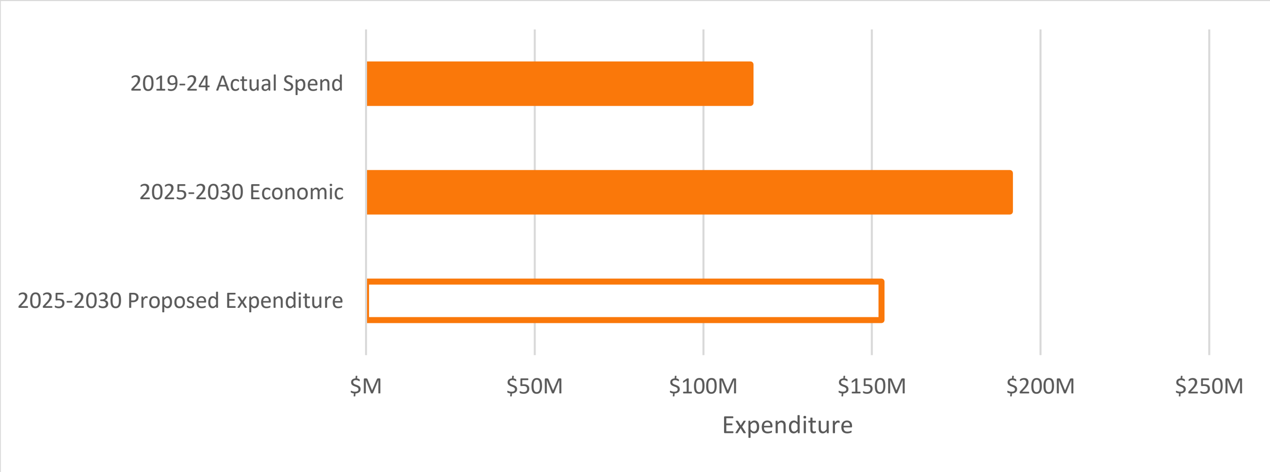


Figure 22 – Pole expenditure comparison

Pole forecast rate of renewal (2019-2030)

Figure 23 shows the historic renewal rate of poles. The proposed rate of renewal with an expenditure of $152 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 RCP.

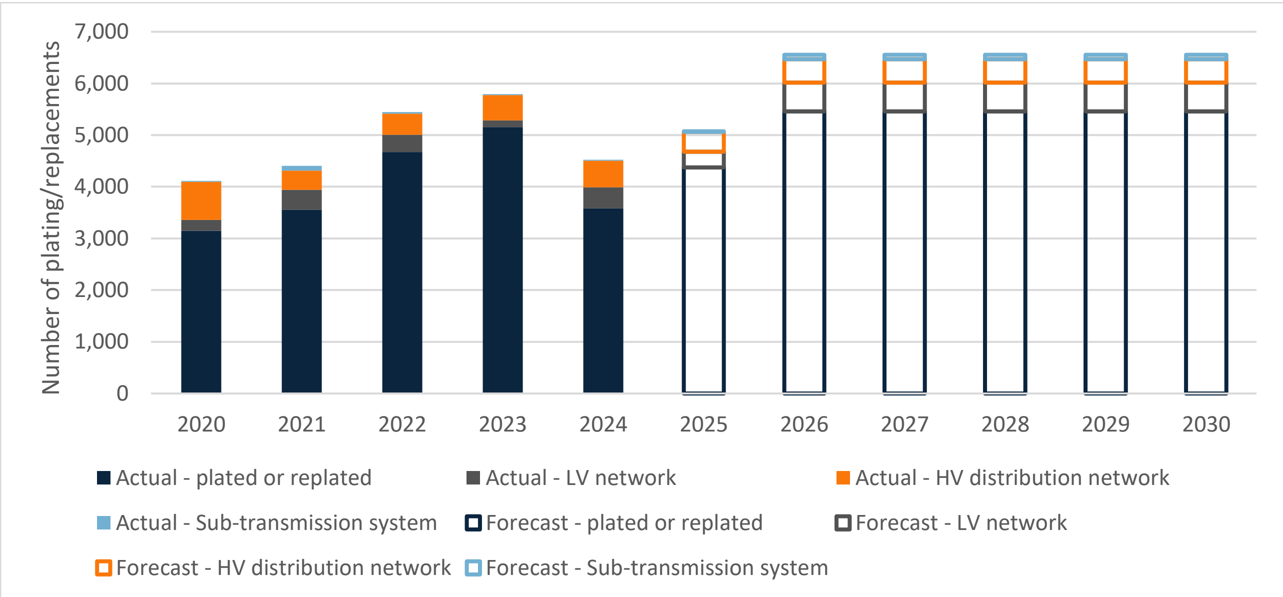


Figure 23 - Pole actual and forecast replacement rate

We compared our proposed pole replacement rates with those of other DNSPs to cross-check our forecasts.[20] 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 24.

20 This uses data from publicly available Category Regulatory Information Notices (RIN) reported over the period 2015-2016 to 2019-2020.

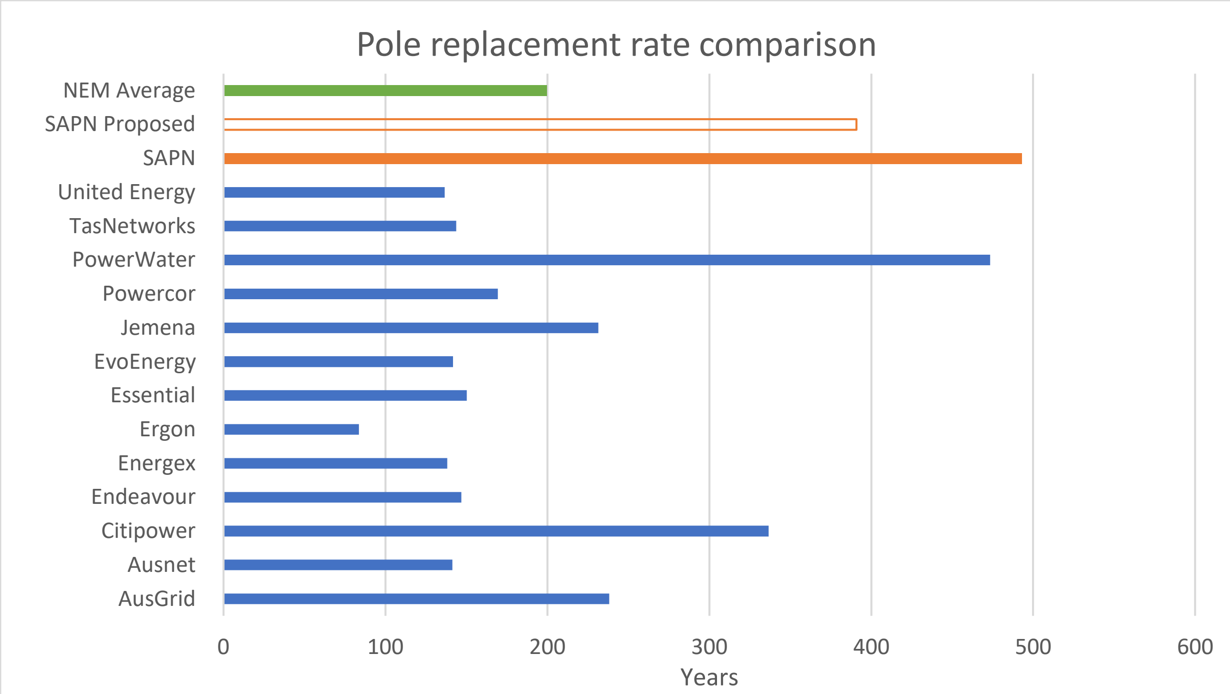


Figure 24 – DNSP pole replacement rate comparison

Pole forecast risk to service outcomes (proposed)

Figure 25 shows the observed performance impact from pole assets along with the forecast impact on service outcomes given our proposed investment. Our risk modelling shows that reliability and bushfire safety outcomes can be maintained, given the proposed expenditure.

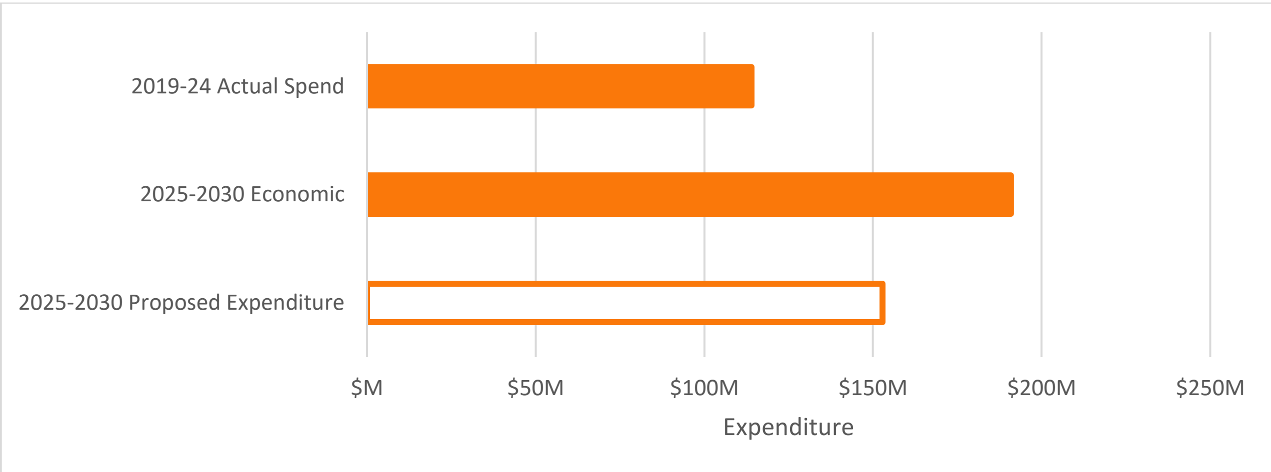


Figure 25 - Historic and forecast pole risk (proposed expenditure)

6.2 Pole top structures

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 (2019-2024)

We have recently been replacing an average of approximately 22,000 pole top structures each year as displayed in Figure 26.

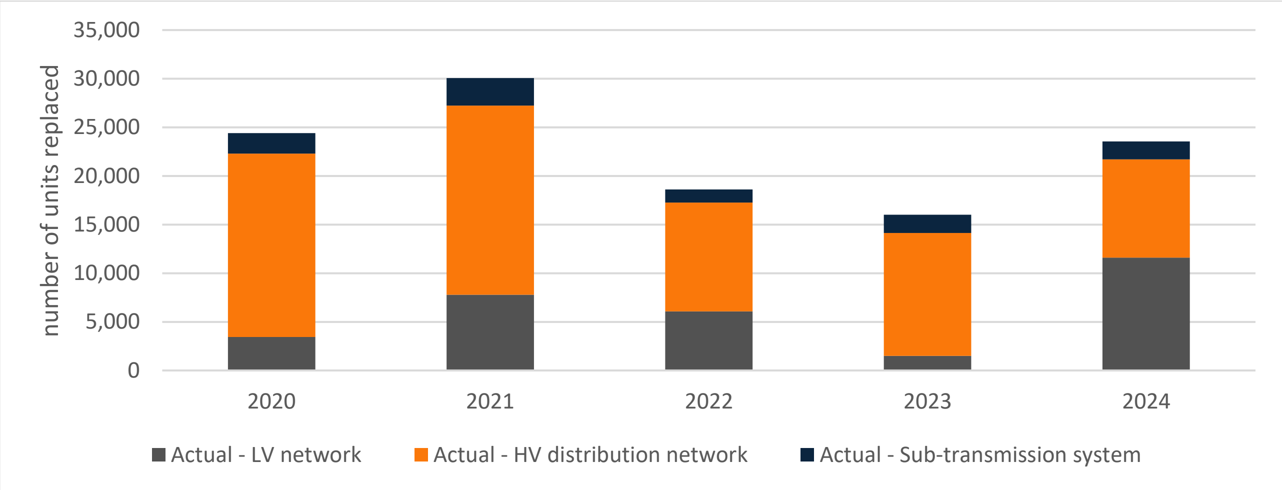


Figure 26 – Pole top structure actual replacement rate

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 (2025-2030)

We have used only one method to forecast expenditure for pole top structures, being historic expenditure. The proposed scenario for pole top structure expenditure includes a minor uplift in expenditure to address end of life disconnect fuse bases that pose a safety risk to personnel.

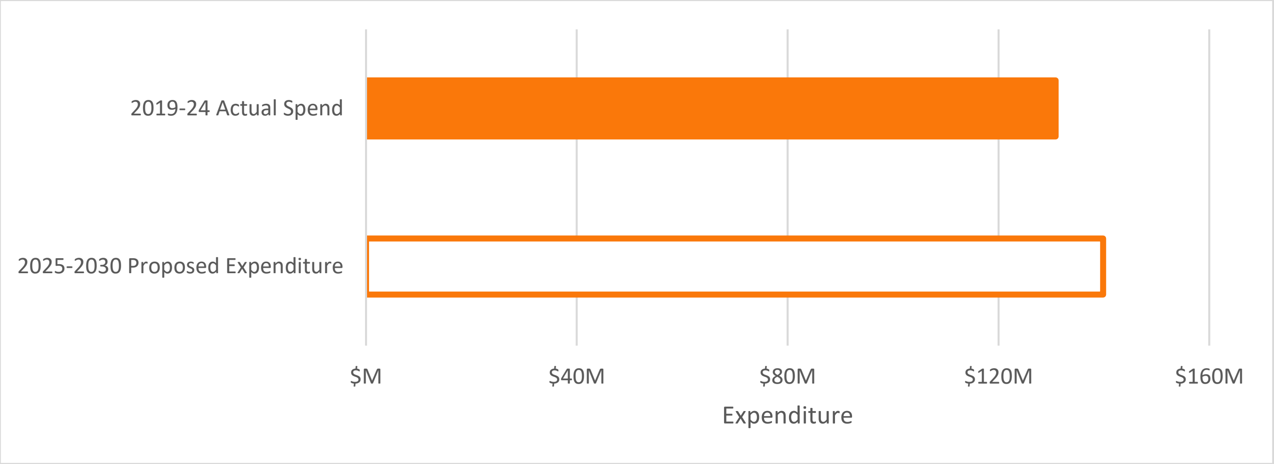


Figure 27 – Pole top structure expenditure comparison

Pole top structure forecast rate of renewal (2019-2030)

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

Pole top structure forecast risk to service outcomes (proposed)

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

6.3 Underground cables (excl. CBD)

This section includes analysis primarily focused on underground cables located outside the CBD. For detail on our forecast for underground cables located in the CBD see '5.3.12 - CBD Reliability - Business case addendum'.

Underground cable asset performance (2019-2024)

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 28 shows the total number of cable failures outside the CBD (LV and HV) has been increasing over the past 5 years. Underground cable failures outside the CBD have also had a significant impact on reliability outcomes as compared to other asset classes as shown in Figure 29.

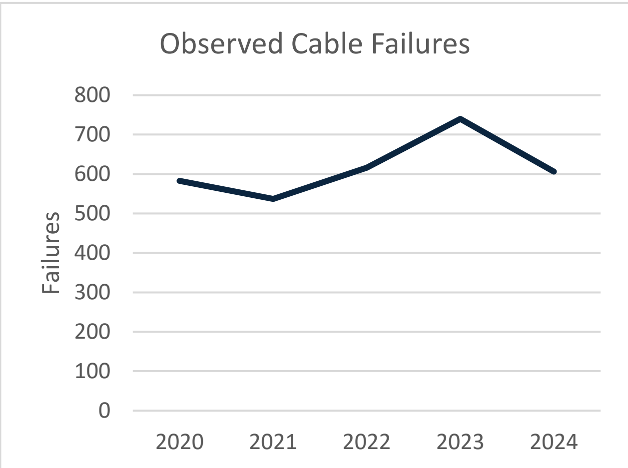


Figure 28 – Observed cable failures (excl. CBD)

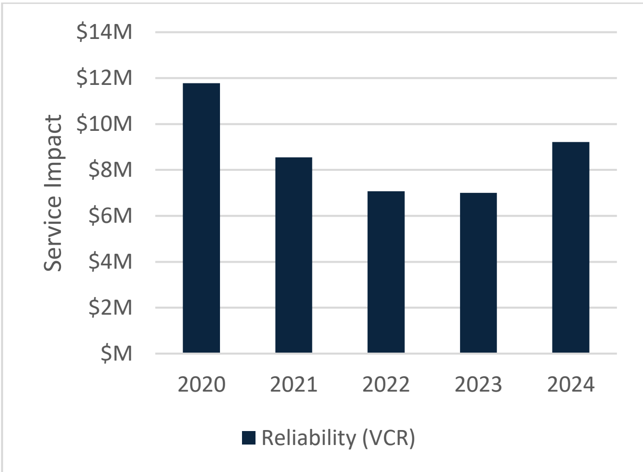


Figure 29 – Impact of cable failures on reliability outcomes (excl. CBD)

Underground cable replacement rate (2019-2024)

We have 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 19,000km. 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 not sustainable.

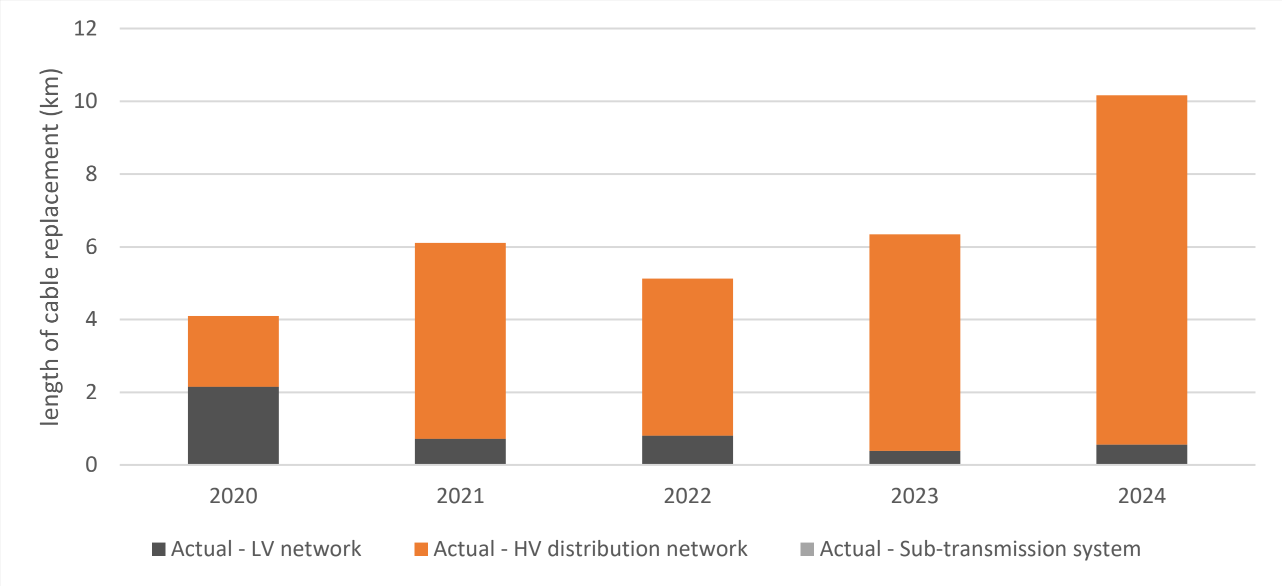


Figure 30 - Underground cable actual replacement rate (excl. CBD)

Underground cable forecast risk to service outcomes (base case)

Figure 31 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.

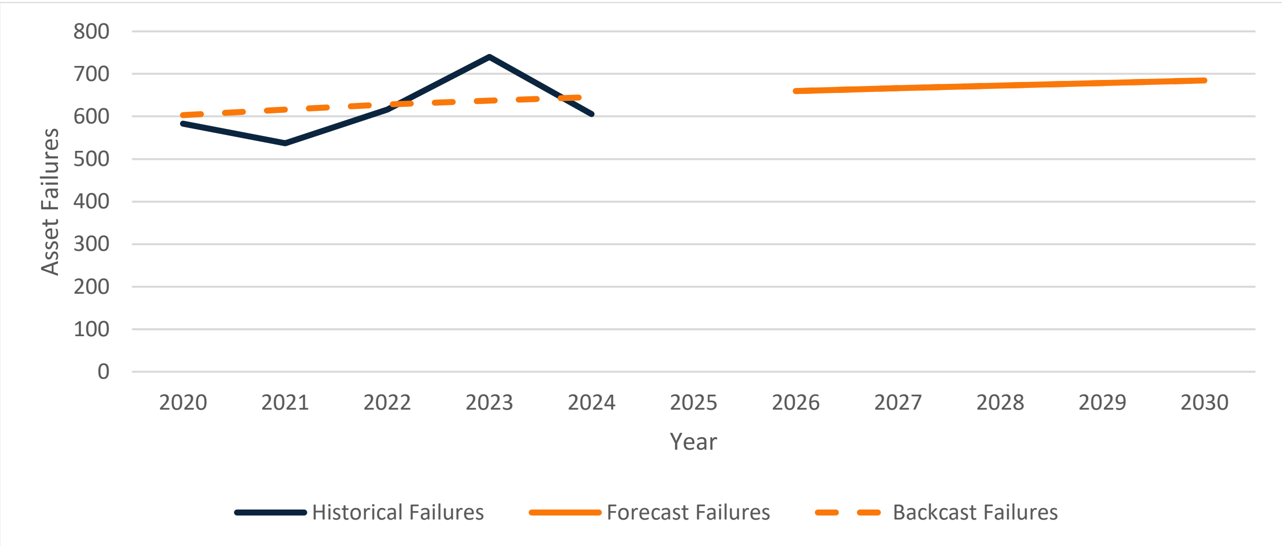


Figure 31 – Historic and forecast underground cable failures (excl. CBD)

Figure 32 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 result in a gradual deterioration of customer reliability risk from our cable assets.

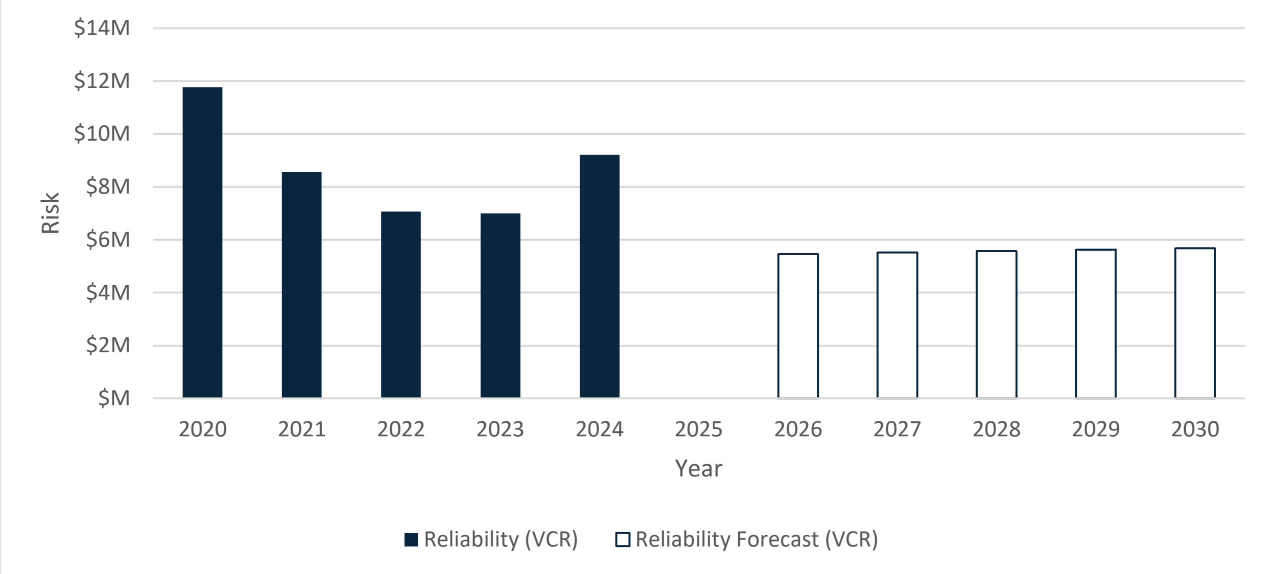


Figure 32 – Historic and forecast underground cable risk (excl. CBD)

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.

A large portion of proactive cable replacement is forecast in the Adelaide CBD to meet the jurisdictional service standard reliability target. 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 the separate 5.3.12 – CBD Reliability – business case addendum.

Underground cable renewal expenditure summary (2025-2030)

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 our **proposed scenario**. We provide an additional comparison with the AER repex model output, showing that our proposed expenditure is less than the expenditure forecast using the AER's repex model for this asset class.

Our modelling shows that maintaining expenditure at our current levels or selecting only economic expenditure is insufficient to maintain performance. An increase in expenditure is required to maintain service outcomes. The proposed expenditure is overall, still economically efficient. Figure 33 displays a comparison of proposed expenditure for non-CBD cables to the AER repex model and recent actual spend.

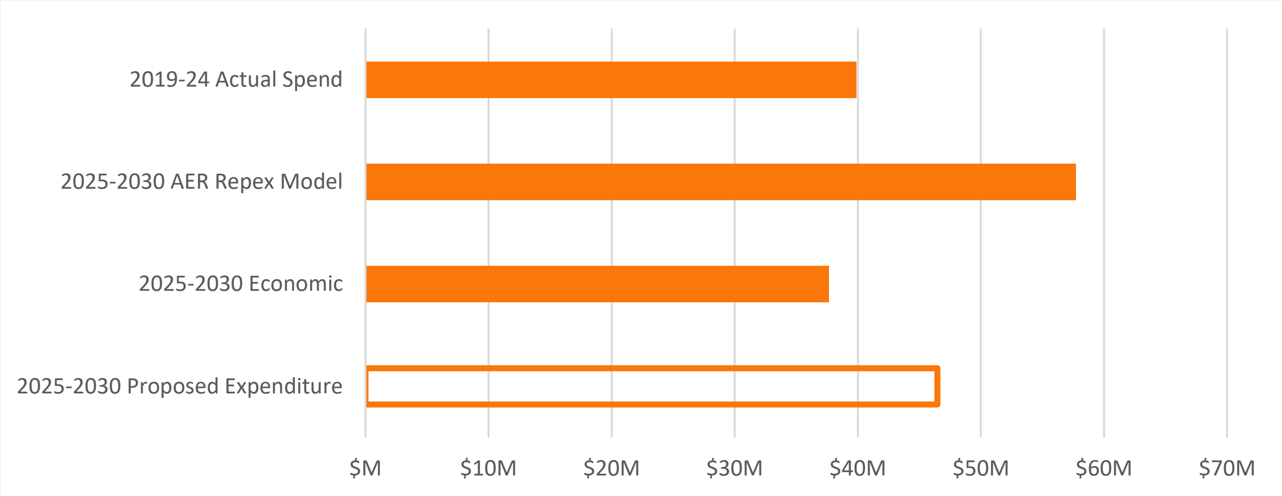


Figure 33 – Underground cable expenditure comparison (excl. CBD)

Underground cable rate of renewal (2019-2030)

Figure 34 shows the historic and proposed renewal rate for cables. The proposed rate of renewal results in less than 0.2% of our cable population replaced over the 2025-30 period.

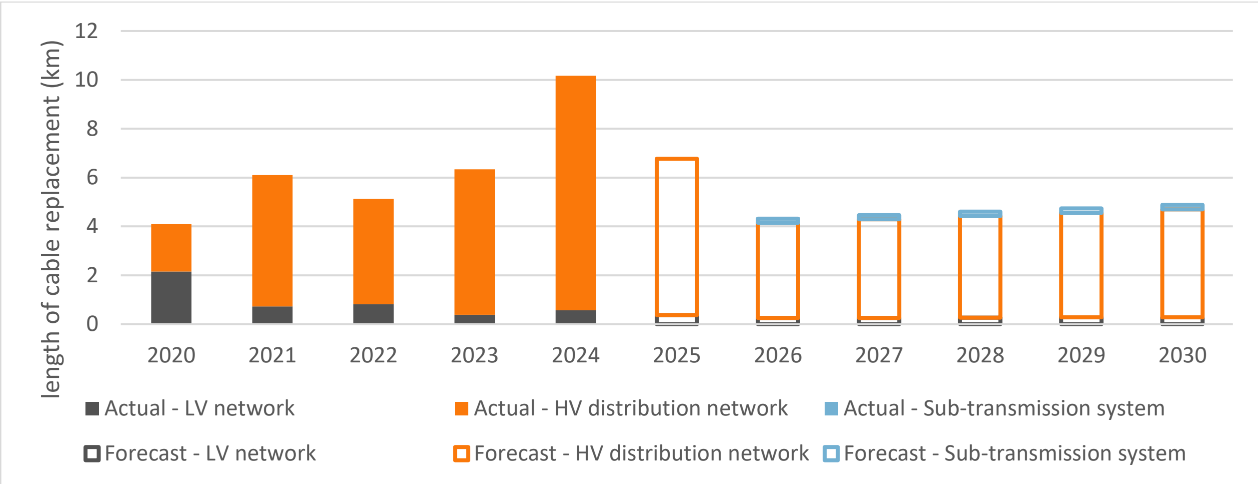


Figure 34 - Underground cable actual and forecasted replacement rate (excl. CBD)

Underground cable forecast risk to service outcomes (proposed)

Figure 35 shows the observed performance impact from underground cable assets along with the forecast impact on service outcomes given the proposed investment above. Our risk modelling shows that reliability service outcomes can be maintained, given the proposed expenditure.

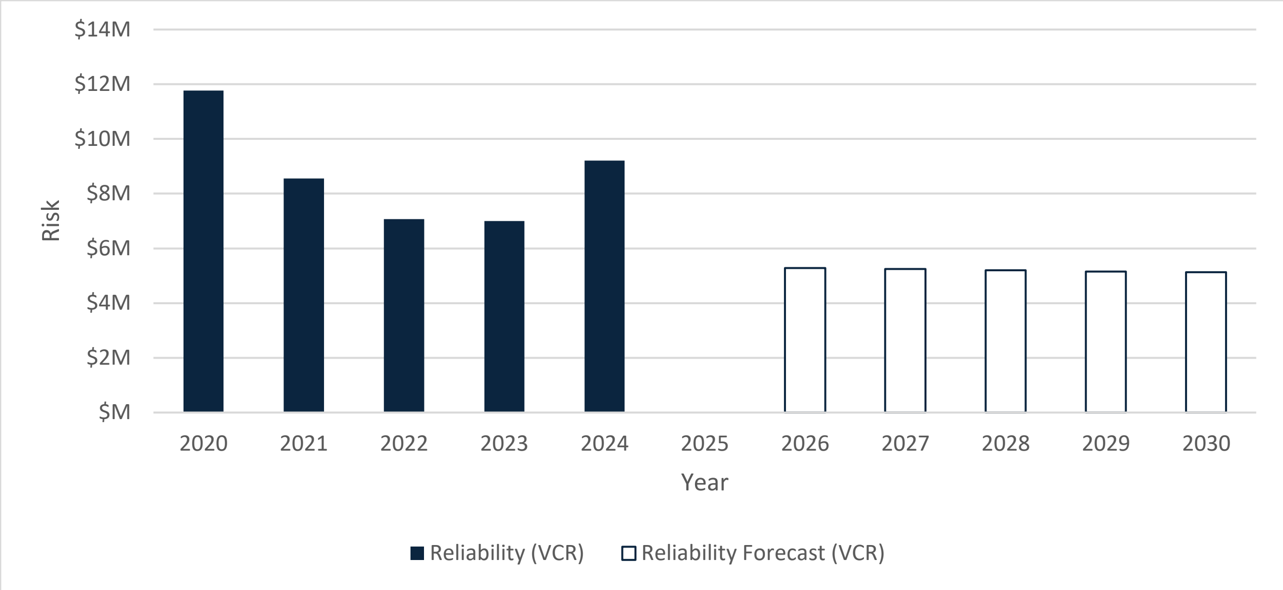


Figure 35 - Historic and forecast underground cable risk (proposed expenditure) (excl. CBD)

6.4 Overhead conductors

Overhead conductor asset performance (2019-2024)

The main risks associated with conductors include:

- potential injury/death of SA Power Networks staff, contractors or the public due to:
  - electric shock through (1) any current transmitted through the pole or live conductors falling to the ground; and (2) 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.

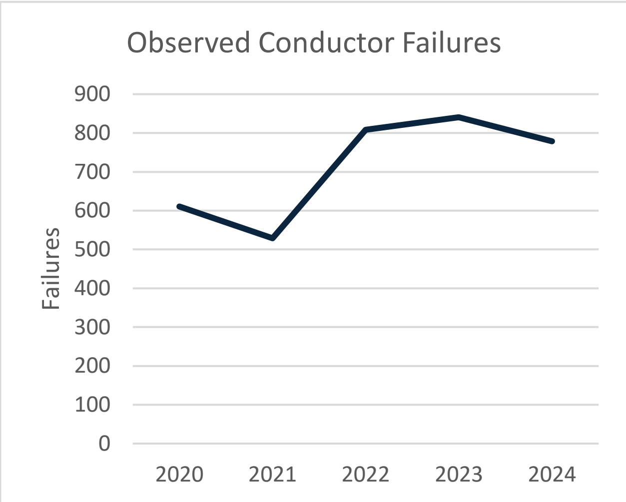


Figure 36 – Observed conductor failures

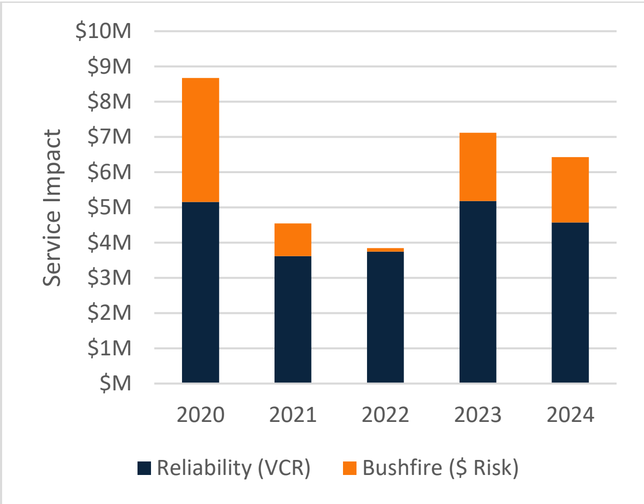


Figure 37 – Impact of overhead conductor failures

Figure 36 shows that the historical number of conductor failures has increased over the last 5 years. Given our extremely low replacement rate with a class of assets approaching the end of their technical life this is expected. The lower bushfire risk in 2021 & 2022 reflects the fact that fire starts from conductor failures can vary (for instance fire starts may be lower during wetter years).

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

Overhead conductor replacement rate (2019-2024)

We have recently been replacing on average less than 170km of overhead conductor per year under our replacement program as displayed in Figure 38. 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.

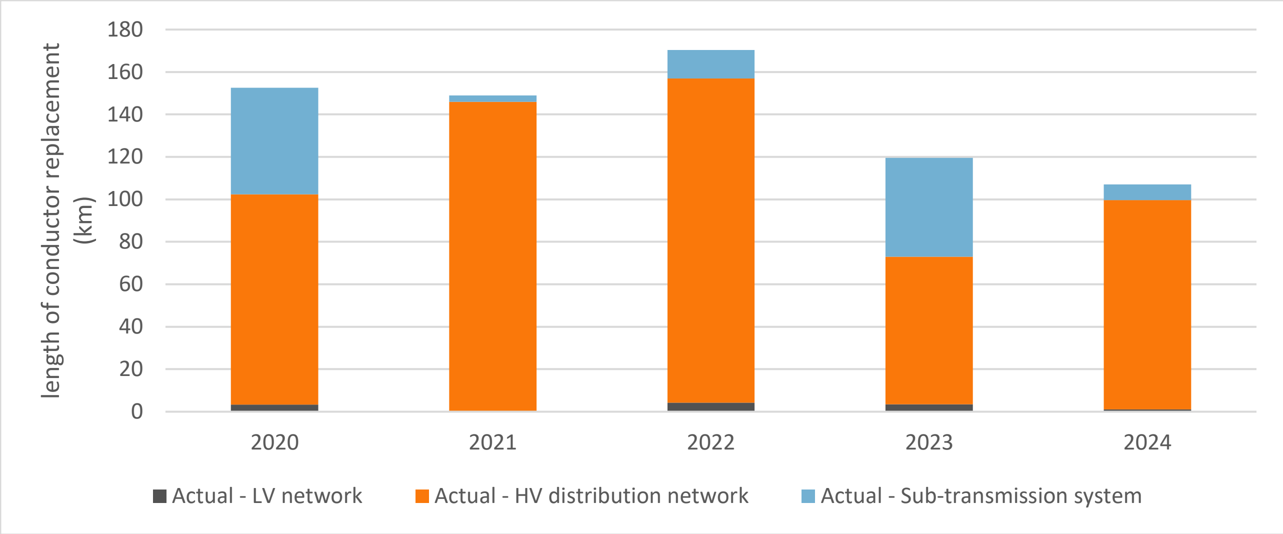


Figure 38 - Overhead conductor actual replacement rate

Overhead conductor forecast risk to service outcomes (base case)

Figure 40 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 39). 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.

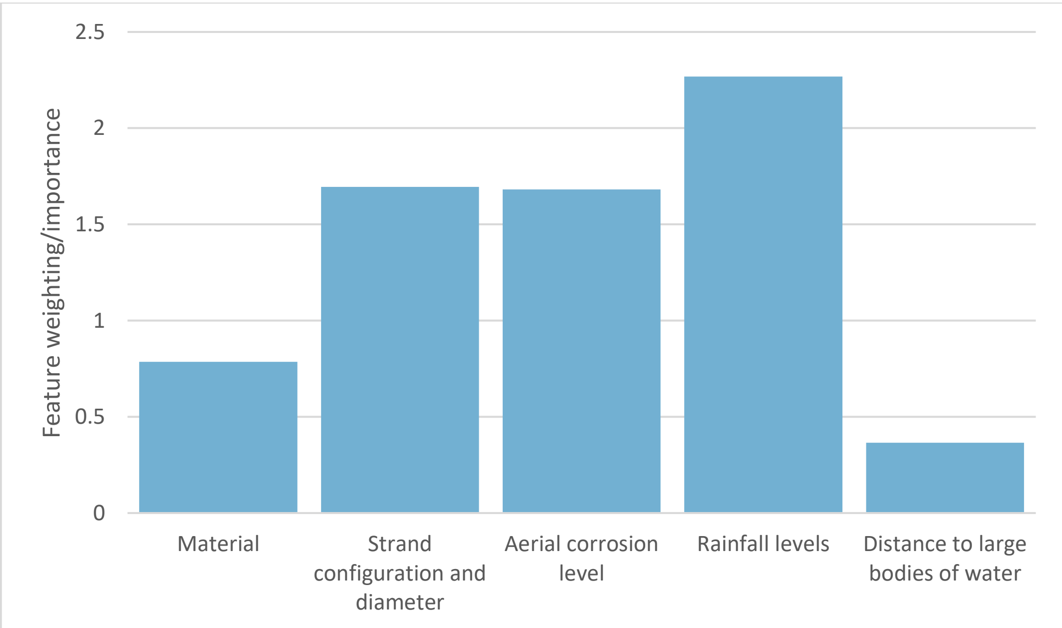
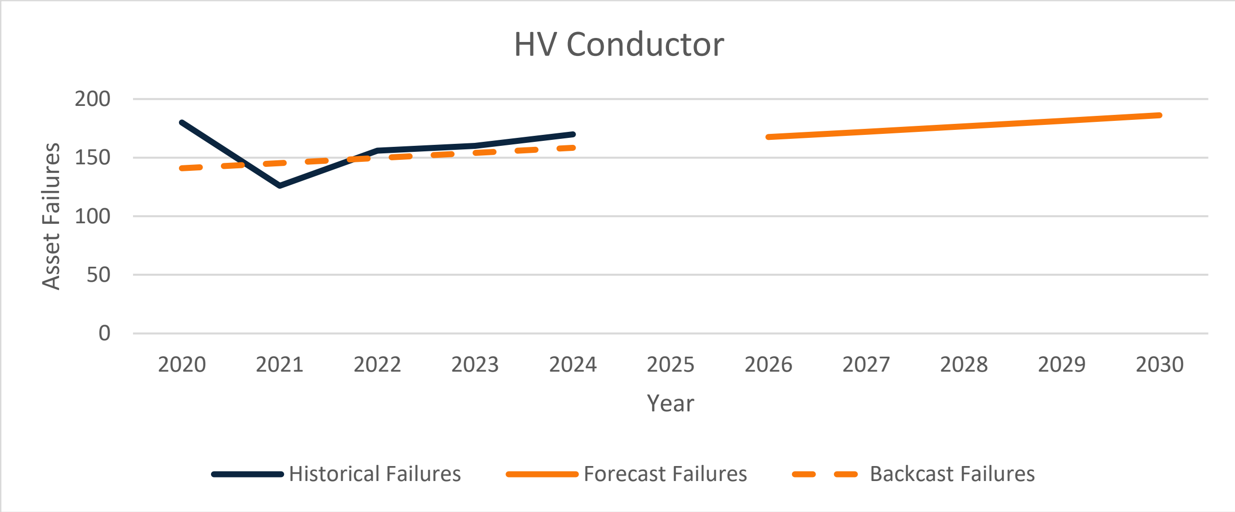


Figure 39 - Feature weighting for conductor probability of failure model

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.



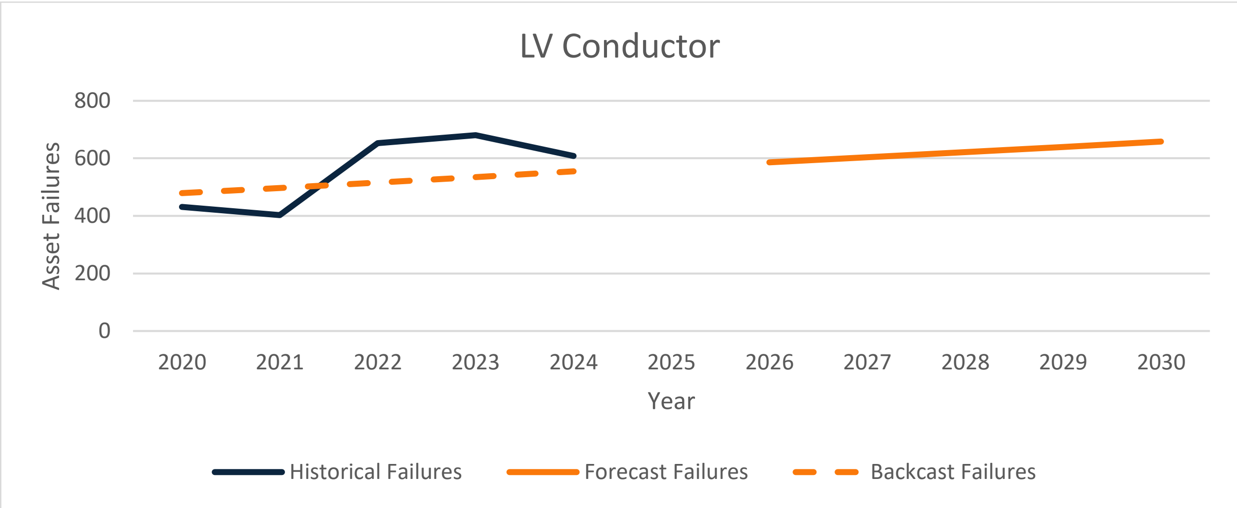


Figure 40 – Historical and forecast overhead conductor failures

Figure 41 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 in gradual deterioration of customer reliability and increase in safety risk (including bushfire risk).

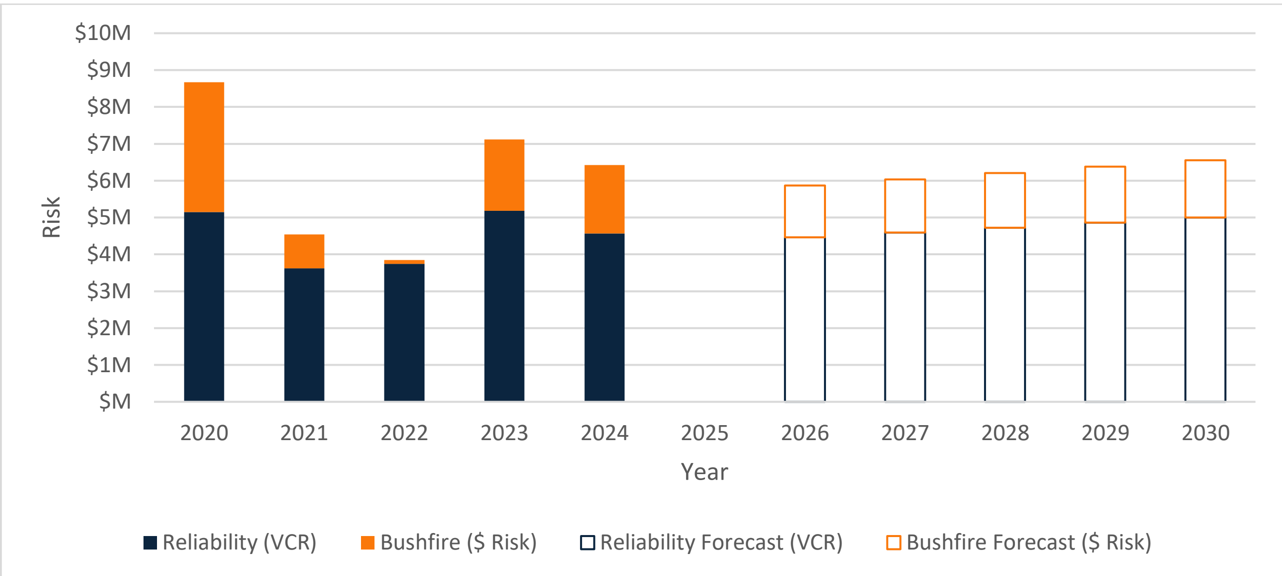


Figure 41 – Historical and forecast overhead conductor risk (base case)

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.

Overhead conductor forecast renewal expenditure summary (2025-2030)

We considered three scenarios in forecasting expenditure for overhead conductors, a **base case** (using actual spend), **economic scenario** and a **proposed scenario**. We provided an additional comparison with the AER repex model. The proposed expenditure for overhead conductors is lower than current expenditure as the modelling suggests there is greater benefit/cost investments to be made in other asset categories, to achieve our target customer service outcomes. It is also worth noting that, although proposed expenditure is lower than current expenditure, the proposed rate of renewal remains consistent and includes a shift to targeting the more cost efficient HV distribution network overhead conductor over the higher cost sub-transmission system (refer Figure 42).

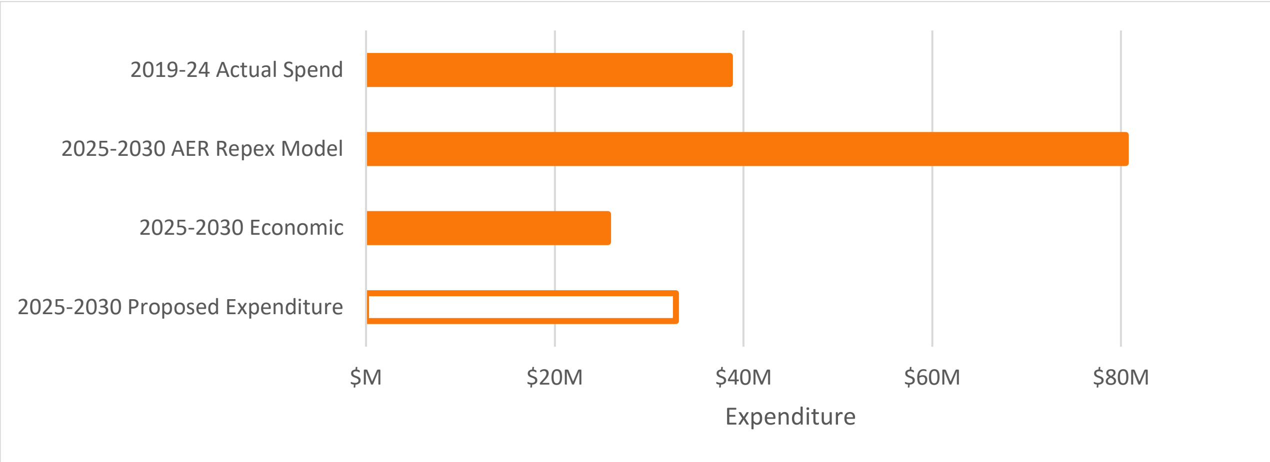


Figure 42 – Overhead conductor expenditure comparison

Overhead conductor rate of renewal (2019-2030)

Figure 43 shows the proposed renewal rate with an expenditure of $32.8 million. The average proposed replacement rate over the 2025-30 RCP is 142km per year, of replacement out of a population of 175,000km, resulting in less than 1% of our conductor population replaced over the 2025-30 period. An increase in replacement rate will be required in future periods.

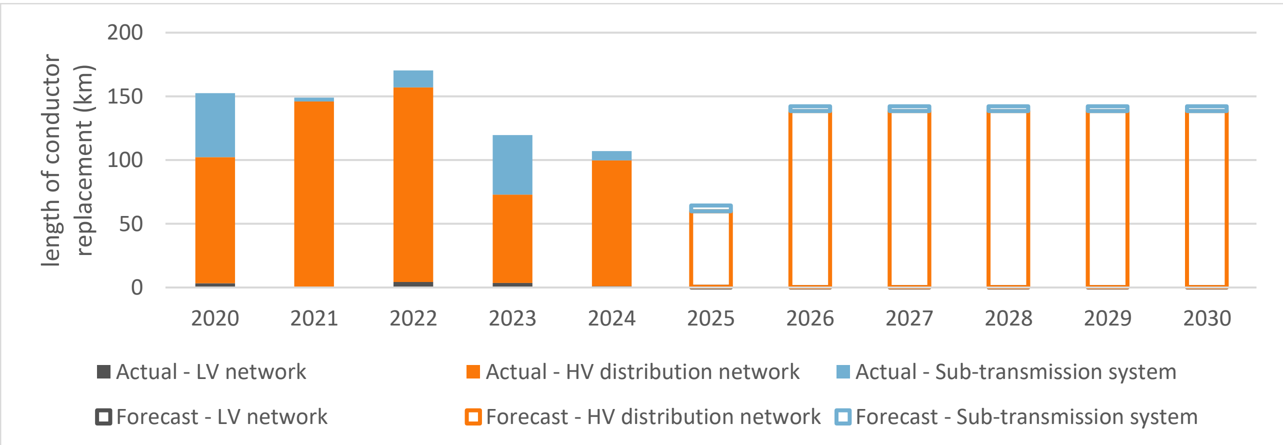


Figure 43 - Overhead conductor actual and forecasted replacements

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.

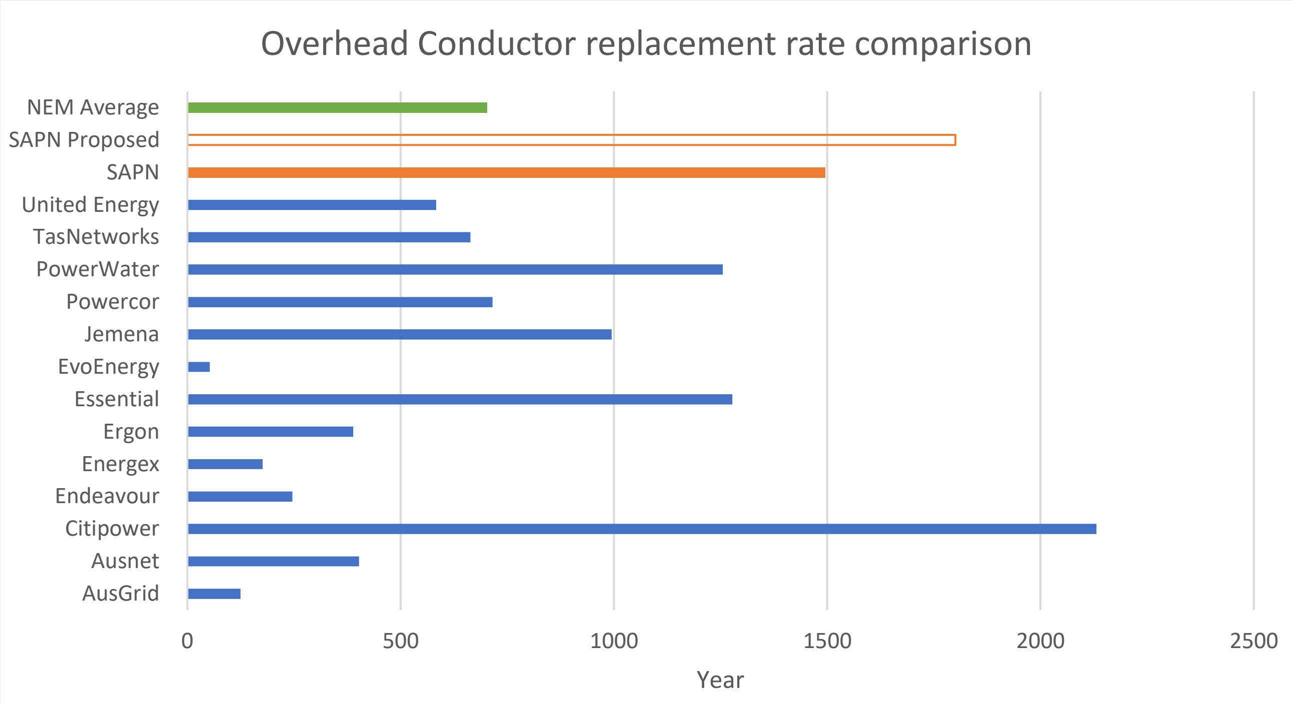


Figure 44 – DNSP Overhead conductor replacement rates

Overhead conductor forecast risk to service outcomes (proposed)

Figure 45 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 given the proposed expenditure, our reliability and bushfire safety outcomes can be maintained at same level as the base case[21].

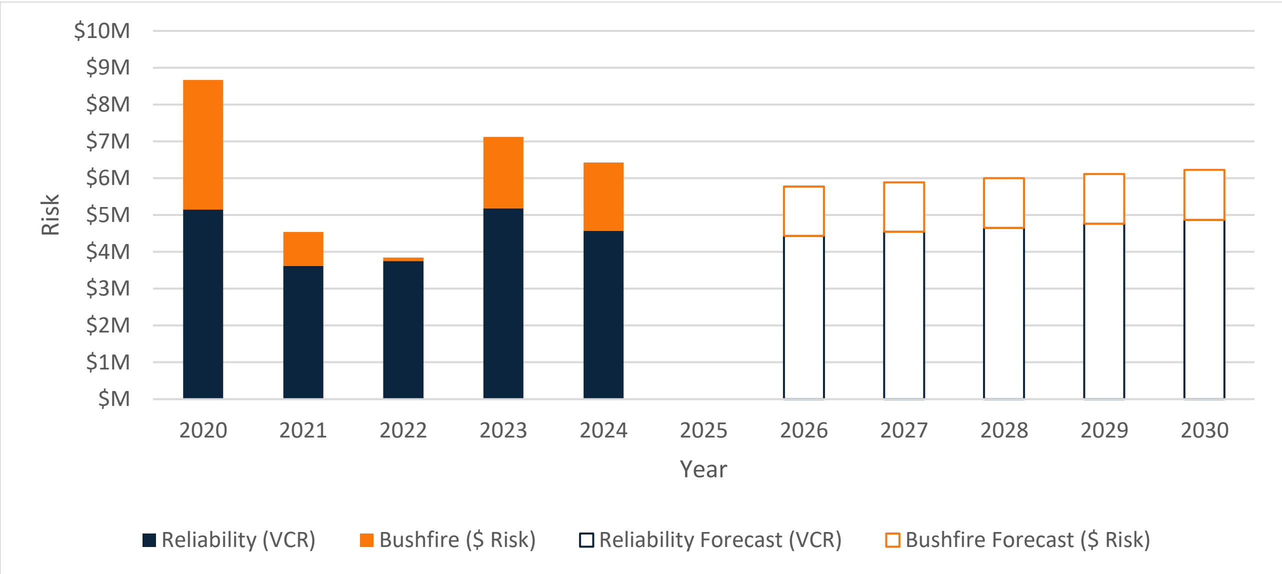


Figure 45 - Historic and forecast overhead conductor risk (proposed expenditure)

21 Proposed expenditure maintains performance (relative to the base case) despite proposing a lower level of expenditure. This is achieved by targeting increased HV conductor replacement, which is more cost efficient in reducing risk, and targeting less sub-transmission conductor compared to previous RCP.

6.5 Switching cubicles

Switching cubicle asset performance (2019-2024)

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 46 shows historical switching cubicle failures have stabilized in recent years.

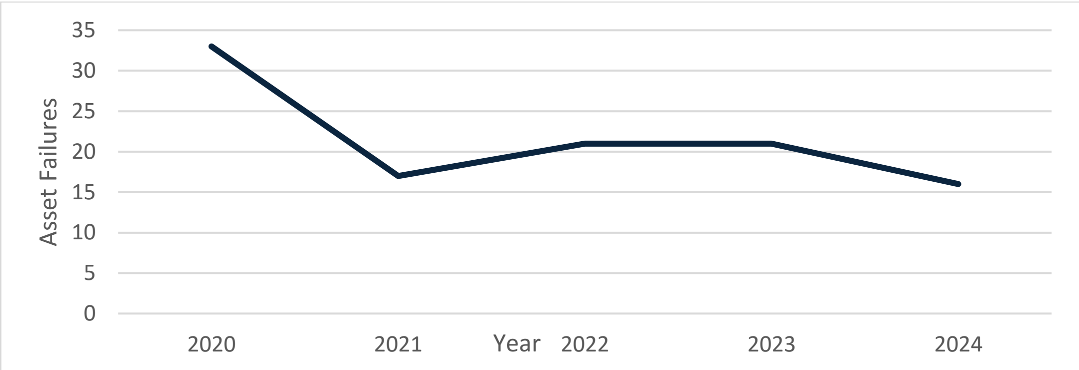


Figure 46 – Observed switching cubicles failures

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 (2019-2024)

We have recently been replacing an annual average of 20-30 switching cubicles. 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.

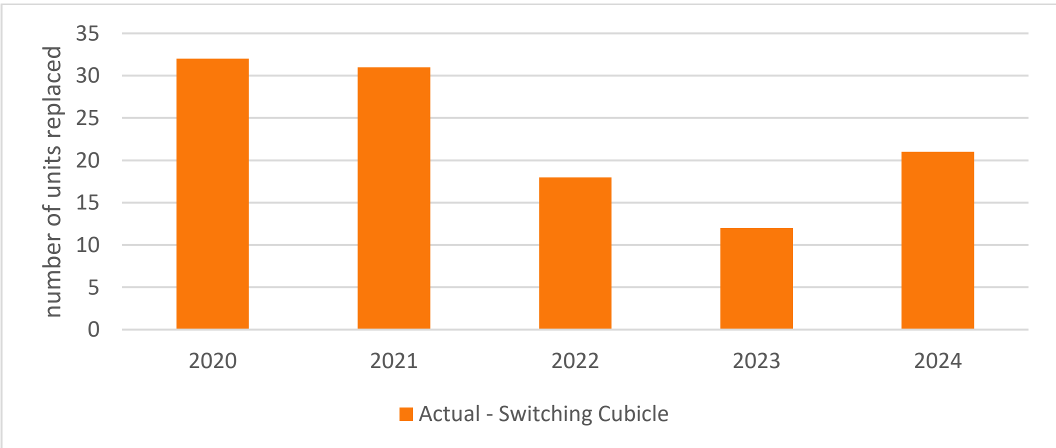


Figure 47 - Switching cubicle replacement rate

Switching cubicle forecast risk to service outcomes (base case)

Figure 48 shows forecast failures. We expect an increase in failures given our current replacement rate.

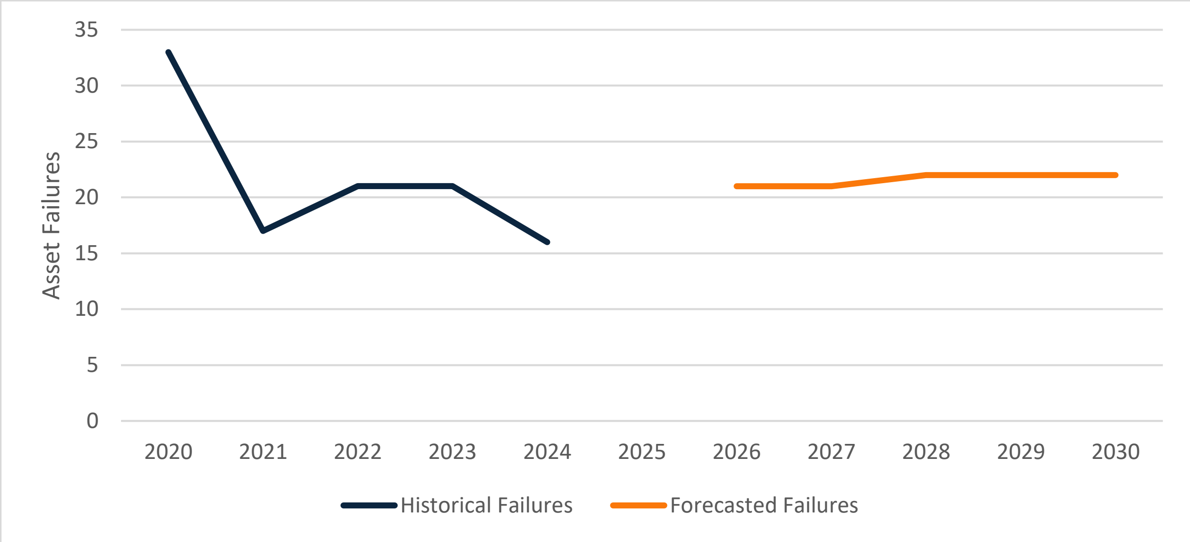


Figure 48 – Historical and forecast switching cubicle failures

Figure 49 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.

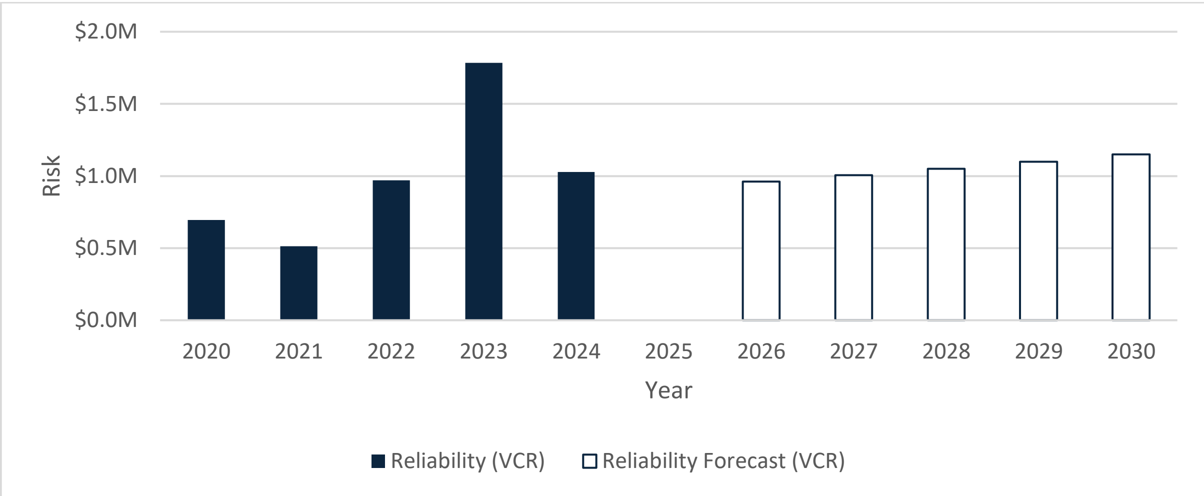


Figure 49 – Historical and forecast switching cubicle risk (base case)

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.

While the current replacement rate is not sustainable, replacement of other asset classes presents better customer value in the overall replacement expenditure forecast.

Switching cubicle renewal expenditure summary (2025-30)

We considered three scenarios (i.e. options) in forecasting expenditure for switching cubicles, being a **base case** (using actual spend), **economic scenario** and our **proposed scenario**.

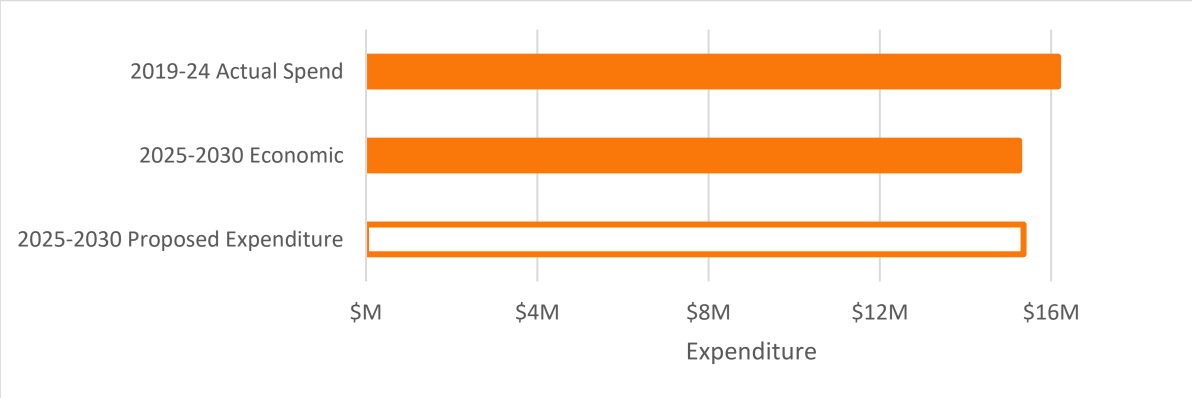


Figure 50 – Switching cubicle expenditure comparison

Switching cubicle rate of renewal (2019-2030)

Figure 51 shows the historic and forecast renewal of switching cubicles. The proposed rate of renewal with an expenditure of $15.3 million provides an average replacement rate of 0.4% per year, resulting in less than 2% of our switching cubicle population replaced over 2025-30.

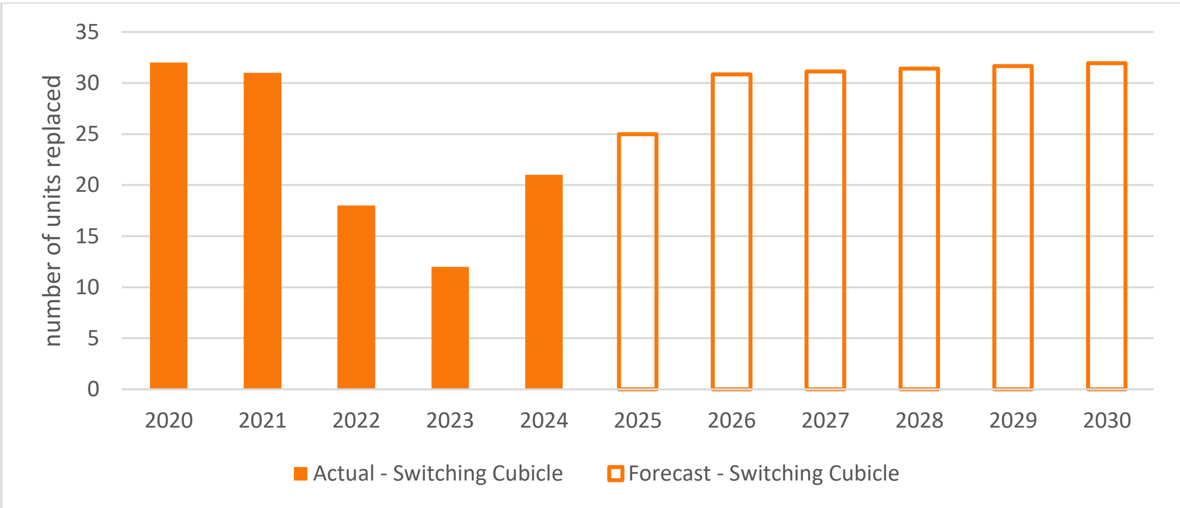


Figure 51 - Switching cubicle actual and forecasted replacements

Switching cubicles forecast risk to service outcomes (proposed)

Figure 52 shows observed performance impacts from switching cubicle assets along with the forecast impact on service outcomes given our proposed repex. 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.

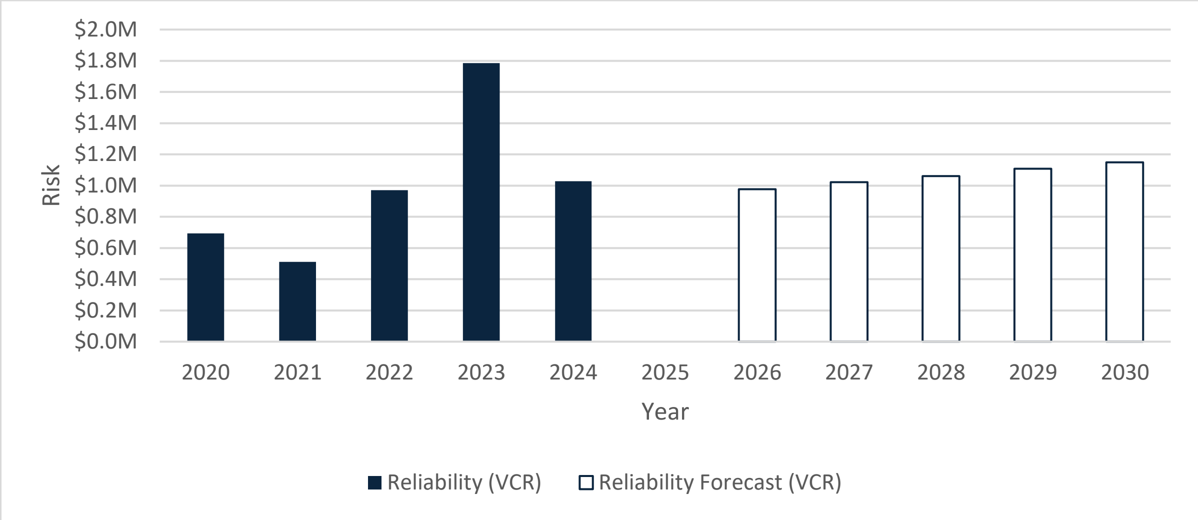


Figure 52 - Historic and forecast switching cubicle risk (proposed expenditure)

6.6 Distribution Transformers

Distribution transformer asset performance (2019-2024)

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 53 shows the historical number of transformer failures. Failure numbers have been on a gradual upward trend. The performance of distribution transformers has been found to correlate with external ambient temperature. The annual failure rate historically has been variable as there is a correlation with ambient temperature and lightning storm activity, this activity can vary significantly year to year.

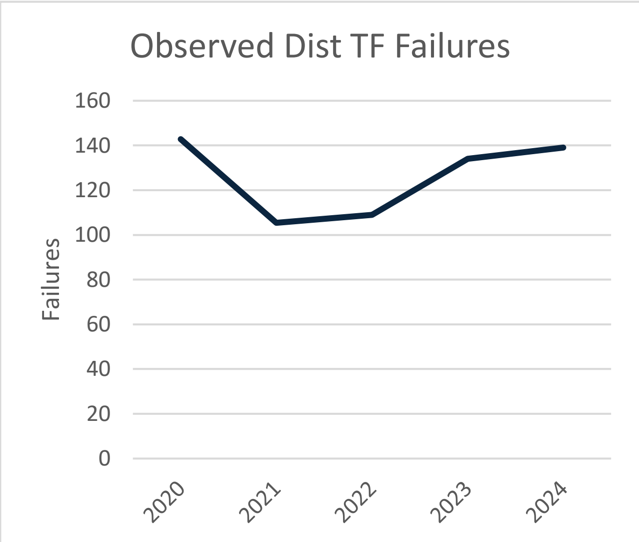


Figure 53 – Observed distribution TF failures

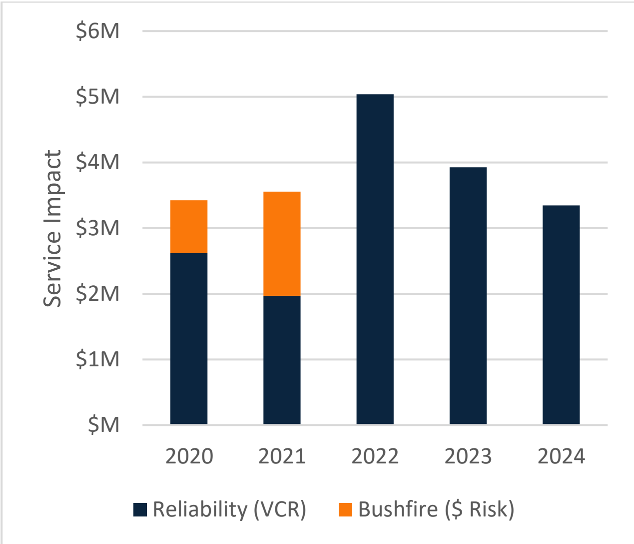


Figure 54 – Impact of distribution TF failures on service outcomes

Distribution transformer failures have had a moderate impact on service outcomes as compared to other asset classes and displays an increasing trend.

Distribution transformer replacement rate (2019-2024)

We have recently been replacing an average of 100-300 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.

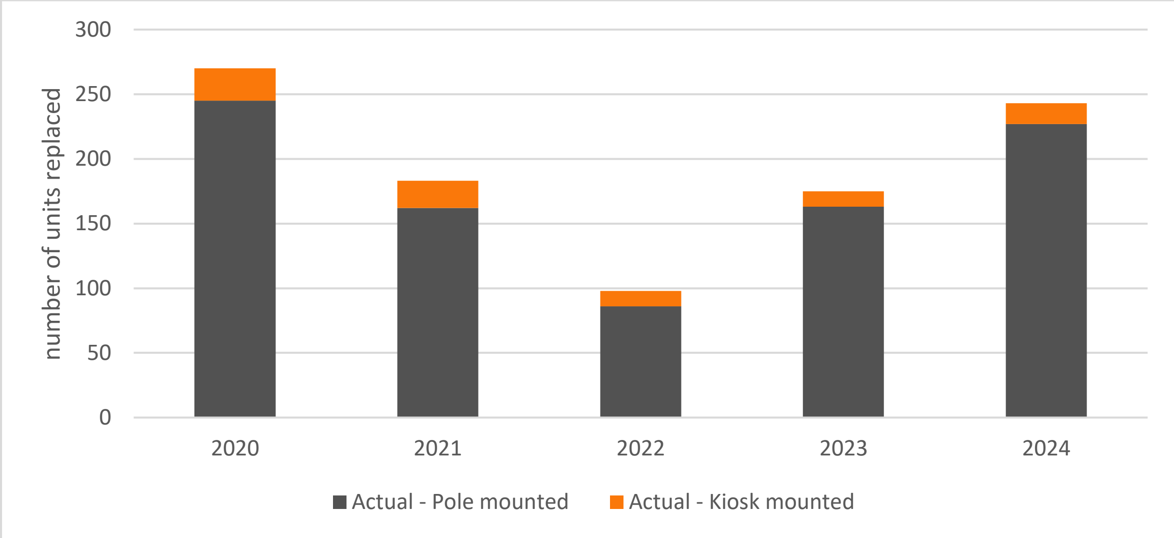


Figure 55 - Distribution transformer actual replacement rate

Distribution transformer forecast risk to service outcomes (base case)

Figure 56 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.

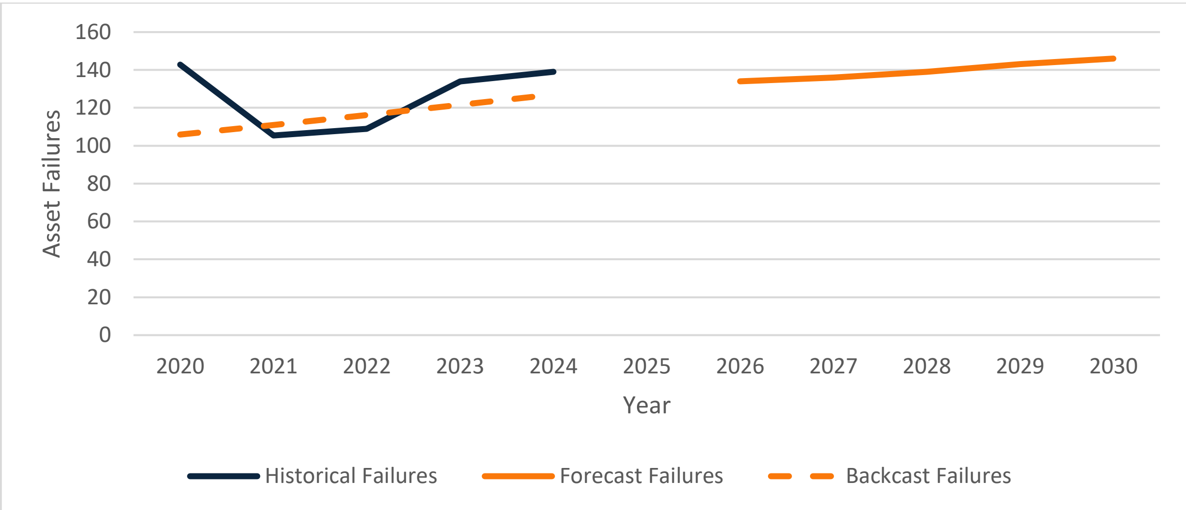


Figure 56 – Historical and forecast distribution transformer failures

Figure 57 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 deterioration in customer reliability and an increase in safety risk (including bushfire risk).

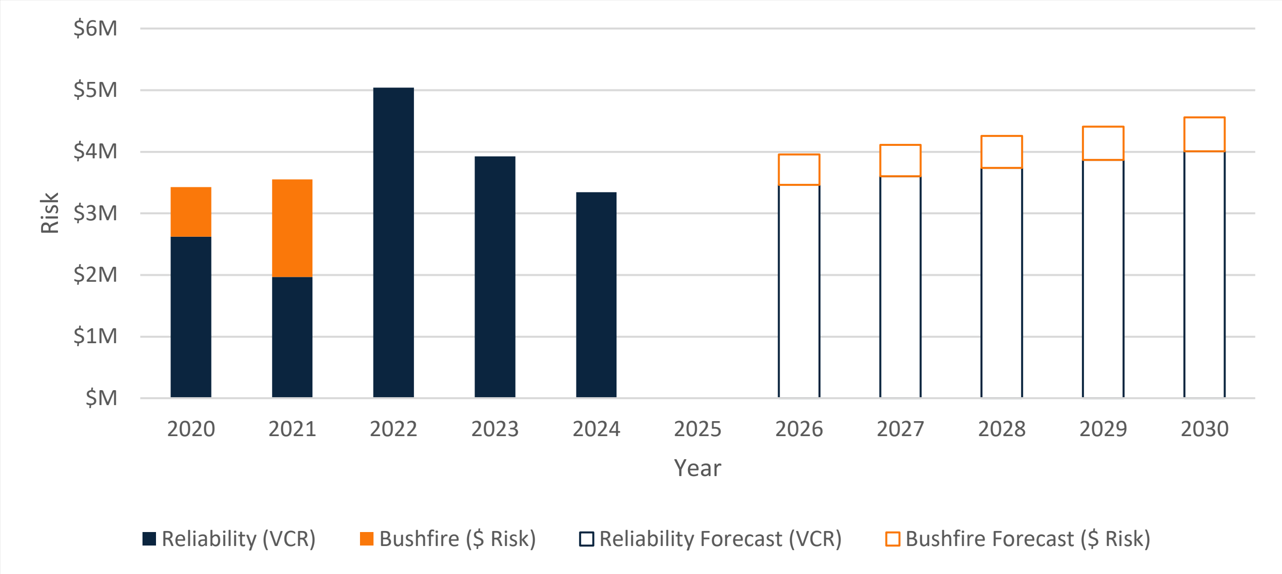


Figure 57 – Historical and forecast distribution transformer risk (base case)

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.

Addressing the increase in forecast risk outlined above, we developed a proposed scenario for distribution transformers aimed at achieving the target customer service outcome.

Distribution transformer forecast renewal expenditure summary (2025-30)

We considered three scenarios (i.e. options) in forecasting expenditure for distribution transformers, being a **base case** (using actual spend), **economic scenario** and our **proposed scenario**. We provided an additional comparison with the AER repex model output.

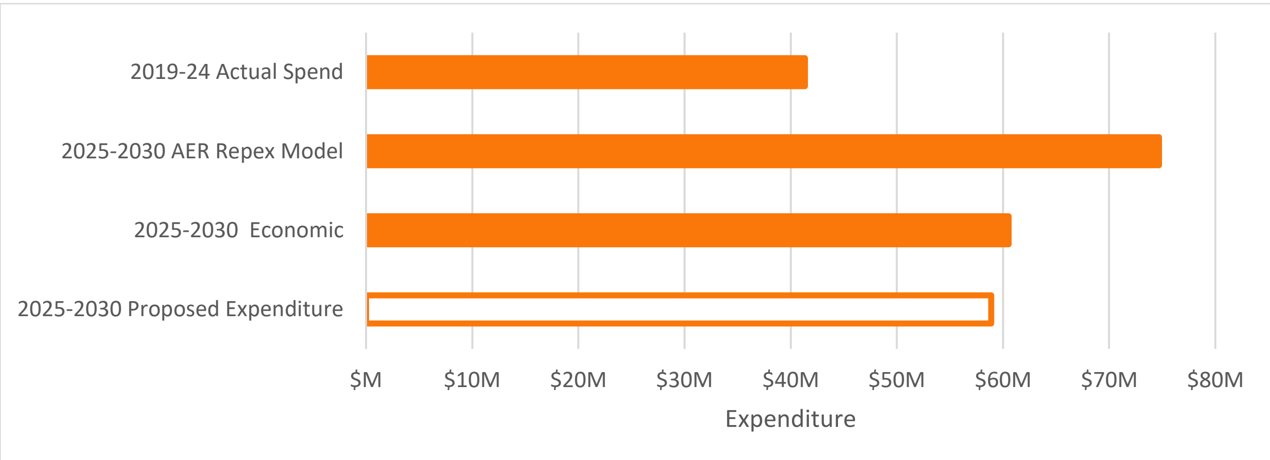


Figure 58 – Distribution transformer expenditure comparison

Distribution transformer rate of renewal (2019-2030)

Figure 59 shows the proposed replacement rate with an expenditure of $58.9 million. The average proposed replacement rate over the 2025-30 RCP is approximately 740 transformers per year out of the population of 77,000 transformers with 4.8% of the population replaced over 2025-30.

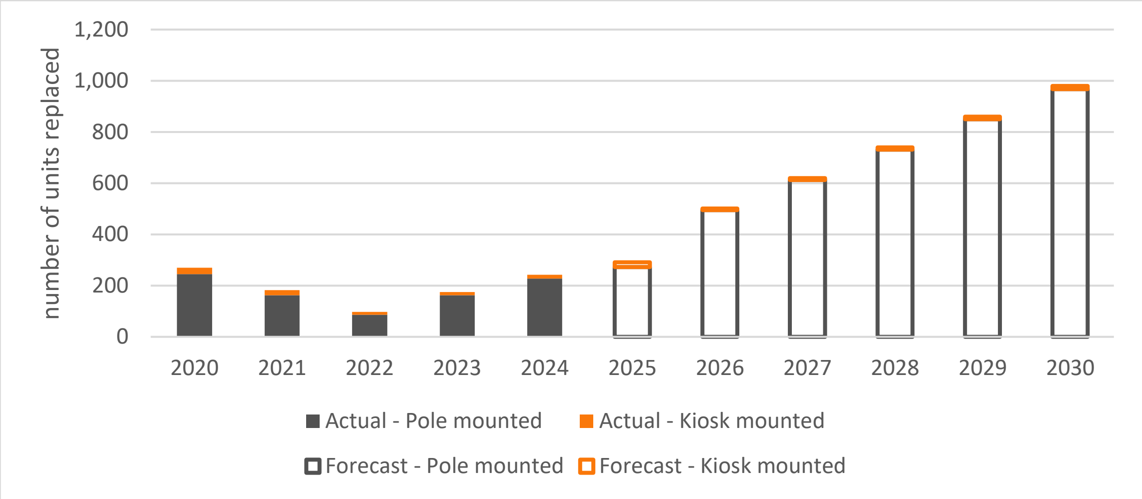


Figure 59 - Distribution transformer actual and forecasted replacement rate

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 showing that our proposed replacement rates would still be among the lowest in the NEM.

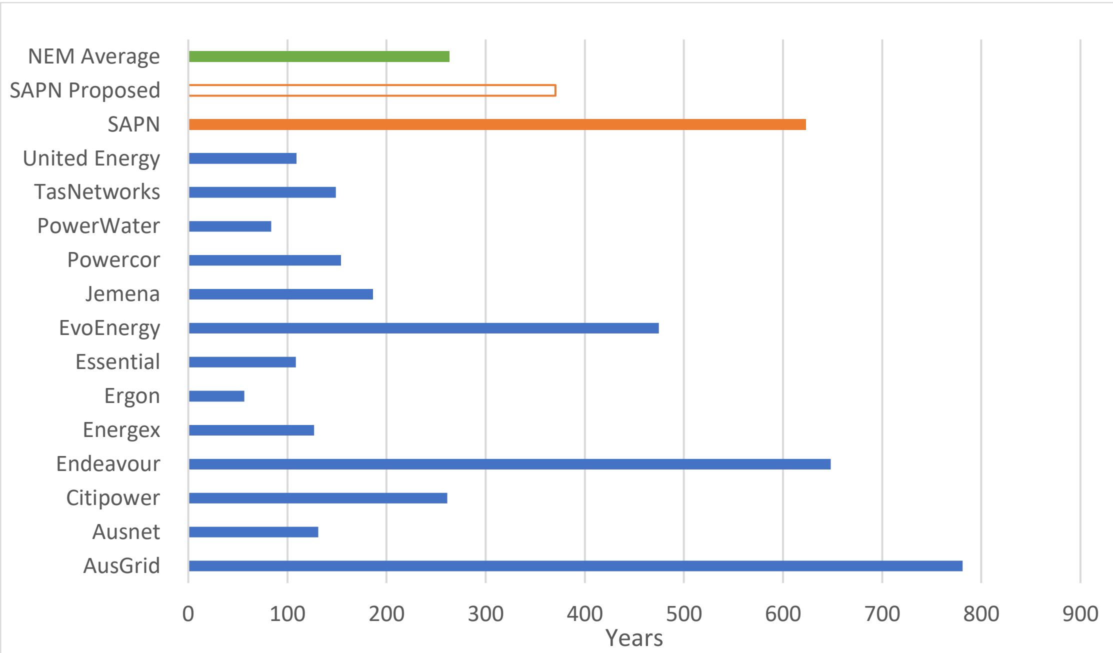


Figure 60 - DNSP distribution transformer replacement rates

Distribution transformer forecast risk to service outcomes (proposed)

Figure 61 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 achieve the target customer service outcome.

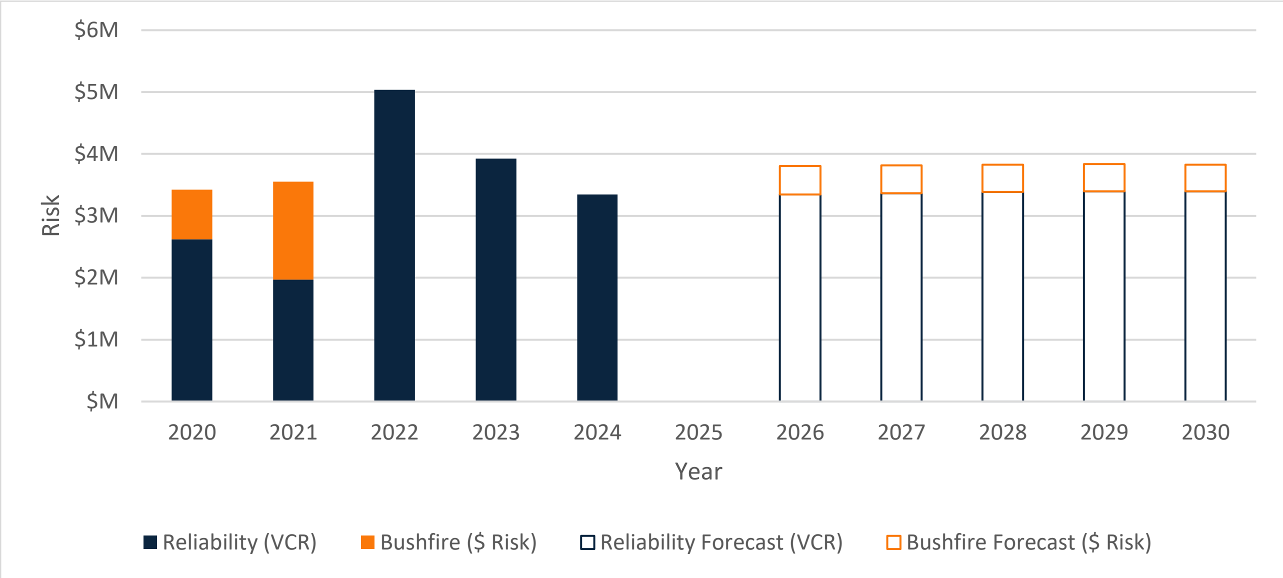


Figure 61 - Historic and forecast distribution transformer risk (proposed expenditure)

6.7 Reclosers and sectionalisers

Recloser and sectionaliser asset performance (2019-2024)

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 62 shows the historical number of recloser and sectionaliser failure have increased over the last 5 years.

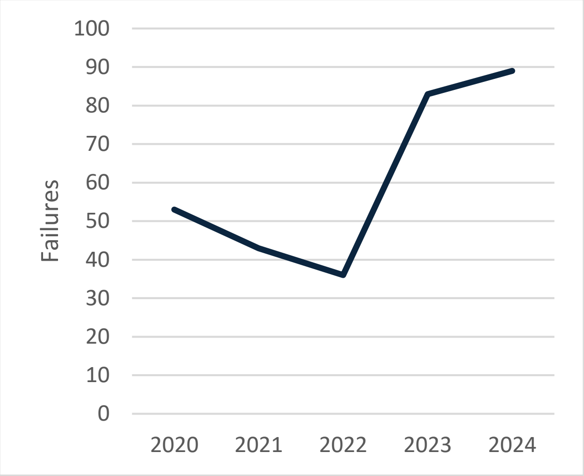


Figure 62 – Observed recloser/sectionaliser failures

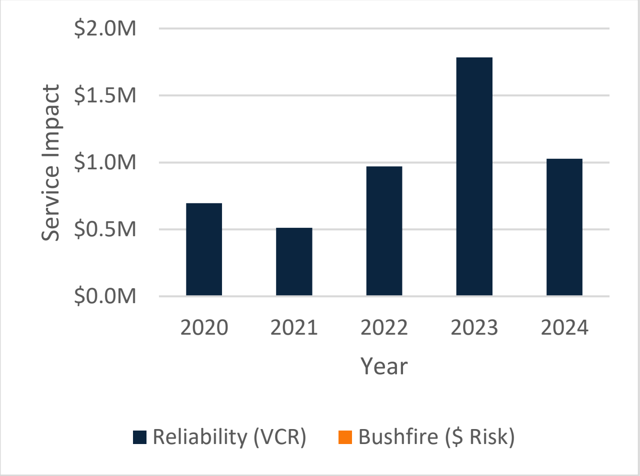


Figure 63 – Impacts of recloser/sectionalisers on service outcomes

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

Recloser and sectionaliser replacement rate (2019-2024)

We have been replacing an annual average of 113 reclosers and sectionalisers. This results in a total effective annual volume of 5.0% of the population replaced each year. With this replacement rate it would take approximately 20 years to replace the entire population.

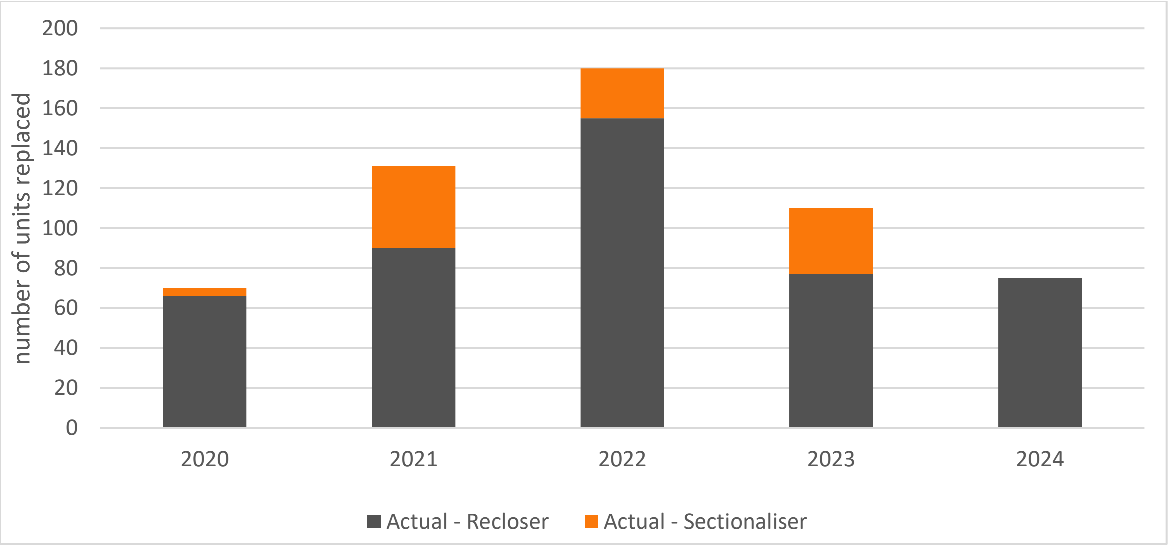


Figure 64 - Recloser and sectionaliser actual replacement rate

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

Figure 65 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.

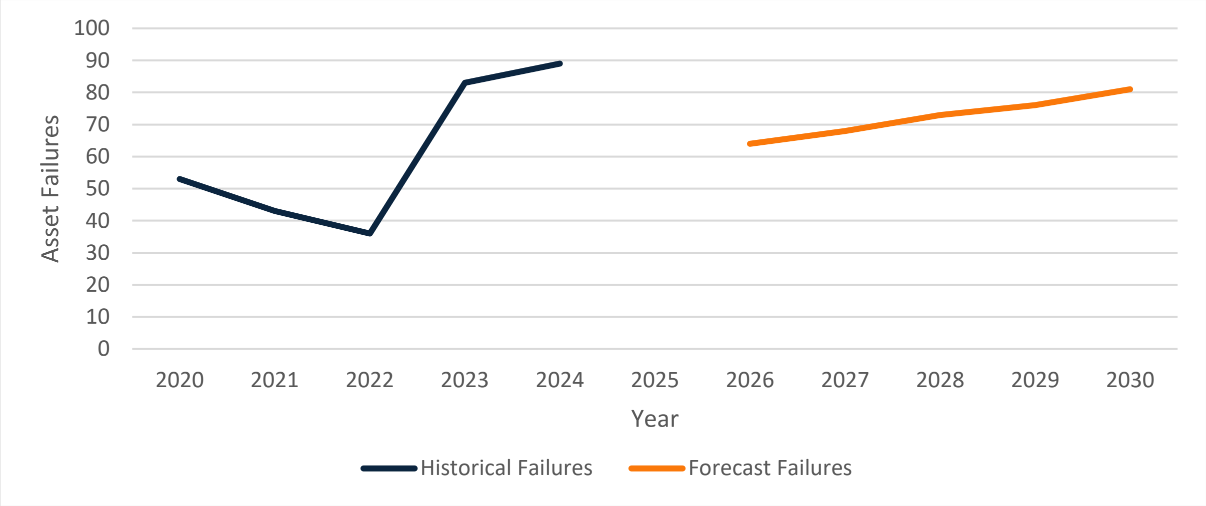


Figure 65 – Historical and forecast recloser and sectionalisers failures

Figure 66 shows the observed performance impact from recloser and sectionaliser 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).

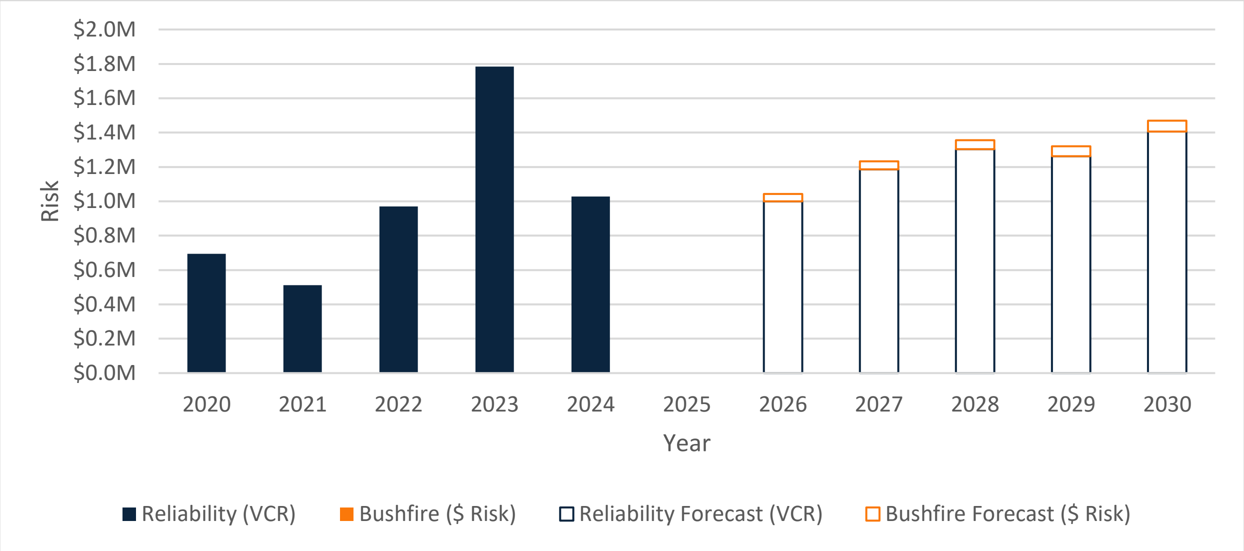


Figure 66 – Historical and forecast recloser and sectionalisers risk (base case)

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.

Recloser and sectionaliser forecast renewal expenditure summary

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

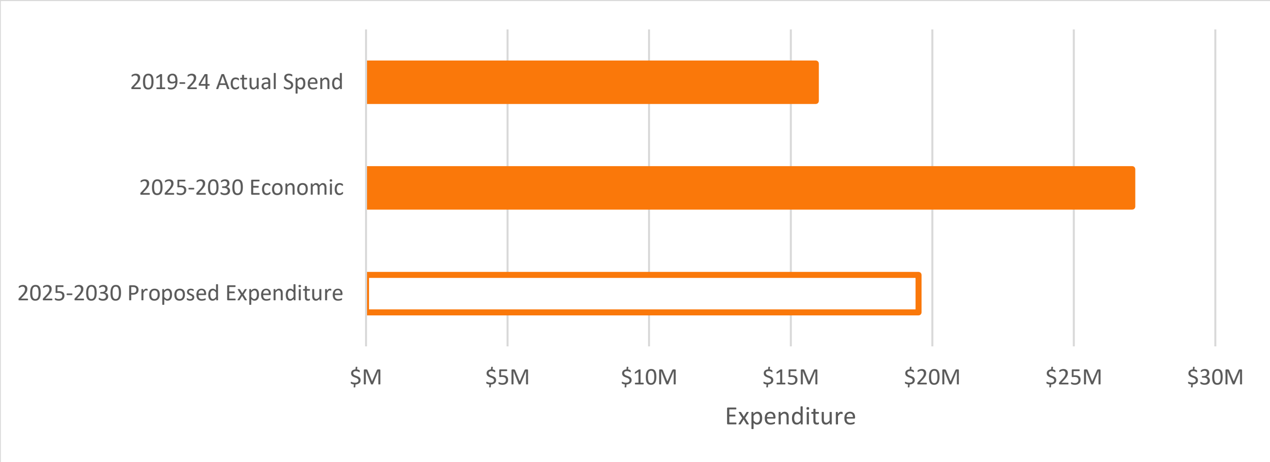


Figure 67 – Recloser and sectionalisers expenditure comparisons

Recloser and sectionaliser rate of renewal (2019-2030)

Figure 68 shows the forecast renewal rate of reclosers and sectionalisers. The proposed rate of renewal with an expenditure of $19.5 million results in an average replacement rate of 6.1% per year, with 30.9% of the population replaced over 2025-30.

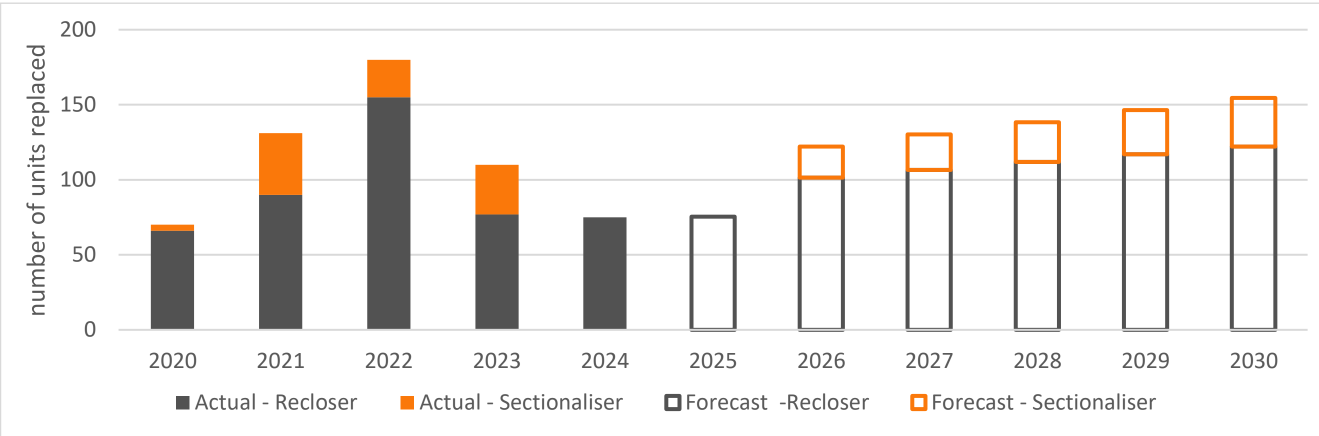


Figure 68 - Recloser and sectionaliser actual and forecasted replacements

Recloser and sectionaliser forecast risk to service outcomes (proposed)

Figure 69 shows the observed performance impact from recloser and sectionaliser assets along with the forecast impact on service outcomes given our proposed repex. Our risk modelling shows that reliability and bushfire safety outcomes can be improved, given the proposed expenditure.

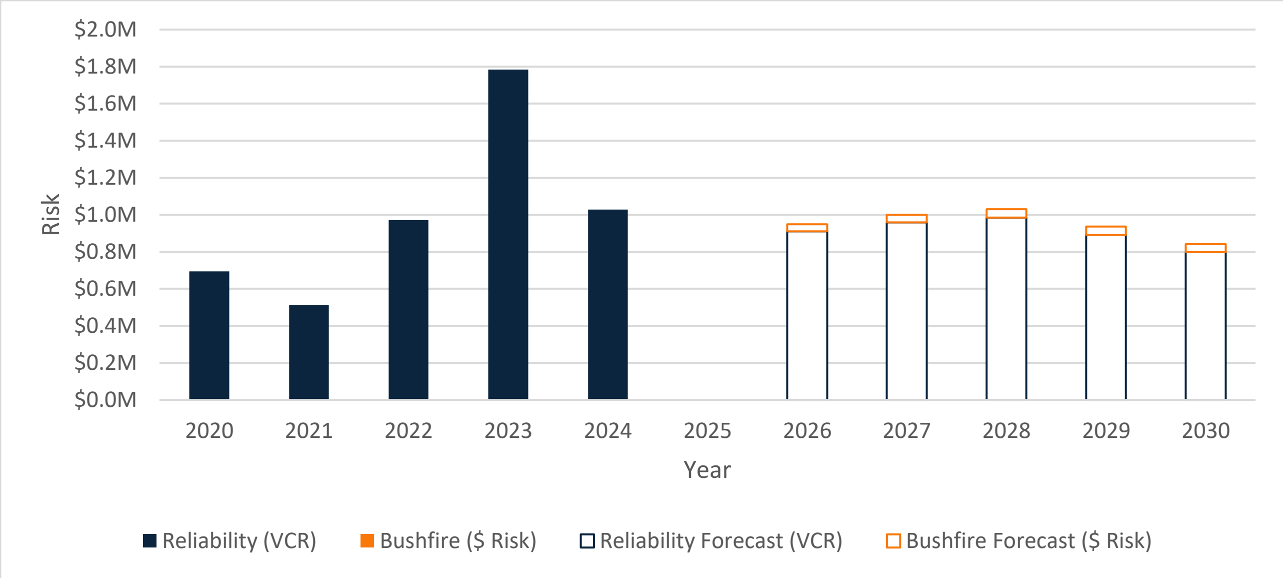


Figure 69 - Historic and forecast recloser and sectionaliser risk (proposed expenditure)

6.8 Services

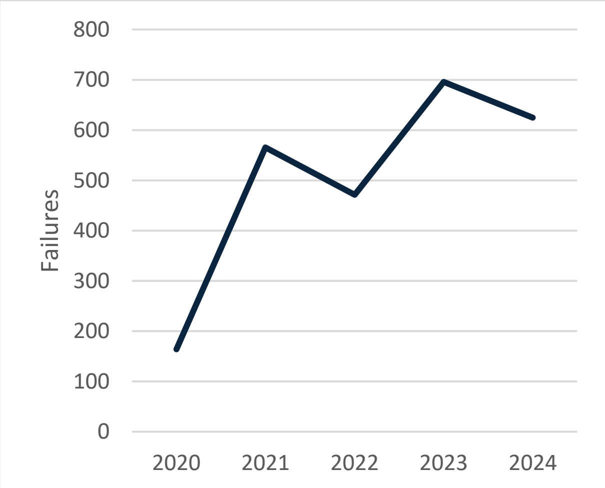
Services asset performance (2019-2024)

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.

The Services asset class consists of service line assets, which have been modelled and analysed in more detail below, and service components, which remain unmodelled due to data limitations. The expenditure and performance for service components is forecasted using historic expenditure.

Figure 70 shows the number of service line failures has decreased in recent years, while the impact to service outcomes has remained relatively stable. The higher bushfire risk in 2020 and 2021 reflects the fact that fire starts from services can vary year on year.



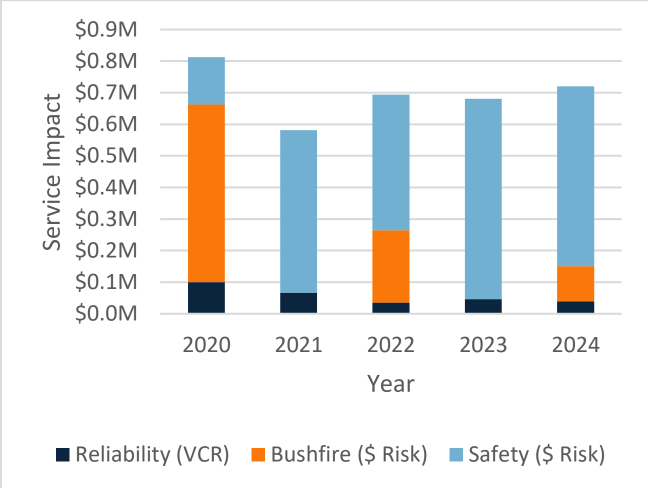


Figure 70 – Observed service failures (modelled) (modelled)

Figure 71 – Impact of service line failures on service outcomes

Service replacement rate (2019-2024)

We have recently been replacing an average of 3,000 to 10,000 service components per year. This results in a total effective annual volume of 0.37% of the service component population (~840,000 connections x 2 service components per connection) replaced each year. With this replacement rate it would take 271 years to replace the entire service population.

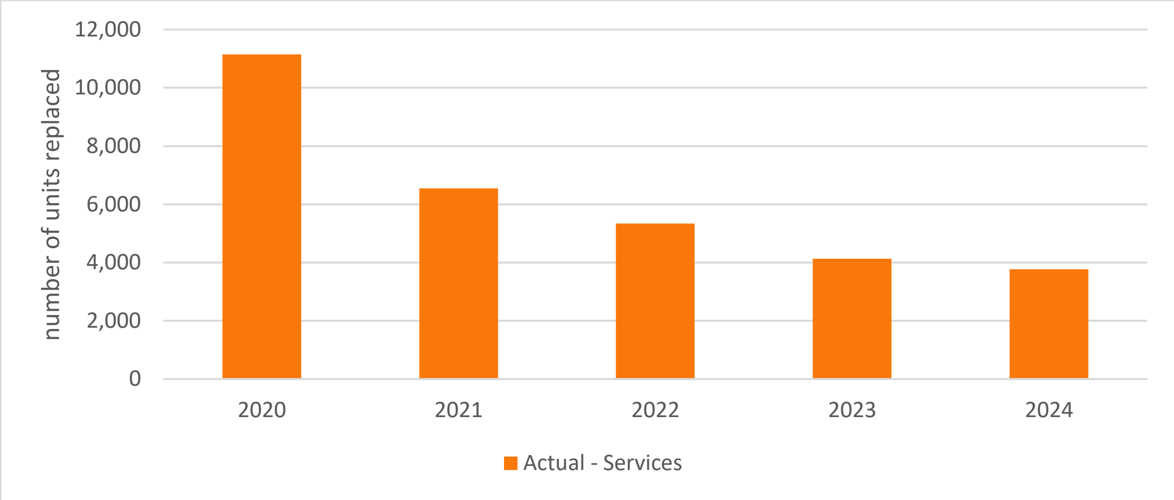


Figure 72 - Services actual replacement rate

Services forecast risk to service outcomes (base case)

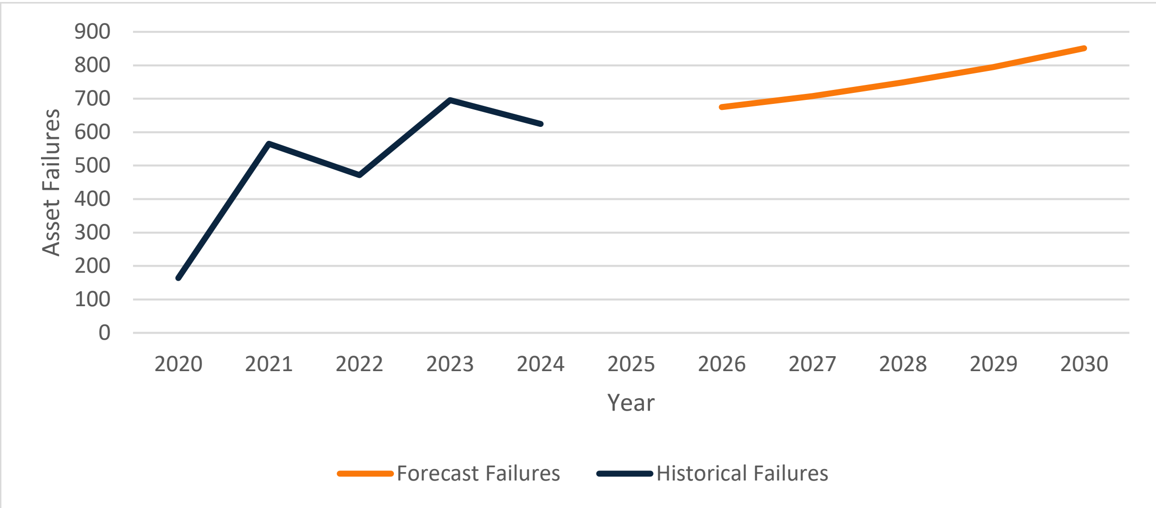


Figure 73 – Historical and forecast service failures

Figure 74 shows the current risk to service outcomes for services and how this would grow if we continue our current replacement rate.

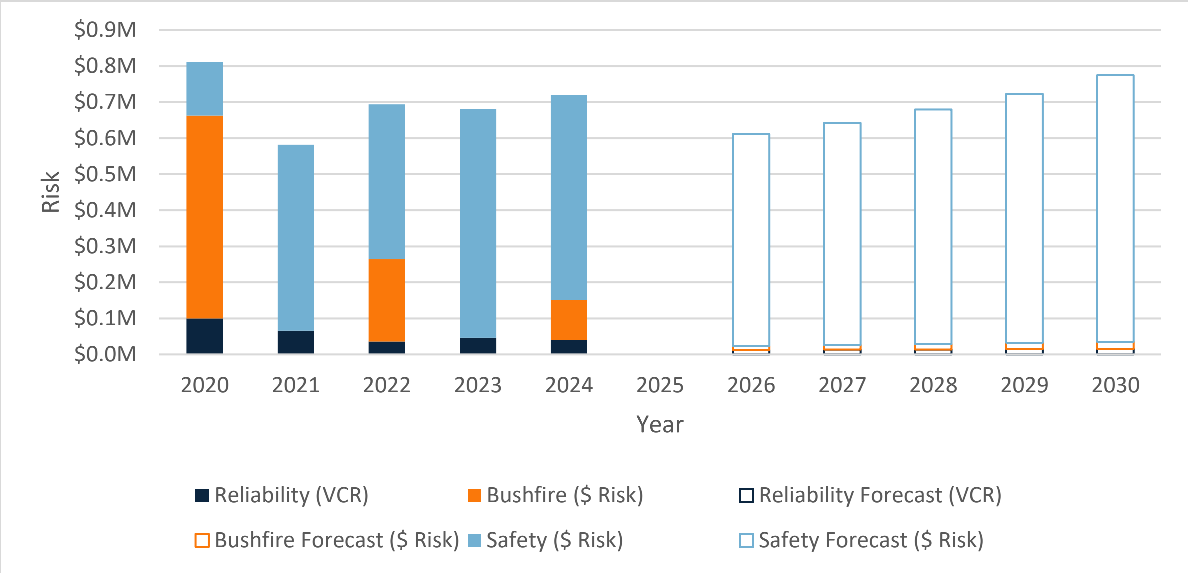


Figure 74 – Historical and forecast services risk (base case, modelled only)

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.

Services forecast renewal expenditure summary (2025-30)

We considered three scenarios (i.e. options) in forecasting expenditure for services, being a **base case** (using actual spend), **economic scenario** and our **proposed scenario**. We have provided an additional comparison with the AER repex model output. The proposed expenditure for services is lower than current expenditure as the modelling suggests there is greater benefit/cost investments to be made in other asset categories, to achieve our target customer service outcomes.

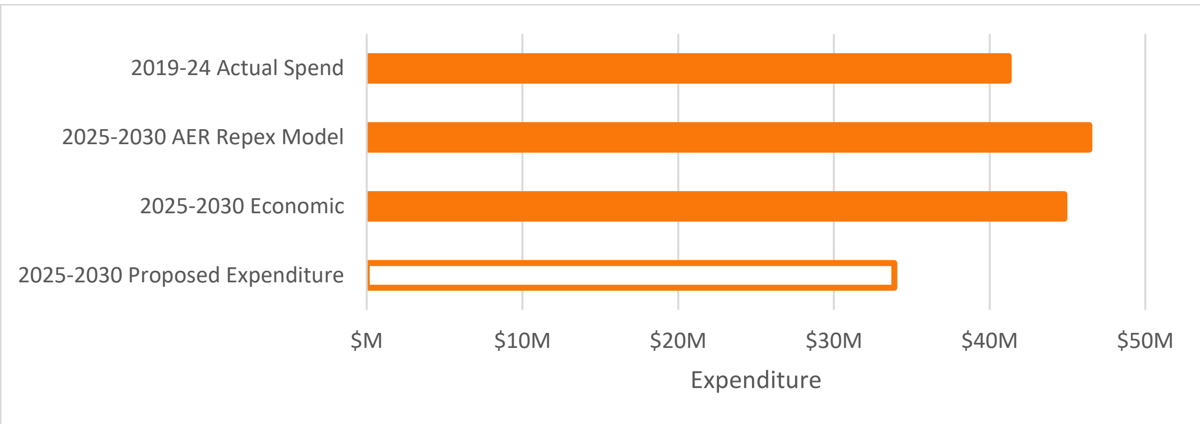


Figure 75 – Services expenditure comparison

Services rate of renewal (2019-2030)

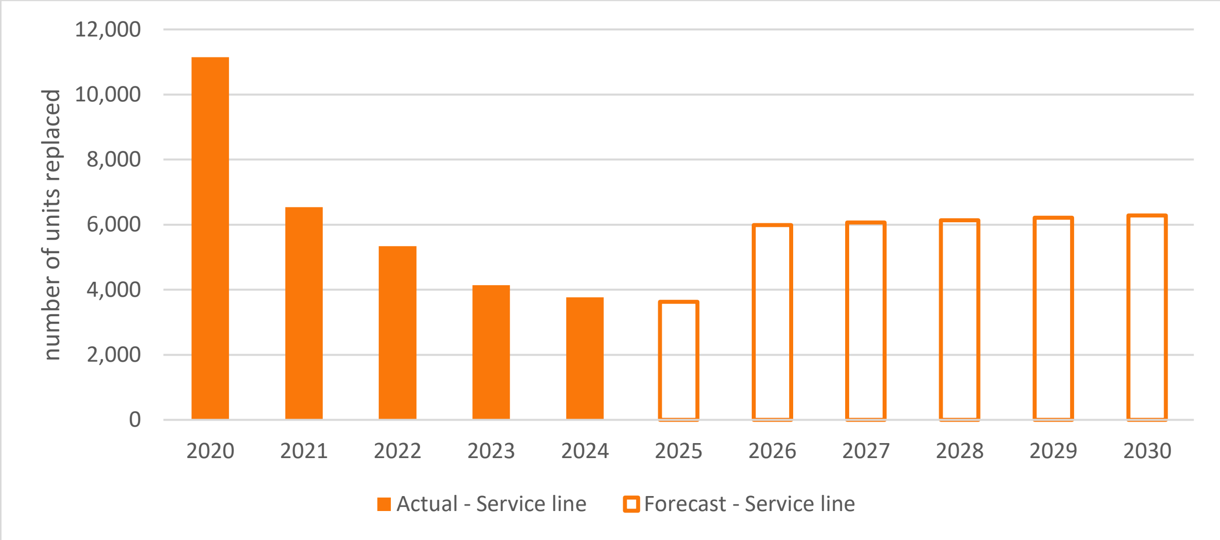


Figure 76 - Services actual and forecasted replacement rate

Figure 76 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 77 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.

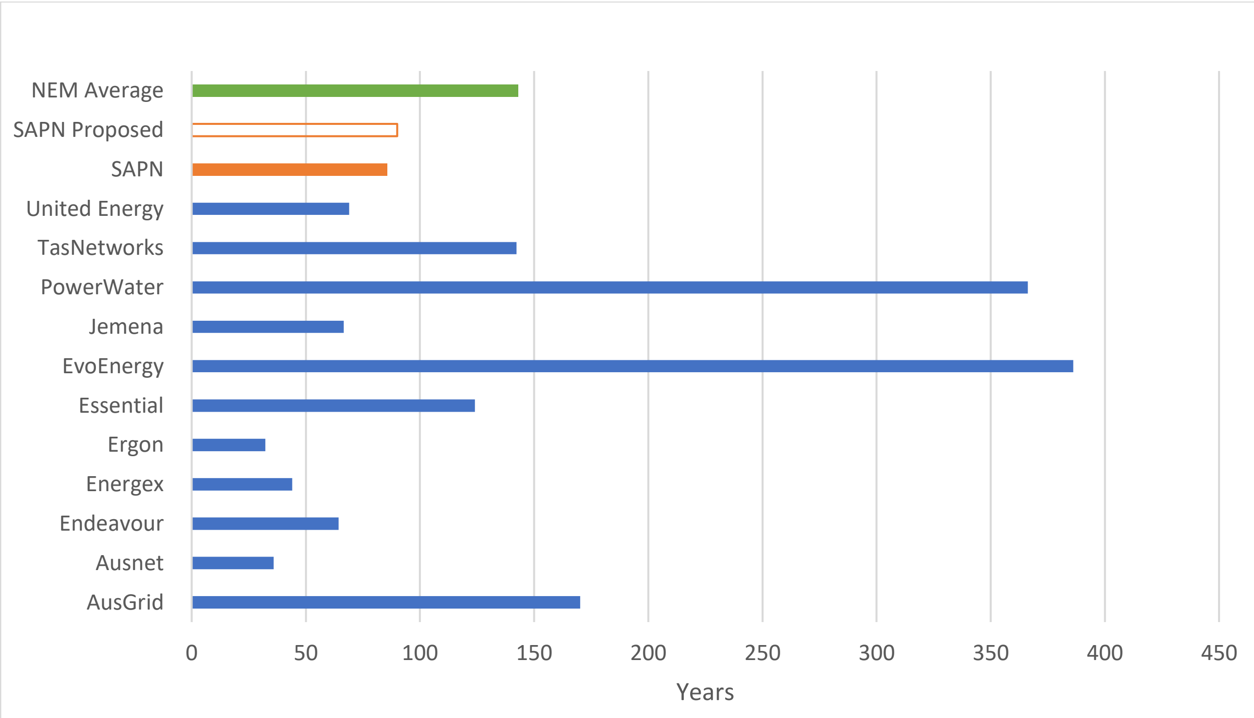


Figure 77 - DNSP service replacement rate comparison

Services forecast risk to service outcomes (proposed)

Figure 78 shows the observed performance impact from service assets along with the forecast impact on service outcomes given our proposed investment. Our risk modelling of service lines, combined with unmodelled projections of service component risk, shows that service outcomes can be allowed to deteriorate slightly in this asset category, relative to the base case, at the benefit of higher value investment in other asset categories.

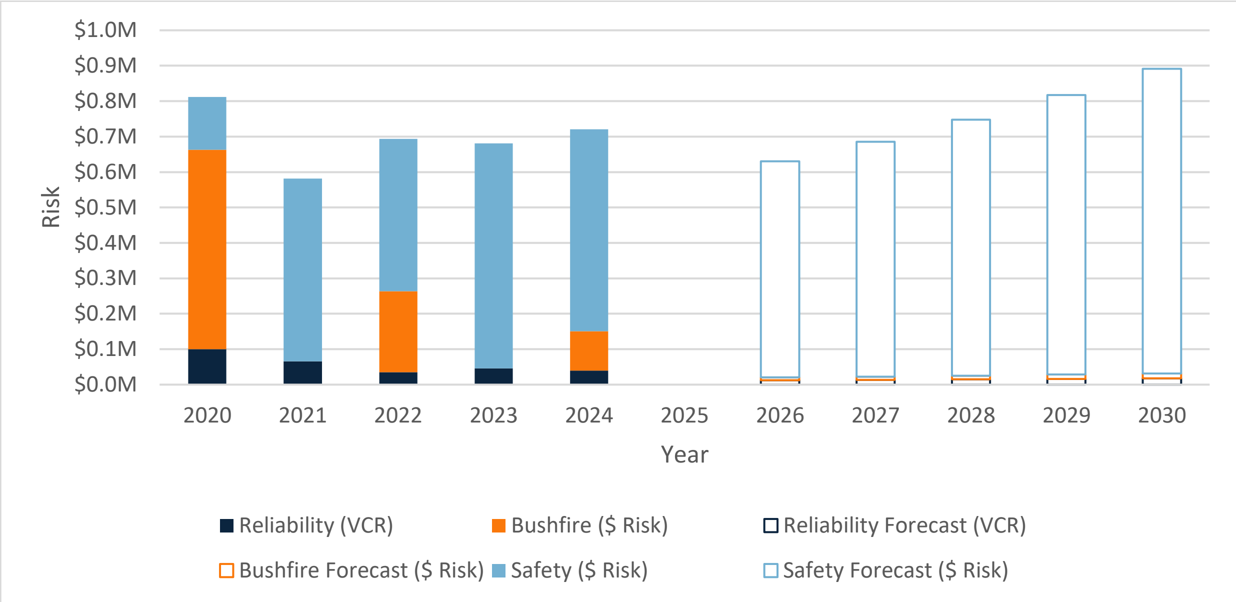


Figure 78 - Historic and forecast services risk (proposed expenditure, modelled only)

6.9 Powerline and Zone Substation – other

The 'other' categories of expenditure was based on historical expenditure and accepted in the Draft Decision and therefore we have not sought to revise our proposal for this expenditure category.

6.10 Zone substation circuit breakers, transformers and protection relays

The forecast expenditure for the Zone substation circuit breakers, transformers and protection relays remain unchanged from our original proposal. The concerns with the risk-modelling outlined in the Draft Decision applied only to Powerline assets. Similarly, the systemic asset failure data issues discovered only related to powerline assets. The risk-cost modelling and expenditure forecasts for Zone substation circuit breakers, transformers and protection relays have not been revised.

It should be noted that while risk-cost modelling has been used in developing the zone substation and protection relay forecasts, these asset class expenditure forecasts are built up from a combination of historical expenditure and forecast proactive expenditure.

6.11 Telecommunications

The expenditure forecast for Telecommunications was accepted in the Draft Decision and therefore we have not sought to revise our proposal for this expenditure category.

6.12 Major projects and targeted programs

The Hindley Street and Northfield substation major projects were accepted in the Draft Decision. No revisions are proposed to the forecast expenditure for these projects.

Appendix A – Analysis of major event weather effects on outage durations

Table 5 – Revised proposal risk cost modelling duration input parameters

	Revised proposal durations (MEDs removed)			
Asset Category	CBD	RURAL LONG	RURAL SHORT	URBAN
CABLE; <=1kV	323.5	280.0	210.0	261.0
CABLE; >1kV & <=11kV	98.7	155.3	209.0	137.0
CABLE; >11kV & <=22kV	0.0	143.0	143.0	0.0
CABLE; >22kV & <= 33kV	89.5	342.4	122.0	184.0
CABLE; >33kV & <= 66kV	0.0	0.0	0.0	0.0
CABLE CBD; <=1kV	323.5	280.0	210.0	261.0
CABLE CBD; >1kV & <=11kV	98.7	155.3	209.0	137.0
CABLE CBD; >11kV & <=22kV	0.0	143.0	143.0	0.0
CABLE CBD; >22kV & <= 33kV	89.5	342.4	122.0	184.0
CABLE; >33kV & <= 66kV	0.0	0.0	0.0	0.0
CONDUCTOR; <=1kV	160.0	234.0	192.5	160.0
CONDUCTOR; >1kV & <=11kV	124.0	169.0	138.0	124.0
CONDUCTOR; >11kV & <=22kV	0.0	286.5	183.8	312.0
CONDUCTOR; >22kV & <=66kV	0.0	153.4	145.2	173.0
POLE; <=1kV	96.0	179.0	103.0	96.0
POLE; >1kV & <=11kV	310.1	198.6	222.6	310.1
POLE; >11kV & <=22kV	422.4	422.4	422.4	422.4
POLE; >22kV & <=66kV	360.3	576.3	360.3	360.3
RECLOSER	0.0	259.0	210.1	308.6
SECTIONALISER	70.9	70.9	70.9	70.9
SERVICE LINE	129.0	232.5	186.5	187.0
SWITCHING CUBICLE	197.7	124.9	286.3	197.7
KIOSK MOUNTED ; < = 22kV ; < = 60 kVA ; SINGLE PHASE	40.7	851.0	636.0	272.5
KIOSK MOUNTED ; < = 22kV ; < = 60 kVA ; MULTIPLE PHASE	40.7	851.0	636.0	272.5
KIOSK MOUNTED ; < = 22kV ; > 600 kVA ; SINGLE PHASE	40.7	851.0	636.0	272.5
KIOSK MOUNTED ; < = 22kV ; > 600 kVA ; MULTIPLE PHASE	40.7	851.0	636.0	272.5
KIOSK MOUNTED ; < = 22kV ; > 60 kVA AND < = 600 kVA ; MULTIPLE PHASE	40.7	851.0	636.0	272.5
KIOSK MOUNTED ; < = 22kV ; > 60 kVA AND < = 600 kVA ; SINGLE PHASE	40.7	851.0	636.0	272.5
KIOSK MOUNTED ; > = 22kV & < = 33kV ;	40.7	851.0	636.0	272.5
POLE MOUNTED ; < = 22kV ; < = 60 kVA ; MULTIPLE PHASE	51.0	232.0	207.0	217.1
POLE MOUNTED ; < = 22kV ; < = 60 kVA ; SINGLE PHASE	51.0	232.0	207.0	217.1
POLE MOUNTED ; < = 22kV ; > 60 kVA AND < = 600 kVA ; MULTIPLE PHASE	51.0	232.0	207.0	217.1
POLE MOUNTED ; > 22kV ; < = 60 kVA	51.0	232.0	207.0	217.1
POLE MOUNTED ; > 22kV ; > 60 kVA AND < = 600 kVA	51.0	232.0	207.0	217.1
POLE MOUNTED ; > 22kV ; > 600 kVA	51.0	232.0	207.0	217.1
POLE MOUNTED ; < = 22kV ; > 600 kVA ; SINGLE PHASE	51.0	232.0	207.0	217.1
POLE MOUNTED ; < = 22kV ; > 600 kVA ; MULTIPLE PHASE	51.0	232.0	207.0	217.1
POLE MOUNTED ; < = 22kV ; > 60 kVA AND < = 600 kVA ; SINGLE PHASE	51.0	232.0	207.0	217.1

Table 6 - Alternative risk cost modelling duration input parameters with proceeding MEDs removed from data set

	Revised proposal durations with day following MEDs also removed			
Asset Category	CBD	RURAL LONG	RURAL SHORT	URBAN
CABLE; <=1kV	323.5	277.0	218.0	261.0
CABLE; >1kV & <=11kV	98.7	155.3	220.2	137.0
CABLE; >11kV & <=22kV	0.0	143.0	143.0	0.0
CABLE; >22kV & <= 33kV	89.5	342.4	122.0	184.0
CABLE; >33kV & <= 66kV	0.0	0.0	0.0	0.0
CABLE CBD; <=1kV	323.5	277.0	218.0	261.0
CABLE CBD; >1kV & <=11kV	98.7	155.3	220.2	137.0
CABLE CBD; >11kV & <=22kV	0.0	143.0	143.0	0.0
CABLE CBD; >22kV & <= 33kV	89.5	342.4	122.0	184.0
CABLE; >33kV & <= 66kV	0.0	0.0	0.0	0.0
CONDUCTOR; <=1kV	160.0	233.0	191.5	160.0
CONDUCTOR; >1kV & <=11kV	129.0	169.0	138.0	129.0
CONDUCTOR; >11kV & <=22kV	0.0	286.0	183.8	312.0
CONDUCTOR; >22kV & <=66kV	0.0	153.4	145.2	173.0
POLE; <=1kV	96.0	179.0	103.0	96.0
POLE; >1kV & <=11kV	310.1	198.6	222.6	310.1
POLE; >11kV & <=22kV	422.4	422.4	422.4	422.4
POLE; >22kV & <=66kV	360.3	576.3	360.3	360.3
RECLOSER	0.0	258.9	210.1	308.6
SECTIONALISER	70.9	70.9	70.9	70.9
SERVICE LINE	129.0	225.0	198.0	182.5
SWITCHING CUBICLE	198.4	124.9	286.3	198.4
KIOSK MOUNTED ; < = 22kV ; < = 60 kVA ; SINGLE PHASE	40.7	851.0	636.0	272.5
KIOSK MOUNTED ; < = 22kV ; < = 60 kVA ; MULTIPLE PHASE	40.7	851.0	636.0	272.5
KIOSK MOUNTED ; < = 22kV ; > 600 kVA ; SINGLE PHASE	40.7	851.0	636.0	272.5
KIOSK MOUNTED ; < = 22kV ; > 600 kVA ; MULTIPLE PHASE	40.7	851.0	636.0	272.5
KIOSK MOUNTED ; < = 22kV ; > 60 kVA AND < = 600 kVA ; MULTIPLE PHASE	40.7	851.0	636.0	272.5
KIOSK MOUNTED ; < = 22kV ; > 60 kVA AND < = 600 kVA ; SINGLE PHASE	40.7	851.0	636.0	272.5
KIOSK MOUNTED ; > = 22kV & < = 33kV ;	40.7	851.0	636.0	272.5
POLE MOUNTED ; < = 22kV ; < = 60 kVA ; MULTIPLE PHASE	51.0	232.0	209.4	210.6
POLE MOUNTED ; < = 22kV ; < = 60 kVA ; SINGLE PHASE	51.0	232.0	209.4	210.6
POLE MOUNTED ; < = 22kV ; > 60 kVA AND < = 600 kVA ; MULTIPLE PHASE	51.0	232.0	209.4	210.6
POLE MOUNTED ; > 22kV ; < = 60 kVA	51.0	232.0	209.4	210.6
POLE MOUNTED ; > 22kV ; > 60 kVA AND < = 600 kVA	51.0	232.0	209.4	210.6
POLE MOUNTED ; > 22kV ; > 600 kVA	51.0	232.0	209.4	210.6
POLE MOUNTED ; < = 22kV ; > 600 kVA ; SINGLE PHASE	51.0	232.0	209.4	210.6
POLE MOUNTED ; < = 22kV ; > 600 kVA ; MULTIPLE PHASE	51.0	232.0	209.4	210.6
POLE MOUNTED ; < = 22kV ; > 60 kVA AND < = 600 kVA ; SINGLE PHASE	51.0	232.0	209.4	210.6

Table 7 - % change between revised proposal duration input parameters and alternative input parameters

	% change			
Asset Category	CBD	RURAL LONG	RURAL SHORT	URBAN
CABLE; <=1kV	0.0%	-1.1%	3.8%	0.0%
CABLE; >1kV & <=11kV	0.0%	0.0%	5.4%	0.0%
CABLE; >11kV & <=22kV	0.0%	0.0%	0.0%	0.0%
CABLE; >22kV & <= 33kV	0.0%	0.0%	0.0%	0.0%
CABLE; >33kV & <= 66kV	0.0%	0.0%	0.0%	0.0%
CABLE CBD; <=1kV	0.0%	-1.1%	3.8%	0.0%
CABLE CBD; >1kV & <=11kV	0.0%	0.0%	5.4%	0.0%
CABLE CBD; >11kV & <=22kV	0.0%	0.0%	0.0%	0.0%
CABLE CBD; >22kV & <= 33kV	0.0%	0.0%	0.0%	0.0%
CABLE; >33kV & <= 66kV	0.0%	0.0%	0.0%	0.0%
CONDUCTOR; <=1kV	0.0%	-0.4%	-0.5%	0.0%
CONDUCTOR; >1kV & <=11kV	4.0%	0.0%	0.0%	4.0%
CONDUCTOR; >11kV & <=22kV	0.0%	-0.2%	0.0%	0.0%
CONDUCTOR; >22kV & <=66kV	0.0%	0.0%	0.0%	0.0%
POLE; <=1kV	0.0%	0.0%	0.0%	0.0%
POLE; >1kV & <=11kV	0.0%	0.0%	0.0%	0.0%
POLE; >11kV & <=22kV	0.0%	0.0%	0.0%	0.0%
POLE; >22kV & <=66kV	0.0%	0.0%	0.0%	0.0%
RECLOSER	0.0%	0.0%	0.0%	0.0%
SECTIONALISER	0.0%	0.0%	0.0%	0.0%
SERVICE LINE	0.0%	-3.2%	6.2%	-2.4%
SWITCHING CUBICLE	0.3%	0.0%	0.0%	0.3%
KIOSK MOUNTED ; < = 22kV ; < = 60 kVA ; SINGLE PHASE	0.0%	0.0%	0.0%	0.0%
KIOSK MOUNTED ; < = 22kV ; < = 60 kVA ; MULTIPLE PHASE	0.0%	0.0%	0.0%	0.0%
KIOSK MOUNTED ; < = 22kV ; > 600 kVA ; SINGLE PHASE	0.0%	0.0%	0.0%	0.0%
KIOSK MOUNTED ; < = 22kV ; > 600 kVA ; MULTIPLE PHASE	0.0%	0.0%	0.0%	0.0%
KIOSK MOUNTED ; < = 22kV ; > 60 kVA AND < = 600 kVA ; MULTIPLE PHASE	0.0%	0.0%	0.0%	0.0%
KIOSK MOUNTED ; < = 22kV ; > 60 kVA AND < = 600 kVA ; SINGLE PHASE	0.0%	0.0%	0.0%	0.0%
KIOSK MOUNTED ; > = 22kV & < = 33kV ;	0.0%	0.0%	0.0%	0.0%
POLE MOUNTED ; < = 22kV ; < = 60 kVA ; MULTIPLE PHASE	0.0%	0.0%	1.2%	-3.0%
POLE MOUNTED ; < = 22kV ; < = 60 kVA ; SINGLE PHASE	0.0%	0.0%	1.2%	-3.0%
POLE MOUNTED ; < = 22kV ; > 60 kVA AND < = 600 kVA ; MULTIPLE PHASE	0.0%	0.0%	1.2%	-3.0%
POLE MOUNTED ; > 22kV ; < = 60 kVA	0.0%	0.0%	1.2%	-3.0%
POLE MOUNTED ; > 22kV ; > 60 kVA AND < = 600 kVA	0.0%	0.0%	1.2%	-3.0%
POLE MOUNTED ; > 22kV ; > 600 kVA	0.0%	0.0%	1.2%	-3.0%
POLE MOUNTED ; < = 22kV ; > 600 kVA ; SINGLE PHASE	0.0%	0.0%	1.2%	-3.0%
POLE MOUNTED ; < = 22kV ; > 600 kVA ; MULTIPLE PHASE	0.0%	0.0%	1.2%	-3.0%
POLE MOUNTED ; < = 22kV ; > 60 kVA AND < = 600 kVA ; SINGLE PHASE	0.0%	0.0%	1.2%	-3.0%