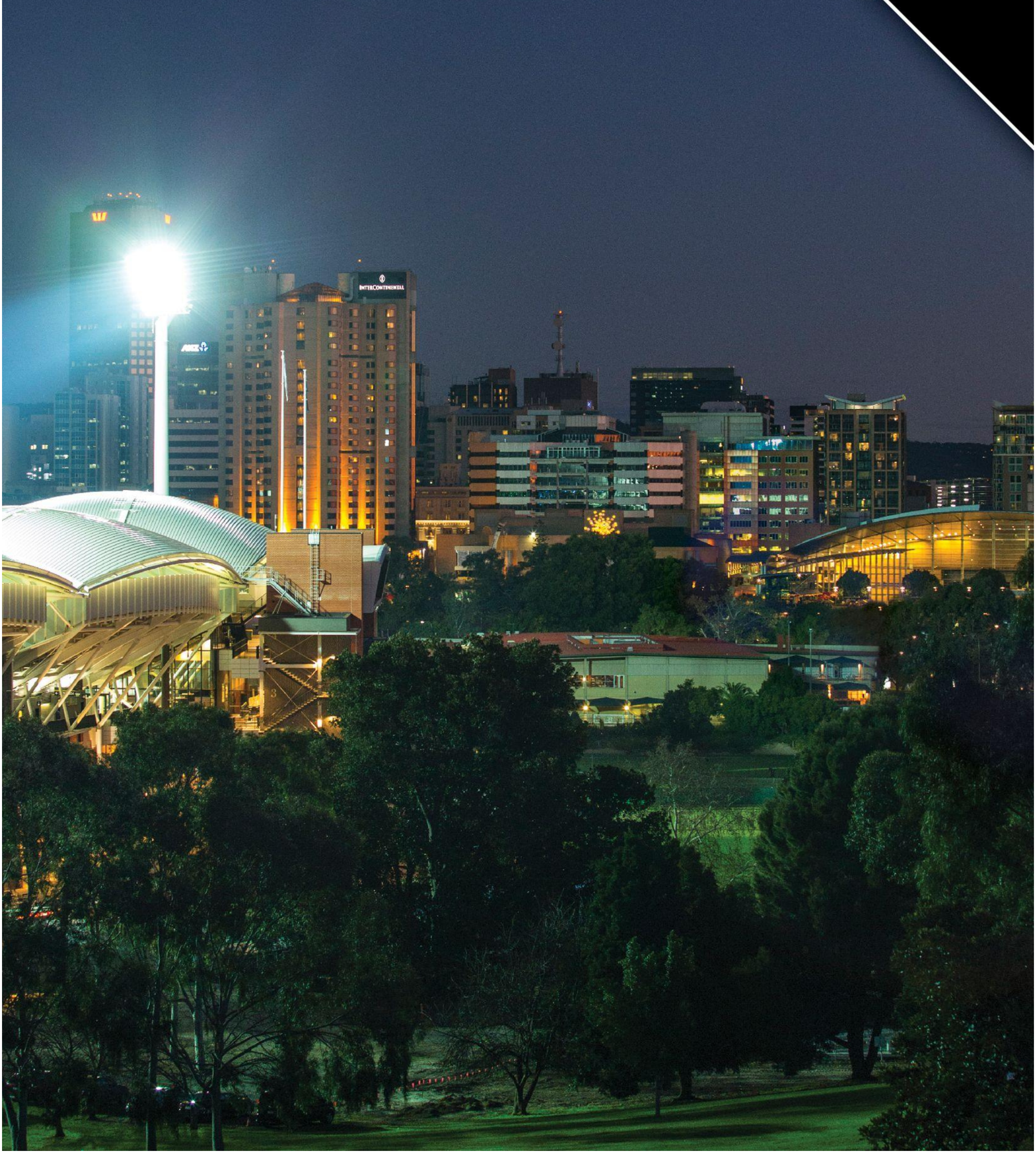
Attachment 20.65

SA Power Networks: Asset Management Plan 3.2.05 Substation Circuit Breakers 2014 to 2025



ASSET MANAGEMENT PLAN 3.2.05 SUBSTATION CIRCUIT BREAKERS

2014 TO 2025

Published: October 2014

SA Power Networks

www.sapowernetworks.com.au

OWNERSHIP OF STANDARD

Procedure 916 Annex B
Issue 2/13

OWNERSHIP OF STANDARD

Name of Standard / Manual: ***AMP 3.2.05 Substation Circuit Breakers***

Standard/Manual Owner - Title: ***Manager Network Asset Management***

Name: ***S Wachtel***

Standard Last Reviewed: August 2014

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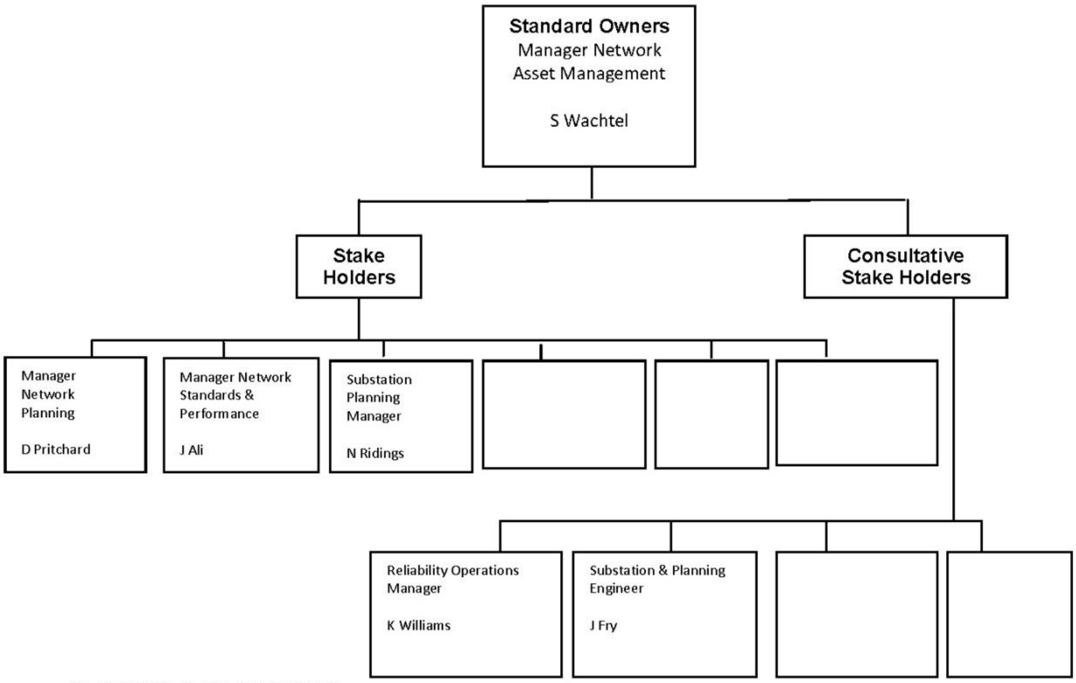
Review Period: 5 Years

Next Review Due: October 2019 *(ie. When the next review process is due to commence)*

STANDARD/MANUAL OWNERSHIP STRUCTURE



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COMMENTS

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(Asset Management Plan 3.2.05 – Substation Circuit Breakers)

DOCUMENT VERSION

Date	Version	Description of Change/Revision
April 2014	0.1	Initial Draft
August 2014	0.2	Final Draft incorporating reviewers comments
28 October 2014	1.0	Final

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1. EXECUTIVE SUMMARY

1.1 Asset Management Objectives

The key asset management objectives to be achieved by SA Power Networks are:

- Safety – To maintain and operate assets such that the risks to employees, contractors and the public are maintained at a level as low as reasonably practicable.
- Regulatory Compliance – To meet all regulatory requirements associated with the Electrical Distribution Networks.
- Environmental - To maintain and operate assets so that the risks to the environment are kept as low as reasonably practicable.
- Economic – To ensure that costs are prudent, efficient, consistent with accepted industry practices and necessary to achieve the lowest sustainable life cycle cost of providing electrical distribution services.
- Customer Service – To maintain and operate assets consistent with providing a high level of service (safety and security of supply) to customers.

1.2 Asset Management Plan Activities

To assist SA Power Networks in achieving the above objectives for substation circuit breakers, an asset management plan is prepared to identify the primary issues and strategies for managing substation circuit breakers, including the asset maintenance and operational functions of substation circuit breakers.

The key objectives of the AMP are essentially:

- To facilitate the delivery of our strategic and corporate goals
- The establishment of a strategic asset management framework
- The setting of asset management policies in relation to user demand, levels of service, life-cycle management and funding for asset sustainability

1.3 Asset Management Strategies

The lifecycle management of substation circuit breakers will assist SA Power Networks in the reliable and cost effective operation of the distribution network. This requires implementing the Asset Management Strategy (referenced in AMP 3.0.01 Condition Monitoring and Life Assessment Methodology 2014-2025).

The Asset Management Strategy is:

> *"to optimise the capital investment through targeted replacement or refurbishment of assets, based on assessment of asset condition and risk, and also seeks to provide sustainable lifecycle management of assets through the use of condition monitoring and life assessment techniques."*

SA Power Networks undertakes Asset Management of substation circuit breakers through condition and performance monitoring that includes routine inspections, maintenance, overhaul and refurbishment to extend asset service life. These key functions ensure that SA Power Networks is consistent with sound asset and risk management principles to satisfy customer service needs, meet licence obligations, provide a safe environment for employees and the community, and deliver optimal returns to shareholders.

Manufacturers state a nominal lifespan for circuit breakers of 30 to 35 years although practical service life expectancies exceed this. SA Power Networks' circuit breaker assets vary greatly in age and construction from oil insulated circuit breakers installed between the period of 1930 to 1990, to more modern vacuum and SF_6 insulated units.

The consequence of in-service failures varies and range from supply interruptions, to environmental damage to fire and other safety issues. Failures may result in a supply interruption to a large number of customers

The lifecycle management of substation circuit breakers is comprised of multiple stages, illustrated in the figure below. The creation, implementation and monitoring of plans in the lifecycle stages are important for the effective implementation of the Substation Circuit breakers Asset Management Plan. This will help ensure that the operation of SA Power Networks' distribution network meets the industry and regulatory standards whilst providing optimal return to shareholders.

The primary focus of this asset management plan is to manage the substation circuit breakers in the Asset Operation and End of Life stages of the asset lifecycle. It is important that issues identified in any of the lifecycle stages are fed back into the other stages. This continuous feedback of information from each lifecycle stage to other stages will improve the reliability and efficiency of SA Power Networks' distribution network. The residual risks after implementing this Asset Management Plan are considered as low.

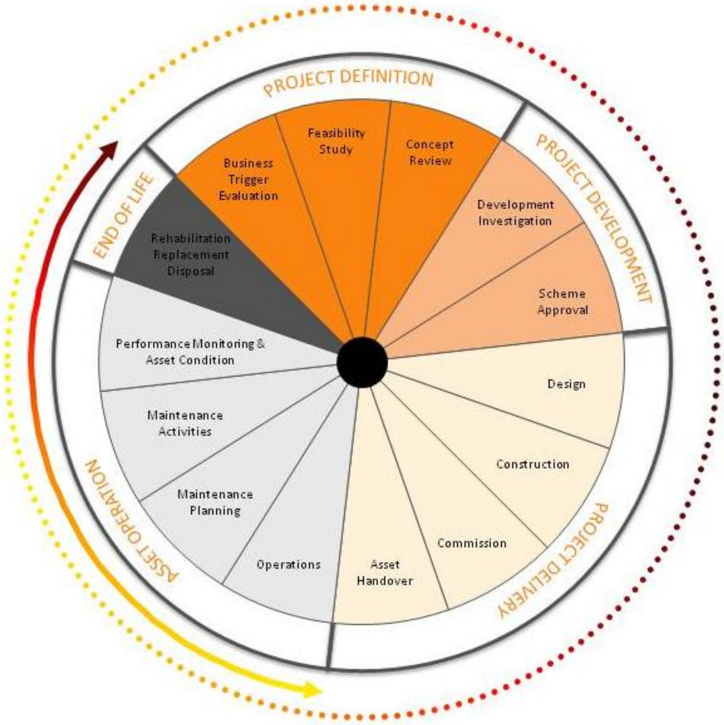


Figure 1 : SA Power Network Asset Life Cycle

1.4 Background

Circuit breakers are power switching devices installed within substations to selectively control the energisation of electricity distribution equipment and provide protection for the public, personnel and equipment by selectively isolating network faults.

The safe and reliable operation of the circuit breaker fleet is vital to network operation, with circuit breakers playing an essential role in limiting risk exposure to the public, personnel and equipment.

SA Power Networks' circuit breaker assets vary greatly in age and construction from oil insulated circuit breakers to modern vacuum and SF_6 insulated units. SA Power Networks' HV circuit breaker assets operate across a range of network voltages including 66kV, 33kV, 11kV, 7.6kV and 6.6kV with service lives extending to 78 years.

As of 30 June 2014, there are approximately 1920 Circuit breakers in service on the network with unit replacement values ranging from $250,000 to in excess of $500,000.

1.5 Expenditure

Annual capital expenditure for substation circuit breaker replacement is shown in the figure below (actual expenditure is shown between 2010 to 2013, 2014 budgeted expenditure and forecast expenditure 2015 through 2025). Historical replacement expenditure is underpinned by investment in aged, deteriorated and unreliable circuit breakers in rural 33kV and 66kV distribution networks, with significant additional expenditure between 2011 and 2013 required to replace poor condition, oil insulated 11kV indoor switchgear.

Replacement expenditure forecasts for 2015 through 2025 reflect a change of investment focus driven by the completion of targeted programs in the 66kV and 33kV networks and the need for greater ongoing levels of investment to manage the current fleet of poor condition indoor Small Bulk Oil 11kV switchgear.

A total of around 223 circuit breakers are programmed to be replaced or refurbished during the period of this plan, 2014 to 2025 which represents a renewal rate of approximately 1% of the population annually through to 2025.

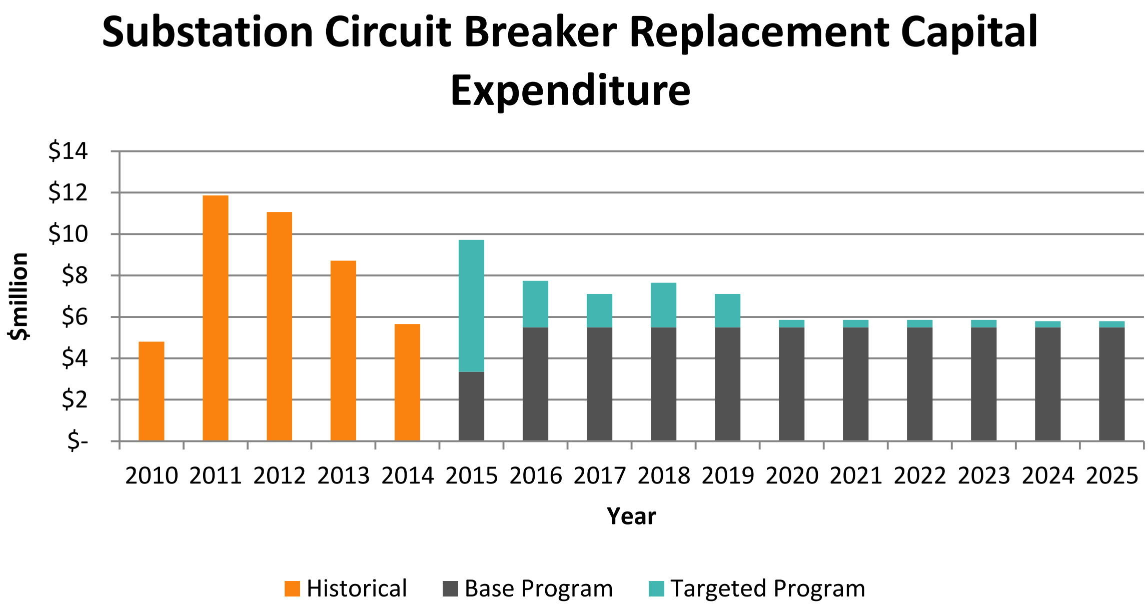


Figure 2 : Substation circuit breakers Replacement Capital Expenditure - historical and forecast

1.6 Planned Improvements in Asset Management

The forecast substation circuit breakers replacement schedule and resulting expenditure plan has been based on available asset information, historical data and guidelines from the SA Power Networks' Risk Management Framework. In order to continue developing and refining expenditure forecasts, SA Power Networks aim to improve and maintain the collection of asset information, specifically targeting:

- Asset condition and defects, including categorised condition ratings/scores
- Asset faults and failures, including detail into cause and symptoms of faults/failures and consequences of failures to better assess risk
- Cost of replacements, including labour and materials
- Improving asset health models to better identify circuit breakers for asset management action
- Investment in condition monitoring tools and techniques.

2. INTRODUCTION

2.1 Background

2.1.1 SA Power Networks' electricity network

SA Power Networks is a distribution network service provider (DNSP) in South Australia, Australia.

The history of SA Power Networks is as follows:

- Electricity Trust of South Australia (ETSA) was formed in 1946 through the nationalisation of Adelaide Electric Supply Company.
- Electricity Trust of South Australia privatised in 1999 and split into power generation, transmission and distribution. The distribution group became known as ETSA Utilities.
- In 2012, ETSA Utilities became rebranded to SA Power Networks. The rebranding emphasised the focus on SA Power Networks core business of serving business and residential customers in metropolitan, regional and remote areas of South Australia.

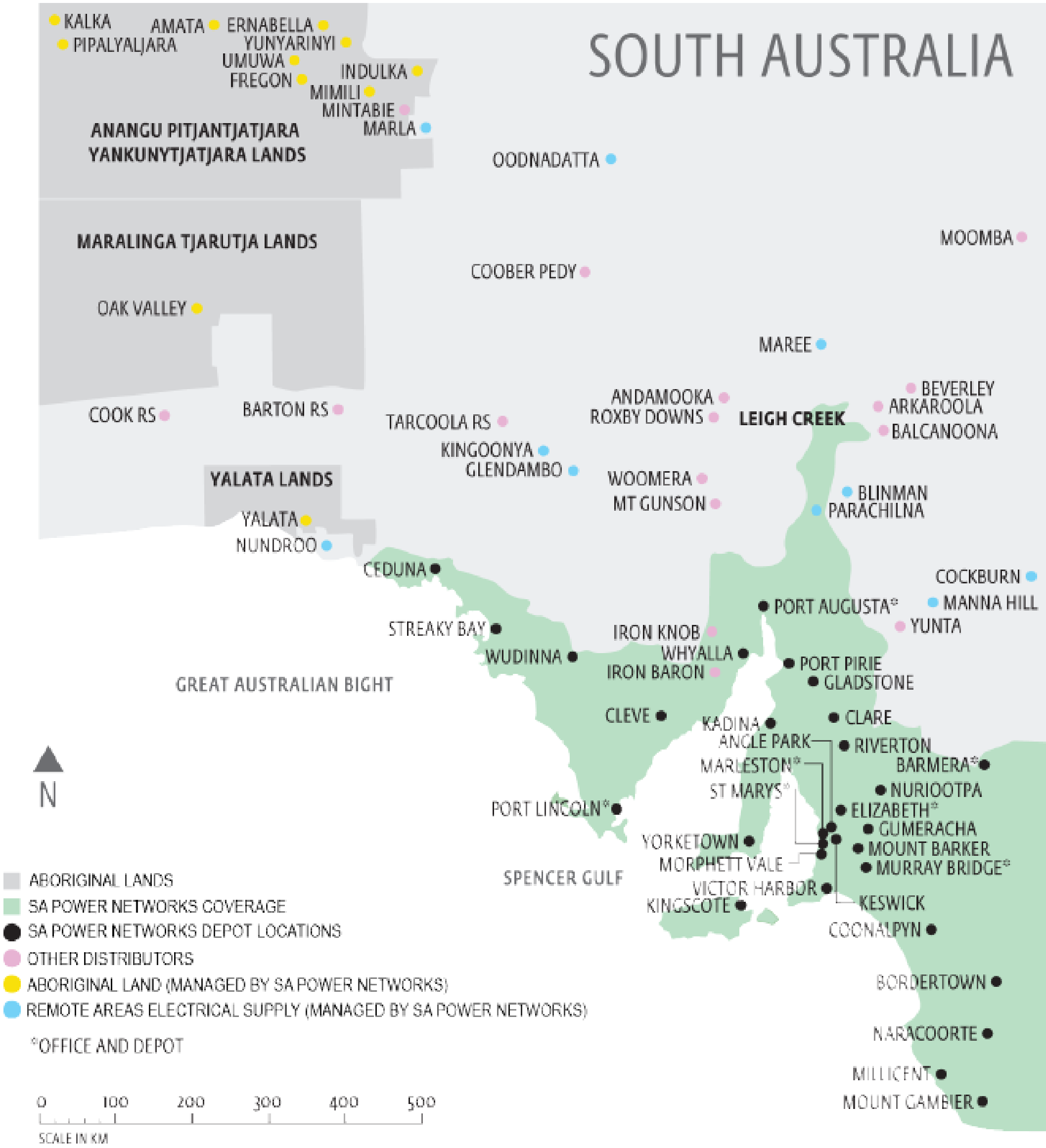


Figure 3 : SA Power Networks network map

2.2 Substation Circuit Breakers

Circuit breakers are power switching devices installed within High Voltage substations to selectively control the energisation of electricity distribution equipment. Circuit breakers play a critically important role in the safe and reliable operation of the electrical network as they are used to rapidly disconnect network faults and provide controlled isolation of sections of the distribution network.

The safe and reliable operation of the circuit breaker fleet is vital to network operation as they play an essential role in limiting the risks posed to the public, personnel and equipment. The consequence of an in-service failure varies from supply interruptions, environmental damage, fire start and related safety issues to wide ranging supply interruption to a large portions of the network.

Circuit breakers are generally classified by the medium used to interrupt the flow of electricity during operation. SA Power Networks' fleet of circuit breakers fall into the following classes:

- Bulk Oil: Current interruption and primary insulation provided by oil in an earthed metallic tank.
- Small Bulk Oil: similar to bulk oil circuit breakers, but smaller oil volume and lower operating voltage.
- Minimum Oil: Current interruption in an oil filler interrupter that is insulated from earth
- SF_6: Current interruption and primary insulation provided by sulphur hexaflouride (SF_6) gas.
- Vacuum: Current interruption in a specially designed vacuum interrupter.

SA Power Networks' circuit breaker assets vary greatly in age and styles from oil insulated circuit breakers installed between the period of 1930 to 1990, to more modern vacuum and SF_6 insulated units. SA Power Networks' circuit breakers operate across a range of network voltages, including 66kV, 33kV, 11kV, 7.6kV and 6.6kV, with service lives extending to 78 years. Within smaller CBD substations, SA Power Networks also has a number of 0.4kV circuit breakers on LV switchboards supplying customers within the Adelaide CBD.

2.3 Goals and Objectives of Asset Management

The key asset management objectives to be achieved by SA Power Networks are:

- Safety – To maintain and operate assets such that the risks to employees, contractors and the public are maintained at a level as low as reasonably practicable.
- Regulatory Compliance – To meet all regulatory requirements associated with the Electrical Distribution Networks.
- Environmental - To maintain and operate assets so that the risks to the environment are kept as low as reasonably practicable.
- Economic – To ensure that costs are prudent, efficient, consistent with accepted industry practices and necessary to achieve the lowest sustainable life cycle cost of providing electrical distribution services.
- Customer Service – To maintain and operate assets consistent with providing a high level of service (safety and security of supply) to customers.

To assist SA Power Networks in achieving the above objectives for substation circuit breakers, an asset management plan is prepared to identify the primary issues and strategies for managing substation circuit breakers, including the asset maintenance and operational functions of substation circuit breakers.

The key objectives of the AMP are essentially:

- To facilitate the delivery of our strategic and corporate goals
- The establishment of a strategic asset management framework
- The setting of asset management policies in relation to user demand, levels of service, life-cycle management and funding for asset sustainability

2.4 Plan Framework

2.4.1 Scope

Detailed Asset Management Plans, including this document, form part of a suite of documents used by SA Power Networks in the delivery of the asset management programs, as represented in Figure 4.

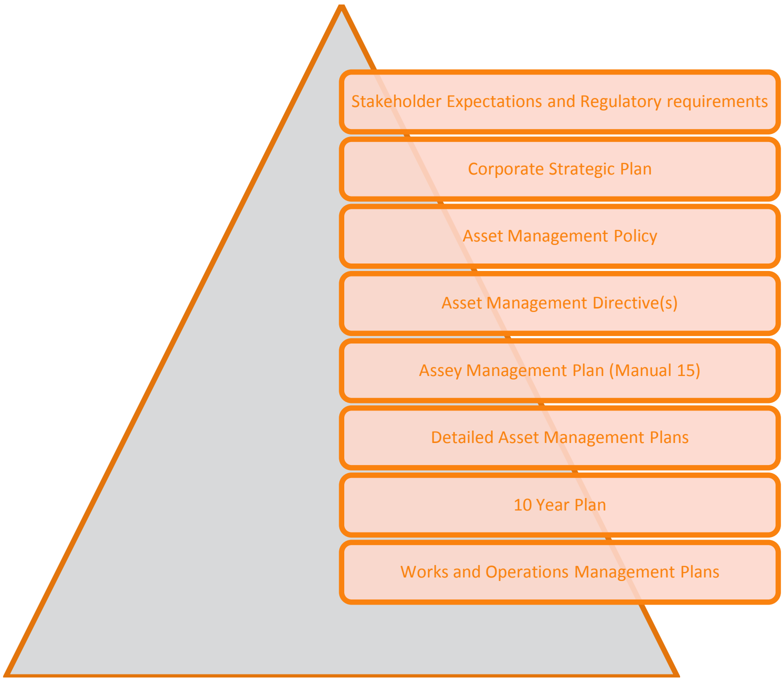


Figure 4 : Asset Management document framework

The Substation Circuit Breakers Asset Management Plan ensures that the distribution network is operating in a safe, reliable, and environmentally conscious manner. This enables the network to provide the required levels of service to customers and optimal returns to SA Power Networks' shareholders.

The scope of the Substation Circuit Breakers Asset Management Plan is to detail SA Power Networks' plans in managing these assets between 2014 and 2025.

2.4.2 Supporting documents and data

The Substation Circuit Breakers Asset Management Plan refers to the following SA Power Networks documents:

- Network Asset Management Plan Manual No. 15
- Network Maintenance Manual No. 12
- Substation Inspection Manual No. 19
- Condition Monitoring and Life Assessment (CM&LA) Methodology AMP.3.0.01

The Network Asset Management Plan Manual No. 15 describes SA Power Networks' management process for assets in the distribution network. The document describes the organisational strategies, process and systems to ensure economical, efficient and effective serviceability of assets in the electricity network.

The Network Maintenance Manual No. 12 details maintenance plans for assets in the distribution network. The maintenance strategies adopted for each asset are described in detail. The description of the type of maintenance and sampling/inspection frequencies is provided for overhead lines and substations.

The Substation Inspection Manual No. 19 provides a detailed guide in assessing the physical condition of substation assets, the procedures in recording the data collected during the condition assessment and prioritisation of defects. High resolution photographs of common defects of components in substations and the codes for capturing the common defects are provided in the manual.

SA Power Networks' asset management philosophy and approach is discussed in the Condition Monitoring and Life Assessment (CM&LA) Methodology Asset Management Plan. The methodology provides a basis for the economic, reliable and safe management of assets including substation circuit breakers.

2.4.3 Structure of Substation Circuit Breakers AMP

This asset management plan is aligned to the framework outlined in International Infrastructure Management Manual (2011) and is to be implemented between 2014 and 2025.

3. LEVELS OF SERVICE

Service levels should represent the expectations that stakeholders (asset owners as well as customers) have of the assets. Desired service levels drive the strategic and operational elements of the asset management plan as assets fulfil their designed intention throughout the asset life-cycle. Issues such as cyclic or periodic replacement cycles, routine maintenance schedules and asset inspections (often part of the Routine Maintenance Plan) are all integral to Service Level provision.

3.1 Customer Research and Expectations

3.1.1 SA Power Networks Customer Research

There is no specific customer expectation survey in relation to substation circuit breakers which form part the overall Distribution Network. It is reasonable to expect that the information derived from customer research for the Distribution Network is applicable to its components and can be adapted to substation circuit breakers.

3.1.2 Network Customer Expectations

SA Power Networks' stakeholder engagement program for the 2015/16-2019/20 regulatory period included commissioning Deloitte to conduct a Consumer Consultation Survey in May 2013, and facilitate a number of stakeholder and consumer workshops held regionally and in the metropolitan area. The survey and workshops content was developed though consultation with SA Power Networks and the Essential Services Commission of South Australia (ESCoSA), and was informed by earlier work. There were 13 Key Consumer Insights as a result of this work.

The key relevant consumer insights were:

- Continue asset management and investment to driver reliability, manage risk and support economic growth. Asset management initiatives that have a direct impact on reliability and/or prevent potential safety hazards were rated as most important. Consumer priority areas included assets in high bushfire risk areas and near roads in residential areas. The priority areas for Business and Government consumers included areas that would support economic growth.

- Prioritise preventative maintenance to mitigate risk. All preventative maintenance initiative should consider potential safety hazards and be completed as a priority when risks can be mitigated.
- CFS Bushfire Safer Places should have continuous power. Investment in bushfire management initiatives would ensure that essential services are managed under critical conditions.
- Maximise opportunities to improve the visual appearance of assets. Undergrounding of the network and substation façade treatment initiatives were universally supported, with priority areas for completion deemed to be in areas where the visual appearance of the network has the largest effect on the community.
- Consider improvements in public safety and reliability in asset planning. Consumers identified high bushfire risk areas and areas where additional safety and reliability benefits could be realised as priority areas for undergrounding the network.

On this basis, SA Power Networks considers that it is appropriate for the forthcoming 2015/16–2019/20 Regulatory Control Period (the 2015 Reset) to establish the reliability performance targets based on average historic performance levels, and develop a forward program of work seeking to maintain current levels of safety and reliability.

3.1.3 ESCoSA Service Standards

ESCoSA consulted with the South Australian community to develop the jurisdictional service standards to apply to SA Power Networks for the next regulatory period 2015/16-2019/20 by releasing an Issues Paper in March 2013 and a Draft Decision in November 2013.

ESCoSA has formed the view (ESCoSA, Final Decision, May 2014) that consistency between the parameters of the AERs STPIS and the jurisdictional service standards is of primary importance for the next regulatory period 2015/16-2019/20 in order to:

- Minimise the potential for conflicting incentives between elements of the service standard framework and the AERs pricing regime, this minimising the potential for unwarranted costs being borne by South Australian consumers; and
- Ensure appropriate incentives are provided to SA Power Networks to maintain current service levels and only improve service levels where the value to customers exceeds the cost of those improvements.

The service standards set are summarised as follows:

- **Network reliability service standards and** targets – reliability of the distribution network as measured by the frequency and duration of unplanned interruptions, with network performance service standards set to reflect difference in the levels of interconnection and redundancy in the physical network across the state. The network reliability targets require SA Power Networks to use its best endeavours to provide network reliability in line with average historical performance in the period 2009/10 to 2013/14. The reliability targets exclude performance during severe or abnormal weather events using the IEEE MED exclusion methodology.

- **Customer Service standards and targets** – Unchanged from the current customer service standards and targets. SA Power Networks will be required to continue to use its best endeavours to meeting the customer service responsive targets defined.
- **GSL Scheme** – SA Power Networks will be required to continue to make GSL payments to customers experiencing service worse than the pre-determined thresholds.
- **Performance monitoring and reporting** - the performance monitoring and reporting framework focus' on four particular areas of performance:
  - Reliability performance outcomes for customers in geographic regions against average historical performance
  - Operational responsiveness and reliability performance during MEDs
  - Identification and management of individual feeders with ongoing low-reliability performance
  - Assessment of the number of GSL Scheme payments made in each geographic region

3.2 Legislative requirements

Under the terms of its Distribution License, SA Power Networks is required to comply with a number of Acts, Codes of Practice, Rules, Procedures and Guidelines including, but not limited to:

- Electricity Act 1996
- National Electricity (South Australia) Law Act (NEL)
- National Energy Retail (South Australia) Law Act (NERL)
- SA Electricity Distribution Code (EDC)
- SA Electricity Metering Code (EMC)
- National Electricity Rules (NER)
- National Metrology Procedures (NMP)
- ESCoSA and AER Guidelines.

3.3 Regulatory Targets and Requirements

3.3.1 Performance Standards

SA Power Networks must use its best endeavours to achieve the reliability standards, as set out in Manual 15, during each year ending on 30 June.

3.3.2 Service Target Performance Incentive Scheme (STPIS)

SA Power Networks is required to operate within a Service Target Performance Incentive Scheme (STPIS), in accordance with the National Electricity Rules (NER). The intent of the STPIS is to provide SA Power Networks with a financial incentive to maintain and improve reliability performance to our customers.

The STPIS is based on annual unplanned SAIDI and SAIFI reliability performance in different feeder categories. Any departure from the specified reliability performance targets will result in an incentive or penalty to SA Power Networks via a distribution revenue adjustment.

3.3.3 Reliability

In the price-service setting process, the establishment of operational standards for the distribution network is fundamental.

For electricity distribution, the two key reliability standards set by the ESCoSA are based around the impact of supply interruptions on customers: the average annual duration of interruptions per customer (SAIDI) and the average annual frequency of interruptions per customer (SAIFI).

While there are no annual performance targets specified for the entire network (state-wide), there are implied targets based on the customer-weighted averages of the implied regional targets.

SA Power Networks' annual obligation to publicly report on low reliability performing feeders for the regulatory period is based on individual SAIDI feeder performance relative to relevant regional SAIDI targets which, on average, results in the identification of about 5% of total feeders (approximately 90 feeders) across the network throughout the regulatory period. A SAIDI threshold multiplier of 2.1 was determined for the current regulatory period, 2010/11 to 2014/15, to provide the required sample.

In assessing performance against the standards, the relevant test is two-fold: first, has the target been met?; if not, did SA Power Networks nevertheless use its best endeavours in its attempts to meet the target?

3.4 Current Levels of Service

The current Level of Service (LoS) as reported to ESCoSA for the period to 30 June published each year by ESCoSA.

4. FUTURE DEMAND

4.1 Demand Drivers

SA Power Networks identifies the following areas to be key influences on demand:

- New residential/commercial developments
- Increased air conditioner use
- New infrastructure

4.2 Demand Forecast

SA Power Networks recognises that there are alternatives to network solutions which may deliver either a lower cost or provide greater benefits to the electricity market, these solutions include and are not limited to:

- Embedded Generation
- Shifting consumption to a period outside the peak period
- Increasing customers' energy efficiency
- Curtailing demand at peak periods, with the agreement of the relevant customer(s)

4.3 Demand Impact on Assets

When circuit breakers are required to operate outside their design capabilities (current ratings and/or fault ratings) there is a risk of catastrophic failure. Failure of a circuit breaker would require the upstream circuit breaker to operate resulting in loss of supply to large parts of the network. Depending on the extent of the damage to the circuit breaker, full restoration of the circuit breaker could take from several days to several weeks.

4.4 Demand Management Plan

The SA Power Networks load forecast is reviewed annually after each summer peak load period. The review considers the impact of new peak load recordings, system modifications and new large load developments.

The load forecasting methodology produces 10% Probability of Exceedance (POE) and 50% POE forecasts for each element in the network

The aggregated impact of customer PV is considered in the forecasts based on measured performance of typical PV installations, installed PV capacity, time of peak demand and PV growth rate. The rapid growth of PV is anticipated to continue in the short term, and gradually slow down over the forward planning period. The rapid update of PV and adoption of energy efficient appliances has offset substation load growth, and in some instances reduced net load. The future of PV growth on peak demand is expected to be minimal as the time of peak load for most substations has shifted past 6PM, which is when PV output is approaching zero.

4.5 Key Asset Programmes to Meet Demand

Circuit Breaker replacements to meet demand are covered in AMP.1.1.01 – Distribution System Planning Report (DAPR). Replacements forecast within this asset management plan assume the implementation of replacements due to network capacity and are supplemental any replacements detailed within the DAPR.

5. LIFECYCLE MANAGEMENT

5.1 Background Data.

Circuit breakers are a vital component of the distribution network, providing critical fault isolation and switching capabilities. They frequently spend long periods between operating but must be able to rapidly disconnect faulted equipment and limit the safety risks posed to the public, personnel and equipment. A circuit breaker must be suitably rated to carry the full load of all circuits it supplies and must have enough fault breaking capacity to safely interrupt high short circuit currents under fault conditions.

The number of circuit breakers currently installed (as of 30 June 2014) at each voltage, and respective age distribution is outlined in Table 1.

It can be seen that the age, quantity and distribution of circuit breaker types varies significantly across the network.

Table 1: Distribution of circuit breakers across the network by age and service voltage

Age	Operating Voltage				
	6.6kV	7.6kV	11kV	33kV	66kV
0-15			443	119	261
16-25		9	110	10	22
26-35			60	2	58
36-45		6	129		46
46-55		16	327	54	46
56-65	10	10	86	56	29
66-75				9	1
76-85				1	
Totals	**10**	**41**	**1155**	**251**	**463**

Circuit breaker functional failures can be classified into a number of common types based on the nature of failure and the consequential effect on circuit breaker performance. The root cause for and failure mode will usually be specific to a particular construction, but typical failures include:

- Failure to trip, resulting in slow clearing of network faults, extended outages and consequential network damage (or network instability).
- Failure to reclose, resulting in an extended interruption of supply for transient faults.
- Failure to interrupt, resulting in a catastrophic explosive failure resulting in public and personnel safety risk, environmental impacts and widespread network outages.

For the purposes of asset management, circuit breaker functional failures can also be classified into common categories based on their consequential impact to network operation. These failure types for all circuit breaker types are set out in Table 2 below.

Table 2: Circuit Breaker Failure Types

Failure Scenario	Description
Minor	Failures (typically defects) that do not result in a service interruption.
Significant	Disruptive failures (unplanned or forced interruptions) that are repairable on site.
Major	Disruptive failures (unplanned or forced interruptions) that require emergency asset replacement or significant refurbishment, leaving the network in a contingency condition.
Condition replacement	Equipment discovered through condition monitoring (without disruptive failure) in a state that is not economically repairable and in need of replacement.
Failure to Trip	Failure whereby the circuit breaker does not operate for an in service protection trip. This category Includes slow circuit breaker operations that result in the operation of back-up protection.

Generally, the design of the network is such that faulty circuit breakers can be bypassed by normal switching or with mobile plant to allow restoration of supply. This allows for individual circuit breakers to be safely isolated to allow replacement, inspection and maintenance.

In the event of circuit breaker failure, operation can typically be restored within a few hours, subject to the location, circuit breaker function and nature of the failure. However, where a simple bypass arrangements are not possible, supply interruption may exceed 12 hours. Bypassing a failed circuit breaker will put further network load at risk as the network will be in operating under abnormal conditions. This means there is an increased risk of subsequent faults occurring in other parts of the network causing extensive outages.

The history of failures by voltage class over the period 1 July 2008 to 30 June 2013 are shown as a per annum figure in Table 3. Failures have been shown as both condition, (ie directly related to equipment condition), and Non-Condition, (ie influenced by external factors such as animals, vegetation or lightning).

Table 3: Circuit Breaker Failures per annum

Failure Scenario		Number of Circuit Breakers	
		Distribution Circuit	Sub Transmission
Minor	Condition	42	92
	Non Condition	3	5
Significant	Condition	1.0	0.4
	Non Condition	0.6	0.0
Major	Condition	1.4	0.2
	Non Condition	0.0	0.4
Condition		2.0	1.4
Failure to Trip		0.6	0.2

Circuit breakers are classified according to operating voltage for the purpose of asset management practices. The subsections below include background information and type specific issues for each circuit breaker classification.

5.1.1 66kV Circuit Breakers

There are a total of 463 circuit breakers operating on the 66kV network. These circuit breakers tend to be located in critical sub-transmission substations and supply significant customer loads. The failure of any 66kV circuit breaker will have a significant impact on the network.

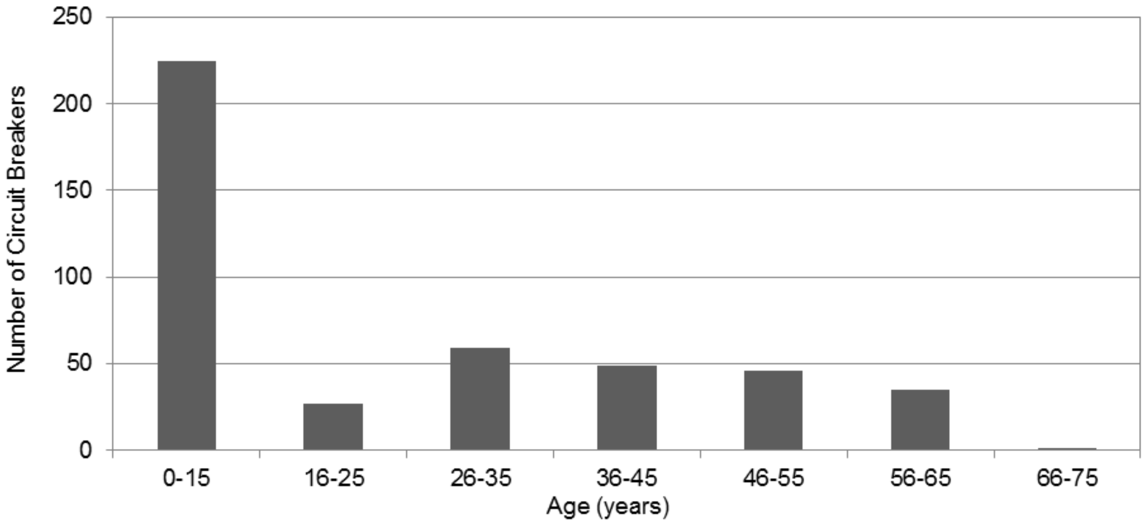
This asset class also includes 30 capacitor bank circuit breakers. Capacitor banks are installed on substations to provide power factor correction and voltage support. They are connected via circuit breakers at this voltage to switch and protect the capacitor banks. Capacitor bank circuit breakers undergo far more switching duty than other circuit breakers in this class, but are less likely to see a fault operation during service.

Further details on the insulation medium and age are included in Table 4, and the age distribution is shown in Figure 5**.**

	2013	2008
Average Age	22	29
Median Age	12	27
Minimum Age	1	1
Maximum Age	67	61

Table 4: 66kV Circuit Breaker Installation Date by Type

Class	Sub-Classes	Installation Date
66kV Circuit Breakers	SF6 GIS Minimum Oil Bulk Oil	1981 – present 1984 – 1991 1963 – 1987 1947 – 1963
66kV Capacitor Bank Circuit Breakers	SF6	1981 – present



	2013	2008
Average Age	22	29
Median Age	12	27
Minimum Age	1	1
Maximum Age	67	61

Figure 5: Age distribution of 66kV Circuit Breakers (at 30 June 2014)

5.1.1.1 Known Asset Issues and Failure Modes Specific to 66kV Circuit Breakers

Known asset issues and targeted programs of work to address these issues are summarised in Section 6.3.3 and detailed in Appendix B.

5.1.2 33kV Circuit Breakers

There are a total of 251 circuit breakers used on the 33kV network. These circuit breakers form part of the distribution network within the Central Business District and Adelaide Hills, as an extensive sub-transmission network in rural areas. Circuit breakers within this class are amongst the oldest circuit breakers still in service on the network. As such, the failure of these circuit breakers will have a significant impact on the subs-transmission network and network contingency arrangements in the Adelaide CBD.

This class also includes two capacitor bank circuit breakers installed at Port Pirie Connection point.

Further details on the insulation medium and age are included in

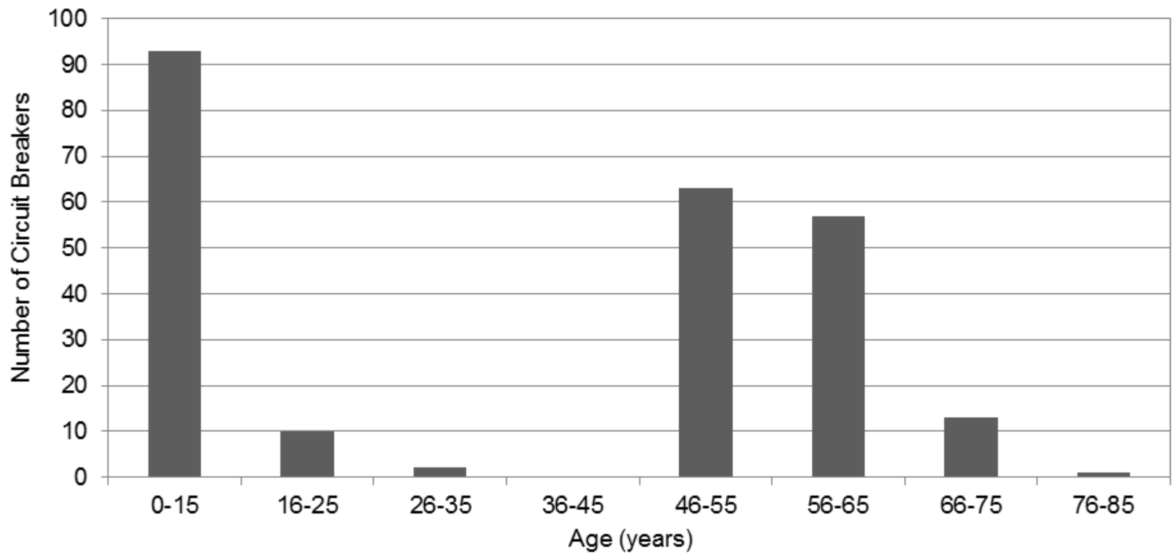
	2013	2008
Average Age	30	40
Median Age	25	44
Minimum Age	1	1
Maximum Age	78	72

Table 5. The age distribution is shown in Figure 6.

	2013	2008
Average Age	30	40
Median Age	25	44
Minimum Age	1	1
Maximum Age	78	72

Table 5: 33kV Circuit Breaker Installation Date by Type

Class	Sub-Classes	Installation Date
33kV Circuit Breakers	SF6 Bulk Oil	1988 – Present 1936 – 1967
33kV Capacitor Bank Circuit Breakers	SF6	2002



	2013	2008
Average Age	30	40
Median Age	25	44
Minimum Age	1	1
Maximum Age	78	72

Figure 6: Age Distribution of 33kV Circuit Breakers

5.1.2.1 *Known Asset Issues and Failure Modes Specific to 33kV Circuit Breakers*

Known asset issues and targeted programs of work to address these issues are summarised in Section 6.3.3 and detailed in Appendix B.

5.1.3 11kV Circuit Breakers

There are a total of 1155 circuit breakers on the 11kV network, which provide the majority of the distribution network across the central business district, metropolitan and rural areas of South Australia. The vast majority of these circuit breakers form indoor switchboards, consisting of multiple interconnected circuit breakers per switchboard.

This class includes 48 capacitor bank circuit breakers and circuit breaker/load switch combinations.

Further details on the insulation medium and age are included in Table 6. The age distribution is shown in Figure 7.

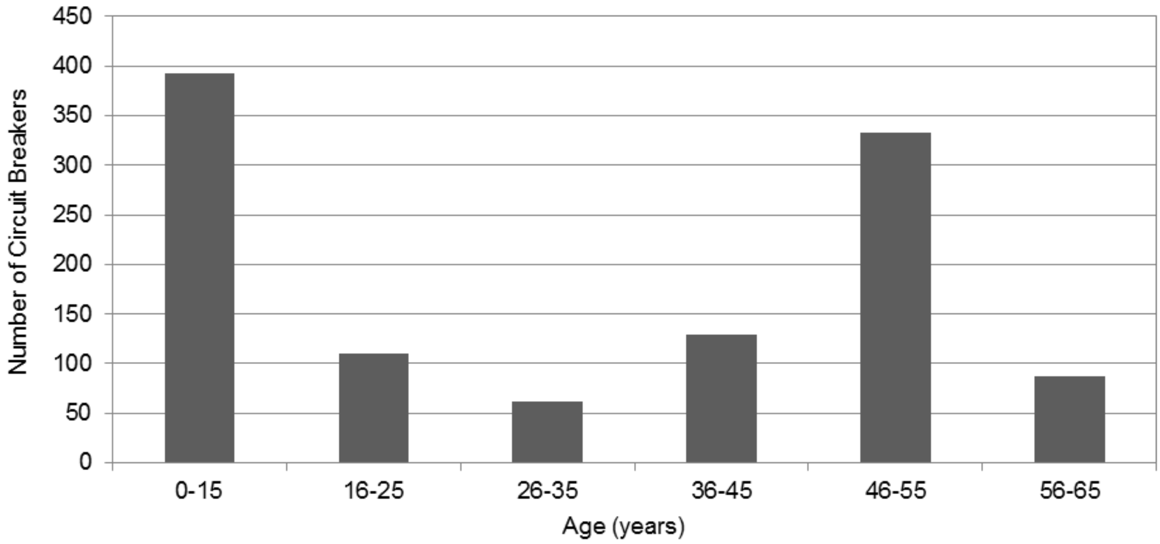
	2013	2008
Average Age	29	32
Median Age	27	39
Minimum Age	1	1
Maximum Age	64	58

	2013	2008

Average Age	29	32
Median Age	27	39
Minimum Age	1	1
Maximum Age	64	58

Table 6: 11kV Circuit Breaker Installation Date by Type

Class	Sub-Classes	Installation Date
11kV Circuit Breakers	SF6 Vacuum Small Bulk Oil	1998 1982 – Present 1950–1982
11kV Capacitor Bank Circuit Breakers	Vacuum Small Bulk Oil	1982 – Present 1957–1982



	2013	2008
Average Age	29	32
Median Age	27	39
Minimum Age	1	1
Maximum Age	64	58

Figure 7: Age Distribution of 11kV Circuit Breakers

5.1.3.1 Known Asset Issues and Failure Modes Specific to 11kV Circuit Breakers

Known asset issues and targeted programs of work to address these issues are summarised in Section 6.3.3 and detailed in Appendix B.

5.1.4 7.6kV Circuit Breakers

There are a total of 41 circuit breakers on the 7.6 kV network; a dated distribution voltage currently being phased out in favour of standardised 11kV distribution. These are located within the north-western suburbs associated with distribution feeders. Within this asset category, there are no circuit breakers that are considered to be specifically problematic.

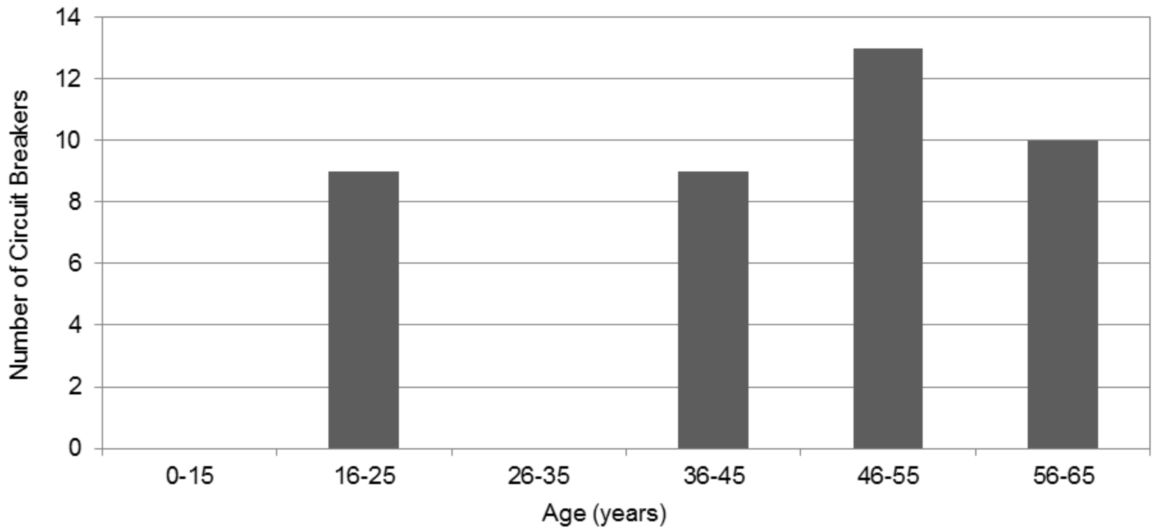
Further details on the insulation medium and age are included in Table 7. The age distribution is shown in Figure 8.

	2013	2008
Average Age	45	39
Median Age	48	42
Minimum Age	23	17
Maximum Age	62	56

	2013	2008
Average Age	45	39
Median Age	48	42
Minimum Age	23	17
Maximum Age	62	56

Table 7: 7.6kV Circuit Breaker Installation Date by Type

Class	Sub-Classes	Installation Date
7.6kV Circuit Breakers	Vacuum Small Bulk Oil	1991 1957 – 1970



	2013	2008
Average Age	45	39
Median Age	48	42
Minimum Age	23	17
Maximum Age	62	56

Figure 8: Age Distribution of 7.6kV Circuit Breakers

5.1.5 6.6kV Circuit Breakers

There are 10 circuit breakers that make up the 6.6kV category to form a single indoor switchboard at a dedicated industrial customer supply substation at Port Pirie. These circuit breakers are 64 years of age and are small bulk oil type.

5.1.5.1 Known Asset Issues and Failure Modes Specific to 6.6kV Circuit Breakers

Known asset issues and targeted programs of work to address these issues are summarised in Section 6.3.3 and detailed in Appendix B.

5.2 Risk Management Plan

Risk management is the term applied to the logical and systematic method of identifying, analysing, assessing, treating, monitoring and communicating risks associated with any event or activity in a way that will enable organisations to minimise losses and maximise opportunities. The main elements of any risk management process are:

- Define the event or activity and the criteria against which the risk will be assessed
- Identify the risks associated with the activity
- Analyse the risks to determine how likely is the event to happen and what are the potential consequences and their magnitude should the event occur

- Assess and prioritise the risks against the criteria to identify management priorities
- Treat the risks by introducing suitable control measures
- Monitor and review the performance of the risk management system

Risk management is a key activity in the Asset Management process. Risk assessment and risk management is used by SA Power Networks in the decision making process for network capital expenditure and in network operations and maintenance activities.

The application of Risk Management is described in the Network Asset Management Plan – Manual 15. This describes the standard process of identifying hazards, identifying the likely causes, assessing the likelihood and consequences (risk) without controls in place and then determining practical and achievable controls followed by re-assessing the residual risks after application of controls.

Inspection and condition monitoring tasks are scheduled at standard intervals as detailed in the Maintenance Plan. Monitoring condition trends over time is a primary strategic asset management tool which tracks deterioration over time. As areas of concern are identified, condition monitoring frequencies may need to be shortened as the risk of an impending failure becomes apparent. Such deterioration can develop slowly over time, or in some cases, quickly and then requiring urgent operational actions to reduce the risk of in-service failure.

5.3 Maintenance Strategy

The maintenance strategy for substation circuit breakers comprises periodic routine inspections, overhauls, maintenance and condition monitoring, supplemented by additional specific inspections as determined by asset condition.

The scope and frequency of tasks of this maintenance strategy are contained in the Network Maintenance Manual 12 plus reference to the Substation Inspection Manual 19 and Substation Maintenance Manual 30.

5.3.1 Maintenance Standards & Schedules

Asset management standards are an integral building block to support asset management decision making and provide the foundation for both asset maintenance and asset replacement. These standards will form a basis of the decision to repair/maintain an asset or to undergo replacement.

Specific standards for circuit breakers will prescribe preventative maintenance requirements and how to treat defects identified either through corrective maintenance or asset inspection processes. The purpose of these standards is to ensure assets operate as designed, safely and achieve their optimal life.

Key factors to consider which are guided by standards include:

- Frequency of inspection and reporting requirements per asset class
- Updating maintenance standards and incorporation new information as required (ie change in maintenance requirements for a certain circuit breaker class as a result of a review of that class)
- Monitoring of actual maintenance against maintenance schedules
- Recording information about condition of circuit breakers and any defects, which will help give an indication of risk of specific assets to assist in prioritising maintenance activities.

5.3.2 Maintenance Categories

Maintenance will generally be defined under the following categories:

- **Preventative** - referring to regular inspections, patrols, defect detection activities, condition testing, asset servicing and tasks involved in shutdowns or switching.
- **Corrective** - referring to activities undertaken when an asset has been identified to be in poor/unserviceable condition and requiring repair. This also includes any additional inspections undertaken outside regular maintenance tasks.
- **Reactive** - referring to actions undertaken directly following unforeseen circumstances, such as a customer complaint, accident, safety response, damage due to environmental factors or third-party interference.

5.3.3 Maintenance Plan for Substation Circuit Breakers

The maintenance strategy for circuit breakers comprises of periodic routine inspections, overhaul maintenance and condition monitoring, supplemented with targeted inspections and testing based on asset performance and condition. The maintenance requirements are detailed within the Network Maintenance Manual.

Inspection and maintenance frequencies have been timed to balance the requirements of appropriate Australian and International Standards, good industry practice, manufacturer's recommendations and the body of experience gained from SA Power Networks' own operating experience.

The routine maintenance and inspection intervals for circuit breakers are defined in Table 8.

Table 8: Circuit Breaker Maintenance Intervals

Maintenance Requirements	Asset Type	Maintenance Interval
Routine Inspection	All Circuit Breakers	6 months
Major Inspection	SF6, GIS and Vacuum Circuit Breakers	4.5 years
Mechanism Check	All 66kV oil Circuit Breakers (except Delle and Reyrolle)	4.5 years
	Delle and Reyrolle 66kV oil Circuit Breakers	1.5 years
	66kV SF6 & GIS Circuit Breakers	9 years
	ABB EDF SF6 66kV Capacitor Bank Circuit Breakers	1500 operations (check contact wear)
Overhaul Maintenance	All 66kV oil circuit breakers (except Dell and Reyrolle)	9 years
	Delle and Reyrolle 66kV oil circuit breakers	4.5 years
	66kV SF5 66kV Capacitor Bank Circuit Breakers	18 years
	ABB EDF SF6 66kV Capacitor Bank Circuit Breakers	2000-2200 operations (replace contacts)
	Sprecher, Alstrol and Areva 77kV Capacitor Bank Circuit Breakers	4500 operations
Diagnostic & Condition Monitoring	All Circuit Breakers	4.5 years

5.3.3.1 Routine Inspections

Periodic routine inspections are carried out on circuit breakers (approximately every 6 months) by Asset Inspectors or Asset Management Officers. These consist of a visual inspection, specifically focusing on circuit breaker oil levels and the SF6 gas pressure, door seals, checking cubicle heater operation. Inspections are non-intrusive to the asset.

5.3.3.2 Diagnostic and Condition Monitoring

Diagnostic and condition monitoring may be carried out either on-line or off-line. Off-line condition monitoring is well established and includes intrusive inspection, contact resistance and circuit breaker timing. A range of targeted testing can be provided by circuit breaker analysers including mechanism timing, dynamic contact resistance duty measurements as well as trip and close trip circuit profiles.

5.3.3.3 Routine Maintenance

Routine maintenance incorporates a detailed inspection, test and overhaul program that requires the asset to be taken out of service and thoroughly examined for wear and tear. During this maintenance cycle, replacement parts are installed as required. On completion, assets are subject to a range of pre-energisation checks to ensure the asset is safe to be placed back in service.

5.3.3.4 Defect Maintenance

Defect maintenance addresses correction of an observed defect or fault which may impact the asset performance or cause a potential failure. Defect maintenance is initiated either through preventative maintenance programs, inspection or the fault management process.

5.3.4 Insurance Spares

The policy relating to the stock level requirements for spare circuit breaker units is currently being drafted. The total inventory of spare units is shown in Appendix E.

5.4 Replacement Plan

See Section 6.

5.5 Creation, Acquisition and Upgrade Plan

See Sections 4 and 7.

5.6 Disposal Plan

The disposal of a circuit breaker must be approved by the Manager Network Planning. If disposal is approved, the Network Planning Department will assess the unit and decide if parts can be salvaged for spares in other units, which are still in service.

Salvaging is arranged by the Logistics Group within Field Services, and is completed in accordance with the PCB Management Plan for oil insulated units, or procedure CB 001/03 for SF_6 insulated units.

The scrapping of an oil insulated circuit breaker involves testing an oil sample for PCB levels and removal of asbestos. If the test results show that PCB levels are less than 50ppm, the oil is moved into bulk storage for appropriate disposal or refining and the remaining components are is sold off as scrap. If the test results show that PCB levels are over 50ppm or asbestos is present the circuit breaker is placed in a holding compound, and specialised disposal is arranged by an approved company.

6. REPAIR AND REPLACEMENT PLAN

6.1 Repair and Replacement Plans

The repair and replacement plans proposed in this section are independent of each other.

Over the life of an asset it suffers from the cumulative deterioration resulting from normal electrical, thermal and environmental stresses experienced on a day-to-day basis plus the abnormal (severe) stresses due to lightning, switching over-voltages and system faults. Due to this, failure is inevitable, and therefore it is prudent to establish a set of criteria, by which to assess a unit's condition. Beyond set condition limits assets are programmed to be repaired, refurbished or replaced.

Repair or replacement decisions are based on the most economical and effective preventative measures to mitigate existing risks. Where circuit breaker repair or refurbishment can not be economically justified, the asset is considered for replacement.

6.2 Refurbishment Plan

SA Power Networks manages a large population of switchgear assets across the various stages of the Asset Life Cycle, with many assets nearing the end of useful life through a number of technical or economic reasons.

Network refurbishment programs are developed to identify and direct appropriate intervention to assets approaching the end of useful life but whose upgrade/replacement is not considered prudent on the basis of condition, reliability or performance.

The scope of network refurbishment program are driven by a number of technical and economic reasons and include both targeted works to recondition specific asset subpopulations and sustained investment to manage ongoing condition risks identified across the general population.

6.2.1 Targeted Refurbishment of 33kV Switchgear

An inherent fault in Horizon 33KV circuit breakers delivered to SA Power Networks in the period 2002 to 2011 has shown to lead to premature failure in these circuit breakers if left unaddressed. This degradation can not be reliably detected in service and has resulted in the establishment of a manufacturer assisted remediation program for all affected circuit breakers commencing in 2013.

Of a total population of 114 Horizon circuit breakers, 78 units have been identified as requiring action by the manufacturer and to date 26 units have been refurbished and returned to service. Fourteen circuit breakers are expected to be complete by the end of 2014, with completion forecast by 2017. Forecast requirements for this program are summarised below.

Table 9: Targeted Refurbishment of 33kV Switchgear

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Total
Units	14	19	19	0	0	0	0	0	0	0	0	0	**52**
$ ('000)	$ 420	$ 570	$ 570	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	**$1560**

6.2.2 Sustained Circuit Breaker Refurbishment

Sustained refurbishment programs address ongoing capital requirements of SA Power Networks' switchgear assets to meet required levels of safety and performance. Expenditure requirements within this area are varied and driven primarily by asset needs identified through condition, reliability, operational performance data and economic assessments.

The introduction of improved maintenance practices shows the need for greater investment in SA Power Networks' fleet of indoor switchgear with aged synthetic resin bonded paper (SRBP) insulation. The operating experience of other utilities has shown similar dielectric degradation patterns of this equipment, which is technically obsolete and has limited serviceable spare parts available without specialist manufacturing.

Proposed refurbishment expenditures are intended to maintain current performance of this asset class and address expected requirements when managed in conjunction with targeted replacement works. Forecast requirements are summarised below.

Table 10: Sustained Circuit Breaker Refurbishment

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Total
$ ('000)	$230	$230	$230	$230	$230	$230	$230	$230	$230	$230	$230	$230	**$2760**

6.3 Replacement Plan

Several different methodologies have been utilised to develop the forecast replacement quantum of works over the period 2014 – 2025 and associated capital expenditure. Methodologies utilised were:

- Top down AECOM developed methodology:
  - Considers whole fleet as a population
  - Failure rates based on SA Power Networks historical rates and asset performance
- CBRM model:
  - Bottom-up detailed assessment
  - Takes into account specific asset, specific asset condition data, specific asset consequences and likelihood of failure
  - Can give several possible outputs; predicted replacements based on likelihood of failure, ie the health Index; Predicted replacement based on maintaining a certain level of risk; or forecast replacements based on NPV.
- Targeted programs of work:
  - Where there is a specific, inherent or known problem with a specific asset model or specific asset and not addressing/replacing/refurbishing will lead to premature failure
  - Where the assets are non-compliant with a required standard
- Historical trend – extrapolation of historical trends in numbers of replacements and spend
- AER repex model:
  - Top-down benchmarking mode
  - Uses age-based replacement modelling
  - Limited high level information required – asset age profile; expected life and standard deviation of expected life; historical expenditure; and average asset replacement cost
  - Simplistic approach which has limitations

The outputs from each methodology are discussed below, along with the resulting forecast expenditure profile for 2014 to 2025.

6.3.1 Top-down methodology

AECOM were employed to develop a top-down circuit breaker replacement strategy for SA Power Networks. The full report produced is included in Appendix A and is summarised below.

6.3.1.1 Replacement Unit Costs

Unit cost estimates for Circuit Breakers per class have been developed and used by AECOM, provided by a third party based on a library of costs. These costs were used in the Top Down replacement forecast and are detailed in the AECOM report in Appendix D.

6.3.1.2 Outputs of Analysis

The replacement capital expenditure profile for circuit breakers based ion the analysis undertaken by AECOM is shown in Figure 9 (expenditure shown in 2013 $s).

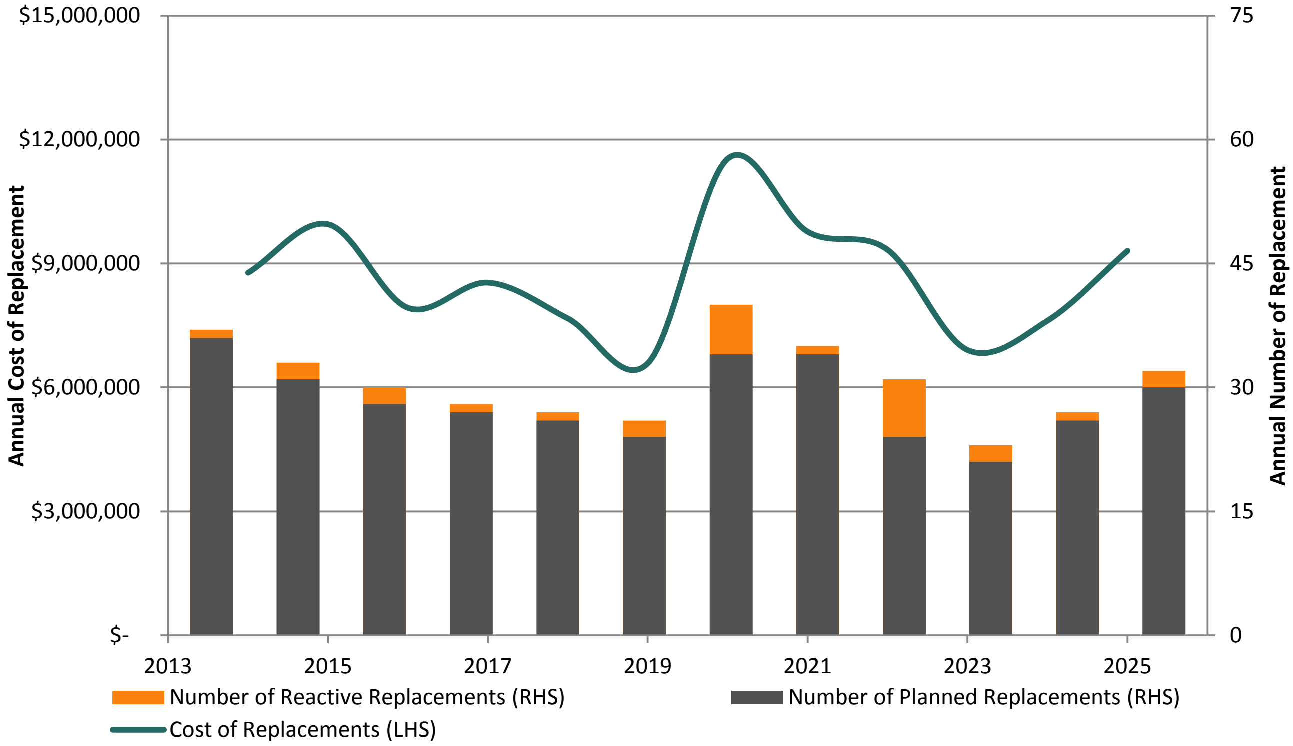


Figure 9: Forecast circuit breaker switchgear replacement profile

The reactive replacement forecast is based on the historical circuit breaker performance, while the planned replacement forecast is based on circuit breaker age. Both replacement forecasts are produced using the risk based methodology detailed the report in Appendix D. There is variability in the replacements based on failure (reactive) and the planned replacements throughout the forecast. The replacements for each category, along with the forecast costs are shown in Table 11.

Table 11: Annual cost ($M) and number of circuit breaker replacements

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Total
Number of replacements													
Reactive	1	2	2	1	1	2	6	1	7	2	1	2	28
Planned	36	31	28	27	26	24	34	34	24	21	26	30	341
TOTAL	**37**	**33**	**30**	**28**	**27**	**26**	**40**	**35**	**31**	**23**	**27**	**32**	**345**
Cost of Replacements ($2013 in millions)													
Reactive	$0.2	$0.4	$0.4	$0.3	$0.2	$0.5	$2.0	$0.2	$2.3	$0.4	$0.2	$0.5	$7.6
Planned	$8.6	$9.5	$7.5	$8.2	$7.5	$6.1	$9.6	$9.5	$7.0	$6.5	$7.4	$8.8	$96.2
TOTAL	**$8.8**	**$9.9**	**$7.9**	**$8.5**	**$7.7**	**$6.6**	**$11.5**	**$9.8**	**$9.3**	**$6.9**	**$7.6**	**$9.3**	**$103.8**

The replacement expenditure profile can be smoothed for budgetary purposes but currently represents the raw output from the analysis. The actual circuit breakers forecasted to be replaced as well as an analysis by sub-station is located in the AECOM report in Appendix D.

6.3.2 CBRM methodology

In 2011 EA Technology was engaged to develop Condition Based Risk Management (CBRM) Models for Substation Circuit Breakers. The CBRM model utilises information, knowledge, engineering experience and judgement for the identification and justification of targeted asset replacement.

CBRM is used as a decision support tool to assist the quantification, communication and management of asset related risk, particularly issues associated with end of asset life. The CBRM process produces computer models that provide quantitative representation of current and projected asset condition, performance and risk. Models can then be used to evaluate possible asset replacement strategies and investment scenarios to arrive at a proposal that best meets the strategic objectives of the organisation.

CBRM seeks to overcome problems of non-availability of reliable and consistent data that is necessary to construct a valid population based statistical models. This problem is particularly acute in the electricity distribution industry where assets have long lives (often many times longer than a typical computer information system), and are subject to many factors that cause asset sub populations within a general asset class to behave differently ie manufacturer make and model differences, quality characteristics, installation practices, operating environment and usage histories).

Rather than use a purely statistical representation of the asset population, CBRM models seek to make the best possible use of available information by combining asset information, operating context, operating history and condition information using rules that are consistent with sound engineering principles and asset specific operating experience. Models are adjusted and calibrated so that the output and behaviour of each model is consistent with historical observations and asset performance. Where CBRM models incorporate subjective SME judgment, it is codified by rules and is applied consistently.

CBRM offers advantages over statistical based approaches in that all available information, including physical observations of condition are incorporated into the assessment, and applied to individual assets within the model. The objective is to produce asset risk rankings and projections to inform asset management strategy as well as providing higher quantity level forecasts necessary for budget and regulatory purposes.

A full description of the CBRM methodology, as applied to Circuit Breakers, can be found in Appendix B.

A core feature of the CBRM methodology is the ability to age assets into the future and forecast future Health Index, Probability of Failure and Risk. This method of forecasting allows different intervention and investment scenarios to be modelled and compared.

CBRM models allow three future (year N) scenarios to be compared;

1. Y_N – No Intervention: Future projection of all assets currently in service
2. Y_N % Replacement: Replacement of a fixed percentage of the population. Replacement priority can be ranked by asset condition, asset risk or asset delta (condition) risk.
3. Y_N Targeted Intervention: Intervention program that may be configured to use the outputs of an NPV optimised analysis or independent replacement programmes.

Methodologies for asset replacement projections under these scenarios:

1. Replacement projections based purely on health index will remove those assets in poorest condition without considering criticality and consequential asset risk.
2. Constant risk projections are based on maintaining a benchmark level of asset performance (failure rate) and consequential risk over time. Forecasts are proportional to the change in risk (asset health) with time and replacements can be optimised by replacement cost and their contribution to overall risk.
3. NPV replacement projections provide a financially optimised year of replacement based on a discounted cash flow analysis of risk and replacement cost. Calculations are highly sensitive to absolute values of risk, replacement and discount rate. Inaccuracy in risk calculations will significantly distort the NPV optimised forecasts.

Each of the above methodologies has merits based on the relative strength of asset information within the model. Discussions with EA Technology recommended the constant risk approach as the most mature risk based methodology appropriate to information within the model.

The annual expenditure and replacement forecast based on a constant risk methodology is shown below in Table 12. This asset replacement program is expected to maintain current levels of safety, reliability and network performance.

This forecast also accounts for other replacement programs proposed for the 2014–2025 period including substation augmentation, targeted asset replacement works and expected failure rates (unplanned replacements).

Table 12: Substation Circuit Breakers planned to be replaced from CBRM

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Total
Number													
11kV Indoor Circuit Breakers - Planned	-	-	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	47
11kV Outdoor Circuit Breakers - Planned	-	-	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	9
33kV Circuit Breakers - Planned	4.0	2.0	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	28
66kV Circuit Breakers - Planned	4.0	2.0	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	11
TOTAL	8.0	4.0	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	95
Expenditure ($,000 2013 dollars)													
11kV Indoor Circuit Breakers - Planned	-	-	$2,585	$2,585	$2,585	$2,585	$2,585	$2,585	$2,585	$2,585	$2,585	$2,585	$25,850
11kV Outdoor Circuit Breakers - Planned	-	-	$315	$315	$315	$315	$315	$315	$315	$315	$315	$315	$3,150
33kV Circuit Breakers – Planned	$2,000	$1,000	$1,100	$1,100	$1,100	$1,100	$1,100	$1,100	$1,100	$1,100	$1,100	$1,100	$14,000
66kV Circuit Breakers - Planned	$2,400	$1,200	$300	$300	$300	$300	$300	$300	$300	$300	$300	$300	$6,600
TOTAL	**$4,400**	**$2,200**	**$4,300**	**$4,300**	**$4,300**	**$4,300**	**$4,300**	**$4,300**	**$4,300**	**$4,300**	**$4,300**	**$4,300**	**$49,600**

6.3.3 Targeted programs of work

The numbers and associated forecast for the targeted programs as identified in Section 5.1 are outlined in Table 11. Targeted programs address specific subpopulations of assets with demonstrated issues of operational performance, design flaws or technical obsolescence. The proposed program of works in Table 13 presents the completion of existing targeted replacement programs and installation/equipment specific issues not adequately captured in forecast models. Completion of this program is independent and prioritised over other planned asset replacement programs.

Table 13: Substation Circuit Breakers targeted replacement programs

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Total
Number													
Port Pirie Switchboard replacement	-	1.0	-	-	-	-	-	-	-	-	-	-	1.0
66kV Areva S1 Refurbishment	3.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	25
11kV Cap Bank Oil Switch (3 Phase) replacements	-	-	2.0	1.0	-	1.0	-	-	-	-	-	-	4.0
11kV Cap Bank Single Phase Switch replacements	-	-	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	-	-	8.0
Reyrolle OSM10 Targeted Replacements	1.0	-	1.0	1.0	2.0	2.0	-	-	-	-	-	-	7.0
Riverland 66kV B/O CBs	-	-	1.0	1.0	1.0	-	-	-	-	-	-	-	3.0
TOTAL	**4**	**3**	**7**	**6**	**6**	**6**	**3**	**3**	**3**	**3**	**2**	**2**	**48**
Expenditure ($,000 2013 dollars)													
Port Pirie Switchboard replacement	-	$5,500	-	-	-	-	-	-	-	-	-	-	$5,500
66kV Areva S1 Refurbishment	$90	$60	$60	$60	$60	$60	$60	$60	$60	$60	$60	$60	$750
11kV Cap Bank Oil Switch (3 Phase) replacements	-	-	$120	$60	-	$60	-	-	-	-	-	-	$240
11kV Cap Bank Single Phase Switch replacements	-	-	$60	$60	$60	$60	$60	$60	$60	$60	-	-	$480
Reyrolle OSM10 Targeted Replacements	$600	-	$600	$600	$1,200	$1,200	-	-	-	-	-	-	$4,200
Riverland 66kV B/O CBs	-	-	$600	$600	$600	-	-	-	-	-	-	-	$1,800
TOTAL	**$690**	**$5,560**	**$1,440**	**$1,380**	**$1,920**	**$1,380**	**$120**	**$120**	**$120**	**$120**	**$60**	**$60**	**$12,970**

6.3.4 Historical trend

The historical spend and 2014 budget for circuit breaker replacement – planned, unplanned and targeted - is shown in Figure 17 below. Expenditure within this asset class is underpinned by targeted replacement in aged, deteriorated and unreliable circuit breakers, predominantly in rural 33kV and 66kV distribution networks. Significant unplanned expenditure between 2011 and 2013 has been required to manage replacement and refurbishment of poor condition oil insulated 11kV indoor switchgear.

The historical unplanned replacement rates have been retained as the forecast for unplanned replacements for the period 2014 to 2025, and are shown in Table 14.

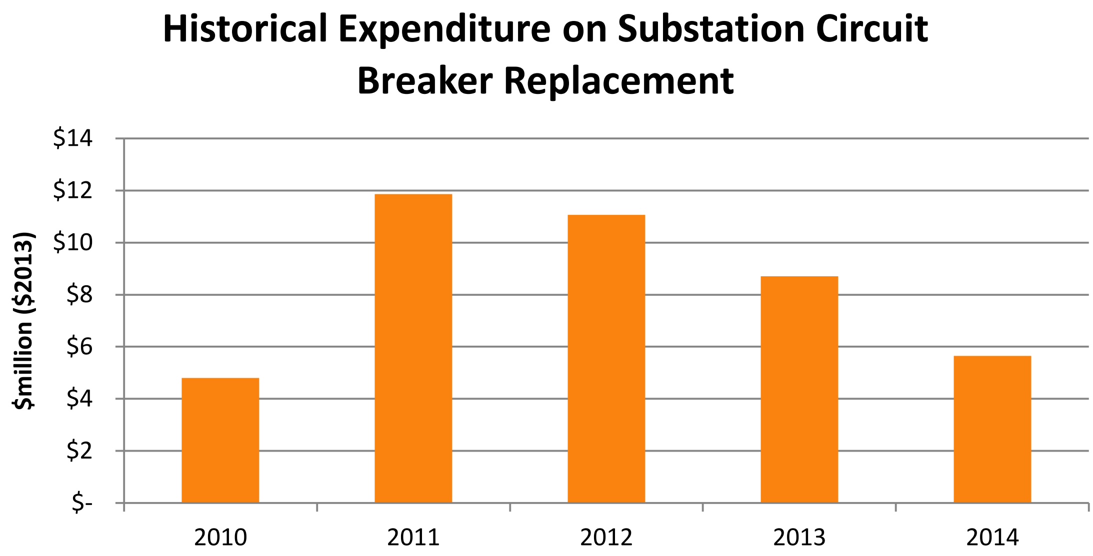


Figure 10 : Historical expenditure on substation circuit breakers replacement

Table 14: Substation Circuit Breakers unplanned replacements forecast

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Total
Number													
11kV Switchboards - Unplanned	-	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	2.0
11kV Outdoor Circuit Breakers - Unplanned	-	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	2.0
33kV & 66kV Circuit Breakers – Unplanned	1.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	23.0
TOTAL	**1.0**	**2.4**	**2.4**	**2.4**	**2.4**	**2.4**	**2.4**	**2.4**	**2.4**	**2.4**	**2.4**	**2.4**	**27.0**
Expenditure ($,000 2013 dollars)													
11kV Switchboards - Unplanned	-	$829	$829	$829	$829	$829	$829	$829	$829	$829	$829	$829	$9,120
11kV Outdoor CB - Unplanned	-	$40	$40	$40	$40	$40	$40	$40	$40	$40	$40	$40	$440
33kV & 66kV Circuit Breakers – Unplanned	$140	$280	$280	$280	$280	$280	$280	$280	$280	$280	$280	$280	$3,220
TOTAL	**$140**	**$1,149**	**$1,149**	**$1,149**	**$1,149**	**$1,149**	**$1,149**	**$1,149**	**$1,149**	**$1,149**	**$1,149**	**$1,149**	**$12,780**

6.3.5 AER Repex model

The Australian Energy Regulator's (AER) replacement model (repex model is intended for use as part of building block determinations for the regulated services provided by electricity network service providers (NSPs). The repex model is a series of Microsoft Excel spreadsheets developed for the AER to benchmark replacement capital expenditure. It was first deployed in the Victorian electricity distribution determination for the 2010/11 to 2014/15 regulatory control period.

An initial version of the repex model has been prepared as part of the completion of the Category Analysis RIN. The results of this initial repex modelling are shown in Table 15 and Figure 11 below. Further discussion of the repex modelling undertaken can be found in Appendix D.

Table 15: Repex Results for Substation Circuit Breakers

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Total
Number of Circuit Breakers													
< 11 kV ; CIRCUIT BREAKER (SUB)	1.1	1.2	1.2	1.3	1.4	1.5	1.5	1.5	1.6	1.6	1.6	1.6	17.0
11 kV ; CIRCUIT BREAKER (SUB)	4.7	5.5	6.4	7.4	8.4	9.6	10.8	12.1	13.4	14.8	16.1	17.4	126.5
> 22 kV & < ≈ 33 kV ; CIRCUIT BREAKER (SUB)	3.5	3.7	4.0	4.2	4.4	4.6	4.8	4.9	5.1	5.2	5.2	5.3	54.9
> 33 kV & < ≈ 66 kV ; CIRCUIT BREAKER (SUB)	1.8	2.0	2.2	2.4	2.6	2.8	3.0	3.3	3.5	3.7	3.9	4.1	35.1
TOTAL	11.0	12.3	13.8	15.3	16.8	18.5	20.1	21.8	23.5	25.2	26.8	28.4	233.5
Expenditure ($millions)													
< 11 kV ; CIRCUIT BREAKER (SUB)	$0.36	$0.39	$0.42	$0.45	$0.47	$0.49	$0.51	$0.52	$0.53	$0.54	$0.54	$0.54	$5.78
11 kV ; CIRCUIT BREAKER (SUB)	$1.58	$1.86	$2.17	$2.50	$2.87	$3.26	$3.68	$4.11	$4.56	$5.02	$5.48	$5.93	$43.02
> 22 kV & < ≈ 33 kV ; CIRCUIT BREAKER (SUB)	$1.54	$1.65	$1.75	$1.84	$1.94	$2.02	$2.10	$2.17	$2.23	$2.27	$2.31	$2.33	$24.14
> 33 kV & < ≈ 66 kV ; CIRCUIT BREAKER (SUB)	$0.89	$0.99	$1.09	$1.20	$1.31	$1.42	$1.52	$1.63	$1.73	$1.83	$1.93	$2.03	$17.57
TOTAL	$4.37	$4.89	$5.43	$6.00	$6.59	$7.19	$7.81	$8.43	$9.05	$9.66	$10.26	$10.82	$9.51

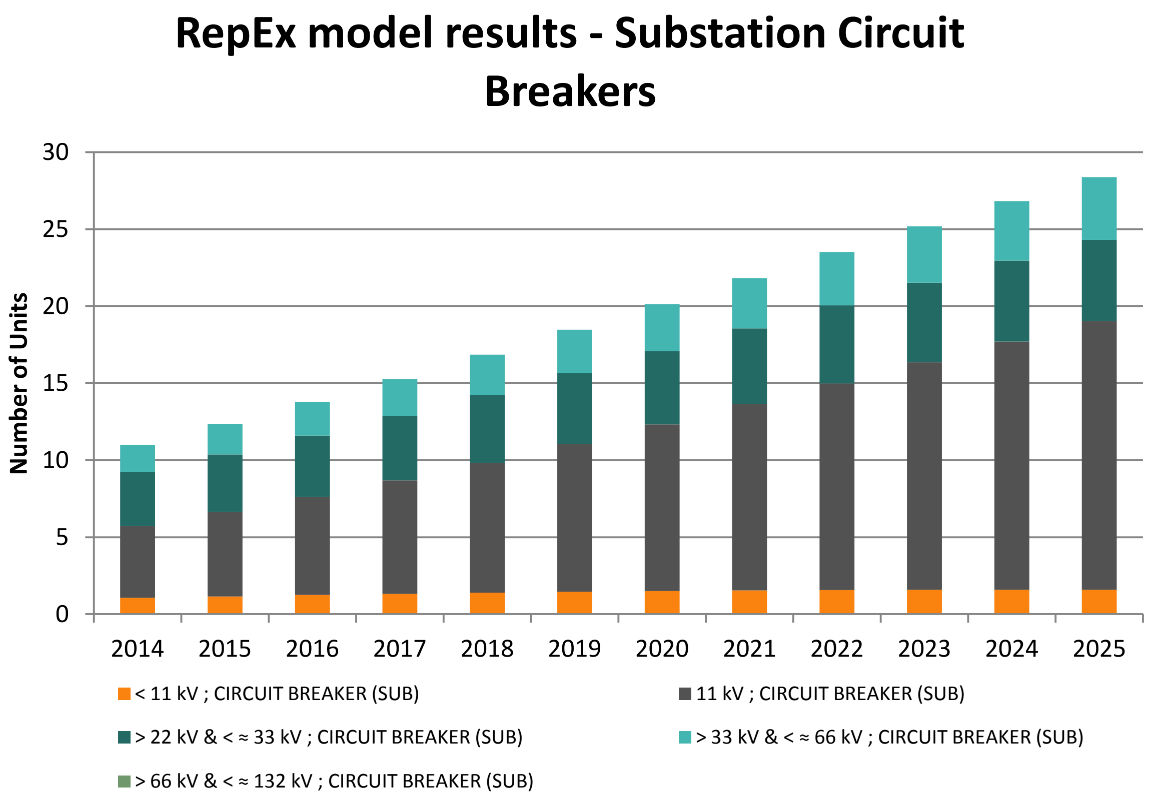


Figure 11 : Repex model results

6.3.6 Results Comparison

Table 16 and Figure 12 below illustrate the average (2015–2025) number of replacements of substation circuit breakers predicted utilising each of the above detailed methodologies, but excluding targeted replacement programs.

Table 16 : Comparison of average number of replacements per annum

	Top Down	CBRM				Historical (2009 – 13)	Repex
		Maintain risk	Unplanned (failure)	Targeted	TOTAL		
11kV	18.4	5.6	2.0	1.0	8.6	8.4	11.96
33&66kV	11.7	2.7	2.0	1.0	4.7	11.2	7.5
TOTAL	**30.1**	**8.3**	**4.0**	**2.0**	**14.3**	**19.6**	**19.5**

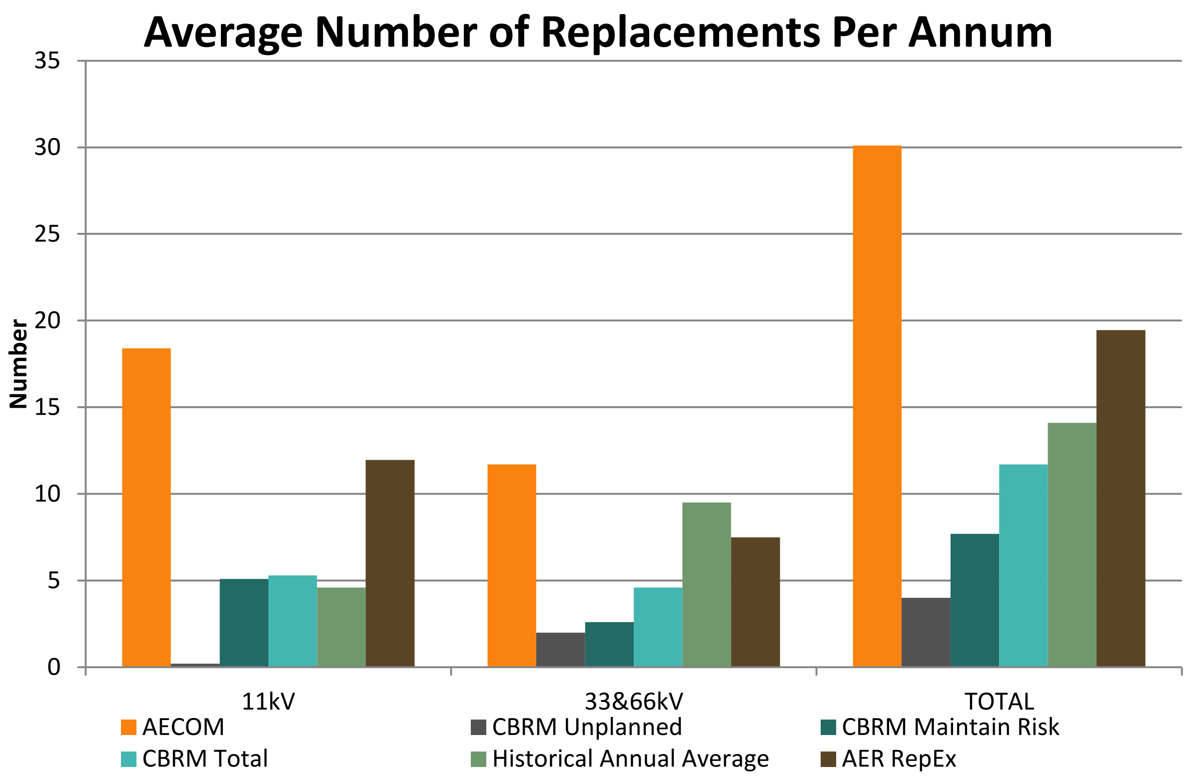


Figure 12 : Comparison of average number of replacements per annum

Figure 13 illustrates the replacement expenditure predicted each year utilising the top down, CBRM maintain risk + unplanned + targeted, and Repex methodologies. As can be seen all the methodologies produce average annual spend over the 2014–2025 period of around the same quantum.

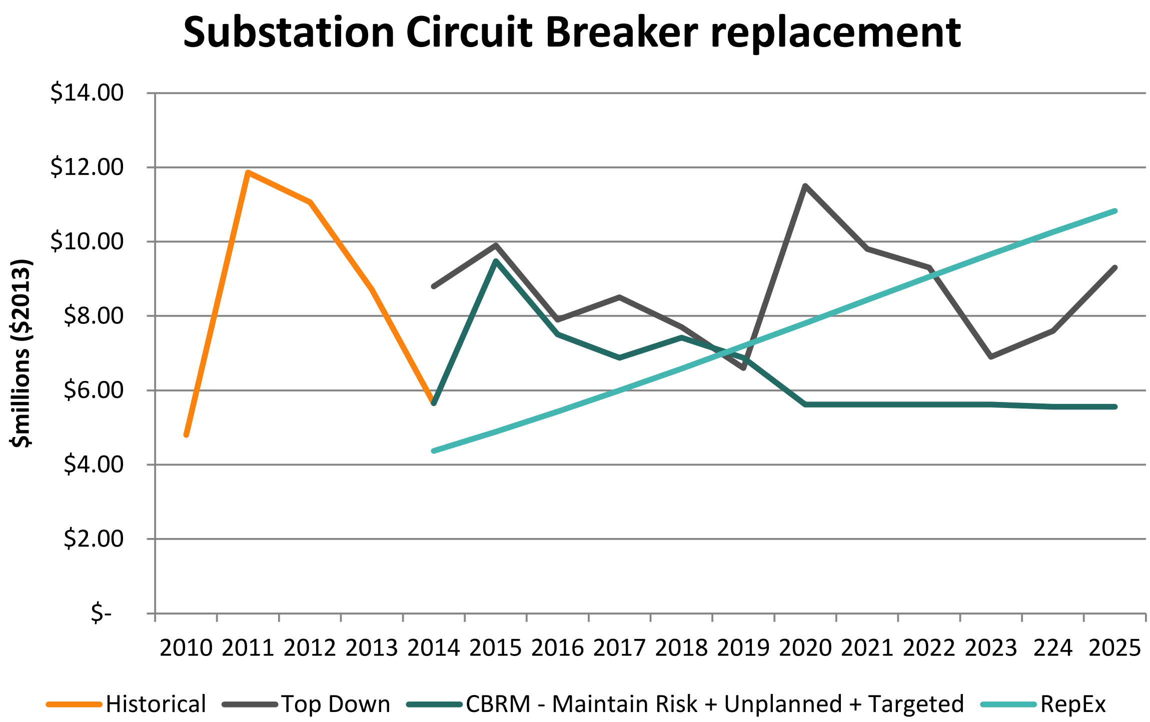


Figure 13 : Comparison of Replacement Expenditure per annum

6.4 Forecasts and Discussion

There are significant differences in the average annual number of substation circuit breaker replacement required in the 2014–2015 period depending on the model and methodology used.

Benchmarking techniques by necessity seek to distil a measurement problem into a model that incorporates limited available input data to produce a representation of true performance.

Each forecast methodology has its own set of specific advantages and limitations for forecasting replacement volumes and a detailed description of each model and methodology is included in the appendices and summarised below.

The AECOM replacement model provides a high level (top down) forecast that considers estimates of both planned (prioritised by age based risk) and unplanned (manufacturer based probability of failure) replacements each year. The intention of this program is to hold the current risk profile (and level of service) constant. While endeavouring to quantify and prioritise replacements based on asset risk, the model is not fine enough to model specific risk, forecast asset performance nor model replacement scenarios.

The AER repex model provides a very high level (top down) modelling approach that considers asset age, asset life statistics and historical expenditure to forecast future replacement volumes and expenditure requirements. Forecasts do not directly factor aspects of condition, criticality or risk, nor differentiate between planned and unplanned (failure) replacement types. Replacement life within the model is used as the proxy for all factors that drive asset replacements, under the assumption that current replacement strategies and practices will remain static into the future.

As this approach relies on overarching population information only, the model does not directly allow deeper analysis of asset performance, condition trends, future risk nor changes in asset management drivers.

CBRM models are based on a (bottom up) engineering approach to the modelling and forecasting of asset performance and risk. CBRM does not in, and of itself, provide predictions of asset replacement requirements, but rather produces a forecast of asset performance and risk which can be used to test the benefits of intervention programs or replacement strategies. CBRM models are able to utilise detailed engineering information on asset specific condition, criticality and consequential risks to forecast and design investment scenarios that present an optimal forward program in light of current understanding of the asset base.

The relative strength of CBRM models come with their ability to leverage established data sources and understanding of asset specific performance and risk. Given the level of detailed, asset specific asset management information available for substation circuit breakers, CBRM is considered to be the most appropriate methodology to forecast requirements for the 2014 to 2025 period.

Within CBRM, there are a number of strategies that may be employed for planning asset replacement forecasts, each with relative strengths based on the quantity and maturity of available data. The two strategies considered most appropriate to SA Power Networks' substation circuit breaker CBRM models are discussed below.

The most sophisticated approach to replacement planning will be to develop a financially optimised plan based on minimising the Net Present Value (NPV) of costs associated with asset failure and the cost of subsequent replacement. NPV calculations are available within CBRM models however the approach is reliant on a literal use of calculated risk to determine timing of an optimum risk/cost trade-off and requires a high degree of confidence in the quality of calculated (absolute) risk; error or uncertainty in risk calculations significantly distorts the optimal forecast.

Further investigation is recommended to confirm that the CBRM risk projections are a correct reflection of an appropriate risk/cost trade-off. SA Power Networks does not believe current models have sufficient information available to be able to confidently apply NPV analysis within CBRM. It remains the long term strategy for CBRM implementation to be able to confidently apply NPV optimisation as a preferred methodology for replacement forecasting.

In light of current experience with CBRM models, discussions with EA Technology have recommended a constant risk forecasting methodology as the most appropriate to both strategic objectives and information confidence within the circuit breaker models.

Forecasts under this methodology are less sensitive to absolute risk calculations, considering only the changes in risk over time with the intention of maintaining existing risk exposure with time.

The investment program generated by this approach seeks to maintain current levels of safety and reliability after considering likely population changes due to substation capacity upgrades, unplanned replacement and targeted replacement programs by identifying and targeting an optimal number of high risk assets.

Forecasts generated by the CBRM maintain risk approach in addition to unplanned and targeted works programs have been selected as the basis of the 2014–2025 forecast. Implementation of this plan:

- Maintains the current level of risk associated with substation circuit breakers.
- Maintains existing levels of service and reliability needs necessary to meet customer expectations of network performance. Forecasts levels of expenditure at or below historical levels, considered prudent and efficient by its targeted, optimal replacement of high risk units.

- Is based on qualified, asset specific assessments of condition and criticality from high confidence level engineering data.
- Has been developed utilising a well proven and well recognised methodology.

7. FINANCIAL SUMMARY

7.1 Introduction

This section contains the financial requirements resulting from available or derived data. Information on SA Power Networks processes and procedures for budgeting and control, project ranking, business cases and regulatory tests can be found in Manual 15.

7.2 Basis of Unit Costs

Costs associated with circuit breaker replacement/refurbishment works have been developed for the categories shown in Table 15 from historical project expenditure over the period 2008 to present.

The scope for individual replacement works will vary to meet site specific needs and any subsequent requirement for upgrade of associated infrastructure (ie Station auxiliaries, protection and control schemes, expansion of control building) to meet equipment needs, regulatory requirements and modern safe operating standards.

Unit costs in Table 17 are derived based on an average allowance for all historical costs typically required to complete a circuit breaker replacement project. An indicative scope of works will include:

- Project management, planning, approval and site establishment
- Equipment and material procurement and delivery costs
- Design (civil, structural, primary and secondary)
- Removal of existing infrastructure
- Installation of new infrastructure
- Functional testing, HV testing and commissioning
- Average Protection and Control replacement works
- Average disconnector replacement works
- Average AC/DC upgrade works
- Average control building upgrade works (switchboard replacements)
- Reinstatement of site and project closeout

Table 17: Unit Costs

Description	Cost ($000s)
66kV Circuit Breaker replacement - Planned	$600.0
33kV Circuit Breaker replacement - Planned	$500.0
33kV and 66kV Circuit Breaker replacement - Unplanned	$140.0
Pt Pirie Switchboard Replacement	$5,500.0
11kV Switchboard replacement – Planned (per panel equivalent cost)	$550.0
11kV Switchboard replacement - Unplanned	$4,560.0
11kV Outdoor Circuit Breaker replacement- Planned	$350.0
11kV Outdoor Circuit Breaker replacement - Unplanned	$220.0
66kV Areva S1 Replacement/Manufacturer Refurbishment	$30.0
33kV Horizon Replacement/Manufacturer Refurbishment	$30.0
11kV cap bank oil switch (Three Phase) replacement	$60.0
11kV cap bank single phase switch replacement	$60.0

7.3 Financial Statement and Projections

The anticipated total cost required per annum for the period 2015 to 2025 associated with substation circuit breaker replacement is shown in Table 18.

Table 18 : CAPEX Forecast

	$million ($2013)											
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	*TOTAL*
Replacement	**$3.35**	**$5.45**	**$5.45**	**$5.45**	**$5.45**	**$5.45**	**$5.45**	**$5.45**	**$5.45**	**$5.45**	**$5.45**	**$57.85**
Refurbishment	$0.80	$0.80	$0.23	$0.23	$0.23	$0.23	$0.23	$0.23	$0.23	$0.23	$0.23	**$3.67**
Target Program	$5.56	$1.44	$1.38	$1.92	$1.38	$0.12	$0.12	$0.12	$0.12	$0.06	$0.06	**$12.28**
CAPEX	$9.71	$7.69	$7.06	$7.60	$7.06	$5.80	$5.80	$5.80	$5.80	$5.74	$5.74	**$73.80**

8. PLAN IMPROVEMENT AND MONITORING

8.1 A summary of the current and desired state of Asset Management practices – data, processes and systems

The maintenance of substation circuit breakers in SA Power Networks' system is presently occurring in the following modes – refurbishment based on condition, and maintenance based on condition and time. Some maintenance activities are being made based on elapsed time and condition whilst reactive remedial works are being based on condition. Off-line condition monitoring includes electrical testing, contact resistance and circuit breaker time. A range of targeted testing can be provided by circuit breaker analysers including mechanism timing, and dynamic contact resistance as well as trip and close circuit profiles.

The low relative cost of many SA Power Networks circuit breaker assets and their distribution through a geographically large network makes some condition based approaches such as ubiquitous online monitoring cost prohibitive. For some critical or high impact assets, investment in on-line systems may be warranted for risk mitigation purposes. SA Power Networks currently has a mobile online PD monitor for indoor air insulated switchgear.

8.2 Improvement Plan – improving what we are doing

SA Power Networks acknowledges the need for continual improvement in its processes. A significant proposal in this area is to investigate acquisition of number of condition monitoring systems for circuit breakers. These will be able to be applied to provide early warning of degradation. Systems such as these allow for timelier and cost effective management of critical plant, targeted intervention refurbishment and maintenance and reduce overall capital and maintenance costs. SA Power Networks is in the process of introducing established condition monitoring techniques to better manage current assets, provide data to populate the CBRM models, and to also better leverage existing techniques (see AMP 3.0.01 Condition Monitoring and Lie Assessment Strategy)

8.3 Monitoring and Review Procedures

The AMP will be reviewed during annual budget preparation and amended to recognise any changes in service levels and / or resources available to provide those services as a result of the budget decision process.

The Plan has a life of 11 years (2014–2025) and is due for revision and updating within 1 year of each AER price ruling.

9. APPENDICES

A. AECOM Replacement Strategy Report

Adobe Acrobat Document

B. CBRM Modelling

CBRM Overview

CBRM is a decision support tool developed to assist asset managers in quantifying, communicating and managing asset related risk, with particular emphasis on issues associated with end of life. The CBRM process produces computer models that provide a quantitative representation of current and projected future asset condition, performance and risk. The models are used to evaluate possible asset renewal strategies and investment scenarios to arrive at a proposal that best meets the objectives of the organisation.

CBRM seeks to overcome the common asset management decision optimisation problem of non-availability of reliable and consistent data that is necessary to construct valid population based statistical models. This problem is particularly acute in the electricity distribution industry where assets have long lives (often many times longer than a typical computer information system), and are subject to many factors that cause asset sub populations within a general asset class to behave differently. Examples of different sub populations would include manufacturer make and model with varying design and quality characteristics, changing equipment specifications and installation practices, operating environment and usage history.

Rather than use a purely statistical representation of the asset population, CBRM models seek to make the best possible use of available information by combining asset register information, operating context, operating history and condition information using rules that are consistent with engineering principles and the operating experience of local asset Subject Matter Experts (SMEs). The resulting models are adjusted and calibrated so that the output and behaviour of the model is consistent with historical observations and SME expectations. While CBRM models incorporate some subjective SME judgment, this judgment is codified by rules and is applied consistently. The rules are transparent and may be subjected to scrutiny, review and tested for sensitivity as required.

CBRM offers a tactical advantage over statistical based approaches in that all available information, including physical observations of condition are incorporated into the assessment, and applied to individual assets within the model. The objective is to produce asset risk rankings and projections that inform asset management strategy and tactics as well as providing higher quantity level forecasts necessary for budget and regulatory purposes.

Relationship with Actuarial or Statistical based approaches

CBRM may be thought of as a ‘bottom up’ engineering model, whereas statistical approaches such as for example REPEX may be thought of as ‘top down’. Each type of model is subject to error from approximations associated with input assumptions and limitations related to the quality of input data. Both types of model will have application in a mature asset management process as they provide complimentary information from with to base a considered view of replacement requirements. While it would not be expected that a bottom up, and top down model will agree precisely, any differences should be subject to rationalization and explanation and in doing so better inform the decision process.

How CBRM Works

CBRM is a process that transforms diverse sources of previously disconnected engineering knowledge, experience and data into a ‘what if’ management tool that can be used to support asset renewal decision making. The CBRM process is illustrated in Figure 14 below.

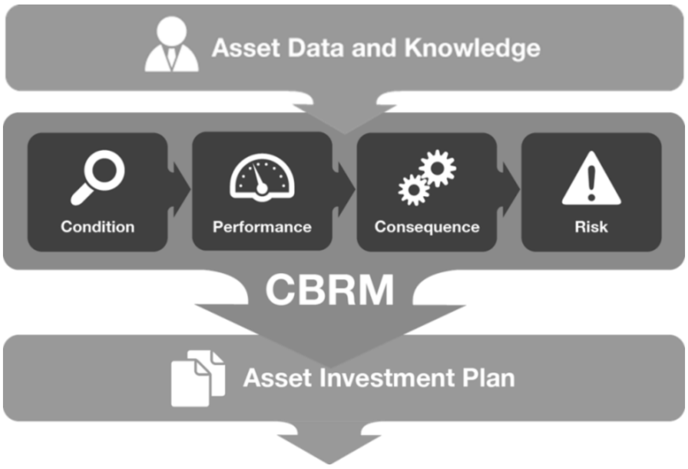


Figure 14: Overview of the CBRM process

Implementation of CBRM process

CBRM determines the level of risk a particular asset exposes SA Power Networks to through the following steps:

- **Define Asset Condition:** The condition of an asset is measured on a scale from 0.5 to 10, where 0.5 represents a brand new asset; this is defined as the Health Index (HI.) Typically an asset with a HI beyond 7 has serious deterioration and advanced degradation processes now at the point where they become significantly unreliable. Determination of the HI of a given asset is made by factoring its age, location, duty, and measured condition points. After the HI is determined, future condition of the asset is forecasted after ***t*** years.
- **Link Condition to Performance:** If an asset has a HI less than 4.0 its Probability of Failure (PoF) distribution is random. When the HI shows further degradation, a cubic relationship is used to measure PoF against HI. Each asset class has unique events; every event is assigned a PoF model, which uses an individual failure rate based on network performance.
- **Determine the Consequence of Failure:** The consequence of failure is divided into the following categories:
  - CAPEX: The Capital Expenditure required to remediate an event.
  - OPEX: The Operational Expenditure required to remediate an event.
  - Safety: The cost incurred due to death/injury to individual(s) as a result of an event.
  - Environment: The cost of environmental cleanup/penalties as a result of an event.
  - Reliability: Financial penalties imposed if an event causes an outage.

  The consequences are individually determined for all of the events associated with the asset using criteria such as location, number of customers, load profiles, SCONRRR category, VCR rates, and type/model.
- **Determine Risk:** Risk is measured in financial units for each asset; it's determined by combining the PoF, consequence and criticality for every event. Criticality defines the significance of a fault/failure for an individual asset, and is determined for each of the categories listed in item 3.

CBRM also models non-condition events, which do not depend on a HI. These events are assigned to every asset and use a random failure based Probability of Failure (PoF) model. An example of a non-condition event is third party damage from a car hit pole incident.

By forecasting every asset's condition, CBRM calculates the total risk, total number of failures and HI profile for an asset group based on the following investment scenarios after ***t*** years:

1. **Do Nothing:** do not replace any assets in the group;
2. **Targeted Replacement:** nominate when assets are replaced/refurbished;
3. **Replace a fixed percentage of assets every year:** nominate the percentage of assets to be replaced every year and choose the priority to be HI, total risk or delta (condition) risk.

CBRM identifies the level of risk exposed for an investment scenario over time. This allows the percentage used in **Scenario 3** to be determined such that a constant level of risk can be maintained, an example of this risk profile is shown below in Figure 15.

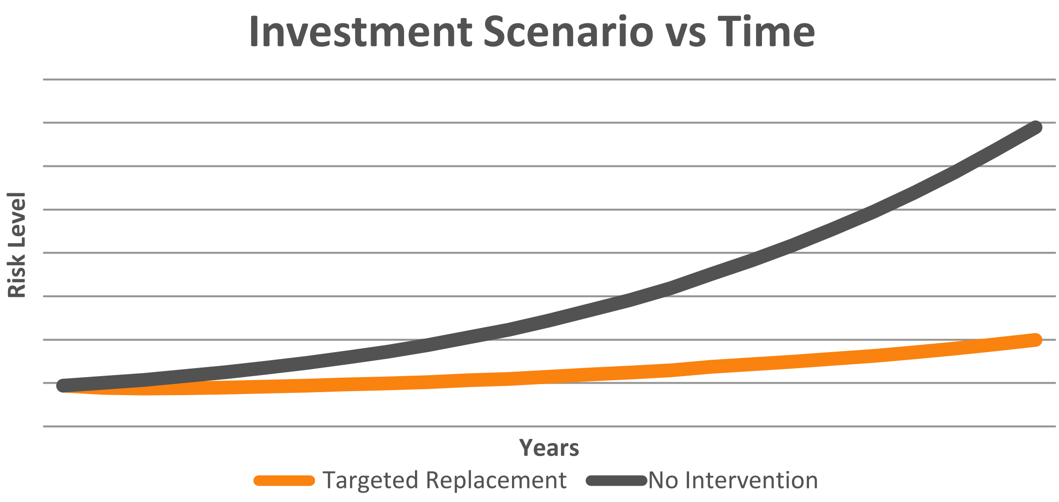


Figure 15 : Example of risk profile over time output graph

CBRM determines the financially optimum year to replace a given asset by finding the right balance between delaying network investment and bearing more risk, a graphical illustration of this is shown below in Figure 16.

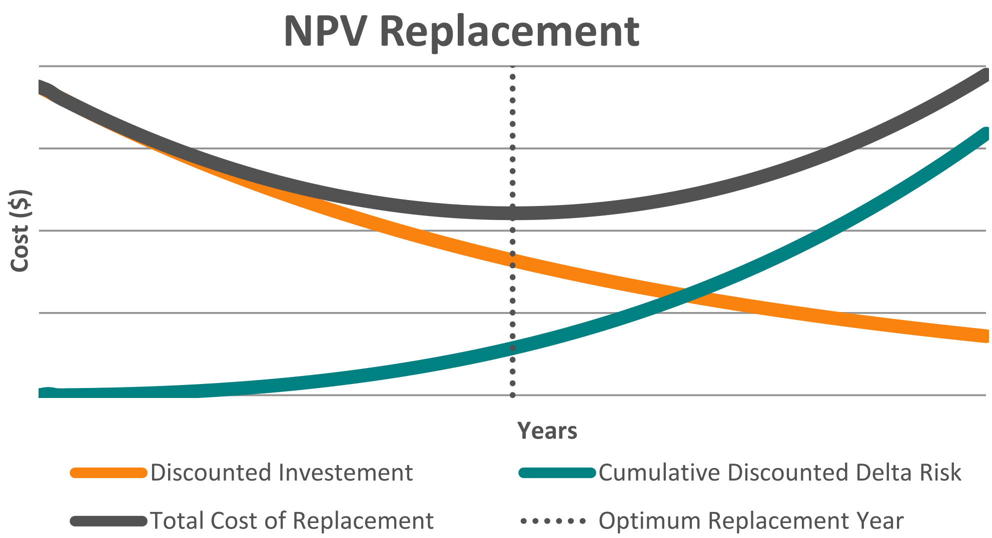


Figure 16 : Example of outputs used to determine optimum replacement year

CBRM allows an NPV approach for discounted investment, where the discount rate is SA Power Networks' Weighted Average Cost of Capital (WACC). The cumulative discounted delta risk is a sum of the risk beared for each year, discounted by the WACC. The total cost of replacement is the sum of the cumulative discounted delta risk and discounted investment, CBRM finds the year where this cost is minimal and identifies this as the financially optimum replacement year for an asset.

In order to accurately determine the financially optimum replacement year, an even balance between risk and unit costs needs to be achieved. SA Power Networks' costing records aren't currently accurate enough to achieve the balance; however improvements in asset records through works management programs are being undertaken. When the improvements are implemented it's anticipated that the network record accuracy will be improved to such a level that the financially optimum replacement year for assets can be correctly identified.

Circuit Breakers Methodology

CBRM uses two independent circuit breaker models for Subtransmission and Distribution circuit breaker assets. This decision was made because Distribution and Subtransmission assets have different reliability consequence models, and expose SA Power Networks to risk levels of an order of magnitude difference between each other.

Determination of Health Index

CBRM determines Circuit Breaker HI1 – Age Related Health Index (HI) by calculating an ageing constant β, which is combined with the Circuit Breaker's age. The information used and dependencies are shown above in Figure 17.

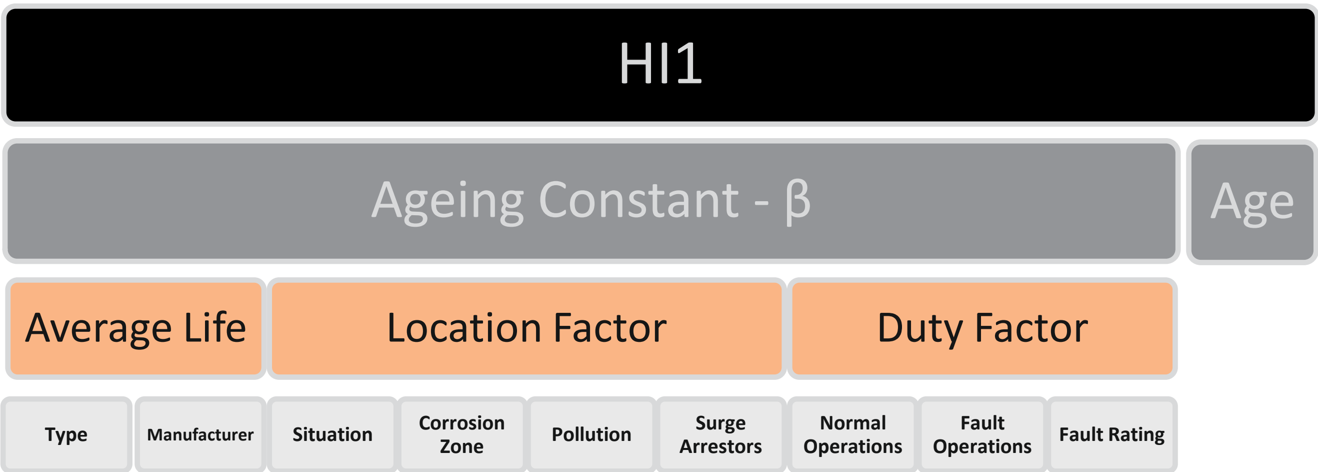


Figure 17: Circuit Breaker HI1 Methodology

The value of β is determined by combining the following information:

- **Average life:** The average life of a Circuit Breaker is determined based on its type, and manufacturer.
- **Location Factor:** The location factor depends on the following information:
    1. Situation – Indoor Circuit Breaker has a mild operating environment when compared to an outdoor Circuit Breaker. Indoor Circuit Breaker can also be installed in air conditioned switch rooms, which controls humidity.
    2. Corrosion Zone – This represents the level of atmospheric corrosion a Circuit Breaker will experience during its operating life.
    3. Pollution – Localised pollution may affect the condition of a Circuit Breaker.

4. Surge Arrestors – The presence of a surge arrestor at the Circuit Breaker location reduces deteriorating effects of transient atmospheric and switching overvoltages.

- **Duty Factor:** The duty factor is determined using the following information:
    1. Normal Operations – this is the number of mechanical operations the Circuit Breaker has undertaken.
    2. Fault Operations – this is the frequency of fault operations the Circuit Breaker experiences.
    3. Fault Rating – this is a ratio derived from *fault level at the site as a proportion of circuit breaker rating.*

It's important to note that HI1 is capped to 5.5, as this indicates the Circuit Breaker is beginning to experience significant degradation. CBRM applies this cap because further degradation cannot be justified without condition based measurements.

HI Y0 represents the CB condition as it stands today. This HI is determined by combining HI1 with an overall 'factor value', which is established by combining factors derived from condition based measurements.

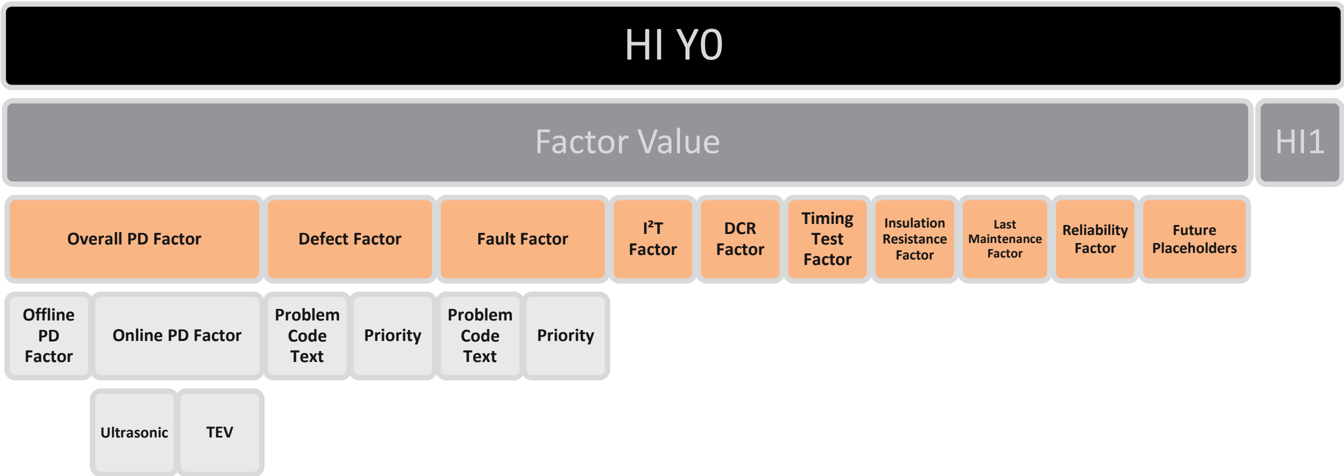


Figure 18: Circuit Breaker HI Y0

The overall 'Factor Value' is a combination of the following condition based factors:

- **Overall PD Factor –** An overall PD factor is formed using the results from online and offline Partial Discharge testing, where the online component takes into account TEV and Ultrasonic measurements.
- **Defect Factor –** CBRM considers the rate of occurrence of defects to be an indication of both the condition and likelihood of future defects or failure. Defect history is incorporated by identifying defects recorded against the asset in SAP, and numerically grading them by Priority and problem type.
- **Fault Factor –** Similar to the rate of occurrence of defects, CBRM considers the rate of occurrence of faults as an indication of both the condition and likelihood of future faults or failure. Fault history is incorporated by identifying the faults recorded against the asset in SAP, and numerically grading them by problem code.
- **I^2T Factor –** Derived from the accumulated fault energy the CB has experienced – a measure of contact wear.
- **DCR Factor –** Derived from the most recent Dynamic Contact Resistance measurement experienced – a measure of contact wear.
- **Timing Test Factor –** Derived from the most recent measurement of the time taken for the trip mechanism to open the contacts – measure of mechanical condition.

- **Insulation Resistance Factor –** Derived from the most recent Insulation Resistance measurement – measure of insulation condition.
- **Reliability Factor –** Captures asset operator knowledge with respect to the CB manufacturer and type reliability.
- **Last Maintenance Factor –** This considers if the CB is overdue for maintenance, and is assigned based on the number of days the maintenance is overdue.

Determination of Risk Consequences

CBRM uses the following events to define circuit breaker risk consequences:

- Major Failure – Failure that results in an unplanned outage requiring major repairs or replacement.
- Significant Failure – Failure that results in an unplanned outage but is repairable on site.
- Minor Failure – Defect that does not result in an unplanned outage.
- Condition– The circuit breaker is replaced on condition during a planned outage.
- Fail to trip – Failure caused by slow or non-operation of a circuit breaker for a fault.

CBRM assumes that each event incurs financial consequences on SA Power Networks, these are separated into the five consequences, an explanation on how CBRM determines the financial consequences for each of the categories is detailed in Table 19.

Determination of Criticality:

For each event, a criticality is defined and assigned to each consequence category. The criticality is normalised so that the average criticality for all CB in the model is unity. The following information is used to determine criticality:

- **CAPEX**
  - Customer Type: SCONRRR category of the substation supplying the CB (taken to be the highest SCONRRR category feeder at the substation).
  - Voltage: Used to scale the CAPEX consequences by the primary voltage of the circuit to account for the difference in capital cost for assets.
- **OPEX**
  - Customer Type: SCONRRR of the substation supplying the CB.
  - Major Customer: Feeders supplying major customers expose the network to a greater level of risk and co-ordination of switching to restore supply.
  - Function Factor: Reflects the different costs based on the CB functional location, such as feeder breaker vs section breaker – work required to safely isolate.
  - Number of Feeders: Recognises repair/replacement/restoration costs can vary by the number of feeders.
  - Spares Obsolescence: Allows for an increase in repair costs for obsolete assets where support/parts are not readily available.
  - Medium: Identifies the different costs based on circuit breaker construction.
- **SAFETY**
  - Internal Arc Rated: CB that do not have an internal arc containment rating have an increased safety risk.
  - Bushing Insulation Type: Every type of bushing has a different safety risk; based on mode of failure.
  - Situation: There are different safety implications between indoor and outdoor located CB.

  - Medium: There are different safety risks for interrupter/insulation medium combinations used in the CB.
- **ENVIRONMENT**
  - Environmental Risk Assessment: Assessment of the installation environment's vulnerability to environmental damage.
- **RELIABILITY**
  - Number of Feeders: The outage duration is modified due to the number of substation feeders – not applicable to Subtransmission CB.
  - Single Bus: Single bus configurations expose the network to more risk with reduced redundancy.
  - Spares/Obsolescence: There's a potential increase in outage duration for obsolete assets where support/parts are not readily available to restore supply.
  - Major Customers: If major customers exist on the feeder, a fault exposes more risk as requires external co-ordination of switching.
  - SCADA Site: Sites with substation control/communication have a faster response time.

The varying asset replacement maturity levels and their relationship to CBRM are discussed in Table 20 below.

Table 19: Financial Consequence categories

<table>
<tr><th>Event</th><th>CAPEX</th><th>OPEX</th><th>Safety</th><th>Environment</th><th>Reliability</th></tr>
<tr><td>Event: Failure to Trip
Condition</td><td>No CAPEX</td><td>Cost of repairs and supply restoration</td><td rowspan="5">For each event, CBRM splits safety into three accidents:
• Minor
• Major
• Fatality

Each accident is assigned an overall consequence representing financial investment to prevent it from occurring.

Each event is assigned an average consequence factor for each subcategory.

CBRM multiplies the average consequence factor by the overall consequence for each accident, and the sum of the results is the overall safety consequence for the specific event.</td><td rowspan="5">For each event, CBRM splits environment into five accidents:
• Loss of Oil/Litre
• SF6 Emission/kg
• Fire
• Waste/tonne
• Disturbance

Each accident is assigned an overall consequence.

Each event is assigned an average consequence factor for each subcategory.

CBRM multiplies the average consequence factor by the overall consequence for each accident, and the sum of the results is the overall environmental consequence for the specific event.</td><td rowspan="2">For Distribution CB, CBRM values reliability consequence by estimating the SPS penalty incurred as a result of CB failure. This is determined using the following information: Total Customers Supplied by the Feeder, Average Outage Duration, Value of a Customer Interruption, and Value of a Customer Minute Lost. These values depend on the CB SCONRRR.

For Subtransmission CB, CBRM values reliability consequence as load put at additional risk >> redundant and non-redundant circuit breaker types. This is determined by multiplying the average load lost, VCR, and a LAFF factor. The LAFF is a cubic relationship of the ratio of Load Above Firm Capacity : Maximum Demand</td></tr>
<tr><td>Event: Major Failure
Condition
Non Condition</td><td>Investment in new circuit breaker</td><td>Supply restoration, testing and assessment</td></tr>
<tr><td>Event: Significant Failure
Condition
Non Condition</td><td>Capital expenditure on major parts / capital items</td><td>Cost of repairs and supply restoration</td><td>Average outage duration, and redundant vs non-redundant circuit breaker types</td></tr>
<tr><td>Event: Minor Failure
Condition
Non Condition</td><td>No CAPEX</td><td>Cost of repairs and supply restoration</td><td>There are no Reliability Consequences associated with this event</td></tr>
<tr><td>Event: Replacement
Condition</td><td>Investment in new circuit breaker</td><td>Cost of isolation, testing/condition assessment</td><td>There are no Reliability Consequences associated with this event</td></tr>
</table>

Table 20: Asset replacement Investment Maturity Levels

Maturity Level/Complexity	Approach	Basis of CBRM Forecasts
Age based	Assets are replaced when they reach a pre-defined nominal life. Rarely used in practice	Decisions and forecasts made from asset age profiles. This approach corresponds to the 'deterministic' option available within the repex model and is rarely if ever used in distribution utility practice
Asset Health based	Assets are replaced when they reach a pre-determined condition or health. Commonly used and often based on quantitative condition monitoring or subjective inspection criteria	Replacement at a pre-defined health index. The replacement health index selected will define the probability of failure. This is the basis of many existing asset management strategies where a global standard defines common 'pass' and 'fail' criteria for all assets regardless of their criticality to business objectives
Target failure rate based	The volume of asset replacements are determined so as to provide a target asset failure rate. Target failure rates will be related, but not necessarily proportional to, service levels such as SAIDI or safety objectives	CBRM model predictions of failure rate may be used to develop an intervention plan to achieve a target number of failures. While overall failure rates are managed, no consideration is given to asset criticality to business objectives >> risk to business
Target risk based	The volume of asset replacements are determined so as to provide a target level of risk. Risk targets may be derived from service level targets	CBRM model predications of risk may be used to develop an intervention plan to achieve a target risk level. Inaccuracies in the absolute calculated value of risk may be minimised by setting targets in relative rather than absolute terms, for example maintaining a constant or static risk or a percentage reduction in risk.
Financially optimised	The volume of asset replacements is determined to balance the net present value of risk associated with retaining each asset in service. In principle, a financially optimised replacement plan correctly balances the impact of failure to both the network business and the community against the cost of replacement/refurbishment	CBRM NPV Optimisation. Accuracy of NPV optimisation is dependent upon the level of confidence in the absolute values of risk as these are considered by the NPV analysis as a cash flow stream. CBRM NPV optimisation should therefore only be used in situations where there is a high degree of confidence with the absolute calculated values of risk. Analysis is very sensitive to risk and WACC

CBRM Model Calibration

The objective of CBRM is to produce a decision support model that consistently combines both objective data, and subjective engineering knowledge to produce more representative projections than would be achieved than other methods, particularly in situations where data is sparse or incomplete. It is not intended that CBRM predictions compete with those of other approaches such as REPEX, rather each method produces a 'data point' that should be considered in totality. In a regulatory discussion, CBRM projections would represent the best available estimates of forward renewal requirements that incorporate available engineering data and engineering opinion. An actuarial model such as REPEX would represent a future projection based on high level historical data and statistics with an accuracy level commensurate with data quality and validity of model assumptions. While it is unlikely that the output of both approaches will agree precisely, any differences should be explainable, and inform the outcome of the regulatory discussion.

The intent of CBRM is to embrace and use subjective knowledge to improve model predictions. Subjectivity is however minimised by referencing the output of the model to observable calibration features. The rationale for calibrating each component of the model is as follows:

Health Index

The intent of the asset Health Index is to produce an estimate of asset health that incorporates both observable data including condition observations, with subjective SME knowledge. The health index and health index forecasts are produced by rules, many of which are calibrated using subjectively determined weighting factors. Weighting factors are progressively adjusted so that the model produces health indices that are reflective of the conclusions that subject matter experts would reach if independently evaluating the same input information. In finalising calibrations for health indices, the process firstly ensures that health indices are correctly ranked, and secondly that the spread or distribution is reflective of evidence and expectations. The absolute value of health indices is less critical for most applications as final predictions are normalised through the Probability of Failure estimation process.

Probability of Failure

The relationship between Health Index and Probability of Failure is calibrated using an objective approach that essentially fits the HI/PoF curve (k) to physical observations of failures. Adjustment is primarily by the scale parameter of the PoF curve. Where data is available, relative rates of failure at different points in the asset lifecycle may be used to further adjust the HI/PoF curve to accommodate relative failure rates at various health index points by adjustment of the shape factor (c). Where such data is not available, a standard HI/POF shape is used that has been found to produce representative forecasts in other models.

Risk

The total value of risk is calculated as the product of the average cost per failure multiplied by the total number of failures. Both quantities can be objectively determined from historical data. The total risk is then spread out over the model population using combinations of POF (discussed above) and criticality factors. The calibration of criticality factors is achieved from a combination of objective measures (for example number of customers affected) and subjective subject matter expert driven measures. It should be noted that the allocation of criticality affects only the relative criticality ranking within the model, and does not affect the overall risk quantum predicted by the model.

Aging Function in CBRM

The relationship between age and condition is complex and dependent upon many factors. Furthermore the form of relationship is variable depending upon the failure mode and its associated degradation mechanism with different forms being applicable for corrosion, thermal deterioration of insulation and fatigue for example. Given the scope and intent of CBRM, it is not practicable to attempt to replicate an engineering evaluation of deterioration curves based on specific degradation mechanisms. Nevertheless it is often the case that rate of deterioration increases as condition decreases due to for example loss of protective coatings, accelerative effects of degradation products, and mechanical impact loading caused by increased tolerances in mechanisms.

The exponential ageing function has been chosen to predict future asset health indices in CBRM models for pragmatic modelling reasons. Firstly experience has shown that the exponential function performs well for short range predictions (<=5 years) matching operational experience. Secondly the exponential form used has the mathematical property that allows a future health index to be projected from an initial health index without reference to the asset age eg $H_f = H_i e^{B(T_f - T_i)}$ which is a useful property in the construction of a condition based model. It should also be noted that a fundamental aspect of CBRM is validation of output against historical data, and when this is not available SME experience. To accommodate tuning of the ageing function a range of additional parameters termed the ageing reduction index is included in each model. These parameters allow ageing rates to be adjusted should it be found that the unadjusted exponential function does not produce representative predictions. Further explanation of the rationale can be found in 'Using modelling to understand and improve CBRM', EA Technology Report No. 5947, 2006.

Model Selection

CBRM derived model output can support a range of asset renewal strategies. These are in order of increasing complexity, as described above:

- Age based
- Condition based
- Performance (failure rate) based
- Risk based
- Economic optimisation (NPV based)

The chosen approach is a matter of asset management strategy, however, EA Technology would normally encourage clients to use either, Performance, Risk or Economic (NPV) approaches over Age and Condition based approaches. The key differences between a performance (failure rate) and condition (health index) driven strategy is as follows:

1. Modern asset management theory, and asset management system standards (PAS-55 and ISO 55000), require that asset management strategy be directly linked to the corporate objectives of the organisation. While corporate objectives can vary from company to company, it is fair to say that most if not all electricity infrastructure organisations objectives, as they relate to renewal decisions would be framed in terms of measures such as customer service levels, public risk and cost. Developing renewal strategies to meet a specified level of performance in terms of number failures or level of risk will be more directly related to corporate objectives than achieving or maintaining a minimum condition level.
2. The future replacement and failure rates of an asset population would be related to the shape of the current health index profile. Under a maximum health index or condition drive strategy it would be theoretically possible for a population to have a low future replacement requirement, yet have an increasing failure rate. This may be undesirable in terms of impact on public safety outcomes, customer service levels, and repair costs, particularly where these are the performance measures upon which an organization is being managed and judged.
3. Where resources are limited, the target performance approach will assist with prioritisation of replacements based on their contribution to failures (worst assets first) by allowing the threshold replacement level to flex. A fixed condition threshold based

approach may result in a less efficient utilisation of resources under constraints should the 'quota' of replacements be spent before all assets have been evaluated.

NPV optimisation balances the future stream of costs, including intangibles against the cost of asset renewal. As such NPV analysis is sensitive to the absolute value of risk calculations. This sensitivity is greatly reduced with other approaches such as constant risk or percentage change in risk. For these reasons NPV optimisation should only be used for models where there is a high degree of confidence in the source data and model calibration.

NPV predictions that don't match reasonable expectations and seem incorrect are an area of concern and possibly suggest an opportunity to improve model calibration and should be further investigated.

CBRM is theoretically capable of producing retrospective to present predictions. To do so however requires a CBRM data set representative of the past starting period. It is however unlikely that this is readily available to SA Power Networks at this time. CBRM can of course make present to future predictions and these may be found in the future year predictions of the model. For future comparison, CBRM data sets may be saved and locked which will readily allow such past to present comparisons to made in the future.

CBRM Model results for Substation circuit breakers

SA Power Networks has identified that the level of risk exposed by circuit breakers can be maintained if a fixed percentage of the overall population is replaced per annum. The, required annual expenditure is summarised below.

This methodology produces results targeted at maintaining risk exposure after allowing for capacity related replacements, the targeted works program detailed below and expected failures (detailed as unplanned replacements below).

This methodology was selected on the recommendation of EA Technology as it is sensitive to absolute values of risk and more reliant on condition and failure rates information, which SA Power Networks holds good data on, than the other methodologies available within CBRM.

Table 21: Substation Circuit Breakers planned to be replaced from CBRM

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Total
Number													
11kV Switchboards - Planned	-	-	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	47
11kV Outdoor CB - Planned	-	-	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	9
33kV Circuit Breakers - Planned	4.0	2.0	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	28
66kV Circuit Breakers - Planned	4.0	2.0	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	11
TOTAL	**8.0**	**4.0**	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	95
Expenditure ($,000 2013 dollars)													
11kV Switchboards - Planned	-	-	$2,585	$2,585	$2,585	$2,585	$2,585	$2,585	$2,585	$2,585	$2,585	$2,585	$25,850
11kV Outdoor CB - Planned	-	-	$315	$315	$315	$315	$315	$315	$315	$315	$315	$315	$3,150
33kV Circuit Breakers - Planned	$2,000	$1,000	$1,100	$1,100	$1,100	$1,100	$1,100	$1,100	$1,100	$1,100	$1,100	$1,100	$14,000
66kV Circuit Breakers - Planned	$2,400	$1,200	$300	$300	$300	$300	$300	$300	$300	$300	$300	$300	$6,600
TOTAL	**$4,400**	**$2,200**	**$4,300**	**$4,300**	**$4,300**	**$4,300**	**$4,300**	**$4,300**	**$4,300**	**$4,300**	**$4,300**	**$4,300**	**$49,600**

C. Targeted Programs

66kV Reyrolle OSM10

Reyrolle OSM10 circuit breakers are outdoor type 66kV minimum oil circuit breakers originally installed on the network in the late 1960s. A circuit breaker review (SKM 1998) identified the Reyrolle OSM10 circuit breaker as having an 'inherent design deficiency' which results in oil leaking from the breaker poles at the porcelain to metal seals. This defect is not considered economically repairable and the recommendation of the review was a planned replacement program for the Reyrolle OSM10 circuit breaker to remove all units from service.

At the date of publication of the SKM Review there were twenty three Reyrolle OSM10 circuit breakers in service. A total of sixteen OSM10 circuit breakers have been replaced since the SKM review at a rate of approximately of one unit per year. At the beginning of 2014, seven Reyrolle OSM10 circuit breakers remain in service, with one unit (CB5271 at Plympton Substation) scheduled for replacement mid 2014. Continuation of this replacement program is recommended to remove all remaining units from service by 2020.

Table 22: 66kV Reyrolle OSM10 expenditure

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Total
Units	1	0	1	1	2	2	0	0	0	0	0	0	7
$ k	$600	$0	$600	$600	$1,200	$1,200	$0	$0	$0	$0	$0	$0	$4,200

66kV EE & BTH Bulk Oil CBs

BTH & EE circuit breakers are outdoor 66kV bulk oil circuit breakers installed throughout the Riverland in the early 1950s. These circuit breakers are amongst the oldest still in service in the network and have a history of operational problems and high maintenance requirements. This class of circuit breaker also presents significant environmental risks in sensitive areas such as the Riverland, given their large oil volume and frequent oil leaks.

A number of repeat circuit breaker failures in the Riverland prompted an internal investigation in 2002. This showed BTH circuit breakers to have failed to operate correctly on at least eight occasions over a two year period from a variety of age and condition related defects, primarily associated with the mal-operation of internal linkages and closing solenoids.

A progressive replacement program of all BTH & EE bulk oil circuit breakers within the Riverland region (Loxton, Berri, North West Bend, Loveday, Renmark, Waikerie, Lyrup, Paringa and Swan Reach Substations) began in 2006. With the completion of circuit breaker replacement at Waikerie Substation in early 2014, sixteen of the nineteen circuit breakers identified in this replacement program will have been completed.

Continuation of this replacement program to address the three remaining Riverland sites (Lyrup, Paringa and Swan Reach) at the rate of one site per year is recommended to remove all bulk oil circuit breakers from the Riverland by 2018.

Table 23: 66V EE & BTH Bulk Oil CBs expenditure

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Total
Units	0	0	1	1	1	0	0	0	0	0	0	0	3
$ (000)	$0	$0	$600	$600	$600	$0	$0	$0	$0	$0	$0	$0	$1,800

66kV AEG / ALSTOM / AREVA S1 model live tank SF6 CBs

S1-72.5F1 model circuit breakers are a 66kV live tank SF_6 insulated circuit breaker installed on the network between 1997 and 2003. 46 of this model circuit breaker were installed before this model was superseded by the GL309-72.5 F1 model circuit breaker in 2003.

Beginning late 2007, repeated low gas alarms from S1-72.5 circuit breakers at New Osborne, Cavan and Edinburgh Substations prompted an intrusive inspection and detailed investigation of condition. It was found that the S1-72.5F1 model circuit breaker has an inherent design flaw that allows pooled moisture to collect at the base of the circuit breaker and corrode around the pole gasket.

Discussions with the manufacturer have shown this issue to be a defect of the S1-72.5 model and subsequently addressed by design changes made to the GL309-72.5 F1. Discussions with the manufacturer have resulted in an ongoing program of replacement with manufacturer repair and modification of faulty circuit breakers as they are identified by SA Power Networks. This design issue affects all unmodified S1-72.5 circuit breakers and to date eight of the original population of S1 circuit breakers have been addressed through repair or replacement with a GL model circuit breaker.

Condition monitoring of these circuit breakers has required an average replacement rate of one unit per year until 2011, although there is no reasonable expectation that this rate will remain constant into the future. Six additional units have been identified since 2012 and so an ongoing allowance of two S1 condition replacements is recommended to meet current and expected failure rates through to 2025.

Table 24: 66kV AEG/ALSTOM/AREVA S1 model live tank SF6 CBs expenditure

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Total
Units	3	2	2	2	2	2	2	2	2	2	2	2	25
$ ('000)	$ 90	$ 60	$ 60	$ 60	$ 60	$ 60	$ 60	$ 60	$ 60	$ 60	$ 60	$ 60	$ 750

33kV Email/Westinghouse 345GC

The 33kV Email/Westinghouse 345GC circuit breaker is an outdoor dead tank bulk oil circuit breaker installed on the network in the 1960s. A circuit breaker review (SKM 1998) identified this model of circuit breaker as having an inherent bushing defect that results in leaking of pitch filled bushings. The recommendation of the review to ensure a program of replacement that maintains an adequate stock of spare of refurbished bushings.

Nineteen Email/Westinghouse 345GC circuit breakers are currently installed on the network and experience has generally shown reliable performance to date. Current spares holdings and forecast replacement rates through asset replacement and site upgrade are considered to be sufficient to manage the population of these assets. No replacement allowance has been made to manage spares requirements for Email/Westinghouse 345GC circuit breakers in this plan.

33kV Ferguson Palin UAP

Ferguson Palin UAP breakers are amongst the oldest model circuit breakers still in service on the network. The youngest of these breakers were installed installation 1944 and with the original manufacturer of the UAP circuit breaker no longer in existence, spares for the UAP can only be obtained through manufacture (extremely expensive) or by salvage of decommissioned units. These circuit breakers show a history of age and condition related reliability issues and have been recommended for ongoing, priority replacement since 2008 at a rate of approximately four per year. Current asset replacement plans will see the last two UAP circuit breakers replaced in 2015.

Table 25:33kV Ferguson Palin UAP expenditure

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Total
Units	0	2	0	0	0	0	0	0	0	0	0	0	2
$ ('000)	$0	$1,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,000

6.6kV BTH 6.6kV switchboard supplying the Port Pirie smelter

Port Pirie Substation consists of three 10 MVA 33/6.6kV transformers suppling a dedicated customer (Nyrstar) a peak load requirement of approximately 21MVA. Distribution switchgear at Port Pirie Connection Point consists of ten BTH type JB821 circuit breakers in three bus sections and five dedicated feeder circuit breakers that supply critical processes at the plant. This switchboard was installed with the substation in 1950 and now (as of 2013) has been in service for 63 years.

There are no spare breakers within the switchboard and the failure of any one of the ten 6.6kV circuit breakers will considerably impact production at the smelter. As the sole 6.6kV network operated by SA Power Networks, there are no alternate points of supply and so a catastrophic failure will leave the smelter without supply for considerable periods of time before the mobile switchboard can be deployed to provide a progressive restoration of load.

Progressive subsidence of the switchroom has caused uneven movement of the floor causing uneven mechanical stress along the switchboard and operational issues when operating CBs. Deteriorating condition has required safe operating restrictions to be applied to the switchboard, preventing and live racking of circuit breakers.

One the basis of extreme safety risks posed by the poor and declining condition of this equipment, replacement of the switchboard and control room is planned for 2015-16.

Cap Banks

66kV ABB EDF-SK1

ABB EDF 66kV circuit breakers were supplied to SA Power Networks as a packaged capacitor bank installation at Golden Grove and Whitmore Square Substations. Following a catastrophic failure of this model circuit breaker at Golden Grove in 2007, investigations have shown this type of CB to be poorly suited to capacitor bank switching applications, which result in the accelerated compromise of the arc commutation arrangements within the circuit breaker.

The result of this is that the circuit breaker has a reduced number of operations before requiring major intrusive maintenance and contact replacement. Manufacturer's revised recommendations now require overhaul and contact replacement at 1000 or 1200 ops for back to back and single bank applications respectively.

11kV Single Phase Cap Bank Oil Load Switches (GEC type FKC-2)

General Electric Corporation (GEC) model FKC switches are motor operated, single phase oil switches installed in the early 1980s. These oils switches are used in eight rural substations as a means of isolating small, pole mounted capacitor banks installed at each site. The standard arrangement of these capacitor bank switches requires manual switching by pushbutton control (positioned directly beneath the switch) to simultaneously operate all devices.

The relatively infrequent operation of these switches and lack of a common operating mechanism make these devices prone to switching out of phase, with consequential risks of ferroresonance and a spurious operation of substation protection. Failure of this sort occurred in August 2013 at Meningie substation, when a single switch failure caused protection to isolate the substation switchyard, resulting in a SPS impact of approximately $130k and the interruption of supply to approximately 1300 customers. The failed switch at Meningie was returned to service after lengthy repairs; however further operation of these switches places substation load at risk in the event of a similar failure.

In addition to being poorly suited to capacitor bank switching, these devices are no longer supported by spares (parts or equivalent switch) and so failure or maintenance of these devices requires lengthy delays to capacitor bank restoration. The consequence of this is the compromise of network voltage support in the states rural distribution networks.

It is recommended that allowance be made for replacement of all eight substations with GEC FKC single phase oil switches (by three phase vacuum capacitor switch) to mitigate the growing risks to operator safety and network security these sites present due to their poor condition.

Note: Three of the eight substations with GEC FKC capacitor switches are proposed for remediation under the Airbreak Disconnector Management Plan (AMP 3.2.17). Provision for capacitor bank switch replacement necessary to these works is sought in this plan.

Table 26: 11kV Single Phase Cap Bank Oil Load Switches (GEC type FKC-2) expenditure

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Total
Units	0	0	1	1	1	1	1	1	1	1	0	0	8
$ ('000)	$ 0	$0	$60	$60	$60	$60	$60	$60	$60	$60	$0	$0	$480

11kV Three Phase Cap Bank Load Switches (McGraw Edison type VCR)

McGraw Edison model VCR oil switches are a three phase capacitor load break device installed in the early 1980s across nine substation sites in the Upper North and Riverland regions. These switches connect to the network through an 11kV circuit breaker (for primary plant protection) and provide the regular capacitor bank switching duty required at these sites.

With the original manufacturer (McGraw Edison, now Cooper Power) no longer able to provide support for these switches, spare parts can only be sourced from replacement of ex-service units. With no recent replacements, all useable spares (component parts or refurbished units) have been exhausted, leaving network security at risk from significant delays to capacitor bank restoration.

There have been two catastrophic failures of this switch model in the last decade, the last of which (Angaston LS710 in early 2012) left the capacitor bank out of service for over a year before a modern equivalent switch could be procured and installed in its place. A failure of any one of the seventeen VCR switches currently in service will require similar delays before they can be returned to service.

It is recommended that allowance be made to replace a total of four VCR switches over the period 2015 – 2020 to manage the remainder of the population over the period of this plan. Completion of this work should mitigate the significant network security risk posed by switch failure and extended capacitor bank unavailability.

Table 27: 11kV Three Phase Cap Bank Load Switches (McGraw Edison type VCR) expenditure

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Total
Units	0	0	2	1	0	1	0	0	0	0	0	0	4
$ ('000)	$ 0	$0	$120	$60	$0	$60	$0	$0	$0	$0	$0	$0	$240

D. Repex Modelling

The Australian Energy Regulator's (AER) replacement model (repex model is intended for use as part of building block determinations for the regulated services provided by electricity network service providers (NSPs). The repex model is a series of Microsoft Excel spreadsheets developed for the AER to benchmark replacement capital expenditure. It was first deployed in the Victorian electricity distribution determination for the 2011-2015 regulatory control period.

Model Description

The AERs Replacement Model Handbook provides a description of the underlying premise and workings of the repex model.

The underlying premise of the model is that age is proxy for the many factors that drive individual asset replacements. The AER notes that with time, network assets age and deteriorate. This can affect their condition, which in turn can impose risks associated with the asset's failure such as network performance, safety, environmental damage and operational risks.

The model simplistically predicts the volume of replacement based on the age of system assets on the network. To do this, the model requires information on the age of assets, and the likely age of replacement. As a final step the model predicts the total expenditure by multiplying volumes by the average cost of replacing an asset in that group.

The repex model can be manipulated in a number of ways to test the replacement capex proposed by the DNSP. In the first instance, the AER uses the information provided in a DNSPs RIN to derive results for the model (termed the 'base case'). The steps involved in the 'base case' are explained in the AERs handbook and are summarised below.

1. Asset categorisation and grouping - The model requires the NSPs network asset base to be broken down into a number of discrete asset categories. This categorisation is required to reflect variations in asset lives and unit costs between different asset types. The AERs regulatory proposal RINs for mandate high level categories, but provide the ability for DNSPs to include lower level sub-categories.
2. Inputs – The key inputs required by the repex model relate to the age profile of each subcategory of assets, the mean age of replacement, and the unit replacement costs of assets within this group. These are collected by the AER as part of the RIN and are described below.
   a. Age profile - Reflects the volume of the existing assets at the various ages within the asset category at a static point in time. The model allows the installation dates to go backwards up to 90 years from the current date of the age profile.
   b. Mean age and standard life - These two parameters define the probability distribution of the replacement life for the asset category. The AER assume a normal distribution around the mean.
   c. Unit replacement cost - This parameter defines the average unit cost to replace one unit within the asset category. This unit cost must reflect the volume unit used within the age profile.
3. Outputs - The model takes these inputs and produces the following outputs for each asset categories:
   d. Age and asset value statistics and charts of the age profile - The model provides summary information of the age profile. This is presented at the asset category and asset group level. This covers information such as total volumes and replacement costs, proportions of the total network, average ages and lives, and proportions of aged assets.

e. 20 year replacement forecasts - Based upon the input data, the model produces year-by-year forecasts of asset replacement for the following 20 years. The forecasts prepared include individual asset category forecasts and aggregated asset group forecasts.

The 20 year replacement forecasts are based on a function within the model that provides a probabilistic estimate that an asset in the group will be replaced at a specific age. The model assumes that the probability is normally distributed around the mean age, taking into account the standard deviation.

SA Power Networks Model

A SA Power Networks repex model has been prepared as a comparator to the other methodologies utilised to develop the forecast expenditure for Circuit Breakers. The following steps were undertaken in development and calibration of the model.

Population of 'Tables' Sheet

The 'Tables' worksheet holds the data required to intialise the repex model.

The 'Asset group names' table holds the names for each of the asset groups, these have been populated to match the Catgory Analysis RIN to allow diret transfer of data from one model to the other.

The now parameter represnts the year that the age profile represents, that is the latest instalaltion date in the age profile, this was set to this year (2014).

The recursive parameter was set to 1, thereby forcing the model to perform a recursive caculation of replacement volumes, that is forecast replacement volumes in one year will themsevles be used to calculate replacenmetn volumes in later years. This is viewed as the most accurate methodology according to the AER model guide.

The first year parameter was set to '0' to make the first year if the forecast 'now', ie 2014, as the first yar of the age profile does not contain a significant number fo assets.

Population of 'Asset Data' Sheet

The 'Asset Data' worksheet within the repex model contains the data required to represent the SA Power Networks asset base. This worksheet has been populated with asset data in the same categories, and with data in the same columns, as the Category Analysis RIN.

The methodology parameter was set to '2' to cause the model to replace all assets assuming a normal distribution, ie the methodology as set out in the AERs Replacement model handbook guide, as SA Power Networks understand this to be the preferred methodology of the AER.

The profile type parameter was set to '3' to cause the model to assume the age profile is defined in terms of the installation date, to allow data to be directly utilised from the Category Analysis RIN, tab 5.2, where the age profile is given in terms of installation date.

The unit costs were populated with the unit costs detail in Section 7.2 above. The unit costs from the Category Analysis RIN were not utilised for the reasons described below.

For the Category Analysis RIN the unit costs were derived from work orders within SAP. An issue has been identified where it appears that not all costs are being correctly booked/allocated to work orders within SAP resulting in lower than expected unit costs. Examples of incorrect booking/allocation found were bundling of work making it difficult to separate out cost to replace components, work orders with no materials allocated, incorrect booking of labour, or no cost allocation although work has been completed..

The unit costs utilised were instead developed by subject matter experts and were based on information in addition to that held in SAP against work orders. These unit costs, as previously explained, are through to be typical unit costs for the type of replacements expected and more representative of the actual cost than those in the Category Analysis RIN. Use of the unit costs, as previously detailed, also ensures consistency of unit costs across the methodologies utilised for development of the forecast.

The replacement life mean and standard deviation (SD) were populated through calibration of the model, described in more detail below.

Model Calibration

It is understood that In addition to the 'base case', the AER also undertakes a calibration exercise to 'fit' the function of the model to historical replacement volumes and costs of the DNSP. This involves:

- Using historical replacement volumes over the most recent 5 years of actual data to adjust the mean replacement life until the forecast volume of replaced assets in the first year of the forecast period equals the average actual volume.
- Adjusting the unit replacement cost to reflect most recent data on the costs of replacing assets.
- Re-calibrating the model (ie: refreshing the outcomes) to allow for the new data.

The AER also note that as part of its calibration technique, it may use other scenarios such as using asset life and unit costs of other DNSPs that it has collected through the benchmarking process.

A calibration exercise was undertaken replicating the process SA Power Networks understands the AER will undertake, as described above.

The following steps were undertaken by SA Power Networks to calibrate the model:

- Worksheet 'Notes' was utilised for the calibration calculations
- For each asset category the following data can be found in the 'Notes' worksheet:
  - 'Original Life' – the average or expected life of the assets based on subject matter experts opinion, repored in previous AMPs or from other sources
  - 'Calibrated Life' – initially set to the same values as 'Original Life', linked to the mean life in the 'Asset Data' worksheet and changed during the calibration process as described below.
  - 'Calibration Factor' – calculated by divifing the 'Calibrated Life' by the 'Original Life'
  - 'Average of Actual Volume Replaced' – caculated from the average historicla replacements from 2008 to 2013 for each asset sub categroy from the Category Analysis RIN
  - 'Model Volume RRR Historic' – linked to the first years replacement quantity forecast in the 'RRR hist forc' worksheet, which when uncalibrated predicts the replacement volumes based on data input which do not necessariliy take into account historical behaviour.
- The model is calibrated by utilising the GOAL SEEK function in MS Excel. Using the GOAL SEEK function the 'Model Volume RRR Histroic' value for each asset sub category is set to match the 'Average of Actual Volume Replaced' by changing the 'Calibrated Life', thereby forcing the first year of replacements wihtin the model to match historcial behaviour/replacement volumes.

Model results

The results of the Repex modelling are shown in Table 28 and Figure 19 below.

Table 28: Repex Results for Substation Circuit Breakers

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Total
Number of Circuit Breakers													
< 11 kV ; CIRCUIT BREAKER (SUB)	1.1	1.2	1.2	1.3	1.4	1.5	1.5	1.5	1.6	1.6	1.6	1.6	17.0
11 kV ; CIRCUIT BREAKER (SUB)	4.7	5.5	6.4	7.4	8.4	9.6	10.8	12.1	13.4	14.8	16.1	17.4	126.5
> 22 kV & < ≈ 33 kV ; CIRCUIT BREAKER (SUB)	3.5	3.7	4.0	4.2	4.4	4.6	4.8	4.9	5.1	5.2	5.2	5.3	54.9
> 33 kV & < ≈ 66 kV ; CIRCUIT BREAKER (SUB)	1.8	2.0	2.2	2.4	2.6	2.8	3.0	3.3	3.5	3.7	3.9	4.1	35.1
> 66 kV & < ≈ 132 kV ; CIRCUIT BREAKER (SUB)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL	11.0	12.3	13.8	15.3	16.8	18.5	20.1	21.8	23.5	25.2	26.8	28.4	233.5
Expenditure ($millions)													
< 11 kV ; CIRCUIT BREAKER (SUB)	$0.36	$0.39	$0.42	$0.45	$0.47	$0.49	$0.51	$0.52	$0.53	$0.54	$0.54	$0.54	$5.78
11 kV ; CIRCUIT BREAKER (SUB)	$1.58	$1.86	$2.17	$2.50	$2.87	$3.26	$3.68	$4.11	$4.56	$5.02	$5.48	$5.93	$43.02
> 22 kV & < ≈ 33 kV ; CIRCUIT BREAKER (SUB)	$1.54	$1.65	$1.75	$1.84	$1.94	$2.02	$2.10	$2.17	$2.23	$2.27	$2.31	$2.33	$24.14
> 33 kV & < ≈ 66 kV ; CIRCUIT BREAKER (SUB)	$0.89	$0.99	$1.09	$1.20	$1.31	$1.42	$1.52	$1.63	$1.73	$1.83	$1.93	$2.03	$17.57
> 66 kV & < ≈ 132 kV ; CIRCUIT BREAKER (SUB)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL	$4.37	$4.89	$5.43	$6.00	$6.59	$7.19	$7.81	$8.43	$9.05	$9.66	$10.26	$10.82	$9.51

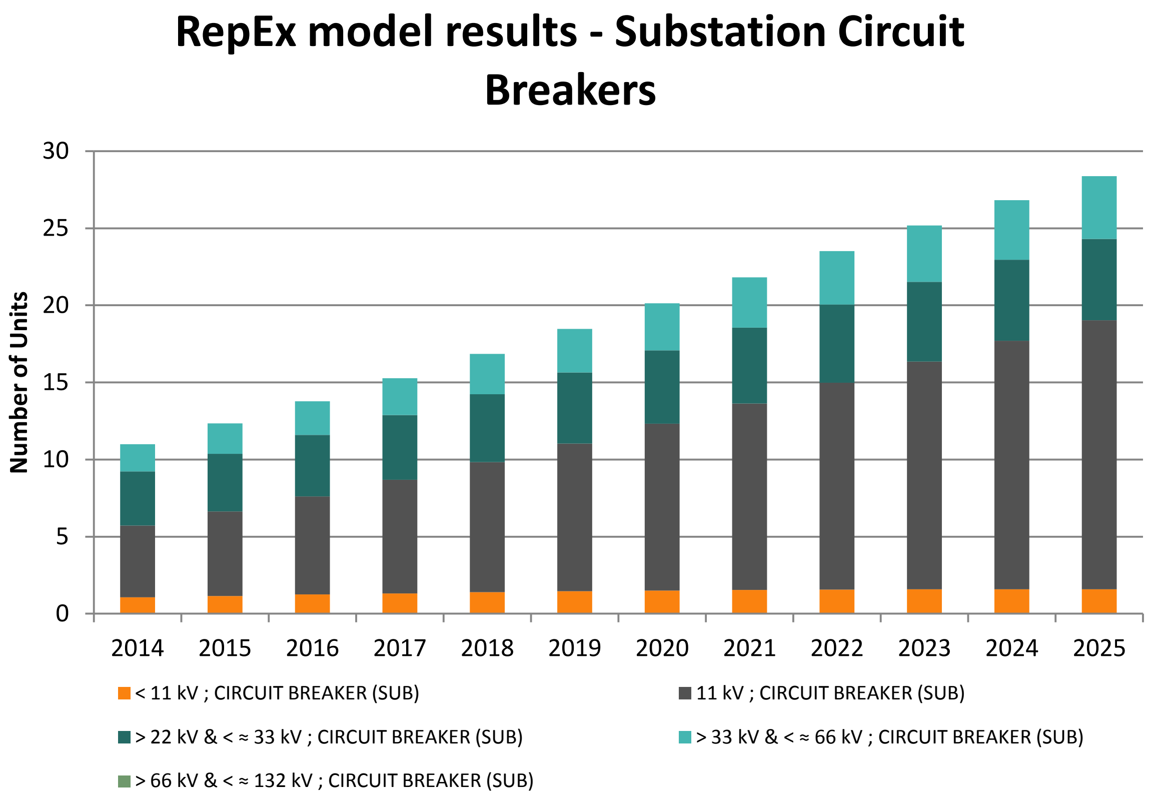


Figure 19 : Repex model results

Limitations and deficiencies of the repex model

In preparing our expenditure forecast SA Power Networks have sought to test whether the repex model can provide an indicator of the efficiency of our replacement forecasts utilising other methodologies. Our review has been limited to a high level conceptual examination of the mode and creation of the model detailed above.

SA Power Networks considers the repex model to have number of shortcomings including weaknesses in the model construct, the underlying data quality and statistical validity, and the application of the model by the AER. These deficiencies are explained in greater detail below.

Deficiencies with model construction

It is important to recognise that a model is an abstract reflection of complex reality, and will therefore never be perfect. Modelling is a key tool used to predict the future, and is therefore used by a prudent network planner to varying degrees in developing forecasts of volumes and unit costs. The key question is whether the construction of the repex model can lead to an accurate prediction of the replacement level that a prudent and efficient DNSP would incur in their circumstances.

A key premise of the repex model is that age asset is an accurate proxy for the likely time that an asset is replaced. There is little doubt that an asset's condition deteriorates with time, and will exhibit a higher probability of failure towards the end of its life. However, we consider there is a high degree of variability around a 'mean' age of replacement that limits the accuracy of its use in predicting volumes of replacement. Even with technologies that experience uniformity in failure mode, there are cases where a prudent DNSP will replace an asset much before, or after, the mean age of replacement. These natural variations in 'wear and tear' of the asset relate to:

- Innate differences in the manufacturing quality of the asset and the installation process and complexity.
- Operating and topological differences when the asset is used over time, for instance an asset installed in coastal regions will exposed to a more corrosive environment than one in the arid areas of the state.
- Differences in maintenance of similar assets over time. For example, some of SA Power Networks' assets were previously owned by local councils, each which had a different approach to maintenance. Obviously, assets that were well maintained over time will exhibit longer lives even if there is uniformity in failure modes.

The likely age of replacement will also depend on the consequences of failure. A prudent DNSP will often undertake proactive replacement programs that strive to replace assets before they fail in service, particularly to mitigate high safety or reliability consequences. For instance, an asset located in a high bushfire risk area is more likely to be replaced that one in an isolated area when there is a chance of failure resulting in a fire start. This means that assets which have uniform failure modes may have very different replacement ages.

Using age as a proxy also fails to take into account other drivers of capex such as duty of care programs. In these cases, age (ie: deterioration in condition) is not the primary driver of replacement but rather the need to ensure our assets meet modern day safety or environmental standards. A key example is clearance heights for feeders, which may not meet a required standard for public safety.

For this reason a prudent asset manager uses a greater variety of tools and information to forecast replacement programs than age based modelling. For instance, for large and costly assets on the sub-transmission network, the prudent asset manager would look to conditional data of the individual asset, and undertake granular risk-consequence analysis.

For categories of assets that contain a high population, the asset manager may use more high level tools such as models. However, the model would be configured to best reflect the individual circumstances of the DNSP and the condition of the asset base. While age based analysis may feature in such analysis, it is likely that a prudent asset manager would also use other data sources to guide its forecasts including conditional data from inspections, failure mode analysis, trends in failure rates, and consequence of failure analysis.

Sub-categories may not be sufficiently granular to reflect replacement age

A key assumption of the repex model is that individual assets in a population share common characteristics, and accordingly that there can be a level of accuracy in predicting replacement costs and age. The repex model allows DNSPs to identify sub-categories of assets under the AERs major categories of assets. For example, a DNSP can provide data on feeder by voltage and/ or technology type so as to group assets with common failure modes and likely similar replacement ages.

However, there are a diverse range of technologies on a DNSPs network, which means that subgroups will rarely contain assets with similar failure modes. In some cases, this issue arises due to a lack of quality data on asset age profiles and replacement lives for assets, which mean that technologies need to be clustered together. This means that even at a sub-category level, the mean age of replacement will be imprecise.

Average unit costs do not provide a realistic estimate of costs

The repex model uses 'average' unit costs for sub-categories of assets to predict the likely levels of expenditure of a DNSP. We consider that this is a problematic assumption and does not provide a realistic expectation of unit costs. Each replacement job is likely to be different due to site specific factors, even when there is sufficient uniformity in the asset being replaced.

On the sub-transmission parts of the network, costs become very site specific and may be impacted by the type of job being undertaken. On the 11kV and distribution network, an averaging approach may provide a more accurate indication of future costs. In these cases, there is a greater population of assets and potentially less variation in scope differences. Even in these cases, there is likely to be significant variation in the types of jobs being undertaken and the complexity of the task.

A prudent network asset manager may not be able to accurately forecast the cost of each individual project but would seek to identify whether there are differences in the type of project being constructed and account for this with different unit rates for particular jobs. In contrast, the repex model is limited in its inability to account for variations and distributions around the mean, and may be impacted by outliers in costs.

A further limitation with using average costs is when the asset has a long delivery time as is the case with sub-transmission major projects. In these cases, the expenditure and commissioning of the asset can be separated by many years, leading to a mismatch in average unit costs for a particular year.

Problems with data quality and statistical validity

An axiom of modelling is that underlying data should be accurate and reliable, and should meet the key principles underlying statistical validity. In the sections below we note that the repex model fails to meet these conditions.

Data quality and accuracy

The underlying data on age of assets, replacement ages and expenditure costs can be highly unreliable and accurate for certain asset categories.

Statistical validity

We note that the AERs repex model handbook does not identify a quantitative statistical test for evaluating the effectiveness of the repex model. We consider that the results of the repex model for each sub-category may fail to meet one or more of the following principles underlying statistical validity:

- Sample size – We consider that for many sub-categories (for example, sub-transmission assets) there are insufficient samples to be confident in the outputs of the model.
- Sample representative of population – For the reasons noted above, we consider that the underlying data for each sub-category is unlikely to contain asset technologies with different failure characteristics and therefore cannot be used accurately to predict replacement age.
- Algorithm is sound – An algorithm sets out the calculation steps involved in developing the function that is used to predict the outputs. We note that the AER has generally used information on the mean and standard deviation to ‘fit’ a normal distribution. This is a very broad assumption, and reflects the lack of samples to derive a more precise algorithm. The algorithm would likely be different for each sub-category, and this means that the replacement density curve is likely to be very imprecise.
- Model outcomes holds outside data range - In many cases, there is insufficient data to know when the asset is likely to be replaced. In some cases, the technology may only be first exhibiting signs of failure, which we know will increase rapidly in the forthcoming regulatory period based on inspection of the equipment.

E. SPARE UNIT INVENTORY

Voltage	Make	Type	No In Service	No Spare Units
66kV	ABB	EDF/EDI	5	1
		ENKGIS	2	3
		LTB72.5	2	0
	AEG / Alstom	S1-72.5F1	43	2
	Alstom / Areva	DT1-72.5	135	6
		GL309	54	2
	AEI	LG4C	5	1
	ASEA	HLC	66	4
		HLE	20	2
	BTH	OW407	24	1
		PD	0	1
	Delle	HPGE9.12E	7	0
	English Electric	OKG6/OWG6	5	0
	Hitachi	CFPT-60-31L	13	0
	Melco	70SFM32A	23	1
		70SFM32A GIS	12	0
	Reyrolle	OSM10	3	0
		66OSM10X1	4	0
	Sprecher	HGF309	10	3
33kV	ABB	EDFSK1-1	2	0
		SF6HB36	2	0
	AEI	LGICS/44 & LGIC/44	2	0
		LG4C/66	1	0
		VSLP	16	0
	Alstom / Areva	DNF7	4	0
	Cook & Ferguson	OE5	21	0
	Compton Greaves	30-SFGP-25A	6	1
	Email	345GCC	23	0
	Ferguson Palin	UAP	5	0
	GE USA	FK036	6	0
	Hawker Siddeley	Horizon	90	2
	Merlin Gerin	FG4/F400	10	0
	Metropolitan Vickers	HG1C-44R	5	0
		G2	2	0
11kV	ABB	RMAG	11	1
	AEI	LGICS/44	2	0
		BRP4	2	0
		BVP3	1	0
		BVRP3	5	1
		BVRP4	20	0
		JB821	3	0
		SC25	14	0
	AGE	SC25	7	0
	BTH	JB821	10	0
	Cook & Ferguson	OE5	7	0
	English Electric	OLX	55	1
		CV	17	2
	Email	J18	343	33

Voltage	Make	Type	No In Service	No Spare Units
		J22	48	2
	Ferguson Palin	BVP4	23	0
	GEC	OLX3	3	10
		SBV2	99	0
	GEC / Alstom / Areva	HWX15	33	0
	GE USA	FK037	3	0
	Hawker Siddeley	Unknown	8	0
	J & P	PDB16A	1	0
		TSB16	10	1
	Merlin Gerin	MCSETLF1	6	0
		MCSETLF3	4	0
	Nulec	MINIVAC	26	0
	Reyrolle	LMTX15MO	3	0
		KZMT	2	1
	Reyrolle / VA Tech	LMVP	382	0
	Schneider	EVOLIS	3	0
	South Wales	C4X	8	0
		D4X4	2	0
	Yorkshire	IVIF13K	7	0
0.415kV	B & S	C7	13	0
	Eaton Magnum	MAGNUM	3	0
	Email	DS532	4	0
	Milsen	DPR0403	4	0
	Oliver J Nilsen	AB3/20/30/40	51	0

F. Abbreviations

Acronym/Abbreviation	Definition
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AMP	Asset Management Plan. A document that provides the high level asset management framework and lifecycles for SA Power Networks.
AS	Australian Standard.
AS/NZS	Australian / New Zealand Standard.
A to O	Authority to Operate SA Power Networks plant by SCADA control.
AWS	Advanced Works Scheduling.
BESS	Best Endeavours Service Standards.
BFRA	Bushfire Risk Area.
BOM	Bureau of Meteorology.
Business Plan	The overall budget program for SA Power Networks.
CAIDI	Customer Average Interruption Duration Index. It is the average supply restoration time for each customer calculated as SAIDI / SAIFI.
CAPEX	Capital Expenditure Budget.
CB	Circuit Breaker.
CFS	Country Fire Service.
CIS - OV	Customer Information System – Open Vision.
CLER	Customer Lantern Equipment Rate.
CPI	Consumer Price Index.
CRC	The Capital Review Committee (CRC) comprises the Chief Executive Officer (CEO), Chief Financial Officer and General Manager Corporate Affairs (as the Asset Owner).
Detailed Asset Management Plans	A set of AMPs which sit under the high level Asset Management Plan (Manual 15).
Disposal	Removal of assets from the asset base.
DMS	Distribution Management System.
DNCL	Distribution Network Controller Level.
DPTI	Department of Planning, Transport & Infrastructure.
DUOS	Distribution Use of System.
ECR	Emergency Control Room.
ElectraNet	The South Australian electricity transmission network owner and planner.
EMG	Executive Management Group.
ENA	Energy Networks Association.
ESCOSA	Essential Services Commission of South Australia.

Acronym/Abbreviation	Definition
ESAA	Electricity Supply Association of Australia.
ESDP	Electricity System Development Plan.
FDI	Fire Danger Index.
FDL	Fire Danger Level.
FS	Field Services is the internal construction workgroup of SA Power Networks.
FSB	Facilities Systems Branch.
FTE	Full Time Employees.
GIS	Gas Insulated Switchgear
GSL	Guaranteed Service Level.
HBFRA	High Bushfire Risk Area.
HV	High Voltage.
IEC	International Electro-technical Commission.
IEEE	Institute of Electrical & Electronics Engineers.
IPWG	Inspection Planning Working Group.
IRR	Internal rate of return is discount rate which produces a present value of zero when applied to the proposed cash flows.
IVR	Interactive Voice Response.
JSWM	Job Safe Work Method - Document that describes a safe system of work on a particular item of plant at a particular location.
JSWP	Job Safe Work Procedure - A document that describes a generic safe system of work on plant and equipment used to build and maintain the Electricity Distribution system.
LV	Low Voltage.
MAIFI	Momentary Average Interruption Frequency Index.
MV	Medium Voltage.
NBFRA	Non Bushfire Risk Area.
NER	National Electricity Rules.
NIEIR	National Institute of Economic and Industry Research.
NM Group	Network Management Group. This group represents the Asset Manager role for managing the distribution business on behalf of SA Power Networks.
NOC	Network Operations Centre.
NPV	Net Present Value is the present value of all expected benefits, less the present value of all expected cost of the project.
O&M	Operations and Maintenance.
OMS	Outage Management System

Acronym/Abbreviation	Definition
OPEX	Operating Expenditure Budget.
PAW	Pre-arranged Work.
PCB	Polychlorinated Biphenyls.
PI	Profitability index is defined as the ratio of discounted benefits to discounted costs.
PLEC	Power Line Environment Committee
PV	Photo Voltaics
QMS	Quality Management System.
RCM	Reliability centred maintenance.
Refurbishment	Work on an asset which corrects a defect and/or normal deterioration and result in an extension to its expected end of life.
Repair / Maintain	Work on an asset which corrects a defect allowing the asset to operate to its expected end of life.
Replacement	Complete change over of 'old for new' asset.
RFP	Request for Proposal.
RIT-D	Regulatory Investment Test – Distribution.
RIT-T	Regulatory Investment Test – Transmission.
RTU	Remote Terminal Unit.
SAIDI	System Average Interruption Duration Index specified in minutes per customer per annum.
SAIFI	System Average Interruption Frequency Index specified in outages per customer per annum.
SAP	Asset and fault records database.
SA Power Networks	The South Australian electricity distribution network owner and planner.
SCADA	Supervisory, Control and Data Acquisition.
SCO	System Control Officer.
Services	Services Department. This group manages core services dealing directly with individual residential or business customers.
SNC	Senior Network Controller.
SOC	Senior Operations Controller.
SOP	Safe Operating Procedure – Document that describes safe operating work procedure.
SPS	Service Performance Scheme – see STPIS.
SSF	Service Standard Framework.
STPIS	Service Target Performance Incentive Scheme.
TF	Transformer.
UFLS	Under-frequency load shedding.

Acronym/Abbreviation	Definition
UID	Underground industrial development.
URD	Underground residential development.
WARL	Weighted Average Remaining Life.

G. References

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