



Supporting
document 5.8

Powerline Asset Management Plan (PAMP)

2020-2025
Regulatory Proposal
January 2019





Power Asset Management Plan – Manual No. 16

Delivering energy services that customers value through
excellence in asset management

SA Power Networks

www.sapowernetworks.com.au



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Document Version

Version	Date	Author	Notes
0.1	25/5/2018	Kane Scott	Draft for comment
0.2	6/7/2018	Kane Scott	Incorporated comments from v0.1 review, document structure and minor content changes
0.3	5/12/18	Kane Scott	Incorporated comments from v0.2 review, internally endorsed levels of service and November 2018 forecasts
0.4	6/12/18	Kane Scott	Issued for approval
0.5	17/12/2018		Document to Stakeholders for approval to publish
0.6	17/01/2019		Document updated for modified poles CBRM outputs, cable and conductor lengths and forecasts to reflect regulatory proposal

OWNERSHIP OF STANDARD

Name of Standard/Manual: Power Asset Management Plan – Manual No. 16

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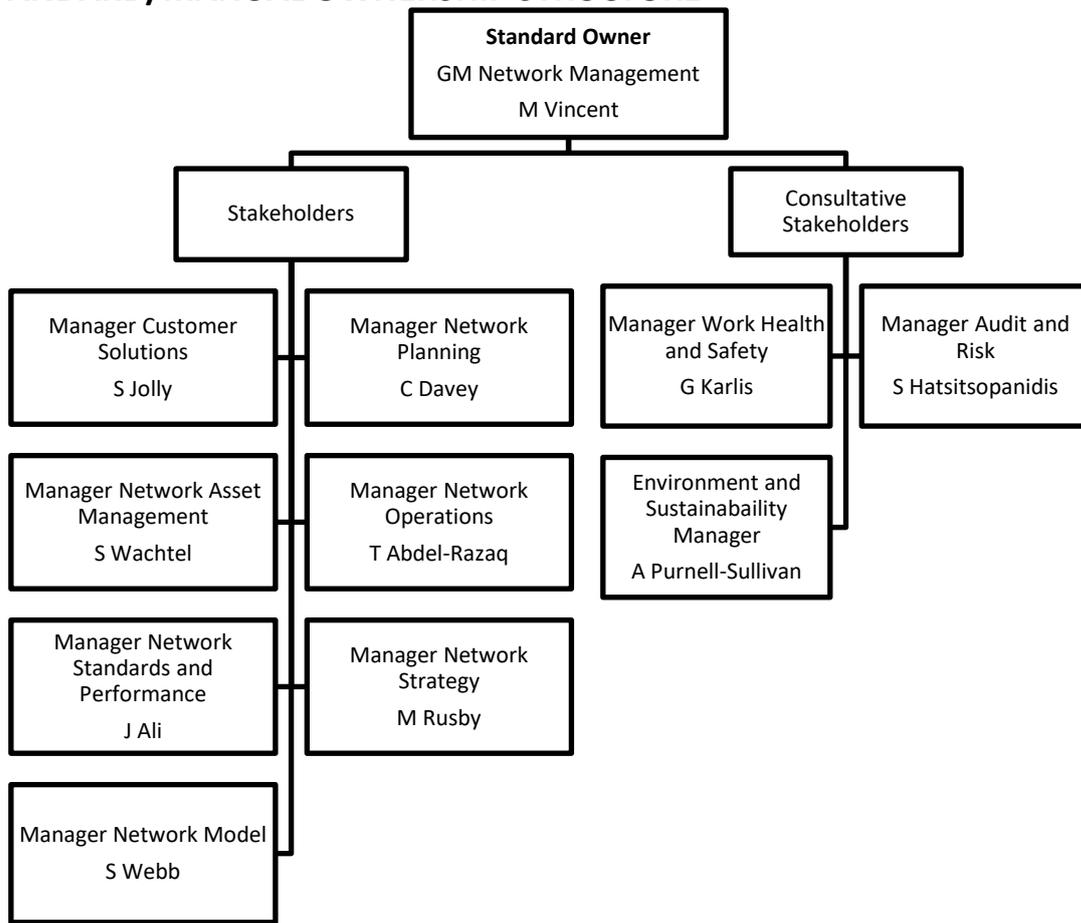
Standard last Reviewed September 2018

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STANDARD/MANUAL OWNERSHIP STRUCTURE



OTHER RELATED MANUALS

Strategic Asset Management Plan – Manual No 15

Network Maintenance Manual – Manual No 12

COMMENTS

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Abbreviations

ABA	Adelaide Business Area
AC	alternating current
ADMS	advanced distribution management system
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
BFRA	bushfire risk area
BFRMM	Bushfire Risk Management Manual
CAIDI	customer average interruption duration index
capex	capital expenditure
CBD	central business district
CBRM	condition based risk management
CFS	Country Fire Service
CSI	customer satisfaction index
CSIRO	Commonwealth Scientific and Industrial Research Organisation
DC	direct current
DER	distributed energy resource
DNSP	distribution network service provider
EPA	Environment Protection Authority
ESCoSA	Essential Services Commission of South Australia
FDS	Fire Danger Season
FRI	fatal risk incident
GIS	geographic information systems
GSL	guaranteed service levels
HBFRA	high bushfire risk area
HI	health index
HV	high voltage
kV	kilovolt (1,000 volts)
LIDAR	light detection and ranging remote sensing
LTI	lost time injury
LV	low voltage
MED	major event day
MBFRA	medium bushfire risk area
MTI	medical treatment injury
NEM	National Electricity Market
NER	National Electricity Rules
NERR	National Energy Retail Rules
NECF	National Energy Customer Framework
NOC	SA Power Networks' Network Operations Centre
OMS	outage management system
opex	operating expenditure
PAMP	Power Asset Management Plan
PILC	paper insulated lead cable
PCB	polychlorinated biphenyl
PLEC	Powerline Environment Committee (South Australia)
PoF	probability of failure
PV	photovoltaic
RAB	regulatory asset base
RTU	remote terminal unit
SAMP	Strategic Asset Management Plan
SCADA	Supervisory Control and Data Acquisition System
SAIDI	system average interruption duration index
SAIFI	system average interruption frequency index

SF ₆	sulphur hexafluoride
SSF	Service Standard Framework
STPIS	AER's Service Target Performance Incentive Scheme
SRMTMP	Safety, Reliability, Maintenance and Technical Management Plan
SWER	single wire earth return
TDU	Telephone dialup unit
TNC	telecommunications network control
WHS	work health and safety

1 Executive Summary

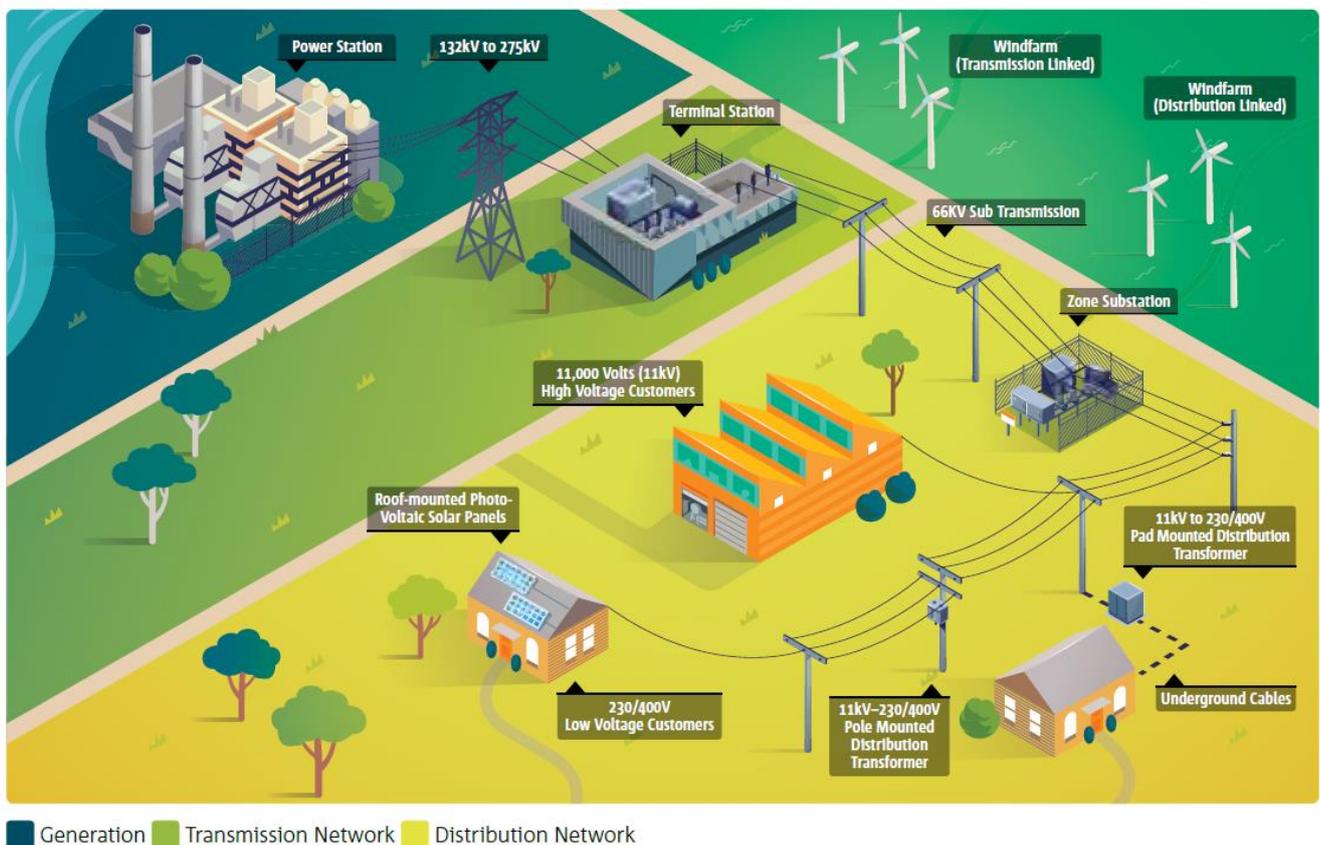
Introducing the 2018 Power Asset Management Plan

The Power Asset Management Plan (PAMP) defines SA Power Networks' approach to managing the electricity distribution assets over the planning period 2018–2030. As a key component of SA Power Networks long-term asset planning and investment framework, the PAMP provides a holistic view of the asset management of the distribution network assets.

The PAMP outlines in more detail the plans and strategies aimed at meeting both current and future requirements of customers and stakeholders as described in the Strategic Asset Management Plan (SAMP).

The assets and services provided

The assets that comprise the distribution network, as shown in the figure below, are largely poles, overhead conductors, underground cables, and substation assets such as transformers, circuit breakers, protection and control assets as well as monitoring systems. Public lighting and metering are covered by separate asset management plans.



The levels of service to be provided to customers to meet expectations include several specific measures and targets, categorised as:

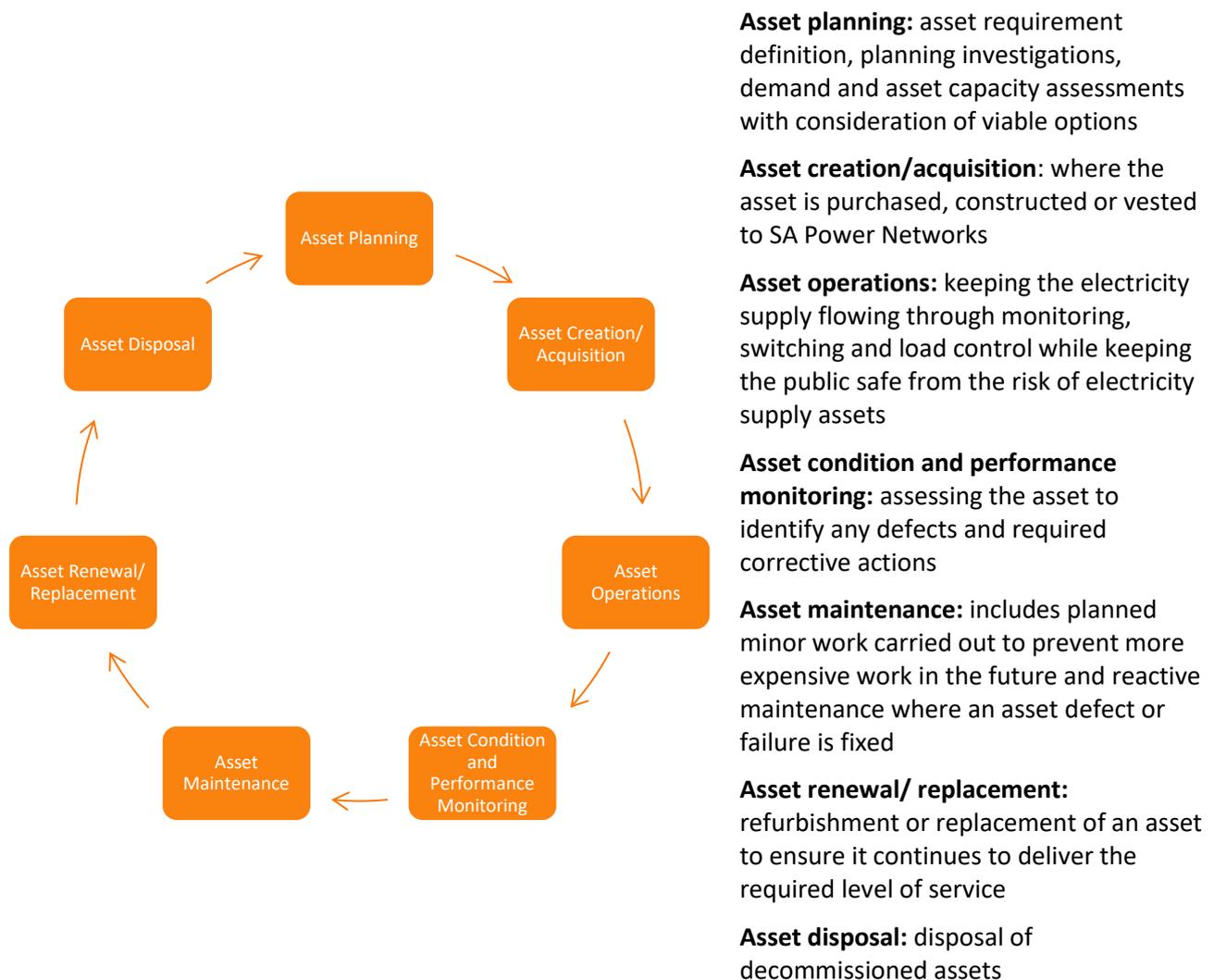
- **Safety:** provide a safe network service
- **Customer experience:** deliver energy services that enhance customer experience
- **Reliability and resilience:** deliver a reliable and resilient network service
- **Environment:** provide an environmentally sustainable network service
- **Aesthetics:** provide an aesthetically pleasing network
- **Two-way grid:** provide a network service that enables customers to both import and export their energy
- **Communication and information:** communicate and make information available
- **Efficiency:** continuously seek out and deliver network service efficiencies.

Life cycle management approach

The PAMP describes how cost is balanced against levels of service and risk throughout each asset's life cycle. SA Power Networks has traditionally benchmarked well in efficiency and reliability in the Australian Energy Regulator annual benchmarking process against other distribution network service providers.

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

The life cycle process applied to power networks assets by SA Power Networks is shown below.



Key strategic issues

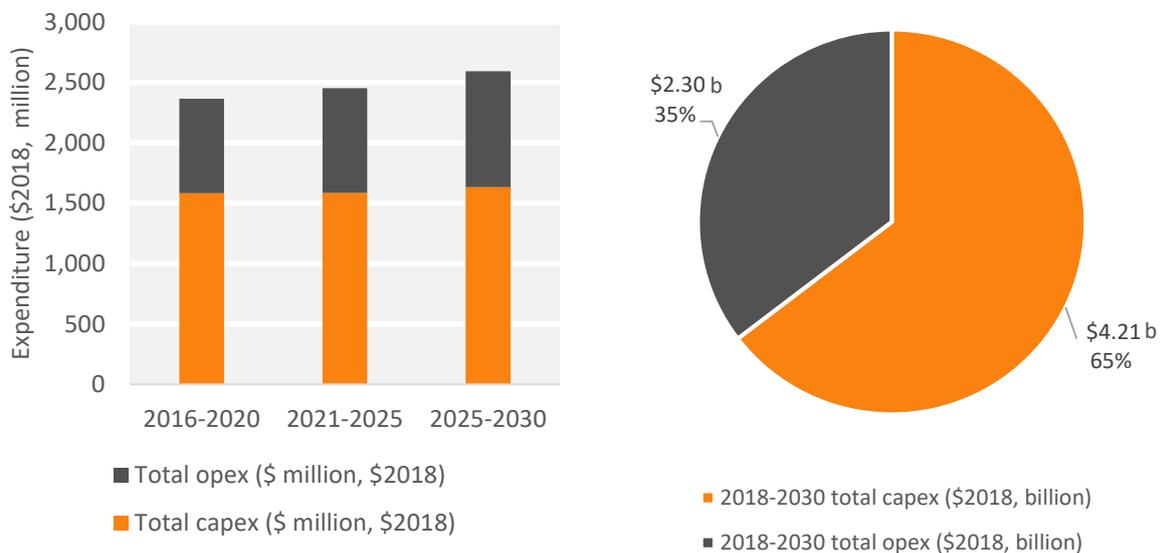
The electricity industry is evolving at a rapid pace. Internal and external issues are challenging the levels of service provided to customers now and into the future with the asset life cycle management approaches continuously evolving in response. The key strategic issues for the distribution network are:

- **Ageing infrastructure:** a remarkably low level of expenditure with, on average, only 0.3% of the assets being replaced per year through renewal driven expenditure in the current regulatory period.
- **Security of supply and reliability:** the changing mix of generation and rapid uptake of solar PV systems is challenging the network capability with the resulting two-way flow of electricity while severe weather events are resulting in a significant number of outages on our network in localised areas and affecting customers perceptions on network reliability.

- **Changing value of the network:** increasing uptake of solar PV systems, battery storage, electric vehicles and large-scale generators offers new challenges and opportunities for virtual power plants, aggregators and traders increasing the value of the network for customers.
- **Pressure on electricity prices:** increasing political and customer pressure on prices combined with increasing scrutiny of regulators may lead to inadequate expenditure allowance to manage the distribution network assets leading to increased network risks and declining levels of service.
- **New and heightened customer expectations:** customers increasing interest in electricity due to rising prices and availability of new technologies and wanting accurate real-time information via a wide range of communication channels.
- **Policy volatility:** changes in regulation and increasing regulatory reporting requirements is increasing costs to enable the required information and systems to support these requirements.
- **Accelerating technology capabilities:** declining costs of technologies generating and/or storing electricity is providing customers more options for managing their electricity consumption while technology development is also creating opportunities improvements to network operations such as new ways to monitor, control, maintain and augment assets that were previously cost prohibitive.

10-year expenditure forecasts

The 10-year forecasts proposed are required to balance the above key strategic issues. Total network expenditure is forecast to average \$501 million per annum over the 2018–2030 planning period with 65% being capital expenditure (capex) to augment or renew/replace existing assets, and 35% forecast for ongoing operation and maintenance (opex) activities as shown in the figures below. The forecasts beyond 2025 are subject to change as part of the 2025-2030 regulatory control period submission and show an increasing trend as the ageing asset base continues to deteriorate. All forecasts will be revised and updated annually as part of the annual review of the PAMP.



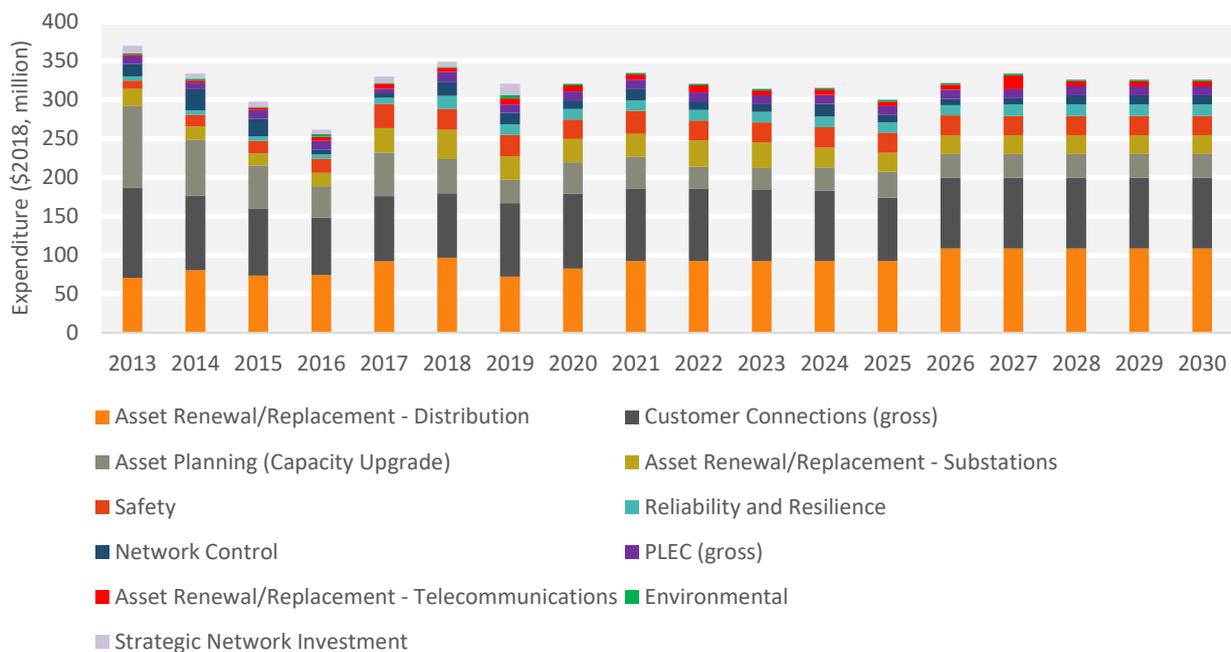
Capital expenditure programs

The planned capital investment for the 2018–2030 planning period (detailed in Chapter 7) reflect a blend of investment across network augmentations, asset renewal and non-network categories. Key changes from the 2015-2020 regulatory period into the 2020-2025 regulatory period include the following:

- **Decreased investment in major network augmentations:** The long-term forecast for total network demand is flat. Some specific locations have been identified where peak summer loads are at risk, but a decline in total network augmentation expenditure is forecast because of improved energy efficiency in household appliances, continued growth in rooftop solar photovoltaic (PV) systems and battery storage systems combined with households and businesses managing their usage.

- **Increased investment in minor network augmentations:** There is a forecast increase in expenditure for minor network augmentations to optimise the use of existing assets and manage the quality of supply provided to customers because of the continued, widespread uptake of solar PV systems and other embedded generator connections across the network with customers seeking to export electricity into the distribution network.
- **Increased investment in customer connections:** The forecast increase in major connections is for projects by commercial, government and developers such as CBD offices, factories, and major engineering constructions. The cumulative expenditure for all other connection categories shows a marginal net increase over recent historical expenditure.
- **Increased investment in distribution line asset renewals:** Asset renewals are forecast to increase over historical levels because a large proportion of assets constructed from the mid-1950s through to the 1970s are now reaching the end of their expected life. As the assets continue to age, delivering the levels of service our customers are expecting will be challenging and will require increased investment in asset maintenance and replacements. The main increases are within the distribution line assets (primarily an increase in expenditure on poles, pole top structures, cables and service lines).

All other capital expenditure programs have a relatively stable (<\$10 million change in real terms from 2015-2020 to 2020-25). The historical and planned capital investment across the various capital expenditure categories is shown in the figure below.

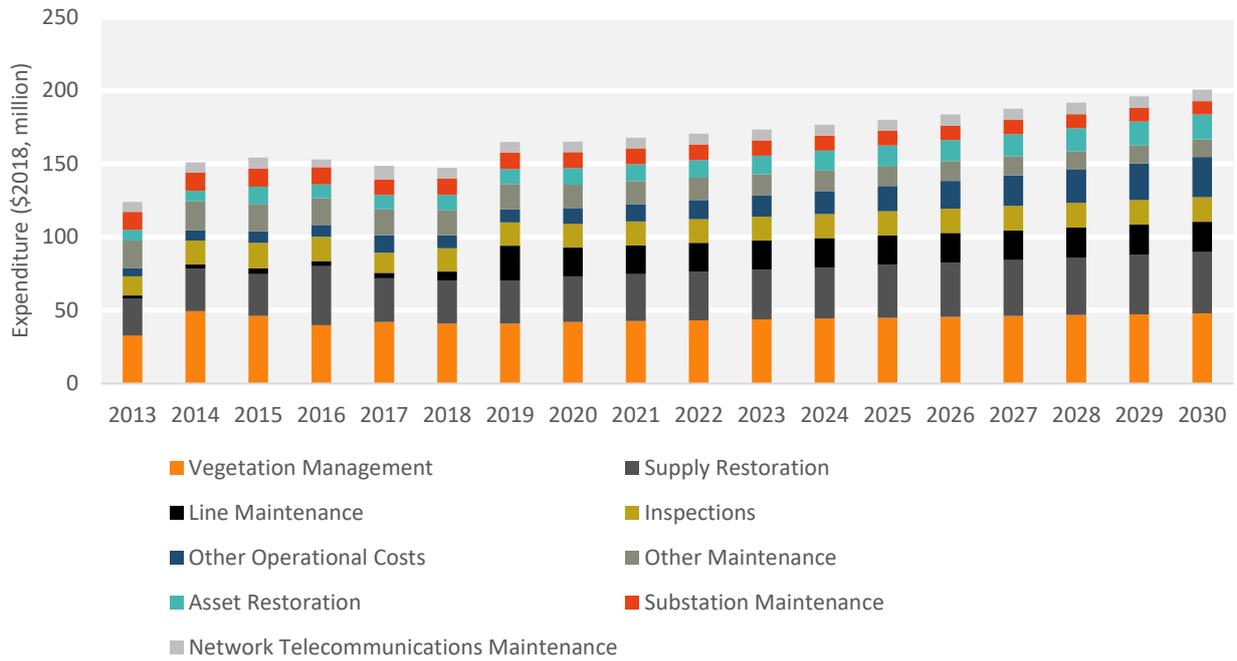


Operating expenditure programs

The operating capital investments for the 2018–2030 period (detailed in Chapter 7) reflect recent historical costs with future forecasts based on the 2018 forecast operating expenditure and recent observed rates of change in actual expenditure for the various operation and maintenance activities. Key observations from recent historical operations and maintenance expenditure include the following:

- **Vegetation costs stable:** Annual vegetation cost have been relatively stable despite increased focus on vegetation clearance to comply with our legislative obligations from 2012 due to continuing review and optimisation of the vegetation management strategy
- **Variable supply restoration costs:** Annual expenditure fluctuations are largely influenced by severe weather events with operating budgets reallocated to restore supply to customers as a priority over other planned operations and maintenance works
- **Expensing of cable and conductor repairs:** Annual expenditure on repairing and replacing short lengths of cable to be expensed from 2019 under line maintenance.

The historical and planned operating investment across the various operations and maintenance expenditure categories for is shown in the figure below. It shows a long term increase in expenditure as the assets continue to age and deteriorate.



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2 Introduction

2.1 Purpose

The Power Asset Management Plan (PAMP) outlines the strategies and plans SA Power Networks employs to effectively manage network assets to deliver value to customers. It summarises the approach to asset management to ensure the strategic and asset management objectives are achieved.

The specific objectives of this PAMP are to:

- express the levels of service SA Power Networks aims to deliver to customers and stakeholders;
- describe the assets available to deliver services and their current condition and performance;
- describe the plans to deliver strategic and asset management objectives;
- explain how assets are managed throughout their life cycle;
- outline how risk is managed while delivering on levels of service;
- show the expenditure required to meet the strategic and asset management objectives; and
- identify improvement opportunities to asset management practices.

2.2 Scope

This PAMP covers the SA Power Networks regulated electricity distribution network assets and the associated systems, comprising:

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

The PAMP does not include metering equipment and public lighting, which are covered under separate asset management plans. It also does not include non-network related assets such as business and commercial telecommunications systems, motor vehicles, properties, office buildings and building equipment (e.g. furniture, computers). It also excludes unregulated network assets.

2.3 Audience

The target audience for this PAMP is primarily:

- SA Power Networks' employees including senior management, asset managers and other employees who play a role in the delivery of electricity services to customers;
- regulators including the Australian Energy Regulator (AER), Essential Services Commission of South Australia (ESCoSA) and Office of the Technical Regulator (OTR); and
- SA Power Networks' stakeholders wanting to understand how we manage our assets (see Section 4.3).

2.4 How to use this document

The structure and content of this PAMP is presented in Table 1. It is supported by detailed asset plans for each of the asset classes.

Table 1: PAMP structure

Section	Description
Executive summary	Summary of the key issues and financial forecasts contained in the body of the PAMP
1 Introduction	Background, context and purpose of the PAMP
2 Network and asset overview – understanding assets	Overview of the distribution network in the supply chain, network coverage, operating environment and an overview of the assets utilised to deliver services to customers
3 Levels of service provided to customers and stakeholders – understanding customers	Levels of service delivered to customers, performance and targets, key observations and initiatives that influence the levels of service measures; includes targets for future levels of service
4 Risks – assets and operations	Overview of the risks to the network and operation of the assets and how these are managed
5 Asset management framework	Overview of asset management lifecycle management as applied to power network assets to deliver services to customers through the capital and operating investment programs
6 Asset lifecycle management	<p>Overview of the asset lifecycle strategies applied to balance cost and service:</p> <ul style="list-style-type: none"> • Asset planning and creation: the factors that influence demand for services, security of supply challenges and the strategy for identifying and responding to network constraints • Customer connections management: the management of provision of customer connection services (new connections, alterations to existing and real estate developments services), and the process for forecasting the expenditure and delivery of those services • Asset operations: how the network is operated, the response to emergency events and the key operational activities to keep the power on • Asset condition and performance monitoring: processes and techniques applied to understand the condition of the assets and how they are performing • Asset maintenance: maintenance practices applied in response to faults and/or to prevent faults from occurring • Asset renewal/replacement: processes used for asset renewal/replacement of the power network assets • Asset disposal: process of asset disposal • Optimisation of expenditure: the processes used to optimise available budgets
7 Asset class strategies	Overview of the strategies employed on the major asset classes to balance cost and service (based around the asset lifecycle management framework)
8 Targeted strategies	<p>Overview of targeted strategies to balance cost and service, enable energy transition and improve resilience of the network:</p> <ul style="list-style-type: none"> • Safety: strategies applied to managing power network assets including the Work Health and Safety Management System and strategy for safety driven capital investment plans

Section	Description	
	<ul style="list-style-type: none"> • Environment: strategies applied to managing power network assets and the processes applied for identifying operating and capital investment plans focused on environmental management • Reliability and resilience: strategies applied for managing the underlying reliability of the network and hardening the network to make it more resilient • Future network: the current and future challenges and opportunities because of the evolving network and increased services the power network assets can provide including a summary of the Future Network Strategy core strategies • Power line environment committee (PLEC): strategy applied for undergrounding of powerlines through the Power Line Environment Committee (PLEC) and the role of SA Power Networks in this collaborative program 	
9	Asset information	Description of the information and information systems used to support asset management practices
10	Continuous improvement plan	Summary of future improvements to asset management practices
11	Capital and operating programs and financial forecasts	Overview of the capital and operating programs of work and their investment requirements to deliver services to customers
12	Appendices	Key supporting information of relevance to the PAMP
13	References	List of references used in the PAMP

2.5 Relationship to other plans and strategies

A number of SA Power Networks' plans and strategies are related to and inform the PAMP, including:

- **Strategic Plan and other corporate strategies:** details our strategic direction, key priorities and core areas of focus, and sets the overarching direction for the organisation. Includes Customer Engagement Strategy, Future Network Strategy and Digital Strategy.
- **Asset Management Policy:** sets out the principles we apply to our asset management activities.
- **Strategic Asset Management Plan:** outlines the operating environment and the challenges faced by SA Power Networks in delivering the service now and into the future, and the overarching strategies implemented to deliver a valuable service to customers.
- **Detailed strategies, plans, manuals, policies, processes and procedures:** gives detailed guidance for maintenance and day-to-day operation activities.

The PAMP also provides information required for the following regulatory documents:

- **Reset Submission(s):** summarises our business plans with a focus on a specific regulatory control period submitted to the AER for consideration during five-yearly price determinations.
- **Distribution Annual Planning Report:** informs National Electricity Market (NEM) regulators, participants and stakeholders about the existing and forecast system limitations on our distribution network; preparation of this document is a regulatory requirement.
- **Safety, Reliability, Maintenance and Technical Management Plan (SRMTMP):** details the management framework, key procedures and associated performance indicators for the safety and technical management of SA Power Networks electricity infrastructure through its life cycle; preparation of this document is a regulatory requirement.

Figure 1 shows the relationship between these plans and strategies.

Asset management documentation framework

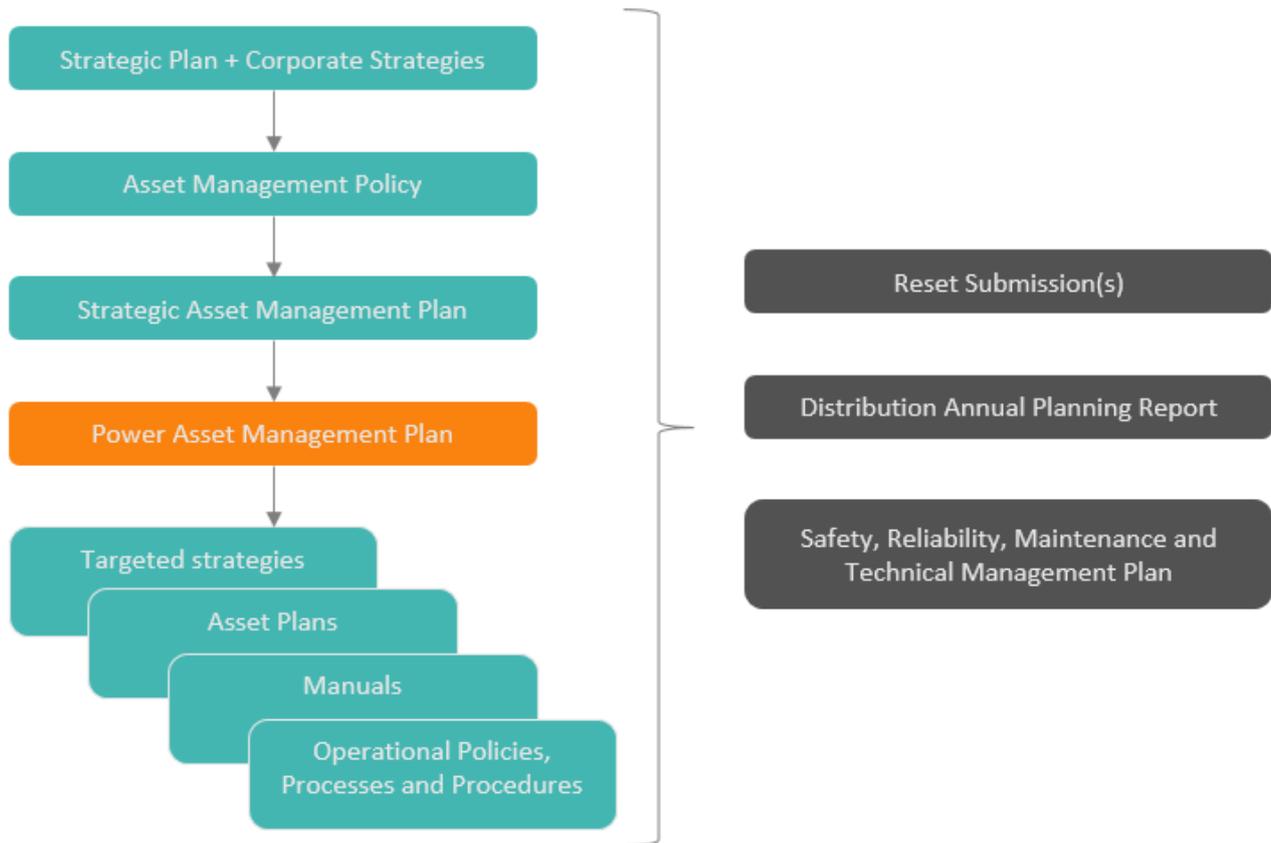


Figure 1: Asset Management Plan relationship to other SA Power Networks plans and strategies

2.5.1 Strategic Asset Management Plan

The Strategic Asset Management Plan (SAMP) describes the asset management objectives and outlines the challenges faced in delivering of services now and into the future and the strategies being implemented to ensure valuable services continue to be delivered to customers.

The SAMP includes a summary of the key operational programs and assets that support service delivery.

The SAMP details the:

- corporate line of sight;
- customer engagement activity;
- asset management context;
- key strategic issues;
- asset management objectives;
- past performance;
- SA Power Networks' response and strategies; and
- Summary of asset management programmes.

The SAMP provides important contextual background information and should be read in conjunction with the PAMP.

2.5.2 Asset plans

The plans are the supporting and underpinning documents to this PAMP and are developed for specific classes of assets and for the various asset management activities. The asset plans provide further detail on the asset management strategy applied to each asset class with a 30-year vision.

The asset plans specify (where applicable) the:

- asset description;
- investment drivers to address current asset condition, performance and specific groups of assets including failure analysis;
- risk quantification and assessment;
- detailed strategy on intervention options;
- forecast asset replacements;
- asset spares.

The asset plans provide important detailed information relating to the asset class and inform the PAMP; the PAMP considers the collective assets as systems to provide the required levels of service. Appropriate asset performance targets are set (where applicable) for each asset plan with asset performance monitored and to achieve a low level of residual risk and optimise the impact of the asset plan.

2.6 Key changes from previous asset management plans

The key changes from the previous versions of the asset management plans were created include:

- Key information previously captured in the 55 detailed asset management plans have been summarised into this one over-arching PAMP, which gives a holistic view of the asset management plans and allows a succinct, coherent and clear understanding of how power assets are managed.
- Previous asset management plans have been restructured as asset plans with the content previously duplicated across these documents consolidated into the SAMP and/or PAMP.
- The restructured PAMP has had generic asset management theory content removed, and the executive summary revised to align it more closely to the key information required by decision makers including executive management and regulators.
- The SAMP translates the organisational objectives into asset management objectives with the PAMP providing the 'line of sight' to the asset specific asset management objectives.
- Levels of service have been revised with a greater emphasis on the service to be provided to customers.

2.7 Asset management oversight

The coordination of asset management activity across SA Power Networks' assets and services they provide is overseen by an internal Asset Management Working Group. The working group has been established to ensure asset management efforts are customer centric, aligned and coordinated across the business.

This ensures a holistic, overarching view of asset management core strategies are applied as listed below:

- **Understand:** engage with customers on what services are important and continue to increase understanding of the network assets to deliver the levels of service;
- **Respond:** balancing the service we deliver against the cost of that service; enabling the transition to distributed energy and improving the resilience of the network in areas of poor performance; and
- **Improve:** empowering our people, investing in our asset management system, and piloting and trialling new technologies and concepts.

Further detail on the asset management framework is discussed in Section 6.

3 Network and asset overview – understanding assets

3.1 Introduction

This section describes the extent of the distribution network, the assets that make up the network, how they work, and where they fit within the electricity supply system.

3.1.1 SA Power Networks role in the electricity supply chain

SA Power Networks main role in the state’s electricity supply chain is distribution, with the assets generally spanning from connection points shared with the transmission network service provider (ElectraNet) and extending to the customer’s point of supply. The distribution of electricity is becoming more diverse with the large take up in solar photovoltaic resulting in two-way flows.

Figure 2 illustrates SA Power Networks functional role in the electricity supply chain.

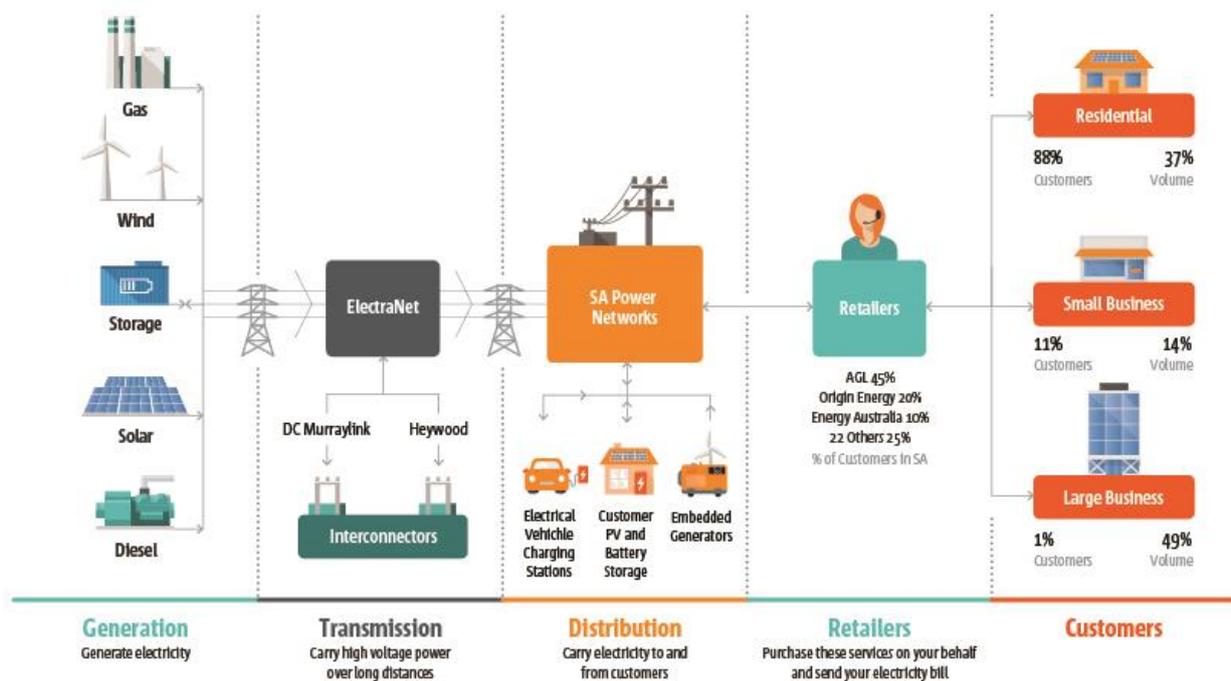


Figure 2: South Australia’s electricity supply chain

As the sole distribution network service provider in South Australia, SA Power Networks supplies electricity to approximately 860,000 homes and businesses ranging from isolated farms in remote and rural areas, industrial areas, regional and metropolitan residential homes, businesses and city centres. SA Power Networks predominantly operates a three-phase electrical system in densely populated areas, with single-phase system referred to as a single wire earth return (SWER) lines being used to supply individual farms and remote areas.

3.2 Network development, coverage and operating environment

3.2.1 History of the SA power distribution network

Electricity distribution in South Australia dates back to 1883 when the Adelaide Railway Station platform was first supplied with electricity. Soon after, the Adelaide Electricity Supply Company (part of which later

Issue: December 2018

became SA Power Networks) was formed and the evolution of the South Australian electricity distribution network began. Figure 3 shows some of the major historical events in the development of South Australia’s electricity supply.

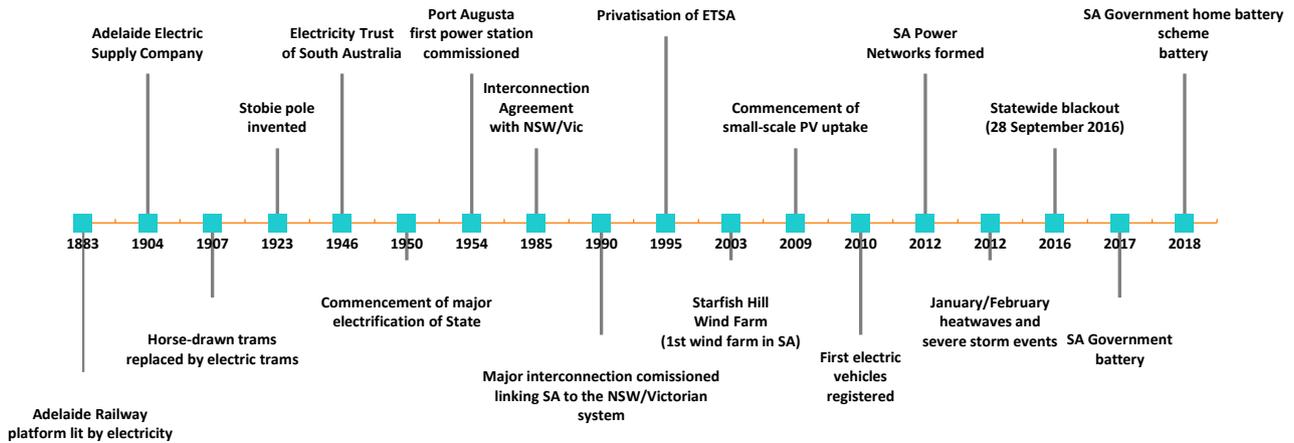


Figure 3: History of electricity distribution in South Australia

Figure 3 shows that the 1900s were largely focused on the development of the network to supply populated areas with one way-flow of electricity and traditional large-scale power generation facilities. Since the early 2000s, the more notable events revolve around small-scale decentralised and renewable energy supplies and significant interruption events since 2010 because of more frequent and damaging storm events.

3.2.2 Service area

The service area supplied by SA Power Networks as shown in Figure 5 spans right across South Australia from the Victorian border in the state’s south-east right through to the far west coast beyond Ceduna and up towards the remote inland regions in central South Australia through an extensive network of sub-transmission and distribution conductors and cables. Most of the route length comprises overhead conductors supported by Stobie poles constructed of steel and concrete and located in rural and remote areas as shown in Figure 4. The network in these rural areas is long, radial and remote with a low customer connection density.

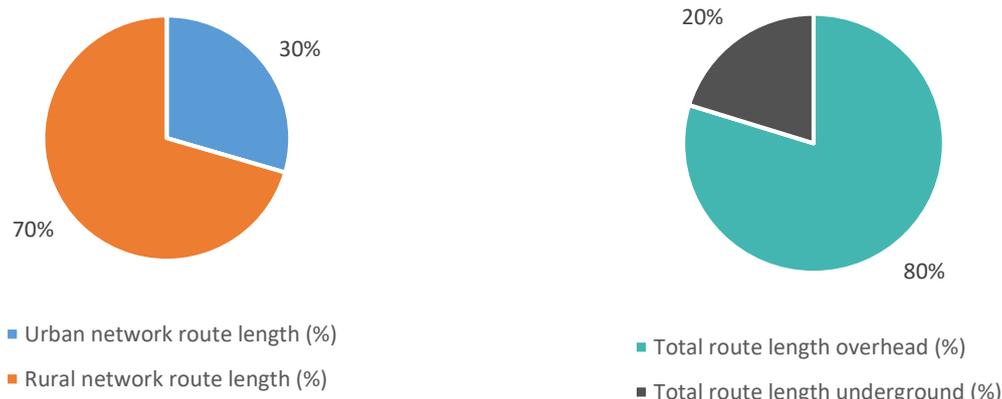


Figure 4: Electricity supply network – route length location and installation type (as of June 2018)

While the network spans across diverse geographical areas, bushfire risk areas and corrosion zones are the two key location factors that influence the life cycle management of network assets across the service area. These location factors are considered when developing the specifications for the types of standard materials and designs used through to how frequently assets are inspected, maintained and replaced.

3.2.2.1 Bushfire risk areas

Bushfires are one of the largest risks to South Australia. The 1983 Ash Wednesday bushfires across South Australia and Victoria, and more recently the 2009 Black Saturday bushfires in Victoria, caused widescale damage and loss of life. Notable outcomes from the 2009 Victorian Bushfires Royal Commissions include:

- the finding that five of 15 fires were the result of electricity asset failures and that the age of those assets contributed to three of the electricity-caused fires; and
- a recommendation to increase investment on replacing aged assets in high bushfire risk areas (recommendation number 27).

A sixth fire was found to be a result of an electricity asset failure following the release of the Commission's findings. Electricity infrastructure is therefore a recognised cause of fire starts and a major risk that must be appropriately managed. Operating an ageing overhead electricity network through natural reserves and conservation parks along with forestry plantations presents a significant bushfire risk that needs careful management.

In the *Electricity (Principles of Vegetation Clearance) Regulations 2010*, the state of South Australia is subdivided into two categories

- non-bushfire risk area (NBFR); and
- bushfire risk area (BFRA).

Maps of these areas are contained in the Regulations.

For operational reasons, SA Power Networks has further subdivided the BFRA as follows:

- **High bushfire risk area (HBFR):** A subset area of the BFRA where a fire could start and readily escape into an unrestricted area of flammable material causing major to catastrophic consequences. HBFR include most protected natural reserves and conservation parks, and forestry plantations.
- **Medium bushfire risk area (MBFR):** An area where a fire could start and readily escape to an unrestricted area of flammable material causing moderate consequences. These areas are the remains of the BFRA-designated areas that are not HBFR; they reflect the risk to developments on the fringe of dense bushland, and are in metropolitan, suburban, and country districts.

The six HBFR locations in South Australia are:

- the Adelaide Hills
- the rural area in the south east of the state
- the rural area surrounding Clare in the mid-north of the state
- the Wirrabara Forest and surrounding rural area (100km north of Clare)
- the rural area around Port Lincoln on lower Eyre Peninsula
- a rural area on Kangaroo Island, between American River and Penneshaw.

The defined bushfire risk areas are shown in Figure 6.

3.2.2.2 Corrosion zones

As electricity assets are predominantly overhead, those assets located near coastal regions are subject to a corrosive atmosphere due to the saline environment that accelerates the rate of corrosion of these assets. The four classifications of corrosion zone (1,2,3 and 4) range from areas that are not significantly subject to corrosion (zone 1) to areas that are significantly prone to corrosion (zone 4). The zone 4 areas are typically small geographic surf coast areas previously encompassed by the very severe corrosion zone (zone 3).

These corrosion zones are shown in Figure 7.

As risk is the product of likelihood and consequence of failure, the risk associated with network assets is highly influenced by corrosion zone (influences probability of failure), and locations such as BFRA and high density urban areas (determines potential consequences of asset failure). The classifications of BFRA and

corrosion zones are shown in contrast to the service area and are shown in Figure 5 through to Figure 7 respectively. As can be seen, there is a significant overlap of the service areas, medium/high BFRA and severe/very severe corrosion zones which presents a significant risk given the ageing assets and deteriorating condition of the power network.

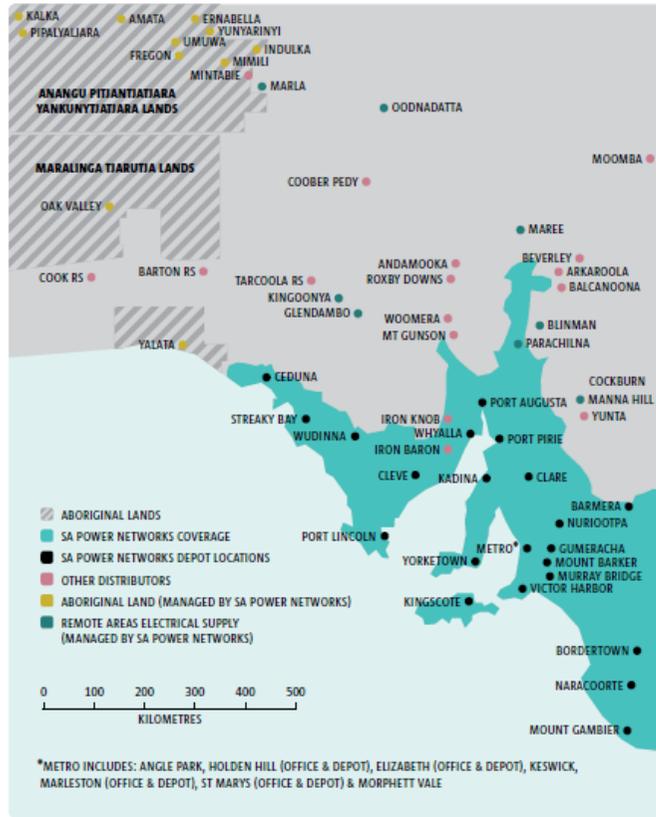


Figure 5: Network service area



Figure 6: Bushfire risk areas



Figure 7: Corrosion zones

3.3 Asset age

Figure 8 shows the replacement cost profile of the major distribution network assets. A significant proportion of the asset base value is between 45 and 60 years of age corresponding to the period when major electrification of South Australia began in around 1950 (see Figure 3).

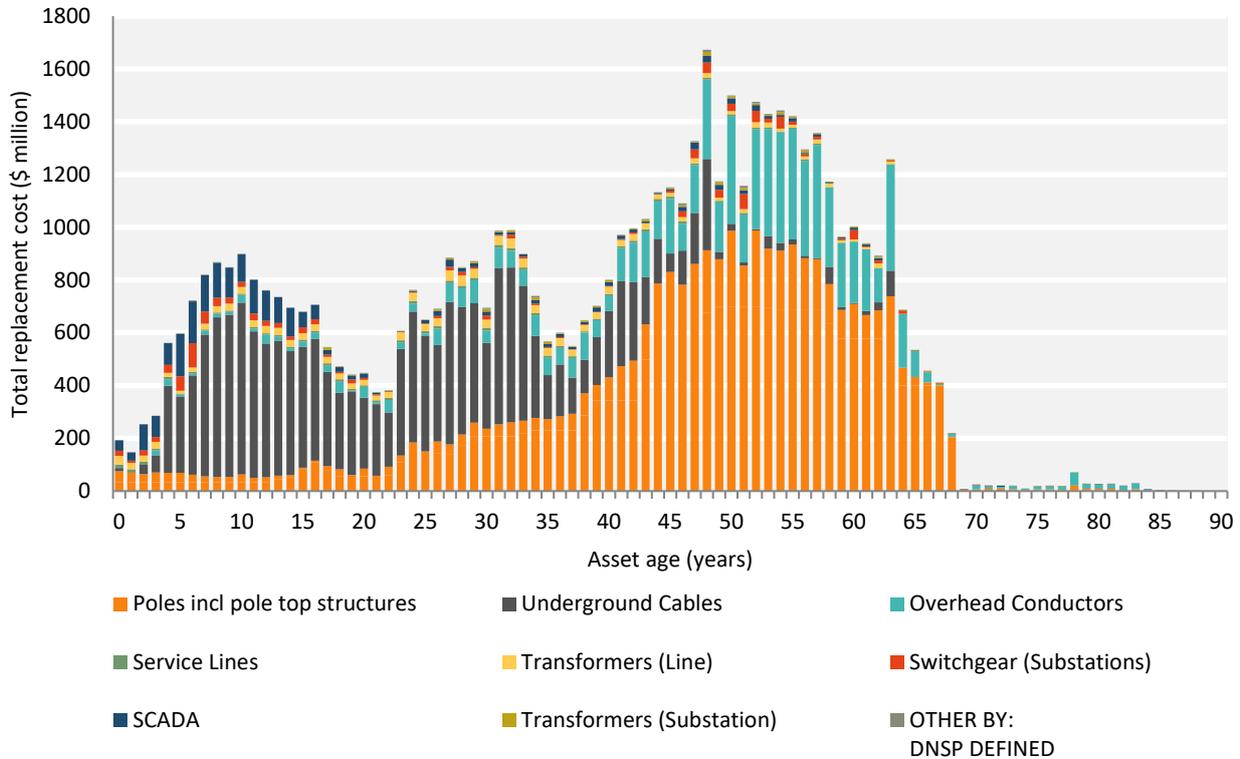
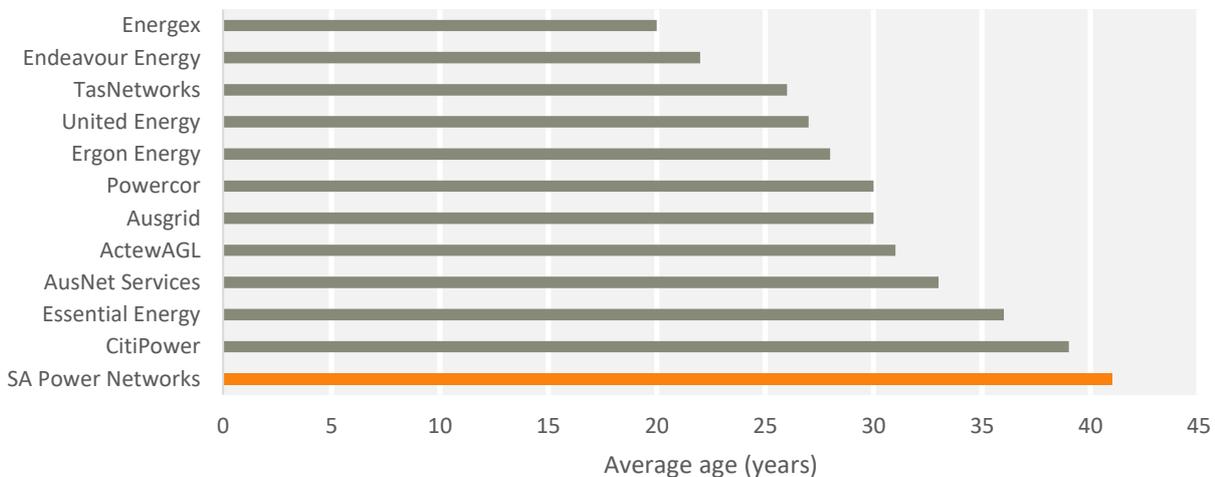


Figure 8: Distribution network replacement cost profile

Figure 8 shows a large proportion of the replacement cost within poles (including pole top structures), underground cables and overhead conductors.

The asset age profile of the South Australian distribution network is the oldest of all distribution networks service providers in the National Electricity Market as shown in Figure 9.



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

Figure 9: Average age of distribution network service providers assets

SA Power Networks have focused on maximising asset life, delivered through asset management strategies targeting cost-effective refurbishments ahead of replacements to minimise life-cycle costs. However, as the assets continue to age, replacements will be required when refurbishment is no longer viable due to overall asset condition, cost, safety or equipment obsolescence. Asset replacement expenditure will need to be increased to maintain the existing levels of service and risk across the distribution network.

3.4 Overview of assets covered by this plan

SA Power Networks categorises assets into both systems and asset classes. Figure 10 shows the various asset classes by system. It shows that some asset classes exist across multiple systems but otherwise provide the same function. The functions of the various major assets is discussed within this section while the strategies applied to the asset classes (across all systems containing those assets) is discussed in Chapter 8.

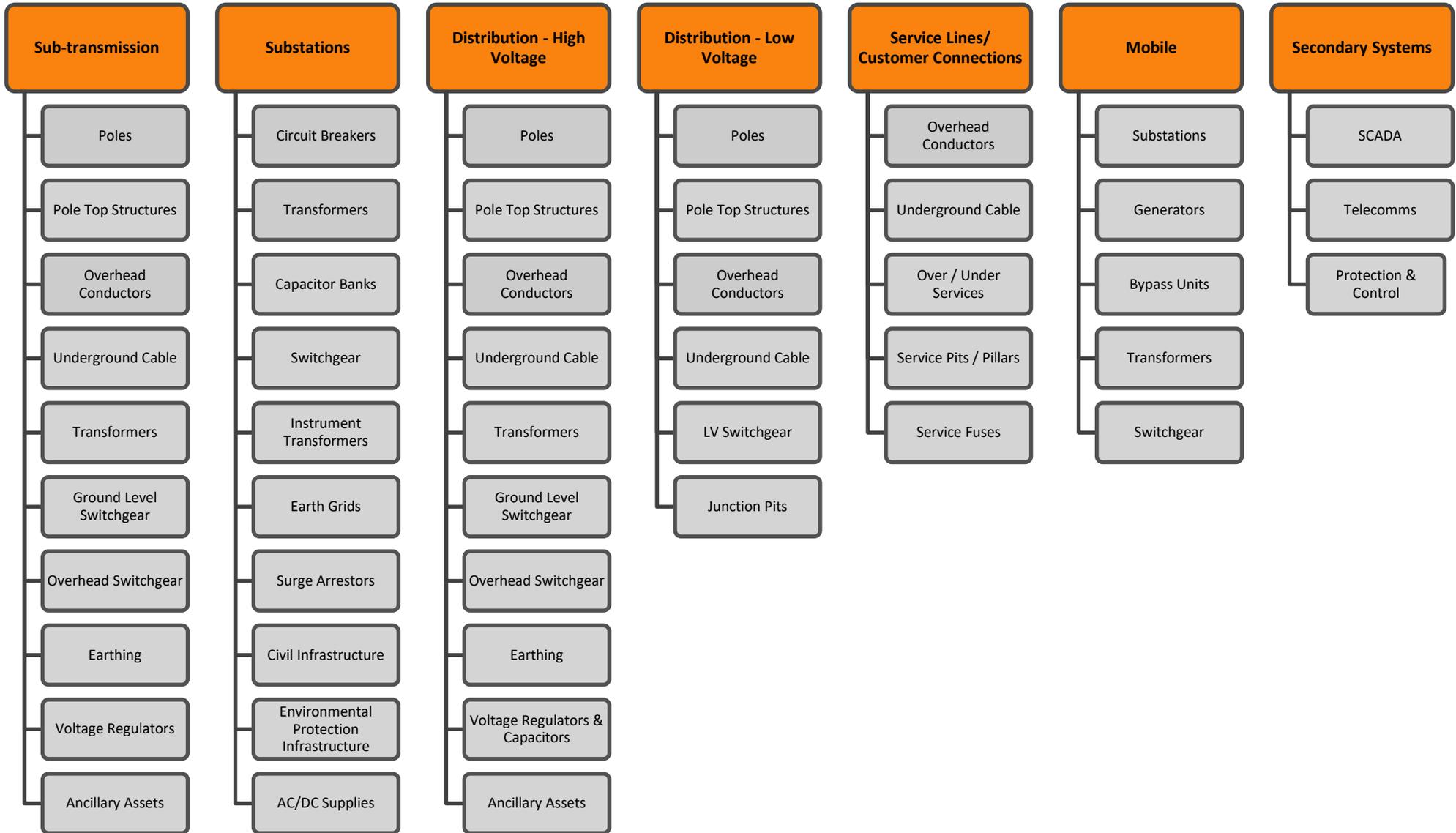


Figure 10: Systems and assets breakdown

3.4.1 Sub-transmission lines

SA Power Networks' sub-transmission system operates at nominal voltages of 66kV and 33kV and provides the bulk electricity supply between the network substations. Sub-transmission lines provide the infrastructure to transfer bulk electricity from the transmission network operated and maintained by the transmission network service provider, ElectraNet, as shown in Figure 11. The ElectraNet transmission network interfaces with power generation facilities and with SA Power Networks sub-transmission system at bulk connection points at joint use substations with ElectraNet.

3.4.2 Substations and power transformers

Network substations connect the transmission system, sub-transmission system and high voltage (HV) distribution networks with substation power transformers at the interface of these systems. Of the 408 SA Power Networks substations, 36 sites are shared with ElectraNet. The number of substations by highest SA Power Networks rated voltage and shared ownership are shown in Table 2.

Table 2: Substation quantities (as at March 2018)

Highest rated voltage	Shared substations	Substations not shared	Total
132kV	1	0	1
66kV	13	139	152
33kV	18	193	211
11kV	3	40	43
3.3kV	1	0	1
Total	36	372	408

Note: There are 50 joint use ('connection point') substations co-located with ElectraNet. These consist of both shared (36) and segregated (14) substation sites.

The location of SA Power Networks substations are scattered across South Australia but are more highly concentrated around the greater metropolitan Adelaide region and regional load centres as shown in Figure 11.

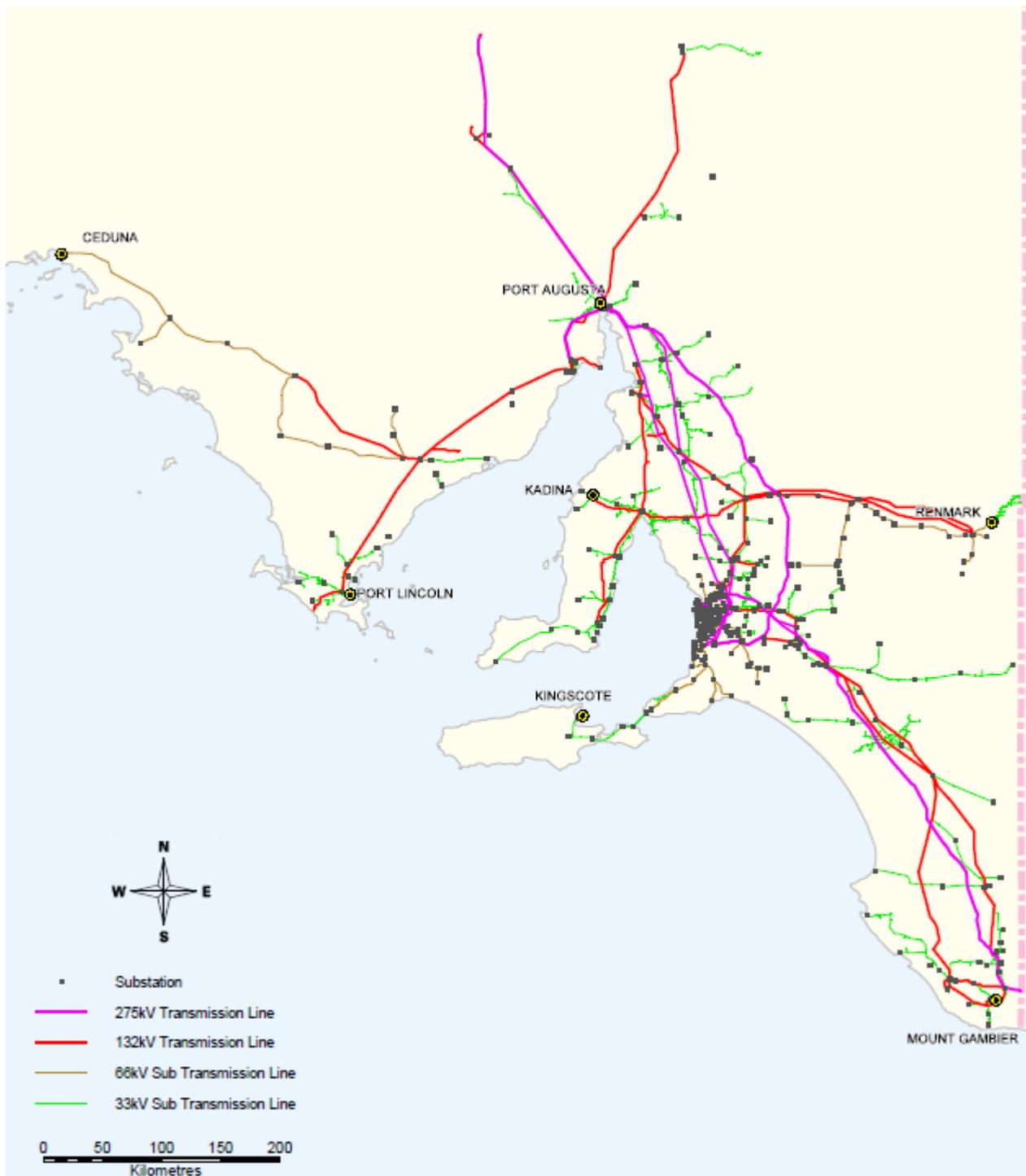


Figure 11: ElectraNet transmission network and SA Power Networks' sub-transmission system and substation locations

3.4.3 High voltage distribution lines and distribution transformers

The distribution network operates 7.6kV, 11kV and 19kV lines that transfer electricity from the substations up to and including the transformers that supply the low voltage (LV) network. The majority of the HV distribution network operates at 11kV in high customer density urban areas and regional centres and at 19kV in rural and remote locations. A small number of bulk supply commercial customers are connected directly to the HV network.

3.4.4 Low voltage distribution lines

The standard LV customer supply is 230/400 volts at 50Hz. The LV network lines transfer electricity from distribution transformers (pole mounted and pad mounted) to the majority of customer connection points.

3.4.5 Service lines

The network also includes service lines connecting the LV network to revenue meters which measure the electricity supplied to customers. The service lines provide electricity to the connection point for SA Power Networks infrastructure to the customer owned mains. In rural areas, the electricity meter may be mounted on a readily accessible Stobie pole to facilitate ease of meter reading with customers supplied through an extension of the network usually comprising Stobie poles and overhead conductors to customer properties with these types of supply referred to as metered mains. Metered mains have an interface point marked to clearly identify the extent of SA Power Networks' and customer asset ownership.

3.4.6 Mobile assets

Mobile equipment consists of various substation and HV distribution plant and equipment including portable substations, a portable switch room, transformers, generating units, switchgear and associated cables and ancillary equipment for temporary supply during extended planned or unplanned network outages to minimise the impact on customer supply.

3.4.7 Secondary systems

Secondary systems include other supporting systems including Supervisory Control and Data Acquisition System (SCADA), network protection and telecommunications assets. These assets are used to continuously monitor and control the network.

3.4.8 Detailed asset summary

The breakdown of the asset classes by voltage as reported in the response to the AER's Annual Category Analysis Regulatory Information Notice 2017-2018, for SA Power Networks is shown in Table 3. The quantities referenced throughout this PAMP are as per this information unless stated otherwise.

Table 3: SA Power Networks asset summary (as of 30 June 2018)

Asset class	Description	Quantity
CONDUCTORS BY: (conductor km)	< = 1kV	75,24
	> 1kV & < = 11 kV	53,635
	> 11kV & < = 22kV; SWER	29,131
	> 22kV & < = 66kV	16,282
	Conductors sub-total	174,293
CABLES BY: (route km)	< = 1kV	13,730
	> 1kV & < = 11kV	4,085
	> 11kV & < = 22kV	61
	> 22kV & < = 33kV	134
	> 33kV & < = 66kV	54
	Cables sub-total	18,064
SERVICE LINES BY:	< = 11kV; residential; simple type	708,692

Asset class	Description	Quantity
(quantity)	< = 11kV; commercial & industrial; complex type	87,433
	Service lines sub-total	796,125
TRANSFORMERS BY: (quantity)	Pole mounted; < = 22kV; < = 60kVA; single phase	40,255
	Pole mounted; < = 22kV; > 60kVA and < = 600kVA; single phase	12,168
	Pole mounted; < = 22kV; > 600kVA; single phase	211
	Pole mounted; < = 22kV; < = 60kVA; multiple phase	2,740
	Pole mounted; < = 22kV; > 60kVA and < = 600kVA; multiple phase	4,925
	Pole mounted; < = 22kV; > 600kVA; multiple phase	25
	Pole Mounted ;> = 22 kV & < = 33 kV; < = 60kVA (DNSP defined)	1,047
	Pole Mounted ;> = 22 kV & < = 33 kV; > 60 KVA AND < = 600 KVA (DNSP defined)	709
	Kiosk Mounted; > = 22 kV & < = 33 kV (DNSP defined)	55
	Kiosk mounted; < = 22kV; < = 60kVA; single phase	307
	Kiosk mounted; < = 22kV; > 60kVA and < = 600kVA; single phase	8,509
	Kiosk mounted; < = 22kV; > 600kVA; single phase	1,235
	Kiosk mounted; < = 22kV; < = 60kVA; multiple phase	21
	Kiosk mounted; < = 22kV; > 60kVA and < = 600 kVA; multiple phase	2,617
	Kiosk mounted; < = 22kV; > 600kVA; multiple phase	506
	Ground outdoor/indoor chamber mounted; < 22kV; < = 60kVA; single phase	11
	Ground outdoor/indoor chamber mounted; < 22 kV; > 60kVA and < = 600 kVA; single phase	373

Asset class	Description	Quantity
	Ground outdoor/indoor chamber mounted; < 22kV; > 600kVA; single phase	188
	Ground outdoor/indoor chamber mounted; < 22kV; > 60kVA and < = 600kVA; multiple phase	8
	Ground outdoor/indoor chamber mounted; < 22kV; > 600kVA; multiple phase	76
	Ground outdoor/indoor chamber mounted; > = 22kV & < = 33kV; < = 15MVA	416
	Ground outdoor/indoor chamber mounted; > = 22kV & < = 33kV; > 15MVA and < = 40MVA	5
	Ground outdoor/indoor chamber mounted; > 33kV & < = 66kV; < = 15MVA	165
	Ground outdoor/indoor chamber mounted; > 33kV & < = 66kV; > 15MVA and < = 40MVA	124
	Transformers sub-total	76,696
SWITCHGEAR BY: (quantity)	< = 11kV; switch	1,458
	< = 11kV; circuit breaker	1,247
	> 11kV & < = 22kV; switch	10
	> 22kV & < = 33kV; switch	1,034
	> 22kV & < = 33kV; circuit breaker	252
	> 33kV & < = 66kV; switch	1,434
	> 33kV & < = 66kV; circuit breaker	485
	Switchgear sub-total	5,920
SCADA, NETWORK CONTROL AND PROTECTION SYSTEMS BY: (quantity)	Field devices	6,941
	Communications network assets	3,196
	Master station assets	350
	Communications site infrastructure	69
	Communications linear assets	2,780
	SCADA, network control and protection systems sub-total	13,336

Asset class	Description	Quantity
POLES BY: (quantity)	< = 1 kV; Stobie pole	242,668
	> 1 kV & < = 11kV; Stobie pole	222,293
	> 11kV & < = 22kV; Stobie pole	113,926
	> 22 kV & < = 66 kV; Stobie pole	34,447
	Pole refurbished; Stobie	36,160
	Poles sub-total	647,497
SWITCHGEAR OTHER BY: (unit)	Recloser; switchgear	1,394
	Sectionaliser; switchgear	676
	>= 11kV & < ≈ 22kV; load break switch; ground level (switching cubicle); switchgear	7,551
	Switchgear other sub-total	9,621

Source: AER Category Analysis Regulatory Information Notice 2017-2018 – 5.2 Asset age profile, SA Power Networks

4 Levels of service provided to customers and stakeholders – understanding customers

4.1 Introduction

SA Power Networks has an ongoing focus on working with customers, stakeholders, building on past experiences, and continuing to embed effective stakeholder engagement practices across the business. The development of customer supported levels of service ensures SA Power Networks understands (and responds appropriately to) what stakeholders and customers value. The levels of service targets aim to strike a balance between the cost of the service and needs of various customers and stakeholders.

Historically, SA Power Networks has been required to have ‘best endeavours’ to meet regulatory targets and while other internal performance targets were developed by individual teams there was no holistic view of the key service performance targets across the organisation to demonstrate an integrated approach to asset management. To improve alignment, the SA Power Networks Asset Management Working Group, a representation of senior managers across the organisation, developed draft levels of service that were quantifiable measures that demonstrate both the performance of the services delivered to customers and how safely and efficiently those services are provided.

To develop levels of service, the Asset Management Working Group recognised the need to understand:

- current levels of service (what is provided now);
- desired levels of service (what customers would like);
- legislative requirements (what must be done); and
- corporate and strategic goals (what shareholders want).

The vision is for these drivers to inform both the levels of service measures and targets developed as shown in Figure 12. This section describes the draft levels of service that were developed, the customer insights gained on these and the refined and future levels of service SA Power Networks aim to achieve.



Figure 12: How levels of service are developed

The levels of service and targets (where appropriate) shall be reviewed annually as part of the annual PAMP review. Engagement with customer reference groups on levels of service measures is ongoing through 2018.

4.2 Draft levels of service categories and measures

The draft SA Power Networks' levels of service categories and measures developed during 2017 included:

- **Safety — provide a safe network service:** measures relate to incidents that directly impacted or had the potential to impact the safety of staff, contractors or the community that are related to our assets and/or asset management activities
- **Customer experience — deliver energy services that enhance customer experience:** measures relate to customer satisfaction with information provided and responsiveness to customer and stakeholder enquiries
- **Reliability and quality — deliver a reliable and quality network service:** measures relate to the frequency and duration of outages and to the quality of electricity supplied to customers
- **Environment — provide an environmentally sustainable network service:** measures relate to environmental pollution and licence compliance
- **Aesthetics — provide an aesthetically pleasing network:** measures relate to visual amenity of our network and operations
- **Two-way grid — provide a network service that enables customers to both import and export their energy:** measures relate to the extent of complaints relating to customers unable to export into the network
- **Communication and information — communicate and make information available:** measures relate to information regarding planned and unplanned outages notifications
- **Cost efficiency — continuously seek out and deliver network service cost efficiencies:** measures relate to how we compare with other network service providers regarding network costs and how much risk we reduce compared to the money we spend in reducing that risk

The draft levels of service were used to undertake specific and targeted engagement with customers and stakeholders to test alignment with customer expectations.

4.3 Customers and stakeholders

A customer is any individual, business or other party who pays SA Power Networks directly or indirectly to use network infrastructure to receive or provide a service while a stakeholder is any individual, business or other party who can affect or be affected by our actions and performance. Figure 13 depicts the broad range of stakeholders and customers that SA Power Networks interfaces with.



Figure 13: SA Power Networks customers and stakeholders

4.4 Customer strategy

SA Power Networks has a strong focus on proactively engaging with customers and stakeholders. The SA Power Networks Customer Strategy shown in Figure 14 sets out the strategies used to increase organisational understanding of customer expectations for use in decision making to increase the value in services provided by the distribution network.



Figure 14: SA Power Networks Customer Strategy

4.5 Customer and stakeholder engagement on levels of service

As part of the customer strategy, customers and stakeholders have been consulted through an extensive stakeholder engagement program throughout 2017-2018.

The key areas of importance to customers and stakeholders included:

- acceptable reliability for all — improving reliability in poor performing areas;
- prudent investments — keeping electricity prices down;
- support for enabling the energy transition — preparing for the future role of the network;
- support from customers to balance current network investment with future uncertainty;
- outage communications — providing reliable information;
- customers to co-design solutions; and
- vegetation management — improving outcomes.

SA Power Networks draft levels of service were developed around these areas of importance. SA Power Networks engaged with representatives of the Customer Consultative Panel and four reference groups (Renewables Reference Group, Community Reference Group, Business Reference Group and Arborist Reference Group) specifically on the draft levels of service on 21 November 2017.

Some general comments on the draft levels of service included:

- consideration be given to different levels of service for different locations;
- consideration be given to the type of customer across categories; and
- auditing of level of service measures could provide a layer of integrity.

Table 4 summarises specific discussion points raised during the workshop grouped by the draft level of service category; more detailed information arising from the workshop is available via SA Power Networks Talking Power website.

Table 4: Draft levels of service ‘Deep Dive’ workshop – documented key feedback points from customers grouped by initial draft level of service category

Level of service category	Description of feedback on levels of service categories and measures
Safety	<ul style="list-style-type: none"> This category was rated mid-range in terms of importance. It was suggested the definition of safety was too narrow and needed to include not only workers but customers as well. There was concerns raised to ensure trees are trimmed on schedule as there could be cost or safety implications. The ‘look up and live’ program is important for farmers and the building industry.
Customer experience	<ul style="list-style-type: none"> This category was rated high relative to most other levels of service categories. Time taken to navigate recorded messages before speaking to someone was deemed too long. Duration of 65 days to provide connection quote was considered too long. Satisfaction with corporate website was deemed low (particularly) by contractors as it was difficult to find relevant documents. Percentage of customer connections delivered on time was considered a good measure. Other potential measures suggested for consideration included: <ul style="list-style-type: none"> length of time from ringing to connection with a person; levels of satisfaction with corporate website; and co-ordination of works with Department of Planning, Transport and Infrastructure and other agencies.
Reliability and quality of supply	<ul style="list-style-type: none"> This category was rated the most important relative to other levels of service categories. Suggested localised information is needed; not just state-wide information. Suggested data collection required to enable visibility of customer voltage issues. Queried how SA Power Networks deals with areas with high installed solar system capacity. Other potential measures to be considered: <ul style="list-style-type: none"> Accuracy of forecasting duration of weather related outages Frequency and duration of voltage related outages
Environment	<ul style="list-style-type: none"> This category was rated high relative to most other levels of service categories. Environment was considered important, particularly in relation to vegetation management (listed under the aesthetics category at the time of the workshop). Some cross over with vegetation clearance within the aesthetics category (e.g. vegetation is considered an environmental issue). Other potential measures to be considered: <ul style="list-style-type: none"> How much ‘green power’ is transported over the network Energy loss through the network (line losses)
Aesthetics	<ul style="list-style-type: none"> This level of service category was given a low rating of importance; limited discussion on measures. It would be useful to identify poor quality tree stock removal and/or replacement.
Two-way grid	<ul style="list-style-type: none"> Much of the discussion regarding quality of supply and the impact of photovoltaic (PV) systems was discussed under the reliability and quality of supply discussion. It is likely this level of service category was confounded with the reliability and quality category which included draft measures on quality of supply and included discussion around customer PV systems and the issues customers face with exporting energy; it was acknowledged that increased monitoring and visibility of the network was required in response increasing quality of supply problems arising from increased customer PV systems.

Level of service category	Description of feedback on levels of service categories and measures
	<ul style="list-style-type: none"> This is supported through the network of the future being raised as an important issue throughout the Directions workshops with most customers supporting moderate to high levels of investment to support PV systems and other energy management technologies. Reporting on the impact of customers exporting electricity to the network could be used as a measure.
Communication and information	<ul style="list-style-type: none"> This category was rated mid-range in terms of importance. Coordination with local government, and clearer two-way flows of information with government agencies and business was identified as a possible measure. There could be a measure to show coverage/penetration of communication. Satisfaction with Corporate website was low for contractors as it was difficult to find relevant documents. Extent of customer knowledge about SA Power Networks could be a measure.
Cost efficiency	<ul style="list-style-type: none"> This level of service category was given a low rating of importance; limited discussion on the stated measures. Queried whether cost efficiency was the right terminology because ‘price’ was not explicitly referenced. Benchmarking with international utilities was discussed but was unclear if this was possible given the geographical differences between networks.

The information from this workshop was considered and discussed with the Asset Management Working Group to refine the levels of service categories and measures used within this PAMP. The key changes from the 2017 draft levels of service are discussed in Table 5. Some of the measures are aspirational and cannot currently be measured, but are included as the first step in the process of developing these. These are marked as future measures.

4.6 Strategic and corporate goals

The SA Power Networks strategic direction states the business objectives, strategies and philosophies as shown in Figure 15. It clarifies how individual efforts and departmental projects can be connected to achieve the best organisational outcome. The SA Power Networks strategic asset management plan (discussed further in Section 6) provides further guidance on the process for achieving these corporate goals.

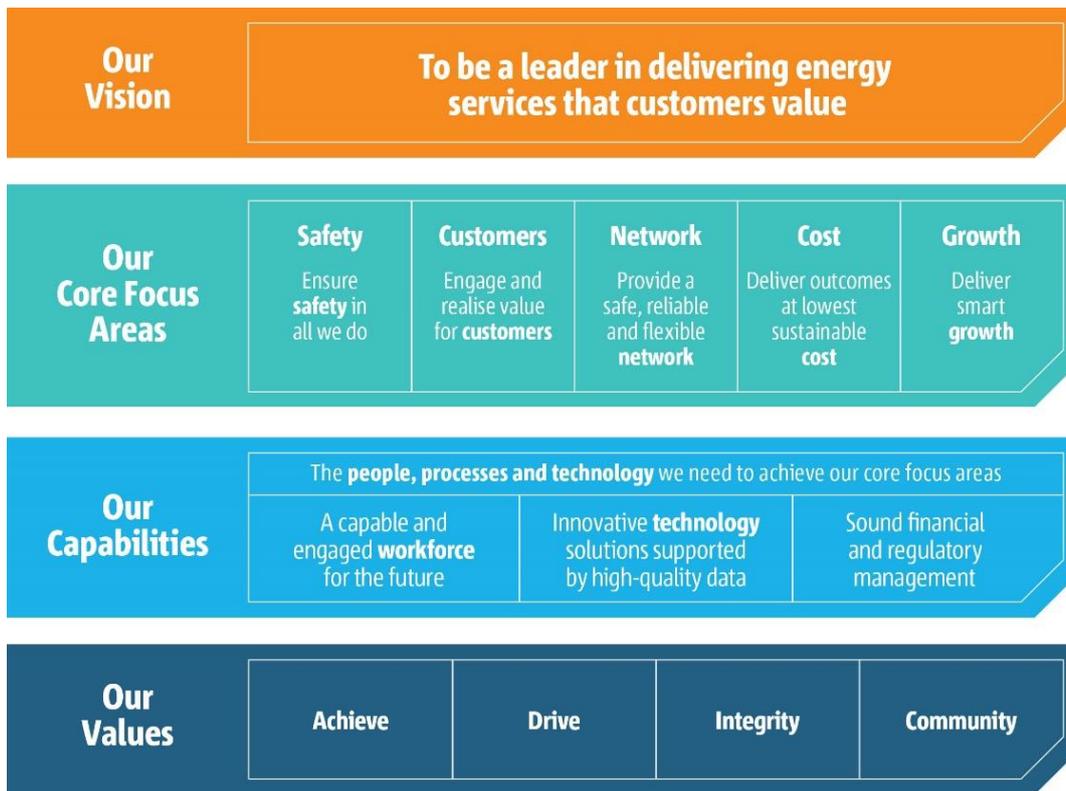


Figure 15: SA Power Networks Corporate Strategic Framework

4.7 Legislative requirements

SA Power Networks is heavily subject to regulation. Being part of the National Electricity Market (NEM), SA Power Networks must comply with the Australian Energy Market Commission National Electricity Objective as stated in the National Electricity Law which is:

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

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

In addition, SA Power Networks is required to comply with many Acts, codes of practice, rules, procedures and guidelines for managing a complex asset base, for example:

- *Electricity Act 1996;*
- National Electricity Law;
- *National Energy Retail Law (South Australia) Act 2011;*
- National Electricity Rules;
- National Energy Retail Rules;
- SA Electricity Distribution Code;
- National Metrology Procedures; and
- Essential Services Commission of South Australia (ESCoSA) and Australian Energy Regulator (AER) Guidelines.

Those legislative requirements that determine the specific levels of service measures and targets are highlighted in Section 4.8.

4.8 Levels of service – drivers, purpose and changes to draft measures

Table 5 summarises the levels of service and changes made since customer and stakeholder engagement on the draft level of service (see Section 4.5) and whether the data is existing or needs to be captured in the future. The historical performance and trends of the proposed measures are discussed in Section 4.9.

Table 5: Levels of service – drivers, purpose and changes from initial draft measures

Performance measure	Future/ existing	Perceived level of customer importance	Purpose of the measures?	Changes from draft levels of service measures?
Safety — provide a safe network service				
Number of injuries to the public attributable to network assets and/or asset management activities	Existing	✓✓	<ul style="list-style-type: none"> Monitor the number of public safety incidents directly related to network assets. 	<ul style="list-style-type: none"> Measure removed. Very low number of incidents; any significant safety incidents to the public to be captured under fatal risk incidents measure.
Pre-fire danger season vegetation clearance compliance with legislated requirements (%)	Existing	✓✓	<ul style="list-style-type: none"> Level of vegetation clearance compliance based on independent auditing of vegetation clearance around conductors. 	<ul style="list-style-type: none"> New measure. Customers raised concerns around ensuring vegetation was cleared on schedule and meet legislated compliance due to safety implications.
Number of fire starts per 1,000km of powerline	Existing	✓✓	<ul style="list-style-type: none"> Monitor the rate of shocks, fire starts and customer damage claims as an indicator of performance or condition of network assets that can impact public safety. 	<ul style="list-style-type: none"> No change. While some other safety aspects were discussed; it was not advocated that they should replace the draft levels of service or be additional measures.
Number of shock reports per 1,000 km powerline	Existing	✓✓		
Number of customer damage claims per 1,000 km of powerline attributable to network assets and/or asset management activities	Existing	✓		
Fatal risk incidents attributable to network assets and/or asset management activities	Existing	✓✓	<ul style="list-style-type: none"> A measure of risk related to an event arising from a failure or interaction with a network asset regardless of the outcome. 	<ul style="list-style-type: none"> New measure.
Number of staff and contractors lost time injuries per year attributable to network assets and/or asset management activities	Existing	✓✓	<ul style="list-style-type: none"> Monitor the number of staff and contractor safety incidents directly related to network assets. 	<ul style="list-style-type: none"> No change. While some other safety aspects were discussed; it was not advocated that they should replace the draft levels of service or be additional measures.

Performance measure	Future/ existing	Perceived level of customer importance	Purpose of the measures?	Changes from draft levels of service measures?
Number of staff and contractor medical treatment injuries per year attributable to network assets and/or asset management activities	Existing	✓✓		
Switching incidents (number per 1,000 switching programs)	Existing	✓	<ul style="list-style-type: none"> Monitor the rate of switching incidents occurring within the network as an indicator of safe network operations ensuring continuous improvement in safe switching. 	
Customer experience — deliver energy services that enhance customer experience				
Customer Combined Satisfaction Index (1-7 scale)	Existing	✓	<ul style="list-style-type: none"> Measure the quality of information provided to customers following contact with SA Power Networks in relation to unplanned interruptions, planned interruptions or telephone enquiries. 	<ul style="list-style-type: none"> No change.
Response to telephone calls within 30 seconds (%)	Existing	✓✓✓	<ul style="list-style-type: none"> A measure of SA Power Networks responsiveness to customer calls and written enquiries. 	<ul style="list-style-type: none"> No change.
Response to written enquiries within 5 business days (%)	Existing	✓	<ul style="list-style-type: none"> A regulatory measure reported annually to ESCoSA as a requirement under section 2.1.1 of the 2015 Electricity Distribution Code. 	<ul style="list-style-type: none"> ESCoSA draft decision on SA Power Networks reliability standards review is proposing to retain these measures as customer service standards (Essential Services Commission of South Australia, 2018).
Customer appointments on time (15 minutes) (%)	Existing	✓✓✓	<ul style="list-style-type: none"> Measures the timelines of SA Power Networks to attend scheduled appointments and for connecting customers to an agreed date. 	<ul style="list-style-type: none"> Measure removed. ESCoSA draft decision on SA Power Networks reliability standards review proposed to remove this as a measure subject to GSL payments

Performance measure	Future/ existing	Perceived level of customer importance	Purpose of the measures?	Changes from draft levels of service measures?
Customer connections delivered to agreed date (%)	Existing	✓✓✓	<ul style="list-style-type: none"> Measures the timelines of SA Power Networks to attend scheduled appointments and for connecting customers to an agreed date. A regulatory measure reported annually to ESCoSA as a requirement under section 2.3.1 of the 2015 Electricity Distribution Code. 	<p>Essential Services Commission of South Australia, 2018).</p> <ul style="list-style-type: none"> No change. ESCoSA draft decision on SA Power Networks reliability standards review is proposing to retain this as a standard subject to GSL payments (Essential Services Commission of South Australia, 2018).
Minor connection quotes (primarily residential) provided within 20 business days (%)	Existing	✓✓✓	<ul style="list-style-type: none"> A measure of the percentage of quotes provided in a timely manner. 	<ul style="list-style-type: none"> New measures. Revised measures for simpler residential connections and more complex non-residential connections and timeframes using existing data for works entirely within SA Power Networks responsibility. Customers suggested to consider customer types within measures (see Section 4.5).
Other connection quotes provided within 65 business days (%)	Existing	✓✓✓		
Responses to quality of supply enquiries within 20 business days (%)	Existing	✓✓✓	<ul style="list-style-type: none"> A measure of the responsiveness to quality of supply enquiries to advise what works are required (if any). 	<ul style="list-style-type: none"> New measures. Customers have suggested to report on the impact of customers PV systems exporting to the network.
Completing minor remedial works for quality of supply enquiries within 80 business days (%)	Existing	✓✓✓	<ul style="list-style-type: none"> A measure of the responsiveness to undertake minor remediation works on the network in response to quality of supply enquiries (where required). 	
Number of customers affected by >1 planned interruptions per week	Future	✓✓	<ul style="list-style-type: none"> A measure of the number of customers who are impacted by repeated interruptions within 1 	<ul style="list-style-type: none"> New measure.

Performance measure	Future/ existing	Perceived level of customer importance	Purpose of the measures?	Changes from draft levels of service measures?
			week in line with the SA Power Networks Network Directives Manual.	<ul style="list-style-type: none"> Added in response to customer concerns received when multiple planned interruptions occur over a short timeframe.
Reliability and resilience — deliver a reliable and resilient network service				
Average number of minutes per year that a customer is without electricity for all unplanned interruptions (excluding MEDs)	Existing	✓✓✓	<ul style="list-style-type: none"> A measure of underlying network reliability (excluding major event days). A regulatory measure reported annually to ESCoSA as a requirement under section 2.2.1 of the 2015 Electricity Distribution Code. 	<ul style="list-style-type: none"> No change.
Average number of times per year that a customer is without electricity for all unplanned interruptions (excluding MEDs)	Existing	✓✓✓		
Average number of minutes per year that a customer is without electricity for all planned interruptions	Existing	✓✓	<ul style="list-style-type: none"> A measure of the duration and frequency of interruptions because of planned works on the network. 	<ul style="list-style-type: none"> Measures removed. Provided customers are informed of planned outages, customer generally accept works are required to maintain the network. Alternate measures for planned interruptions including frequent interruptions (customer experience) and exceeding specified duration of planned outages and cancellation of planned outages (communication and information) added.
Average number of times per year that a customer is without electricity for all planned interruptions	Existing	✓✓		
Reliability duration customer GSL payments	Existing	✓✓	<ul style="list-style-type: none"> A measure of the customer experience for excessive interruption duration or frequency and includes the impact of MEDs. A regulatory measure reported annually to ESCoSA as a requirement under section 2.3 of the 2015 Electricity Distribution Code. 	<ul style="list-style-type: none"> Measures removed. Number of customer payments largely influenced by duration payments for MEDs; highly variable and largely out of SA Power Networks direct control.
Reliability frequency customer GSL payments	Existing	✓✓		

Performance measure	Future/ existing	Perceived level of customer importance	Purpose of the measures?	Changes from draft levels of service measures?
Region based reliability targets achieved (%) ²	Future	✓✓✓	<ul style="list-style-type: none"> Performance against unplanned interruption duration and frequency targets for ten regions (excluding MEDs). 	<ul style="list-style-type: none"> New measures (subject to outcomes of SA Power Networks 2020 reliability standards review). Customers suggested localised information is needed; not just state-wide. ESCoSA draft decision on SA Power Networks reliability standards review is proposing to include ten regions and reliability and restoration targets for each (Essential Services Commission of South Australia, 2018).
Region based restoration targets achieved (%) ²	Future	✓✓✓	<ul style="list-style-type: none"> Performance against average restoration time targets for ten regions. 	
Environment — provide an environmentally sustainable network service				
Number of oil spills per year from in service network assets	Existing	✓✓	<ul style="list-style-type: none"> Measures of pollutants entering the environment as an indicator of asset condition. Measure of compliance against an Environmental Protection Authority licence issued for the power generation facility on Kangaroo Island. 	<ul style="list-style-type: none"> No change.
Quantity of sulphur hexafluoride (SF ₆) (a greenhouse gas) emissions attributable to network assets (kg)	Existing	✓✓		
Environment Protection Authority licence compliance (%)	Existing	✓✓		
Aesthetics — provide an aesthetically pleasing network				
Proportion of network underground (%)	Existing	✓	<ul style="list-style-type: none"> Percentage of network underground vs overhead for aesthetic purposes. 	<ul style="list-style-type: none"> Measure removed. Customers viewed this as low importance. No regulatory or legislative target for length to be undergrounded.
Customers satisfied with vegetation clearance (%)	Existing	✓✓	<ul style="list-style-type: none"> Measure of proportion of customers satisfied with vegetation clearance through targeted surveys. 	<ul style="list-style-type: none"> No change. Customers discussed the importance of vegetation management improvements during the environment category discussions.

Performance measure	Future/ existing	Perceived level of customer importance	Purpose of the measures?	Changes from draft levels of service measures?
Two-way grid — provide a network service that enables customers to both import and export their energy				
Average number of high voltage (over voltage) enquiries per month related to PV systems	Existing	✓✓✓	<ul style="list-style-type: none"> Measure of quality of supply enquiries relating to high voltage (over voltage) related to PV systems which require further investigation by SA Power Networks. 	<ul style="list-style-type: none"> No change. Surrogate measure in the absence of proactive network voltage monitoring. Much of the reliability and quality category discussion from the workshop revolved around PV systems and the impact on the network. Addition of a measure in customer experience category for responsiveness to customers quality of supply enquiries.
Voltage compliance with Australian Standard voltage (% of time)	Future	✓✓✓	<ul style="list-style-type: none"> Measure of the measured quality of supply compared to the relevant Australian Standard. 	<ul style="list-style-type: none"> No change. Not currently measured; customers have advocated that SA Power Networks increased monitoring and visibility of the network.
Communication and information — communicate and make information available				
Percentage of planned interruptions for which four business days' notice provided	Existing	✓✓	<ul style="list-style-type: none"> A measure for the percentage of planned outages providing the required advance notice. 	<ul style="list-style-type: none"> No change. Reworded to provide a timeframe for measurement and linked to the number of planned interruptions rather than customers.
Percentage of planned interruptions completed within specified timeframe	Future	✓✓✓	<ul style="list-style-type: none"> Measures for the number of planned outages not completed within nominated timeframe and number of planned outages cancelled without providing appropriate advanced notification to customers. 	<ul style="list-style-type: none"> New measure. Aimed at providing customers timely and accurate information on planned interruptions and increased stakeholder confidence.
Number of planned interruptions cancelled without four business days' notice	Existing	✓✓✓	<ul style="list-style-type: none"> A measure of the accuracy of information provided for unplanned outages. 	<ul style="list-style-type: none"> Aimed at providing customers timely and accurate information on planned interruptions and increased stakeholder confidence.
Percentage of unplanned interruptions provided with accurate rectification times	Future	✓✓✓	<ul style="list-style-type: none"> A measure of the accuracy of information provided for unplanned outages. 	<ul style="list-style-type: none"> Measure removed. Priorities can change and durations amended as a result; could drive a culture of providing overly conservative estimated restoration times.

Performance measure	Future/ existing	Perceived level of customer importance	Purpose of the measures?	Changes from draft levels of service measures?
Percentage of unplanned outages for which customers were provided with information via SMS	Future	✓✓✓	<ul style="list-style-type: none"> A measure for providing timely, current and accurate information for unplanned outages. 	<ul style="list-style-type: none"> Measures of restoration targets for unplanned interruptions added (reliability and resilience) and SMS communication for unplanned interruptions (communication and information) to be used as alternate measures for unplanned interruptions. New measure (subject to outcomes of SA Power Networks 2020 reliability standards review). ESCoSA draft decision on SA Power Networks reliability standards review is proposing to include SMS communication standard (Essential Services Commission of South Australia, 2018).
Overall customer satisfaction with Corporate website	Future	✓✓✓	<ul style="list-style-type: none"> A measure of overall customer satisfaction with information available on website and ease of access. 	<ul style="list-style-type: none"> New measure. Added measure to assess customer satisfaction with accessing information from the Corporate website; a measure of satisfaction with information provided to customers.
Efficiency – continuously seek out and deliver network service efficiencies				
Relative performance efficiency rank compared to other Australian distributors	Existing	✓	<ul style="list-style-type: none"> A productivity index used by the Australian Energy Regulator using inputs and outputs. 	<ul style="list-style-type: none"> No change.
Ratio of capital spend to risk reduction	Future	✓	<ul style="list-style-type: none"> A measure of return on investment. 	<ul style="list-style-type: none"> Measure removed. Measure was unclear to customers.
Annual average asset renewal rate	Existing	✓	<ul style="list-style-type: none"> A ratio of regulatory year reported renewal expenditure as a percentage of total asset replacement value. 	<ul style="list-style-type: none"> New measure.
✓✓✓ = high importance ✓✓ = moderate importance ✓ = low importance				

4.9 Level of service descriptions and key observations on past performance

This section discusses the individual levels of service measures, why they are important, historical performance and trend discussion. Most of the levels of service measures are currently measured (see Table 5); new measures require further investigation to determine whether existing business systems have the data and capability to measure actual performance.

Where available, long-term data has been used for trend analysis. The Australian Energy Regulator's Annual Benchmarking Report information has also been used to compare SA Power Networks level of service performance to other distribution network service providers and is used to continue tracking achievements and identify potential areas for improvement. Overall, the AER benchmarking shows that SA Power Networks has consistently performed well at a national level.

4.9.1 Safety

Safety is the number one priority for SA Power Networks given the network infrastructure has the potential to injure or kill members of the public, our staff or our contractors. Safety levels of service provide an indication of how safely the network is operated and maintained to minimise safety risks to staff, contractors, customers and the community in general.

The customer engagement on levels of service (see Section 4.5) rated this category mid-range in terms of importance; potentially considered by customers as a mandatory requirement placed on SA Power Networks and given the limited access to the predominantly overhead network generally presents a low overall risk to customers and stakeholders.

Overall, SA Power Networks performance on measures for injuries to staff, contractors and the public arising from power assets has remained good due to the comprehensive safety systems and processes. While the rate of equipment related fire starts and equipment related switching incidents has remained stable this has corresponded with an increasing rate of asset renewals. It is anticipated that increased expenditure will be required to maintain these trends in response to the continued ageing and deterioration of the distribution network assets. In addition, the recent increase in the rate of shock reports is subject to a current ongoing investigation to determine underlying causes and required risk mitigation strategies.

The safety strategies applied and resulting capital and operating programs of work to achieve the safety levels of service are discussed in Section 9.2.

4.9.1.1 Vegetation clearance compliance

To achieve continuous improvement, vegetation clearance is audited to demonstrate compliance against legislative requirements. SA Power Networks undertakes independent concurrent cyclic audits and pre-fire danger season audits to assess infringements into the clearance zone, as well as the potential for vegetation to bend or grow into the clearance zone before the next cyclic cut or during the fire danger season respectively. The audits assess the number of audit sites (e.g. target Stobie pole location) and the number of conductor spans (e.g. up to three spans each direction from the target Stobie pole). The performance of compliance for both cyclic and pre-fire danger season audits for sites and spans and the level of non-conformance records (NCRs) are shown in Figure 16.

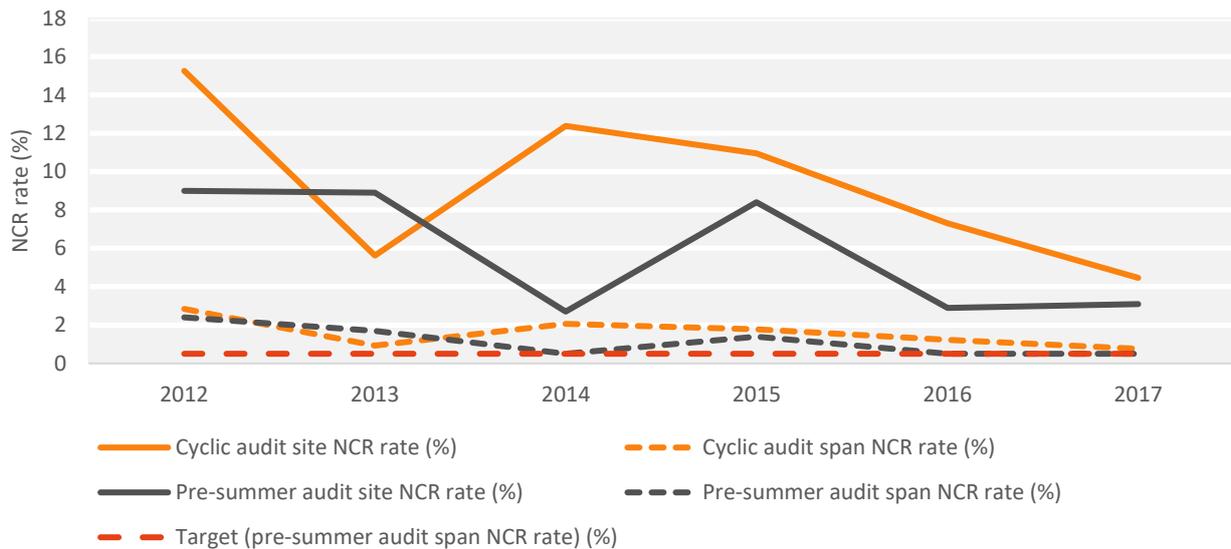


Figure 16: Long-term vegetation clearance audit non-compliance record rate trend comparison (2012-2017)

Figure 16 shows a significant improvement in vegetation clearance performance since 2012 with the pre-summer span NCR rate being 0.5% for the past two years. Notwithstanding, the audits include recommendations and priority for identified improvements to ensure SA Power Networks continuously improves the vegetation clearance practices to minimise bushfire risks and maintain reliability standards; the recent historical level of performance should be considered the minimum target.

Further explanation of clearance zone and the vegetation management strategy of which audits comprise a component of is discussed further in Section 7.5.5.

4.9.1.2 Fire starts

Bushfire risk is one of SA Power Networks largest risks given the extreme summer climate and extensive overhead rural distribution network traversing bushfire risk areas. SA Power Networks investigates all fire start events that occur near network assets. Fire starts related to the network rarely lead to larger bushfires; however, each such event is investigated to understand its root cause and to identify and mitigate emerging issues to minimise the likelihood of a catastrophic fire start event. The causes of fire start events and typical risk controls applied are listed in Table 6.

Table 6: Fire start event causes and controls

Category	Causes	Targeted risk controls
Environment	<ul style="list-style-type: none"> • Birds • Possums • Vegetation • Lightning • Wind 	<ul style="list-style-type: none"> • Installation of animal guards at targeted locations • Proactive program replacement of current limiting arcing horn (CLAHs) and rod air gaps (RAGs) in HBFRA prone to flashovers from bird contact • Ongoing vegetation management program and installation of line covers on conductors prone to vegetation contact • Installation of modern lightning resistance equipment such as surge diverters and polymer insulators being installed throughout the network
Equipment	<ul style="list-style-type: none"> • Hot joints, insulation breakdown, corrosion, etc. 	<ul style="list-style-type: none"> • Thermographic inspections on most critical overhead lines • Asset inspections and defect maintenance • Asset refurbishment/replacements
Third party	<ul style="list-style-type: none"> • Farm machinery and tipper trucks 	<ul style="list-style-type: none"> • ‘Look up and live’ campaign • Increased electrical awareness advertising

Category	Causes	Targeted risk controls
		<ul style="list-style-type: none"> • Reflective pole markers to improve visibility of overhead infrastructure
Other/unknown	<ul style="list-style-type: none"> • Unknown causes not covered by those above 	<ul style="list-style-type: none"> • Inconclusive root cause investigations

The long-term trend for fire starts near SA Power Networks distribution network has been relatively stable back to 2005 as shown in Figure 17.

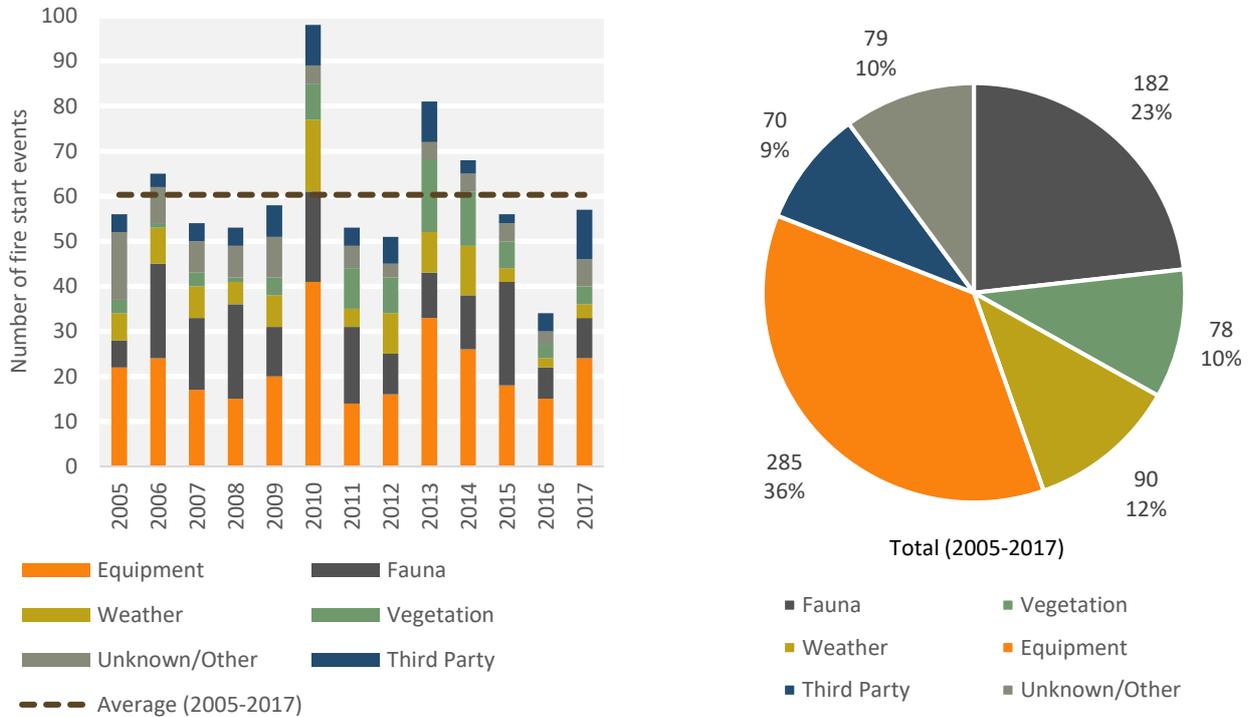


Figure 17: Fire start events by cause (2005-2017)

Figure 17 shows equipment being the most significant contributor which combined with fauna (birds and possums) accounts for around 60% of all reported fire starts since 2005. The underlying data suggests hot joints are the most dominant equipment cause accounting for approximately one third of fire starts linked to equipment. Considering the large quantity of joints in the HV distribution network and LV network, the number of hot joint related fires is low.

Figure 18 shows the long-term trend of equipment related fire starts split by bushfire risk area; for which data is available from 2008.

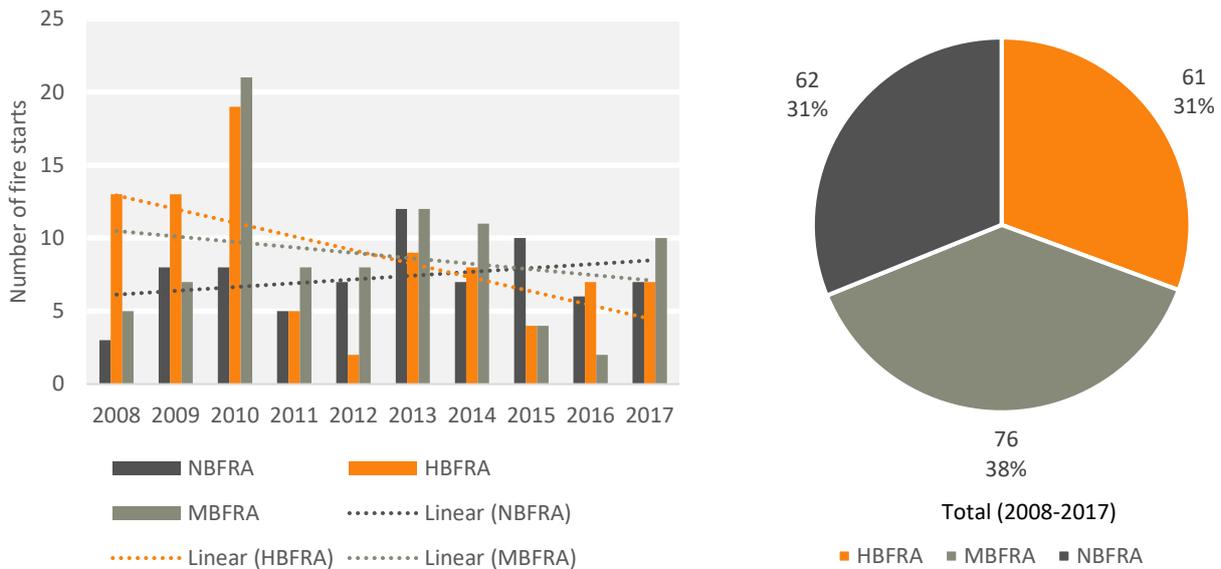


Figure 18: Total fire starts attributed to equipment across BFRA (2008–2017)

Figure 18 shows a declining trend in the number of fire starts due to equipment across MBFRA and HBFRA while NBFRA has shown a slight upward trend. The total number of fires in each BFRA is relatively evenly distributed with a slightly higher proportion in MBFRA which is unsurprising expected given the extent of the service area contained within the MBFRA (see Figure 5 and Figure 6).

SA Power Networks utilises information from historical fire starts to continually improve inspection and condition monitoring practices to ensure this downward trend continues. Achieving further reductions in equipment related fire starts will include the existing repair/replacement risk based approach but will also include targeted replacement programs (e.g. rod air gaps and current limiting arc horns prone to animal flashovers) and/or works identified through the cost benefit analysis model for bushfire risk mitigation (see Section 7.5.4.1.2).

The long term declining trend for fauna related causes is largely due to the reliability and resilience strategy through the installation of conductor line covers and animal guards (see Section 9.4) and similarly the declining trend in vegetation related fire starts since 2013 a result of the improved vegetation management strategy geared towards ensuring legislated clearances between vegetation and conductors are achieved (see Section 7.5.5).

4.9.1.3 Shock reports

Electric shocks to staff, contractors or the public from distribution network assets can occur through several causes including but not limited to:

- a poor neutral connection between the customer and the transformer supplying the circuit increasing the voltage in a home;
- damage to the neutral wire on a service connection can result in the energisation of household objects;
- overvoltage due to HV conductors contacting LV conductors (clashing); and
- direct contact with the conductor.

Electric shocks reported by a customer, contractor or staff have a legislated requirement to be reported to the Office of the Technical Regulator (OTR). In addition, shock reports to staff or contractors are logged within the internal risk and incident management system towards determining root causes and required actions as part of a continuous safety improvement process.

Figure 19 shows the total number of shock reports submitted to the OTR and a rate per length of network where the cause was found to be due to the distribution network (e.g. not on the customer side of the electricity meter).

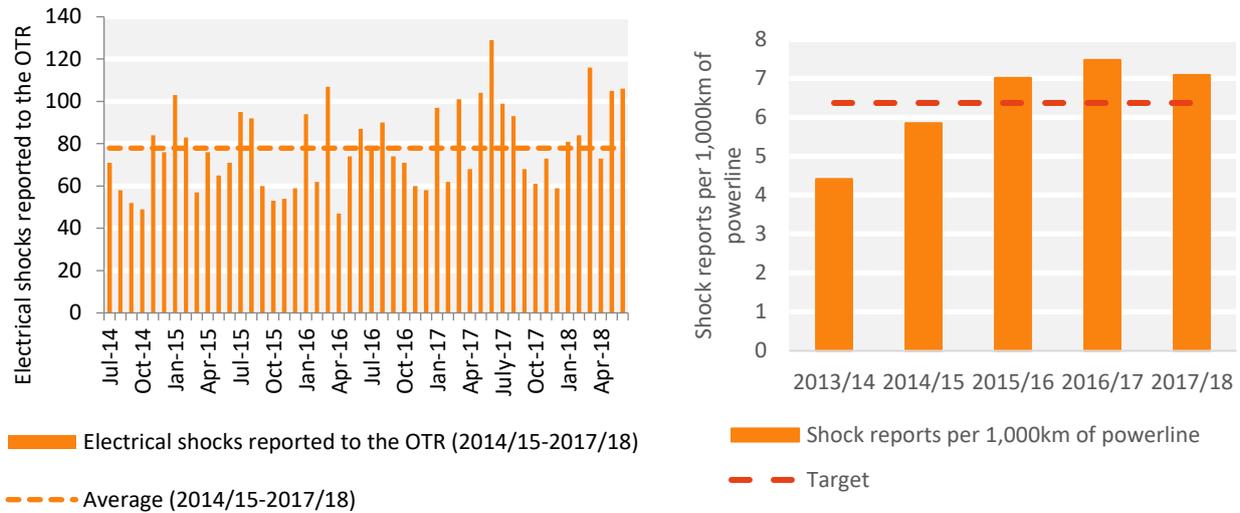


Figure 19: Total reported shocks and shock reports per 1,000km of powerline attributed to network assets

Figure 19 shows the number of shock reports has remained relatively stable, although the rate of shock reports attributed to network assets has increased notably since 2013-2014. While most shock reports are very minor and often observed as a ‘tingle’, the consequences can be severe and are investigated as a priority to confirm, locate and repair any faults or put in controls on the network.

In response to the increasing trend, a detailed analysis of shock report data found neutral problems to be the primary cause of shocks arising from the distribution network as shown in Figure 20.

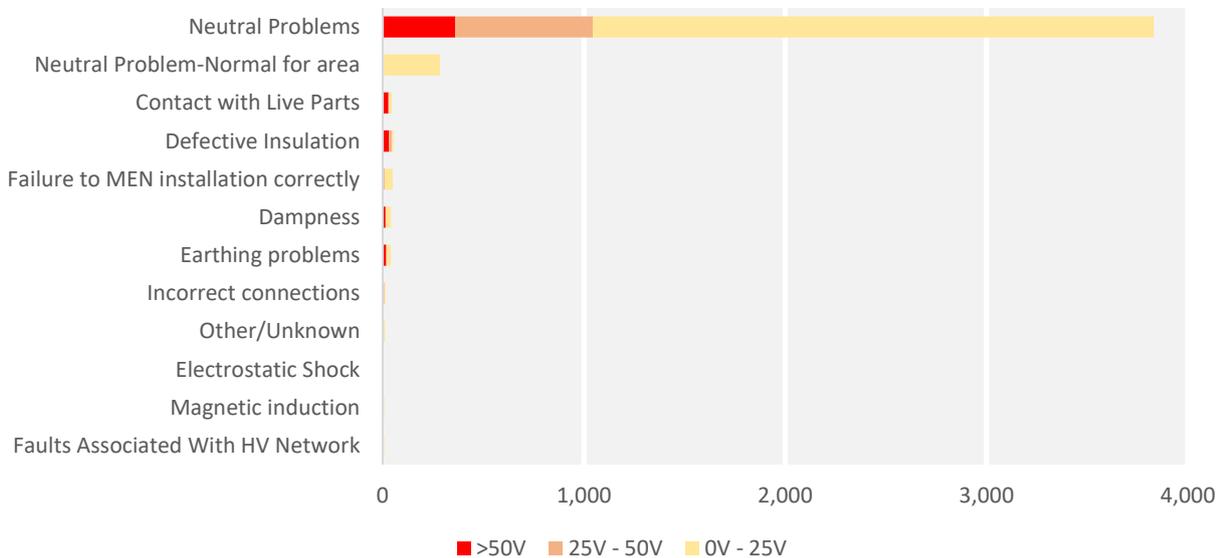


Figure 20: Network problem identified for shock report analysis (2000-2018)

Figure 20 shows the majority of neutral problems having a measured voltage of 0-25V. Notwithstanding, corrective works are undertaken to address network assets concluded to have contributed to the shock report.

The failure mode of neutral problems was investigated and found to be largely due to corrosion as shown in Figure 21.

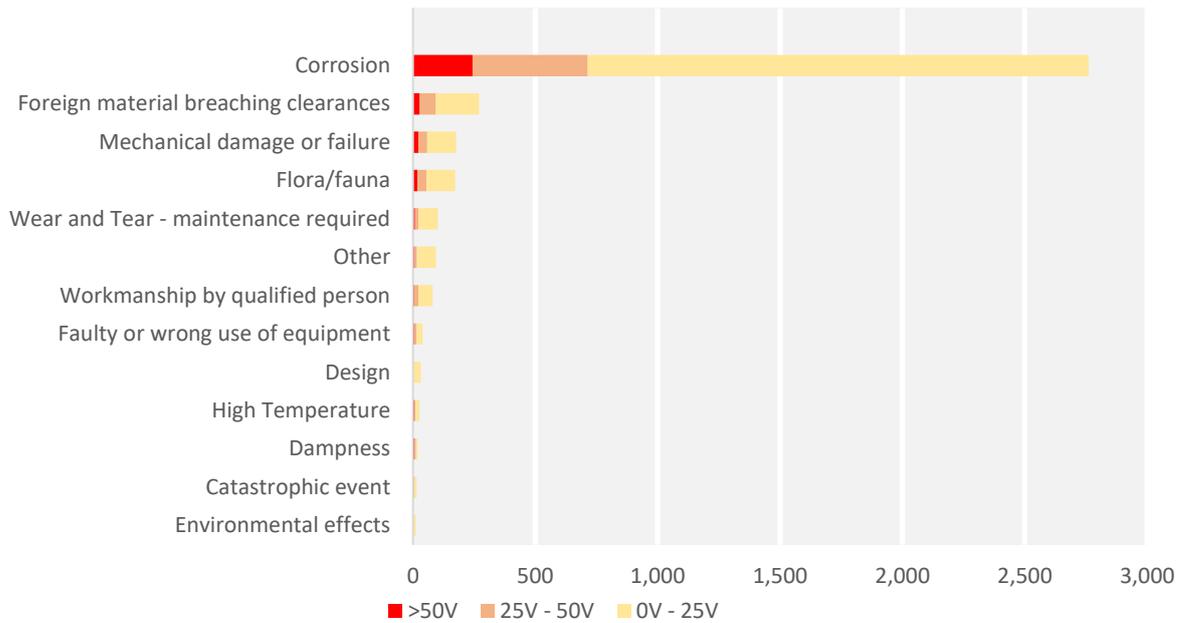


Figure 21: Failure mode of neutral lines

Figure 21 shows the majority of the neutral problems are a result of corrosion with other failure types representing around 25% of causes combined. The overhead aluminium neutral screen service lines have been identified as the most likely asset contributing to the increasing trend. Further investigations into the trending increase in shock reports and the required risk mitigation controls are ongoing during 2018.

4.9.1.4 Customer damage claims

Damage to customer property allegedly caused by prolonged or momentary fluctuation of high or low voltage can result in a damage claims being lodged with SA Power Networks; multiple claims can occur due to a single network event. This measure indicates how well the network maintains a continuous and stable quality of supply that does not adversely impact customers use of the network.

Figure 22 shows the number of customer damage claims which have been lodged because of electrical, property, appliance or fire damage for which payment has been accepted or considered. Data is only available from 2015-2016 onwards with claims categorised based on the largest cost component of the claim. Claims relating to damage that has been denied are not included.

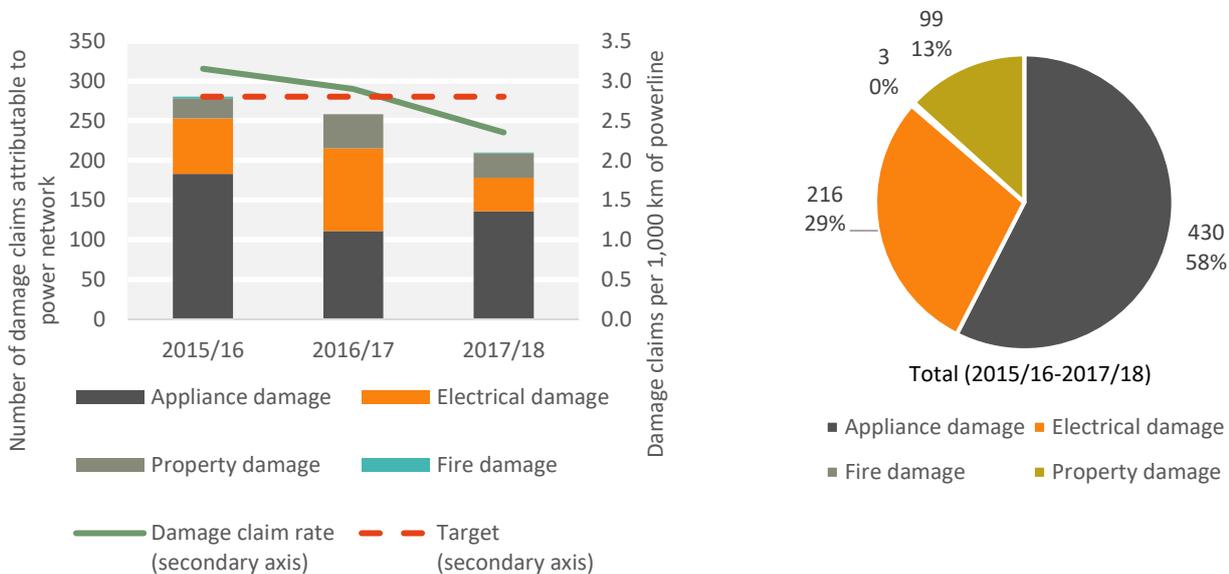


Figure 22: Customer damage claims (2015/16-2017/18)

Figure 22 shows a very low number of accepted claims annually given the length of the network and number of customers supplied with the claim rate trending downwards. A reduction in claim numbers from 2016-2017 to 2017-2018 was largely due to procedural changes including more stringent application of rulings in relation to customer PV system damage claims. Notwithstanding, each claim is assessed individually and any improvements relating to processes or assets undertaken as required. Over half of the accepted damage related claims from 2015-2016 resulted in appliance damage to customers property which accounts for approximately two-thirds of the annual claim costs incurred.

4.9.1.5 Fatal risk incidents

Protecting the public, our employees, contractors and the environment from the inherent risks of operating and maintaining a distribution network is SA Power Networks’ highest priority. SA Power Networks classifies serious safety incidents as shown in Table 7. A fatal risk incident is where a serious safety incident occurred and where person(s) were in the vicinity.

Table 7: Serious incident definitions within SA Power Networks

Event classification	Description	Definition	Additional factors
High potential incident	There was potential for a serious outcome	An event that could have resulted in death(s), multiple lost time injuries, permanent disability, intensive care or equivalent serious chronic, long term illness	Person(s) not in direct line of fire
Fatal risk incident (FRI)	Someone could have died	A fatal risk incident (FRI) is defined as one with credible potential to cause death(s) where preventative/control measures were absent or potentially deficient.	Person(s) were in the line of fire of the unmitigated risk/ energy
Significant incident	There was a serious outcome	An event that resulted in death(s), multiple lost time injuries, permanent disability, intensive care or equivalent serious chronic, long term illness	

The FRIs cover incidents involving both staff and contractors and is the measure of risk related to an event regardless of outcome and has been monitored since 2015; although detailed data of 2015 FRIs is unavailable. Figure 23 shows the historical trend of FRIs and the breakdown for power network related FRIs by root cause.

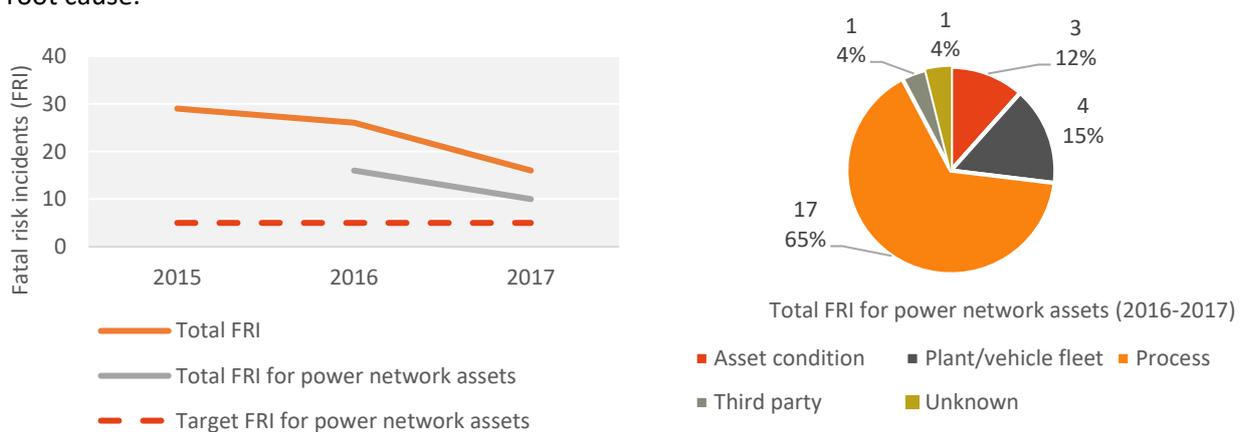


Figure 23: Fatal risks incidents – total vs FRI relating to power network (2015-2017) and FRI by cause (2016-2017)

Figure 23 shows a declining trend from 29 FRI in 2015 down to 16 FRI in 2017 with around half of these occurring through undertaking works on the power network. The remainder largely involve works undertaken on public lighting or plant/fleet at depots. The significant majority of FRI on the power network were concluded to be due to a process deficiency with a low number of FRI attributed to the asset

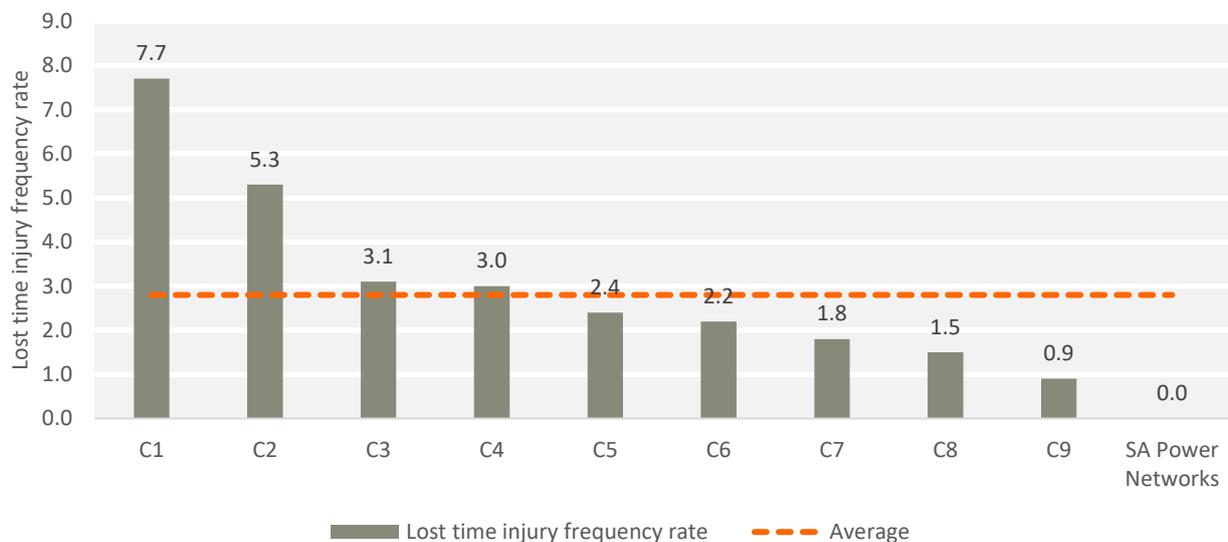
condition or asset failure. Given the small number of asset condition FRIs, there is no asset class trends with an overhead switch, a pole and service line condition failure accounting for the three FRI over the 2015-2017 period. Given the potential consequences of FRIs, each incident is investigated towards determining the underlying cause and whether existing systems or processes need to be modified to prevent future similar occurrences. This avoids complacency with the power network FRI target reducing over time aimed at driving continuous safety improvements.

4.9.1.6 Lost time injuries

A lost-time injury (LTI) is an injury suffered by a person who requires time off from work for one complete day/shift or more at any time after the injury. The measure of a LTI attributed to an asset is defined by unsafe interaction with an asset or substandard inspection/maintenance/operation of the asset leading to injury. SA Power Networks has a very low rate of LTIs. A single LTI in 2014 was a result of a SA Power Networks contractor work practice resulting in an electric shock; since then there has not been any recorded LTIs because of asset failure or asset lifecycle management on power network assets. All LTIs are investigated towards determining the root cause to avoid similar future occurrences with any identified improvements integrated into existing systems and processes.

Energy Networks Australia in partnership with the Australian Energy Council have previously undertaken safety benchmarking across the electricity distribution sector across several safety measures with the most recent comparison undertaken in 2015-2016.

Figure 24 shows the lost time injury frequency rate for SA Power Networks direct operational employees compared to other Australian distribution network service providers (DNSPs).



Source: Energy Networks Australia and Australian Energy Council, 2016, Occupational Health and Safety Report 2015-2016 – OHS Report 2015-2016 for SA Power Networks.

Figure 24: Lost time injury frequency rate comparison of SA Power Networks to other Australian DNSPs (2015-2016)

Figure 24 shows SA Power Networks most recent comparison showed a very high level of safety performance. While there have been no recent lost time injuries to staff or contractors attributable to power network assets or related asset management activities, high levels of safety training and risk controls are required to sustain this performance. The continual identification and reduction of safety hazards associated with the distribution network is ongoing through application of the Work Health and Safety Management System and SA Power Networks Safety Strategy 2020.

4.9.1.7 Medical treatment injuries

A medical treatment injury (MTI) is an injury suffered by a person which requires treatment beyond first aid, but does not require the employee to be absent from work for a complete day or shift after the injury.

Similar to lost time injuries, the measure of a MTI attributed to an asset is defined by unsafe interaction with an asset or substandard inspection/maintenance/operation of the asset leading to injury. A summary of the MTIs to staff or contractors attributed to the network assets are summarised in Table 8.

Table 8: Medical treatment injury events (2014 -2017)

Year	Medical treatment injury descriptions
2014	<ul style="list-style-type: none"> • 1 x vehicle struck by third party (Asset Inspection - distribution network) • 1 x twisted knee (Field Services - distribution network) • 1 x lower back injury (Field Services- distribution network)
2015	<ul style="list-style-type: none"> • None reported
2016	<ul style="list-style-type: none"> • 2 x muscular strain due to digging (Asset Inspection - distribution network) • 1 x dog bite (Asset Inspection - distribution network)
2017	<ul style="list-style-type: none"> • 1 x result of liquid fuse break (Field Services - distribution network) • 1 x recloser securing bolt worked free (Field Services - distribution network) • 1 x splinter in chest from cross arm (Field Services - distribution network)

Table 8 shows that MTIs are due to a variety of different reasons with no conclusive trends due to the very low number of events. All MTIs are investigated towards determining the root cause to avoid similar future occurrences with any identified improvements integrated into existing systems and processes.

4.9.1.8 Switching incidents

A switching program is the sequence of operations and actions involved in de-energising or energising network assets in response to unplanned outages, planned outages or other activity required on the network as part of day to day operations. A switching incident is any unintended occurrence arising while carrying out or intending to carry out a switching program. Figure 25 shows the historical trend of the switching incident frequency rate (SIFR) defined as the frequency of switching incidents per thousand switching programs).

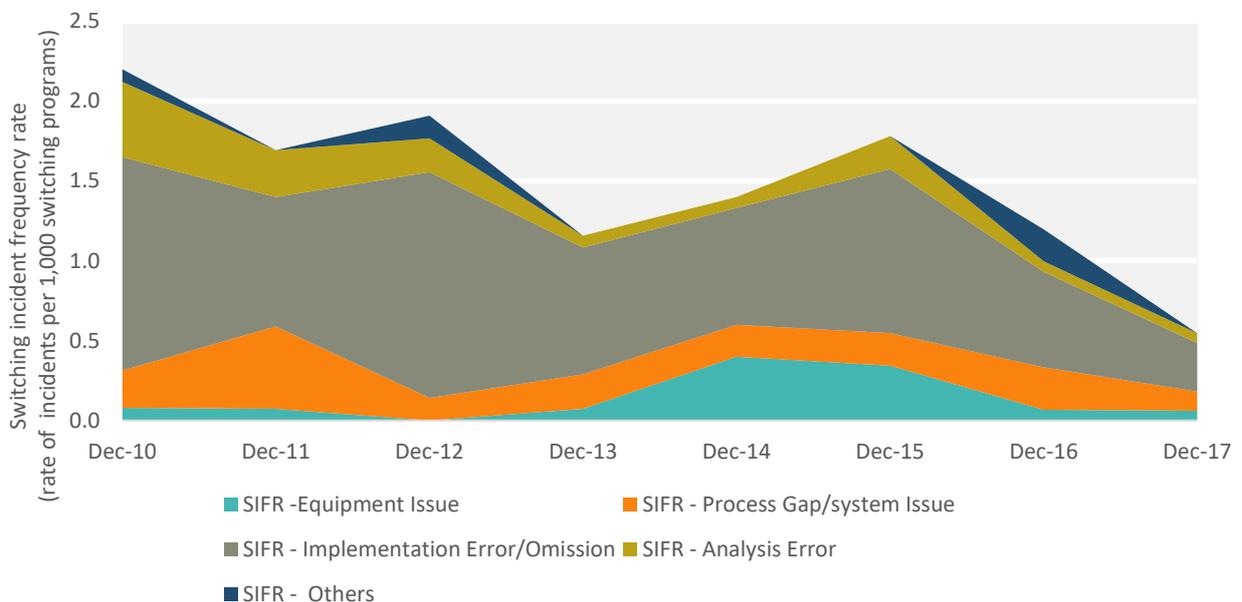


Figure 25: Switching incident frequency rate contribution by root cause (2010-2017)

Overall, the switching incident frequency rate has been decreasing since 2010 through ongoing training and awareness of staff in the development (analysis) and implementation of switching programs. The contribution of equipment issues to the total rate increased slightly during 2014-2015 but has since returned and stabilised in line with longer term levels; due to the low number of incidents, there is no asset specific trend. Every switching incident is subject to a detailed investigation to determine the root cause

with lessons learned communicated to staff and identified improvements integrated back into existing operational processes and procedures.

4.9.2 Customer experience

Customer experience levels of service measures relate to how quickly customer enquiries are responded to and the quality of the service provided by SA Power Networks through interactions with customers and stakeholders. The performance reflects how well SA Power Networks engages with customers, the speed and quality of responses and planned works undertaken by SA Power Networks for customers.

4.9.2.1 Customer Combined Satisfaction Index

The customer Combined Satisfaction Index (CSI) is an aggregate of customer satisfaction scores in relation to SA Power Networks communication from three categories: unplanned outages, planned outages and telephone enquiries. Customers are surveyed in the month following the customer contact with SA Power Networks to determine the levels of satisfaction with the information provided. The CSI is therefore a measure of customer satisfaction regarding the quality of information provided. The ratings range from 1–7, with a value of 7 being the maximum satisfaction score.

Figure 26 shows the historical trend for the CSI for the past five years.

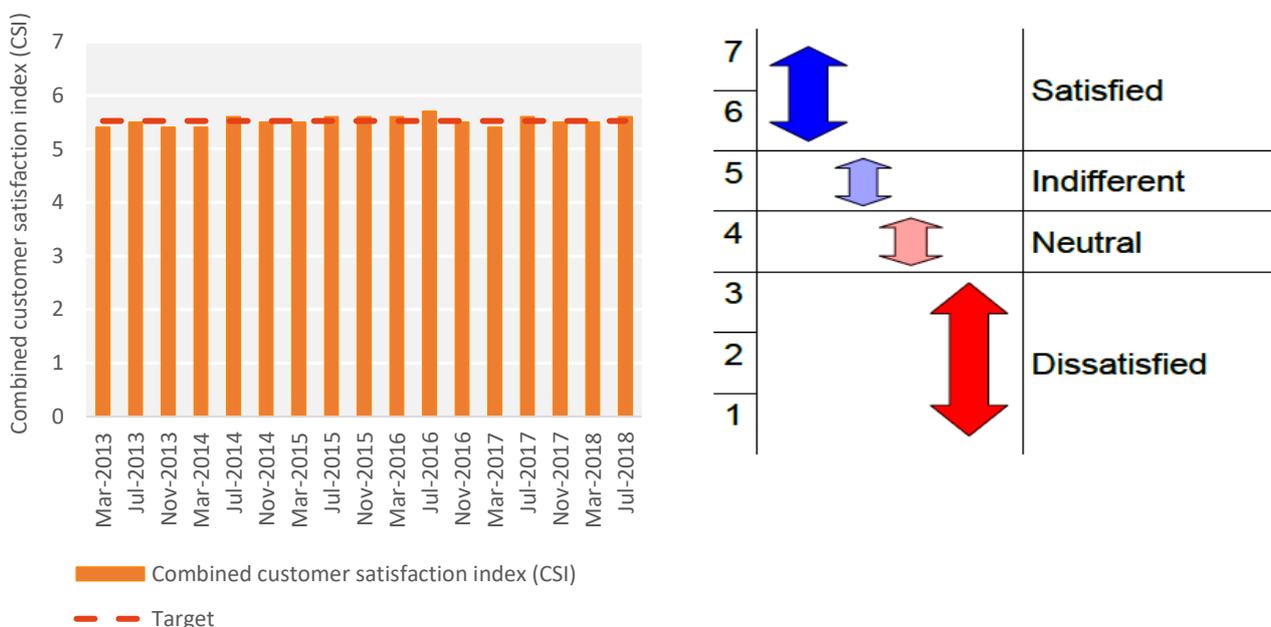


Figure 26: Combined customer satisfaction index (2013-2018)

Figure 26 shows that the CSI has been stable around 5.5 out of 7.0 for the past 5 years which is the current target on the 1-7 CSI scale. The state-wide blackout event in September 2016 and widespread damage caused by storms in December 2016 resulted in a slight decline to 5.4 in March 2017, which is the lowest CSI recorded since 2014. Some recovery was made in late 2017 and has stabilised into 2018.

4.9.2.2 Response to telephone calls and written enquiries

The responsiveness to telephone general enquiries and complaints provides an indication of appropriate levels of resourcing for responding to customer and stakeholder enquiries. The service standard targets, which are determined by ESCoSA, state the required response times by SA Power Networks to telephone and written enquiries from customers.

SA Power Networks has consistently achieved these targets in recent years with more than 400,000 calls in 2014–2015 and in 2015–2016. In the 2016–2017 year, which saw a record number of storm events and prolonged outages, and more than 600,000 calls, the service standard was still achieved.

4.9.2.3 Customer connections delivered to agreed date

SA Power Networks has a regulatory obligation to use best endeavours to connect a new supply address to an agreed date or within 6 days after the customer has met the necessary pre-conditions; GSL penalties apply when this is not achieved. While there is no regulatory standard, the reported performance suggests SA Power Networks consistently achieves a high level of compliance this measure.

4.9.2.4 Customer connections quotes provided on time

Under Section 5A of the National Electricity Rules (NER), a DNSP must use its best endeavours to make a negotiated connection offer to the connection applicant within 65 business days after the date of the application for the connection. Considering these obligations, and customer concerns regarding 65 days being too long (see Section 4.5), performance against a 20 business day target for residential connections and 65 business days for other larger connection types typically associated with commercial, industrial, government and greenfield real estate development, asset relocations and other complex connection types) which are typically more complex projects are proposed. Data available from 2016 indicates SA Power Networks achieves a high level of achievement for these measures.

4.9.2.5 Customer response and minor remediation works in response to quality of supply enquiries

As discussed in Section 3.2.1, small-scale PV uptake commenced around 2009 and has increased rapidly since 2010-2011 (see Section 7.3.4.1). The widespread customer PV systems exporting electricity into the distribution network is having an increasingly adverse impact on customers quality of electricity supply, which can be due to network capacity or capability constraints, with customers increasingly interfacing with SA Power Networks on quality of supply matters (see Section 4.9.6.1). The ability to respond to the increasing number of customer enquiries and to undertake any minor remediation work on the network (e.g. relocating the connection point of the customer service to the network) has become increasingly difficult as shown in Figure 27.

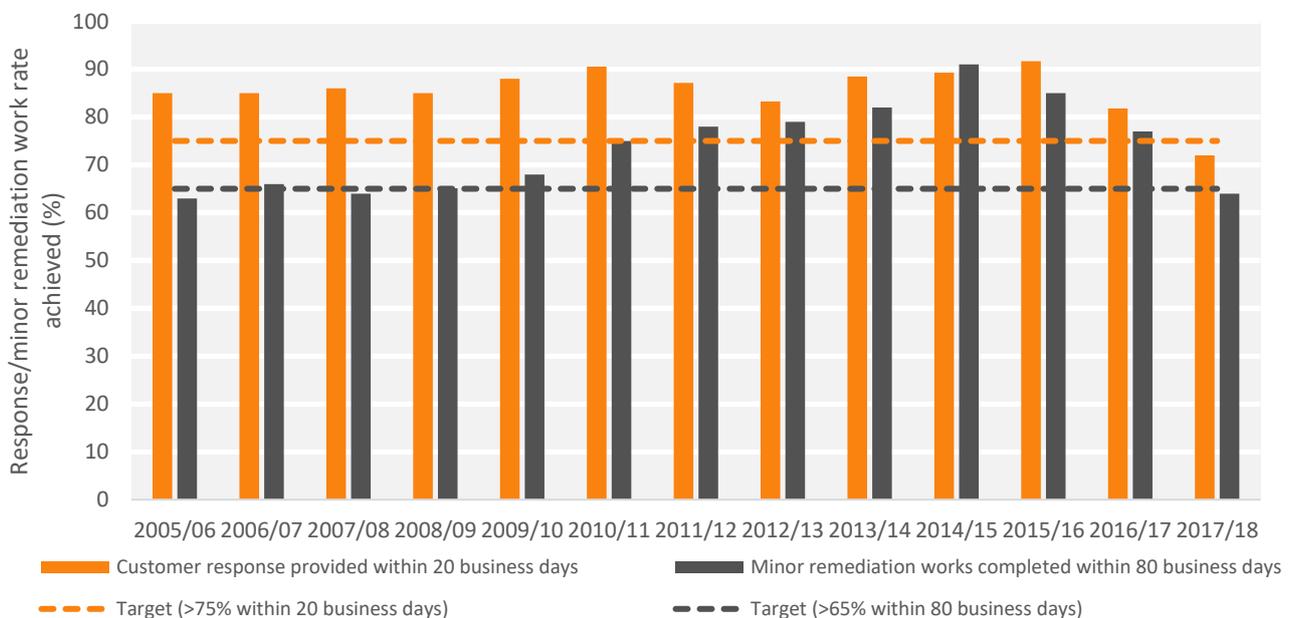


Figure 27: Customer response and minor remediation work completion rate for quality of supply enquiries

Figure 27 shows targets largely achieved historically with a sharp decline in performance since 2015-2016 with the targets not achieved during 2017-2018; largely attributed to numerous factors including increased customer enquiries due to exponential uptake of PV systems and the impact observed by customers (see Section 4.9.6.1) and resourcing issues to install loggers and undertake reactive remediation works.

4.9.2.6 Number of customers affected by >1 planned interruptions per week

This proposed measure is to determine the number of customers who are impacted by repeat interruptions exceeding 15 minutes within a 1 week period. This measure is geared towards ensuring customers do not receive a poor supply experience and drive improved planned works coordination in accordance with SA Power Networks planned power interruptions directive as outlined in the Network Directives Manual. This measure is not currently reported and so there is no historical information for discussion.

4.9.3 Reliability and resilience

The customer and stakeholder engagement program throughout 2017-2018 highlighted reliability of the network as the most important issue for customers; it is important to monitor performance to ensure the overall average reliability of the network is maintained. Underlying reliability measures are used to measure normalised network performance in relation to unplanned interruptions (e.g. the measures exclude the impact of major event days (MEDs)). The number of region based reliability and restoration time targets (subject to outcomes of SA Power Networks 2020 reliability standards review) is to help customers understand performance in their region and understand what to expect from SA Power Networks when unplanned outages occur.

4.9.3.1 Underlying network reliability

The two key measures for network reliability are the system average interruption duration index (SAIDI) and the system average interruption frequency index (SAIFI). They are measures of underlying performance for the average duration and frequency of unplanned interruptions and exclude the variable impact of significant weather events. The customer average interruption duration index (CAIDI) is directly determined by SAIDI and SAIFI and gives the average outage duration that any given customer would experience (e.g. an average restoration time). These network performance measures are regularly monitored throughout the year to monitor performance and allow resources to be focussed on any emerging trends (see Section 7.6.4).

Figure 28 shows the historical performance for SAIDI and SAIFI against current and previous ESCoSA regulatory targets for unplanned interruptions excluding MEDs.

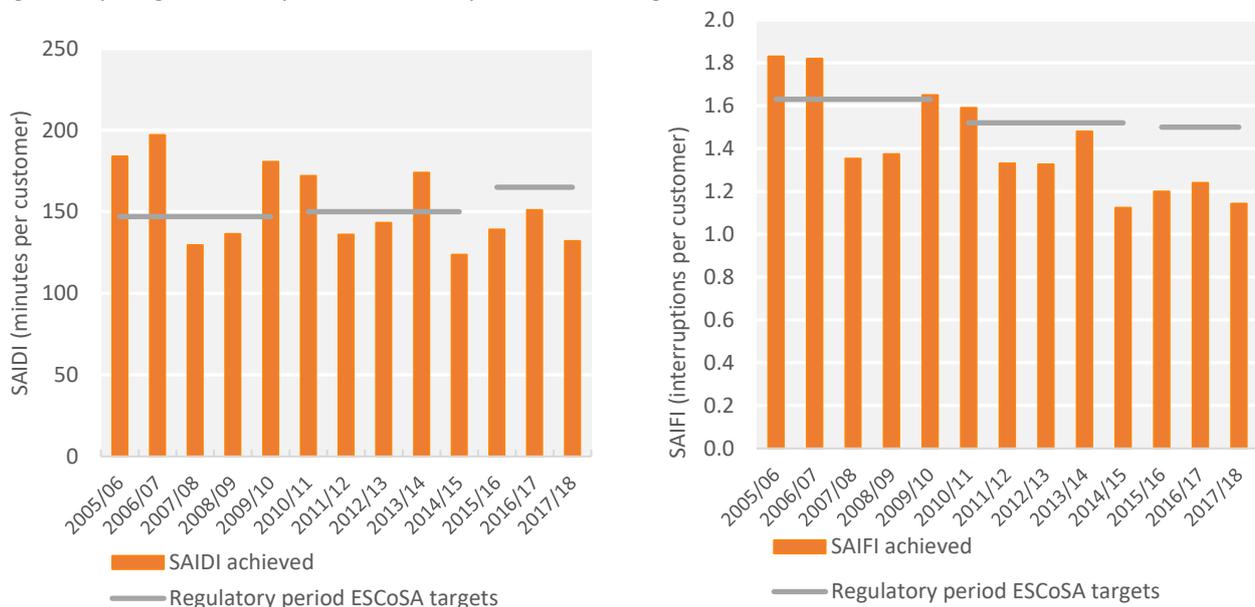


Figure 28: Historical SAIDI and SAIFI performance against ESCoSA regulatory targets (excluding MEDs)

Figure 28 shows the underlying reliability trend (excluding MEDs) is stable indicating that SA Power Networks has been successful in maintaining the average reliability performance at historical levels. SA

Power Networks has generally outperformed the ESCoSA SAIDI and SAIFI targets since 2005–2006. Following good performance in 2014–2015, both SAIDI and SAIFI figures have increased since but have been below the regulated targets. The SAIFI targets have been achieved on a more consistent basis than the SAIDI targets as SAIDI is significantly influenced by the variability of supply restoration times during storms.

The net impact of these SAIDI and SAIFI trends is an increase in CAIDI with the long-term trend shown in Figure 29.

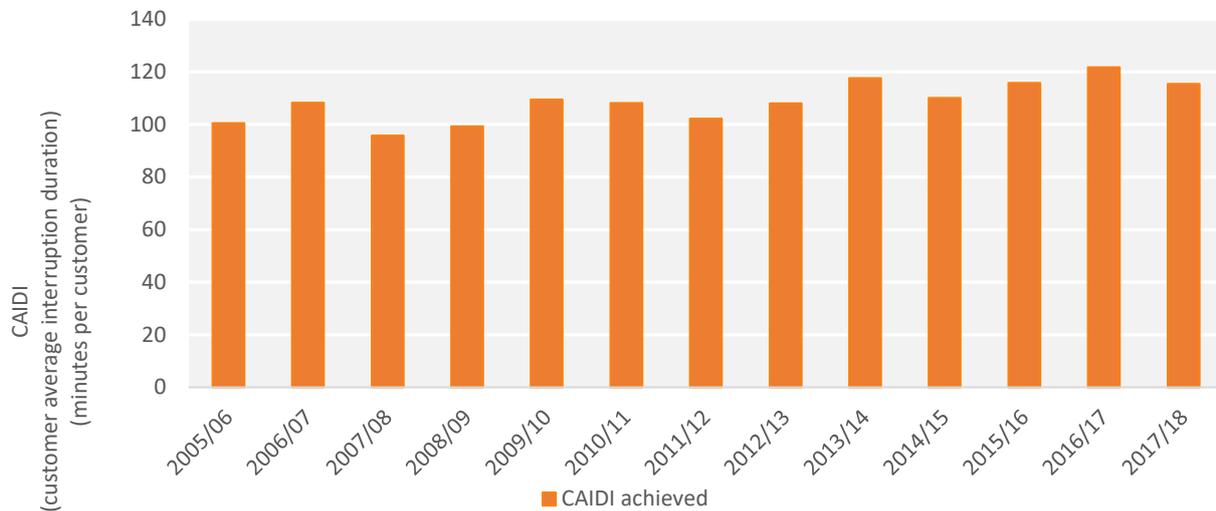


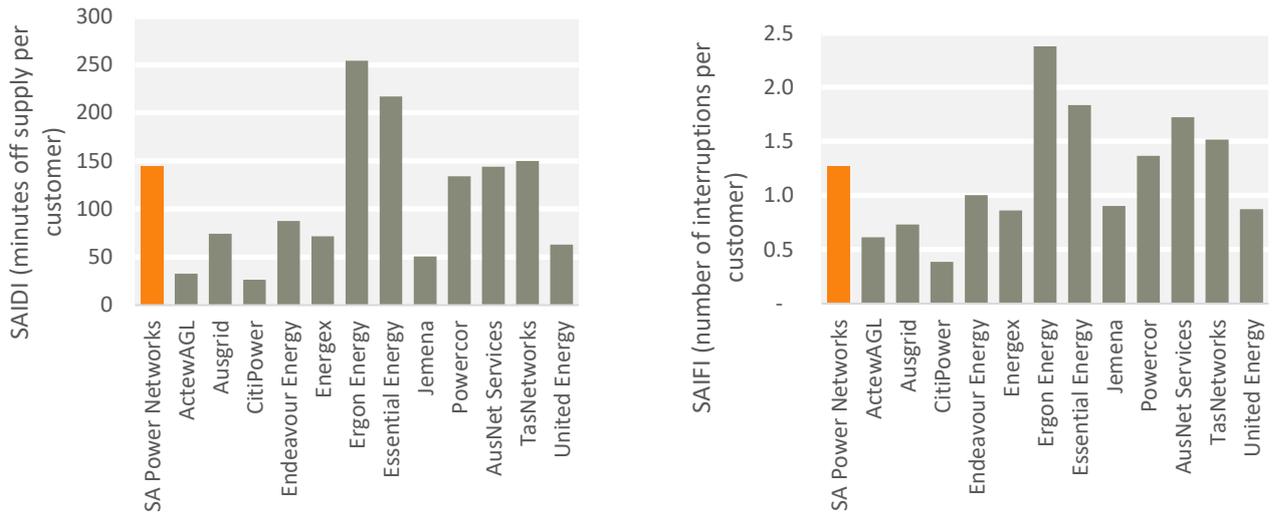
Figure 29: Historical CAIDI performance (excluding MEDs) (2005/06-2017/18)

To reduce the numbers of customers interrupted when a network fault occurs, SA Power Networks installs additional protective devices (automatic switches) that reduce the number of customers interrupted by a fault. Prior to installation of the additional protective devices, a larger number of customers would have been interrupted by a fault, with some of those customers being restored via manual switches once field crews had determined that the fault was not in the network section that supplied those customers (e.g. first stage of restoration). The crews would then locate the fault, repair it and restore supply to the remaining customers (e.g. second stage of restoration). With the installation of the additional protective device(s), customers who were restored in the first stage of restoration would not see a sustained interruption. However, customers restored in the second stage would still need the crews to locate the fault, repair it and then restore supply and would see a similar duration interruption to that without the additional protective devices. The combination of some customers no longer seeing an interruption and other customers seeing a similar duration outage, generally increases average restoration times (e.g. CAIDI).

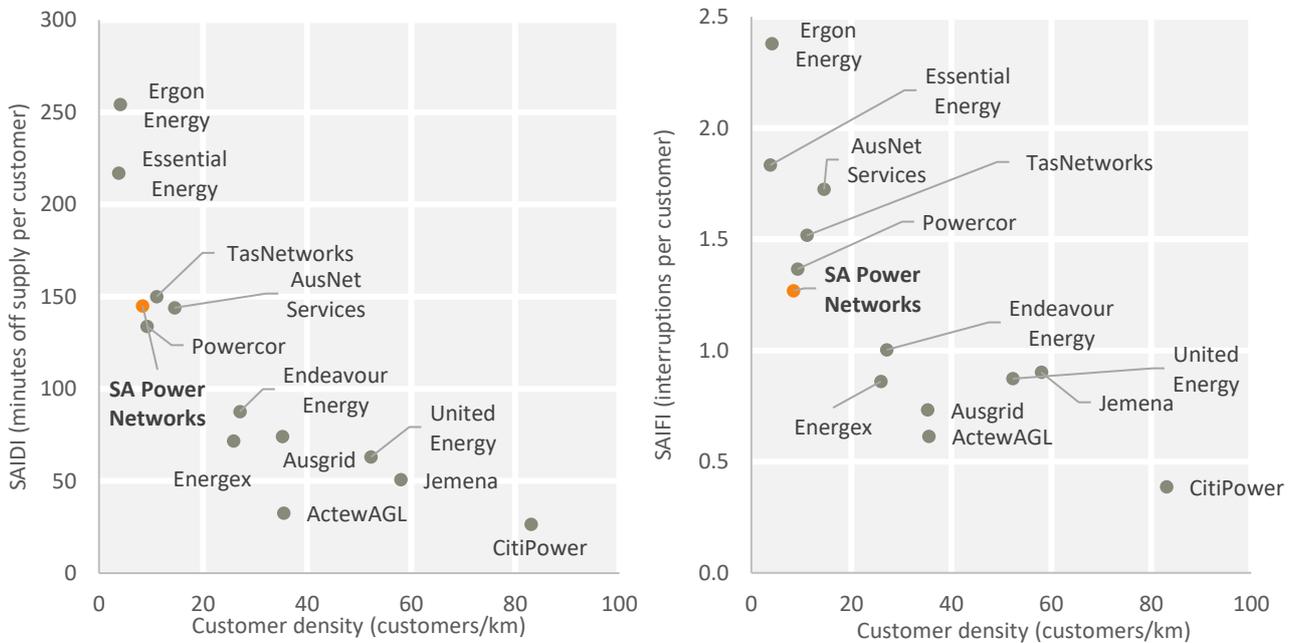
4.9.3.2 Reliability performance benchmarking

Historically, SA Power Networks' SAIDI reliability performance (measured in minutes off supply) has maintained the average reliability performance at historical levels.

Figure 30 and Figure 31 show a five year average comparison of SA Power Networks performance for both SAIDI and SAIFI to those of other DNSPs.



Source: AER Annual Benchmarking Report - Electricity Distribution Network Service Providers, November 2018
Figure 30: Australian distribution network service providers SAIDI and SAIFI (2013–2017) five year average comparison



Source: AER Annual Benchmarking Report - Electricity Distribution Network Service Providers, November 2018
Figure 31: Australian distribution network service providers SAIDI and SAIFI (2013–2017) comparison by customer density

Figure 30 and Figure 31 show that SA Power Networks average performance has outperformed most other utilities with a customer density <20 customers/km for both SAIDI and SAIFI (excluding the effects of MEDs, planned outages and transmission outages).

4.9.4 Environment

The impact of the distribution network on the environment is monitored to ensure legislative compliance and to minimise the environmental risks associated with the distribution network. The monitoring of pollutants such as oil and greenhouse gasses are undertaken to ensure environmental performance is maintained in line with past performance while measures for vegetation clearance are aimed at measuring performance of legislative clearance requirements while balancing the aesthetic appearance of the clearance to minimise the visual impact observed by customers and stakeholders.

4.9.4.1 Oil spills

The number of oil spills is an indication of the environmental impact of the distribution network assets and operational and maintenance activities. It is important to understand the quantity of such events and the causes to enable the risks to be appropriately managed.

Figure 32 shows the trend in reported oil spills that have required a clean-up due to the presence of fresh oil being identified on the ground; the data has been split by cause and contribution by major equipment types.

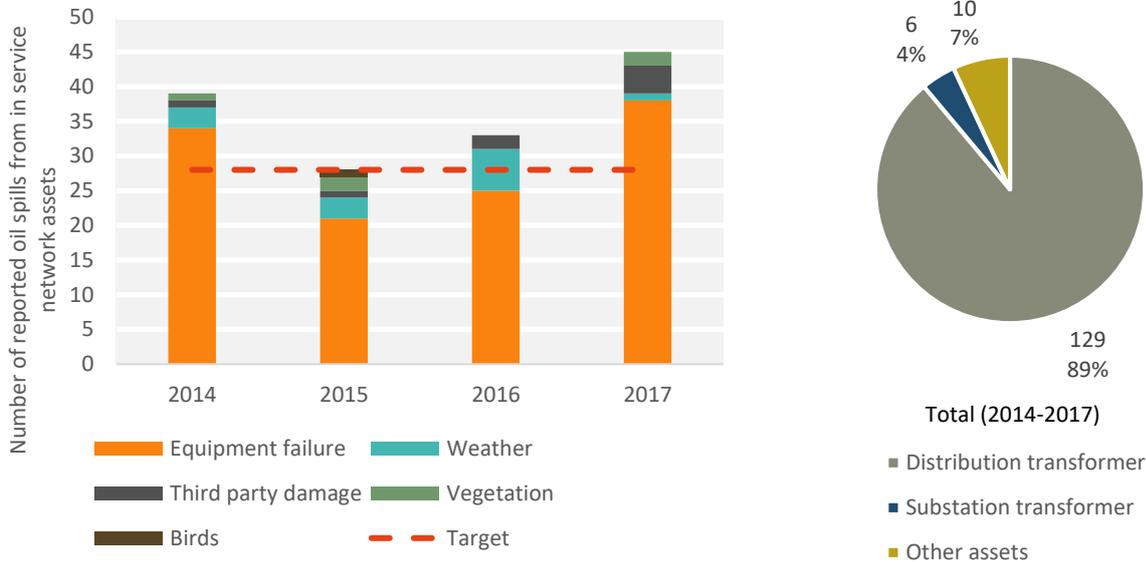


Figure 32: Reported number of oil spills for in service network assets by cause and asset type (2014 – 2017)

Figure 32 shows a relatively stable trend between 2014 and 2017 with equipment failure of distribution transformers accounting for most of the reported oil spills and an increasing trend. A target of 28 oil spills per annum equates to less than four oil spills per 10,000 distribution transformers per annum; a very low rate.

There have not been any historical oil spill targets being driven by legislative requirements or benchmarking; targets are based on outperforming historical performance towards achieving continuous improvement. The pending rollout of the Enablon risk and incident management systems in late 2018 (see Section 9.2.4) may result in a step change in the reported oil spills as the ability to capture environmental incidents becomes more streamlined. This may result in improved data and analytics to enable further analysis of asset age and make/model of the distribution transformers enabling the oil spill targets to be refined and a targeted distribution transformer replacement program to be considered.

4.9.4.2 Sulphur hexafluoride (SF₆) emissions

Sulphur hexafluoride gas (SF₆) is a potent greenhouse gas used as an HV insulator and arc interruption medium (because it is stable and inert) in network and substation gas-insulated switchgear including switching cubicles, overhead switchgear, circuit breakers and substation switchboards. Given its potency, leakage is actively detected and top ups are closely monitored and reported on annually.

The quantity of SF₆ emissions has reduced over the past four years as shown in Figure 33.

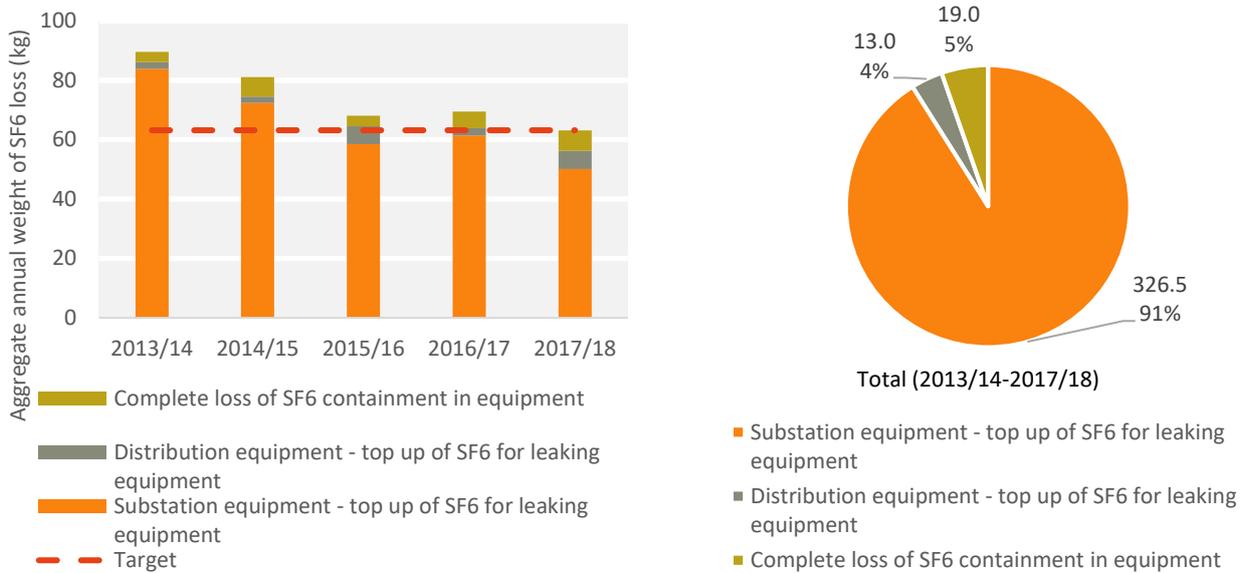


Figure 33: Aggregate annual weight of SF6 loss (kg) (2013/14 to 2017/18)

Figure 33 shows that substations have the largest contribution to overall SF₆ emissions, which is due to the relatively common use of SF₆ gas as an insulation and interrupting medium in 66kV and 33kV circuit breakers. Approximately 66% of outdoor 66kV & 33kV circuit breakers containing SF₆, however SF₆-free switchgear has been introduced in 2014 to mitigate the environmental and operational risks associated with using SF₆ gas breakers.

Principal contributors to annual substation SF₆ emissions in Figure 33 come from a small number of problematic (leak-prone) live tank 66kV circuit breakers and from the outdoor 66kV Gas Insulated Switchboard (GIS) at the Northfield Connection Point (see Section 8.4.4.1). Collectively, this leak-prone equipment has contributed the majority of substation SF₆ losses over the 2013-2018 period.

Experience has shown this equipment to be prone to corrosion across flanges and sealing O-rings, which has resulted in significant SF₆ leaks developing suddenly across many sites. A reactive approach has been taken to date in responding to these leaks leading to several forced outages for urgent top-ups; the difficulties in obtaining planned outages to replace leaks has led to a significant amount of SF₆ emissions. On average, there are around 2 of these circuit breakers that require a refurbishment intervention annually; in some cases, major refurbishment or complete replacement is required. The SF₆ loss trend is therefore largely influenced by the rate of SF₆ substation switchgear renewals.

There have not been any historical SF₆ targets being driven by legislative requirements or benchmarking; targets are based on outperforming historical performance towards achieving continuous improvement.

4.9.4.3 Compliance with Environment Protection Authority licences

SA Power Networks has an operating licence issued by the South Australian Environment Protection Authority (EPA) for the power generation facility located on Tinsmith Road, Brownlow on Kangaroo Island for providing emergency power supply. Annual air quality monitoring and mandatory National Pollutant Inventory reporting is undertaken to maintain EPA licence compliance for this network asset.

A 100% compliance has been achieved in all except one year since 2013-2014. In 2015-2016 SA Power Networks breached one of the 13 licence conditions. The nitrogen emissions measured on the 26th and 27th October 2015 exceeded the emissions targets stated in the licence. The cause of the breach was due to a combination of factors relating to the equipment configuration and settings on the urea dosing system attached to the generators which is used to control nitrogen oxide emissions. The cause of the breach was investigated and was rectified on 18th November 2015.

Other operating licenses including one trade waste licence from SA Water and two EPA licences for polychlorinated biphenyl (PCB) and other listed wastes at Marlestone and waste recycling depot at Angle Park are outside of the scope of this PAMP as they relate specifically to depots.

4.9.5 Aesthetics

4.9.5.1 Customer satisfaction with vegetation management

Proactive vegetation management activities ensure vegetation is appropriately managed near overhead powerlines to mitigate bushfire risk, ensure community safety, maintain reliability of the electricity supply and meet legislative compliance. The work is highly visible to the community; minimising the visual impact while meeting legislated requirements is therefore important.

The proportion of all customer complaints received by SA Power Networks compared to those directly related to vegetation trimming has reduced from 16% in 2013 to approximately 5.6% in 2017. This indicates that vegetation is now managed more in line with community expectations. SA Power Network's community engagement strategy includes informing the local community about the vegetation clearance program. Since 2016, between 200-500 residents/landholders across multiple council areas subject to upcoming vegetation clearance programs were surveyed to seek feedback on the level of satisfaction of the tree cutting and other related issues. While the survey responses to date are limited, it provides a good understanding of community sentiment and customer feedback on existing vegetation clearance practices and provides insights to enable continuous improvement.

The aggregated results for the overall satisfaction for vegetation clearance is shown in Figure 34.

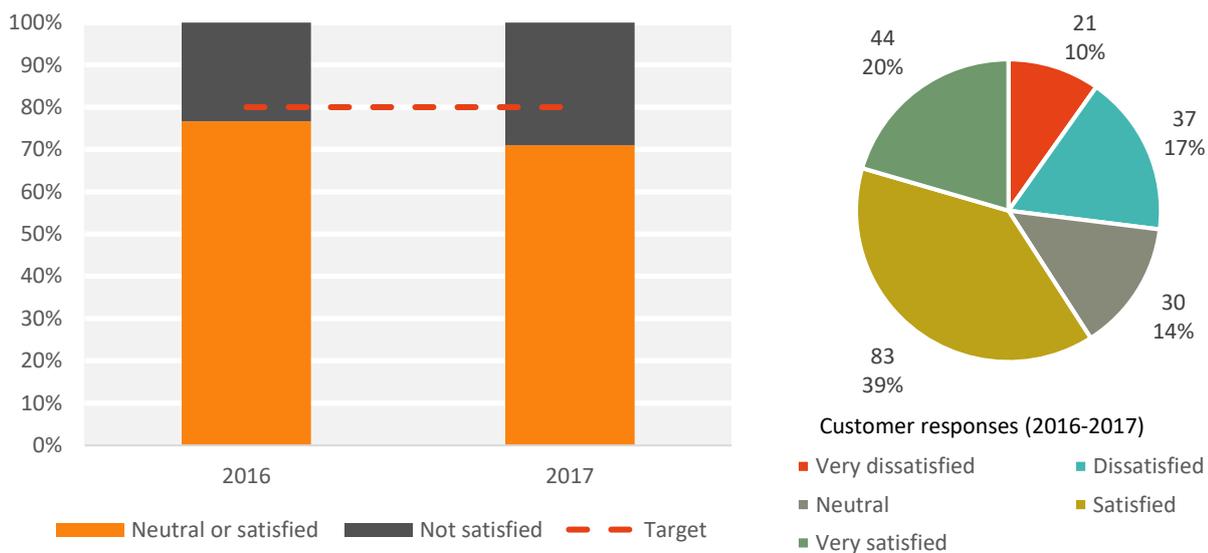


Figure 34: Customer satisfaction with vegetation clearance (2016-2017)

Figure 34 shows a relatively stable level of satisfaction over the limited timeframe for the targeted surveys with approximately 75% of customers surveyed either neutral or satisfied with the vegetation clearance. The future best endeavours target has been set at 80% aimed at improving on existing processes through opportunities identified through customer feedback.

4.9.6 Two-way grid

The customer and stakeholder engagement program throughout 2017-2018 indicated support for a moderate level of investment to adapt for the changing use of the network and support the uptake of new technologies. The uptake of solar PV systems by customers has increased significantly since around 2009–2010 and is forecast to continue to grow along with battery storages forecast to increase from around 2020 (see Section 7.3.3). As these systems become more economical for customers, there is an increasing expectation that the network should allow customers to both import and export energy. It is important to

measure the performance of the network to adapt to the increasing customer and stakeholder expectations of the network.

The challenges in meeting current and future two-way grid requirements include:

- the need for more advanced planning and demand forecasting methods;
- improving the monitoring and operation of the LV network to effectively manage the reliability and quality of supply due to distributed energy resources (DERs);
- ensuring that assets are appropriately sized with functionality to utilise the electricity produced from DERs where possible; and
- addressing network constraints that are restricting traders entering the market.

4.9.6.1 Number of PV related HV (over voltage) customer enquiries

A good quality of electricity supply can be defined as a steady supply voltage that stays within the prescribed range so that customers use is not noticeably impacted. A poor quality of supply is typically observed by customers as solar PV system inverters frequently switching off and/or lights flicking/dimming usually because of high voltages (also referred to as over voltage). In the absence of online monitoring, customer enquiries are an indicator of network quality of supply; noting that not all enquiries are because of the network and can be because of the customers' PV system operational settings. Notwithstanding, the customer enquiries lead to further investigation by SA Power Networks to determine the remedial actions required on the network (if any). The levels of service measures for responding to and remediating any network issues have been discussed previously (see Section 4.9.2.5).

The total quality of supply enquiries and average PV related HV customer enquiries per month are shown in Figure 35. The future targets are based on the rate of change of installed PV capacity in the network over the past five years applied to the historical average PV related HV customer enquiries.

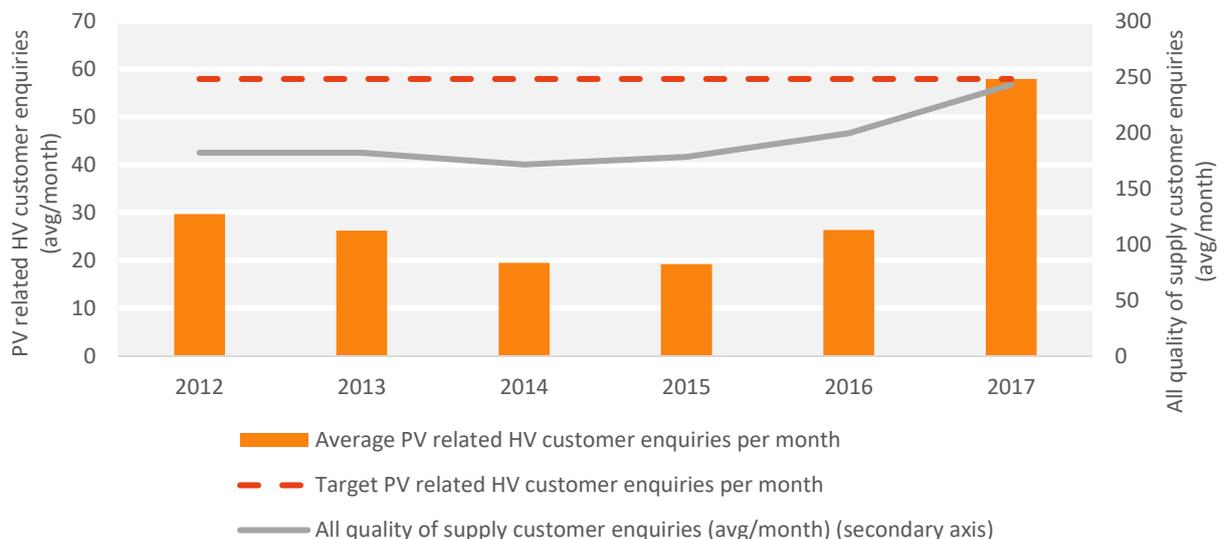


Figure 35: Solar photovoltaic-related customer enquiries (March 2012 – April 2018 inclusive)

Figure 35 shows that the total quality of supply enquiries and PV related high voltage enquiries are rapidly increasing. This is due to the increased uptake of solar PV systems (solar panels) which impact the ability to regulate voltages in the LV network. Under Australian Standard AS 60038-2012 Standard Voltages, the voltage for household customers must be maintained between 216 volts and 253 volts. The escalating number of PV related high voltage (over voltage) enquiries is impacting the performance to respond and undertake remediation works (see Section 4.9.2.5).

The complexity of the increased uptake of solar PV, battery storage systems and electric vehicles, introduce many challenges for meeting the levels of service targets for quality of supply. The strategies applied to manage the increasing quality of supply challenges are discussed further in Section 7.3.6.3.

4.9.6.2 Percentage of time voltage is compliant with Australian Standard voltage

This measure is a measurement of voltage within the network at defined locations. With limited monitoring currently on the LV network, additional monitoring and/or data from other sources of voltage monitoring (e.g. enabled smart meters) to enable voltage measurement and target setting is required. Increased monitoring of the network voltages is supported by customer feedback (see Section 4.5). There is no historical data currently available for discussion.

4.9.7 Communication and information

Communication and information is becoming increasingly important to customers, as acknowledged throughout the stakeholder engagement program throughout 2017-2018 and in the Customer Strategy. Providing accurate information for both planned and unplanned outages enables customers to be kept informed and builds customer confidence with SA Power Networks services. With the progression of mobile technology, customers are seeking access to accurate and timely information in different ways from SA Power Networks across numerous communication channels. SA Power Networks Customer Relations is developing a Channel Shift Strategy to address this.

4.9.7.1 Percentage of planned interruptions for which four business days' notice was provided

This is a measure of the number of instances where the minimum four business days' notice for planned interruptions to undertake operations, maintenance or asset replacement activities was required but not given. It is a measure of the customer experience for planned works to ensure customers are provided sufficient time to plan for upcoming outages. The target is based on the long-term average performance back to 2005-2006 and is shown in Figure 36.

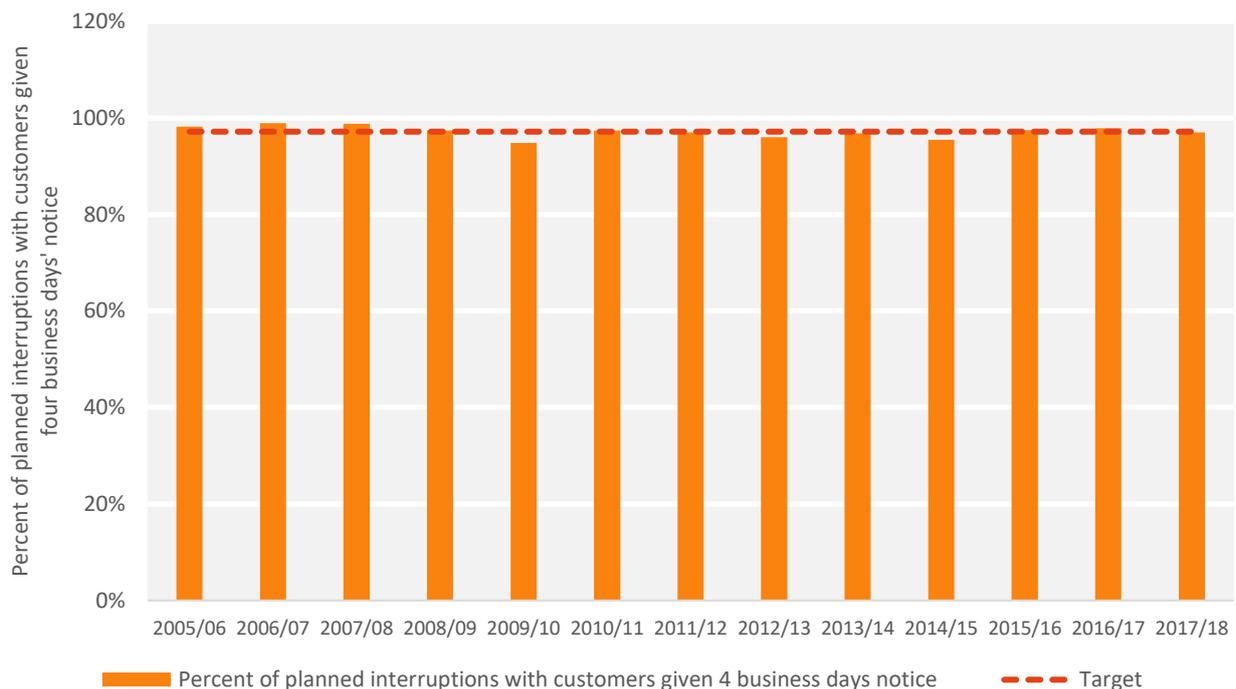


Figure 36: Percentage of customers accurately notified of planned outages (2005/06-2017/18)

Figure 36 shows a high level of achievement in providing four business days' notice to customers; a service standard required under the National Energy Retail Rules (NERR) and outlined in the SA Power Networks Customer Charter.

4.9.7.2 Number of planned interruptions completed within specified timeframe

This is a measure of the number of occasions where the specified timeframe for planned outages for undertaking planned works on the network was achieved. It is a measure of the accuracy of information provided to customers for both the timing and duration of a planned outage for undertaking planned works on network assets. This measure is not currently reported and so there is no historical information for discussion.

4.9.7.3 Number of planned jobs cancelled without four business days' notice

This is a measure of the number of planned jobs requiring an interruption to supply that, for whatever reason, were cancelled and impacted customers were not provided with four business days' notice. While a low number of customer complaints are received regarding no notification of cancelled jobs; the actual performance of this measure is not actively measured. This measure is not currently reported and so there is no historical information for discussion.

4.9.7.4 Customer notification of unplanned planned outages by SMS

Customers rely on many channels to gain information from SA Power Networks. The SA Power Networks reliability standards review (Essential Services Commission of South Australia, 2018) acknowledged customers seek timely information for unplanned outages and have proposed SMS communication as a new service standard. This measure (subject to outcomes of SA Power Networks 2020 reliability standards review) will reflect that to be used for regulatory reporting. This measure is not currently reported and so there is no historical information for discussion.

4.9.7.5 Overall customer satisfaction with Corporate website

Customers and stakeholders have indicated the Corporate SA Power Network's difficult site is difficult to navigate to find relevant information (see Section 4.5). A Corporate website upgrade is planned for late 2018 that will include the ability for monitoring customer satisfaction regarding the content of information accessed by customers and stakeholders. This measure is not currently reported and so there is no historical information for discussion.

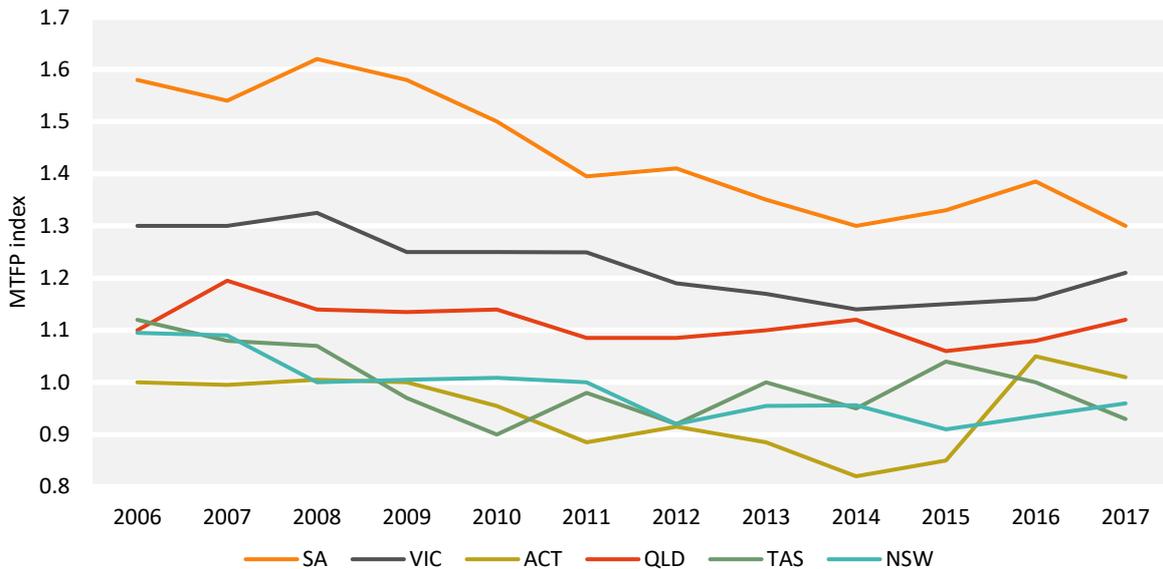
4.9.8 Efficiency

SA Power Networks manage life-cycle costs and optimise asset management outcomes for the long term. Effective asset management strategies require that both physical and non-physical assets are holistically managed and operated. The stakeholder engagement program throughout 2017-2018 highlighted concerns over price and undertaking expenditure prudently and efficiently. Monitoring efficiency and the rate of asset replacements enables SA Power Networks to demonstrate efficient asset management practices.

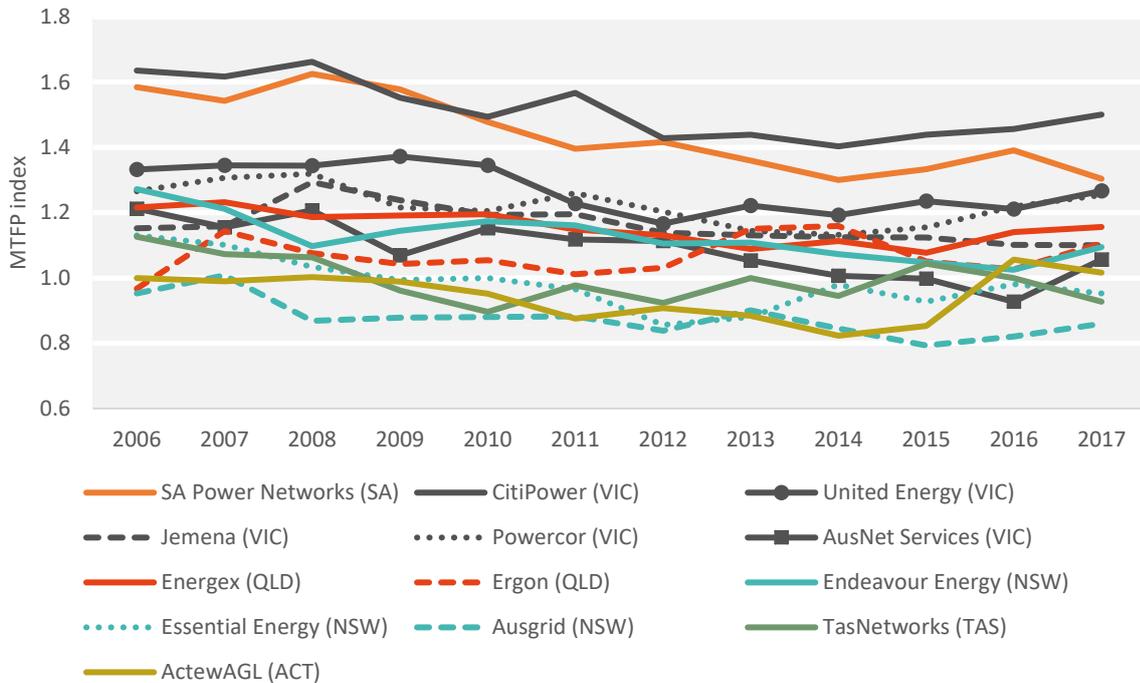
4.9.8.1 Efficiency benchmarking

Each year, the AER undertakes annual benchmarking of electricity DNSPs. Benchmarking provides consumers with useful information about the relative efficiency of the electricity networks they rely on, helping them to better understand the performance of their networks, the drivers of network productivity and the charges that can account for up to 30-40% of their electricity bills (AER, 2018).

The multilateral total factor productivity (MTFP) is the primary technique used to measure and compare the relative productivity and efficiency of jurisdictions and individual DNSPs under the NER reporting requirement. It is a productivity index calculated using several reported DNSP input and output variables; the higher the value the better the performance. The results of this benchmarking by jurisdiction are shown in Figure 37 while Figure 38 shows performance by DNSP.



Source: AER Annual Benchmarking Report - Electricity Distribution Network Service Providers, November 2018
Figure 37: Multilateral total factor productivity by jurisdiction



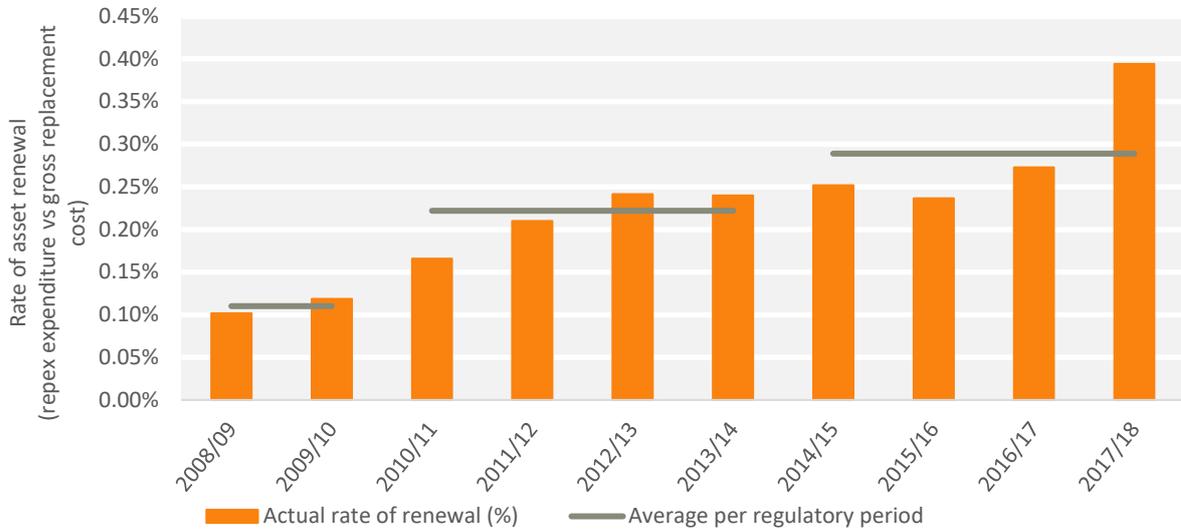
Source: AER Annual Benchmarking Report - Electricity Distribution Network Service Providers, November 2018
Figure 38: Multilateral total factor productivity by DNSP

Figure 37 shows SA Power Networks consistently being the best performer at an aggregated state level while Figure 38 shows SA Power Networks consistently amongst the top 2-3 at an individual DNSP level. SA Power Networks MTFP declined slightly in 2017, although it retained its ranking of second in terms of productivity levels. This reduction in MTFP was in part due to a number of abnormal weather events that contributed to higher than normal emergency response costs and guaranteed service levels (GSL) payments to customers in 2017 (AER, 2018).

4.9.8.2 Rate of average annual asset renewal

The rate of average asset renewal is defined as the total refurbishment or replacement expenditure undertaken on the regulated asset base as a percentage of the estimated regulated asset base replacement cost. While the targets are largely set by regulatory period allowance, Figure 39 shows the change in

average asset renewal (e.g. refurbishment or replacement) over time. The rate of average asset replacement has been determined through comparing the historical annual renewal expenditure (\$, real) relative to the estimated asset replacement cost.



Source: AER Category Analysis Regulatory Information Notice 2008-2009 to 2017-2018, SA Power Networks (renewal expenditure) and AER Repex Model (replacement cost)

Figure 39: Rate of average annual asset renewal (2008/09-2017/18)

Figure 39 shows over a doubling of the rate of renewal from the 2006-2010 regulatory period to the 2011-2015 regulatory period. A marginal increase occurred from 2011-2015 to 2016-2020 regulatory periods. The average rate of renewal in the current regulatory period means assets would be required to last 350 years if that rate of renewal was to be maintained. This is clearly unrealistic and unsustainable and so the rate of renewal will need to increase as the asset base continues to age and deteriorate is currently levels of service and risk are to be maintained.

4.10 Levels of service, performance measures and targets

Table 9 shows the recent historical, current and future levels of service for a total of 33 measures that SA Power Networks delivers to customers and stakeholders.

Table 9: SA Power Networks' levels of service

Performance measure	Actual performance				Performance target									
	FY 14	FY 15	FY 16	FY 17	FY 18	FY 19	FY 20	FY 21	FY 22	FY 23	FY 24	FY 25	FY 26–30	
Safety — provide a safe network service														
Pre-fire danger season vegetation clearance compliance with legislated requirements (%) ¹	0.5	1.4	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	
Number of fire starts per 1,000km of powerline ²	0.89	0.60	0.57	0.51	0.88	0.69	0.69	0.69	0.69	0.69	0.69	0.69	0.69	
Number of shock reports per 1,000 km powerline ²	4.4	5.8	7.0	7.5	7.1	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	
Number of customer damage claims per 1,000 km of powerline attributable to network assets and/or asset management activities ²	8.1	4.4	3.2	2.9	2.3	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.0	
Fatal risk incidents for staff and contractors attributable to network assets and/or asset management activities ¹	N/a	N/a	16	11	8	8	8	5	5	5	5	5	3	
Number of staff and contractors lost time injuries per year attributable to network assets and/or asset management activities ¹	1	0	0	0	0	0	0	0	0	0	0	0	0	
Number of staff and contractor medical treatment injuries per year attributable to network	3	0	3	3	0	0	0	0	0	0	0	0	0	

¹ FY = SA Power Networks financial year from January to December.

² FY = SA Power Networks regulatory year from July to June.

Performance measure	Actual performance				Performance target									
	FY 14	FY 15	FY 16	FY 17	FY 18	FY 19	FY 20	FY 21	FY 22	FY 23	FY 24	FY 25	FY 26–30	
assets and/or asset management activities ¹														
Switching incidents (number per 1,000 switching programs) ¹	1.4	1.8	1.2	0.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	
Customer experience — deliver energy services that enhance customer experience														
Customer Combined Satisfaction Index (CSI) (1-7 scale) ³	5.49	5.57	5.61	5.53	5.50	5.50	5.50	5.50	5.50	5.50	5.50	5.50	5.50	
Response to telephone calls within 30 seconds (%) ^{2,4}	88	91	87	87	90	85	85	85	85	85	85	85	85	
Response to written enquiries within 5 business days (%) ^{2,4}	98	99	99	99	98	95	95	95	95	95	95	95	95	
Customer connections delivered to agreed date (%) ²	98.9	98.8	98.3	98.0	98.0	98.0	98.0	98.0	98.0	98.0	98.0	98.0	98.0	
Minor connection quotes (primarily residential) provided within 20 business days (%) ¹	N/a	N/a	75	79	80	80	80	80	80	80	80	80	80	
Other connection quotes provided within 65 business days (%) ¹	N/a	N/a	94	94	92	92	92	92	92	92	92	92	92	
Responses to quality of supply enquiries within 20 business days (%) ²	88.5	89.3	91.7	81.9	72.0	75	75	75	75	75	75	75	75	
Completing minor remedial works for quality of supply enquiries within 80 business days (%) ²	82.0	91.0	85.0	77.0	64.0	65	65	65	65	65	65	65	65	

³ FY = Data collected from November to October

⁴ 2026 – 2030 targets subject to future ESCoSA reviews.

Performance measure	Actual performance				Performance target									
	FY 14	FY 15	FY 16	FY 17	FY 18	FY 19	FY 20	FY 21	FY 22	FY 23	FY 24	FY 25	FY 26–30	
Number of customers affected by >1 (frequent) planned interruptions per week ¹	N/a	N/a	N/a	N/a	New measure that requires further business system and reporting development (see Section 11).									
Reliability and resilience — deliver a reliable and resilient network service														
Average number of minutes per year that a customer is without electricity for all unplanned interruptions (excluding MEDs) ^{2,4}	174	124	139	151	132	168	168	Subject to ESCOSA Service Standard Framework Review						
Average number of times per year that a customer is without electricity for all unplanned interruptions (excluding MEDs) ^{2,4}	1.48	1.12	1.2	1.24	1.14	1.54	1.54	Subject to ESCOSA Service Standard Framework Review						
Region based reliability targets achieved (%) ²	TBC	TBC	TBC	TBC	TBC	TBC	TBC	Subject to ESCOSA Service Standard Framework Review						
Region based restoration targets achieved (%) ²	TBC	TBC	TBC	TBC	TBC	TBC	TBC	Subject to ESCOSA Service Standard Framework Review						
Environment — provide an environmentally sustainable network service														
Number of oil spills per year from in service network assets ¹	39	28	33	45	28	28	28	28	28	28	28	28	28	
Quantity of sulphur hexafluoride, (SF₆) (a greenhouse gas) emissions attributable to network assets (kg) ²	90	81	68	69	63	63	63	63	63	63	63	63	63	
Environment Protection Authority licence compliance (%) ²	100%	100%	92%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	
Aesthetics — provide an aesthetically pleasing network														
Customers satisfied with vegetation clearance (%) ¹	N/a	N/a	76.6	70.4	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	85.0	

Performance measure	Actual performance				Performance target									
	FY 14	FY 15	FY 16	FY 17	FY 18	FY 19	FY 20	FY 21	FY 22	FY 23	FY 24	FY 25	FY 26–30	
Two-way grid — provide a network service that enables customers to both import and export their energy														
Average number of high voltage (over voltage) enquiries per month related to PV systems ¹	20	19	26	58	70	85	100	100	100	80	60	40	20	
Voltage compliance with Australian Standard voltage (% of time) ^{TBA}	N/a	N/a	N/a	N/a	New measure that requires investment in voltage monitoring (see Section 9.5).									
Communication and information — communicate and make information available														
Planned interruptions for which four business days’ notice provided (%) ²	97.2	95.5	97.4	97.8	97.0	97.0	97.0	97.0	97.0	97.0	97.0	97.0	97.0	
Planned interruptions completed within specified timeframe (%) ¹	N/a	N/a	N/a	N/a	New measures that require further business system and reporting development (see Section 11).									
Number of planned interruptions cancelled without four business days’ notice ¹	N/a	N/a	N/a	N/a										
Unplanned outages for which customers were notified with information via SMS (%) ²	N/a	N/a	N/a	N/a	N/a	N/a	N/a	Subject to ESCOSA Service Standard Framework Review						
Overall customer satisfaction with Corporate website ^{TBA}	N/a	N/a	N/a	N/a	New measure that requires further business system and reporting development (see Section 11).									
Efficiency — continuously seek out and deliver network service efficiencies														
Relative performance efficiency rank compared to other Australian distributors ²	Upper quartile	Upper quartile	Upper quartile	Upper quartile	Upper quartile	Upper quartile	Upper quartile	Upper quartile	Upper quartile	Upper quartile	Upper quartile	Upper quartile	Upper quartile	
Average annual asset renewal rate (%) ²	0.24	0.25	0.24	0.27	0.39	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.30	

4.11 Managing levels of service

Capital and operating programs of work are delivered as ongoing programs to manage levels of service and risk, with targeted programs developed as required. Table 10 links the more notable current or recently completed programs of work to the level of service category that the program primarily supports.

Table 10: Current and recently completed works programs

Category	Program of work
Safety	<ul style="list-style-type: none"> Continuing investment in risk based strategies to address the community and workforce safety risks posed by a range of older substation and line assets. Investigating the increase in shock reports and consider the value of proactive monitoring and replacements of old aluminium neutral wires on service mains. Providing primary and backup protection at high risk substations to meet legislative requirements. Upgrading substation security lighting and fencing. Continuing management of vegetation clearance to ensure compliance in bushfire risk areas. Continuing pre-bushfire patrols of networks in bushfire risk areas, prioritised repair/replacement of defective assets in such areas and having a robust bushfire risk management plan in place. Continued investment in community education to improve safety awareness around powerlines. Developing a cost benefit analysis model for bushfire risk assessment. Extending SCADA to switches on the boundary of high bushfire risk areas to provide timelier disconnection/reconnection during extreme fire danger conditions and eliminate the need for staff to manually access and operate. Safety emergency contact information quickly accessible via the SA Power networks website.
Customer experience	<ul style="list-style-type: none"> Enhancing customer communications during planned and unplanned outages. Transferring the emergency radio communications for field crews from a proprietary system to the South Australian Government Radio Network to provide highly reliable communications between field crews and network control employees during network outages. Further developing customer self-service options by providing a ‘single view’ of outage information and energy use, 24/7, across multiple communication channels. Implementing systems to allow a single view of the customer to enable tailored customer service. Enhanced large embedded generator connection process to support growth in market.
Reliability and resilience	<ul style="list-style-type: none"> Undertaking several programs within the CBD to minimise interruption duration associated with cable faults including increased monitoring, control, resourcing, inspecting and finalising management of line fault indicators, prioritising a list of cables to be replaced and installing several SCADA monitored and feeder automation compatible devices to minimise customer impacts associated with CBD cable faults. Continuing targeted investment in hardening sections of the network most vulnerable to lightning and storms during MEDs. Installing feeder automation on selected urban feeders to minimise interruptions to urban customers. Installing a second cable to supply Kangaroo Island to provide security of supply against any prolonged outages on the pre-existing cable.

Category	Program of work
	<ul style="list-style-type: none"> • Commencing MED resilience for low reliability feeders. • The utilisation of lightning strike information for supply restoration. • Ongoing investment in renewal of aged, poor condition and high risk electrical assets to maintain underlying average network reliability. • Continuing investment in the use of mobile plant (substations, transformers and power generators) to minimise service interruptions required for planned maintenance or resulting from equipment failure. • Trial to test the value of mobile, localised battery storage near Cape Jervis to provide ‘peak lopping’ in demand to assist management of the local LV network to defer a substation transformer upgrade.
Environment	<ul style="list-style-type: none"> • Continuing the program of substation oil containment until all sites have compliant oil containment systems installed. • Ongoing management of oil containing polychlorinated biphenyls from network assets. • Ongoing programs for removal of asbestos contained in network assets. • Using dedicated environmental resources for construction programs. • Improving the vegetation management program to meet legislative requirements while managing community expectations.
Two-way grid	<ul style="list-style-type: none"> • Developing the Future Network Strategy (see Section 9.5). • Addressing quality of supply issues in the worst performing areas of the network and/or in response to customer complaints. • Proactively undertaking targeted monitoring of the LV network to more accurately plan LV capacity upgrades. • Improving knowledge of and support for customer take-up of DER (including micro-generation, energy storage and electric vehicles). • Developing a network-wide view of the hosting capacity of the network (e.g. capacity to accommodate more and more customer-connected solar PV and other distributed energy resources before hitting thermal or voltage constraints). • Optimising whole of system security and reliability.
Communication and information	<ul style="list-style-type: none"> • Enhancing customer communications during planned and unplanned outages. • Developing multi-channel communication tools to interact with customers. • Using timely, relevant and targeted social media communications. • Enhancing information access to customers through a website upgrade. • Extending SCADA to 33kV switches and midline devices to improve network visibility and response to outages. • Extending SCADA to 11kV metropolitan midline reclosers to improve network visibility and response to outages. • Replacing telephone dialup units with remote terminal units to phase out communication technology that is no longer supported and provide a more robust and reliable communication network. • Transferring radio communications for field crews from proprietary system to the South Australian Government Radio Network to ensure reliable and timely information between field crews and the control centre. • Strengthening data collection and information flows from field personnel to customers. • Implementing a free message service to customers (Power@MyPlace) which provides timely and accurate information on power outages and restoration times.
Efficiency	<ul style="list-style-type: none"> • Investing in the development of greater condition monitoring programs, tools and techniques to inform condition-based decision making.

Category	Program of work
	<ul style="list-style-type: none">• Using condition-based asset risk assessment and identification of required asset renewals.• Refurbishing assets where viable to defer asset replacements.• Implementing a methodology for valuing the work undertaken on assets and making it visible to the field employees.

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5 Risk – assets and operations

5.1 Introduction

The electricity network has inherently high risk. It has the potential to start a major bushfire, cause widespread property damage, and injure or kill staff or members of the public. This section describes the risks SA Power Networks faces in delivering service to its customers. Risk is often expressed in terms of a combination of the likelihood of an event occurring and the consequences of an event.

The SA Power Networks Risk Management Policy defines risk as:

The chance of something happening that will have an impact upon objectives. It is measured in terms of consequence and likelihood.

SA Power Networks has adopted an enterprise risk management approach to managing risk as documented in the Risk Management Framework. The framework includes instructions and templates for risk assessments. The Asset Management Policy requires asset managers to manage assets to satisfy customer service needs, meet licence and regulatory obligations, and provide a safe environment for employees, contractors and the community.

Key components of the risk management system at SA Power Networks includes:

- **Risk Management Policy:** Outlines the risk management approach to all business activities to ensure that the organisation maximises opportunities without exposing the business to unacceptable levels of risk.
- **Risk Appetite Statement:** Provides guidance in decision making around strategic risks such as safety, bushfire, asset management, unregulated business and workforce capability.
- **Risk Management and Compliance Committee:** Oversees and makes recommendations to the Board on the risk profile of the business and ensures that appropriate policies and procedures are adopted for timely and accurate identification, reporting and management of significant risks to the business.
- **Risk Management Framework:** Outlines how risk management information should be used and reported within the business as a basis for decision making and accountability; includes risk assessment templates and guidance of application.
- **Corporate risk register:** Identifies key whole-of-business risks that have the potential to impact the achievement of the business strategic objectives. They are not a reflection of the ‘top ranked’ risks for the business (by risk rating), but are risks that all workers should be aware of. Dedicated cross-departmental effort is required to manage these risks.
- **Departmental risk registers:** Department specific risks that require controls to be in place. While there is crossover between departments for certain risks, they will only be elevated to the corporate risk register where there is a potential impact a large cross section of the organisation.

Risks are assessed at both the corporate level (top-down) and at an individual asset level (bottom-up). The risk registers are reviewed formally and reported to the Executive Management Group, Risk Management and Compliance Committee and CKI (Hong Kong) on a six-monthly basis.

5.2 Corporate and departmental risks

Corporate risks are those risks that present the greatest potential risk across the entire organisation and are largely related to the network assets and their ability to deliver services to customers. Departmental risks are other significant risks that are managed by specific departments across the organisation. Corporate risks are assessed qualitatively and reviewed annually. Qualitative risk assessment is the most basic risk assessment type used to support simple and rapid assessment. Assessment levels of ‘low’, ‘medium’ and ‘high’ are used to identify risks to be targeted for further analysis and risk mitigation.

Corporate and departmental risks categories:

- **External risks:** Risks largely beyond SA Power Networks control including impacts to services arising from extreme weather events, regulatory changes and technological changes. In addition, external risks because of unforeseen state and federal government initiatives (e.g. solar panel incentives or government infrastructure investment programs).
- **Operational risks:** Risks associated with operational processes, including business processes such as emergency management and business continuity planning, critical human skills and critical asset information.
- **Asset risks:** Risks associated with asset failures or inadequate asset capacity. When an asset fails, there can be an impact on the service the asset provides, and other consequences that do not necessarily affect the service but have an impact, for example on the environment. Examples of asset introduced risks include bushfires and oil spills to the environment.

Appendix 13.1 gives a summary of the key corporate risks and the departmental risks of relevance to the power assets that directly impact the service delivered to customers. Several asset or asset class specific risks included in department risk registers are included in the relevant asset life cycle management section (see Chapter 8).

5.2.1 Managing external risks

SA Power Networks has a risk management framework that establishes the methodology for identifying, measuring and tracking external risks on an ongoing basis. The business identifies the risk for inclusion in risk registers. The risk registers document how these are managed and identifies risk owners.

5.2.2 Managing operational risks

Operational risks are mitigated by operational procedures and standards including preparation of detailed contingency plans for all credible critical contingencies which could lead to undesirable outcomes such as plant damage, loss of supply or compromises in public safety.

5.2.3 Managing asset risks

Asset risks are mitigated by understanding the impact of asset failures on delivering the service to the customers and stakeholders and using good asset management practices during the life cycle of an asset.

Asset defects identified through inspection and condition monitoring processes (see Section 7.6) have their risk quantified and the estimated cost to repair or replace the defect determined through the value and visibility process (see Section 7.10.3). As of mid-2018, substation assets use a previously applied risk prioritisation method, however a transition plan is in place towards migrating substation defects to the value and visibility process. This process is actively used to manage the identified network risks enabling the prioritisation of resources across various work types. The results are used to compare the relative risk and cost of works to aid in day-to-day decision making.

The long-term management of assets risks capital forecasting is undertaken through condition based risk management (CBRM) (see Section 7.8.5.1). The CBRM models use asset performance and condition data to calculate both current individual and aggregated asset class condition and risk information and determine the impact of different intervention strategies on risk and condition over time.

Further analysis on the breakdown of asset risks and impacts on capital forecasts and levels of service is an area of future improvement (see Section 11).

6 Asset management framework

6.1 Introduction

This section sets out the asset management approach applied within SA Power Networks. It outlines the overarching asset management policy, objectives and core strategies. It also discusses the asset management views applied to the power network assets, governance and the asset management system.

6.2 Asset management policy

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

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

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

6.3 Asset management objectives

SA Power Networks has developed asset management objectives which underpin SA Power Networks' asset management core strategies. The asset management objectives align with the organisation's strategic intent, goals and key priorities are:

1. Keep the public, staff and contractors **safe**
2. Develop levels of service that are supported by comprehensive **customer and key stakeholder engagement**
3. Achieve agreed current and future **levels of service** while complying with legislative requirements
4. Deliver sustainable network investments and performance that are **cost efficient** and consistent with prudent risk management approaches
5. Maintain an asset management system that satisfies the criteria and evidentiary needs of **regulatory stakeholders**
6. Promote clarity and transparency to build **stakeholder confidence**

6.4 Asset management core strategies

As mentioned in Section 2.7, and detailed in the Strategic Asset Management Plan, our asset management core strategies (understand, respond, improve) are shown in Figure 40.

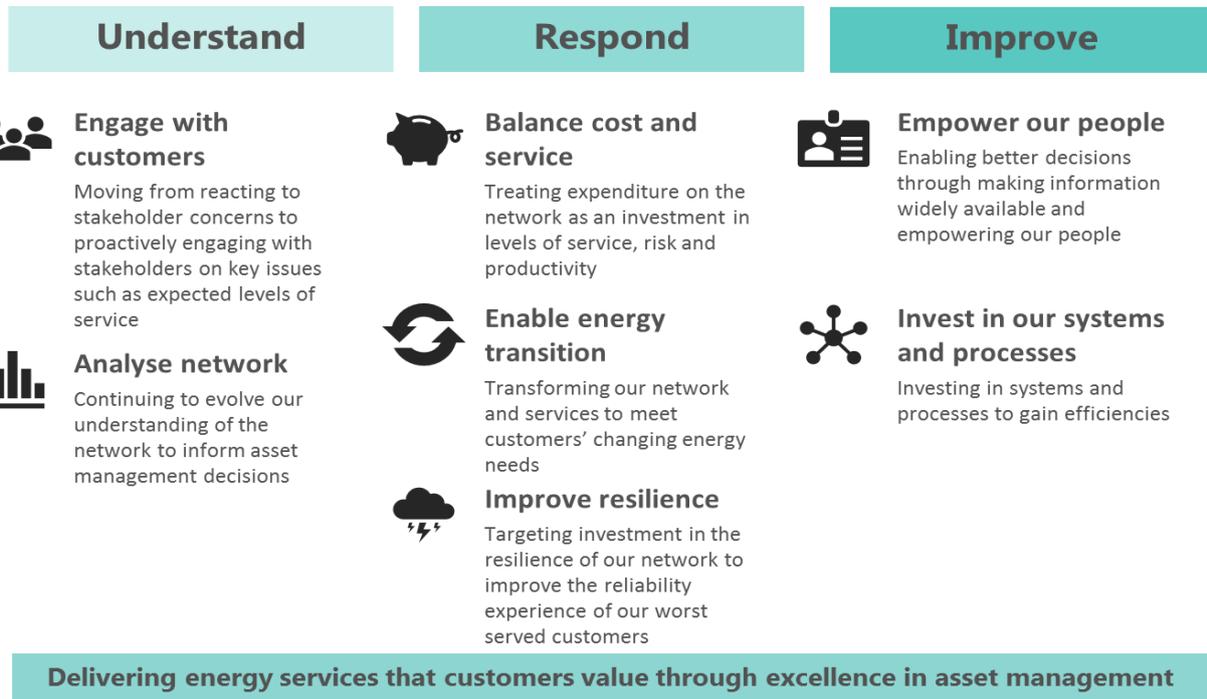


Figure 40: Asset management core strategies

The features of SA Power Networks' asset management approach, include:

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

SA Power Networks is continually improving its asset management practices and systems to provide a balanced outcome that meets shareholder, risk, compliance and customer objectives. A major part of that improvement has been the continuation of a transition to a risk based replacement approach for assets through expanding the scope of coverage of condition based risk management (CBRM). This transition requires good asset condition data combined with improved analytical techniques enables asset risks to be quantified. Increased condition monitoring will be used to provide better knowledge on the condition of the assets to enable better asset decisions to be made, such as replacement time and maintenance intervals and to manage risks associated with asset operations.

6.5 Asset management views

For the purposes of this PAMP, there are three different asset management views discussed as follows:

- **asset lifecycle management:** the view by asset lifecycle stages applied to power network assets (see Section 7);
- **asset class strategies:** the view of asset lifecycle management as applied to specific asset classes (see Section 8); and
- **targeted strategies:** the view of targeted activities that span multiple asset classes and asset lifecycle stages (see Section 9).

6.6 Governance

6.6.1 SA Power Networks organisational structure

Asset management is an essential part of doing business for the whole of SA Power Networks, not just the technical personnel. The successful implementation of asset management requires a well-coordinated effort across all sections of the organisation. Different models for organising roles and responsibilities can achieve this objective.

SA Power Networks' organisational structure is predominantly geared towards the regulated distribution network roles and activities. The exception is the ring-fenced Enerven department which provides competitive services to commercial customers.

SA Power Networks has adopted this arrangement:

- Network Management Group is responsible for understanding customers and assets and translating business objectives into asset management strategies and plans
- Field Services is responsible for carrying out asset management activities on the network in the most cost-effective manner
- IT Services, Customer Relations and corporate groups provide services and insight support to the management of assets.

The organisational structure is shown in Figure 41.

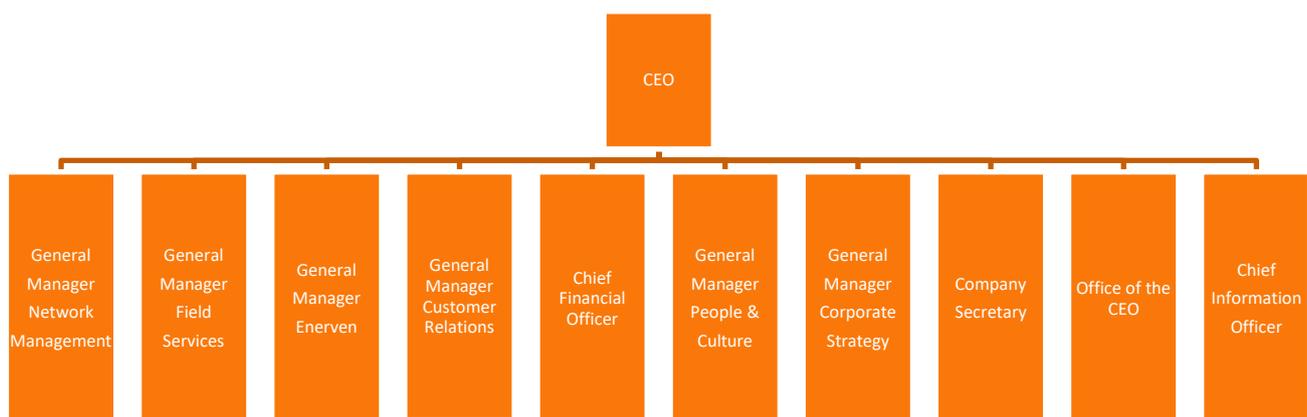


Figure 41: SA Power Networks organisational structure

6.6.2 Asset management working group

The asset management working group is a high-level group whose membership spans key departments of SA Power Networks, primarily Corporate Strategy, Customer Relations, Network Management and Field Services involved with the provisions of services delivered to customers. Its purpose is to embed, integrate, monitor, support and report on the development and implementation of asset management practices at SA Power Networks.

6.7 Asset management system

Asset management is the systematic and structured process of managing the whole life of infrastructure assets with the objective of supporting the delivery of services to customers while minimising costs and managing risk effectively.

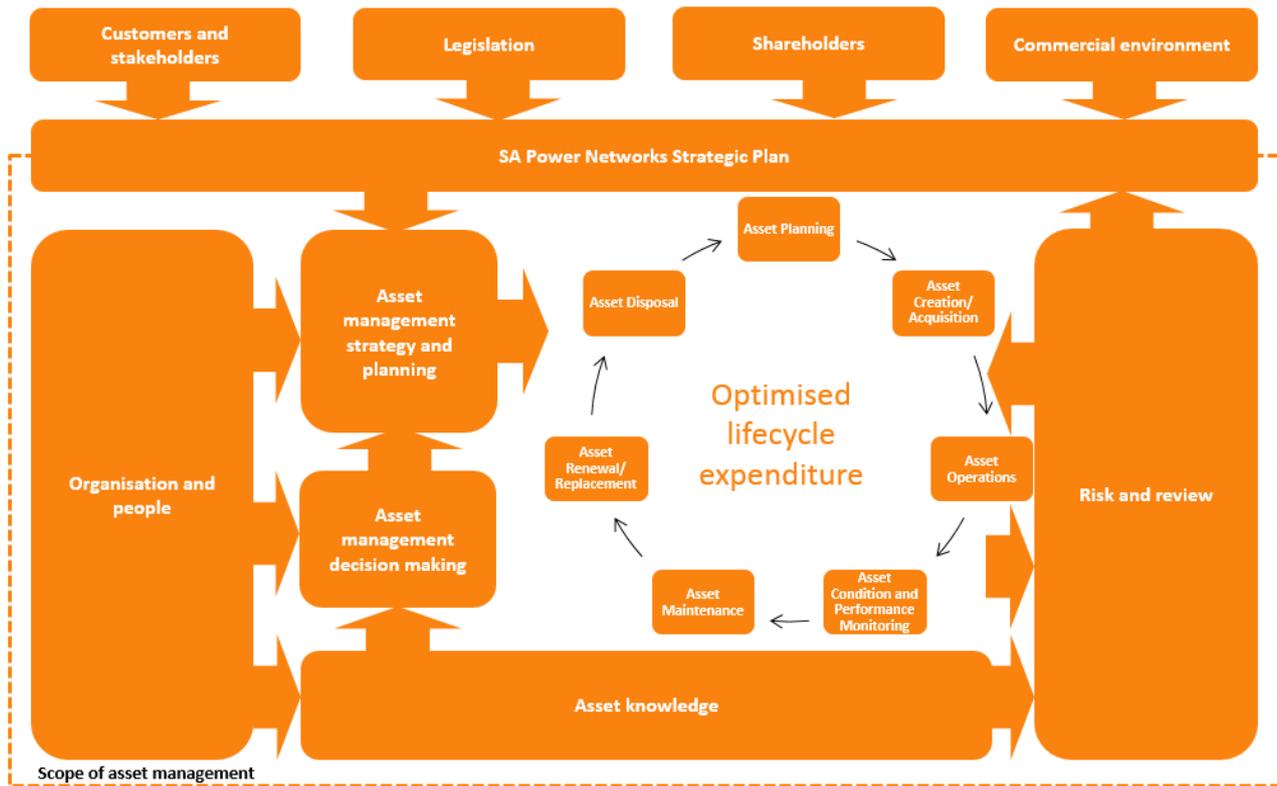
In addition to SA Power Networks quality system already being ISO 9001 Quality Management Systems certified, SA Power Networks are aligning our processes with that of the ISO 55000:2014 Asset Management and ISO 14001:2015 Environmental Management frameworks.

To deliver effective asset management, SA Power Networks has evolved and continues to develop an Asset Management System (AMS). The AMS ensures the many aspects of asset management are addressed, risks are identified and managed, asset management activities are integrated with other business planning functions and review and improvement are organised and ongoing.

SA Power Networks AMS includes but is not limited to:

- Strategic asset management documentation including the Strategic Asset Management Plan, the Power Asset Management Plan (this document) and supporting detailed strategies, plans, manuals, processes and procedures fully integrated with the Corporate Strategic Plan;
- Comprehensive, centralised management of asset information and standards;
- Specific strategies for managing all classes of assets and all operating environment issues;
- A risk management process;
- Systemised relationship management to ensure asset management activity integrates fully with other departments;
- Effective management of life-cycle delivery mechanisms; and
- Work process documentation including provision for review and improvement.

Like many other large utility organisations, the SA Power Networks AMS is based around the conceptual model shown in Figure 42.



Source: Institute of Asset Management, 2015

Figure 42: Asset management system structure

Figure 42 shows that the elements of the AMS are integrated and reliant on each other. The performance of any one element has knock on effects to other elements.

Several key improvement initiatives have been identified throughout the preparation of this PAMP towards achieving continuous improvements (see Chapter 11).

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7 Asset lifecycle management

7.1 Introduction

SA Power Networks has a focus organisationally on asset management and employs good industry asset management practices, guided by its Asset Management Policy, objectives, strategies and plans. This section discusses the strategies developed for asset lifecycle management activities.

7.2 Asset lifecycle activities

The lifetime of an asset starts with planning and ends with disposal. The network asset life cycle is continually repeated as assets move in and out of the asset base.

The objective of life cycle asset management is to maximise the asset life and minimise the costs of acquisition, use, maintenance and disposal of assets. Figure 43 shows the typical asset life cycle process.

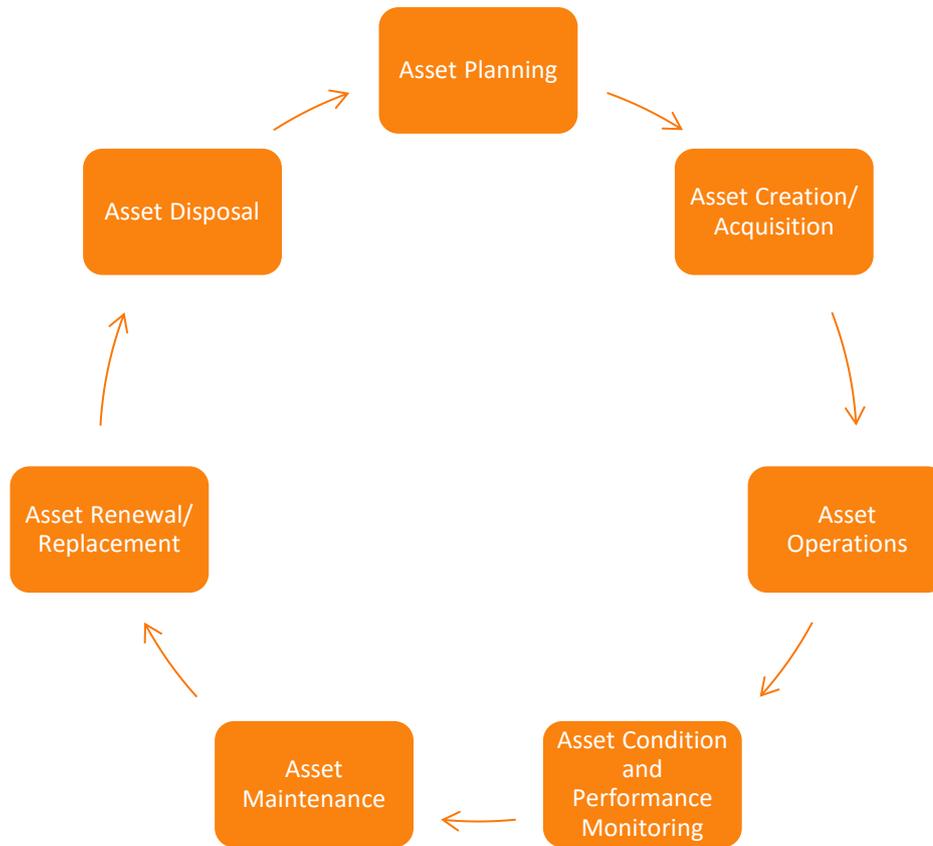


Figure 43: Typical asset life cycle stages

Table 11 summarises these stages as applied by SA Power Networks to distribution network assets.

Table 11: Power network asset life cycle stages - application within SA Power Networks

Asset life cycle stage	Description
Asset planning	<ul style="list-style-type: none"> The process of asset requirement definition, planning investigations, demand and asset capacity assessments with consideration to viable options. Projects are ranked based on risk to ensure the available funding is directed to projects that will generate the maximum benefits to stakeholders and achieve the strategic direction of the business. Only technically feasible options are considered in a business case. The ‘do nothing’ option is always the first option analysed as this option sets the

Asset life cycle stage	Description
	<p>scene for the present and forecast risks and constraints. The option that minimises life-cycle costs is selected as the preferred option. The discounted cash flow technique is applied in evaluating all classes of proposed capital investment.</p>
Asset creation/acquisition	<ul style="list-style-type: none"> • The process where the asset is purchased, constructed or vested to SA Power Networks. • Historical asset risks, performance and standardisation of asset types are considered in developing equipment standards. Technical drawings ensure the asset design, construction and commissioning complies with the legislative requirements outlined in the Safety, Reliability, Maintenance and Technical Management Plan (SRMTMP), and industry codes of practice. This also applies to new and altered customer connections. • When external service providers are required, panel type arrangements are established to minimise the number of tenders issued and to minimise the overhead requirements of tendering. • Testing and commissioning procedures are developed to ensure that new assets are safe and ready to connect to the network. • Updating the information systems is an ongoing task in the life cycle asset management. A critical stage in the life cycle is when the asset is commissioned on the network at which point key and relevant business systems are updated with the assets and their attributes.
Asset operations	<ul style="list-style-type: none"> • The process of keeping the electricity supply flowing through monitoring, switching and load control while keeping the public safe from the risk of electricity supply assets. • Typical operational activities undertaken on the network include: <ul style="list-style-type: none"> • real time operation of the network through remote switching and monitoring of the network status and system load using the control system (SCADA); • operation of network resource planning to ensure planned outages are coordinated and can occur safely; and • effective switching to allow work on assets with minimal disruption while ensuring the safety of staff, contractors and the public. • Other operational activities undertaken on the network include: <ul style="list-style-type: none"> • monitoring and clearance of vegetation growing near the assets; and • bushfire patrols — annual planned program undertaken across the state to prepare for summer and the bushfire season, includes aerial and ground patrols of lines in high bushfire risk areas and is a rapid visual assessment.
Asset condition and performance monitoring	<ul style="list-style-type: none"> • The assessment of the asset to identify any defects and required corrective actions • Comprehensive asset inspection and condition monitoring programs are undertaken across line and substation assets to identify defects that most commonly lead to asset failures⁵. The many assessment techniques used include visual inspections, thermography, partial discharge tests and other diagnostic techniques to determine the condition of the assets.

⁵ Failure of an asset is defined as the asset unable perform its intended function safely and in compliance with jurisdictional regulations, and not because of external impacts such as extreme weather events, third party interference/damage, wildlife or vegetation interference and excludes planned interruptions (Australian Energy Regulator, 2014).

Asset life cycle stage	Description
	<ul style="list-style-type: none"> • The line inspection and condition monitoring programs are working towards meeting cycles nominated in the Network Maintenance Manual with the detailed line inspection programs on track to be back within the cycle by the end of 2018. • Regular monitoring the network reliability and performance and emerging trends. • Investigating and monitoring equipment failures and emerging trends. • Ongoing trials with several emerging technologies towards cost-effective condition and asset assessments including the use of autonomous drones, fixed wing aircraft, specialised condition monitoring equipment and laser scanning technology referred to as light detection and ranging (LIDAR). • Optimisation of the frequency of inspection cycles across the network are ongoing. • Historical failure rates of assets inform the decision-making processes. Asset failure data provides a high-level indicator of the asset management practices and is used to determine the probability of failure in the condition based risk management capital forecasting model. • For consistency, the failure data for individual asset classes in this Power Asset Management Plan has been aligned to the reporting categories for the annual Regulatory Information Notice to the Australian Energy Regulator.
Asset maintenance	<ul style="list-style-type: none"> • The process of undertaking planned minor work carried out to prevent more expensive work in the future and reactive maintenance where an asset defect or failure is fixed • Maintenance work is prioritised based on the greatest return on investment.
Asset renewal/ replacement	<ul style="list-style-type: none"> • The process of refurbishment or replacement of an asset to provide required functionality taking into consideration current and forecast network requirements to ensure it continues to deliver the required level of service. • Assets are replaced when they fail. • A risk based approach is taken in renewing/replacing assets with condition defects prior to failure. Asset risks are assessed based on the probability of the asset failing and the consequence(s) of its failure. • Renewal work is prioritised based on the greatest return on investment. • The decision whether to refurbish or replace is based on remaining whole of life-cycle costs. Refurbishment can significantly extend the expected life of the asset prior to requiring replacement but does not restore the asset to 'as new' condition.
Asset disposal	<ul style="list-style-type: none"> • The disposal of decommissioned assets. Above ground assets are removed with components salvaged for reuse where possible with the remainder disposed for scrap value. Below ground assets are typically left in the ground unless they can easily be removed (e.g. cables in conduits) or if there are environmental considerations that require the decommissioned asset to be removed.

7.3 Asset planning and creation (network planning)

7.3.1 Introduction

This section describes the current and future electricity demand and the factors that impact the capacity, capability and quality of supply provided to customers through the distribution network. It also gives an overview of the asset planning strategy applied to managing power network assets, the process for identifying network capability and capacity constraints, non-network options and network augmentation methods considered and the programs of work supporting the asset planning objectives and levels of service.

Asset planning and creation summary

As the principal South Australian distribution network service provider, SA Power Networks primary responsibility is planning, building, operating and maintaining the South Australian electricity distribution network. Many demand drivers across population, industry growth, technological changes, energy efficiency, climate and pricing can influence customer demand.

Each year SA Power Networks prepares the Distribution Annual Planning Report to inform National Electricity Market regulators, participants and stakeholders about existing and forecast system limitations (constraints) on our distribution network, and where and when they are expected to arise within the forward planning period.

The planning process includes annual reviews of the network load forecast after each summer to identify capability and capacity constraints against defined planning criteria, considering any recent changes to the network including use of latest load recordings, generator connections (including PV and battery), system modifications and any new committed large load developments. The reviews assess viable non-network options and network augmentations to identify the most cost-effective solutions for addressing those constraints. While demand at a state macro level is relatively flat, demand within planning regions are increasing and decreasing. That is, growth in some parts of the network are offset overall by decreases in other parts of the network, but localised networks still require upgrades to increase capacity. The required projects to address these constraints and timing have been determined including programs of minor works to respond to the increasing rate of quality of supply issues arising in the network due to the increased uptake of PV systems.

The annual reviews are used to identify likely projects for informing the required forward investment on necessary network augmentations for maintaining the reliability and quality of supply levels of service.

```

graph TD
    AP[Asset Planning] --> ACA[Asset Creation/Acquisition]
    ACA --> AO[Asset Operations]
    AO --> ACM[Asset Condition and Performance Monitoring]
    ACM --> AM[Asset Maintenance]
    AM --> AR[Asset Renewal/Replacement]
    AR --> AD[Asset Disposal]
    AD --> AP
    
```

7.3.2 Asset planning objectives

The asset management objectives specific to asset planning are summarised in Table 12.

Table 12: Asset planning (network planning) asset management objectives

Level of service category	Asset planning asset management objectives
Safety	<ul style="list-style-type: none"> No new network assets constructed resulting in injury/death.
Reliability and resilience	<ul style="list-style-type: none"> Minimise unplanned interruption frequency and duration from network constraints. Minimise planned interruption frequency and duration for network augmentation works.
Two-way grid	<ul style="list-style-type: none"> Minimise the impact of distributed energy resources (DERs) on the network quality of supply.
Efficiency	<ul style="list-style-type: none"> Balance network augmentation costs and reliability levels of service for viable options to select preferred solution. The viability of non-network options assessed for cost and risk to resolve identified network constraints.

7.3.3 Demand drivers

There are many electricity demand drivers that can result in an increase or decrease in electricity demand. The key electricity demand drivers, observed trends and anticipated impacts on the distribution network are summarised in Table 13.

Table 13: Demand drivers and anticipated impacts on distribution network demand

Demand driver	Description of demand driver trends	Impact on distribution network demand
Population 	<ul style="list-style-type: none"> 1.7 million total population in 2017 increasing to projected 1.9 million by 2030 (medium projection) with an annual growth rate of ~1% (DPTI, 2015). Most significant growth across Adelaide, Barossa, Light, Lower North and Fleurieu regions (DPTI, 2016). Growth within the Adelaide region will largely be infill development (76%) near existing distribution network infrastructure with the remaining greenfield areas (24%) (Government of South Australia, 2017). 	
Business and Industry 	<ul style="list-style-type: none"> Short term forecast localised decrease in demand with the announced closure of the Australian automotive vehicle manufacturing sector (AEMO, 2017) Mild growth in demand is expected in the longer term, driven largely by industrial investment and increased growth in certain business sectors (AEMO, 2017). Several identified medium and major connection projects identified across many sectors to 2020-2021 will result in spot loads across the network (BIS Oxford Economics, 2018). 	
Tourism 	<ul style="list-style-type: none"> Domestic tourism is forecast to increase at an average annual rate of 2.2% for up to 2026-2027 (Tourism Research Australia, 2017a, 2017b). In comparison, international tourism will increase at an average of 5.9% per year over the same period (Tourism Research Australia, 2017a, 2017b). 	

Demand driver	Description of demand driver trends	Impact on distribution network demand
Rooftop PV Penetration 	<ul style="list-style-type: none"> • South Australia’s installed rooftop PV penetration per household is the highest in the National Electricity Market, with more than 30% of dwellings with rooftop PV systems installed (AEMO, 2017a). • The main drivers behind rooftop PV uptake are government rebates and feed in tariffs, declining installation costs and increases in retail electricity prices (AEMO, 2017a; AEMO, 2017d) • The rate of growth in uptake of residential PV systems in South Australia is forecast to slow as saturation has been reached in some regions, with the commercial sector forecast to have a steady growth mainly driven by the falling installation costs and the projected higher retail prices (Jacobs, 2017). • Installed rooftop PV capacity in South Australia is forecast to double from around 800 MW in 2018 to over 1600 MW by 2030 (medium projection) (Jacobs, 2017). • The anticipated uptake of PV systems in South Australia is predicted to offset 100% of minimum summer demand in around 2027 (AEMO, 2017b). 	
Integrated PV and storage systems (IPSS) 	<ul style="list-style-type: none"> • IPSS system uptake is expected to become significant after 2020 in both the residential and commercial sectors, mainly driven by the falling system costs but also by the increasing retail prices (Jacobs, 2017) • The future of the cost of energy storage technologies is subject to considerable uncertainty, but is generally expected to sharply decline by 2022 with the proportion of IPSS increasing at a greater rate than standalone PV systems (Jacobs, 2017). • The total IPSS installed capacity in South Australia is forecast to account for around 400 MW by 2030 (Jacobs, 2017). 	
Electric Vehicles 	<ul style="list-style-type: none"> • The uptake of EVs in South Australia is forecast to increase from 0.1% of all vehicle sales in 2017 to 17.2% by 2030 corresponding to a non-coincident maximum demand of 0.12 MW to 25.61 MW respectively for the neutral forecast (AEMO, 2017c). • The increase from 2030 to 2050 is more pronounced as the EV sales increase in South Australia to 89.8% by 2050 and a non-coincident maximum demand of 591 MW for the neutral forecast. (AEMO, 2017c). • Energeia’s modelling shows EV charging management avoiding increasing maximum demand in any of the regions over the period 2017 to 2036, based forecast of underlying operational demand (AEMO, 2017c). 	
Energy Efficiency Uptake	<ul style="list-style-type: none"> • Large number of ageing air-conditioners expected to be replaced in the next 10 years (replacement technology is approximately twice as efficient) (AEMO, 2017a). • Replacement of inefficient lighting with LED lighting across residential/commercial and public lighting. 	

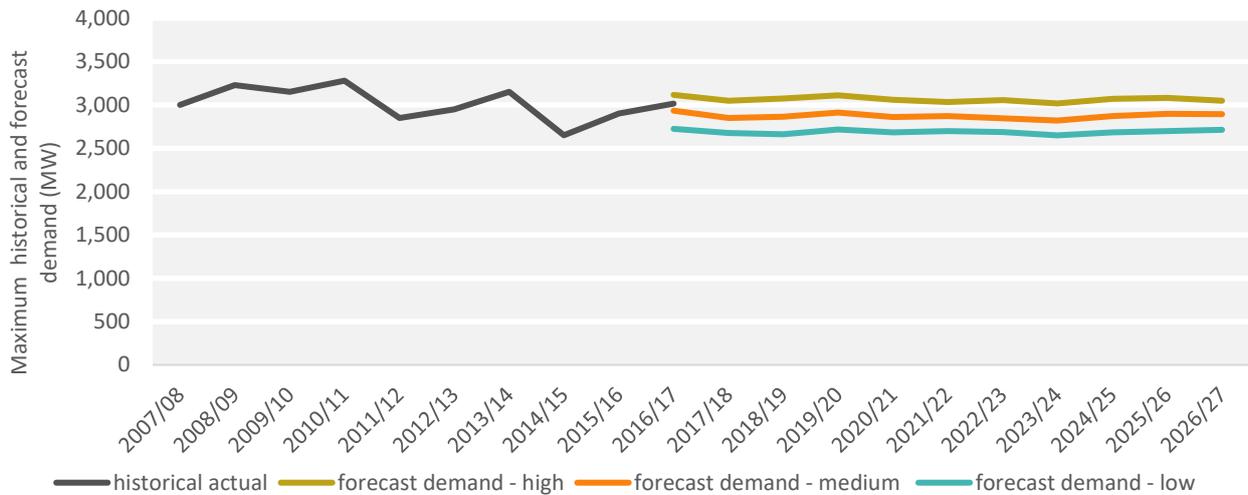
Demand driver	Description of demand driver trends	Impact on distribution network demand
	<ul style="list-style-type: none"> Equipment Energy Efficiency (E3) Program: a national framework for product energy efficiency in Australia promoting the development and adoption of products that use less energy and energy labelling for equipment. Retailer Energy Efficiency Scheme: This South Australian Government initiative requires energy retailers to help households and businesses save on energy use and costs, and lower their greenhouse gas emissions. 	
Climatic changes	<ul style="list-style-type: none"> South Australia's electricity demand peaks from its average demand to such a height that South Australia has the 'peakiest' demand in Australia. The linear trend of long term maximum summer day temperatures has increased by two degrees Celsius over the last 20 years and on average, South Australian heatwaves are becoming more frequent and increasingly exceeding the 40 degrees Celsius criteria (3 days \geq 40 degrees) since 2006 (Bureau of Meteorology, 2017). 	
Retail Electricity Price 	<ul style="list-style-type: none"> The South Australian price is currently the highest amongst the mainland regions, which reflects the higher marginal cost of its generation resources. Electricity retail prices are forecast to increase to 2019, fall to 2030 (because of falling demand) and then rebound because of increasing retirement in generation (Jacobs, 2017a). 	
Net Result	<p>Despite increases in population and business and industry growth leading to increased new or altered connections, increased electric vehicle uptake, and tourism, the net impact of the above drivers is for system demand to remain relatively flat over the next 10 years. This is largely due to households and businesses managing their use through ongoing investments in rooftop PV and IPSS, financial pressure of high electricity prices, and increasing efficiency of appliances.</p>	

7.3.4 Future demand forecasts

The impact of the various demand drivers discussed in Section 7.3.3 has been evaluated and built into the future demand forecasts applied across the asset systems.

7.3.4.1 South Australia overall demand forecasts

AEMO undertakes overall demand forecasts for the whole of South Australia. Figure 44 shows the historical and forecast peak demand for South Australia.



Source: AEMO, 2017b, South Australian Demand Forecasts, July 2017

Figure 44: Peak electricity demand forecasts, South Australia

Figure 44 shows the long-term trend for peak electricity demand in South Australia is forecast to remain relatively flat with the net impact as result of the demand drivers described in Table 13.

The embedded generators are one of the main demand drivers behind this trend. Figure 45 shows the trend of the cumulative installed embedded generation capacity connected to the SA Power Networks distribution network.

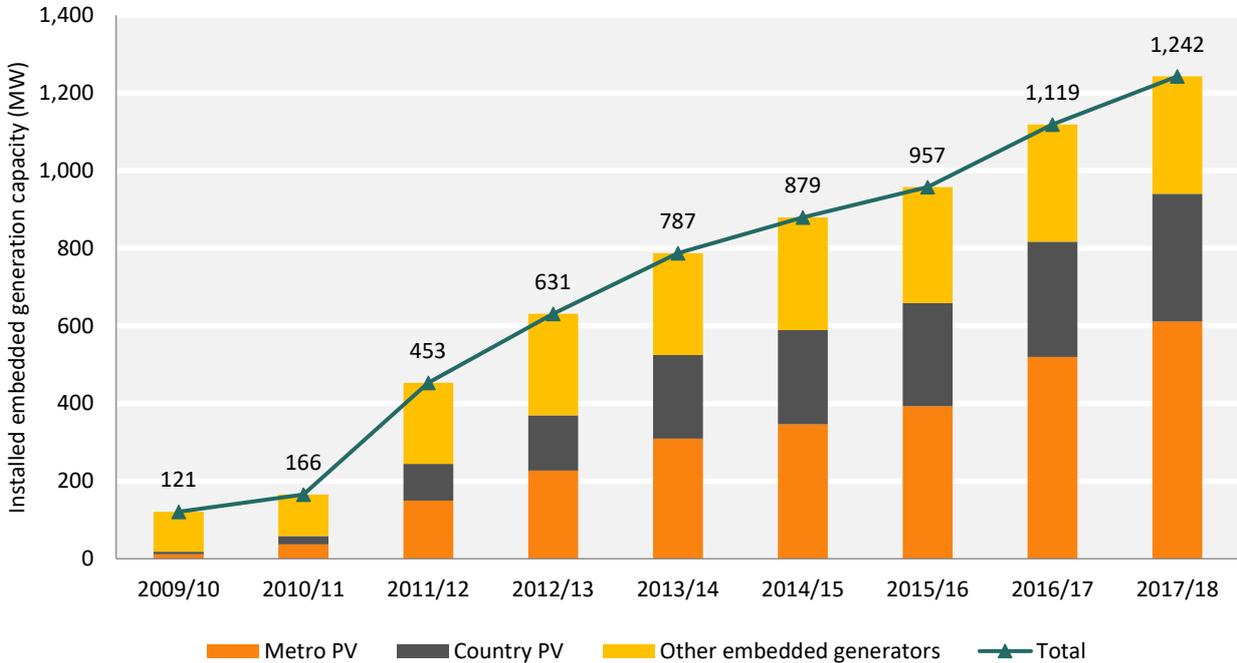


Figure 45: Installed embedded generation capacity connected to the distribution network

The most significant consequence of this uptake is PV systems potentially offsetting 100% of summer minimum demand. Figure 46 shows forecast maximum and minimum operational demand for both summer and winter in South Australia.

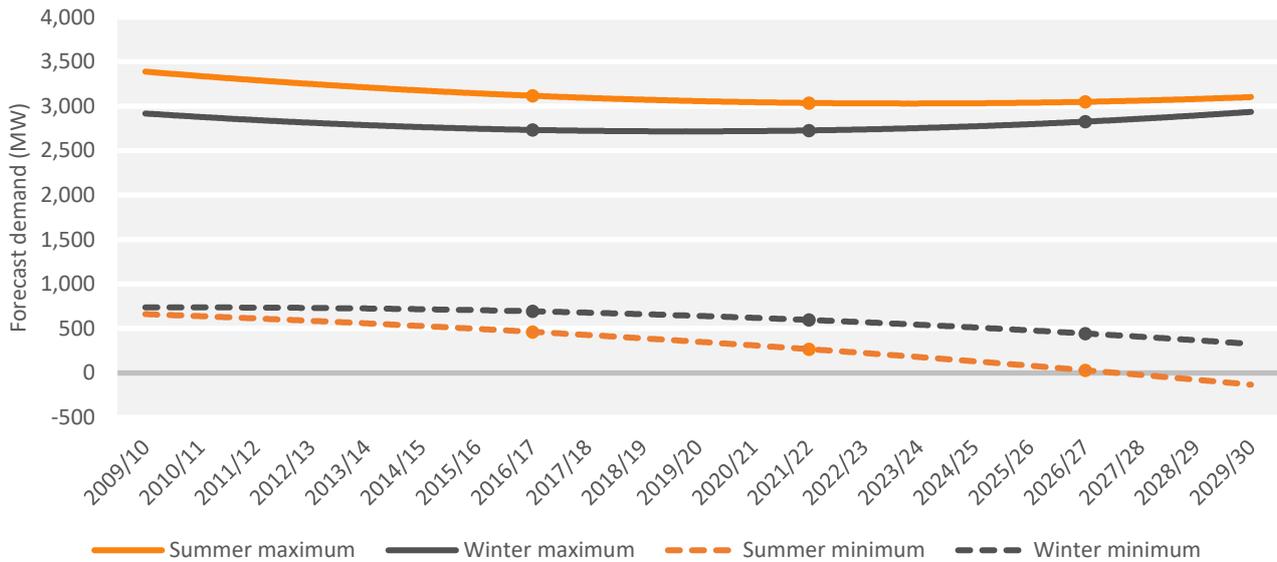


Figure 46: Forecast maximum and minimum operational electricity demand, South Australia

Source: AEMO, 2017d, *Electricity Forecasting Insights for the National Electricity Market*, June 2017

Figure 46 shows maximum operational demand for both summer and winter is forecast to stay relatively flat up to around 2026 but, in the longer term, increase. This increase is largely driven by the expected rise of electric vehicles combined with slower growth of solar PV system installations. The minimum summer and winter operational demand is forecast to decline in the medium and long term. This is largely due to the forecasted growth in rooftop solar PV which shifts the minimum operational demand to the middle of the day, when PV generation is at its highest, thus reducing grid demand. The negative demand in summer from around 2026-2027 because of PV electricity generation exceeding demand will present challenges in the distribution network voltage regulation and system stability.

In addition, while demand at a state macro level may be relatively flat, demand within planning regions could be increasing or decreasing. That is, growth in some parts of the network may be offset overall by decreases in other parts of the network, but localised networks may need upgrades to increase capacity. Spatial demand forecasts are used to assess localised network constraints.

7.3.4.2 SA Power Networks system demand forecasts

SA Power Networks uses a combination of historical data, the projected uptake of PV and the incorporation of large spot loads to calibrate network models and ensure the model outputs are reflective of the AEMO trends for peak summer demands (see figure 44). The network demand is forecast across several planning regions (see Figure 47).

Further detail on the demand forecasts, planning criteria and assumptions is available within SA Power Networks Distribution Annual Planning Report.

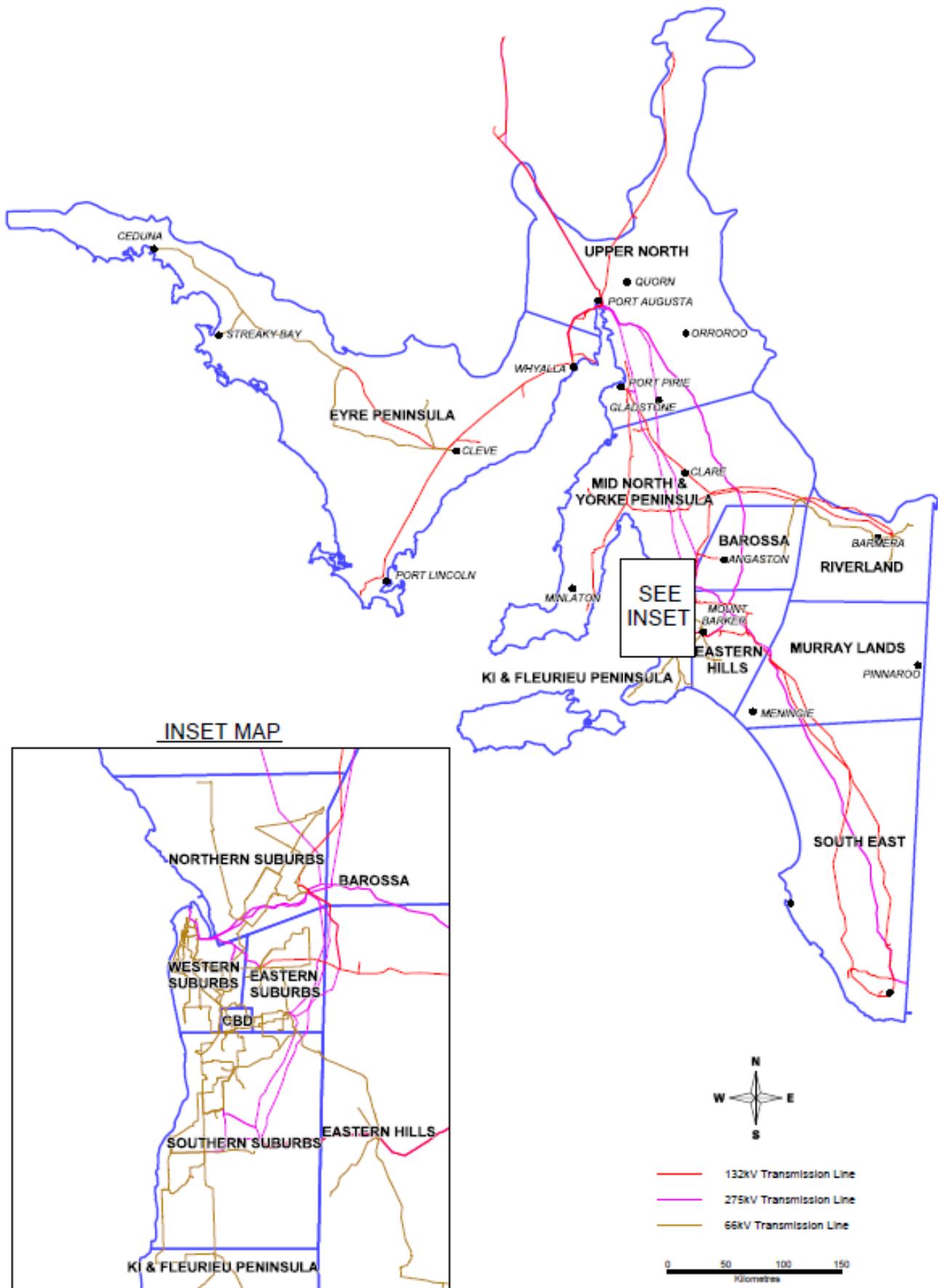


Figure 47: SA Power Networks planning regions

Figure 48 shows the forecast average annual change in electricity demand for the various planning regions out to 2030.

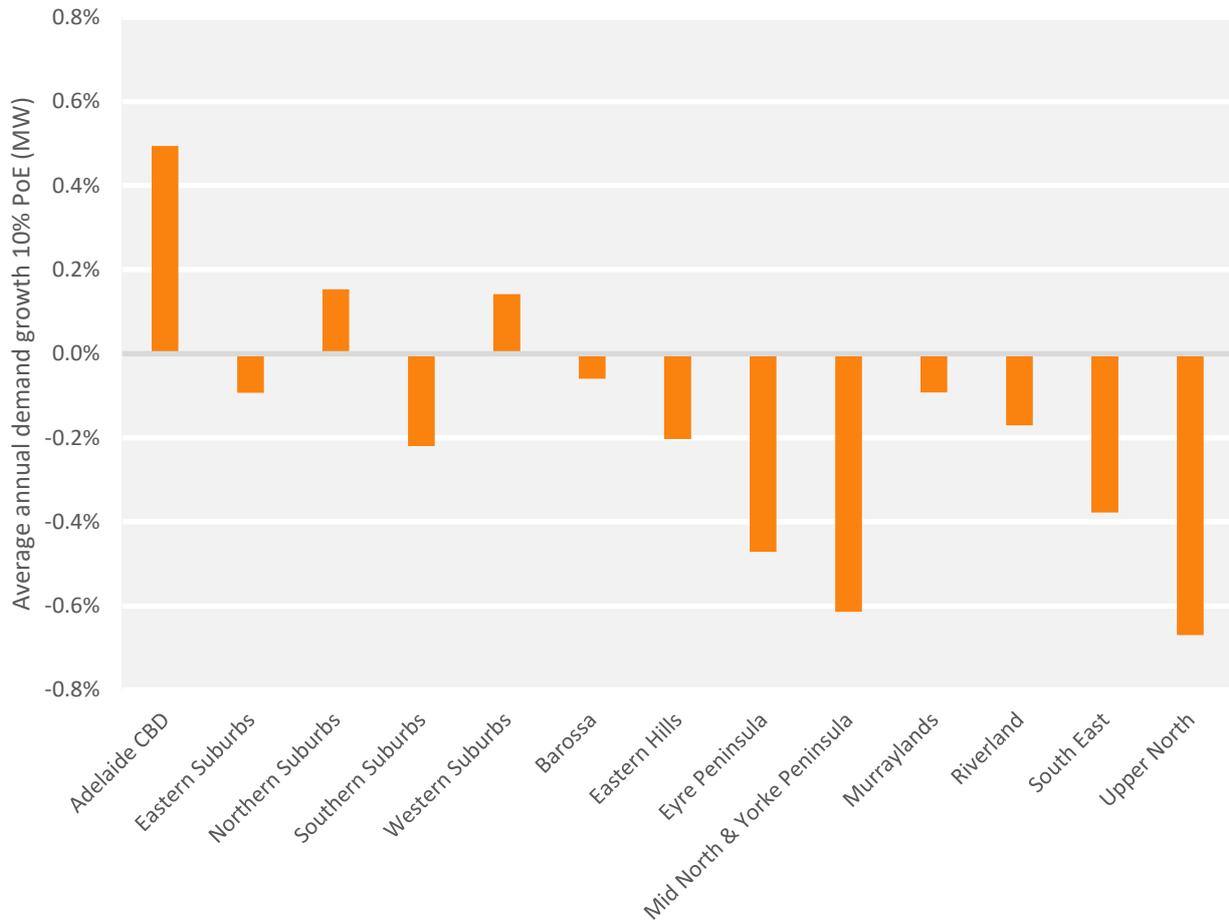


Figure 48: Regional annual electricity demand change forecasts (2017/18–2029/30)

Source: SA Power Networks Distribution Annual Planning Report 2017/18 – 2021/22, December 2017

Figure 48 shows the average annual electricity demand change for all planning regions is forecast to be minimal (<1%), with most areas forecast to decline very slightly in demand. The Adelaide CBD forecast demand increase (about 0.5% per annum) is mainly due to new building development in the CBD combined with limited space for use of PV systems to offset the increase in network demand. The models are used to identify where network constraints exist and when those constraints are likely to occur.

7.3.5 Capability to meet current and future demand

The security of supply is the capability of the electricity supply chain (see Section 3.1.1) to maintain normal supply to customers. The security of supply observed by customers can be impacted across the generation and transmission lines or distribution networks and are discussed briefly in sections 7.3.5.1 and 7.3.5.2 respectively.

7.3.5.1 Security of supply on the national electricity grid

Security of supply relates to how the national electricity grid reacts to events that may influence it. Broadly, it includes ensuring sufficient power generation to meet demand on the highest demand day along with the grid's capability to react and recover securely to major events. The Australian Energy Market Operator (AEMO) is responsible for maintaining the reliability and security of the interconnected national electricity grid.

The distribution network provides the link between generators and transmission network service providers and customers (see Section 2) and while the security of supply for the National Electricity Market (NEM) is beyond SA Power Networks' control, it can impact the reliability observed by SA Power Networks' customers.

The recent closures of the 520MW Northern and 240MW Playford coal-fired power stations near Port Augusta have compromised the ability for the remaining electricity sources within South Australia to meet peak power demand. The state was left heavily reliant on the interconnectors to the NEM grid, which interconnects the regional market jurisdictions of South Australia, Victoria, Queensland, New South Wales (including Australian Capital Territory) and Tasmania.

In times of high electricity demand, these interconnectors can export electricity into South Australia from the eastern states. AEMO has forecast a potential supply shortfall for peak summer periods for South Australia from 2017–2018, following the recent closure of the Hazelwood coal fired power station. While this means there may be potential interruptions to supply to some customers during peak demand periods, interruptions to the NEM through unplanned interruptions can also occur. AEMO's investigation of the 28 September 2016 blackout recommended the following measures to help manage South Australia's security of supply:

- New constraints on the Heywood interconnector during credible contingencies.
- A minimum requirement of two sufficiently large synchronous generators on the national grid to be online at all times.
- Improvements to emergency frequency control schemes.
- New processes for reclassifying credible contingencies in response to changing network conditions.
- Enhanced voltage ride-through settings on South Australian wind farms.
- Addressing generator capabilities to withstand rapid changes in frequency.

In response, and as part of its Energy Supply Plan, the South Australian Government also announced several measures to improve the resilience of the South Australian power system. The initiatives implemented as part of this plan in 2017 were:

- installation of 100MW back up battery storage connected to the ElectraNet transmission lines and adjacent to the Hornsdale windfarm power generation near Jamestown in the state's mid-north (battery commissioned 1 December 2017); and
- installation of nine state-owned turbine generators with a nameplate capacity of 276MW at the Adelaide desalination plant at Lonsdale and the General Motors Holden site at Elizabeth (commissioned in November 2017).

The South Australian Government also introduced the *Emergency Management (Electricity Supply Emergencies) Amendment Bill 2017*, which gives the South Australian Energy Minister powers of direction in an electricity supply emergency for use as a last resort to direct a market participant to restrict, suspend or generate electricity in an electricity supply emergency.

The AEMO recommendations arising from the September 2016 blackout and the South Australian Government Energy Supply Plan actions aims to provide South Australia with improved control over the security of supply into the distribution network during times of an electricity supply emergency.

Notwithstanding, all electricity systems include load shedding (switching off selected parts of the network) as an essential option for dealing with significant generation/demand imbalances to help avoid significant damage to generation equipment. Therefore, while load shedding results in interruptions to SA Power Networks customers, it is not included in the underlying network reliability performance measures (see Section 4.9.3.1).

The manual rotational load shedding is controlled by SA Power Networks through the Network Operations Centre (see Section 7.5.4.2).

7.3.5.2 Distribution network capacity and capability

As a DNSP within the NEM, SA Power Networks must comply with the requirements relating to reliability and system security contained in Schedule 5.1 of the National Electricity Rules (NER) relevant to planning for future electricity needs and with the service obligations imposed by the South Australian Electricity Distribution Code (EDC). SA Power Networks has developed its planning criteria to meet and maintain the reliability and security of supply requirements of the NER and EDC. Where the forecast load breaches the planning criteria, a constraint is established and a suitable solution is sought whether this involves implementation of a major network augmentation, a deferral solution or a suitable contingency plan taking all risks and their associated consequences into consideration. The planning criteria is discussed in detail within the SA Power Networks Distribution Annual Planning Report.

Overall, the distribution network has adequate capacity to meet the 10-year forecasted demand. However, in some locations, demand is expected to exceed the capacity of the network due to local factors such as specific commercial/industrial electricity demands, changes in land use or increased demands at holiday locations subject to short-term transient populations.

The security of the network is continuously reviewed. If a positive market benefit is shown for upgrading the network to meet customer reliability standards or customer security of supply, network improvement solutions will be considered for deployment.

Network constraints requiring network augmentations typically include:

- ElectraNet projects requiring replacement of distribution network assets to enable interfacing of equipment;
- customer demand exceeding the capacity of network assets at substations, sub-transmission lines and distribution feeders during peak demand periods;
- single source of supply radial lines supplying large areas subject to ongoing interruptions; and
- quality of supply unable to be maintained within required voltage ranges in accordance with Australian Standard, AS 60038-2012 Standard Voltages.

7.3.6 Asset planning strategy (network augmentations)

7.3.6.1 Asset planning strategy

Asset planning starts with a review of annual load growth on the sub-transmission system and high voltage (HV) distribution network after each summer to identify capability and capacity constraints against defined planning criteria, considering any recent changes to the network including use of latest load recordings, generator connections (including PV and battery), system modifications and any new committed large load developments. It includes assessment of the network against specific planning criteria to enable prudent planning of the network's capacity, security and switching systems, for achieving the performance targets of the business over the medium to long term. The network asset planning strategy is based on the net projected impact of the factors influencing demand (see Section 7.3.3). The strategy aims to ensure electricity can be supplied to existing and new customers without breaching the planning criteria to ensure compliance with the NER and EDC.

Strategy for planning new network assets (summarised in Figure 49):

- **Connecting new customers on request:** Manage customer connections services in accordance with the SA Power Networks Connection Policy and National Energy Customer Framework (see Section 7.4).
- **Monitoring existing loads:** Each year, review peak loads on the network after summer for the impact of:
 - modifications that have occurred on the network including embedded generation and spot loads;
 - changes in spatial demand and consumption diversity;
 - impacts of DER; and
 - quality of supply.
- **Reviewing changes to equipment ratings:** Undertake annual reviews of equipment capacity and load transfer capability.

- **Comparing forecast against equipment ratings:** Compare the projected demand forecast against equipment capacity at key locations in the network for various planning criteria including normal operation and contingency conditions. The forecast includes any identified spot loads including any key State Government projects having a high probability of proceeding. The constraint capacity, or load at risk, takes into consideration the level of load SA Power Networks is prepared to allow to remain unsupplied following the performance of all available feeder transfers and the ability to connect one of the mobile substations in the event of a transformer outage.
- **Capital budget:** Identify non-network and network augmentation solutions to address identified network constraints including their anticipated timing. SA Power Networks forecasting for augmentation programs is developed through a ‘bottom up’ approach with estimated costs developed using a set of standard component or unit costs.

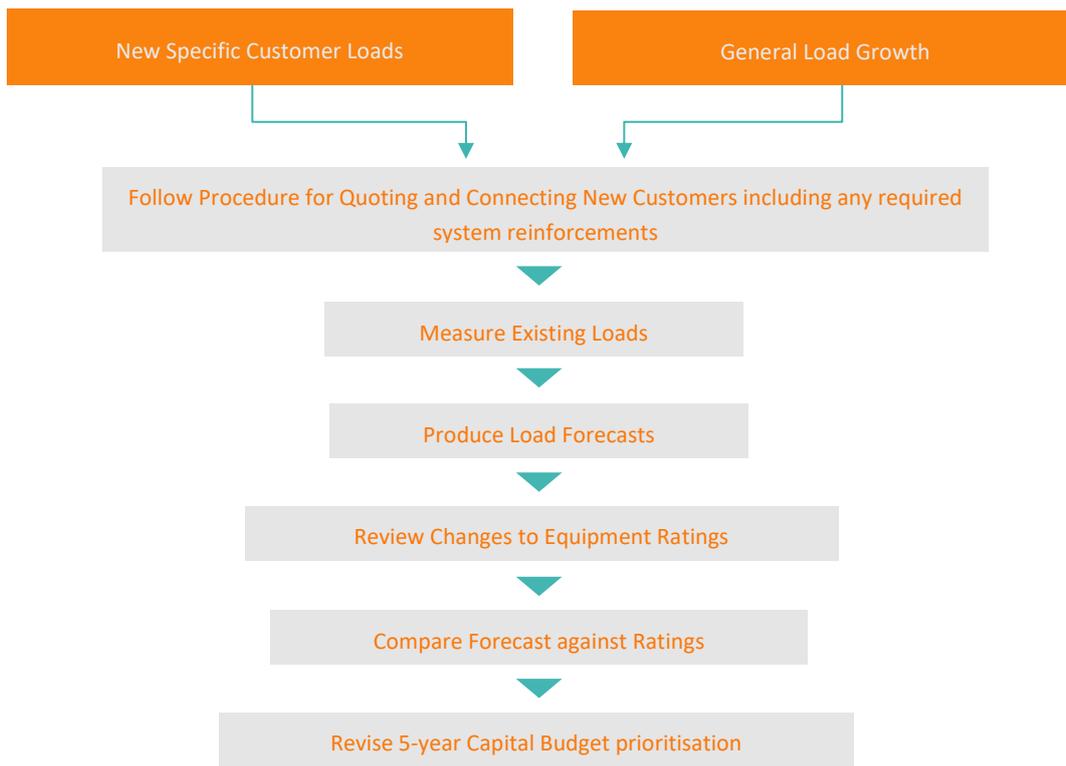


Figure 49: Distribution Network Asset Planning Strategy

Further detail on SA Power Networks planning standards and procedures is outlined in the SA Power Networks Distribution Annual Planning Report.

The potential non-network and network augmentation solutions considered are described briefly below.

7.3.6.2 Constraint resolution methods considered

Demand can be managed through a mix of non-network and network augmentation options. The appropriateness of each is considered on a case-by-case basis to minimise costs while meeting the required levels of service.

7.3.6.2.1 Non-network options

Non-network options provide alternatives to creating new or improved assets to meet demand. They address ways of modifying customer behaviour to maximise the use of existing assets, particularly during the short peak demand periods, and defer or reduce the need for new assets.

The viability of non-network options such as demand side participation solutions depends on the ability of electricity consumers and/or distribution network service providers to reduce or curtail consumers' electricity demand at will. It could reduce peak electricity demand, for example, using direct load control through firm load reduction or load shedding contracts with customers.

Such arrangements could delay the need for some reinforcement projects, if a guaranteed amount of load can be reduced on request from SA Power Networks' Network Operations Centre.

As a matter of course, SA Power Networks considers various non-network options when attempting to determine its preferred solution to an identified constraint on its network, for example:

- **Power factor correction:** Installing capacitor banks in the network to reduce the apparent power demand on the network and maintain voltage levels within the required limits or through customers improving their power efficiency through incentivised tariff structures.
- **Demand management agreements:** Amending or creating network system support agreements with customers to generate or curtail load on demand.
- **Load transfers:** Transferring demand between substations during periods of peak supply where the network configuration and capacity exists to do so.
- **Temporary generators:** Using where it is more cost effective to implement short-term power generation into the grid over permanent infrastructure (strategy used at Bordertown to avoid more expensive capital works).
- **Commercial embedded generators:** Providing a supply into the network to offset or defer other network augmentations.

SA Power Networks has previously trialled deployment of up to 100 energy storage systems on customer premises across three 11kV distribution feeders in the Salisbury area, to defer an infrastructure augmentation with a capital cost of \$2.9 million.

Direct load control and other non-network options have and are being actively investigated and trialled by SA Power Networks. The non-network options are likely to be adopted only where they can be shown to be economically and technically viable, and able to be implemented in a timely enough fashion to resolve the identified network constraint. The non-network options typically consist of both an initial capital expenditure and an ongoing operational cost.

7.3.6.2.2 Network augmentation options

If they are required, network augmentation options would permanently create an asset that did not previously exist, or upgrade an asset beyond its original size or capacity.

The main network augmentation options considered during planning to manage electricity demand are:

- **network augmentations** (network capacity upgrades);
- **network topology upgrades** (increased network interconnectivity); and
- **permanent generators** connected into the network.

All projects estimated to cost more than \$6 million are subject to the Regulatory Investment Test for Distribution in accordance with Section 5.17 of the National Electricity Rules. Where a screening test (assessment of viable network and non-network options) determines that publication of a Non-Network Options Report is warranted, the report is created and issued for public consultation seeking alternative solutions to remedy the identified network constraint.

7.3.6.3 Quality of supply

Quality of supply can be defined as a steady supply of electricity that stays within a prescribed voltage range. The most common quality of supply issues related to the range of supply voltage as summarised in Table 14.

Table 14: Primary quality of supply measure and objectives

Quality of supply measure	Description	SA Power Networks objective
Range of supply voltage	Supply voltage is the sustained voltage existing at any time, from phase to neutral or phase to phase, at the customer meter.	SA Power Networks aims to maintain the steady-state sustained voltage (between 216 and 253 volts) at the supply point in accordance with AS/NZS 60038:2012. Such a range would only be exceeded under abnormal or emergency situations.

Other quality of supply measures including but not limited to voltage fluctuations, voltage dips and lightning are largely due to abnormal conditions and are investigated on a case by case basis. For further information on other quality of supply standards, refer to SA Power Networks Power Quality Manual (Manual 24).

SA Power Networks is not accountable for, nor can it influence, the frequency of electricity supplied through its electricity network. However, it is important to maintain a steady state supply voltage within acceptable limits at the supply point to ensure customers’ appliances and equipment do not get damaged. If SA Power Networks’ steady state supply voltage departs from the relevant codes, standards and guidelines, remedial works are undertaken to improve the quality of supply.

7.3.6.3.1 Low voltage network and distribution transformers

The historical and forecast uptake of PV systems (see Section 7.3.4.1) is having a significant impact on voltage levels within the distribution network. Figure 50 shows a significant step increase in customer PV related HV enquiries in 2017 extending into 2018. While most of these relate to customers’ solar PV inverters not working, some require more detailed investigations and remedial works on the network.

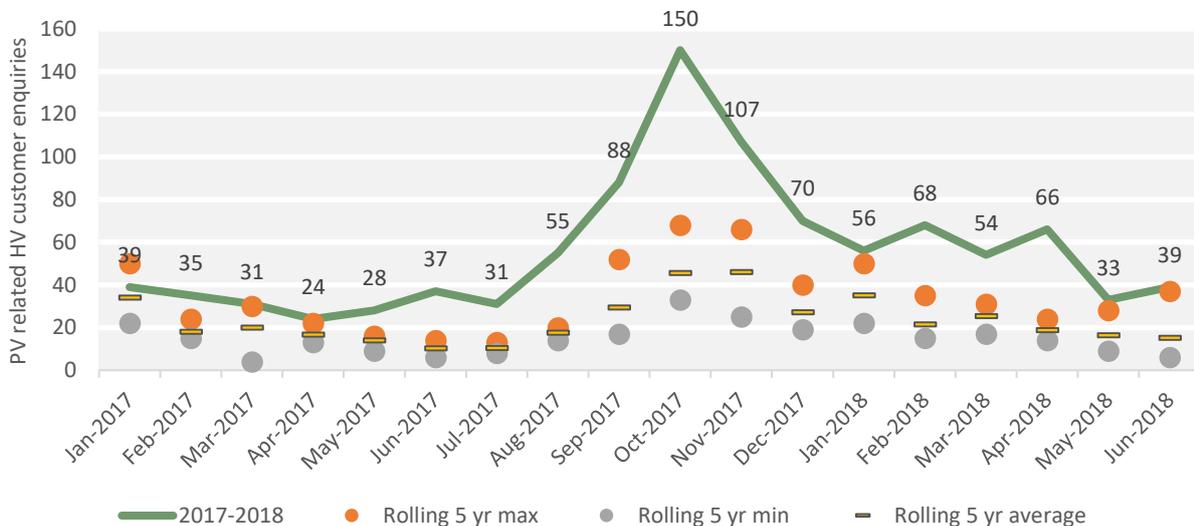


Figure 50: Solar photovoltaic related high voltage customer enquiries (Jan 2017 – June 2018)

Figure 50 shows customer enquiries for PV related HV enquiries are consistently on the rise compared to historical levels. As a short-term measure, mandatory connection conditions were introduced from 1 December 2017 to mitigate impact of additional DER (mainly PV) and maximise the ability of network to absorb DER without augmentation including:

- maximum out of balance export to network of 5kW;
- PV limit voltage raised to 258V at the customers PV system; and
- power quality characteristics applied to PV inverters to limit the voltage rise due to PV when voltage exceeds a threshold.

These connection conditions aimed at providing greatest benefit to customers DER to operate more continuously in environments of high voltage.

Given there is currently limited operational visibility of voltages and network modelling of the LV network, the strategy for responding to resolve quality of supply related enquiries includes:

- distribution transformer tap adjustments;
- installation of infill distribution transformers;
- upgrading LV and/or HV conductors with a higher capacity conductor;
- LV switching by changing open points to transfer loads to other parts of the network;
- installation of LV regulators; and
- phase balancing.

These works are part of an ongoing program of work to address localised, minor network constraints.

Notwithstanding, with the significant rise in customer enquiries largely driven by PV related HV enquiries (see Section 4.9.6), a reactive approach to quality of supply is no longer sustainable. In 2017, a program to install permanent metering in rural substations commenced, as did a program that installs LV network metering on distribution transformers in 200 metropolitan locations with high solar PV penetration; this is being expanded to regional centres in 2018. This will provide greater visibility of power quality issues on the network, enabling a more proactive remediation approach. It is envisaged the LV monitoring program will be rolled out further in response to solar PV related issues on the network, particularly as the uptake of solar PV is forecast to continue to increase (see Section 7.3.4.1).

7.3.6.3.2 Substations and high voltage network

The historical and forecast uptake of PV systems (see Section 7.3.4.1) is also having an increasing impact on the HV distribution network and substation transformers, which will lose the ability to control voltage in accordance with AS 60038.

The strategy for responding to large scale quality of supply impact on substation supply areas includes:

- incorporating Australian Energy Market Operator medium (neutral) solar PV growth into demand models;
- identifying the substation supply areas and transformers with limited voltage response at risk of being unable to meet quality of supply in accordance with AS 60038;
- completing a desktop assessment of the extent and cost of reinforcing the downstream LV networks of the identified substations;
- assessing the status of SA Power Networks approved distribution level voltage control equipment; and
- determining those substation transformers requiring replacement to lower the voltage on the HV distribution network and globally reduce voltage on LV network to ensure quality of supply can be maintained;
- changing equipment specifications for substation power transformers to provide greater range of voltage control; and
- determining those substation transformers requiring replacement through reverse power flow capacity limitations to ensure quality of supply can be maintained.

7.3.6.4 Responding to identified network constraints

Section 7.3.5.2 described the types of network constraints experienced on the network. Table 15 summarises the network augmentation plan to address the identified constraints to 2030 listed by system. It also includes projects identified through joint planning with the transmission network service provider, ElectraNet. ElectraNet works at its connection point substations, whether augmentation or asset replacement, generally affect the distribution network assets and require expenditure by SA Power Networks. Such works are coordinated between the parties through a common notification process. These joint projects are shaded in Table 15 for clarity.

Table 15: Network augmentation plan

Planned upgrade location	Capacity constraint description	Planned upgrade work	Indicative timing
Connection points (ElectraNet interface)			
Leigh Creek South 132/11kv transformer replacement	Works associated with project by ElectraNet at Leigh Creek South connection point	Network augmentation: Works associated with project by ElectraNet to replace end of life 132/11kV transformers at Leigh Creek South connection point	2020
Mount Gambier 132/33kv transformer replacement	Works associated with project by ElectraNet at Mount Gambier connection point	Network augmentation: Works associated with project by ElectraNet to replace end of life 132/33kV transformers at Mount Gambier connection point	2021
Mannum 132/33kv transformer replacement	Work associated with project by ElectraNet at Mannum connection point	Network augmentation: Works associated with project by ElectraNet to replace end of life 132/33kV transformers at Mannum connection point	2022
Yadnarie 66kv segregation	Works associated with project by ElectraNet in Cultana-Yadnarie region	Network augmentation: Works associated with project by ElectraNet to refurbish the transmission network in Cultana–Yadnarie region	2022
Sub-transmission system			
Square Waterhole to Myponga 66kv sub-transmission line	Several radial 66kV lines in the Fleurieu Peninsula are subject to interruptions with potential to impact Victor Harbor, Middleton and Goolwa regions	Topology: Market benefit to customers at risk of failure of single 66kV line will consider the installation of a new 66kV line Project to be subject to AER Regulatory Investment Test for Distribution	2023-2024
Woodville Industrial Park and Cheltenham to Finsbury No 1 and 2 distribution feeders	Sub-transmission lines designed for a temperature of 50 degrees, now overloaded during present day summer conditions	Network augmentation: Convert sub-transmission lines and associated distribution transformers to 11kV and retire redundant 33kV network	2020
Naracoorte to Naracoorte East 33kv sub-transmission line	Section of sub-transmission line between Naracoorte and tee-off to Naracoorte East zone substation forecast to be overloaded during peak periods	Network augmentation: Increase design rating of sub-transmission line to a higher temperature rating by increasing conductor clearances	2020
Athol Park to Woodville new 66kv sub-transmission line	Sections of sub-transmission lines overloaded during N-1 conditions during peak summer conditions.	Network augmentation: Construct a new 66 kV sub-transmission line between the Athol park and Woodville substations.	2024-2026

Planned upgrade location	Capacity constraint description	Planned upgrade work	Indicative timing
Sub-transmission system (Continued)			
Penola Tee to Penola 33kV Uprate	Section of sub-transmission line between Naracoorte and tee-off to Naracoorte East zone substation forecast to be overloaded during peak periods	Network augmentation: increase design rating of sub-transmission line to a higher temperature rating by increasing conductor clearances	2020
Mount Schank to Allendale East 33kV Uprate	Section of sub-transmission line between Naracoorte and tee-off to Naracoorte East zone substation forecast to be overloaded during peak periods	Network augmentation: increase design rating of sub-transmission line to a higher temperature rating by increasing conductor clearances.	2020
Substations			
Substation transformer voltage control for quality of supply	Forecast loss of voltage control due to increasing customer solar PV at substations: <ul style="list-style-type: none"> • Lower Mitcham • Athol Park • New Richmond • Noarlunga Centre • Northfield 	Asset augmentation: Multiple solutions to be deployed such as extended top range zone substation transformers, and variable control plant	2020–2025
Cape Jervis 33/11kV substation	Substation overloaded during present day summer conditions	Network augmentation: Upgrade Cape Jervis 33/11kV substation with 2MVA 33/11kV transformer, 33kV recloser and associated infrastructure	2020
Curramulka 33/11kV substation	Substation overloaded during present day summer conditions	Network augmentation: Upgrade Curramulka 33/7.6kV pole-top substation with 500kVA pole-top 33/11kV transformer and replace 7.6/0.4kV distribution transformers	2022
Tintinara 33/11kV substation	Substation overloaded during present day summer conditions	Network augmentation: Upgrade Tintinara 33/11kV substation with 3MVA pad-mount 33/11kV transformer, 33kV and 11kV reclosers and associated infrastructure	2020
Gumeracha 33/11kV sub/station	Substation overloaded during present day summer conditions	Network augmentation: Upgrade Gumeracha 33/11kV pole-top substation with 500kVA pole-top 33/11kV transformer, 11kV recloser and 33kV fuses	2021
Portee 66/11kV substation	Substation overloaded during present day summer conditions	Network augmentation: Upgrade Portee 66/11kV substation with 2.5MVA 66/11kV transformer, 66kV circuit breaker and associated protection/infrastructure	2023

Planned upgrade location	Capacity constraint description	Planned upgrade work	Indicative timing
Deloraine 33/11kV Substation	Substation overloaded during present day summer conditions	Network augmentation: Upgrade Deloraine 33/11kV pole-top substation with 500kVA pole-top 33/11kV transformer, 11kV recloser and 33kV fuses	2023
HV distribution network			
Upgrades of numerous metropolitan/rural feeders	Feeder upgrades and new feeder ties due to forecast network overloads (further information on locations in SA Power Networks Distribution System Planning Report)	Network augmentation: Various network augmentation works to address localised capacity constraints in the metropolitan and rural distribution – HV feeder networks	2020–2025
LV network			
Network-wide: Quality of supply and LV management strategy	Ongoing program to address existing quality of supply problems combined with minimal visibility of the LV network limits operational visibility, control, understanding and response to network operations. Thus, informed decision making is impeded for maximising integration of distributed energy resources and two-way flows, and ultimately providing the operational visibility required for active DER management as distribution system operator and managing customer quality of supply.	<p>Network augmentation: Ongoing program of quality of supply investigations and subsequent upgrades (e.g. infill transformers) to improve understanding of localised parts of the network and achieve compliance to required regulated standards</p> <p>Network augmentation: Increased LV network monitoring to improve understanding of the network and provide increased visibility in response to a rapid rise in uptrace of DER.</p> <p>Network augmentation:</p> <ul style="list-style-type: none"> • Building an LV network model in the advanced distribution management system monitoring system • Developing LV monitoring and analytics including external data sources • Managing customer DER information • Active DER management • Establishing a distribution system operator transition team 	2017–2030

The significant changes occurring in the network mean most forecast augmentation projects are limited to short term (<5 years), involve the creation of new assets, and should be reviewed annually for need and timing.

Further detail is outlined in the SA Power Networks Distribution Annual Planning Report and the Distribution System Planning Report (Asset Plan 1.1.01).

7.4 Asset planning and creation (customer connections management)

7.4.1 Introduction

This section outlines the management of provision of customer connection services (new connections, alterations to existing and real estate developments services), and the process for forecasting the expenditure and delivery of those services. For further information, refer to the connection management asset plan.

Customer connections summary

Every year, more than 20,000 customer requests are received for a new or altered service connection to the distribution network (excluding embedded generators).

Connection requests typically take three main forms:

- **Residential connections:** Generally, a basic connection service which requires minimal or no extension or upgrade (augmentation) to the distribution network; includes residential customers, small business and small embedded generator connections
- **Commercial and industrial connections:** New connections or alterations to existing connections to commercial or industrial developments or for larger property developments
- **Real estate developments:** Construction of a distribution network for greenfield or multi-tenanted apartment residential (usually) developments to facilitate final connection by the eventual resident owner or tenant

The creation of new assets or alternation of existing assets also results in some existing assets being decommissioned. Once constructed and tested to SA Power Networks requirements, the connection assets are gifted to SA Power Networks and become part of the regulated asset base.

All connection services require expenditure in network infrastructure to create new and/or alter existing assets. The expenditure incurred net of any customer contributions in accordance with the Australian Energy Regulator approved SA Power Networks Connection Policy determines the required connections expenditure. Independent forecasting is undertaken to advise of the required net expenditure (currently independently forecast out to 2026).

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graph TD
    AP[Asset Planning] --> ACA[Asset Creation/Acquisition]
    ACA --> AO[Asset Operations]
    AO --> ACM[Asset Condition and Performance Monitoring]
    ACM --> AM[Asset Maintenance]
    AM --> AR[Asset Renewal/Replacement]
    AR --> AD[Asset Disposal]
    AD --> AP
    
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7.4.2 Customer connections asset management objectives

The asset management objectives specific to customer connections are summarised in Table 16.

Table 16: Customer connections asset management objectives

Level of service category	Customer connections asset management objectives
Safety	<ul style="list-style-type: none"> No injuries/deaths to staff or contractors through installing, altering, inspecting, maintaining/repairing, replacing or decommissioning customer connections. Ensure personnel are aware, trained and competent in aspects of their roles for safety of design of any works related to connections. Establish, check and audit quality management system to maintain compliance to standards and process requirements.
Customer experience	<ul style="list-style-type: none"> Deliver customer connection quotes on time. Deliver customer connection services/alterations and development works in a timely manner or to agreed expectations. Compliance to the AER approved SA Power Networks Connection Policy to provide customer connection services as specified in the National Energy Retail Law and National Electricity Law.
Efficiency	<ul style="list-style-type: none"> Design and construct the most cost effective, technically feasible works to approved technical standards which have pre-considered equipment life-cycle costs including the cost of installation, operations, maintenance, replacement and disposal.

7.4.3 Risks

The main risks associated with the customer connections management include:

- The economic climate and government initiated programs play a significant role in the extent of customer connection projects and expenditure year to year. In the event of a major government project or initiative being announced on short notice, which requires a large new or modified connection or many smaller works, any unbudgeted non-customer funded cost needs to be absorbed within the total capital budget.
- The increasing complexity of customer-side generation and storage is leading to more complex connection requirements and cost.
- Uptake of new technology by customers may instigate either thinner (smaller in capacity) or thicker (larger in capacity) connection works. As an example, electric vehicles may be recharged by customer-installed embedded generation (thinner) or require fast charging from the distribution network (thicker).
- Inset networks whereby customers requesting a connection to the distribution network are geographically separated due to a third-party network being constructed.
- Personnel and community risks associated with driving, life cycle safety, working near powerlines, working on or near roadways, and consistent application governance process and systems.
- Competing works programs and resourcing availability to manage a customer driven category of works (sags and surges in connection works activity based on customer demand, economy, government incentives or individual customer needs).
- The extension and connection portion of work is contestable where accredited design and construction contractors can complete these works and gift the assets to SA Power Networks prior to energising leading to greater variability in forecast expenditure.
- Environmental considerations such as contamination, cultural heritage, flora and fauna.
- Development approvals, creation of easements (where required) and access and approvals by other utilities or identities utilising the space in road corridors.

To mitigate risks within SA Power Networks control, primarily around the processes for scoping and delivering the connection work, Network Management has a mature externally accredited Quality Management System that delivers quality products and services that customers value, that ensures SA Power Networks:

- work safely and consider the environmental impact of the services provided;
- commit to monitoring, reviewing, auditing and continually improving the Quality Management System by addressing both risks and opportunities to maintain compliance with ISO 9001:2015 Quality Management Systems;
- comply with all statutory obligations, standards, specifications and codes of practice including corporate policies and directives;
- understand current and future customer needs, meet customer requirements and strive to exceed customer expectations;
- adopt a process approach towards business management that drives consistency and efficiency across the workplace;
- establish a consistent, evidence-based approach to problem solving and decision making;
- engage people on all levels to take ownership and responsibility to solve problems, seek opportunities to make improvements and enhance competencies, knowledge and experience; and
- establish relationships with internal/external parties and customers which are based on a mutual commitment to quality assurance principles.

7.4.4 Customer connection management strategy

Under the National Electricity Rules and National Energy Customer Framework (NECF), distribution networks service providers have a legislative requirement to offer a connection to the network or modify an existing service to residential and business customers on request. In addition, various requirements and obligations must be met through the interaction with customers required under the NECF, which requires a high degree of governance. The SA Power Networks Connection Policy, required to be approved by the Australian Energy Regulator, outlines the connection services including the cost sharing arrangements with customers.

The connection services are classified into four connection types broadly based on the main economic drivers:

- **Minor customer connections (projects less than \$30,000):** Residential commencements, alterations and additions, and small non-residential building commencements of <\$1 million.
- **Medium customer connections (projects between \$30,000 and \$100,000):** Commercial developments typically <\$20 million value such as offices, shops, warehouses, agriculture.
- **Major customer connections (projects greater than \$100,000):** Commercial, government and developer connections typically >\$20 million such as CBD offices, factories and major engineering constructions.
- **Real estate developments:** Typically, greenfield real estate developments including major land subdivisions incorporating new roads and associated infrastructure, and a growing infill market (State Government supported) demolishing existing residences and replacing them with more residences.

Figure 51 shows the historical trend in the number of projects for minor connections which represents the clear majority of connection projects.

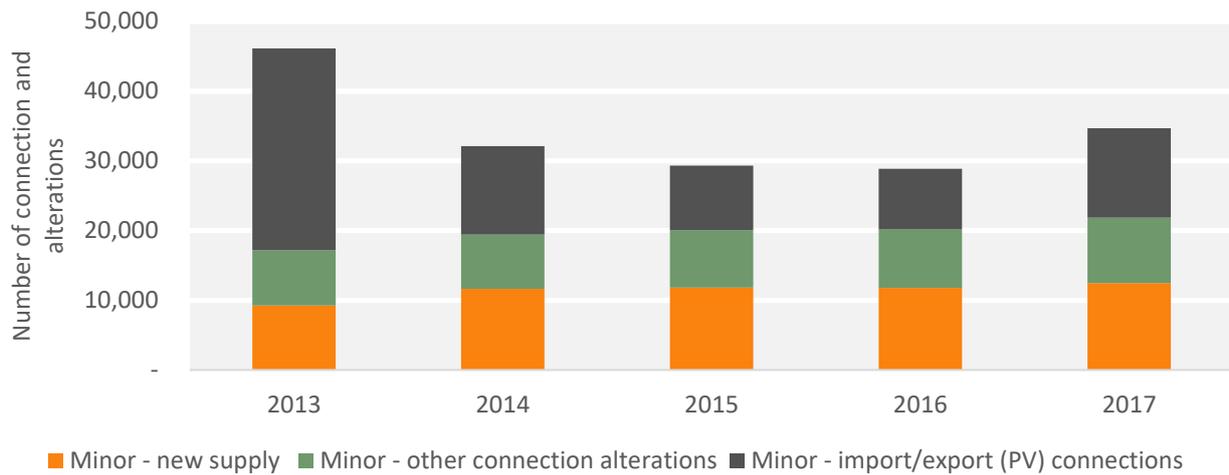


Figure 51: Historical minor connection and alterations

Figure 51 shows the number of minor connections was higher in 2013, which had a significant uptake of solar photovoltaic (PV), than in the following years. The number of new connections and connection alterations has remained relatively stable since then. From 31 March 2018 metering contestability came into full effect meaning new meter installations are completed by retailers and are no longer the responsibility of SA Power Networks. The number of SA Power Networks minor connection projects relating to import/export (solar PV) connections will therefore be zero from approximately April 2018 onwards.

Figure 52 shows the historical trends in the number of projects for the medium, major and real estate development connection types.

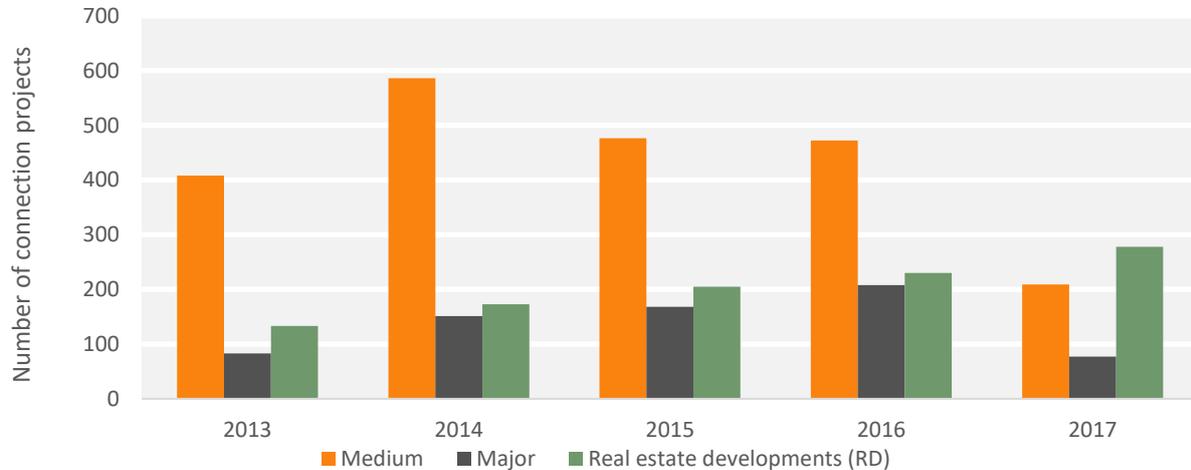


Figure 52: Historical medium, major and real estate development connection projects

Figure 52 shows that the number of medium connection works has reduced since 2014, largely due to a downturn in the South Australian economy and lack of government supported construction programs. The number of major projects has remained relatively stable; and real estate development connection projects have increased in volume, largely driven by changes in NECF obligations in 2015 when the definition for a real estate development changed from >10 allotments to >2 allotments.

The customer connections expenditure forecasting strategy, in determining the forecast customer connection expenditure, considers:

- a review of the historical number of connection projects for each connection type;
- Australian Bureau of Statistics data for historical and forecast population, building activity, engineering construction and building approvals;

- identification, size and timing of identified third party major developments or government supported projects;
- regular independent assessment of the economic outlook for South Australia across many sectors requiring connection to the network;
- the most recent approved version of the SA Power Networks Connection Policy detailing the customers level of contributions;
- NECF reporting requirements and associated auditing and governance required to meet legislated obligations; and
- historical customer contributions as a percentage of gross customer connection expenditure.

The forecast expenditure is determined through independent economic forecasting considering the above factors. The outcome is the projected gross expenditure, customer contributions and net expenditure for each connection type to deliver the forecast connection works. The historical number of connection projects is not used to project the forecast number of connection projects as the capacity and site-specific works for each project can vary significantly particularly for medium, major and real estate development connections.

Upon receiving requests from customers for a new or altered service connection, the strategy for developing the most cost-effective customer connection solution includes:

- determining the customer’s power requirements;
- assessing network connectivity and possible connection point(s);
- assessing asset condition and whether the proposed connection will adversely impact the existing assets performance and require existing assets to be refurbished, replaced or upgraded;
- assessing option(s) to connect to the distribution network;
- estimating costs of viable options;
- customer acceptance of proposed works and costs;
- delivering of the proposed works; and
- customer arranging the retailer to arrange the final connection to the electricity meter.

The specific works under this strategy are shown in Table 17.

Table 17: Customer connections works programs

Deliver energy services that enhance customer experience	
Capital programs of work	Benefits and outcomes
Customer connections	
<ul style="list-style-type: none"> • Minor customer connections (less than \$30,000) 	<ul style="list-style-type: none"> • Provide connections generally associated with new residences or small business or additions and alterations to existing residences or small businesses
<ul style="list-style-type: none"> • Medium customer connections (between \$30,000 and \$100,000) 	<ul style="list-style-type: none"> • Provide connections (generally associated with non-residential buildings, e.g. businesses and ‘other’ dwellings (e.g. flats)
<ul style="list-style-type: none"> • Major customer connections (more than \$100,000) 	<ul style="list-style-type: none"> • Provide connections generally associated with large business investment (e.g. defence, mining, major non-residential buildings, shopping centres and intensive agriculture, and government and private infrastructure investment, e.g. schools, railways and water supply)
<ul style="list-style-type: none"> • Real estate developments 	<ul style="list-style-type: none"> • Provide real estate development connections to the existing distribution network of new residential developments

The creation of new assets or alternation of existing assets also results in some existing assets being decommissioned. Once constructed and tested to SA Power Networks requirements, the connection assets are gifted to SA Power Networks and become part of the regulated asset base.

7.5 Asset operations (network operations)

7.5.1 Introduction

This section gives an overview of the principles and processes used for the real-time management and operation of the distribution network including emergency management and operational maintenance activities.

Asset operations summary

SA Power Networks operates a network operations centre (NOC) on a 24 x 7 basis that is responsible for:

- coordinating switching on the SA Power Networks distribution network to minimise risk to the safety of personnel, plant and continuity of supply;
- coordinating access to the network for work;
- directing and monitoring fault finding and repairs on the network; and
- managing the day-to-day risks associated with operation of the network.

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graph TD
    AP[Asset Planning] --> ACA[Asset Creation/Acquisition]
    ACA --> AO[Asset Operations]
    AO --> ACM[Asset Condition and Performance Monitoring]
    ACM --> AM[Asset Maintenance]
    AM --> AR[Asset Renewal/Replacement]
    AR --> AD[Asset Disposal]
    AD --> AP
  
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The central, integrated and dynamic system used by the NOC for managing and monitoring the comprehensive distribution network is the advanced distribution management system. This system is also used for feeder automation to automatically restore supply to un-faulted sections of a feeder when a network fault occurs.

A key function of network operations is risk management during emergency events including but not limited to:

- **Bushfire risk management:** Operational activities detailed in the annual Summer Preparations Plan (SPP), encompassing but not limited to vegetation management and asset patrols, to be actioned leading up to the Fire Danger Season (FDS), to mitigate the risk of the distribution network starting a fire. The Bushfire Risk Management Manual (BFRMM) details the preventative, preparatory and operational activities undertaken to mitigate the risk of fires starting from the distribution network. A Cost Benefit Analysis (CBA) model has been developed to quantify the bushfire risk and identify cost effective capital investment projects. This capital works program primarily involves installation of fast acting reclosers and modern surge diverters in HBFRA.
- **Disconnection of supply:** Manage the disconnection and reconnection of powerlines with risk line sections under defined fire danger level conditions.
- **Load shedding:** If the NEM electricity forecast consumption (demand) exceeds the supply availability, then AEMO may direct SA Power Networks to interrupt supply to restore the balance. In these situations, SA Power Networks will minimise the impact on any one customer group by rotating and interchanging the customers interrupted.

Other key network operations activities undertaken on a day-to-day basis include:

- **Operational maintenance:** Defect maintenance to address condition defects identified through the cyclic asset inspections or through preventative maintenance tasks.
- **Vegetation management:** Proactive vegetation management activities that ensure vegetation is appropriately managed near overhead powerlines to mitigate bushfire risk, ensure community safety, maintain reliability of the electricity supply and meet legislative compliance.

7.5.2 Asset operations objectives

The asset management objectives specific to asset operations are summarised in Table 18.

Table 18: Asset operations asset management objectives

Level of service category	Asset operations asset management objectives
Safety	<ul style="list-style-type: none"> • Protect SA Power Networks employees, contractors and the community from the risks of operating and maintaining the electricity distribution network. • Minimise the potential of fires starting from vegetation interfering with network infrastructure. • Minimise the number of switching incidents during the restoration of unplanned or planned interruptions to supply.
Reliability and resilience	<ul style="list-style-type: none"> • Minimise unplanned interruption frequency and duration arising from vegetation contact with network assets. • Minimise the number of risk line sections on the disconnection list leading up to the Fire Danger Season (FDS). • Minimise the duration of any planned interruptions resulting from planned disconnections during FDS through automation where the benefits of those works exceed the costs. • Feeder automation system to consistently restore the maximum number of customers within 60 seconds to minimise network reliability impact on customers.
Environment	<ul style="list-style-type: none"> • Increase percentage of customers satisfied with vegetation clearance undertaken near overhead powerlines. • Identify and implement alternatives to vegetation clearance such as tree removal and replacement. • Appropriate species selection for planting near overhead powerlines.
Communication and information	<ul style="list-style-type: none"> • Provide accurate information on restoration times for unplanned outages. • Provide accurate advanced notice for planned outages for operations, maintenance and asset replacements.
Efficiency	<ul style="list-style-type: none"> • Minimise life-cycle costs of asset replacements or upgrades for safety driven capital works including the cost of installation, operations, maintenance, replacement and disposal. • The feeder automation system to be readily expandable to operate widely on the distribution network. • Identify and implement cost effective capital works for bushfire risk mitigation. • Minimise vegetation management costs including the cost of scoping, clearance and disposal.

7.5.3 Network operations centre

SA Power Networks operates a network operations centre (NOC) on a 24 x 7 basis that is responsible for:

- coordinating switching on the SA Power Networks distribution network to minimise risk to the safety of personnel, plant and continuity of supply;
- coordinating access to the network for work;
- directing and monitoring fault finding and repairs on the network; and
- managing the day-to-day risks associated with operation of the network.

The NOC employs many critical operational technology systems and applications, including remote supervisory and control systems, to achieve its functions.

The NOC coordinates and controls all operational activity, both planned and unplanned, on the high voltage distribution network to ensure safety, compliance and performance. It reviews, coordinates and directs switching and isolation to permit the safe access for field workers to carry out work on electrical assets.

The NOC receives information of supply interruptions through both remote monitoring systems and through customer reports received by the call centre. Supply interruption details are recorded in the outage management system (OMS) which is used to consolidate, prioritise and dispatch the work to field crews. Those crews then undertake investigative work to identify the cause of the supply interruption, then under the direction of the NOC, undertake remedial work and restore supply to customers.

SA Power Networks has detailed network operation procedures and contingency plans in place which are reviewed and updated on a regular basis. The contingency plans are developed for critical assets where there is an identified high consequence of failure such as widespread supply failure, risk of plant damage, or risk to public health and safety.

7.5.3.1 Advanced distribution management system

The advanced distribution management system (ADMS) is a central, integrated and dynamic system used for managing and monitoring the comprehensive distribution network. It is currently used in the NOC as the primary SCADA master system, as well as for feeder automation. It is also used to initiate load shedding when directed by AEMO as well as for expediting the feeder disconnection process during high risk fire days (see Section 7.5.4).

The ADMS provides:

- **real-time execution and operations:** visibility and control across the distribution network settings;
- **a network operational model:** a representation of the electrical transmission network, sub-transmission system and distribution network that represents the network connectivity;
- **integration with other enterprise systems:** enabling of integration with the SAP works management system, OMS, protection settings database and outlook email system; and
- **off-line network analysis and operations planning:** ‘what if’ scenarios to be undertaken without impacting the operational system.

The connected geographic network model has been built in ADMS used to support all planned and unplanned switching from mid-2018. This means all switching writing and execution will be conducted using electronic switching programs in the ADMS. By performing electronic switching on a connected network model in ADMS leads to increased visibility of the real-time state of the network, potentially leading to more efficient supply restoration times and a decrease in switching incidents.

The ADMS supports the future operations of the network through having a live, real-time and connected network model, providing the central platform to meet future challenges, such as LV management, DER management, and automatic network re-configuration.

The lifecycle management of the assets forming the ADMS and those facilitating the transfer of information to this control system are discussed in Section 8.6.

7.5.3.2 Feeder automation

The purpose of feeder automation is to provide an automated fault location, isolation and supply restoration system to un-faulted sections of the feeder within the ADMS to improve customer reliability. In summary, the feeder automation system:

- provides a centralised means by which to determine fault location on feeders based on telemetered data from field devices;
- determines the isolation points for the faulted line section and the automatic execution of the switching to achieve that isolation;

- determines the most ideal supply restoration options for healthy feeder sections and automatically conducts the restoration based on limitations of the power system; and
- collects and collates fault data from relevant field devices for situational real-time display to operators.

Since commissioning, benefits have included process improvements by standardising installation, commissioning, and configuration philosophies, as well as operational improvements by installation of remote operable switching devices. The increase in remote switching capability at multiple points down the feeder, as well as the introduction of remote tie points, has improved fault finding speeds, switching efficiency and supply restoration times. The feeder automation system has improved supply restoration procedures and has allowed for remote restoration of healthy sections of line before field crews have even reached the site. This can reduce restoration times from hours to minutes (or less) preventing or minimising financial penalties to SA Power Networks arising from the fault. Full automation to restore all un-faulted parts of SCADA enabled feeders commenced in mid-2018.

7.5.3.3 Low voltage management

As discussed in section 7.3.6.3, there has been an observed a sharp increase in the number of customer complaints for voltage-related issues since 2017, as PV penetration in many areas begins to exceed the technical limits of the low voltage network. In areas of very high PV penetration, reverse current in the middle of the day can eventually become high enough to exceed the thermal rating of LV transformers or other assets.

These issues will be exacerbated by the emergence of battery storage and, in particular, Virtual Power Plants (VPPs) that enable customer batteries to be dispatched in a coordinated manner in response to market signals. This can cause very large swings in energy flow in local networks and has been observed in data from a VPP trial in Salisbury.

There is currently no active monitoring or management of the LV network; LV network issues are only identified reactively in response to customer complaints, followed by temporary installation of monitoring to investigate the problem and determine the necessary remediation work. As more distributed energy resources connect to the network and the volume of LV-related remedial work increases, this reactive approach is no longer sustainable. A transition to a more proactive approach to managing the LV network is required to maintain security and quality of supply for all customers.

The operation of the network must adapt in response; this includes a plan to transition to active LV network management over the 2018-2025 period including:

- **Modelling 'hosting capacity' across the LV network:** better forecasting of when issues will arise and will leverage the LV modelling work undertaken for the new OMS;
- **LV network monitoring:** installation of LV transformer monitors in 2017 to targeted areas, supplemented with voltage data from smart meters and other devices; and
- **Dynamic export limits:** offer dynamic export limit control to VPPs and potentially single customers, similar to the 'Generator Dispatch Limit (GDL)' signals provided to large embedded generators today. This will enable higher exports at times when there is no network constraint, with the facility to reduce exports to stay within the technical limits of the network at times of high solar output and low demand.

7.5.4 Emergency management

Emergency management is a key duty undertaken by SA Power Networks, and its purpose is to:

- minimise the risk to public health and safety;
- minimise the duration of supply outages;
- minimise the number of customers impacted by supply outages;
- minimise the risk of plant damage; and
- coordinate and support external emergency authorities.

Where high volume or emergency conditions occur, an appropriate emergency response level or fire danger level response is initiated. For escalated or forecasted emergency situations, an Emergency Response Team is convened to coordinate SA Power Networks response to network emergencies and liaise with other organisations including State Government Emergency Management organisations. All activities and decisions by the Emergency Response Team are recorded and all significant emergency response efforts are subject to meticulous review to identify opportunities for improvement.

For further information, refer to the Network Emergency Response Manual.

7.5.4.1 Bushfires

7.5.4.1.1 Introduction

South Australia faces a high risk of bushfires when hot, dry and windy weather conditions create high fire danger across many areas. As discussed in section 3.2, most of the network is overhead and much of it in high and medium bushfire risk areas (HBFRA and MBFRA). Consequently, one of the most significant risks to SA Power Networks is starting a major bushfire.

Fire starts from or near distribution infrastructure are regularly reviewed and reported through SA Power Networks’ Bushfire Risk Management Committee. Fires can start from both controllable (equipment or vegetation) and limited control (fauna, weather, third party, unknown) causes. The number and causes of fire starts varies from season to season with the majority triggered during the warmer months from November to March. Fire start data since 2010 shows an overall downward trend with the number of fire starts in HBFRA substantially reduced as shown in Figure 53.

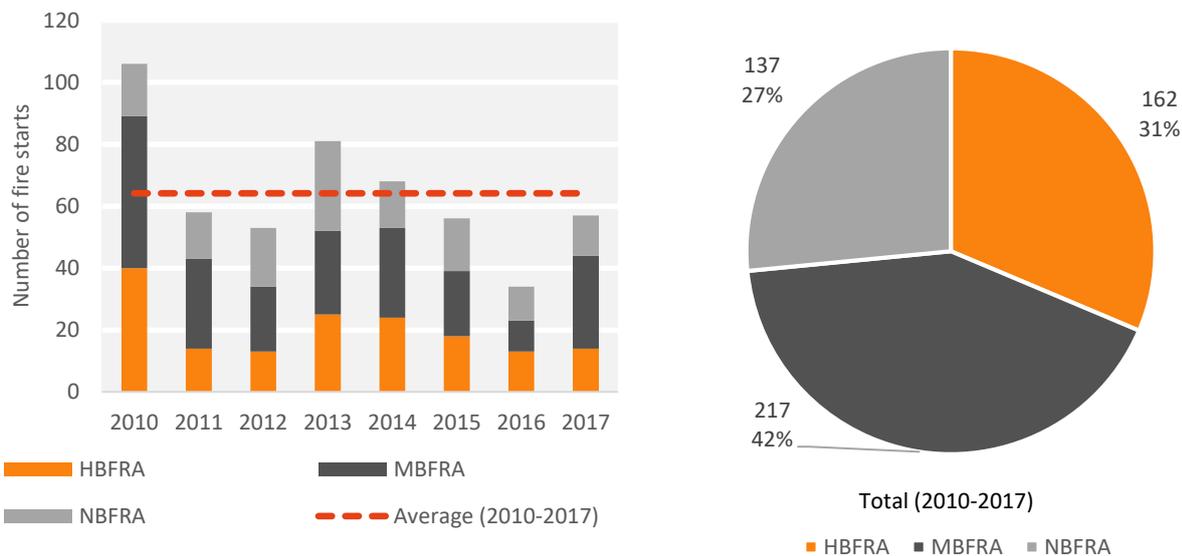


Figure 53: Fire starts near SA Power Networks infrastructure (2010–2017)

Several conclusions can be drawn from the data in Figure 53 including:

- The 57 fire starts near SA Power Networks infrastructure in 2017 was below the long-term average.
- The number of fire starts tends to be highest in MBFRA, with HBFRA and non BFRA having a similar percentage of fire starts.

The proportion of fire starts in MBFRA is expected given the extent of the network being operated in MBFRA (see section 3.2).

7.5.4.1.2 Bushfire risk management strategy

The network is designed, constructed and operated with consideration of the potential bushfire risks. Once assets are installed, the mitigation of bushfire risk includes a systematic focus on prevention of fire starts from the network operations leading up to the start of the Country Fire Service (CFS) declared FDS and safe operation of the network during the FDS. Operational activities to mitigate the risk of bushfire are outlined in the SA Power Networks Bushfire Risk Management Manual (BFRMM). Each year before the fire danger period, SA Power Networks implements preventative measures and prepares contingency plans to reduce the risk of bushfire start.

The bushfire risk management strategy, combining operational and capital works programs, can be summarised as follows:

- **Prevention before fire danger season:** Procedures for the identification and remediation of network faults and defects include
 - identifying potential bushfire start risks on network assets;
 - rectifying those risks;
 - applying contingency plans where those risks are outstanding;
 - ensuring feeder disconnection plans are in place where required; and
 - confirming necessary preparations for pre-FDS are completed.
- **Development and implementation of a summer preparations plan:** A consolidated plan detailing responsibilities and actions to be taken before the start of the FDS includes actions to reduce the risk of asset-related fire starts. The plan also lists actions for reducing the risk of heatwave supply interruptions.
- **Safe operation of the network during FDS:** Procedures for operation of the network during the FDS include:
 - determining the FDS and fire ban districts;
 - monitoring weather and configuring and operating the network for high fire danger conditions;
 - total fire bans;
 - contactability of personnel; and
 - fire reports.
- **Development of cost benefit analysis model:** A bushfire risk assessment model specifically developed for SA Power Networks' distribution network with input from CSIRO and key external stakeholders is used as a planning tool for mitigating bushfire risk. It incorporates:
 - the probability of fire starts in HBFRA's;
 - simulation of potential fire footprints based on a selection of fire danger rating and fire weather patterns;
 - quantification of the consequences of a fire including property, livestock, and equipment losses, fatalities and injuries;
 - quantification of the average annual bushfire risk attributable to the distribution network;
 - comparison of bushfire risks in different parts of the network in HBFRA; and
 - identification of locations on the network where the benefits of undertaking capital works exceeds the capital cost to mitigate the bushfire risk.

Figure 54 shows the effectiveness of the first three strategies; the cost benefit analysis strategy is still under development.



Figure 54: Controllable and limited control causes of fire starts v time from 2010 to 2017

Figure 54 shows that while annual fire start numbers rise and fall, those resulting from limited control causes (environment, third party and other/unknown) are trending downwards suggesting that SA Power Networks’ strategies for mitigating fire start risk are having a positive impact. Figure 54 shows controllable causes (equipment and vegetation) have a long-term increasing trend; mainly due to vegetation fire starts in 2010, 2013 and 2014. Figure 55 shows the split of the controllable causes showing equipment related starts are stable and that while vegetation causes were increasing to 2014; recent years have shown a significant decline because of the vegetation management strategy (see Section 7.5.5).

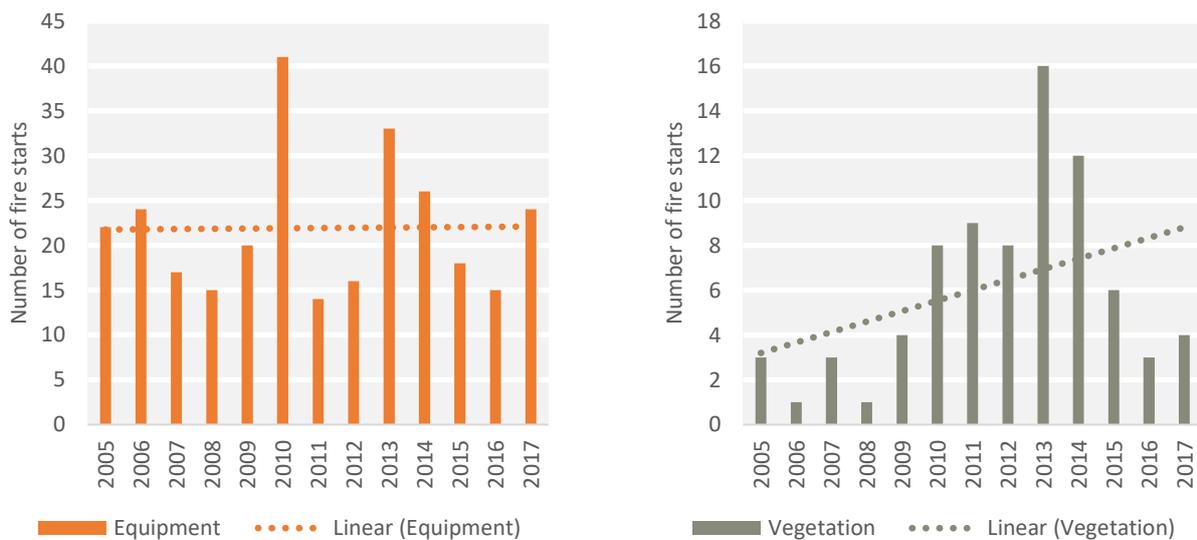


Figure 55: Controllable causes – equipment and vegetation long term trends

Figure 55 also shows the long-term trend for equipment related fire starts has remained stable largely because of the asset lifecycle asset management approaches applied to assets on the overhead network and the targeted replacement of assets identified to have caused fire starts.

The cost benefit analysis model is expected to further reduce the number of fire starts through a risk based approach with emphasis on identifying locations where capital works would have most benefit for risk reduction.

Other capital and operating programs do contribute to these trends (e.g. some asset renewals may have eliminated potential future fire start events), but the bushfire risk management strategies detailed in this section have the most significant influence on reducing fire start risk.

Further information on the bushfire risk management strategy is available in the SA Power Networks BFRMM.

The programs of bushfire risk management work are summarised in Table 19.

Table 19: Planned bushfire risk management programs of work

Operating programs of work	Benefits and outcomes
All systems	
<ul style="list-style-type: none"> Summer preparations plan: Consolidated plan of works to be implemented ahead of the FDS arising out of activity undertaken as part of the BFRMM 	<ul style="list-style-type: none"> Centralises control of works to mitigate identified and controllable causes of bushfire risk
<ul style="list-style-type: none"> Cost benefit analysis model: Bushfire simulation model specific to the South Australian distribution network 	<ul style="list-style-type: none"> Planning tool quantifies bushfire risk exposure Identifies locations presenting the highest bushfire risk exposure Identifies locations where the reduction in bushfire risk exceeds the cost of undertaking capital works
Capital programs of work	
All systems	
<ul style="list-style-type: none"> Fast acting recloser automation: Installation of fast acting, remotely operated switching devices on the network in HBFRA 	<ul style="list-style-type: none"> Enables rapid fault clearing on extreme fire danger days, and remote control to either re-configure protection settings or disconnect supply on extreme fire danger days Sectionalises feeders to reduce impacts on customers when disconnecting supply on extreme fire danger days
<ul style="list-style-type: none"> Surge diverter program: Replacement of high voltage (HV) protection devices prone to causing bushfire starts due to animal contact 	<ul style="list-style-type: none"> Phases out infrastructure prone to animal contact and flashovers that can trigger fire starts
<ul style="list-style-type: none"> Automatic weather station program: Acquisition of additional weather stations to improve decision making during fire danger season 	<ul style="list-style-type: none"> Improves weather observation and forecasting information to improve decision making during fire danger season Improves operational models to better understand bushfire risk

7.5.4.1.3 Disconnection of supply

To minimise the potential risk of fire starts, SA Power Networks annually develops a disconnection list of feeders prior to the FDS. Section 53 of the South Australian *Electricity Act 1996* specifies the conditions under which SA Power Networks may, without incurring any liability, disconnect the supply of electricity in

SA Power Networks opinion, it is necessary to do so to avert danger to person or property. SA Power Networks may also be required to disconnect supply to comply with a direction, order or requirement given under the acts detailed in Section 54 of the Electricity Act.

The Electricity Act requires that SA Power Networks should, if practicable, consult with the Chief Officer of the CFS before switching off supply to avert danger on high fire risk days.

Once switched off, a line will remain switched off until conditions have abated and the line is assessed as safe to restore supply.

Further information on the disconnection procedure is available in the SA Power Networks BFRMM.

7.5.4.2 Load shedding

Supply to customers may need to be deliberately interrupted, without notification, under emergency response conditions. This may be necessary for significant events occurring across the National Electricity Market (NEM) or for more localised distribution network emergencies such as safety violations, or overloads which could otherwise damage plant. Lines supplying critical infrastructure and the CBD are exempt from rotational load shedding.

There are two main types of load shedding:

- **Automatic load shedding:** when equipment in the electricity grid automatically switches off load to protect networks. This is normally associated with a sudden and unexpected disruption on the electricity grid such as the collapse of the transmission towers which led to the State-wide blackout on 28 September 2016.
- **Manual rotational load shedding:** when demand increases towards available generation and the Australian Energy Market Operator has time to direct utilities to shed load to restore the generation and demand balance in the national electricity grid. In these situations, SA Power Networks will minimise the impact on any one customer group by rotating and interchanging the interruption. This rotation of customers interrupted — called a rotational manual load shed event — occurs at an interval of approximately 30 minutes.

7.5.4.3 Heatwave management

Heatwave events are managed in accordance with the emergency response level procedures detailed in the Network Emergency Response Manual, including development of the required response plan by the Emergency Response Team.

7.5.5 Vegetation management

7.5.5.1 Introduction

Most of the distribution network is overhead (see Section 3.2.2). Consequently, there are risks associated with trees and vegetation in relation to their proximity to powerlines to avoid power outages, damage to the lines, fires or risks to people's safety. There are prescribed legislative requirements for SA Power Networks to undertake vegetation management to:

- mitigate bushfire risk;
- maintain reliability of electricity supply;
- ensure community safety; and
- meet legislative requirements.

SA Power Networks acknowledges that vegetation and trees also form a fundamental part of the urban and rural landscape. They grant a wide range of aesthetic and environmental value and benefits on both private and public land. There is a need to balance the risks and legislative requirements against the aesthetics and environmental value trees and vegetation provide the community.

The specific nature of vegetation clearance is based on forming the legislated ‘clearance zone’ between vegetation and infrastructure with a focus on safety and reliability. A clearance zone is the minimum safe distance between vegetation and powerlines and considers movement of the trees and powerlines in windy conditions and the growth rates of the trees during the cyclic cutting interval. The extent of the clearance zones and frequency of clearance varies according to whether the vegetation is in a BFRA or not, the voltage of the conductor, the swing and sag of the conductor, and whether the overhead conductor is insulated or bare.

The concept of a clearance zone for an HBFRA is shown as an example in Figure 56.

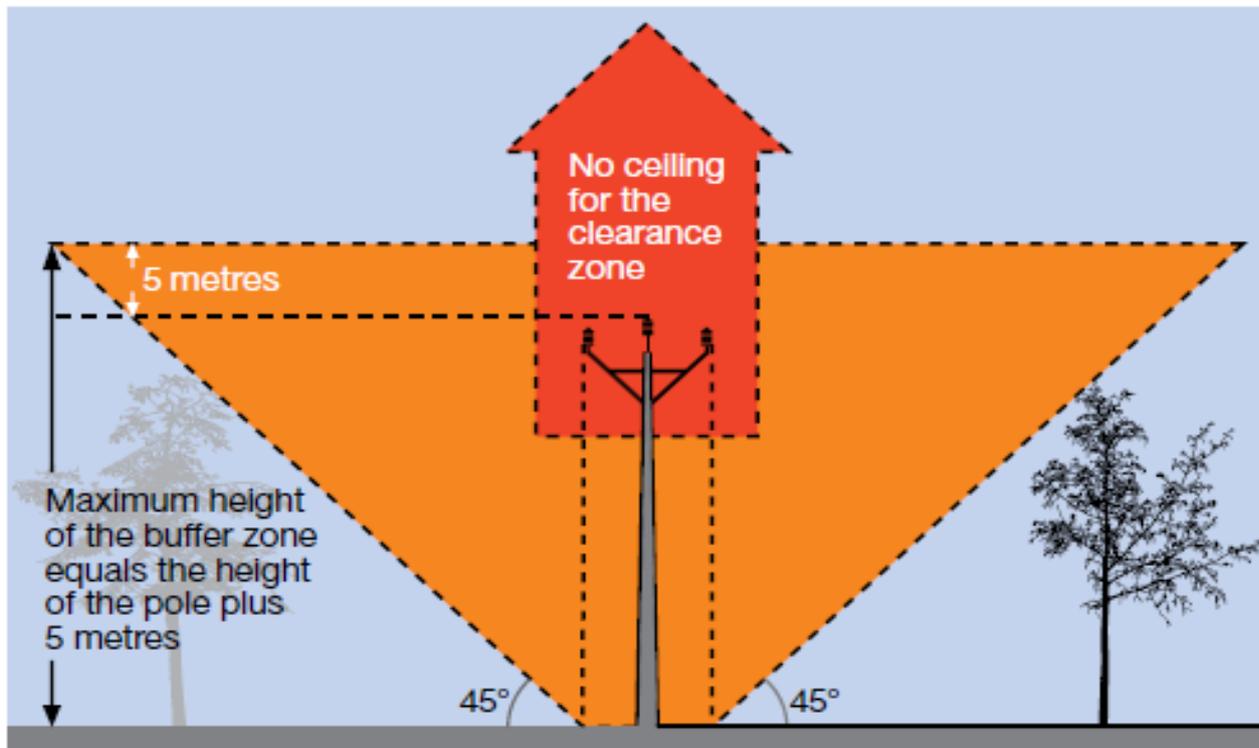


Figure 56: Clearance zone concept – high bushfire risk area

Figure 56 also shows a ‘buffer zone’ which is an additional area around a clearance zone. The vegetation clearance within the buffer zone will usually allow the clearance zone to remain clear until the next trimming is due. Further information on clearance and buffer zones is available in SA Power Networks *Protocol for vegetation management near powerlines*.

The current legislative framework was put in place after the 1983 Ash Wednesday bushfires. The specific nature of clearance requirements was framed around safety and reliability requirements, not aesthetics. The strategy for vegetation management aims to provide a more holistic approach that both ensures safety and maintains sustainable trees and environments.

7.5.5.2 Legislative requirements

SA Power Networks is required to meet many specific vegetation management regulatory obligations as a distribution networks service provider including a duty under section 55 of the Electricity Act and *Electricity (Principles of Vegetation Clearance) Regulations 2010* which includes:

- keep vegetation of all kinds clear of public powerlines under SA Power Networks control in accordance with the principles of vegetation clearance;
- keep naturally occurring vegetation clear of all private powerlines under SA Power Networks control in accordance with the principles of vegetation clearance;

- inspect and clear vegetation from around powerlines at regular intervals which cannot exceed three years; and
- achieve defined ‘clearance zones’, with specific references to clearance distances for use in making judgements on the extent and nature of cutting required.

7.5.5.3 Vegetation management strategy

SA Power Networks completes many vegetation management activities to provide a safe and reliable network, and meet legislative obligations. The vegetation management strategy, in summary, is:

- notifying or consulting affected parties, in conjunction with contractors, about vegetation management near powerlines;
- developing partnerships with councils to improve vegetation outcomes;
- clearing to manage vegetation near powerlines including (collectively the SA Power Networks vegetation management plan):
 - annual cyclic program in HBFRA and risk-based approach in MBFRA,
 - pre-fire danger season program in HBFRA,
 - three-year cyclic program in non BFRA,
 - three-year cyclic program in metropolitan areas, and
 - metropolitan 33kV/66kV pre-fire danger season preventative maintenance program on HV feeders;
- applying operational processes for employees and contractors with defined roles and responsibilities in clearing around powerlines, as outlined in the Vegetation Management Manual;
- investigating alternatives to vegetation clearance in partnership with councils to improve how vegetation near powerlines is managed, including tree removals and amenity pruning;
- applying the environmental management system to vegetation clearance activities to prevent or minimise adverse impacts on the environment;
- working with the Arborist Reference Group and LGA Working Group, to assess the effectiveness of the SA Power Networks long-term vegetation management strategy; and
- engaging in community education and awareness of vegetation clearance requirements.

Improved collaboration between SA Power Networks and local councils has seen fewer vegetation related complaints, reducing from 16% in 2013 to approximately 5.6% in 2017. This would indicate that vegetation is now managed more in line with community expectations.

The trend of fire starts suspected to be caused by vegetation encroachment on network infrastructure is shown in Figure 57. Data pre-2010 did not accurately identify vegetation as a cause of fire starts.

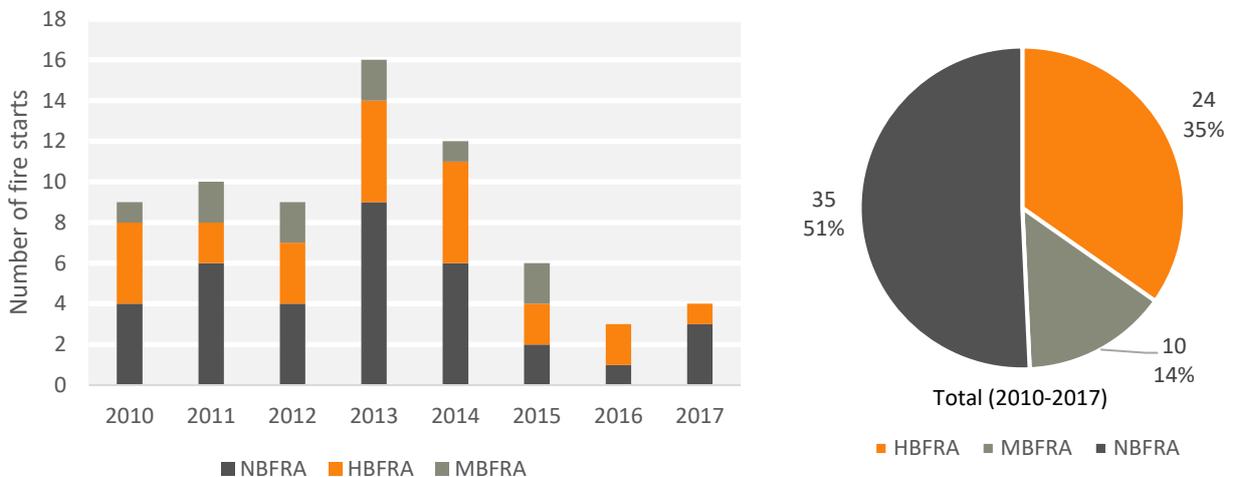


Figure 57: Total fire starts attributed to vegetation across BFRA 2010–2017

Figure 57 shows that the number of fire starts due to vegetation has reduced significantly since 2013 across all BFRA. Importantly, the number of fire starts in HBFRA has significantly reduced through improvements in vegetation management combined with a shift to annual inspections and clearance in BFRA.

The operating programs forming the vegetation management strategy are summarised in Table 20.

Table 20: Planned vegetation management operating programs of work

Operating programs of work	Benefits and outcomes
Sub-transmission system, HV distribution network, LV network	
<p>Consultation, notification, communication and decision-making processes:</p> <ul style="list-style-type: none"> • Formalised process for notification of scoping, planned cutting, emergency cutting • Communication of works through several communication channels and platforms • Community information and education material on vegetation management near powerlines, appropriate species to plant near powerlines and bushfire safety • Establishment of consultative groups to collaboratively discuss initiatives and issues • A proposed visibility tool to display the scoping and cutting programs and provide a means of enquiry and customer feedback 	<ul style="list-style-type: none"> • Improves notification and consultation on SA Power Networks vegetation management • Increases community and stakeholder awareness and understanding of vegetation management around powerlines • Identifies opportunities to improve stakeholders are informed of the vegetation clearance program and how SA power Networks will continue to engage with key stakeholders • Reduces longer-term costs of tree clearance around powerlines through improved planting location and species selection
<p>Agreements with councils, community, landholders and other land managers:</p> <ul style="list-style-type: none"> • Developing partnerships with councils to improve vegetation outcomes, including tree replacement and amenity pruning • Working with key stakeholders to identify opportunities for improvement 	<ul style="list-style-type: none"> • Improves working relationships with stakeholders • Aligns vegetation management practices and mutually beneficial outcomes achieved with stakeholders • Improves community acceptance of vegetation management practices • Reduces long-term costs for both SA Power Networks and councils
<p>Pruning and vegetation clearance:</p> <ul style="list-style-type: none"> • Scoping, pruning techniques, pruning cycle frequency, timing and scheduling considerations documented in a vegetation management protocol 	<ul style="list-style-type: none"> • Documents clear, consistent process for the vegetation clearance approach
<p>Alternatives to vegetation pruning:</p> <ul style="list-style-type: none"> • Tree removal and replacement programs — targeted removal of inappropriate, fast growing or large trees in consultation with local government and community • Growth management — invest in innovative trials such as the use of pesticides and a growth management system to inhibit regrowth • Relocating electricity assets — undergrounding of overhead powerlines can manage vegetation clearance and improve visual amenity (see Section 9.6 Power Line Environment Committee Program) 	<ul style="list-style-type: none"> • Provides alternatives to trimming in locations where aesthetics is of high importance • Minimises public safety risks from the network infrastructure • Provides targeted cost-effective solutions for localised vegetation encroachment • Applies alternative techniques in selected locations to provide more aesthetically pleasing and/or cost-effective solutions to pruning • Reduces SA Power Networks vegetation clearance costs over time

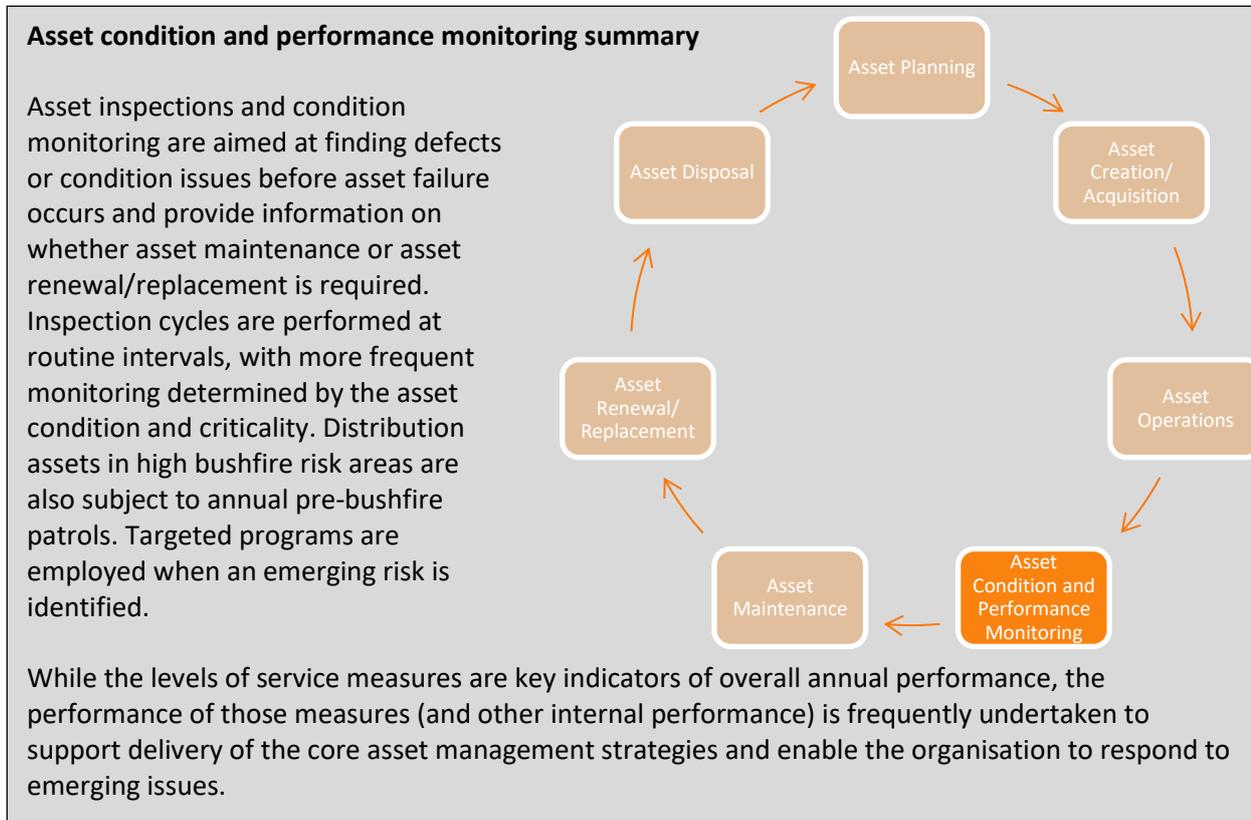
Operating programs of work	Benefits and outcomes
<p>Environmental management:</p> <ul style="list-style-type: none"> • Ensuring supporting processes are in place for: <ul style="list-style-type: none"> • preventing spreading of declared weeds • significant and regulated trees • protecting sensitive and protected areas and sites of cultural significance • fauna management • soil, waste and noise control 	<ul style="list-style-type: none"> • Minimises the environmental impacts of vegetation strategy and ensure compliance with SA Power Networks environmental management system • Increases awareness for operations staff of environmental, cultural and politically sensitive issues • Increases stakeholder confidence with the vegetation management clearance program
<p>Monitoring and review:</p> <ul style="list-style-type: none"> • Work with consultative groups, the Arborist Reference Group and LGA Working Group, to assess the effectiveness of the long-term vegetation management strategy • Pre-summer audits of vegetation clearance in BFRA • Identify and collaborate on opportunities for legislative changes 	<ul style="list-style-type: none"> • Continues improvements to adapt the strategy to the changing expectations and requirements of stakeholders • Advocates for legislated change in collaboration with other stakeholders

Further details of these programs of work are available in the *Protocol for vegetation management near powerlines*. Details regarding cutting cycles and resources are available in SA Power Networks Vegetation Management Manual.

7.6 Asset condition and performance monitoring

7.6.1 Introduction

This section gives an overview of the objectives and processes used for the asset condition and performance monitoring of the power network assets including the types of inspections undertaken for line and substation assets and the tools and techniques applied.



7.6.2 Asset inspection and condition monitoring objectives

The asset management objectives specific to asset inspections and condition monitoring are summarised in Table 21.

Table 21: Asset inspection and condition and performance monitoring asset management objectives

Level of service category	Asset condition and performance monitoring asset management objectives
Safety	<ul style="list-style-type: none"> Protect SA Power Networks employees, contractors and the community from the risks of condition and performance monitoring of the electricity distribution network. Minimise the potential of fires starting from assets due to condition and/or failure.
Reliability and resilience	<ul style="list-style-type: none"> Minimise unplanned interruptions through ongoing monitoring of network reliability and identification and responding to emerging trends. Minimise unplanned interruption frequency and duration arising from asset condition leading to asset failure. Minimise the impact on customer supply for any condition monitoring requiring assets to be isolated.
Communication and information	<ul style="list-style-type: none"> Provide accurate advanced notice on planned outages that are required for specific and targeted asset condition assessment.

Level of service category	Asset condition and performance monitoring asset management objectives
Efficiency	<ul style="list-style-type: none"> • Identify and implement cost effective asset inspection and condition assessment approaches. • Utilise asset inspection and condition information to continuously improve risk based decision tools. • Outperform forecast guaranteed service level payment costs across each regulatory period. • Achieve an overall neutral or better Service Performance Scheme result across each regulatory period.

7.6.3 Network asset inspection and condition monitoring strategy

Asset inspections and condition monitoring are aimed at finding defects or condition issues before asset failure occurs and provide information on whether asset maintenance or asset renewal/replacement is required. Inspection cycles are performed at routine intervals, with more frequent monitoring determined by the asset condition and criticality. Distribution assets in high and medium bushfire risk areas are also subject to annual pre-bushfire patrols. Targeted programs are employed when an emerging risk is identified.

Each asset class (and sub-class where appropriate) is assessed to determine appropriate inspection requirements. Detailed information on the asset assessment strategies, including inspection cycles and processes, are documented in SA Power Networks' Network Maintenance Manual, Line Inspection Manual and Substation Inspection Manual.

Inspection of substation and distribution system assets is conducted to assess the condition of accessible components of assets and identify hazards and/or components that have deteriorated to the extent that failure of the asset is likely. Emphasis is placed upon identification and management of known hazards and component failure modes which could jeopardise the:

- safety of the public, employees and contractors;
- safety of SA Power Networks' equipment; and
- continuity of supply to customers

7.6.3.1 Distribution system inspections

Inspections are predominantly based on a visual external inspection of line assets which are readily accessible to the inspector, including:

- inspection of overhead conductors for required clearance distances to ground, structures and vegetation;
- asset condition inspection of conductors, poles, pole top structures, transformers and other overhead assets for defects;
- asset condition inspection of underground network assets including access pits, cable supports, cable joints and other underground assets able to be accessed; and
- condition monitoring testing (e.g. thermographic inspections, corrosion measurements).

The inspections and testing undertaken on the major asset classes within the sub-transmission system and HV distribution network are discussed further in Section 8.2.

7.6.3.2 Substation inspections

Inspections are predominantly based on a visual external inspection of those components within the substation which are readily accessible to the inspector, including:

- building and property checks (fencing, overhanging trees, security system, signs, locks, etc)
- records of equipment oil levels, operating temperatures and gas pressures;
- records of operational counters and alarms (e.g. number of times equipment has operated)
- assessment of asset visual condition; and

- diagnostic or condition monitoring testing (e.g. thermographic inspections).

The inspections and testing undertaken on substation assets are discussed further in Section 8.4.

7.6.3.3 Asset inspection and condition monitoring techniques

SA Power Networks' inspection and condition monitoring practices include those listed in Table 22.

Table 22: SA Power Networks inspection and condition monitoring practices

Inspection or condition monitoring practice	Asset condition and performance monitoring asset management objectives
Ground Component Inspections (GCI)	<ul style="list-style-type: none"> • These visual inspections assess in detail the assets at ground level. In particular, the condition of poles and footings including an assessment of mechanical integrity and the level of corrosion of channels on the pole.
Overhead Component Inspections (OCI)	<ul style="list-style-type: none"> • These visual inspections (using binoculars) assess in detail, components of assets above ground level that GCI does not cover. For example, all other components on the pole, including conductors (conductor, fittings, tie wires, joints, services etc) and overhead equipment (switchgear, transformers, regulators, pole top structures, etc).
Aerial Inspections	<ul style="list-style-type: none"> • SA Power Networks has contracts for outsourced aerial inspection and patrol services using helicopters. These are primarily utilised for annual pre-bushfire patrols but are also utilised for emergency patrols, typically for storm related events.
Helidrone Inspections (Unmanned Aeronautical Vehicles (UAV))	<ul style="list-style-type: none"> • SA Power Networks engages aerial photography specialists to undertake remote controlled aerial surveillance and photography using state of the art micro UAVs. These are used in areas that cannot usually be accessed by full size helicopters where the top of the pole inspection is required and cannot be assessed visually from the ground (e.g. some suspension construction on 66kV lines).
Aerial LIDAR Inspections	<ul style="list-style-type: none"> • SA Power Networks is currently trialling the use of LIDAR technology to assess the benefits of assisting with vegetation scoping, vegetation auditing and asset inspection.
Thermographic Inspections	<ul style="list-style-type: none"> • The use of thermographic cameras to provide thermal imagery, to identify those components that have deteriorated due to a combination of corrosion and/or high load current to the extent that failure is likely by detecting hot spots within the inspected assets. These inspections are conducted on overhead assets, in substations and selected switchgear.
Substation Inspections	<ul style="list-style-type: none"> • Substations are inspected using a combination of visual inspection and thermographic inspection. Inspections include a check of the overall condition of assets (e.g. transformer, circuit breakers), the condition of all structural elements, the integrity of insulators and bushings, switchgear gas pressures, security of the site (e.g. fencing), oil levels in oil-insulated equipment, earthing connections, counter readings (for circuit breakers, reclosers).
Substation Switchgear Condition Monitoring	<ul style="list-style-type: none"> • Specialist switchgear inspections are conducted to assess the condition and performance of switchgear components to identify hazards and component deterioration. A combination of transient earth voltage (TEV) and ultrasonic detection, thermographic and visual inspections is used as part of non-intrusive electrical testing techniques to assess asset condition.
Substation Transformer	<ul style="list-style-type: none"> • Routine oil quality and dissolved gas analysis are performed on transformers. Specialist diagnostic and condition tests include thermographic inspections,

Inspection or condition monitoring practice	Asset condition and performance monitoring asset management objectives
Condition Monitoring	insulation testing and other specialised technologies for assessing specific asset condition.
Underground Cable Testing	<ul style="list-style-type: none"> Since mid-2016, a proactive cable condition assessment program has been undertaken using specialised equipment on HV distribution cables. Most testing is undertaken while cables remain in service; selective and more accurate testing may be undertaken but requires cables to be isolated.

These use of these inspection and condition monitoring on the various asset classes is discussed within the respective asset class strategies (see Section 8).

7.6.4 Performance monitoring strategy

While the levels of service measures are key indicators of overall annual performance, the performance of those measures (and other internal performance) is frequently undertaken to support delivery of the core asset management strategies and enable the organisation to respond to emerging issues. Examples of performance monitoring are listed in Table 23.

Table 23: Performance monitoring initiatives

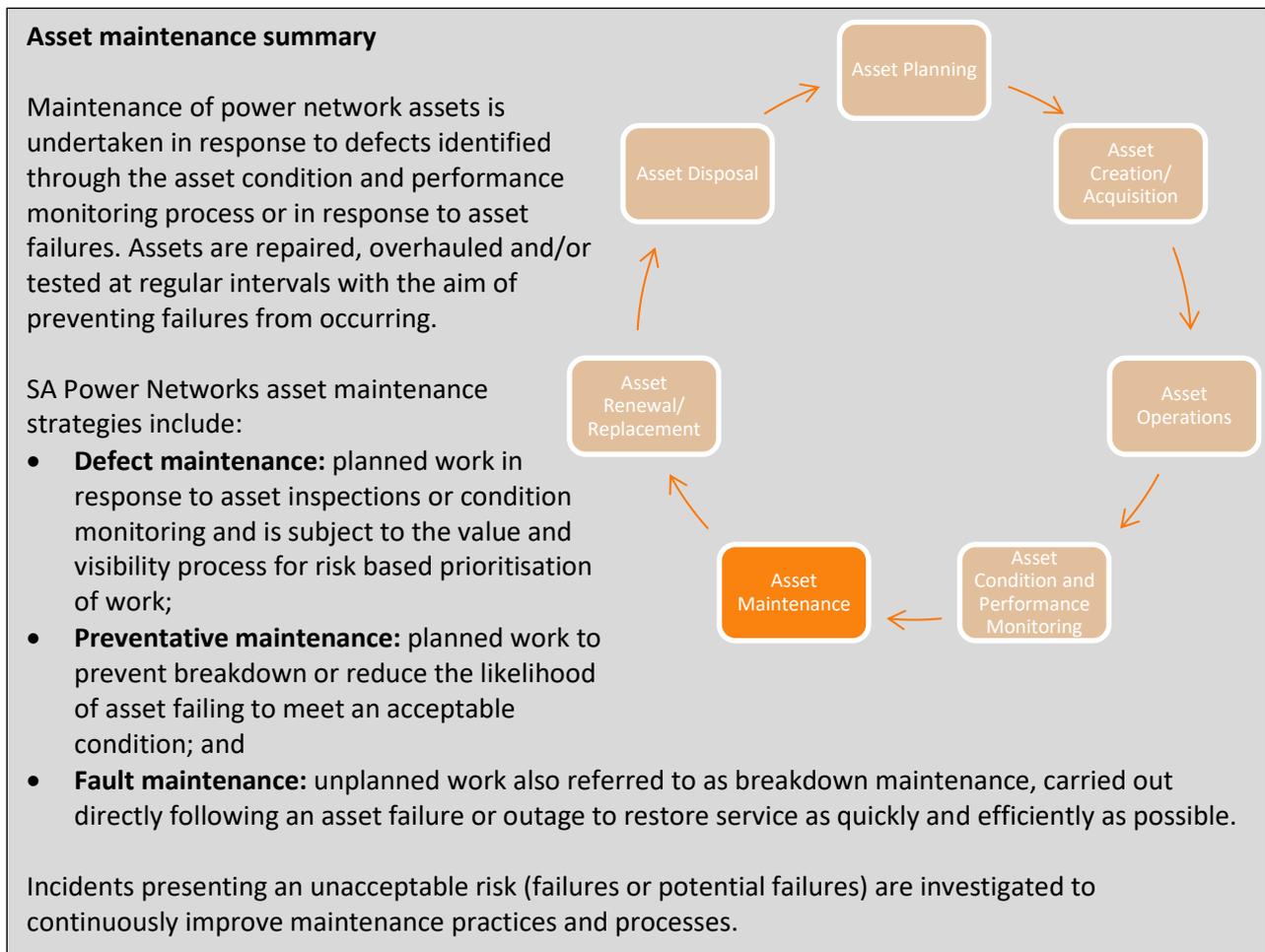
Initiative	Description of initiative	Benefit or outcome
Asset assessments	<ul style="list-style-type: none"> Monthly monitoring and reporting on the rate of completion of asset inspections and condition monitoring and testing. 	<ul style="list-style-type: none"> Monitor number of asset inspections completed v forecast inspections to inform and adjust resourcing requirements.
Performance reliability reports	<ul style="list-style-type: none"> Year to date reporting on SPS, SAIDI, SAIFI, CAIDI and GSL duration payments. 	<ul style="list-style-type: none"> Monitor current year network reliability trends against historical system average performance.
Fire reports database	<ul style="list-style-type: none"> Investigation of all fire starts near SA Power Networks assets to determine root causes, monitor trends and implement follow up actions. 	<ul style="list-style-type: none"> Monitor bushfire starts to ensure trends are monitored and that continuous improvement initiatives in reducing fire starts due to factors within SA power Networks control are implemented.
Equipment failure investigations	<ul style="list-style-type: none"> Investigation of major asset failures and/or unusual events across network substations and the HV distribution network. 	<ul style="list-style-type: none"> Key learnings fed back into existing processes and standards.
Service Performance Scheme (SPS) Steering Committee	<ul style="list-style-type: none"> Deliver optimal reliability and SPS outcomes for SA Power Networks; Monitor progress, performance and trends; Review high impact events and causes; Consider and approve mitigation strategies; Identify SPS opportunities and threats; 	<ul style="list-style-type: none"> Improve or maintain performance for the benefit but not at the expense of customers.

Initiative	Description of initiative	Benefit or outcome
	<ul style="list-style-type: none"> Seek strategic management solutions, projects, ideas and innovations; Challenge the current processes; and Facilitate agreement and provide endorsement. 	
Distribution defect and fault maintenance notification report	<ul style="list-style-type: none"> Monitoring of the quantity and value of defect and fault notifications raised (identified), issued (offered to Field Services after being valued), completed and outstanding (notifications that have been raised but yet to be completed) 	<ul style="list-style-type: none"> Compares the rate at which defects are being identified vs the rate at which the required work is being completed.
Notifications attached to assets report	<ul style="list-style-type: none"> Monitoring the percentage of open notifications attached to individual assets (or feeders). 	<ul style="list-style-type: none"> Improved condition information at individual asset level for improved asset management decision making.
Notifications valued report	<ul style="list-style-type: none"> Monitoring the percentage of open notifications valued across the network. 	<ul style="list-style-type: none"> Improved work selection processes for 'pulled' work.
Return on investment (ROI) report	<ul style="list-style-type: none"> Monitoring the total network risk removed divided by the expenditure to complete the works. 	<ul style="list-style-type: none"> Monitoring the overall return on investment for completed works.
Request for network design (RFND) report	<ul style="list-style-type: none"> Monitoring the quantity and value of distribution defects requiring a design. 	<ul style="list-style-type: none"> Inform resourcing and prioritise design work based on return on investment.

7.7 Asset maintenance

7.7.1 Introduction

This section gives an overview of the objectives and processes used for asset maintenance of the power network assets.



7.7.2 Asset maintenance objectives

The asset management objectives specific to asset maintenance are summarised in Table 21.

Table 24: Asset maintenance asset management objectives

Level of service category	Asset maintenance asset management objectives
Safety	<ul style="list-style-type: none"> • Protect SA Power Networks employees, contractors and the community from the risks of asset defects or failures. • Protect SA Power Networks employees, contractors and the community from the risks during planned maintenance. • Minimise the potential of fires starting from assets due to condition and/or failure.
Reliability and resilience	<ul style="list-style-type: none"> • Minimise unplanned interruption frequency and duration arising from asset condition leading to asset failure. • Maximise the application of safe maintenance practices that do not require supply to be interrupted to customers. • Minimise the impact on customer supply for any maintenance requiring assets to be isolated.

Level of service category	Asset maintenance asset management objectives
Communication and information	<ul style="list-style-type: none"> • Provide accurate information on restoration times for unplanned outages requiring fault maintenance. • Provide accurate advanced notice on planned outages that are required for planned asset maintenance.
Efficiency	<ul style="list-style-type: none"> • Identify and implement cost effective asset maintenance approaches. • Outperform forecast guaranteed service level payment costs across each regulatory period. • Achieve an overall neutral or better Service Performance Scheme result across each regulatory period.

7.7.3 Maintenance strategies

Maintenance of assets is undertaken at regular intervals (with the aim of preventing failures from occurring), in response to defects identified through the asset condition and performance monitoring process or in response to asset failures. As detailed knowledge of failure modes is developed, maintenance practices and strategies are refined. Each asset class (and sub-class where appropriate) is assessed to determine appropriate maintenance requirements.

The purpose of asset maintenance is to ensure that:

- the safety risks to staff, contractors and the community due to asset failures are minimised;
- the risk of interruptions to supply are minimised;
- standard maintenance practices are consistently applied and maintain optimum network performance;
- legislative, regulatory and organisational requirements are met; and
- asset performance is optimised and life cycle costs are minimised.

Each asset class (and sub-class where appropriate) is assessed to determine appropriate preventative maintenance requirements. Detailed information on the asset maintenance strategies, including maintenance cycles and processes, are documented in SA Power Networks' Network Maintenance Manual, Line Inspection Manual and Substation Inspection Manual.

SA Power Networks asset maintenance strategies include:

- **Defect maintenance:** planned work for the correction of a detected deficiency in an asset which would otherwise impact on the performance or lead to the failure of the asset; work to repair defects identified through routine inspections, servicing and testing to identify the needs for repair work;
- **Preventative maintenance:** planned work carried out in accordance with a predetermined policy or plan to prevent breakdown or reduce the likelihood of an asset failing to meet an acceptable condition; and
- **Fault maintenance:** unplanned work also referred to as breakdown maintenance, carried out either pre-emptively or directly following an asset failure or outage to restore service as quickly and efficiently as possible.

7.7.3.1 Defect maintenance program

Defect maintenance is initiated either through preventative maintenance, inspection or condition monitoring processes (see Section 7.7.3.2) or following breakdown maintenance (see Section 7.7.3.3). All outstanding defects are constantly assessed and defects are issued for rectification with the aim of reducing the maximum risk within the available budget through the value and visibility process (see Section 7.10). Where the risk is assessed as being too high for the available budget, requests for additional funds are escalated through the organisation.

7.7.3.2 Preventative maintenance program

The preventative maintenance strategies are unique to each asset class and asset subclasses. The frequency and maintenance tasks vary and take into consideration the manufacturers recommendations, industry practice, SA Power Networks' own experience and Reliability Centred Maintenance (RCM) principles specific to the installed asset.

Increasing emphasis is being placed on condition monitoring, including non-invasive diagnostic tests of plant as techniques and technologies for this become better developed. This can be a cost-effective means of identifying defects, often not able to be identified through visual inspections or more traditional diagnostic testing to identify assets at risk of failure. The results of the preventative maintenance are captured within the SAP system (see Section 10.3) used as inputs into condition based risk management (CBRM) models. The types of preventative maintenance strategies applied to each of the major asset classes are discussed later (see Chapter 8).

7.7.3.3 Fault maintenance

Undertaken following asset failure, this work may or may not permanently repair the failed equipment, as the objective is to restore supply as safely and efficiently as possible. Any work that is outstanding is recorded as a defect and prioritised through the defect maintenance program (see Section 7.7.3.1).

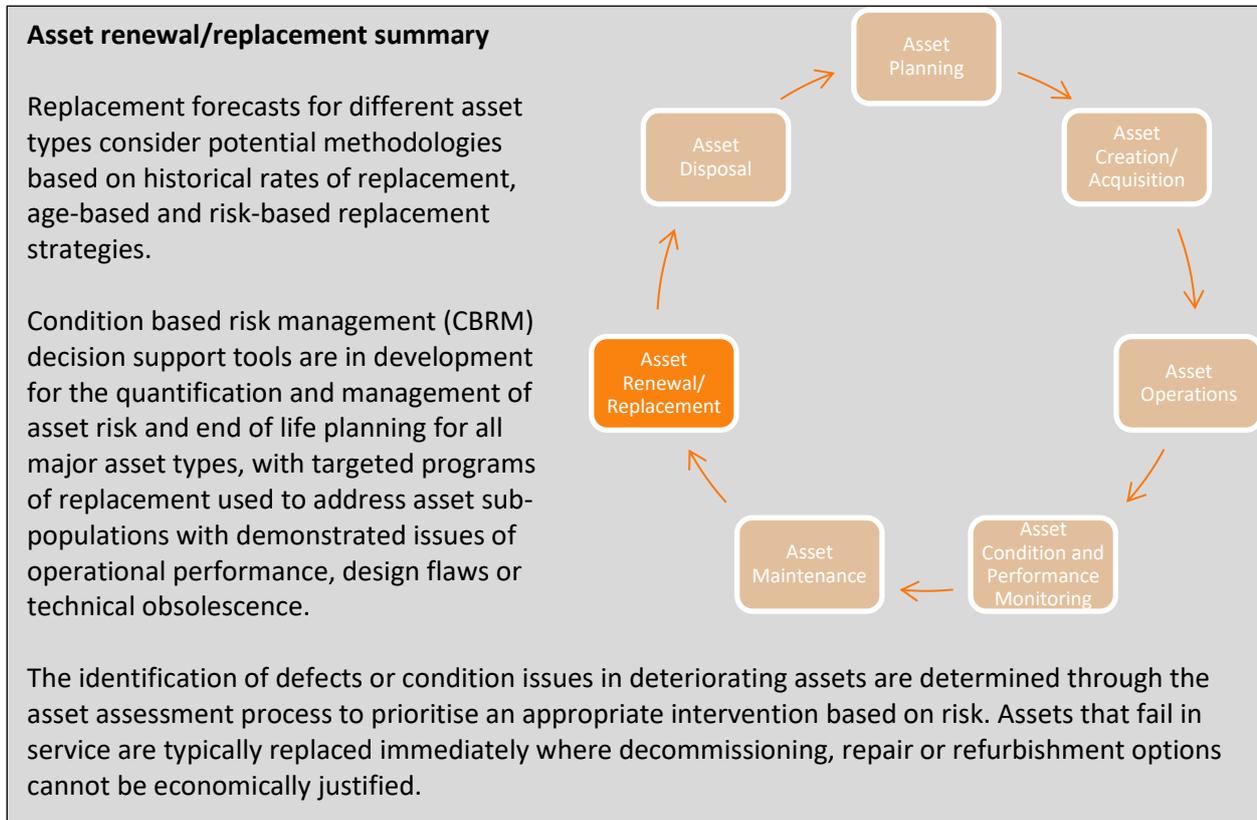
7.7.4 Performance incident investigations

Incidents presenting an unacceptable risk (failures or potential failures) are investigated by the appropriate asset management group for the purposes of preventing re-occurrences and improving system performance and reliability. The aim of any investigation is to ascertain the root cause of the incident and where possible implement changes to eliminate or reduce the risk of such events re-occurring.

7.8 Asset renewal/replacement

7.8.1 Introduction

This section gives an overview of the objectives and processes used for asset renewal/replacement of the power network assets. The Repex overview/justification document describes the methods considered in developing future renewal forecasts and the reasoning for selecting a preferred method and resulting expenditure which aligns with the financial forecast within this PAMP (see Section 12).



7.8.2 Asset renewal/replacement objectives

The asset management objectives specific to asset renewal/replacement are summarised in Table 25.

Table 25: Asset renewal/replacement asset management objectives

Level of service category	Asset renewal/replacement asset management objectives
Safety	<ul style="list-style-type: none"> No injury/death to staff, contractors or customers through installing, operating, inspecting, maintaining/repairing, replacing or decommissioning assets. No asset condition failures resulting in bushfire starts. No asset condition failures resulting damage to third party property.
Reliability and resilience	<ul style="list-style-type: none"> Minimise unplanned interruption frequency and duration from asset failures. Minimise planned interruption frequency and duration for asset renewal/replacement works.
Environment	<ul style="list-style-type: none"> Minimise the environmental impact through the renewal/replacement of assets.
Communication and information	<ul style="list-style-type: none"> Provide accurate information on restoration times for unplanned outages requiring asset renewal/replacement. Provide accurate advanced notice of any planned asset renewal/replacement works involving outages.
Efficiency	<ul style="list-style-type: none"> Minimise life-cycle costs of assets including the cost of installation, operations, maintenance, replacement and disposal.

7.8.3 Asset renewal forecasting methodologies

SA Power Networks assets are diverse and complex. Assessing the condition and performance of each asset and maintaining accurate records presents many challenges relating to processes and systems used to collect the data. While data quality improvements are ongoing, several models used to estimate the replacement forecast are heavily reliant on good quality asset and condition data.

The forecasting methodologies that have been considered for forecasting the proposed capital replacement expenditure (repex) on assets to maintain the level of service and manage the risk across the network are summarised below.

- **Current regulatory control period (RCP) expenditure:** based on current RCP actual and forecast expenditure; top down methodology using historical expenditure and forecast budgets (ignoring the effects of annual variations in expenditure). Generally used for ongoing renewal programs that don't expect significant changes to current levels of capital expenditure.
- **Projected trend:** based on the trend of historical expenditure over the previous and current regulatory periods; top down methodology using historical data to project a forward trend (including the effects of annual variations in expenditure). Generally considered where there is demonstrated, consistent trend of (increasing) capital expenditure required to manage the asset class.
- **Condition based risk management (CBRM):** a bottom-up methodology of an asset population, determining the individual condition of each asset, the consequences of its failure modes, and hence the risk each asset presents. Generally used for high consequence assets, actively targeted for optimised asset management decision making and supported by robust asset and condition data. Allows analysis of numerous intervention scenarios to determine the optimal choice of action for the desired asset management outcome including:
 - **Maintain health:** monitoring of asset condition and deterioration across the asset class and replacing assets based on forecast condition (to avoid asset failure); this scenario treats all assets within a population equally (ignoring failure consequence and replacement cost), to replace assets that have exceeded a specified health index (HI) value and are considered likely to fail; and
 - **Maintain risk:** efficiently maintaining a constant risk profile for an asset class through proactively targeting renewal/replacement interventions for critical assets in poorest condition and most likely to suffer a major failure.
- **Australian Energy Regulator Repex Model:** a bottom-up methodology; Microsoft Excel based model developed for the Australian Energy Regulator to benchmark replacement capital expenditure; predicts an aggregated volume of replacements based on the age of assets on the network and the aggregated average age of replacement (mean life).
- **Targeted expenditure:** intervention programs based on a bottom-up engineering analysis to address specific asset risks related to design flaws or performance issues (beyond age related degradation) that make them prone to early failure without intervention or present unacceptable risks to staff, contractors or the community.

For further detail see the SA Power Networks Repex overview/justification document.

The forecasting methodologies considered for each major asset class are shown in Table 26.

Table 26: Repex expenditure forecast models

	Historic expenditure	Historic trend	CBRM	RepEx	Targeted
Powerlines					
Poles	○	○	●	○	
Pole top structures	●	○			
Reclosers	●	○			
Conductors	●	○	△	○	
Distribution transformers	●	○		○	
Service lines	●	○		○	●
Switching cubicles	●	○	△		
Cables	●	○	△	○	●
Other	○	○			●
Substations					
Protection relays	○	○	●		
Circuit breakers	○	○	●		
Power transformers	○	○	●	○	
Other	●	○			
Telecommunications	○	●			●
Safety	○	●			●

○ = other forecast models considered

● = proposed forecast method(s)

△ = under development

The outputs from these methodologies are compared and considered based on the level of confidence in the quality of data used for each methodology, appropriateness to asset class strategies, historical practice and contrast to recent historical levels of expenditure and asset performance to develop a balanced view of the required level of investment required.

Short term renewal expenditure is based on prudent risk management principles, historical program expenditures, targeted replacement programs/projects and subject matter expert/ engineering judgement regarding the need to address emerging risks.

7.8.4 Asset health

CBRM models can provide a systematic measure of asset health through calculation of a health index (HI), which reflects the condition and likelihood of failure of an asset; the higher the HI the higher the probability of failure.

The HI is used to compare the relative condition between assets or across asset classes. The following major asset classes have been modelled using the CBRM methodology:

- Circuit breakers
- Power transformers
- Protection relays
- Poles
- Conductors (commenced but requires data quality improvements)
- Cables (commenced but requires data quality improvements)
- Switching cubicles (commenced but requires data quality improvements)

The HI of individual assets is calculated based on many factors including:

- the age and average life expectancy (expected life) of the equipment type;
- localised factors affecting the rate of equipment degradation (such as the installation environment);

- the physical or operating loads placed on the asset;
- inspection, maintenance and condition assessment results;
- known defects in certain assets or groups of assets;
- failure history of the assets;
- issues that limit expected life such as compliance with safety or environmental regulations.

The expected life is the time (in years) in an asset's life when it would be expected to first observe significant deterioration, taking into consideration location or duty, in addition to the asset type. The HI of assets class can be aggregated to indicate the overall condition for the asset class. The higher the HI the higher the probability of failure (PoF) for that asset. Table 27 summarises the HI categories used in the CBRM models.

Table 27: Health index categories

HI	HI description
0–4	Represent normal deterioration in early stages (good condition). This may be considered as normal ageing, e.g. the difference between a new asset and one that has been in service for some time but is still in good condition. In such a condition, the PoF remains very low and the condition and PoF would not be expected to change significantly for some time.
4–5	Represent some observable to serious deterioration, degradation processes starting to move
5–6	from normal ageing to processes that potentially threaten failure. In this condition, the PoF, although low, is starting to rise and the rate of further degradation is steadily increasing.
6–7	
7–8	Represent advanced deterioration (nearing or at end of reliable service life), degradation
8–9	processes are now reaching the point that they threaten failure. In this condition, the PoF is now
9–10	significant and the rate of further degradation will be relatively rapid.
>10	Asset is beyond its reliable service life

7.8.5 Renewal/replacement strategies

7.8.5.1 Risk based replacements

SA Power Networks' long and short-term renewal replacement strategies adopt a risk based approach. The identification of defects or condition issues in deteriorating assets are determined through the asset assessment process to prioritise an appropriate intervention based on risk (see Section 7.10.3). Assets that fail in service are typically replaced immediately where decommissioning, repair or refurbishment options cannot be economically justified.

Condition based risk management (CBRM) decision support tools are in development for the quantification and management of asset risk and end of life planning for all major asset types, with targeted programs of replacement used to address asset sub-populations with demonstrated issues of operational performance, design flaws or technical obsolescence.

The failure consequences modelled within CBRM include:

- **Safety:** minor, significant or major injury to the community and employees because of an event;
- **Network performance:** financial penalties imposed if an event causes an outage in the form of customer interruptions (e.g. system average interruption duration and frequency index impacts);
- **Environment:** cost of environmental clean-up/penalties as a result on an event;
- **Capex:** capital investment required to renew/replace a failed asset; and
- **Opex:** operational cost associated with a failed asset, including operational cost to restore power in the event of a failed asset.

The CBRM models calculate an individual assets likelihood of failure based on the observed population's historical failure rates. Quantifiable measures of condition, performance, failure consequences and asset deterioration allow risk to be modelled for individual assets and forecast for future years. The change in risk profile over time is forecast by CBRM which calculates the deterioration over time for individual assets

which can then be aggregated at the asset class level or by system. CBRM outputs for the asset classes modelled are included in Chapter 8.

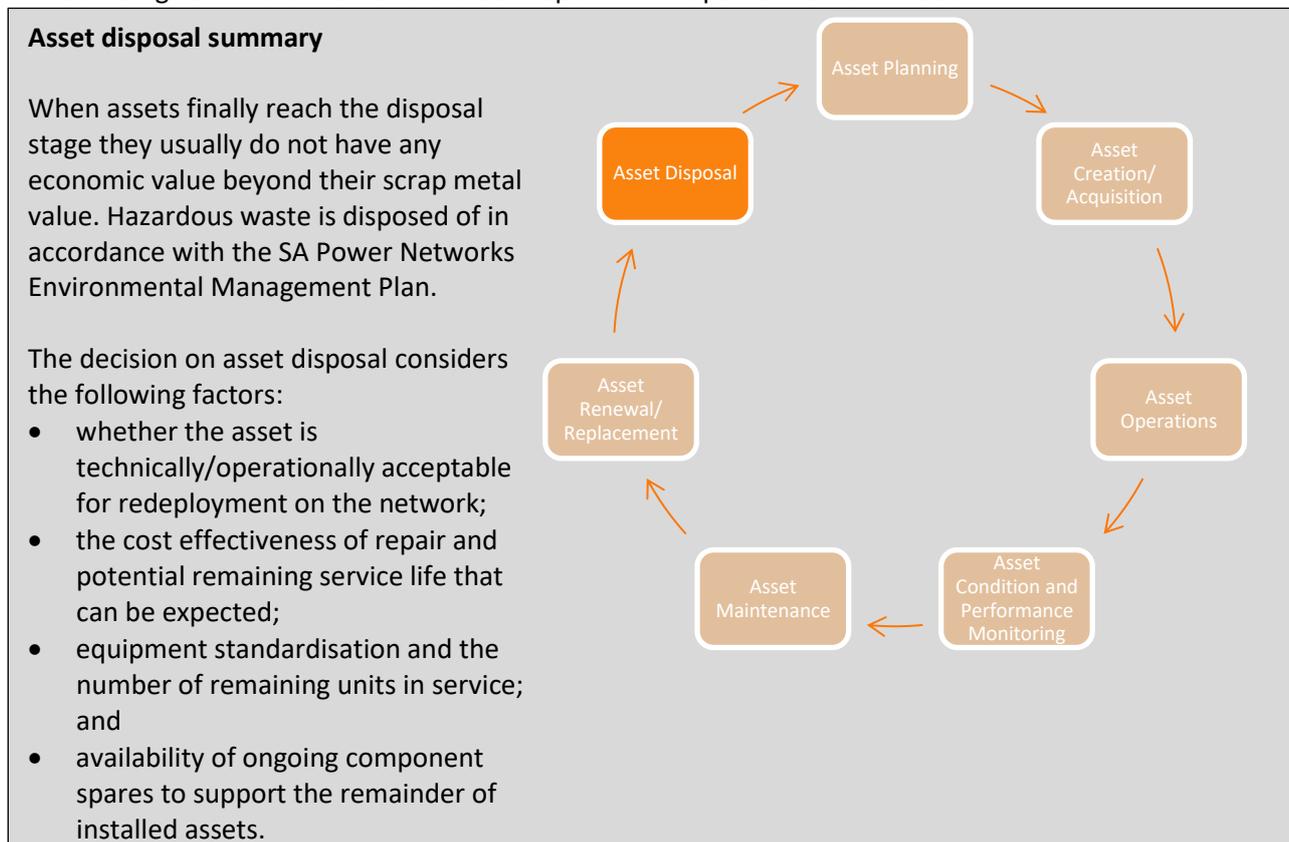
SA Power Networks also has an active program to rationalise the number of equipment variations on the network. Reducing the variances of equipment and plant standardises equipment and reduces the number of safe operating procedures that need to be developed, maintained and referred to. This provides a safe environment for employees, contracts and the community while reducing the whole of life cost as its easier to keep spares and dispose of equipment.

7.8.5.2 Targeted replacements

Targeted replacement programs are treated separately to CBRM modelling as outliers to the general population (or non-modelled asset types) with risks related to specific design flaws or performance issues (beyond age related degradation) that make them prone to early failure without specific intervention. These programs are referred to as ‘pushed work’ (see Section 7.10.2) as it targets a replacement of a group of assets deemed to present a high risk requiring replacement.

7.9 Asset disposal

This section gives an overview of the asset disposal of the power network assets.



7.10 Optimised lifecycle expenditure

7.10.1 Asset lifecycle management activity

Throughout the asset lifecycle, opportunities are taken to optimise expenditure and simultaneously minimise the impact on customers levels of service. Provided network performance, safety and customer service levels are not adversely impacted by optimisation methods, a combination of systems and processes are used to optimise resources and minimise impact on the customer is shown in

Table 28 with further discussion where applied on the major asset types or within targeted strategies discussed in Chapters 7 and 8 and in the various Asset Plans.

Table 28: Optimisation of capital and operating expenditure across the asset management lifecycle

Asset life cycle stage	Description of opportunity	Benefit or outcome
Asset planning	<ul style="list-style-type: none"> improving the accuracy of demand forecasts after each summer using latest load recordings, generator connections (including PV and battery), system modifications and any new committed large load developments Regulatory Investment Test (RIT-D) for projects to \$6 million managing customer peak demand – demand management; maintaining models to predict asset operating limits project risk ranking through application of the SA Power Networks risk management framework 	<ul style="list-style-type: none"> undertake augmentation expenditure in line with network demands utilisation of non-network options to address network constraints where feasible extend life of existing assets optimise configuration of network ensures highest network risks are prioritised
Asset creation/ acquisition	<ul style="list-style-type: none"> reconfiguring the network to accommodate new connections use of modern day equivalent assets internal resources for minor replacement works, external panel arrangements for larger projects for open tender process 	<ul style="list-style-type: none"> appropriate level of customer contributions towards the construction of assets within regulatory guidelines improved equipment reliability and functionality competitive tendering to achieve competitive pricing
Asset operations	<ul style="list-style-type: none"> increasing the power factor and load factor on equipment introducing dynamic and overload ratings increasing the utilisation of assets 	<ul style="list-style-type: none"> extend life of existing assets optimise configuration of network
Asset condition and performance monitoring	<ul style="list-style-type: none"> implementing the optimal level of condition monitoring predictive risk modelling on major asset classes introducing new low risk technologies to reduce whole of life cost (e.g. inspection drone trials) 	<ul style="list-style-type: none"> focus resources on assessing condition of most critical assets focusing available capital on the highest risks in the network use of emerging technologies to undertake asset inspections to evaluate the suitability of pole top inspections and feeder patrols
Asset maintenance	<ul style="list-style-type: none"> utilising live line work practices greater reliance on condition and risk based maintenance programs 	<ul style="list-style-type: none"> reducing number of planned outages optimising maintenance delivery
Asset renewal/ replacement	<ul style="list-style-type: none"> push and pull work selection (see section 7.10.2) development of a work valuing tool (see Section 7.10.2) 	<ul style="list-style-type: none"> ensures most important work delivered first; lower priority work delivered subject to resource capacity

Asset life cycle stage	Description of opportunity	Benefit or outcome
	<ul style="list-style-type: none"> visibility map for planned work (see Section 7.10.2) condition based risk modelling to undertake scenario modelling for various expenditure profiles extending the effective life of assets through asset refurbishments deferring capital expenditure by implementing lower-cost short-term projects minimising the range and quantity of spare holdings maintaining strategic spares for high risk assets 	<ul style="list-style-type: none"> enabling works to be more consistently prioritised to achieve the greatest return on investment enables works in close proximity to be bundled to improve delivery efficiency maximising risk reduction for capital outlay more cost-effective refurbishment to defer asset replacement incorporation of most recent network design features and components in the eventual replacement or refurbishment program to integrate with the evolving network equipment standardisation and reduced risk of obsolescence less risk of prolonged interruptions through having critical spares readily available
Asset disposal	<ul style="list-style-type: none"> salvaging components for reuse sale of scrap materials 	<ul style="list-style-type: none"> minimise environmental impact and disposal costs

In addition, there are several incentive schemes regulated by the AER that incentivises efficient use of capital and operating expenditure as well as for considering non-network options to defer the need for network augmentation. There are potential benefits for both SA Power Networks and customers resulting from these schemes arising through the practices outlined in Table 28.

7.10.2 Push vs pull work selection

SA Power Networks has a well-structured approach for capital delivery and optimisation of resources. Capital work can be categorised as either ‘pushed’ or ‘pulled’ on the basis of the importance, date dependency and complexity of the task as shown in Figure 58.

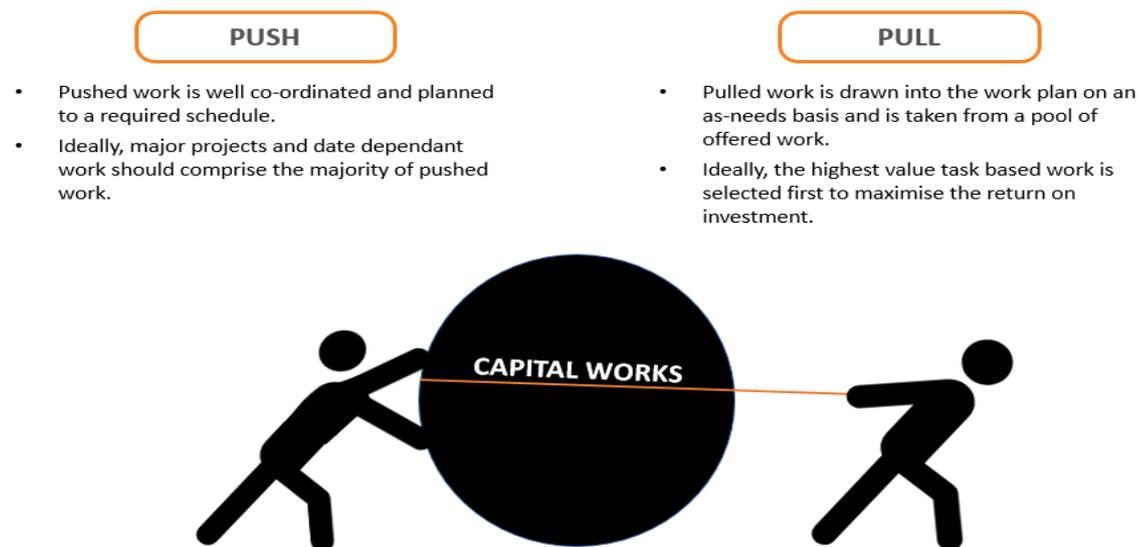


Figure 58: Capital works ‘push’ and ‘pull’ levers

Figure 58 shows pushed work should enter the plan first with any remaining capacity with resources and/or budgets then filled via pulled work. Pushed work are typically larger and/or complex projects > \$200,000 usually requiring design. Pulled work is ‘valued’ and ‘offered’ through the value and visibility process (see Section 7.10.3) and may or may not require design.

7.10.3 Value and visibility

In 2014 SA Power Networks agreed with the OTR and ESCoSA to address and rectify outstanding defects using a risk-based approach with the objective to return overall asset condition and risk to more satisfactory levels over a 10 year period (2015–2025). A key feature of SA Power Networks’ asset management decision making process is based on return on investment. The process of valuing work enables SA Power Networks to select the optimum maintenance and replacement strategy for each asset class that is technically feasible, economically viable, and delivers an acceptable residual risk against SA Power Networks’ risk strategy measure while delivering customer value.

The value and visibility (V&V) is the current operational tool used on line assets and being implemented on substation assets to assess the level of risk present in the network arising from identified defects and other required works for small and medium repeatable jobs by:

- **Having an agreed comparison of work value:** the sum of the reduction in risk and the benefits being gained by undertaking work whether it be capital or operating expenditure
- **Making work visible to everyone:** enables works in close geographic proximity to visible for improved planning
- **Enabling bundling:** grouping together other less urgent (secondary) work to augment the primary task (‘anchor jobs’)

The V&V process is currently applied to SAP work management system notifications (identified works) including distribution defects (DD), fault management notifications (FM), reported quality of supply faults (QS), customer negotiated services (CN) (e.g. new service connection infrastructure) and identified reliability works (RI). The application to substation defects (SD) is being progressed during mid-late 2018. It provides an additional level of defect scrutiny to allow identified work to be valued for prudence (confirms work is required) and efficiency (prioritise the work that provides the greatest reduction in risk for the investment). The required maintenance or renewal/replacement work is prioritised based on greatest return on investment (e.g. priority given to low cost; high value work).

The trend of the identified network risks raised, completed and outstanding at the end of each year based on the V&V application is shown in Figure 59.

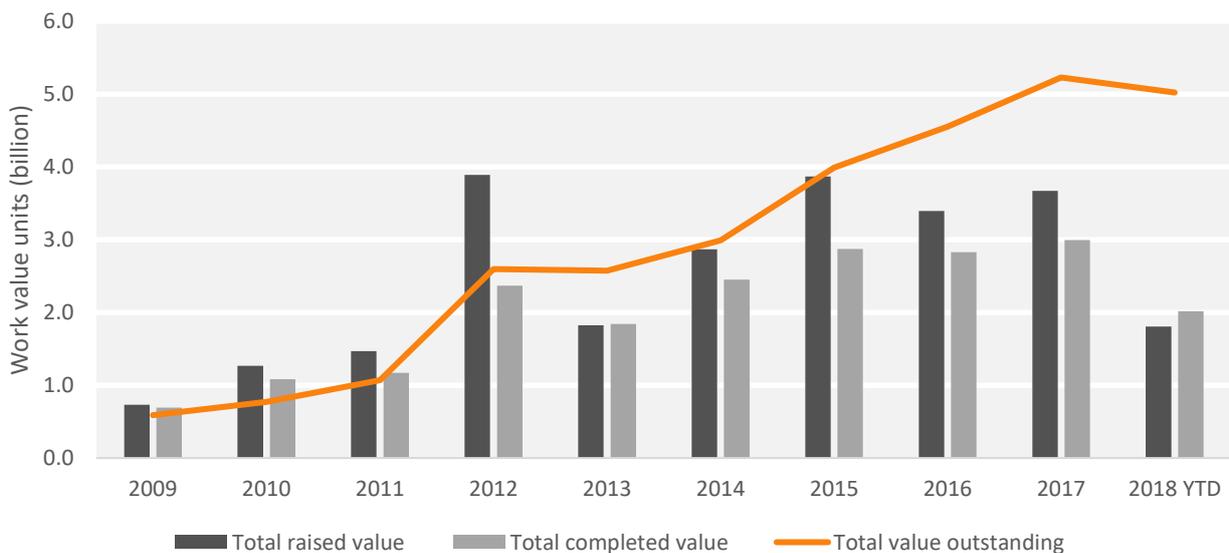


Figure 59: Value of work outstanding, raised and completed at the end of each year through the value and visibility process (2009 – July 2018)

Figure 59 shows that the outstanding risk within the network at the end of each year has been steadily increasing since 2009 because of raised work value exceeding the completed work value consistently. The value of work both raised and completed has plateaued since around 2015.

The distribution of the outstanding work value at the end of each year for identified DDs across various asset types is shown in Figure 60.

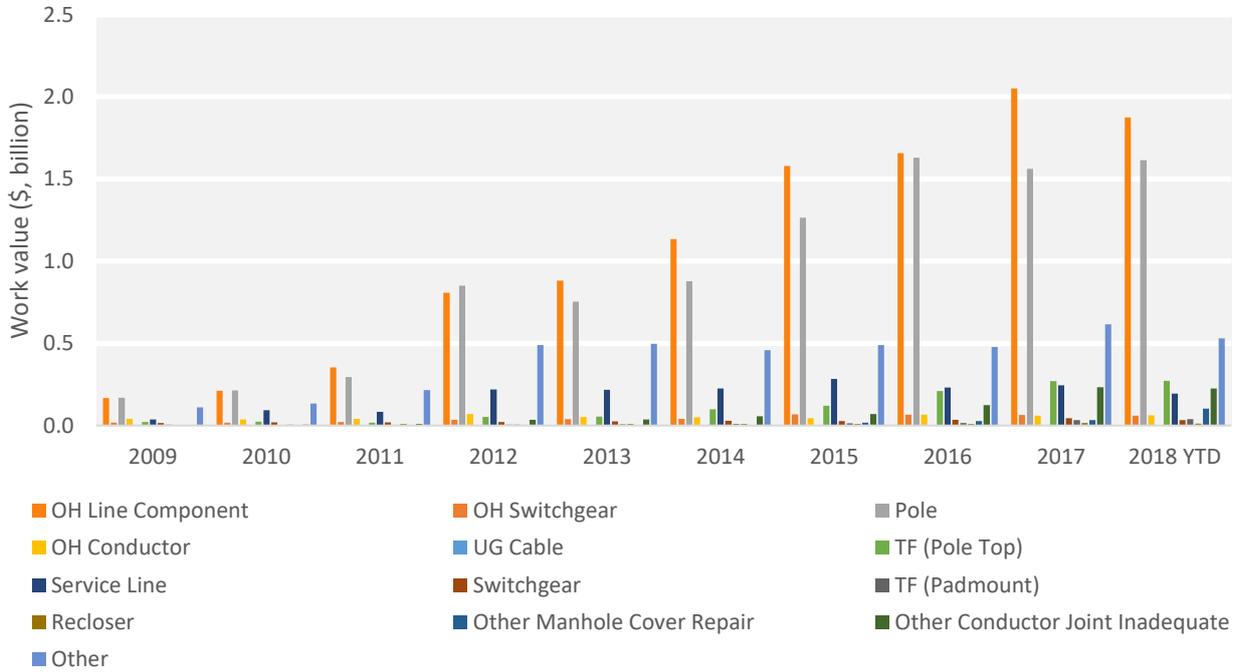


Figure 60: Outstanding year end work value by asset class (2009 – July 2018)

Figure 60 shows most of the risk identified through the cyclic inspection program that has yet to be addressed remains on overhead line components (pole top structures) and poles. The outstanding work value for pole top structures has continually increased since 2009 while that on poles has plateaued since around 2016.

Figure 61 shows the return on investment (ROI) for both poles and overhead line components (pole top structures) for completed programs of work to address identified distribution defects.

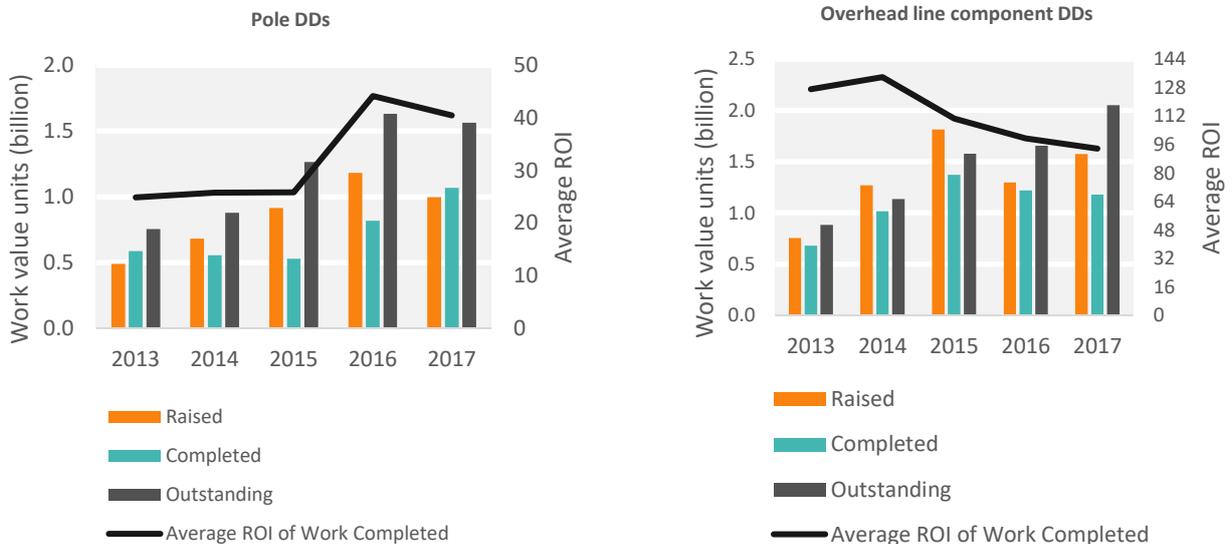


Figure 61: Return on investment for pole and overhead line component expenditure

Figure 61 shows a higher ROI for overhead line components; the result of defects having potential similar consequences but the cost to undertake remedial works (typically) being significantly lower. The ROI for both poles and the overhead line components (pole tops structures) remains high with the work selection for poles showing significant improvement through a step increase in ROI since V&V implementation. This demonstrates that the cost of undertaking the works is significantly lower than the risks associated with leaving the defect. The process of optimising V&V work selection through ROI is ongoing.

While V&V is an operational and quantitative risk based tool in response to identified works, significant asset specific risks and controls are also reviewed via six-monthly qualitative risk assessments (see Section 5.2).

8 Asset class strategies

8.1 Introduction

This section describes how various major asset classes are managed (based on the lifecycle management framework, see Section 7) from the point when a decision is made to install an asset through to when the asset has failed⁶, is replaced or decommissioned. The detailed Asset Plans for the assets provide further detail on the assets including differences in materials used, age limiting factors, types of failures and failure mode analysis.

Asset class strategy summary

Asset class strategies are developed for major asset classes and consider all stages of the asset lifecycle. The level of sophistication of asset class strategies varies depending on the criticality of the asset class and the quality of asset and condition information available. This ranges from detailed asset condition information on high value individual assets through to low value assets with limited detail and relatively low levels of risk which are replaced on failure.

Asset class strategies prioritise assets for repair or replacement using a risk based approach. Figure 62 below shows the assets discussed and the relative level of detail.

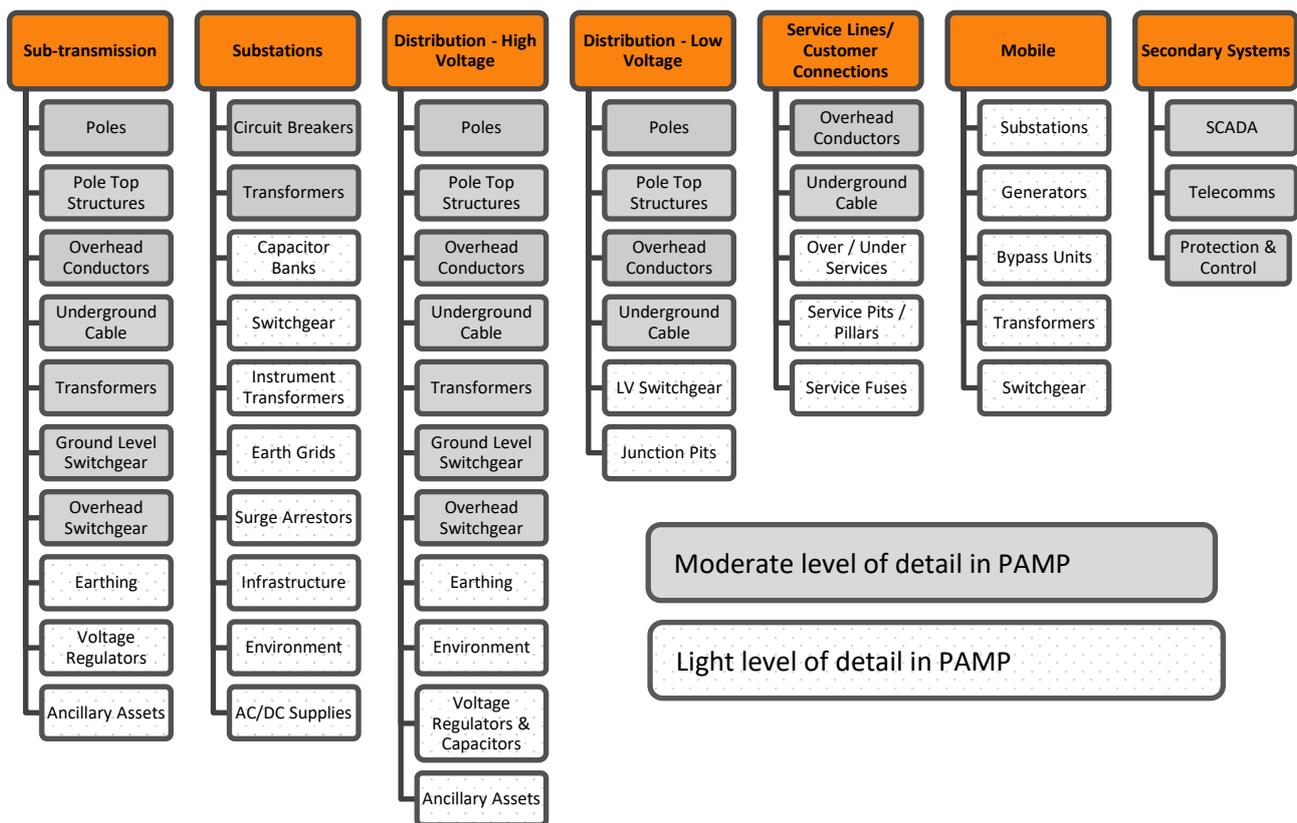


Figure 62: Systems and assets breakdown – level of detail in asset class strategy chapter of the PAMP

⁶ Failure of an asset is defined as the asset unable perform its intended function safely and in compliance with jurisdictional regulations, and not because of external impacts such as extreme weather events, third party interference/damage, wildlife or vegetation interference and excludes planned interruptions (Australian Energy Regulator, 2014).

8.2 Sub-transmission and distribution network assets

8.2.1 Underground cables

8.2.1.1 Introduction

An overview of underground cable assets, including their population, age and condition, and the life cycle management approach, is given in this section along with replacement forecasts and resulting risk and asset condition for the planning period. For further information, refer to the underground cable asset plan.

Asset summary

The underground cable network, which transmits electricity between substations and from substations to customers, extends for 18,064km. A small proportion (~1%) of these cables are more than 50 years of age

The number of cable failures has remained relatively stable since 2011, but was higher in 2016 and 2017 mainly due to an increase in low voltage (LV) cable failure. The management of high voltage (HV) cable assets is transitioning from a reactive ‘fix on fail’ approach to one of proactively managing the assets in response to outcomes from a proactive cable condition assessment program. The LV cables will continue to be fixed on failure due to the relatively low consequence of fault events.

The underground cables have not been reliably modelled within CBRM to assess risk or asset health; data quality improvements are required. The historical performance and expenditure of this asset class informs the required forward investment to 2030.

8.2.1.2 Underground cable asset management objectives

The asset management objectives specific to cables are summarised in Table 29.

Table 29: Cable asset management objectives

Level of service category	Cable asset management objectives
Safety	<ul style="list-style-type: none"> No injury/death to staff or contractors through installing, operating, inspecting, maintaining/repairing, replacing or decommissioning cables. No cable condition failures resulting in injury/death.
Reliability and resilience	<ul style="list-style-type: none"> Minimise planned and unplanned interruption frequency and duration from cable failures and replacements. Prioritise high voltage (HV) cable repairs to minimise network abnormality risks following supply restoration after cable faults.
Environment	<ul style="list-style-type: none"> Minimise the number and quantity of oil leaks from oil insulated cables.
Communication and information	<ul style="list-style-type: none"> Provide accurate information on restoration times for unplanned outages due to cable faults. Provide accurate advanced notice of any planned cable replacement works involving outages.
Efficiency	<ul style="list-style-type: none"> Minimise life-cycle costs of cable assets including the cost of installation, operations, maintenance, replacement and disposal.

8.2.1.3 Asset description

The purpose of cables is to transmit electricity between substations and from substations to customers. They perform the same function as overhead conductors but are below ground. Cables are installed underground primarily for aesthetic reasons but also to make the powerlines less susceptible to outages during storm events. They are typically installed in high building density areas such as the Adelaide CBD and in new housing subdivisions. The requirement for undergrounding power network assets to new subdivisions is determined by individual councils under their respective development plans.

8.2.1.4 Population and age profile

There are 18,064km of cables across the network.

Figure 64 shows the distribution of the cable route length for the different systems, with 76% of total cable length in the low voltage (LV) network.

Figure 65 shows the current age profile of cables being relatively stable since 1972 (45 years of age). The significant and sustained 200-400km per annum of cable installed aligns with large scale real estate developments in areas such as West Lakes (1970s) and Golden Grove (1980s and 1990s) extending to outer suburbs and infill developments that require undergrounding of the distribution network since then. A very small proportion of cable length (~1%) is more than 50 years of age.

The expected life of cables varies but is typically between 75 and 83 years. Although manufacturers' design life for cables can be significantly lower, the actual rate of replacement of cables in the network suggests that the life of many cables is being extended beyond that previously expected. The main factors that influence expected life are cable type, size, age and location. Based on the existing age profile, there are no cables more than 75 years of age by 2025.

8.2.1.5 Current condition and performance

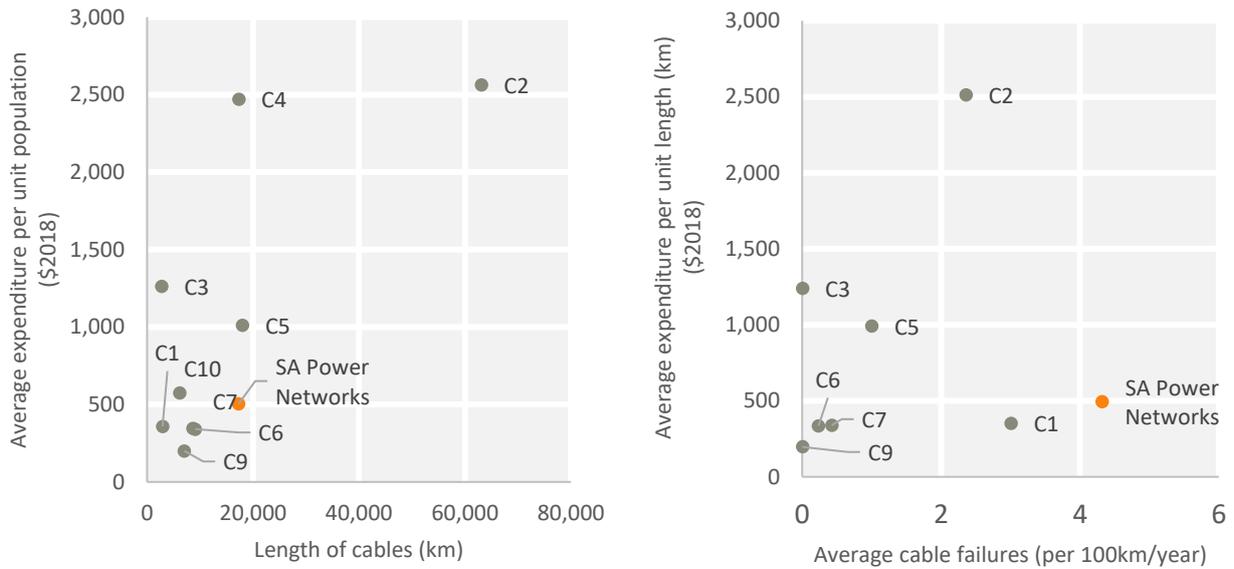
Cable failures can be used as a lag indicator of how the overall cable asset base is performing in response to the asset management approach.

Figure 66 shows the historical number of cable failures excluding those associated with public lighting infrastructure⁷. It shows that the number of cable failures remained relatively stable from 2011 to 2015. It is hypothesised that the higher failure rate in 2016–2017, attributed primarily to an increase in LV network cable faults, was largely attributable to higher rainfall during that timeframe. Cables are prone to water ingress and increased termite activity following periods of high rainfall. Most LV cable failures are due to insulation breakdown and present a relatively low network risk and consequently the increase in 2016-2017 was not investigated further.

Cable assets have not been confidently modelled using CBRM to assess risk or asset health because the underlying data requires improvements to provide confidence in model outputs (see Section 11).

A comparison of cable performance in contrast to other DNSPs was undertaken analysing data from publicly available Category Regulatory Information Notices (RIN) reported over the period 2013-2014 to 2016-2017 inclusive (outliers excluded). A comparison of average annual renewal expenditure per unit length and failure rate is shown in Figure 63.

⁷ Power Asset Management Plan excludes public lighting. SA Power Networks included public lighting cable faults in Regulatory Information Notice underground LV network cable failure reporting up until 2013-2014.



Notes: C8 excluded from both charts as no expenditure information available.
 C4 and C10 excluded from failure rate chart due to zero or no failure data reported.
 C11 excluded from average length of cables chart due to very high reported population relative to other DNSPs.

Figure 63: Cable benchmarking of SA Power Networks vs other DNSPs (2013-2014 to 2016-2017 data)

Figure 63 shows SA Power Networks currently has a mid-range level of average annual expenditure per length of cable even with one of the higher reported failure rates amongst DNSPs. Many other DNSPs with large proportions of their cable assets within CBD districts are contained within ducts leading to a lower failure rate due to the mechanical protection ducts provide whereas the majority of SA Power Networks cable population outside of the CBD is direct buried. SA Power Networks experienced a period of real estate developments (RD) where developers installed the cheapest cable material able to comply with specifications at the time (see Section 8.2.1.6). Patching has typically been undertaken in response to failures in lieu of cable replacement due to most faults occurring on cable sections that have previously not had any recorded faults with around 70% of faults occurring within the LV network. This shows SA Power Networks lifecycle management of cables is very efficient.

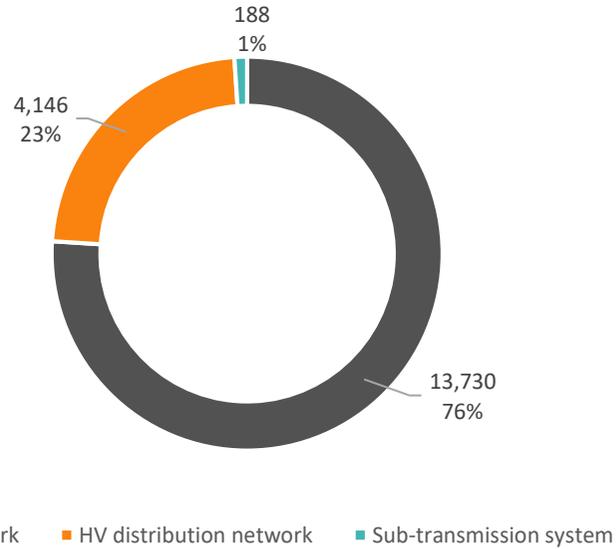


Figure 64: Cable route length (km) by system

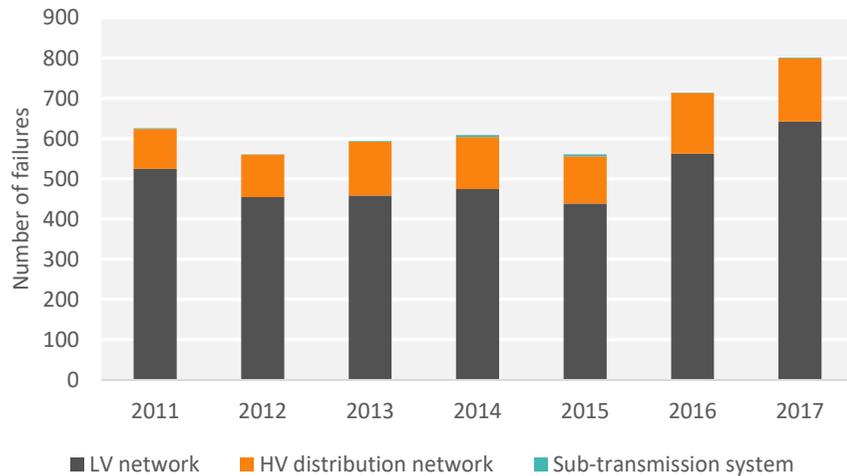


Figure 66: Cable historical failures

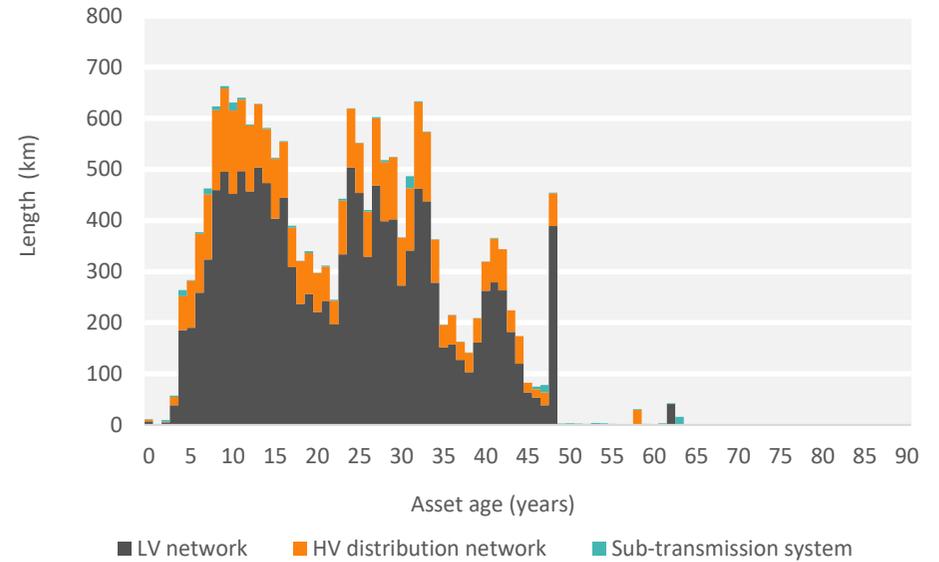


Figure 65: Cable age profile

This asset class has not been reliably modelled using CBRM; data quality improvements are required to provide increased confidence in model outputs.

Figure 67: Current cable health index distribution

8.2.1.6 Risks

The main risks associated with cables include:

- potential injury/death of SA Power Networks staff, contractors or the public due to:
 - accessing failed/faulty cable terminations for operational purposes,
 - a cable fault causing a localised explosion, and
 - failed neutrals on cables resulting in potential electric shocks;
- impact on reliability service standards due to the time associated with locating and repairing cable faults;
- reputational risks associated with CBD cable fault, and in particular ABA cable faults, that can adversely affect stakeholder confidence due to the media focus on that area; and
- potential environmental damage because of oil filled cable failures.

The management of risks for the cable network has historically been reactive with cable assets fixed on failure. In 2016, a proactive online cable testing program began which aims to identify HV distribution network cables at risk of failure to enable proactive remediation. This condition testing program has identified several defects on HV cables and proactive repairs have been made. Risk modelling of cable assets within CBRM has commenced although improvements to cable asset and failure data is required to increase confidence in the model outputs.

The cable specific risks are listed below.

- An increase in cable faults within the ABA during 2017 — primarily on the HV network on a specific cable type referred to as bare paper insulated lead cable (PILC), see Section 8.2.9.1.
- External protective coatings on some of the oldest cables installed in the ABA more prone to degradation than modern cable materials, and joints on these cables prone to failure. The replacement of these cables is complicated by older conduits (ducts) containing the cables not large enough to fit new cables with limited availability of spare cable ducts (used to install new cables to enable rapid restoration of failures) or the use of good condition existing cable ducts becoming limited.
- Limitations of the condition testing program — including access to the cables (e.g. some cables have unsafe or no access), the type of cables (e.g. unsheathed cables limit the test methods able to be applied) and the physical condition of the cable terminations affecting the results of the test — meaning cable condition not able to be confidently determined.
- Potential future failure of either of the Kangaroo Island undersea cables for an extended period
- Many old, oil filled 66kV underground cables with limited remaining spares and jointing systems; and the obsolescence of the materials used limit the ability to undertake repairs on underground cables of this construction type.
- The Magill to Whitmore Square 66kV oil filled cable, extending approximately 3km from Rose Park to Whitmore Square in the CBD as a backup supply to the CBD, having had many failures and a failing external protective cover leaking oil into the environment; past operation resulting in it being overloaded; the eastern section experiencing heat damage reducing its reliability when required to operate; requiring excessive time to locate faults on this cable and expense to repair (costs can be >\$500,000 per event).
- Several locations around metropolitan Adelaide including Elizabeth, Paralowie, Adelaide, Craigmore and Salisbury with frequent historical LV cable failures largely attributed to developers previously installing the cheapest cable material able to comply with specifications at the time; these cable assets continue to be fixed on failure.
- Poor historical data on the LV cable asset GIS model and LV cable faults resulting in limited understanding of the LV cable network.

8.2.1.7 Life cycle management strategy

8.2.1.7.1 Underground cable asset creation

All new cables installed in the distribution networks are cross linked polyethylene and predominantly single core, except for within the CBD where physical space limitations mean 3-core cables provide greater flexibility as they can be installed in a single conduit. A new type of 4-core sectorised LV cable is being introduced to replace the bundled cable design mainly used in real estate development and Power Line Environment Committee projects (undergrounding of powerlines). They will provide a more compact and higher capacity cable installation with fewer cables.

8.2.1.7.2 Underground cable operations and maintenance strategy

Cables are subject to fault maintenance (repaired on failure) with more critical HV cables currently subject to preventative maintenance program (where technically feasible and safe to do so).

In the event of a cable fault, the priority is supply restoration to customers through locating the fault and switching to isolate the faulted sections and minimise the number of customers impacted until the faulty cable is repaired. Once isolated, repairs are undertaken immediately for cable sections that are unable to provide an alternate supply to customers. However, depending on the connectivity within the sub-transmission system and HV distribution network, this means the cable repair can be undertaken through defect maintenance after supply is restored, creating temporary network operation abnormalities and increasing the risk on the network. An assessment of risk including network configuration, the criticality of the cable within the network and complexity of repairs are considered for determining the priority level for repairs. Cable repairs of this nature are referred to as asset restoration and are given a high priority. Radial (single source of supply) cables are typically repaired immediately.

A shift to a proactive preventative maintenance online condition assessment program on the HV cable network began in 2016 aimed at identifying cable defects prior to failure. It is primarily focused on 11kV cables in the metropolitan Adelaide area that are safely accessible. Online tests are undertaken while the cable remains energised so there is no interruption to supply. Offline tests are also undertaken for cables that have suspected defects identified through the online tests or following repairs. Offline tests are considered more accurate than online testing but require the cable to be isolated. They could require a planned interruption depending on network connectivity and the location of switching devices.

These condition assessments have resulted in some localised repairs of cable joints and terminations; and some cable sections have been recommended for replacement. Localised repairs are also undertaken on faulty cables where repairs are considered to have a higher work value (more cost efficient) than complete replacement of the entire cable section. Both the online or offline testing has limited application on sub-transmission cables due to the testing equipment limitations.

Other limited preventative maintenance inspections undertaken on HV cables include:

- cable joints condition assessment every 5-10 years (on the 33kV and 11kV in Adelaide CBD where manholes are accessible) to assess the condition of the manhole structures, cable supports and joints with thermographic assessment subject to the outcomes of the visual inspections;
- oil pressure monitoring in response to cable oil leaks through low level alarms fitted to oil tanks; and
- visual inspections of cable terminations.

Low voltage cables are repaired or replaced on failure (fault maintenance) and while undertaking repairs other defects may be identified and depending on the risk present are either repaired immediately or scheduled for defect maintenance. There is no preventative maintenance undertaken for LV cables due to the relatively low risk and cost of condition assessments in most cases exceeding cost of repairs or replacement. Records of historical failures and maintenance on LV cables have been poor leading to a lower level of confidence for application of CBRM than for HV cables.

8.2.1.7.3 Underground cable renewal/replacement strategy

Cables can be repaired but not refurbished, and a planned replacement is considered the preferred option when the risks and costs associated with the ongoing performance are higher than replacement costs.

The decision to replace a HV or LV cable rather than continuing to undertake repairs considers whether:

- cable has a history of multiple failures (HV and LV);
- testing of the cable insulation following repairs finds it in poor condition (HV and LV);
- diagnostic (condition assessment) testing shows cables to be in poor condition and at risk of failure (HV only); and
- local field staff knowledge of environmental factors (e.g. white ants or water ingress) or repeated customer complaints (LV only) indicate replacement.

Cable assets have not been reliably modelled using CBRM to assess risk or asset health because the underlying data requires improvements to provide confidence in model outputs as outline in the continuous improvement plan (see Section 11). The historical performance and expenditure of this asset class informs the required forward replacement plan. The replacement strategy is based on managing the long-term risk of cable assets to replace the poorest condition cable assets in response to failures on the LV network and application of a replacement decisions for HV and sub-transmission cables based on historical cable performance and the preventative maintenance condition monitoring program.

Figure 68 shows a summary of the underground cables replacement plan to 2030.

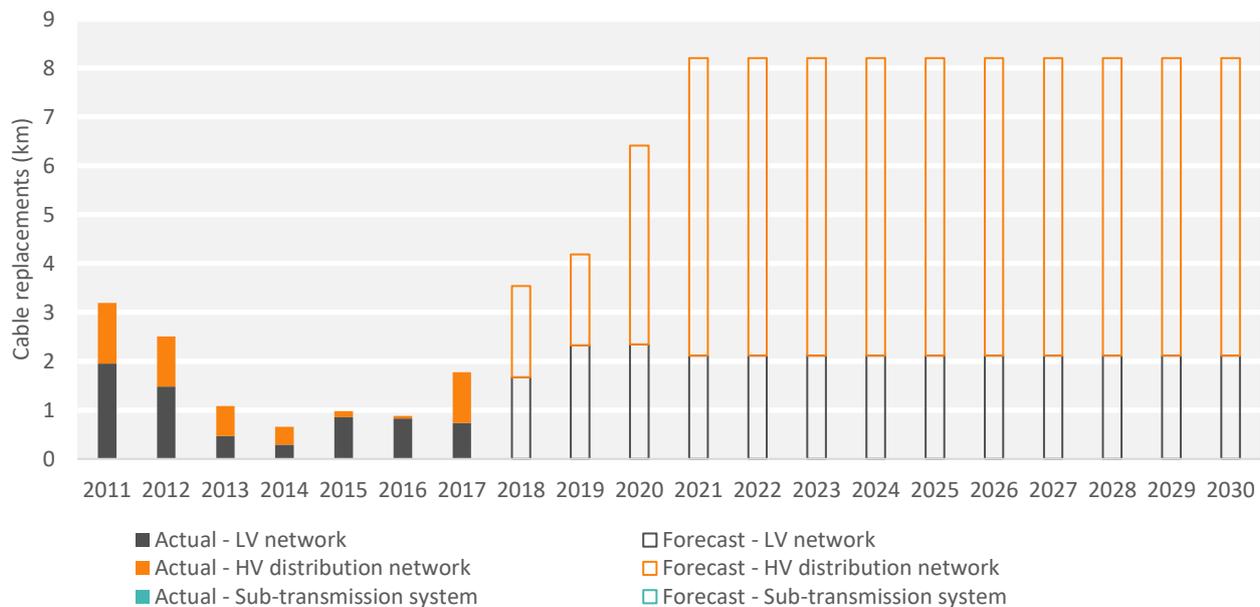


Figure 68: Underground cables renewal/replacement plan

Figure 68 shows there is a forecast increase rate of replacements up to 2020 primarily on the LV network in response to increasing failures and the replace on fail strategy; a marginal increased proactive replacement of HV and sub-transmission cables in response to the condition monitoring program identifying poor condition lengths. The increase in HV replacements from 2020 is due to the proposed increase in replacement rate of 11kV bare paper insulated lead cables (PILC) within the CBD due to poor reliability arising from failure rates on this cable type (see Section 8.2.9.1).

8.2.1.7.4 Underground cable disposal strategy

Most cable assets are direct buried in the ground meaning recovery is uneconomic. Thus, nearly all replaced cables are decommissioned and left in the ground. The decommissioning process for oil-filled cable assets includes the removal of oil using compressed air.

Removed cable assets usually do not have any economic value beyond their scrap metal value. Hazardous waste, such as oil filled cables, must be disposed of in accordance with SA Power Networks Environmental Management Guidelines and Procedures.

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8.2.2 Poles

8.2.2.1 Introduction

An overview of the pole assets, including their population, age and condition, and the life cycle management approach, is given in this section along with replacement forecasts and resulting risk and asset condition for the planning period. For further information, refer to the poles asset plan.

Asset summary

Poles are the support structure for overhead conductors at a height above ground level and at a distance from all other objects that exceeds prescribed safety clearances.

Of the approximately 647,492 poles across the network, a significant proportion (~74%) are 40–65 years of age.

The number of pole failures has remained relatively stable since 2010–2011. Management of pole assets is transitioning from refurbish or replace on condition to risk-based investment on defect identification through the cyclic inspection program.

Pole assets have been modelled within CBRM to assess their current health and projected deterioration and failure risk based on current asset and condition data. Current condition data indicates 90% of poles are currently in good condition, 9% with observable to serious deterioration and 1% having advanced deterioration. Model outputs inform the required forward investment to 2030 to maintain the risk across the pole asset base.

8.2.2.2 Pole asset management objectives

Asset management objectives specific to poles are summarised in Table 30.

Table 30: Pole asset management objectives

Level of service category	Pole asset management objectives
Safety	<ul style="list-style-type: none"> No injury/death to staff or contractors through installing, operating, inspecting, maintaining/repairing, replacing or decommissioning poles. No pole condition failures resulting in injury/death. No pole condition failures resulting in bushfire starts. No pole condition failures resulting in damage to third party property. Opportunistic pole relocation for planned pole replacements or relocations required as part of local council or Department of Planning, Transport and Infrastructure streetscape upgrades to improve road safety.
Reliability and resilience	<ul style="list-style-type: none"> Minimise planned and unplanned interruption frequency and duration from pole failures and replacements.
Communication and information	<ul style="list-style-type: none"> Provide accurate information on restoration times for unplanned outages due to pole failures. Provide accurate advanced notice of any planned pole replacement works involving outages.
Efficiency	<ul style="list-style-type: none"> Minimise pole life-cycle costs including the cost of installation, operations, maintenance, refurbishment/replacement and disposal.

8.2.2.3 Asset description

The purpose of poles is to provide the support structure for overhead conductors at a height above ground level and at a distance from all other objects that exceeds prescribed safety clearances. They also support other network equipment such as transformers, switches, reclosers, sectionalisers, voltage regulators and capacitors.

Stobie poles are used almost exclusively across the network and consist of a concrete core with two outer steel beams connected by bolts to ensure strength. The small number of municipal tramway poles (mainly within the LV network) and wooden poles (former Telstra poles with only SA Power Network assets attached) present a low risk to the network and will not be discussed further.

8.2.2.4 Population and age profile

Of the approximately 647,492 poles across the network, more than half are in the HV distribution network (Figure 70). LV overhead conductors and LV pole top structures can also be mounted on these HV poles (the pole voltage is that of the highest voltage overhead conductor attached to the pole).

Figure 71 shows the age profile of the poles. A significant proportion (~74%) are 40–65 years of age. There is a significant increase in poles installed from 55–65 years of age commencing from the early 1950s when major electrification of the State commenced under the Playford Government (see Section 3.2.1) which involved a rapid expansion of the network across metropolitan areas and to major regional centres. As not all poles have a defined year of construction within the SAP works management system, the feeder date is used as an indicative pole age leading to the observed spike in pole quantities in 1955 (eg. 63 year old poles). The pole replacement program is contributing to the observed increase in pole quantities less than 10 years old.

The expected life of poles varies but is typically 70–120 years. The main factors that influence expected life are corrosion zone, load capacity, atmospheric pollution and fatigue. Based on the existing age profile, there is currently 1% of poles more than 70 years increasing to 3% by 2025

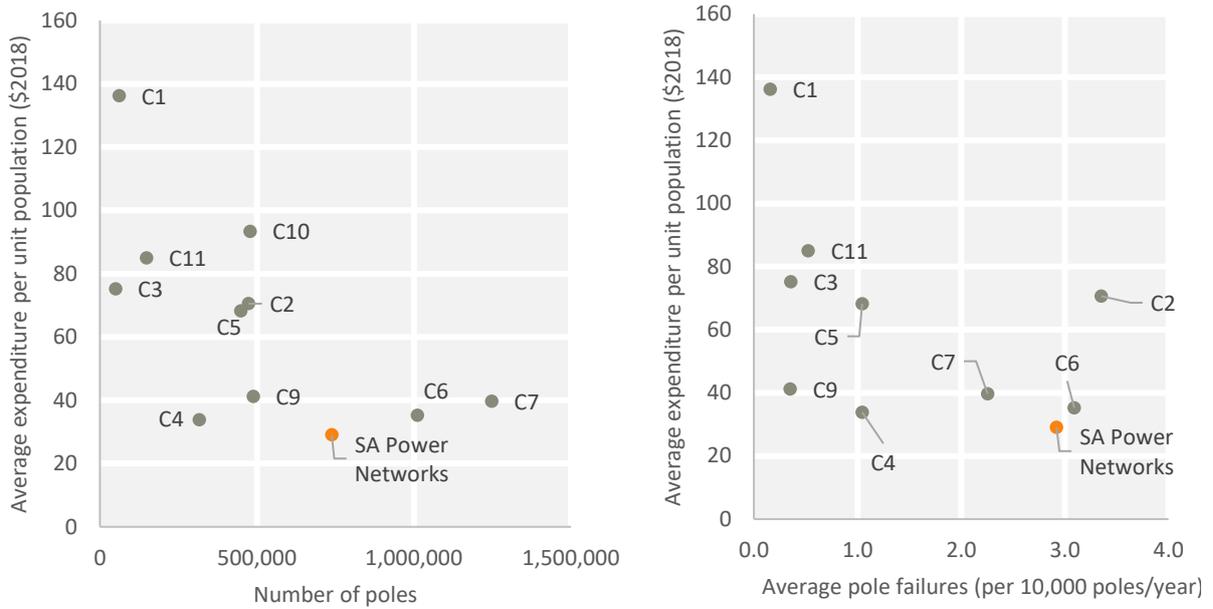
8.2.2.5 Current condition and performance

Pole asset failures can be used as a lag indicator of how the pole asset base is performing in response to the asset management approach. Pole failures include, but is not limited to, poles that have physically fallen to the ground.

Figure 72 shows the historical number of pole failures has remained relatively stable since 2010–2011 aside from the relatively high number of failures in 2013–2014 and 2016–2017. The spikes in condition failures in those years is partly due to inspections that occur following major event days (MEDs) and the identification of poles that are assessed as requiring potential replacement.

Pole assets have been modelled using CBRM to assess their current health based on current asset and condition data. Figure 73 shows 91% of poles are currently in good condition (HI 0–4), 9% have observable to serious deterioration (HI 4–7) and <1% have advanced deterioration (HI>7).

A comparison of pole performance in contrast to other DNSPs was undertaken analysing data from publicly available Category Regulatory Information Notices (RIN) reported over the period 2013–2014 to 2016–2017 inclusive (outliers excluded). A comparison of average annual renewal expenditure per unit population and failure rate is shown in Figure 69.



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

Figure 69: Pole benchmarking of SA Power Networks vs other DNSPs (2013-2014 to 2016-2017 data)

Figure 69 shows SA Power Networks currently has the lowest level of average annual expenditure per pole even with one of the higher reported failure rates amongst DNSPs. This shows SA Power Networks lifecycle management of poles is very efficient.

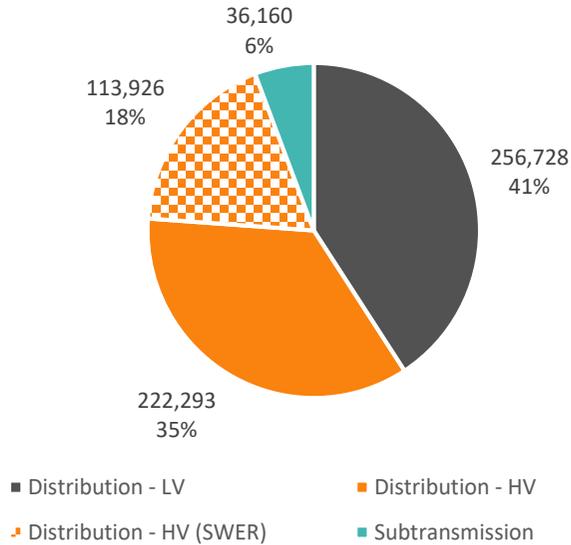


Figure 70: Poles quantity by system

Note: System based on highest voltage conductor attached to pole

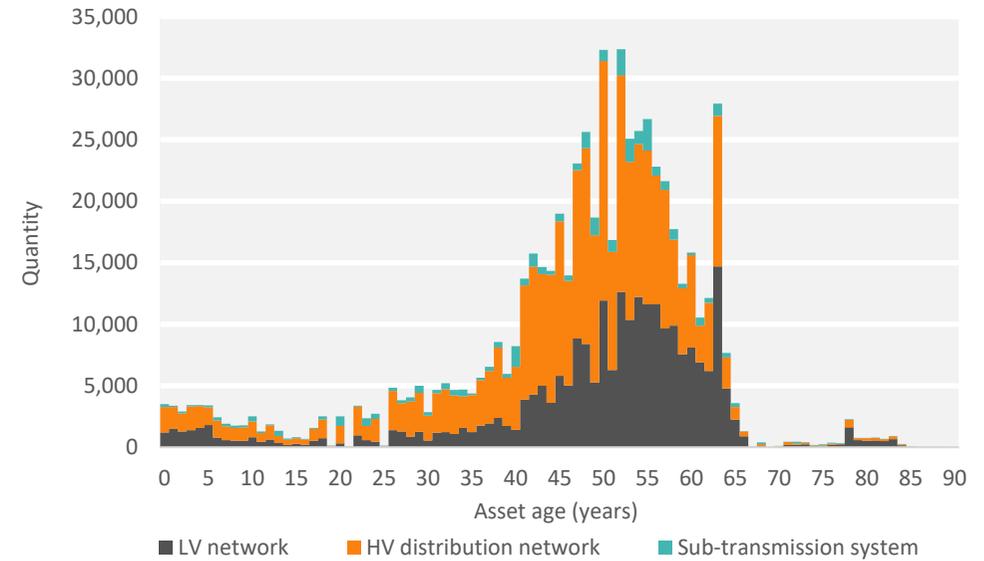


Figure 71: Poles age profile

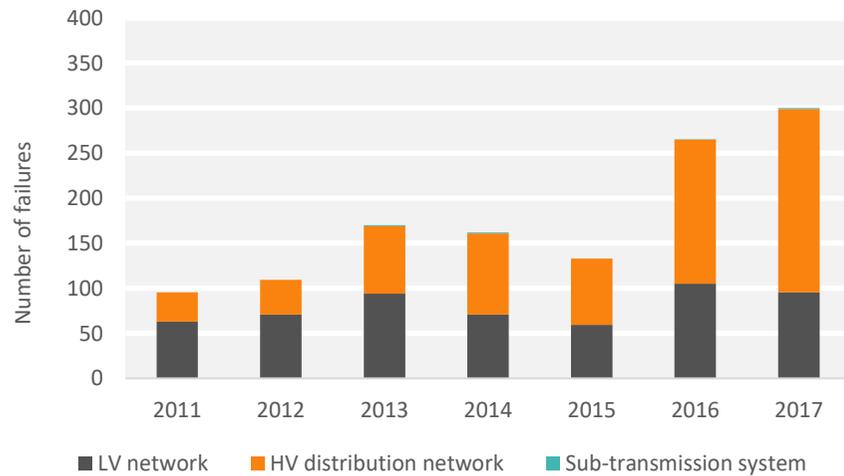


Figure 72: Poles historical failures

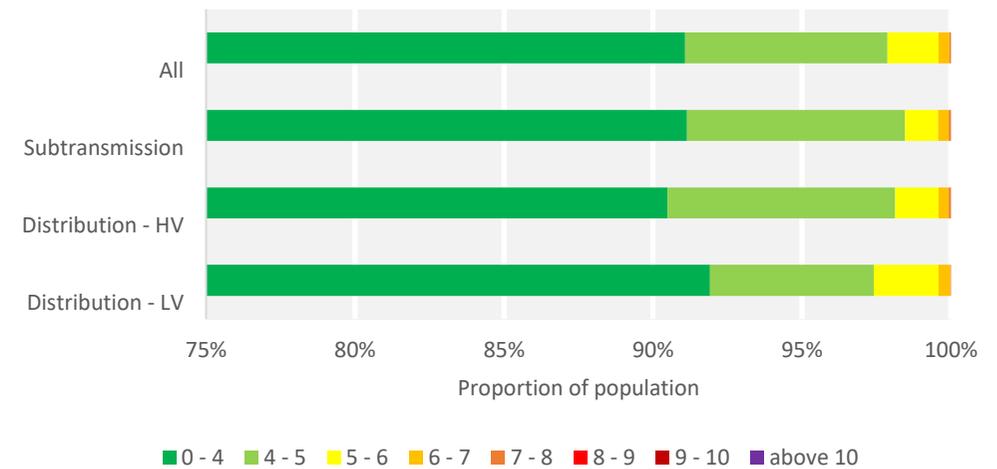


Figure 73: Current pole health index distribution

8.2.2.6 Risks

The main risks associated with poles include:

- potential injury/death of SA Power Networks staff, contractors or the public due to:
 - electric shock through any current transmitted through the pole or live conductors falling to the ground,
 - physical contact through a pole falling to the ground because of pole condition,
 - bushfire start resulting from pole defects and live conductors falling to the ground, or
 - road safety risk to people involved in road accidents;
- potential third-party property damage due to pole corrosion and collapse; and
- impact on reliability service standards due to the time associated with unplanned pole replacements.

Cyclic asset inspections play a key role in identifying defects to manage the risks associated with poles. In addition, pole assets have been modelled using CBRM to assess the current and future risk and asset health based on available asset and condition data.

The pole specific risks are listed below.

- Below-ground corrosion on poles. Poles in the Lameroo to Pinneroo, Upper Spencer Gulf regions, and some localised metropolitan locations, are subject to a higher rate of below-ground corrosion. The ‘pitting’ corrosion occurs on the section of steel in the ‘toe and collar’ design of Stobie poles (Figure 74)
- Current corrosion measurement practices of toe and collar poles at ground level. The cost of visually assessing corrosion below the collar is comparable with pole replacement because of the cost of supporting the network infrastructure to excavate around the base of a Stobie pole. Further investigations are currently seeking alternative and more innovative methods of assessment for below-ground corrosion. Plated poles and re-plated poles are at higher risk of below-ground corrosion as they are typically some of the oldest poles.
- No access poles. These Stobie poles are unable to be exposed below ground level to measure for corrosion because of third party infrastructure such as paved and concrete footpaths. Any ‘no access’ poles with significant corrosion observed above ground are scheduled for replating/replacement depending on the extent of corrosion identified. The technology being investigated for assessing the condition of ‘toe and collar’ Stobie poles will also be trialled for application on ‘no access’ Stobie poles.

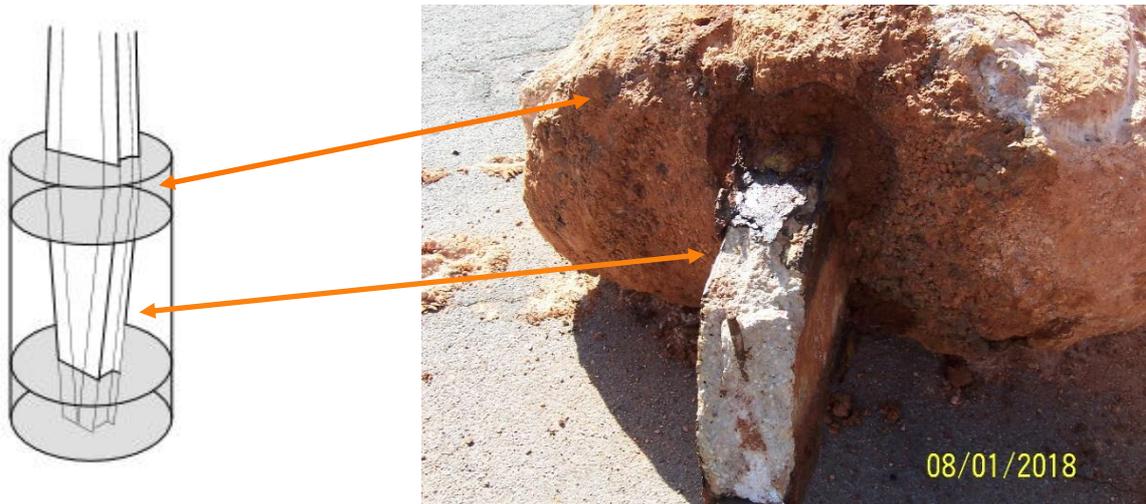


Figure 74: Below ground Stobie pole corrosion

8.2.2.7 Life cycle management strategy

8.2.2.7.1 Pole asset creation

Stobie poles continue to be the preferred standard for poles as the lifespan and ‘Mechano’ like construction is simple, user friendly and well proven.

Other pole types have been evaluated but cannot be justified to replace the Stobie pole due to factors such as life expectancy and strength of alternate materials and significant backwards compatibility issues that would exist with integrating into the network (e.g. interfacing with other existing standard network assets and components).

8.2.2.7.2 Pole operations and maintenance strategy

The operations and maintenance strategy for poles is centred around detailed asset inspection and asset patrols. Patrols quickly inspect the asset with the aim of identifying obvious defects in bushfire risk areas (BFRA); detailed asset inspection assesses each pole in detail to identify defects and assess the condition of the pole, including detailed steel corrosion measurement to determine steel condition. The steel measurements and overall pole condition inform whether poles can be plated to defer the pole replacement.

Table 31 gives a summary of the routine inspection, maintenance and condition monitoring tasks for poles.

Table 31: Poles inspection, maintenance and condition monitoring tasks

Inspection, maintenance or condition monitoring task	Frequency
Pre-bushfire patrols of all sub-transmission and distribution overhead lines in BFRA	Annually
Patrols of metropolitan sub-transmission radial (single source of supply) line poles	Annually
Detailed inspection of poles in corrosion zones 2, 3 and 4	5 years
Detailed inspection of poles in corrosion zone 1	10 years

Further details for the inspection and maintenance strategy for poles are covered in Section 6.2 (Sub-transmission lines) and Section 6.3 (Distribution lines) of the Network Maintenance Manual.

Little physical maintenance work is undertaken on poles. Any minor maintenance, such as repairs to small sections of cracked or spalling concrete, are generally only undertaken when the pole is plated as part of the refurbishment program.

8.2.2.7.3 Pole renewal/replacement strategy

Poles that have failed resulting in an interruption to supply are replaced immediately. Any pole defects identified through the asset inspections have their work value assessed to remove as much risk from the network in the most cost-efficient manner (see Section 7.10). Where economical and feasible, poles are plated to reinforce the base instead of being completely replaced. Pole plating significantly extends the life of the asset at a much lower cost than complete replacement. Factors such as corrosion higher on the pole and concrete spalling can affect expected life, but pole plating will generally add 10–50 years to the expected life of the asset.

The decision to plate or replat a pole considers factors including the overall condition of the pole (if not satisfactory the pole is replaced) which includes:

- extent of the corroded section of steel at ground level (if greater than 150mm long the pole is replaced);
- condition of the section of steel above ground level (steel spalling);
- level of concrete spalling; and
- number of times a pole has been plated (a pole will only be plated once and replated once due to concerns with potential below-ground corrosion).

While customer connection alterations can also involve pole replacements the level of replacements are insignificant. Most of risk removed through deteriorating poles is funded through the planned pole replacement program.

The annual proportion of refurbishments compared to replacements has remained stable since 2011, with a rate of almost two out of every three poles refurbished instead of replacement demonstrating efforts to deliver cost effective capital solution for poles.

The renewal/replacement strategy for poles is based on maintaining the long-term risk and performance across the pole population and has been modelled using CBRM.

Figure 75 gives a summary of the poles renewal/replacement plan to 2030.

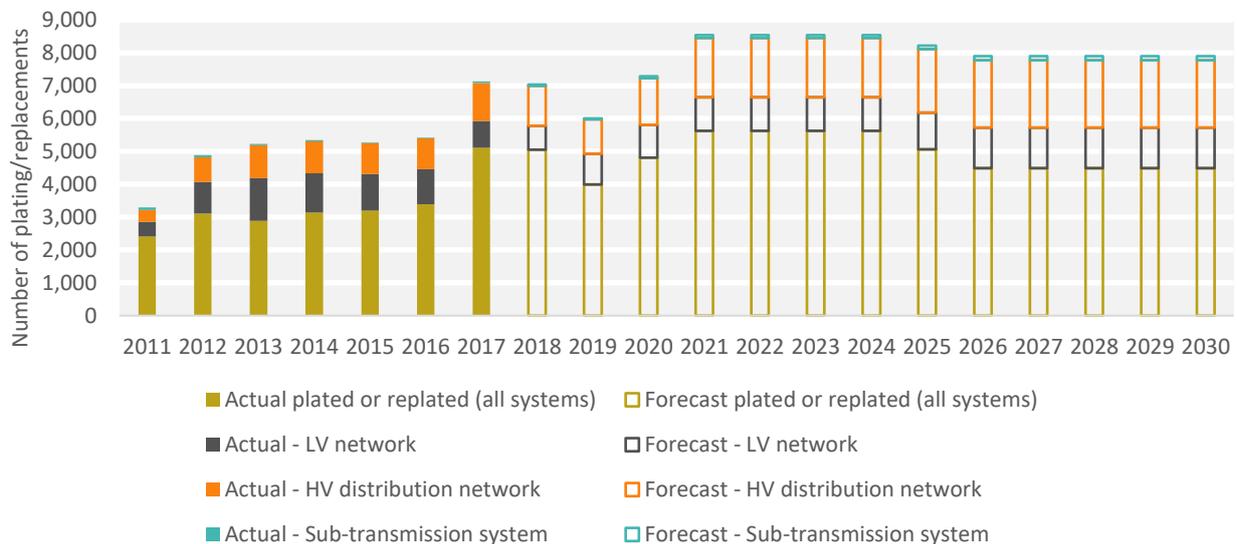


Figure 75: Poles plating/replacement plan

A continuation of refurbishments/replacements is forecast for the short term. The proposed replacements will include targeted pole replacements in response to ‘toe and collar’ corrosion and Stobie pole failures in recent years. Third party damaged poles are included in the above and typically range in the order of 300-400 poles p.a.

The impact of the renewal/replacement plan on the risk across the pole assets was forecast using CBRM.

Figure 76 shows the current risk for poles and how it would grow if the pole assets continued to deteriorate without intervention. It shows that the current risk for poles in the sub-transmission system, HV network and LV network all increasing by approximately 20% by 2030 if no replacements are undertaken because of continued ageing and deterioration processes leading to increased probabilities of failure.

Figure 77 shows the resulting risk profile based on the proposed expenditure through to 2030 to maintain a stable level of network risk on the pole assets. It also shows the planned expenditure to 2019–2020 will return the risk of poles more in line with 2015 levels with the proposed expenditure to 2030 maintaining that level of risk. This is due to the ramped increase in poles expenditure for poles over 2015-2020.

Figure 78 and Figure 79 compare how the health index of the poles population would change by implementing the proposed renewal strategy. The proportion of poles with advanced deterioration (HI >7) decreases from <1% to 0%; those with observable to serious deterioration (HI 4–7) remains relatively stable at 9% as does the proportion of good condition poles (HI 0-4) at 91% by 2030. The risk based management approach for poles also maintains allows poles to continue to marginally deteriorate within the observed to serious deterioration condition range (HI 4-7) with replacements targeting the highest risk poles within that range.

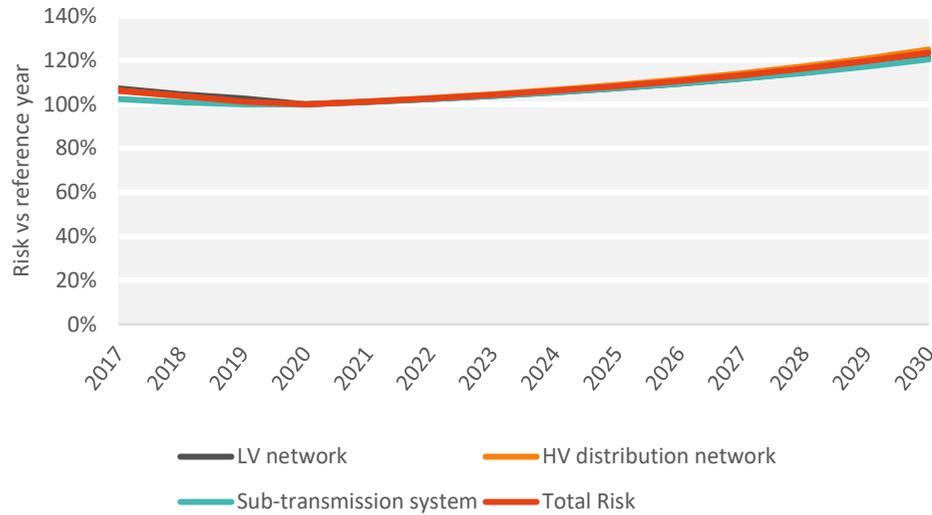


Figure 76: Pole risk profile — do nothing

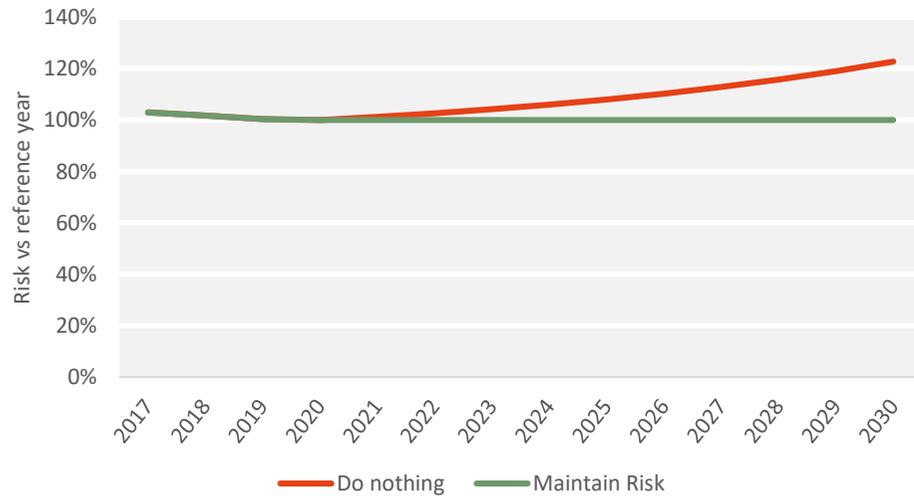


Figure 77: Pole risk profile — proposed expenditure

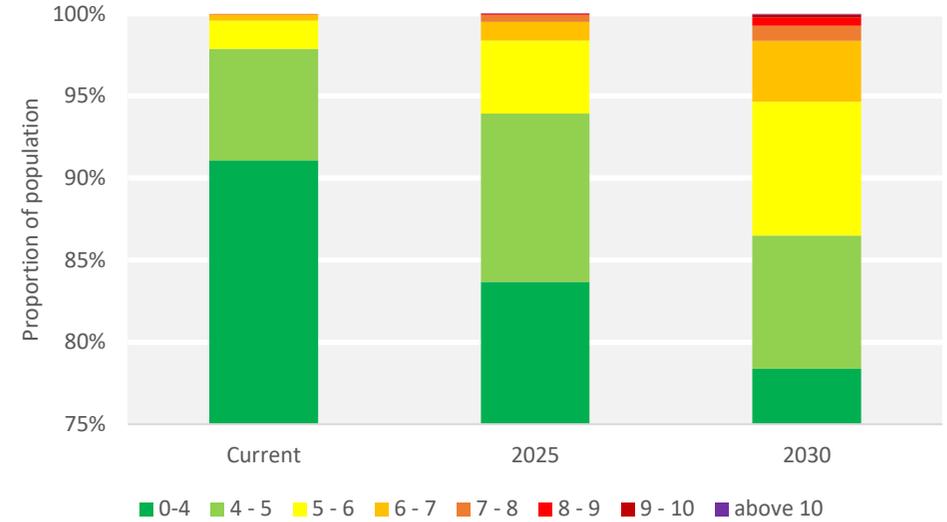


Figure 78: Pole health index — do nothing

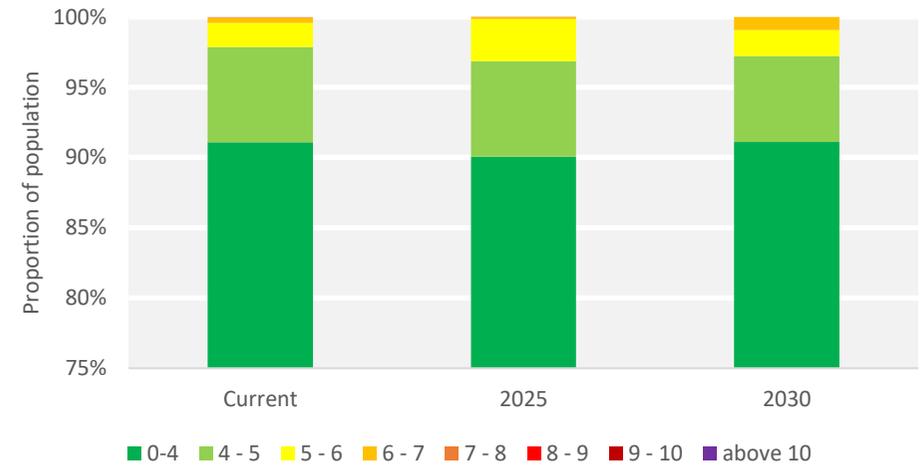


Figure 79: Projected poles health index — proposed expenditure

8.2.2.7.4 Pole disposal strategy

Three methods are considered when removing poles from service. Each removes the overhead structure but the location, situation and complexity of the removal determines the method used:

- **Complete pole and footing removal:** extracts both pole and footing from the ground either as a single unit or in sections, backfills the excavation and compacts it back to the original ground level.
- **Complete pole structure removal:** removes the pole in its entirety and leaves the footing in the ground. This method is common where a former type of footing was installed in the original construction and is no longer required or is unsuitable for the replacement pole. The footing is filled with sand, and soil is used to backfill the remainder of the excavation to original ground level.
- **Cut pole removal:** cuts the pole off approximately 450mm below ground level or as close as possible to the footing. That section of pole and the footing remain in the ground. The excavation is backfilled with soil and compacted back to normal ground level.

All Stobie poles are salvaged and sold in their 'as is' complete state for the steel scrap value. The cost of handling salvaged Stobie poles and the revenue raised from pole steel salvage are approximately cost neutral. Hazardous waste is disposed of in accordance with the SA Power Networks Environmental Management Plan.

8.2.3 Pole top structures

8.2.3.1 Introduction

An overview of the pole top structure assets, including condition, and the life cycle management approach, is given in this section along with replacement forecasts for the planning period. For further information, refer to the overhead line components and overhead switchgear and line fuse bases asset plan.

Asset summary

Pole top structures enable overhead conductors to be securely attached to their support structures, support other pole mounted equipment and connect the overhead conductors to other equipment. Pole top structures include cross arms, insulators, overhead switchgear, joints and taps, and other components.

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

Pole top structures have not been modelled using CBRM to assess risk or asset health because they are so numerous and varied, and data is limited. The historical performance and expenditure of this asset class informs the required forward investment to 2030.

8.2.3.2 Pole top structures asset management objectives

Asset management objectives specific to pole top structures are summarised in Table 32.

Table 32: Pole top structures asset management objectives

Level of service category	Pole top structures asset management objectives
Safety	<ul style="list-style-type: none"> No injury/death to staff or contractors through installing, operating, inspecting, maintaining/repairing, replacing or decommissioning pole top structures. No pole top structure condition failures resulting in injury/death. No pole top structure condition failures resulting in bushfire starts. No pole top structure condition failures resulting in damage to third party property.
Reliability and resilience	<ul style="list-style-type: none"> Minimise planned and unplanned interruption frequency and duration from pole top structure failures and replacements.
Communication and information	<ul style="list-style-type: none"> Provide accurate information on restoration times for unplanned outages due to pole top structure failures. Provide accurate advanced notice of any planned pole top structure replacement works involving outages.
Efficiency	<ul style="list-style-type: none"> Minimise pole top structure life-cycle costs including the cost of installation, operations, maintenance, replacement and disposal.

8.2.3.3 Asset description

Pole top structures are needed to securely attach overhead conductors to their support structures, to support other pole mounted equipment and to connect overhead conductors to other equipment. Pole top structures include cross arms, insulators, overhead switchgear, joints and taps and other miscellaneous components.

8.2.3.4 Population and age profile

The quantity of pole top structures and distribution across each system is unknown.

The expected life of pole top structures varies but is typically 40–50 years. The expected life of pole top structures is highly variable because they themselves are varied as is the environment in which they operate. The main factors that influence expected life are the materials used, corrosion zone, load capacity, atmospheric pollution and fatigue. Due to their wide variety and condition and the uncertainty of the age profile, the proportion of these assets past their expected life cannot be determined.

8.2.3.5 Current condition and performance

Historical asset failure data is used as the primary indicator of the overall asset condition for this asset class and informs the volume of pole top structures that require replacement over the forward planning period.

Figure 82 shows the number of historical number of pole top structure failures, which has been on an upward trend since 2011. The reasons are the ageing pole top structure population and condition degradation.

Historically, detailed condition information has not been collected on all pole top structures because of the very large number of assets in service. Condition information is captured by exception (e.g. only identified failures or defects are captured).

This asset class does not have detailed asset information for each asset due to the very large number of assets.

This asset class does not have detailed age profile information for each asset due to the very large number of assets.

Figure 80: Pole top structures quantity by system (estimated)

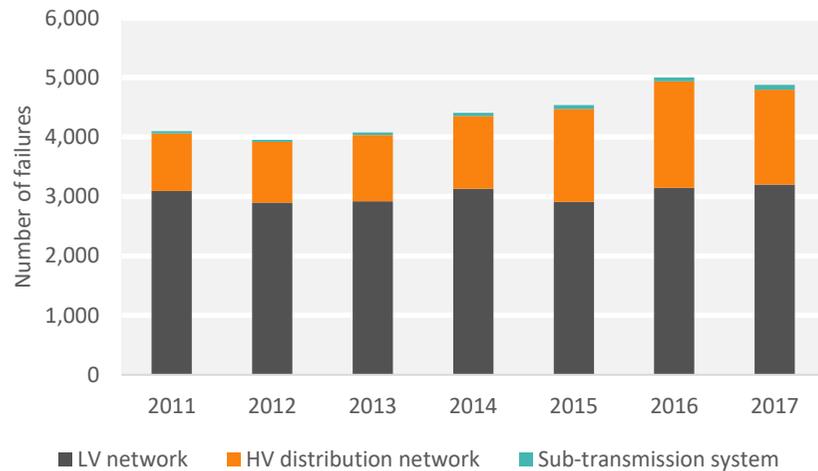


Figure 82: Pole top structures historical failures

Figure 81: Pole top structures age profile

This asset class does not have detailed condition information for each asset due to the very large number of assets.

Figure 83: Current pole top structures health index distribution

8.2.3.6 Risks

The main risks associated with pole top structures include potential:

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

Cyclic asset inspections play a key role in identifying and managing the risks associated with pole top structures. They are supplemented by the ongoing use of emerging inspection and condition assessment tools such as autonomous drones, for visual patrol and thermographic inspections. Together, they enable proactive replacements before these assets fail.

Figure 84 shows planned and unplanned replacements of pole top structures since 2011. Planned replacements have significantly increased in that time; and the number of failures increased by more than 20% over the same period.

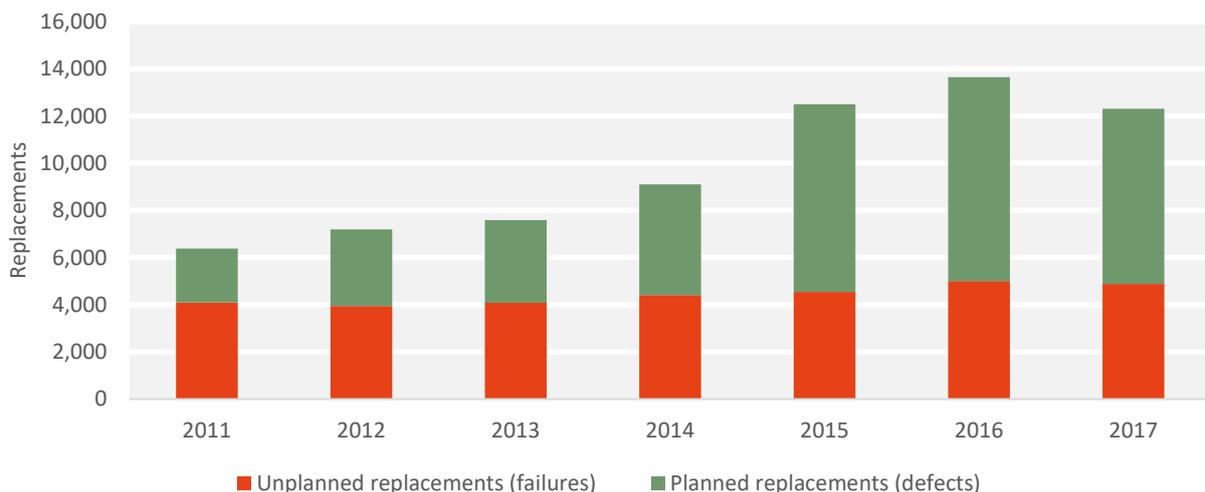


Figure 84: Unplanned and planned replacements of pole top structures

The pole top structure specific risks are listed below.

- **The limited number of thermographic inspections:** Pole top structures are currently only inspected on the backbone of some HV feeders and on selected feeders supplying upcoming high-profile community events. Some failures from thermal damage will continue in some locations where thermographic testing is not undertaken. Cost effective alternatives such as drone and fixed wing aircraft fitted with thermal cameras are currently being trialled to assess their cost and effectiveness of data capture.
- **Dissimilar metals for joints:** Aluminium to steel joint systems can induce galvanic corrosion and cause conductor failure. This information is collected through the cyclic inspections but it is difficult to visually identify the extent of corrosion at the joint.
- **Liquid fuses:** The type of liquid fuse currently in use is not environmentally friendly and contains carcinogenic materials. Their replacement with alternatives requires a new fuse base which takes longer to install and would need planned interruptions. Investigations into how these fuses can be phased out are in progress.
- **Insulator pin and tie wire failures:** Wear and corrosion of some pole top structures are difficult to reliably detect using current inspection techniques.

8.2.3.7 Life cycle management strategy

8.2.3.7.1 Pole top structures asset creation

Some pole top structures, such as cross arms and brackets, are typically galvanised steel. Alternative materials for some of these components in severe corrosion areas has been considered and may be trialled for viability in the future.

8.2.3.7.2 Pole top structures operations and maintenance strategy

The maintenance strategy for pole top structures is centred around detailed asset inspections and asset patrols to identify asset defects. They are both visually assessed and given more detailed thermographic inspections. The inspection frequency for pole top structures varies depending on corrosion zone classification.

Table 33 gives a summary of the routine inspection, maintenance and condition monitoring tasks for pole top structures.

Table 33: Pole top structures inspection, maintenance and condition monitoring tasks

Inspection, maintenance or condition monitoring task	Frequency
Pre-bushfire patrols of all sub-transmission and distribution overhead lines in BFRA	Annually
Patrols of metropolitan sub-transmission radial (single source of supply) line pole top structures	Annually
Thermographic inspections of sub-transmission and distribution 7.6kV and 11kV line pole top structures	2–5 years
Inspection of pole top structures in corrosion zones 2, 3 and 4	5 years
Inspection of pole top structures in corrosion zone 1	10 years

Further details on the inspection and maintenance strategy for pole top structures are covered in Section 6.2 (Sub-transmission lines) and Section 6.3 (Distribution lines) of the Network Maintenance Manual.

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

8.2.3.7.3 Pole top structures renewal/replacement strategy

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

Figure 85 shows a summary of the replacement quantities according to the pole top structures replacement plan to 2030.

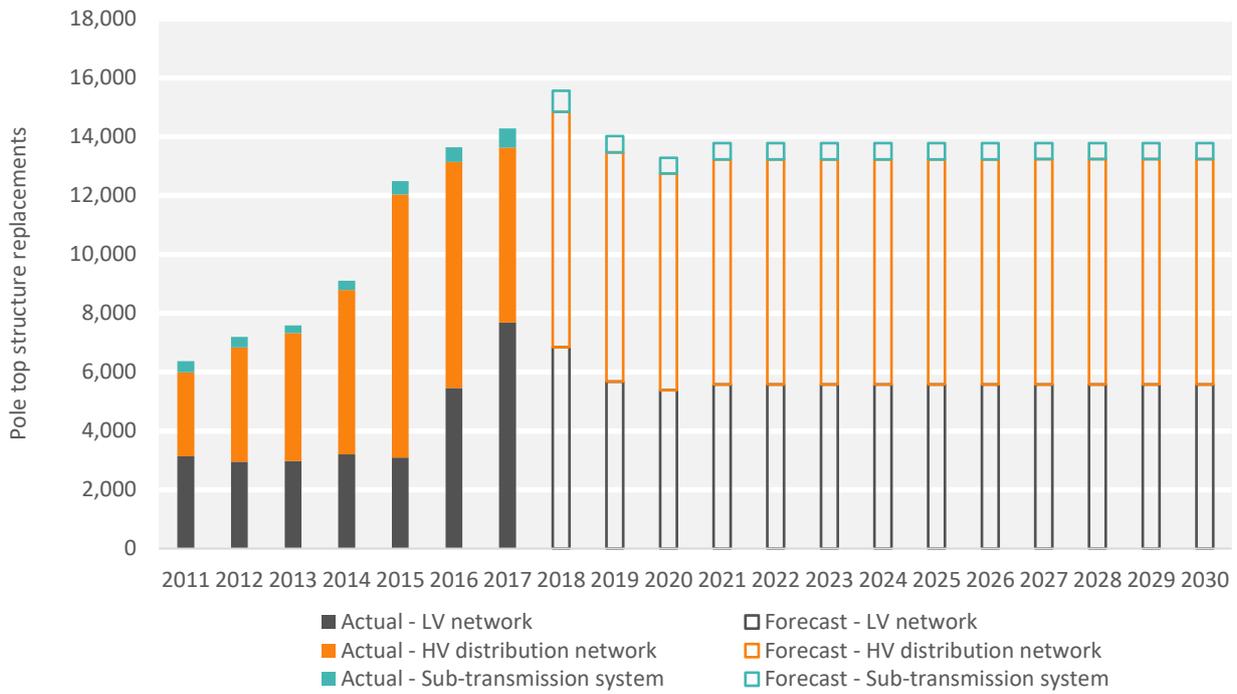


Figure 85: Pole top structures replacement plan

There is a forecast increase rate of replacements up to 2018 which then plateau to approximately 14,000 replacements p.a. based on current forecasts and a stable level of expenditure out to 2030.

8.2.3.7.4 Pole top structures disposal strategy

Hazardous waste, such as liquid fuses, must be disposed of in accordance with the SA Power Networks Environmental Management Guidelines and Procedures. The assets otherwise have no residual environmental effect and are of scrap value only. As such no special considerations are needed in dealing with these assets at the end of their expected life.

8.2.4 Overhead conductors

8.2.4.1 Introduction

An overview of the overhead conductor assets, including their population, age and condition, and the life cycle management approach, is given in this section along with replacement forecasts and resulting risk and asset condition for the planning period. For further information, refer to the overhead conductor asset plan.

Asset summary

Overhead conductors transmit electricity between substations and from substations to customers. Of the 174,293km of conductors across our network (over a route length of 71,258km), a significant proportion (~79%) are 40–65 years old.

Aside from 2013–2014 and 2016–2017, the number of conductor failures has remained relatively stable since 2011. Conductor assets are managed by repairing or replacing any failed conductors, identifying defects through the cyclic inspection program and prioritising work. The management approach is transitioning from refurbish or replace on condition to one of risk-based investment.

The overhead conductors have not been reliably modelled within CBRM to assess risk or asset health; data quality improvements are required. The historical performance and expenditure of this asset class informs the required forward investment to 2030.

8.2.4.2 Conductor asset management objectives

The asset management objectives specific to conductors are summarised in Table 34.

Table 34: Conductor asset management objectives

Level of service category	Conductors asset management objectives
Safety	<ul style="list-style-type: none"> No injury/death to staff or contractors through installing, operating, inspecting, maintaining/repairing, replacing or decommissioning conductors. No conductor condition failures resulting in injury/death. No conductor condition failures resulting in bushfire starts. No conductor condition failures resulting in damage to third party property. No breaches of legislated conductor clearances. Increase public awareness to minimise the likelihood of accidental contact with conductors.
Reliability and resilience	<ul style="list-style-type: none"> Minimise planned and unplanned interruption frequency and duration from conductor failures and replacements.
Two-way grid	<ul style="list-style-type: none"> Conductors sized and configured to manage two-way flows.
Communication and information	<ul style="list-style-type: none"> Provide accurate information on restoration times for unplanned outages due to conductor failures. Provide accurate advanced notice of any planned conductor replacement works involving outages.
Efficiency	<ul style="list-style-type: none"> Minimise conductor life-cycle costs including the cost of installation, operations, maintenance, replacement and disposal.

8.2.4.3 Asset description

The purpose of overhead conductors is to transmit electricity between substations and from substations to customers. They are supported by Stobie poles and pole top structures to ensure they meet legislated clearance requirements and minimise safety risk to the public. As overhead assets they are more prone to corrosion and the impacts of extreme weather events.

8.2.4.4 Population and age profile

There are 174,293km of conductors (excluding customer service lines) over a route length of 71,258km. Figure 87 shows the distribution of the conductor wire length across each system. Many conductors (approximately 47% of the total conductor wire length) are in the HV network with 17% of the total overhead conductor wire length made up of 19kV single wire earth return (SWER) lines, commonly used to supply customers in regional areas.

Figure 88 shows the age profile of overhead conductors. The LV and HV conductor length profiles follow a similar pattern. This is because the HV network was constructed to supply LV networks typically using the same alignment and the conductors attached to the same Stobie poles. Consequently, the conductor age profile also follows a similar age profile to that of the poles (see Section 8.2.2.4).

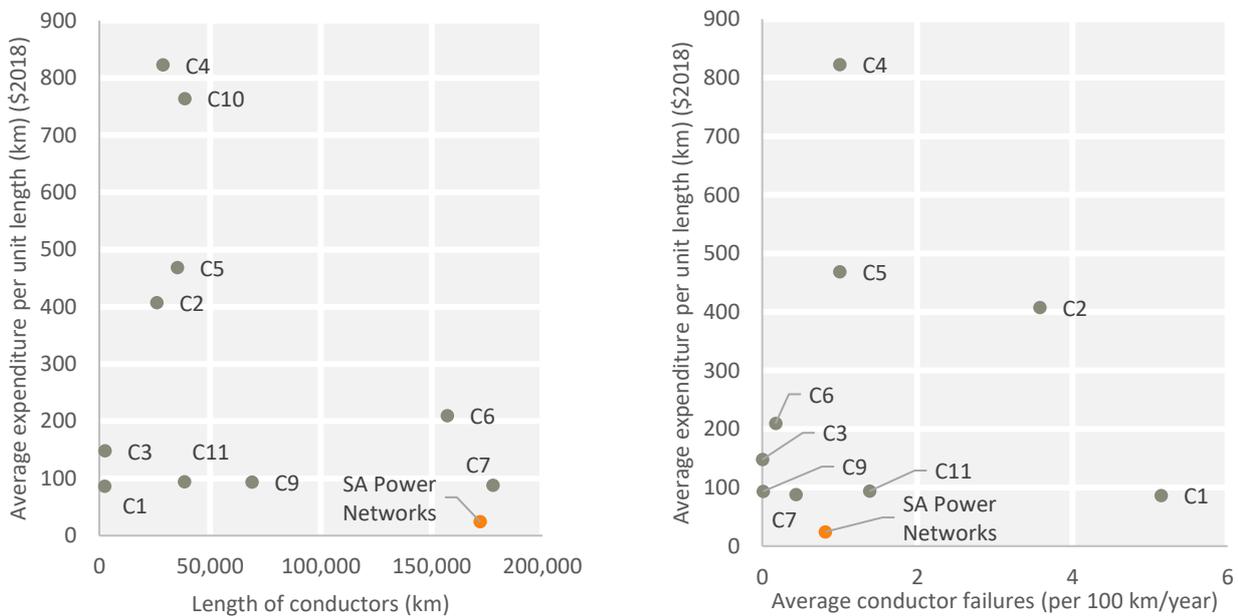
The expected life of conductors varies but is typically 65–95 years. The main factors that influence expected life are corrosion zone, load capacity, atmospheric pollution and fatigue. Based on the existing age profile, there is currently 3% of overhead conductors more than 65 years increasing to 21% by 2025.

8.2.4.5 Current condition and performance

Conductor failures can be used as a lag indicator of how the conductor asset base is performing in response to the asset management approach.

Figure 89 shows the historical number of conductor failures since 2009, with more failures in 2013–2014 and in 2016–2017. The spikes in condition failures in those years is partly due to inspections that occur following major event days (MEDs) and the identification of conductors that are assessed as requiring repairs.

A comparison of conductor performance in contrast to other DNSPs was undertaken analysing data from publicly available Category Regulatory Information Notices (RIN) reported over the period 2013-2014 to 2016-2017 inclusive (outliers excluded). A comparison of average annual renewal expenditure per unit length and failure rate is shown in Figure 86.



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

Figure 86: Conductor benchmarking of SA Power Networks vs other DNSPs (2013-2014 to 2016-2017 data)

Figure 86 shows SA Power Networks currently has the lowest level of average annual expenditure per conductor length with a mid-range failure rate amongst DNSPs. This shows SA Power Networks lifecycle management of conductors is very efficient.

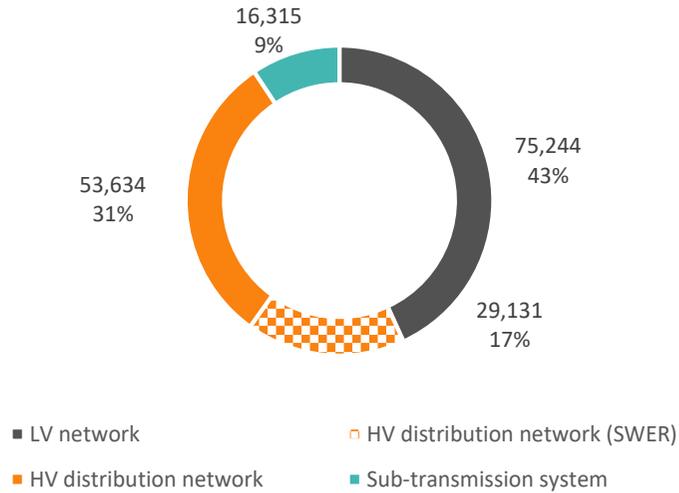


Figure 87: Overhead conductor length by system

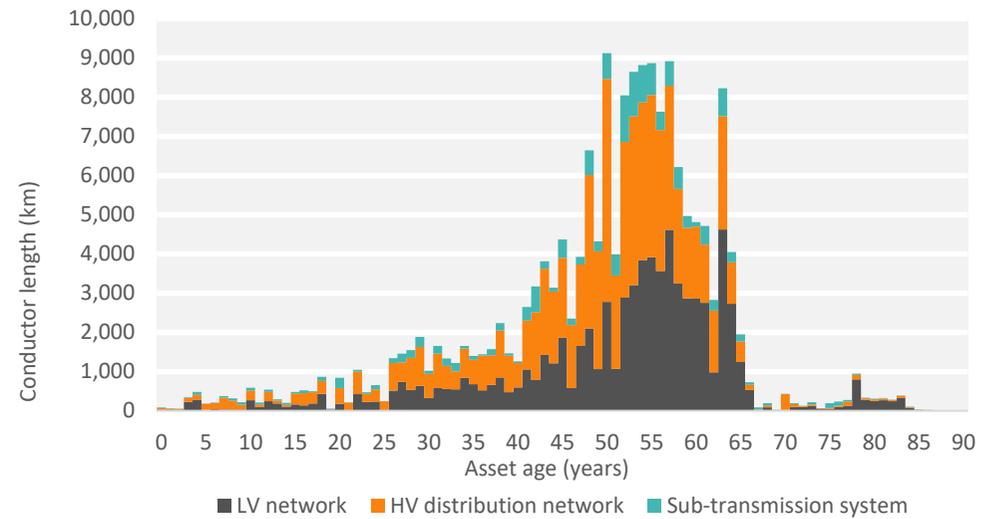


Figure 88: Conductor age profile

This asset class has not been reliably modelled using CBRM; data quality improvements are required to provide increased confidence in model outputs.

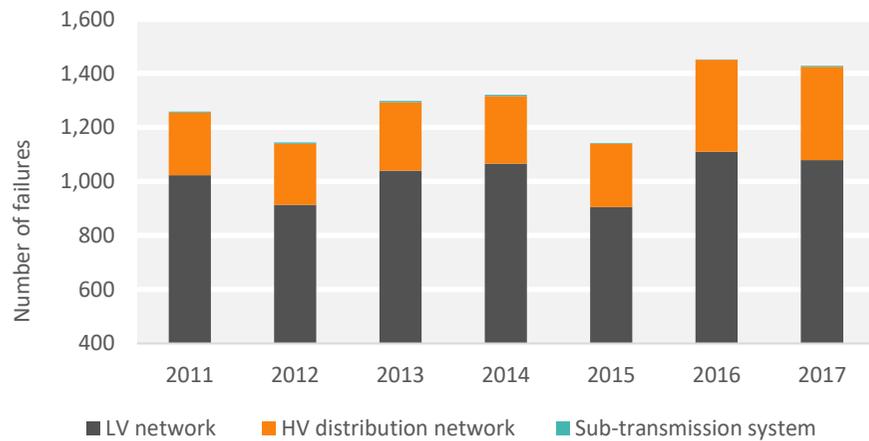


Figure 89: Conductors historical failures

Figure 90: Conductor health index distribution

8.2.4.6 Risks

The main risks associated with conductors include:

- potential injury/death of SA Power Networks staff, contractors or the public due to:
 - electric shock through any current transmitted through the pole or live conductors falling to the ground,
 - electric shock through physical contact of vehicles, machinery and other equipment primarily in rural areas,
 - electric shock or fire starts due to breaches of conductor clearances to ground, buildings, structures or vegetation,
 - physical contact through conductor falling to the ground because of the pole, pole top structure or conductor condition, or
 - bushfire start due to conductor defects or failures;
- impact on reliability service standards due to unplanned conductor failures; and
- impact on quality of supply complaints due to limited capacity of conductor size and/or ability to accommodate two-way flows.

Cyclic asset inspections play a key role in identifying defects to manage the risks associated with conductors. Supplemental use of emerging inspection and condition assessment tools such as autonomous drones (for visual patrol and thermographic inspections) and LIDAR (for identification of conductors breaching clearance distances) are ongoing. Risk modelling of conductor assets within CBRM has commenced although improvements to conductor asset and failure data is required to increase confidence in the model outputs.

The conductor specific risks are listed below.

- Current visual inspections do not provide quantitative measurements of material loss. The likelihood of defects resulting in failure are therefore heavily reliant on asset inspectors identifying visible defects.
- The rate of defect identification is increasing on conductors of specific material types including small copper conductors (prone to vibration/fatigue failures), galvanised steel and aluminium steel reinforced conductors (prone to corrosion failures in high corrosion zones), and conductors with aluminium taps used to connect conductors to other network equipment of dissimilar materials which results in corrosion and ultimately conductor failure.
- Tarlton to Ceduna 66kV sub-transmission line: This single source of electricity to the Ceduna region, approximately 100km in length. However, a 30km section towards Ceduna is known to be in poor condition. Failures on this sub-transmission line require specialised resources to be mobilised from Adelaide for repairs, which prolongs outages. Any conductor failures on this sub-transmission line can directly impact approximately 2,400 customers. Further investigations of an alternative power supply at Ceduna are subject to Regulatory Investment Test for Distribution and will need to consider deferral of the remaining sections of conductor replacement.
- Square Water Hole to Willunga 66kV sub-transmission line: This single source of supply to Victor Harbor, Goolwa and Middleton areas, approximately 15km in length with certain sections known to be in very poor condition. Any conductor failures on this sub-transmission line can directly impact approximately 20,000 customers. Further investigations of providing a new 66kV link are planned and will need to consider deferral of sections of this sub-transmission line replacement.
- Goolwa to Square Water Hole 66kV sub-transmission line: This single source of supply to the Goolwa and Middleton areas, approximately 20km in length. Any conductor failures on this sub-transmission line can directly impact approximately 8,000 customers. Further investigations of providing a new 66kV link are planned and will need to consider deferral of this sub-transmission line replacement.
- Hummocks to Kadina East 33kV sub-transmission line: This back up supply to northern Yorke Peninsula supplying the Kadina, Moonta and Wallaroo region areas, is approximately 37km in length with sections known to be in poor condition. Any conductor failures on this sub-transmission line can directly impact approximately 2,000 customers.

- Hummocks to Dalrymple 33kV sub-transmission line: This single feed, approximately 100km in length, into southern Yorke Peninsula supplies most of the mid and lower Yorke Peninsula region. Any conductor failures on this sub-transmission line can directly impact approximately 4,500 customers.
- Uley 33 kV sub-transmission line: This sub-transmission line is located west of Port Lincoln near Coffin Bay on Eyre Peninsula with sections of this line in poor condition. Any conductor failures on this sub-transmission line can directly impact approximately 1,500 customers.

8.2.4.7 Life cycle management strategy

8.2.4.7.1 Conductor asset creation

Conductors used on the network continue to be predominantly all aluminium, all aluminium alloy, and aluminium steel reinforced; minimal copper conductors are used in special circumstances. A new 66kV aluminium composite core conductor is under trial to assess the improved corrosion performance over the aluminium steel reinforced conductor. It also allows longer spans and higher tensions than all aluminium and all aluminium alloy conductors.

8.2.4.7.2 Conductor operations and maintenance strategy

The operations and maintenance strategy for conductors is centred around the visual inspections, patrols and thermographic inspections at overhead conductor joints to identify defects on conductors. The inspection frequency for overhead conductors varies depending on corrosion zone classification. The maintenance strategy for overhead conductors is a combination of corrective and reactive maintenance in response to overhead conductor faults. Repairs are undertaken until the extent and cost of such repairs requires consideration for overhead conductor replacement. Breaches of minimum conductor clearances are also identified as defects through the cyclic asset inspections.

Table 35 gives a summary of the routine inspection, maintenance and condition monitoring tasks for conductors.

Table 35: Conductor inspection, maintenance and condition monitoring tasks

Inspection, maintenance task or condition monitoring task	Frequency
Pre-bushfire patrols of all sub-transmission and distribution overhead lines in BFRA	Annually
Patrols of metropolitan sub-transmission radial (single source of supply) line conductors	Annually
Thermographic inspections of sub-transmission and distribution 7.6kV and 11kV line conductor joints	2–5 years
Inspection of conductors in corrosion zones 2, 3 and 4	5 years
Inspection of conductors in corrosion zone 1	10 years

Further details on the maintenance of conductors are covered in Section 6.2 (Sub-transmission conductors) and Section 6.3 (Distribution conductors) of the Network Maintenance Manual.

8.2.4.7.3 Conductor renewal/replacement strategy

The renewal/replacement strategy for conductors is based on maintaining the current total risk across the conductor population. The decision to replace an HV or LV conductor rather than continuing to undertake repairs considers these factors:

- Where there are three previous conductor failures on braced sections of conductors, all conductors in those sections will be replaced.
- If multiple locations of corrosion or deterioration are identified through the inspection program, then the section of conductors would be replaced and replacement works prioritised based on risk.
- Small copper conductors in BFRA are being proactively replaced due to failures of this conductor material type in all corrosion zones.
- Galvanised steel conductors in BFRA and high corrosion zones are being proactively replaced due to failures of this conductor material type particularly at previously repaired joints.

- The extent of the steel conductors installed with aluminium taps where the probability of localised corrosion increases.

Figure 91 shows a summary of the conductor renewal/replacement plan to 2030.

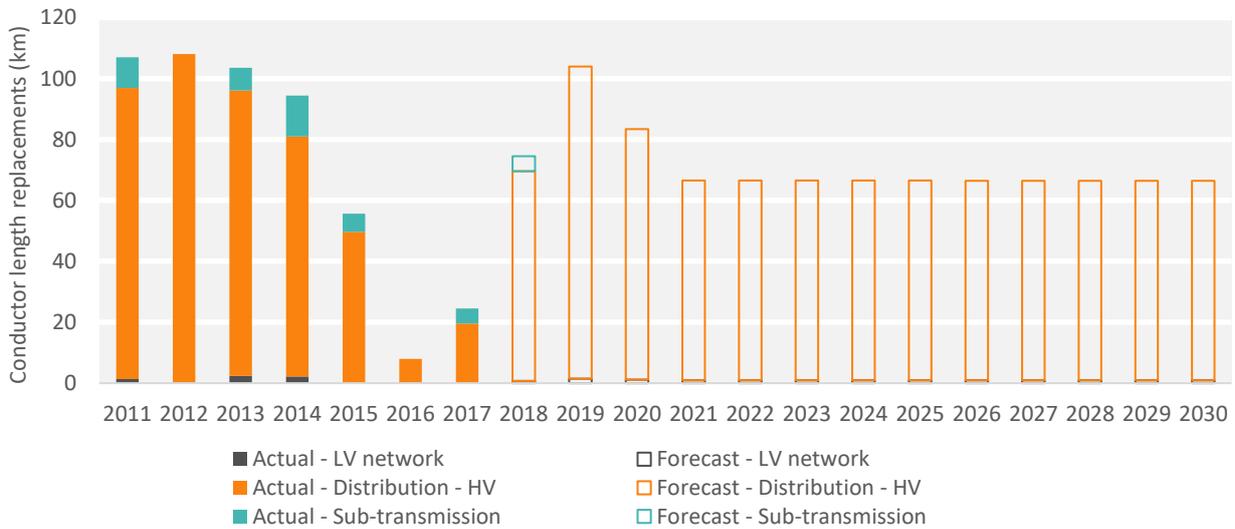


Figure 91: Conductors renewal/replacement plan

Figure 91 shows a decline in conductor length replaced from 2014 to 2016. This was largely due to a change in asset management approach for conductors from replacing longer lengths to only replacing short sections (patching) for replacement. This resulted in significantly higher unit costs for replacement over the 2015-106 period. While some localised patching is still undertaken, the asset management approach has since reverted to replacing longer lengths with a history of defects. There is a significant increase in planned replacements across 2018–2020 with replacements thereafter reducing to around 67km pa.

8.2.4.7.4 Conductor disposal strategy

Assets that reach the disposal stage usually do not have any economic value beyond their scrap metal value. Hazardous waste is disposed of in accordance with the SA Power Networks Environmental Management Plan.

8.2.5 Distribution transformers

8.2.5.1 Introduction

An overview of the distribution transformer assets, including their population, age and condition, and the life cycle management approach, is given in this section along with replacement forecasts and resulting risk and asset condition for the planning period. For further information, refer to the distribution transformers asset plan.

Asset summary

Distribution transformers change the voltage of electricity. Electricity is transported across the network at higher voltages to save energy and the 75,945 distribution transformers installed across the network progressively reduce voltage to a level that it can be used by customers. They are installed overhead and mounted on poles (pole top), or installed at ground level inside a cabinet/cubicle (padmount) or in enclosed chambers (ground level station). A significant proportion (~47%) of distribution transformers are 30–60 years old.

The number of failures on distribution transformers has remained relatively stable since 2011. Their management is largely based on renewal/replacement on failure due to the relatively low consequence of such events.

The distribution transformers have not been modelled using CBRM to assess risk or asset health. The historical performance and expenditure of this asset class informs the required forward investment to 2030.

8.2.5.2 Distribution transformer asset management objectives

The asset management objectives specific to distribution transformers are summarised in Table 36.

Table 36: Distribution transformer asset management objectives

Level of service category	Distribution transformer asset management objectives
Safety	<ul style="list-style-type: none"> No injury/death to staff or contractors through installing, operating, inspecting, maintaining/repairing, replacing or decommissioning distribution transformers. No distribution transformer condition failures resulting in injury/death. No distribution transformer failures resulting in bushfire starts. No distribution transformer condition failures resulting in damage to third party property.
Reliability and resilience	<ul style="list-style-type: none"> Minimise planned and unplanned interruption frequency and duration from distribution transformer failures and replacements.
Environment	<ul style="list-style-type: none"> Minimise the number of oil spills from distribution transformers.
Two-way grid	<ul style="list-style-type: none"> Locate and size distribution transformers to manage two-way flows. Maintain network voltage levels within Australian Standard Voltage.
Communication and information	<ul style="list-style-type: none"> Provide accurate information on restoration times for unplanned outages due to distribution transformer failures. Provide accurate advanced notice of any planned distribution transformer replacement works involving outages.
Efficiency	<ul style="list-style-type: none"> Minimise distribution transformer life-cycle costs including the cost of installation, operations, maintenance, refurbishment/replacement and disposal.

8.2.5.3 Asset description

The purpose of distribution transformers is to change the voltage of electricity. Electricity is transported across the network at higher voltages to save energy and transformers progressively reduce voltage through the distribution network to a level that it can be used by customers. For the purposes of this document, distribution transformers comprise all transformers not located within a zone substation. They may be connected directly to the sub-transmission system or distribution networks.

8.2.5.4 Population and age profile

The 75,945 distribution transformers across the network are installed overhead and mounted on poles (pole top), or installed at ground level inside a cabinet/cubicle (padmount) or in enclosed chambers (ground level station). Most distribution transformers are pole top transformers. The proportions of different installation types are shown in Figure 93.

Figure 94 shows the age profile of transformers in the distribution network. A significant proportion (~47%) of distribution transformers are 30–60 years old.

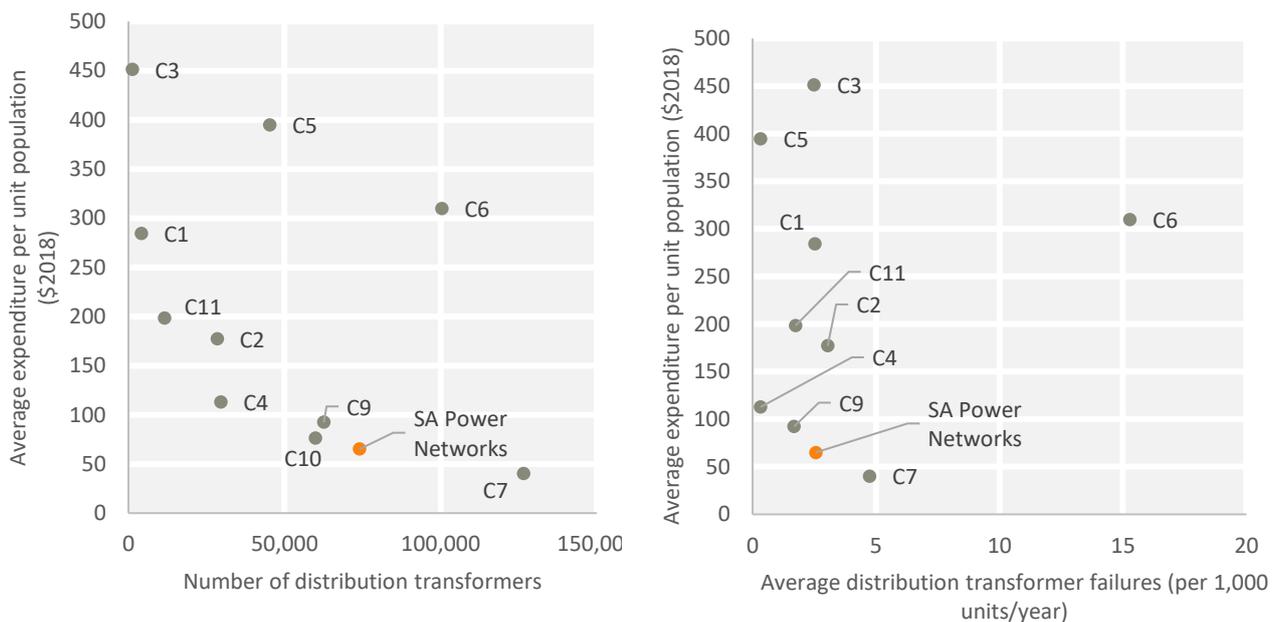
The expected life of distribution transformers varies but is typically 50–70 years. The main factors that influence expected life are corrosion zone, overloading of capacity and atmospheric pollution. Based on the existing age profile, there is currently 13% of distribution transformers more than 50 years of age increasing to 22% by 2025.

8.2.5.5 Current condition and performance

Figure 95 shows the historical number of distribution transformer failures, with the number remaining relatively stable since 2011. Historically, many distribution transformer failures were due to overloading, but those failures were reduced by increased solar photovoltaic (PV) system uptake and quality of supply practices leading to infill transformers to better distribute load within the LV network.

The HI of distribution transformers has not been modelled.

A comparison of distribution transformer performance in contrast to other DNSPs was undertaken analysing data from publicly available Category Regulatory Information Notices (RIN) reported over the period 2013-2014 to 2016-2017 inclusive (outliers excluded). A comparison of average annual renewal expenditure per unit population and failure rate is shown in Figure 92.



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

Figure 92: Distribution transformer benchmarking of SA Power Networks vs other DNSPs (2013-2014 to 2016-2017 data)

Figure 92 shows SA Power Networks currently has the lowest level of average annual expenditure per distribution transformer even with a failure rate comparable with the majority of other DNSPs. Typically, SA Power Networks replaces distribution transformers when they no longer function or in response to significant defects (see Section 8.2.5.7). This shows SA Power Networks lifecycle management of distribution transformers is very efficient.

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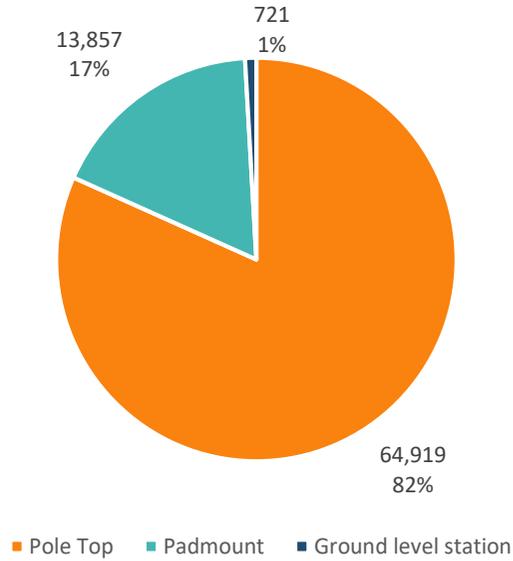


Figure 93: Distribution transformer types

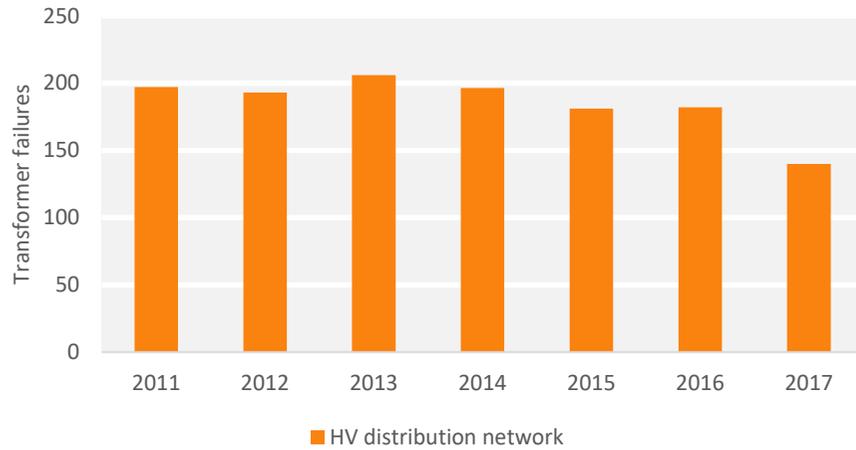


Figure 95: Distribution transformers historical failures

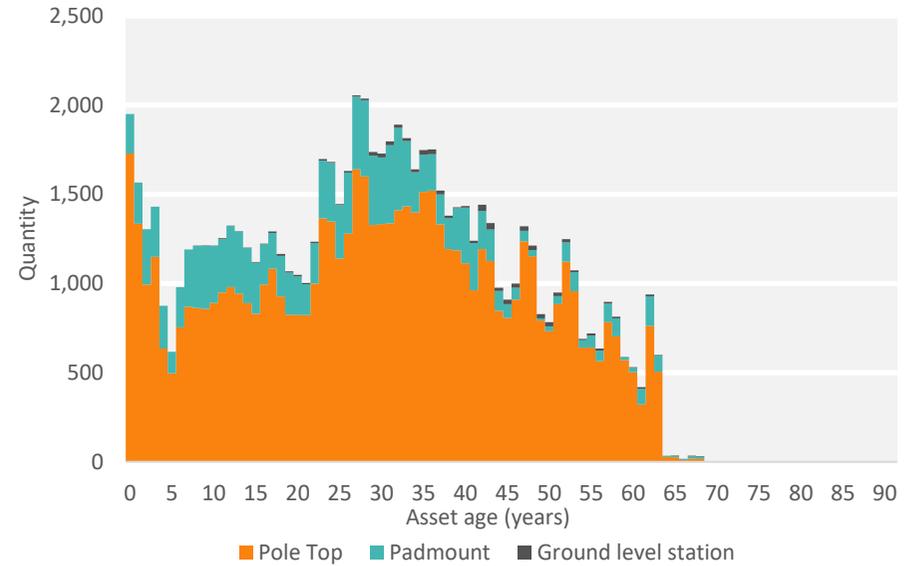


Figure 94: Distribution transformers age profile

This asset class has not yet been modelled using CBRM.

Figure 96: Current distribution transformer health index distribution

8.2.5.6 Risks

The main risks associated with distribution transformers include:

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

Cyclic asset inspections play a key role in identifying any obvious defects to manage the risks associated with distribution transformers. Monitoring of distribution transformers is limited across the network.

The distribution transformer specific risks are listed below.

- **Limited proactive condition monitoring:** Oil testing analysis is not undertaken on distribution transformers to identify impending failure as is done for substation power transformers. This is largely due to the high number of distribution transformers, accessibility (e.g. majority are pole top) and the relative risk of distribution transformers compared to other assets. Distribution transformer failures due to internal faults will therefore continue to occur.
- **Limited thermographic inspections:** As for pole top structures, distribution transformers are only thermographically inspected on the backbone of some feeders, on specific request or for distribution transformers supplying high profile community events. This is largely due to the many distribution transformers, the cost to undertake such works and the limitations of thermographic equipment on lightly loaded transformers. Some failures from thermal damage will continue in some locations where thermographic testing is not undertaken. Cost effective alternatives such as drone and fixed wing aircraft fitted with thermal cameras are currently being trialled to assess their effectiveness in data capture and costs.
- **PV related customer enquiries and emerging technologies:** Customer solar PV enquiries significantly increased during 2017 because of high voltages in the network and customers being unable to export electricity into the network. The cause in some cases can be settings on customers' solar PV systems, but the enquiries can result in modification to distribution transformers or in some instances require distribution transformers to be upgraded. The emergence of battery storage and Virtual Power Plants and associated un-diversified peaks in energy import or export will also impact on local distribution transformers. The cost for optimising the existing network assets needs to be carefully managed to avoid a significant increase in network augmentation expenditure. In addition, a range of customer-side solutions to help to mitigate these risks, including mandatory inverter settings, tariffs and the potential for active management of VPP export limits.
- **Suitability of small transformers (5–10kVA):** Under certain conditions, customer demand can exceed the capacity of the transformers and customer export of electricity from solar PV systems can also cause overload issues. The fuses in these small transformers are oversized compared to the capability of the HV windings. These distribution transformers are currently run to fail at which point they are replaced with a more suitably sized transformer.

8.2.5.7 Life cycle management strategy

8.2.5.7.1 Distribution transformer asset creation

Distribution transformer specifications have remained largely unchanged apart from minor efficiency improvements in recent years. New functionality is being investigated and trialled including transformers with in-built load tap changers and/or voltage regulation to assist with high penetration of solar PV.

8.2.5.7.2 Distribution transformer operations and maintenance strategy

Some distribution transformers are monitored for load and voltage by 200 permanent monitors randomly installed across the metropolitan regions. Selected transformers are also monitored in response to customer voltage complaints. Additionally, a proactive test survey on the transformers is undertaken based on expected demand. The key maintenance strategy for distribution transformers is centred around the asset condition assessment. Distribution transformers are visually assessed to identify obvious external defects, as part of the overall planned overhead and ground level inspections. Inspections are supplemented by more detailed thermographic inspections of transformer joints but these are typically limited to the most critical feeders in the HV network. The inspection frequency for distribution transformer assets varies depending on the corrosion zone classification.

Table 37 gives a summary of the routine inspection, maintenance and condition monitoring tasks for distribution transformers.

Table 37: Distribution transformers inspection, maintenance and condition monitoring tasks

Inspection, maintenance and condition monitoring tasks	Frequency
Pre-bushfire patrols of overhead sub-transmission and distribution transformers in BFRA	Annually
Sample inspection of pad mounted transformers	Annually
Thermographic inspections of overhead distribution metropolitan 7.6kV and 11kV transformers	2 years
Thermographic inspections of overhead distribution country 7.6kV and 11kV transformers	5 years
Inspection of overhead transformers in corrosion zones 2, 3 and 4	5 years
Inspection of overhead transformers in corrosion zone 1	10 years

Further details for the maintenance of distribution transformers are covered in Section 6.3 (pole top transformers) and Section 6.7 (pad mount transformers) of the Network Maintenance Manual.

8.2.5.7.3 Distribution transformer renewal/replacement strategy

The renewal/replacement strategy for distribution transformers is based on managing risk. As the consequence of a distribution transformer failure is low, the renewal strategy is based on prioritising for replacement transformers that have failed or identified to be in poor condition.

The decision to refurbish or replace a distribution transformer considers these factors:

- Distribution transformers that have catastrophically failed are disposed of to salvage.
- The inventory levels of the various makes/models of distribution transformers are maintained to ensure a minimum number of each type of transformer is readily available. Specific makes/models that are no longer able to be purchased are refurbished to ensure emergency stocks for rapid response to network outages.
- Pole top transformers are only refurbished when they are unique in relation to voltages or have specific features that are required for a specific location.
- Pole top transformers of galvanised construction and fitted with a tap switch to enable adjustments on voltage levels are refurbished where viable otherwise the transformer is sent to salvage.
- Padmount transformers are generally refurbished. Any corrosion of the cabinet is replaced as part of the refurbishment process.
- Any large and/or unique ground level distribution transformers (e.g. a specific physical size for certain space constrained locations) are generally refurbished.

Figure 97 shows a summary of the distribution transformer renewal/replacement plan to 2030.

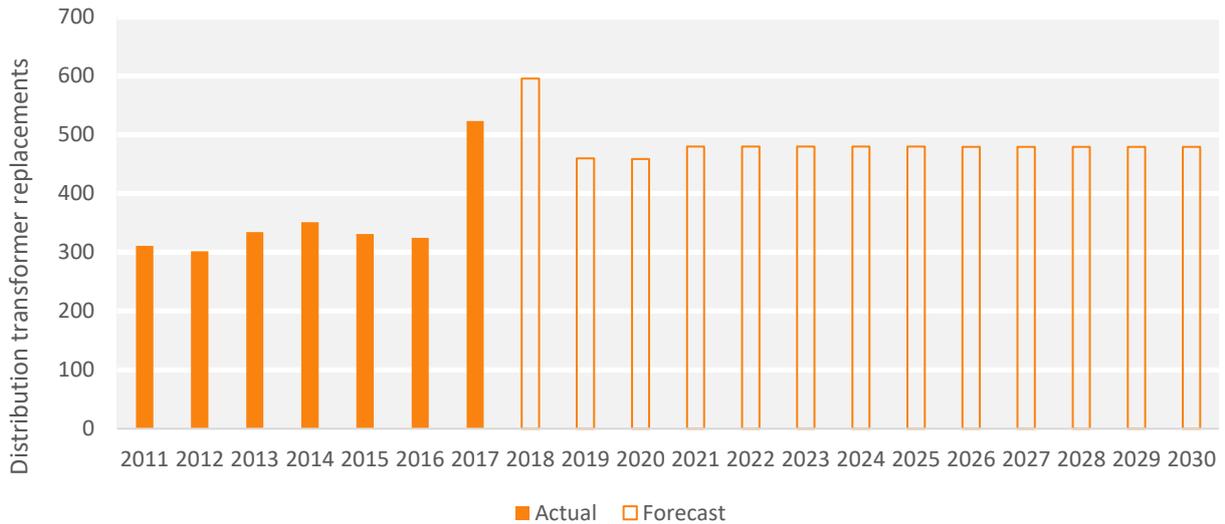


Figure 97: Distribution transformers renewal/replacement plan

Figure 97 shows an increase in the number of distribution transformer replacements to 2020 and then plateauing around 400 replacements p.a. for the remainder of the planning period.

8.2.5.7.4 Distribution transformer disposal strategy

Distribution transformers are only disposed of for potential scrap value after salvaging reusable parts. Some may contain polychlorinated biphenyl (PCB) as an additive. Any distribution transformers requiring disposal have the oil drained and tested for PCB to ensure disposal is in accordance with the Environmental Management Plan.

8.2.6 Switching cubicles

8.2.6.1 Introduction

An overview of the switching cubicle assets, including their population, age and condition, and the life cycle management approach, is given in this section along with replacement forecasts and resulting risk and asset condition for the planning period. For further information, refer to the ground level switchgear asset plan.

Asset summary

Switching cubicles are devices mounted on the ground that connect components of the underground cable network. These devices enable the safe connection and disconnection (ie switching) of cables and transformers for operational and maintenance purposes. A significant proportion (78%) of the 7,551 switching cubicles across the network are less than 20 years old.

The number of switching cubicle failures has reduced slightly since 2013–2014; approximately 9% of all ground level switches are currently unable to be switched while energised. The management of switching cubicles is based around condition assessments and equipment performance. Management of switching cubicle assets is transitioning from refurbish or replace on condition to risk based investment.

The switching cubicles have not been reliably modelled within CBRM to assess risk or asset health; data quality improvements are required. The historical performance and expenditure of this asset class informs the required forward investment to 2030.

8.2.6.2 Switching cubicle asset management objectives

The asset management objectives specific to switching cubicles are summarised in Table 38.

Table 38: Switching cubicle asset management objectives

Level of service category	Switching cubicle asset management objectives
Safety	<ul style="list-style-type: none"> No injury/death to staff or contractors through installing, operating, inspecting, maintaining/repairing, replacing or decommissioning switching cubicles. No switching cubicle condition failures resulting in injury/death.
Reliability and resilience	<ul style="list-style-type: none"> Minimise planned and unplanned interruption frequency and duration from switching cubicle failures and replacements. Ensure ground level switches can be switched live to minimise reliability impacts on customers during network operations and maintenance activities.
Environment	<ul style="list-style-type: none"> Minimise greenhouse gas (sulphur hexafluoride, SF₆) emissions from switching cubicle assets.
Communication and information	<ul style="list-style-type: none"> Provide accurate information on restoration times for unplanned outages due to switching cubicle failures. Provide accurate advanced notice of any planned switching cubicle replacement works involving outages.
Efficiency	<ul style="list-style-type: none"> Minimise switching cubicle life-cycle costs including the cost of installation, operations, maintenance, refurbishment/replacement and disposal.

8.2.6.3 Asset description

Switching cubicles are devices mounted on the ground and connect components of the underground cable network. These devices enable the safe connection and disconnection (e.g. switching) of cables and transformers for operational and maintenance purposes.

8.2.6.4 Population and age profile

The 7,551 switching cubicles across the network are mainly in the HV distribution network.

Figure 98 shows the age profile of switching cubicles. A significant proportion (78%) are less than 20 years old. This is mainly due to network growth and real estate developments requiring underground cable networks; also, many original switching cubicles have been refurbished/replaced.

The expected life of switching cubicles varies but is typically 15–45 years. The main factors that influence expected life are the manufacturer make/model, insulation medium and corrosion zone.

8.2.6.5 Current condition and performance

Switching cubicle asset failures can be used as a lag indicator of how the switching cubicle asset base is performing in response to the asset management approach.

Approximately 9% of ground level switches are currently unable to be switched while energised.

Figure 99 shows the historical failures of switching cubicles. The number of switching cubicle failures has slightly reduced since 2014, largely because of the increase in planned switching cubicle replacements including the Krone switchgear replacement program.

Switching cubicle assets have not been confidently modelled using CBRM to assess risk or asset health because the underlying data requires improvements to provide confidence in model outputs (see Section 11).

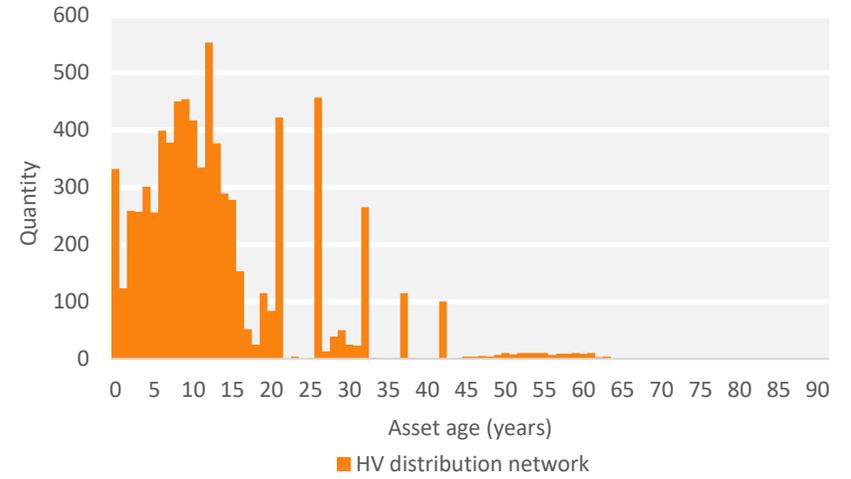


Figure 98: Switching cubicle age profile

This asset class has not been reliably modelled using CBRM; data quality improvements are required to provide increased confidence in model outputs.

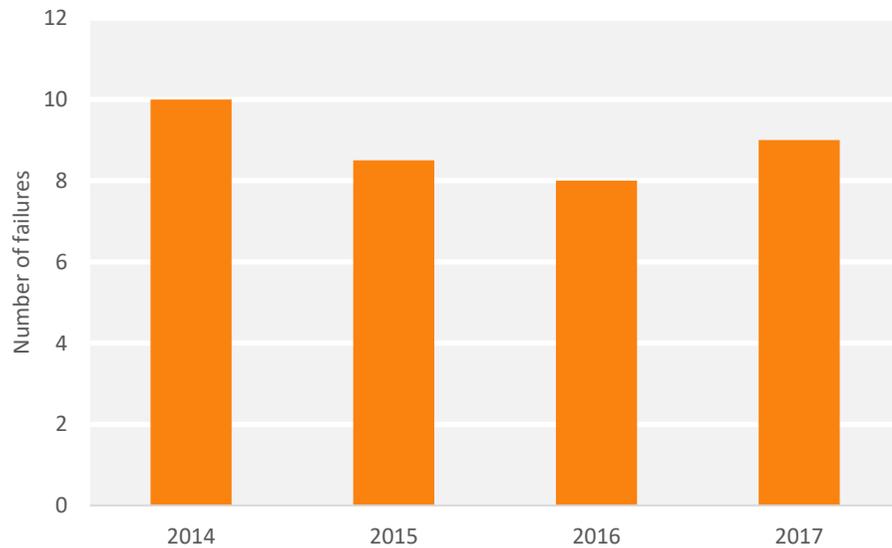


Figure 99: Switching cubicle historical failures

Figure 100: Switching cubicle health index distribution

8.2.6.6 Risks

The main risks associated with switching cubicles include:

- potential injury/death of SA Power Networks staff, contractors or the public due to switches catastrophically failing:
 - during switching operations, or
 - when not being operated;
- impact on reliability service standards of the time associated with unplanned switching cubicle failures; and
- environmental impacts of greenhouse gas emissions (SF₆) from asset condition or failure.

Cyclic asset inspections play a key role in identifying defects to manage the risks associated with switching cubicles. Risk modelling of switching cubicle assets within CBRM has commenced although improvements to switching cubicle asset and failure data is required to increase confidence in the model outputs.

The switching cubicle specific risks are listed below.

- The potential failures of Krone switchgear causing loss of supply or injury/death (scheduled to be phased out of the network through planned replacements by 2020).
- Other specific makes and models banned from being operated due to safety risks and/or poor condition, including: ETSA Utilities D-Type, Statter and GEC AEI models.
- Switching cubicles requiring replacement due to external cabinets condition deteriorating to unsatisfactory levels.
- Asset obsolescence where the switching cubicle unit and/or spares are no longer available.

8.2.6.7 Life cycle management strategy

8.2.6.7.1 Switching cubicle asset creation

Switching cubicles are available in both local control only and full SCADA version suitable for feeder automation. A recent change to the housing specification has allowed the housing and switchgear to be supplied as a single packaged unit saving hours of construction time on site.

8.2.6.7.2 Switching cubicle operations and maintenance strategy

Switchgear assets have moving parts that are affected by wear and degradation. The maintenance strategy for switching cubicles is a combination of reactive and preventative maintenance arising from information obtained from condition assessments and equipment performance. Switching cubicles are inspected as part of the overall planned ground level switchgear inspections. The frequency of inspections and maintenance is different for each type of switching cubicle, based on manufacturer, make/model and insulation medium, manufacturers standards and operational experience.

Table 39 gives a summary of routine inspection, maintenance and condition monitoring tasks for switching cubicles.

Table 39: Switching cubicle inspection, maintenance and condition monitoring tasks

Inspection, maintenance and condition monitoring tasks	Frequency
Visual inspections of switching cubicle (general condition, inspection of cable terminations, check for oil leaks, partial discharge testing, gas emissions)	1–5 years (frequency varies depending on make/model and type of insulation)
Diagnostic testing of switching cubicles	1–5 years (frequency varies depending on make/model and type of insulation)
Thermographic inspections	Frequency depends on make/model and outcomes of visual inspections

Further details for the maintenance of switching cubicles are covered in Section 6.6 (Ground level distribution switchgear) of the Network Maintenance Manual.

Limited maintenance work, such as minor repairs and insulation replacement, is undertaken on switching cubicles.

8.2.6.7.3 Switching cubicle renewal/replacement strategy

The renewal/replacement strategy for switching cubicles is based on maintaining the long-term risk and performance across the switching cubicle population. It includes replacing many switching cubicles in the network that cannot be safely operated while energised. Limited refurbishment of switching cubicles is undertaken, with most makes/models replaced. Switching cubicle refurbishment significantly extends the life of the asset at a much lower cost than replacement.

The decision to refurbish a switching cubicle includes factors such as:

- availability of spare parts from previously replaced switching cubicles or availability of new components for specific make/models (e.g. NAL12);
- the atmospheric environment in which the switching cubicle resides — the higher the severity of the corrosive environment, the less viable the opportunity for refurbishment;
- the electrical service duty of the switching cubicle (e.g. fit for modern purpose) and to be switchable under full load; and
- physical space limitations for replacing the cubicle with an alternative make/model.

Figure 101 shows a summary of the switching cubicles renewal/replacement plan to 2030.

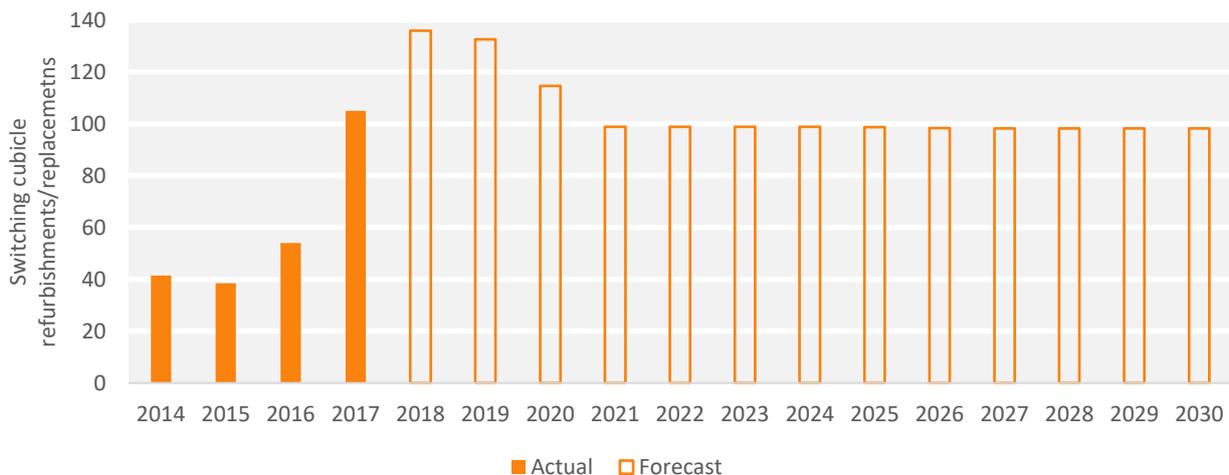


Figure 101: Switching cubicles renewal/replacement plan

Figure 101 shows a relatively stable rate of switching cubicle replacements out to 2030.

8.2.6.7.4 Switching cubicle disposal strategy

Disposal of switching cubicles is for potential scrap value only after salvaging of reusable parts for switching cubicles still in service. Switchgear containing hazardous substances, such as SF₆ gas, will require disposal procedures according to regulations. In addition, some oil-insulated switching cubicles may contain PCB as an additive. Any switching cubicles requiring disposal have their oil drained and tested for PCB to ensure disposal in accordance with the Environmental Management Plan.

8.2.7 Reclosers and sectionalisers

8.2.7.1 Introduction

An overview of the recloser and sectionaliser assets, including their population, age and condition, and the life cycle management approach, is given in this section along with replacement forecasts for the planning period. For further information, refer to the overhead protection devices asset plan.

Asset summary

Reclosers and sectionalisers are specialised switchgear located on the overhead network. A recloser is similar to a circuit breaker connected to adjacent sections of overhead conductors in an electrical circuit. A sectionaliser is a switch always used in conjunction with an associated recloser. They are positioned within the network to reduce the risk of damage from electrical faults and to improve the reliability of supply to customers. Of the 1,394 reclosers installed across the network, 92% have been refurbished or installed in the last 10 years. The age profile of 676 sectionalisers installed across the network is relatively evenly distributed over the last 50 years.

The failure rate has trended downward for reclosers and remained stable for sectionalisers since 2010–2011. Management of reclosers is based on the cyclic inspection program to identify defects; the frequency of recloser operation informs the refurbishment program. Any reclosers or sectionalisers that have failed to operate during an outage event are repaired, refurbished or replaced.

Reclosers and sectionalisers have not been modelled using CBRM to assess risk or asset health. The historical performance and expenditure of this asset class is therefore used to inform the required forward investment to 2030.

8.2.7.2 Reclosers and sectionalisers asset management objectives

The asset management objectives specific to reclosers and sectionalisers are summarised in Table 40.

Table 40: Recloser and sectionalisers asset management objectives

Level of service category	Recloser and sectionalisers asset management objectives
Safety	<ul style="list-style-type: none"> No injury/death to staff or contractors through installing, operating, inspecting, maintaining/repairing, replacing or decommissioning reclosers and sectionalisers. No recloser or sectionaliser condition failures resulting in injury/death. No recloser or sectionaliser failures resulting in bushfire starts. Rapid restoration of failed reclosers to ensure ongoing network protection against bushfires and community safety.
Reliability and resilience	<ul style="list-style-type: none"> Minimise planned and unplanned interruption frequency and duration from recloser and sectionaliser failures and replacements. Monitor and control reclosers remotely in critical areas such as on BFRA boundaries and on feeders supplying large numbers of customers.
Communication and information	<ul style="list-style-type: none"> Provide accurate information on restoration times for unplanned outages due to recloser and sectionaliser failures. Provide accurate advanced notice of any planned recloser and sectionaliser replacement works involving outages. Provide ability to remotely control and alarm on failure for fast response and notification of network status.
Efficiency	<ul style="list-style-type: none"> Minimise life-cycle costs of reclosers and sectionalisers including the cost of installation, operations, maintenance, refurbishment/replacement and disposal.

8.2.7.3 Asset description

Reclosers and sectionalisers are specialised switchgear located on the overhead network. They are positioned within the network to reduce the risk of damage that may be caused by electrical faults and improve the reliability of supply to customers.

A recloser is like a circuit breaker connected to adjacent sections of overhead conductors in an electrical circuit. It constantly monitors the line current of the attached conductors to detect a fault in the downstream portion of the network. Most faults are transient and disappear after a short time. A recloser takes advantage of this and facilitates automatic disconnection of a downstream faulted line and automatic reconnection after a few seconds with the process repeated up to four times.

A sectionaliser is a specialised switch that is always used with an associated recloser. One or more sectionalisers may be installed downstream of a single recloser. The sectionaliser acts in conjunction with its associated recloser to isolate just the portion of the network downstream of the sectionaliser if a permanent fault is detected in this portion; it thus allows the recloser to restore supply to the rest of the network.

Controllers may also be used to operate a recloser or sectionaliser. It can be an integral, or a separate, device and can be powered by battery or by mains power.

8.2.7.4 Population and age profile

There are 1,394 reclosers and 676 sectionalisers installed across the network. Figure 102 shows the distribution of these assets across systems; Figure 103 shows their age profile. Approximately half of the recloser population is on the 11kV lines within the HV distribution network while over 80% of sectionalisers are on the 19kV SWER lines.

A significant proportion (92%) of reclosers have been refurbished or installed in the last 10 years. Some reclosers were installed as part of the feeder automation project and a significant number of recloser refurbishments have been undertaken over the last five years. The remaining expected life of a refurbished recloser will not be as long as its original expected life. Sectionalisers have been installed progressively over time with limited replacements.

The expected life of hydraulic reclosers varies but is typically around 45 years. The main factors that influence expected life are deterioration and/or failure due to corrosion, number of operations, and inherent and often undetectable manufacturing defects. Hydraulic reclosers can be refurbished although their functionality and ability to interface with modern equipment is limited. Currently, all recloser tanks were refurbished within the last 20 years.

The expected life of sectionalisers varies but is typically around 45 years. The main factors that influence expected life are similar to those for reclosers. Currently, <1% of sectionalisers are beyond 45 years of age with this increasing to 4% by 2025 based on the existing age profile.

8.2.7.5 Current condition and performance

Figure 104 shows the historical failures of reclosers and sectionalisers. The trend in recloser failures has been downward since 2011 but has stabilised in recent years, largely due to the significant recloser refurbishment program over the last five years.

The number of failures of sectionalisers has remained relatively stable since 2011.

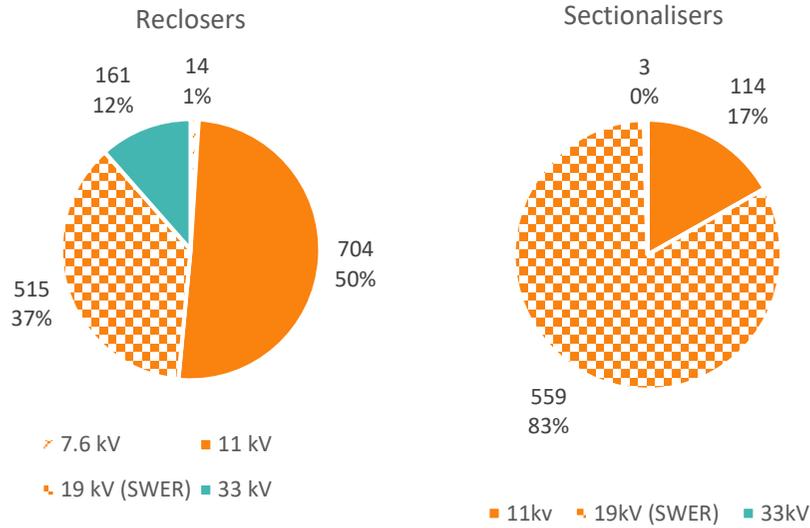


Figure 102: Recloser and sectionaliser quantity by operating voltage

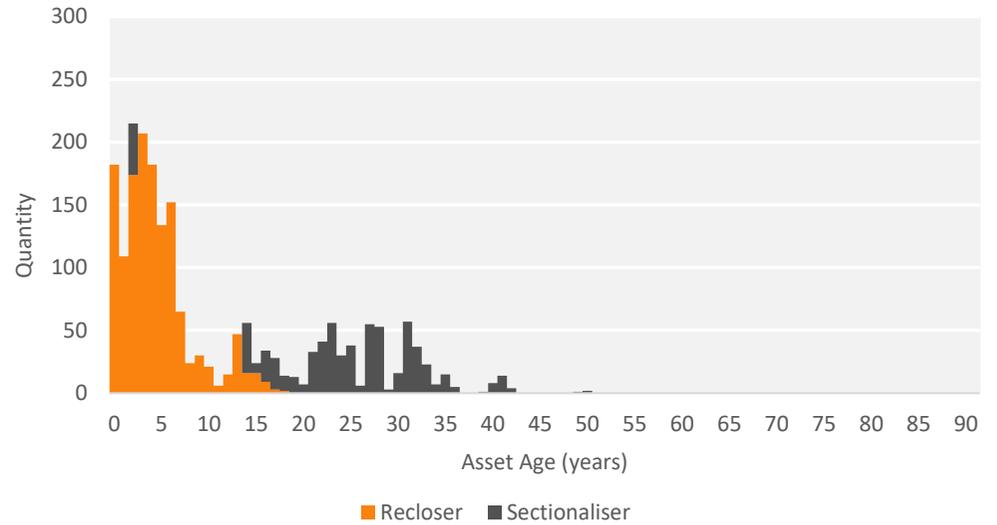


Figure 103: Reclosers and sectionalisers age profile

These asset classes have not yet been modelled using CBRM.

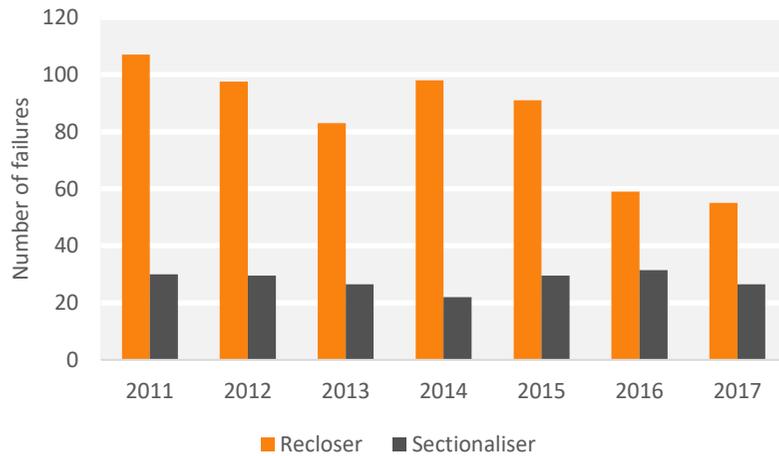


Figure 104: Reclosers and sectionaliser historical failures

Figure 105: Current recloser and sectionalisers health index distribution

8.2.7.6 Risks

The main risks associated with reclosers and sectionalisers include:

- potential injury/death of SA Power Networks staff, contractors or the public from inadequate protection due to the inability to detect faults or clear faults within required timeframes;
- many reclosers not connected to SCADA resulting in 'silent' failures of recloser controllers; and
- impact on reliability service standards due to unplanned recloser or sectionaliser failures.

The cyclic overhead line inspection program inspects reclosers and sectionalisers for external corrosion and obvious defects. Recloser counter readings are also used to predict when the probability of the unit failing to operate as intended will increase.

The cable specific risks are listed below.

- Selected makes/models of reclosers becoming increasingly difficult to refurbish due to no ongoing manufacturer support or limited availability of spares.
- The availability of internal specialised resources for refurbishment, testing and commissioning of older recloser units.
- Some components outside of required tolerances due to wear.
- The electronic reclosers being more prone to damage/interference from lightning strikes than the older hydraulic reclosers.
- There is no current standard approved sectionaliser for replacement of failed sectionalisers.

8.2.7.7 Life cycle management strategy

8.2.7.7.1 Reclosers and sectionalisers asset creation

Recloser specifications have undergone significant revisions recently for suitability for feeder automation. All SCADA capable reclosers are now commissioned as a protection device to ensure consistency for feeder automation. Sectionalisers are now almost exclusively used on SWER lines only to reduce patrol times.

8.2.7.7.2 Reclosers and sectionalisers operations and maintenance strategy

Any reclosers connected to SCADA are monitored for the number of operations, alarms and load passing through the recloser. Manual readings are taken on reclosers not connected to SCADA with the number of operations used to inform the recloser refurbishment program. More frequently operated reclosers are prioritised for refurbishment. No operational activities are undertaken on sectionalisers and they are not connected to SCADA.

The maintenance strategy for reclosers and sectionalisers is based on information obtained from the asset condition assessment along with the number of operations and the identification of reclosers or sectionalisers that have failed to operate during network outages.

Reclosers that fail to operate during a network outage have their protection settings investigated to determine if protection settings or equipment failure was the underlying cause of failure to operate. The majority of sectionalisers are on SWER lines and are generally bypassed on failure as no current SA Power Networks approved sectionalisers are available on the market.

Table 41 gives summary of routine inspection, maintenance and condition monitoring tasks for reclosers and sectionalisers.

Table 41: Reclosers and sectionalisers inspection, maintenance and condition monitoring tasks

Inspection, maintenance and condition monitoring tasks	Frequency
Recloser counter reading on all hydraulic reclosers (number of operations)	6 monthly
Pre-bushfire patrols of all sub-transmission and distribution reclosers and sectionalisers in BFRA	Annually
Visual inspections in corrosion zones 2, 3 and 4	5 years

Inspection, maintenance and condition monitoring tasks	Frequency
Visual inspection in corrosion zone 1	10 years
Battery replacement of recloser controllers	3–5 years

Further detail for the maintenance of overhead switchgear, including sectionalisers and reclosers, is covered in Section 6.4 (Overhead distribution switchgear) of the Network Maintenance Manual.

8.2.7.7.3 Reclosers and sectionalisers renewal/replacement strategy

The renewal/replacement strategy for reclosers and sectionalisers is based on managing risk according to information obtained from condition assessments and counter readings.

The decision to refurbish or replace reclosers and sectionalisers considers several factors:

- The older electromechanical reclosers are refurbished where viable as this is more cost effective than replacement.
- Where protection functionality requires upgrading to meet current standards;
- Reclosers are replaced when they are unable to be refurbished, spares become obsolete, or if the units need to be provided with SCADA capability to enable remote monitoring and switching.
- Electronic reclosers are typically replaced as a complete unit.
- Recloser controllers are typically replaced given most of the early electro-hydraulic controllers are obsolete and the high cost of refurbishment; or if the controllers are unable to be integrated into the SCADA environment.
- Sectionalisers are not able to be refurbished and are therefore replaced on failure.

Figure 106 shows a summary of the sectionalisers and reclosers renewal/replacement plan to 2030.

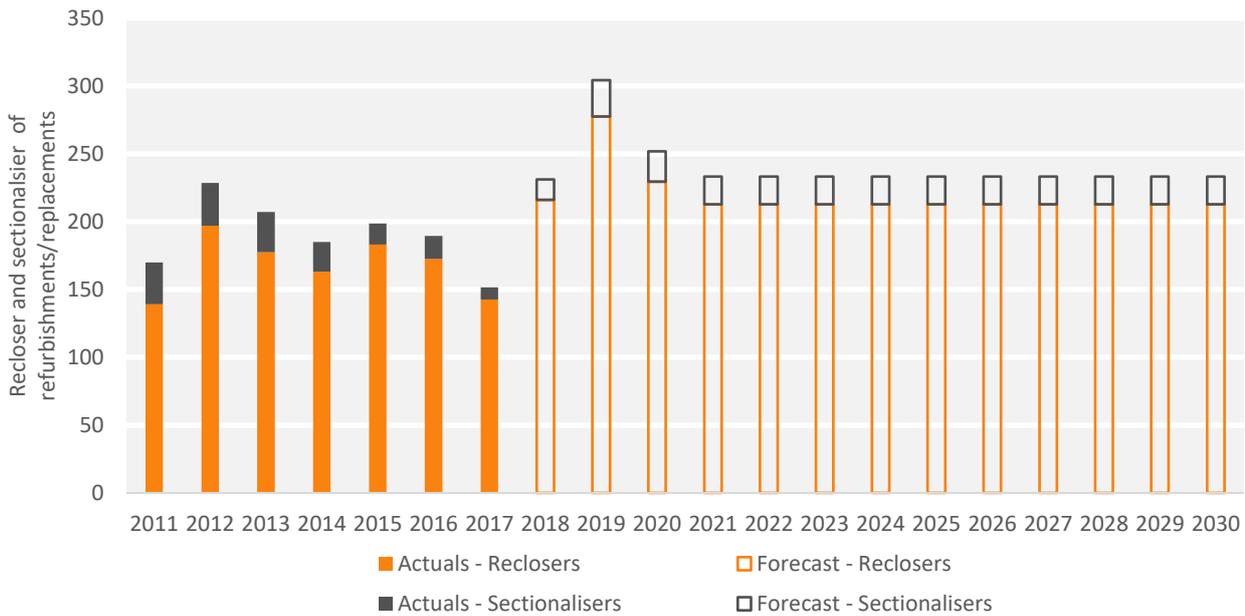


Figure 106: Reclosers and sectionalisers renewal/replacement plan

The planned recloser renewal/refurbishments will reduce from 2019 as a major program of electromechanical recloser refurbishment backlog tapers off. The planned sectionaliser replacements includes clearing a backlog of failed sectionalisers that have yet to be replaced.

8.2.7.7.4 Reclosers and sectionalisers disposal strategy

Disposal of reclosers, sectionalisers and controllers is for potential scrap value only after salvaging of reusable parts. Oil insulated reclosers and sectionalisers may contain PCB as an additive. Any reclosers or sectionalisers requiring disposal have the oil drained and tested for PCB to ensure disposal is in accordance with the Environmental Management Plan.

8.2.8 Other sub-transmission system and distribution network assets

8.2.8.1 Introduction

An overview of other sub-transmission system and distribution network assets is given in this section. Due to their relatively low expenditure compared to the assets previously discussed, the overview is limited to key points only. For further information, refer to the respective line assets asset plans.

Asset summary

The ‘other’ sub-transmission assets are earthing systems, regulators and capacitors, and ancillary assets.

- Earthing: ensure current is directed to earth rather than through the asset to minimise risks to staff, contractors and the public.
- Regulators and capacitors: ensure the line voltage is maintained within acceptable limits — of increasing importance as voltage fluctuations across the network increase with the two-way grid.
- Ancillary assets: prevent unauthorised access, enable staff and contractors access to our assets, and assist network operations staff with locating faults.

These assets are typically replaced on failure. They have not been modelled using CBRM. The historical performance and expenditure of this asset class inform the required forward investment to 2030.

8.2.8.2 Other sub-transmission system and distribution network assets asset management objectives

The asset management objectives across these remaining sub-transmission system and distribution network assets to guide day-to-day asset management activities and support the asset management objectives are summarised in Table 42.

Table 42: Other sub-transmission and distribution assets asset management objectives

Level of service category	Other sub-transmission and distribution assets asset management objectives
Safety	<ul style="list-style-type: none"> • No injury/death to staff or contractors through installing, operating, inspecting, maintaining/repairing, replacing or decommissioning other sub-transmission system and distribution network assets. • No earthing system condition failures resulting in injury/death.
Reliability and resilience	<ul style="list-style-type: none"> • Minimise unplanned interruption duration through maintaining access roads and line fault indicators. • Minimise planned and unplanned interruption frequency and duration for other asset failures and replacements.
Two-way grid	<ul style="list-style-type: none"> • Maintain network voltage to the required standard through maintaining the functionality of regulators and capacitors.
Communication and information	<ul style="list-style-type: none"> • Provide accurate information on restoration times for unplanned outages due to failures of other assets resulting in interruption to supply. • Provide accurate advanced notice of any planned other asset replacement works involving outages.
Efficiency	<ul style="list-style-type: none"> • Minimise other asset life-cycle costs including the cost of installation, operations, maintenance, refurbishment/replacement and disposal.

8.2.8.3 Asset description

Table 43 summarises the remaining asset classes within the sub-transmission system and distribution network.

Table 43: Other sub-transmission and distribution line assets

Asset class	Asset description	Quantities (approx.)
Earthing	The electrical connection of all exposed and accessible conductive parts of the distribution network (other than those conductors which are or could be intentionally live) are connected to the general mass of earth. Earthing is applied to assets so that if a live conductor comes in contact with it, the resulting current will be directed safely to earth	Unknown
Regulators and capacitors	Devices that ensure the line voltage is maintained within acceptable limits: <ul style="list-style-type: none"> voltage regulators maintain a constant voltage level in an active conductor capacitor banks connect 'imaginary' electrical load to the active conductors 	655 voltage regulator sites (SAP) 60 capacitors (SAP)
Ancillary assets	Fences, gates, locks, signs, access roads to provide access to assets, reduce entry to unauthorised persons and warn people of the danger associated with entry Line fault indicators assist with network fault locating	Unknown

8.2.8.4 Population and age profile

Table 43 contains the estimated quantities of these assets. For further information on these assets including any age profile data refer to the asset plan for the respective asset classes.

8.2.8.5 Current condition and performance

For information on these assets including condition and performance data refer to the asset plans for the respective asset classes.

8.2.8.6 Risks

For information on the risks associated with these assets refer to the asset plans for the respective asset classes.

8.2.8.7 Life cycle management strategy

Operations and maintenance activity, renewal/replacement strategy for the other network assets are summarised in Table 44.

Table 44: Other network assets life cycle strategies

Asset classes	Inspection, maintenance and condition monitoring tasks	Renewal/ Replacement strategy
Earthing, regulators and capacitors, ancillary assets	Typical inspection activities include: <ul style="list-style-type: none"> visual inspections 5 years for corrosion zones 2, 3 and 4 and 10 years for corrosion zone 1 thermographic inspections 2–5 years depending on voltage For further information see Section 6 (Maintenance strategies – Sub-transmission and distribution mains) of the Network Maintenance Manual	Replace based on risk or replace asset if it fails

8.2.9 Major projects and targeted programs

This section discusses major replacement projects or targeted replacement programs of work within the subtransmission and distribution systems.

8.2.9.1 Bare paper insulated lead cables in the Adelaide Business Area

As a highlighted cable risk (see Section 8.2.1.6), late 2017 saw an increase in cable faults within the Adelaide Business Area (ABA), which forms part of the Adelaide CBD (Figure 107). The ABA is defined in the Electricity Distribution Code and is predominantly supplied by a complex cable network referred to as ‘CBD feeders’. Under the current Essential Services Commission of South Australia (ESCOSA) Service Standard Framework this geographic area has the most stringent of the reliability targets of the regulatory feeder categories.

The ABA accounts for 0.6% of SA Power Networks customers and 0.3% of the distribution system by length. The distribution network in the ABA is about 97% underground and is therefore not normally affected by severe weather. The ABA contains a high concentration of offices and businesses reliant on SA Power Networks supply. Therefore, while the total number of faults within the ABA is low compared to the annual number of cable faults, any network outages and the nature of customers impacted tends to attract more media attention.

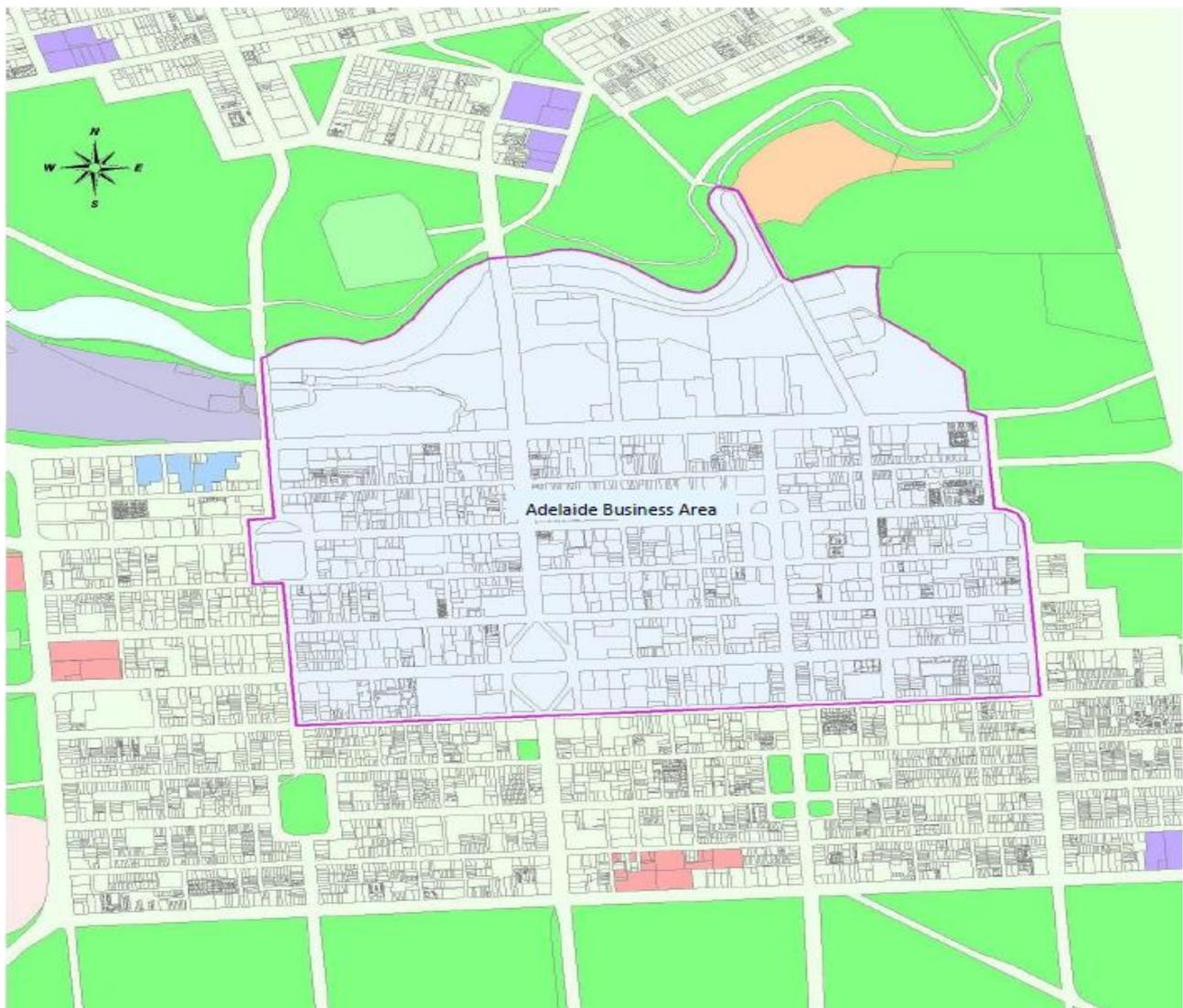


Figure 107: Adelaide Business Area service standard region supplied by CBD feeders

Source: Essential Services Commission of South Australia, 2015.

Figure 108 shows the historical performance of cable faults supplying the ABA.

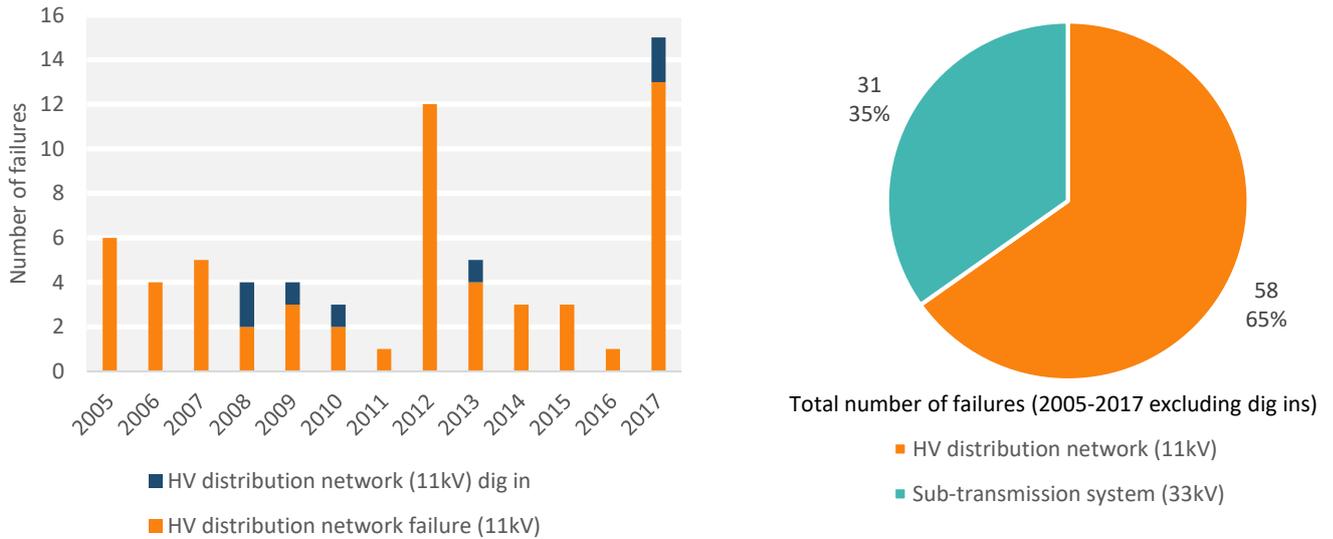
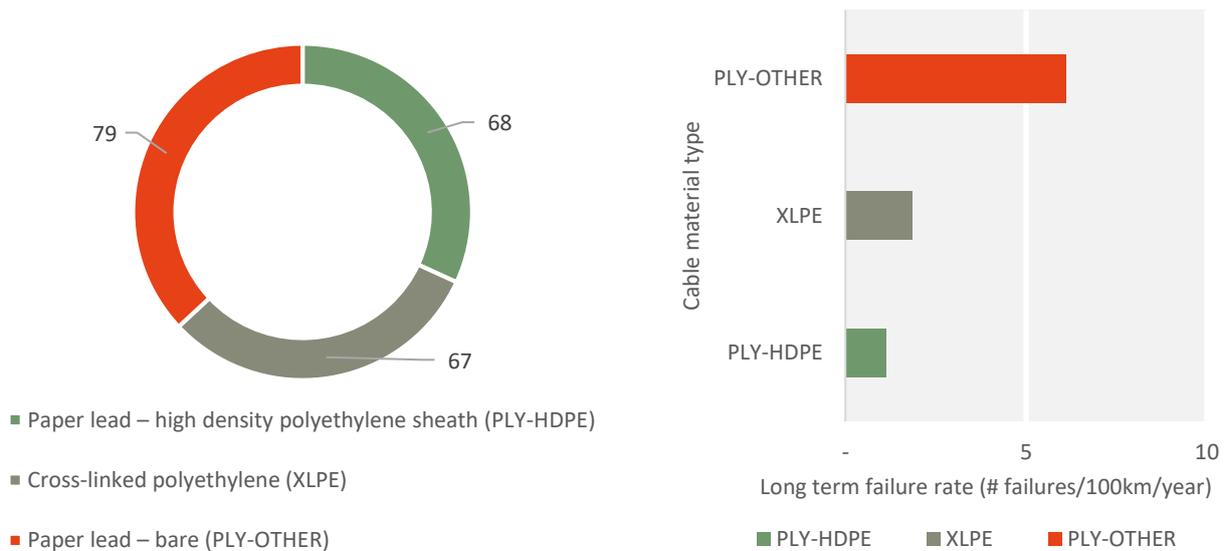


Figure 108: Historical HV cable failures for CBD service region

Figure 108 shows the number of HV cable failures impacting the ABA has remained below six in most years since 2005 except for 2012 and 2017. The increase in failures in 2017 was investigated in early 2018 and found to be largely attributed to bare paper insulated lead cables (PILC) in the 11kV network; the oldest material type used on the 11kV network within the CBD installed through the 1960s. An analysis of these faults also concluded there is no clear pattern of failure with incidents scattered across the CBD.

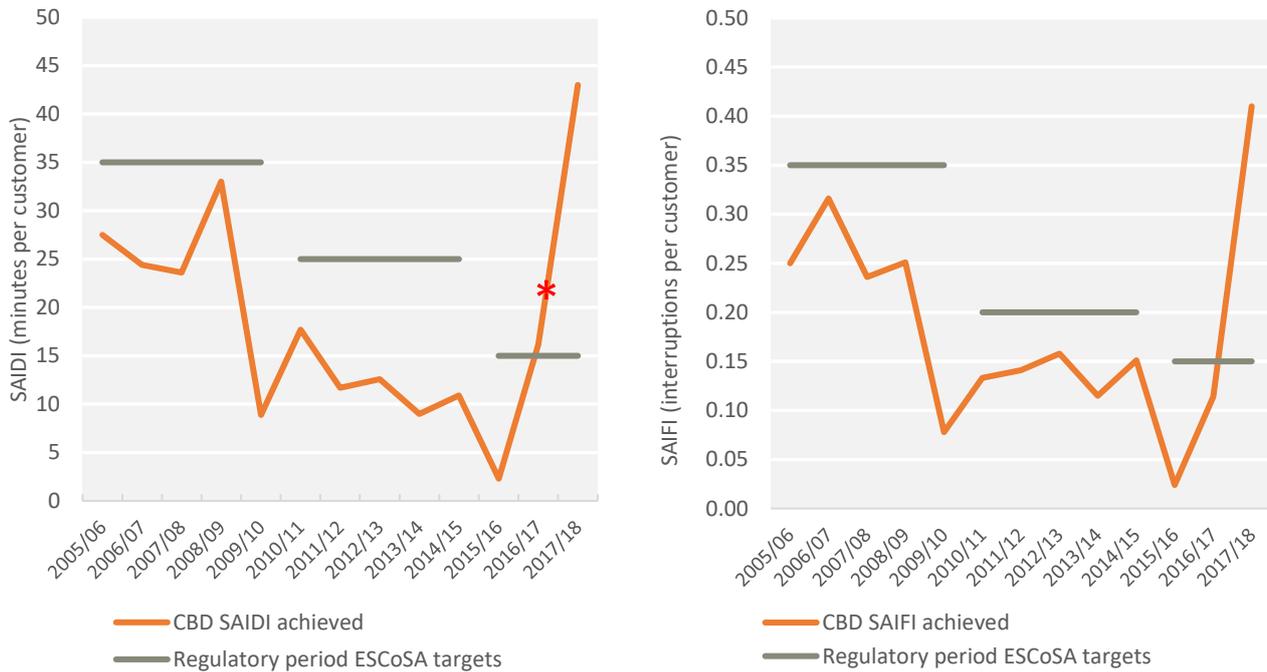
Figure 109 shows a relatively equal distribution of HV cable material lengths installed across the geographic CBD and North Adelaide but the long-term failure rate of bare paper insulated lead covered (PILC) cables is 3–4 times higher than the other material types due to a combination of both age and material type (no external sheath to provide increased cable protection). A number of actions have been completed during 2017–2018 to minimise the impact of further cable fault outages; however, PILC assets remain in service and without replacement are highly likely continue to affect the reliability service standard for the ABA. It is estimated that over 94% of the bare PILC cable population supplies the ABA.



Note: PLY-OTHER in the above figure refers to bare paper insulated lead cable (PILC) material type.

Figure 109: Long-term CBD HV cable failures material length and failure rates (2005-2017)

The net result is SA Power Networks actual performance for the ABA has exceeded the ESCoSA reliability targets in 2016-2017 and 2017-18 as shown in Figure 110.



Notes: * SA Power Networks assessed by ESCoSA as having used best endeavours in attempting to meet targets.

Figure 110: Long-term CBD reliability standards vs actual performance⁸

Cable investment in the medium term is proposed to be increasingly focused on HV distribution cables (11kV) within the CBD and particularly the bare PILC due to their overall poorer condition and the impact on reliability service standards observed across 2016–2017 and 2017–2018. In addition, devices enabling remote monitoring of line fault indicators have been installed in early 2018 and are actively used in responding to CBD network outages aimed at reducing restoration times following a cable fault.

⁸ Reliability targets exclude SA Power Networks’ performance during severe or abnormal weather events through the application of the Institute of Electrical and Electronic Engineers MED exclusion methodology. This approach allows the impact of MEDs to be studied separately from SA Power Networks’ daily operations and, in the process, better reveals trends in daily operation that would be hidden by the large statistical effect of major events.

8.3 Service lines/customer connection assets

8.3.1 Introduction

This section provides an overview of the service connection assets, including their population, age and condition. It outlines the life cycle management approach and gives replacement forecasts for service connection renewals for the planning period. For further information, refer to the low voltage services asset plan.

Asset summary

Service lines connect the distribution network to customers. They include electrical equipment, such as a length of conductor, service pits and fuses designed to supply customer loads from the distribution network nominally at 230V (for single phase connections) or at 400V (for 3 phase connections). Service cables are the property of the landowner. There are 796,125 service connections across the network.

Metered mains are an alternative type of service connection with the metering point located on a readily accessible Stobie pole for meter reading convenience. This construction is typically found on rural properties. There are estimated to be <5,000 metered main locations across the state with customers responsible for infrastructure on their side of the interface point.

Aside from 2017, the number of service line failures has remained relatively stable since 2011. Service lines are managed by repairing or replacing any failed services, identifying defects through the cyclic inspection program and prioritising work. Metered mains locations are progressively being identified and inspected as part of the asset inspection program. The observed increase in customer low voltage shocks is attributed to the overhead aluminium neutral screen service line population which is proposed for a proactive phasing out over the next 30 years.

Service lines have not been modelled using CBRM to assess risk or asset health. Historical performance and expenditure of this asset class informs the required forward investment to 2030.

8.3.2 Service lines asset management objectives

The asset management objectives specific to service lines are summarised in Table 45.

Table 45: Service line asset management objectives

Level of service category	Service line asset management objectives
Safety	<ul style="list-style-type: none"> No injury/death to staff or contractors through installing, operating, inspecting, maintaining/repairing, replacing or decommissioning service lines. No service line condition failures resulting in electric shock and injury/death typically because of failed neutral screen. No service line failures resulting in bushfire starts. No service line failures resulting in property damage.
Reliability and resilience	<ul style="list-style-type: none"> Minimise planned and unplanned interruption frequency and duration from service line failures and replacements. Minimise planned interruption frequency and duration for service line replacement works.
Two-way grid	<ul style="list-style-type: none"> Service lines sized to manage two-way flows.
Communication and information	<ul style="list-style-type: none"> Provide accurate information on restoration times for unplanned outages. Provide accurate advanced notice of any planned service line replacement works involving outages.
Efficiency	<ul style="list-style-type: none"> Minimise service line life-cycle costs including the cost of operations, maintenance, refurbishment/replacement and disposal.

8.3.3 Asset description

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

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

Metered mains are an alternative type of service connection with the metering point located on a readily accessible Stobie pole for meter reading convenience. This construction is typically found on rural properties.

8.3.4 Population and age profile

There are 796,125 service lines across the network as shown in Figure 112.

Figure 113 shows the age profile of service lines. A significant proportion (~89%) are less than 50 years of age as 10,000–20,000 service lines are installed or replaced per year.

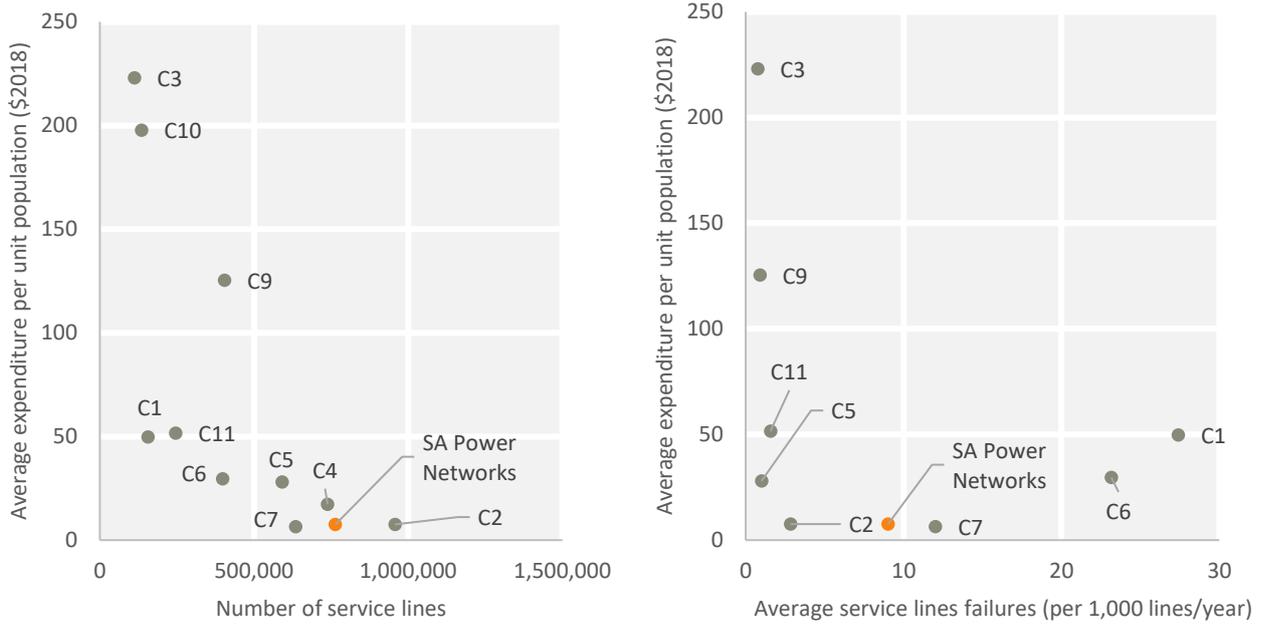
The expected life of service lines varies but is typically 30–50 years. The main factors that influence expected life are corrosion zone, abrasion, and inherent and often undetectable manufacturing defects. Based on the existing age profile, there is currently 44% of service lines more than 30 years increasing to 60% by 2025.

The number of metered main locations is unknown. Approximately 2,300 metered main locations have been assessed. There are estimated to be <5,000 metered main locations across the state.

8.3.5 Current condition and performance

Figure 114 shows the historical number of service line failures. The number of service line failures has remained relatively stable since 2011.

A comparison of service line performance in contrast to other DNSPs was undertaken analysing data from publicly available Category Regulatory Information Notices (RIN) reported over the period 2013-2014 to 2016-2017 inclusive (outliers excluded). A comparison of average annual renewal expenditure per unit population and failure rate is shown in Figure 111.



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

Figure 111: Service line benchmarking of SA Power Networks vs other DNSPs (2013-2014 to 2016-2017 data)

Figure 111 shows SA Power Networks currently has one of the lowest level of average annual expenditure per service line even with a mid-range reported failure rates amongst DNSPs. This is largely due to the fix on failure approach (see Section 8.3.7). This shows SA Power Networks lifecycle management of service lines is very efficient.

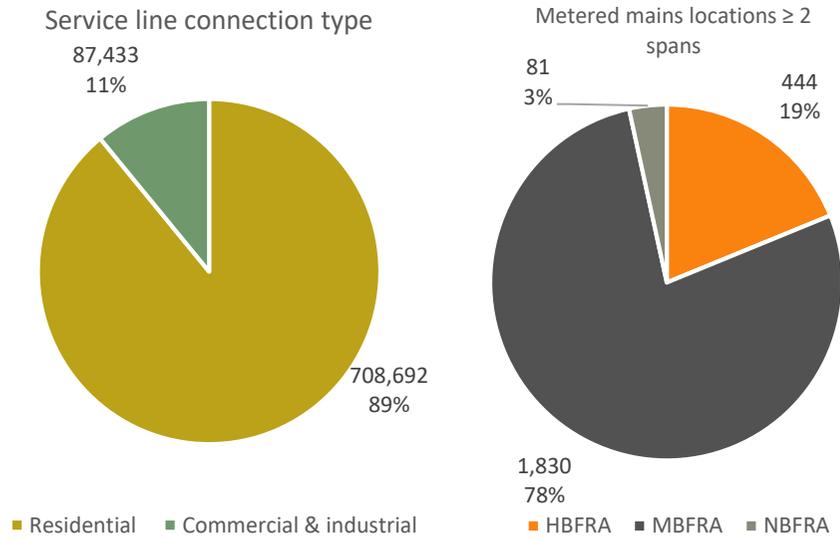


Figure 112: Service connection type

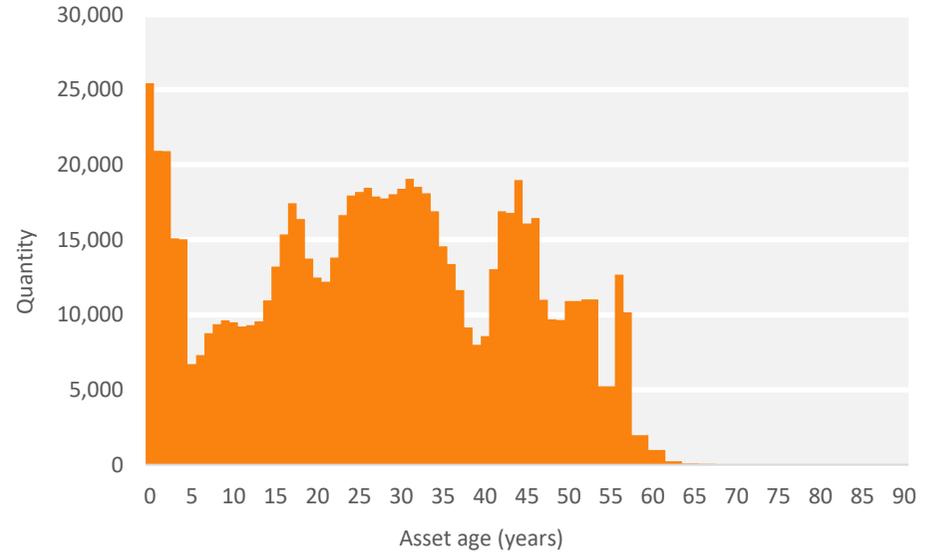


Figure 113: Service line age profile

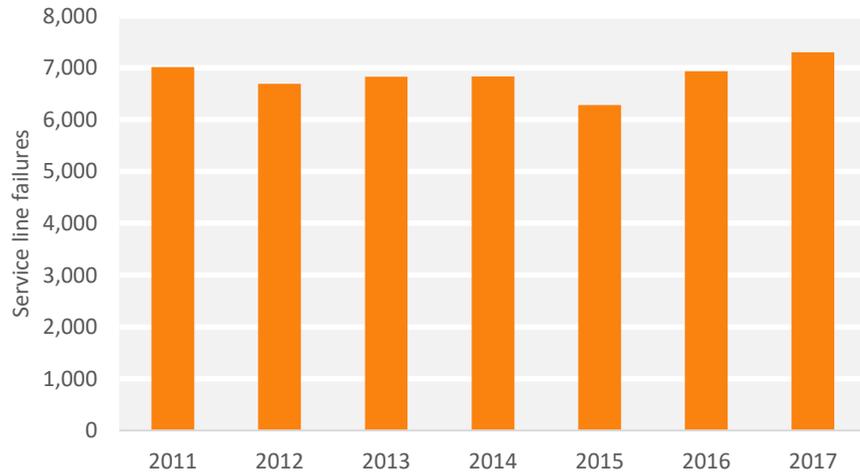


Figure 114: Service line historical failures

This asset class has not yet been modelled using CBRM.

Figure 115: Current service connection health index distribution

8.3.6 Risks

The main risks associated with service lines include:

- potential injury/death of SA Power Networks staff, contractors or the public due to:
 - electric shock through any current transmitted through the service to the customer because of the service line condition,
 - physical contact through an overhead service line because of service line location and/or condition,
 - bushfire and/or house fire start because of overhead service lines clashing, service box failure and/or falling to the ground,
 - potential injury/death from contact of vehicles, machinery and other equipment primarily in rural areas, or
 - potential injury/death or fire start from failure of aluminium neutral screens and Nilcrom 660F services;
- impact on reliability service standards due to the time associated with unplanned service line failures; and
- impact on quality of supply complaints due to limited capacity of service line size and/or to accommodate two-way flows.

Cyclic asset inspections play a key role in identifying defects to manage the risks associated with service lines.

The service line specific risks are listed below.

- The increase in customer shock reports attributed to the network is largely due to corrosion of aluminium neutral screen services (see Section 4.9.1.3).
- The existing inspection practices are limited to a visual assessment of obvious defects from outside the customers property only.
- Service line fuse boxes are not proactively inspected due to the time and accreditation requirements to inspect; reactive inspections are undertaken in response to any shock reports.
- The lack of clarity regarding the location, ownership and responsibility for maintenance of metered mains.

8.3.7 Life cycle management strategy

8.3.7.1 Service lines asset creation strategy

Standard service lines used are aerial bundled cables.

8.3.7.2 Service lines operations and maintenance strategy

The key maintenance strategy for overhead service lines is responding to faults and managing risk based on the information obtained from visual condition assessments. Visual assessments are limited to what can be observed from the property boundary. Below ground service lines are not inspected as they are buried and generally inaccessible. Below ground services are only maintained reactively when faults occur. Both reactive and corrective maintenance are undertaken on service lines.

Metered mains locations are progressively being identified and inspected as part of the asset inspection program with connection points being marked to delineate SA Power Networks and customer asset responsibilities.

Table 46 gives a summary of routine inspection, maintenance and condition monitoring tasks for service lines.

Table 46: Service line inspection, maintenance and condition monitoring tasks

Inspection, maintenance and condition monitoring tasks	Frequency
Pre-bushfire patrols of service lines and metered mains in BFRA	Annually
Inspection of overhead service lines and metered mains in corrosion zones 2, 3 and 4	5 years
Inspection of overhead service lines and metered mains in corrosion zone 1	10 years

Further detail for the maintenance of service lines is covered by Section 6.3 (Overhead distribution assets) and Section 6.8 (Overhead distribution services) of the Network Maintenance Manual.

8.3.7.3 Service lines renewal/replacement strategy

The renewal/replacement strategy for service lines is based on managing risk. Service lines that have interrupted supply or those with defects with high work value are replaced reactively. Metered mains that are non-compliant to SA Power Networks' construction standards and present safety or fire start risks are notified to the customer via a defective electrical installation notice who is responsible for undertaking the required maintenance work.

The decision to replace a service line considers:

- significant defects identified through overhead inspections;
- service boxes containing asbestos;
- damage to insulation on aluminium neutral screens;
- 660F services being used; and
- whether the time associated with replacement is less than that for repairs.

The decision to replace a metered mains service considers:

- whether construction is not to SA Power Networks' standard with significant defects identified through overhead inspections;
- safety risks arising from low span clearances, meter boxes mounted on transformer poles and in poor condition, and significant defects identified through overhead inspections;
- whether the cost of upgrading to remove metered mains is less than that required for repairs; and
- when customers have requested upgrades, whether it presents an opportunity to replace the assets to SA Power Networks construction standards.

Figure 116 shows a summary of the service line (or service line component) replacement plan to 2030.

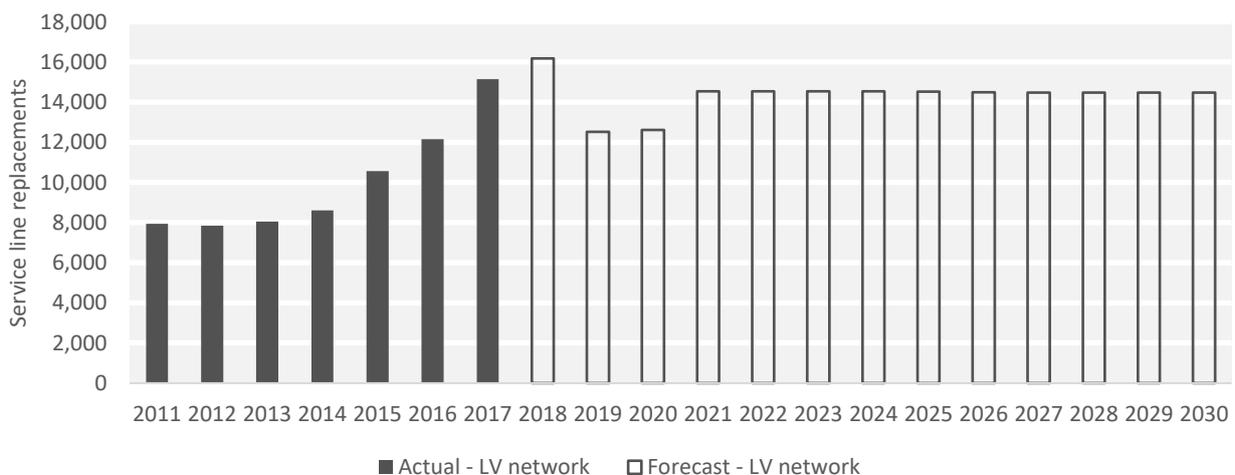
**Figure 116: Service lines replacement plan**

Figure 116 shows an increase in the number of service lines (or service line component) replacements to 2018 and then plateauing at around 14,000 service lines p.a. for the remainder of the planning period. There is a forecast increase primarily attributed to a planned phase out of aluminium neutral screen service lines corroding leading to an increase in LV shocks (see Section 4.9.1.3). Customer connection alterations also install new assets and remove pre-existing above and below ground service lines.

8.3.7.4 Service lines disposal strategy

Service line assets that reach the disposal stage usually do not have any economic value beyond their scrap metal value. Any hazardous waste is disposed of in accordance with the SA Power Networks Environmental Management Plan.

8.4 Substation assets

8.4.1 Substation power transformers

8.4.1.1 Introduction

Substation power transformer (and regulator) asset's population, age, condition and lifecycle management approach is outlined in this section, as are replacement forecasts and resulting risk and asset condition for the planning period. For further information, refer to the substation power transformers asset plan.

Asset summary

Power transformers and regulators within zone substations provide voltage transformation and regulation of electricity in the HV network (sub-transmission system and HV distribution network). As of December 2017, there were 682 substation power transformers in service with a significant proportion (approximately 40%) have been in service for more than 45 years.

Typical rates of unplanned replacements are around five transformers per year with approximately 55% of transformer failures detected through condition monitoring prior to major in-service failure. The power transformers asset strategies to 2030 include:

- Replace failed and poor condition power transformers (primary strategy)
- Replace high-risk Tyree 66/11kV 21MVA transformers (new strategy to address identified risk)
- Power transformer refurbishments – main tank and radiators (continuation of existing refurbishment program)
- Power transformer refurbishments – high-risk 66kV bushings & 11kV cable boxes (new strategy to address identified risk)

Power transformer assets have been modelled within CBRM to assess their current health and projected deterioration and failure risk based on current asset and condition data. Current condition data indicates 94% of power transformers are currently in good condition, with 6% having observable to serious deterioration. The model outputs inform the required forward investment to 2030 to maintain risk across the power transformer asset base, allowing for the effects of other replacement programs (such as substation capacity upgrades and equipment failures).

8.4.1.2 Substation power transformer asset management objectives

The asset management objectives specific to substation power transformers are summarised in Table 47.

Table 47: Substation power transformer asset management objectives

Level of service category	Power transformer asset management objectives
Safety	<ul style="list-style-type: none"> No injuries/deaths to staff or contractors through installing, operating, inspecting, maintaining/repairing, replacing or decommissioning power transformers. No power transformer failures resulting in injury/death. No power transformer failures resulting in fires causing substantial damage to neighbouring equipment or other critical substation assets.
Reliability and resilience	<ul style="list-style-type: none"> Minimise planned and unplanned interruption frequency and duration from power transformer failures and replacements. Minimise long term (10 year) equipment major failure rates.
Environment	<ul style="list-style-type: none"> No significant oil fires from substation transformers. No significant oil spills and minimise the oil loss from power transformers entering the environment. Comply with legislated noise limits.
Two-way grid	<ul style="list-style-type: none"> Maintain network voltage levels within Australian Standard Voltage limits.
Communication and information	<ul style="list-style-type: none"> Provide accurate information on restoration times for unplanned outages. Provide accurate advanced notice of any planned power transformer works involving outages.
Efficiency	<ul style="list-style-type: none"> Minimise power transformer life-cycle costs including the cost of installation, operations, maintenance, refurbishment/replacement and disposal. Continual improvement of the transformer CBRM model for life-cycle decision making.

8.4.1.3 Asset description

Substation power transformers are those transformers within zone substation sites that transform the voltage levels of the electricity in the sub-transmission system and HV distribution network.

8.4.1.4 Population and age profile

There are 682 substation power transformers (Figure 118) as of December 2017.

Figure 119 shows the age profile of substation power transformers. A significant proportion (approximately 40%) of substation transformers have been in service for more than 45 years. The majority of the aged power transformers are small and medium sized transformers. The oldest in service transformer is 75 years of age.

The expected life of a power transformer varies but is typically in the range of 60–75 years. The main factors that influence expected life are transformer loading, nameplate capacity, operating temperature, equipment design and operating duty. Based on the existing age profile, there is currently 5% of power transformers more than 60 years increasing to 15% by 2025 mainly due to the ageing small and medium size power transformers.

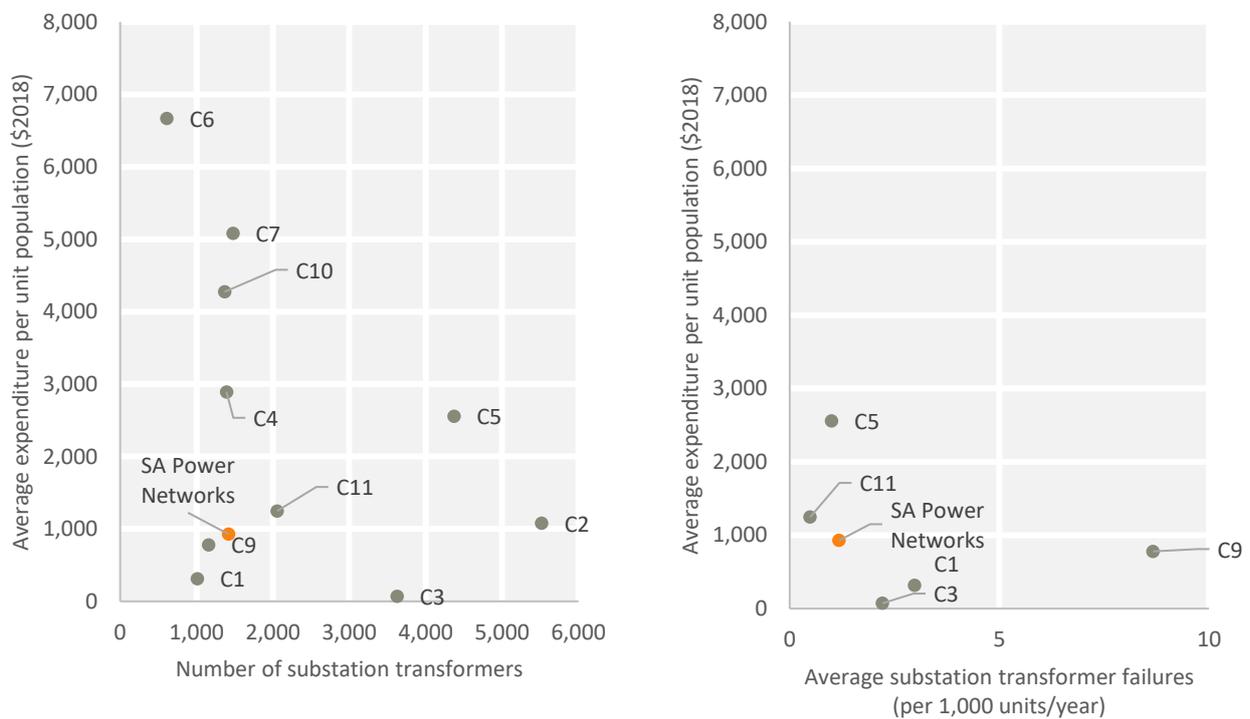
8.4.1.5 Current condition and performance

Figure 120 shows the historical number of substation transformer in service and condition based failure types since 2011. Average rates of unplanned replacements over this period are approximately 5 transformers per year with approximately 55% of transformer failures detected through condition monitoring prior to major in-service failure. Although relative replacement volumes in Figure 120 vary considerably year to year, failure numbers over the long term remain relatively stable.

The performance of the transformer fleet across 2014-2016 was better than originally forecast, however three recent in-service failures have identified additional areas of risk in older power transformers. Some of these failure modes relate to equipment design and manufacture and cannot be mitigated through maintenance and condition monitoring.

Power transformer assets have been modelled using CBRM to assess their current health based on current asset and condition data. Figure 121 shows the current HI distribution of power transformers: 94% are currently in good condition (HI 0-4) and 6% showing some observable to serious deterioration (HI 4-7).

A comparison⁹ of ground outdoor / indoor chamber mounted transformers of all types (includes both substation and distribution substation transformers) in contrast to other DNSPs was undertaken analysing data from publicly available Category Regulatory Information Notices (RIN) reported over the period 2013-2014 to 2016-2017 inclusive (outliers excluded). The comparison of average annual renewal expenditure per unit population and failure rate is shown in Figure 117.



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

Figure 117: Substation power transformer benchmarking of SA Power Networks vs other DNSPs (2013-2014 to 2016-2017 data)

Figure 117 shows SA Power Networks currently has one of the lowest level of average annual expenditure for the ground outdoor/indoor chamber mounted transformers even with a mid-range reported failure rates amongst DNSPs. This is largely due to the asset management practices and targeted refurbishment programs to extend the expected life of these major assets where possible (see Section 8.4.1.7). While the data used for this asset class comparison is highly variable across the DNSPs it generally demonstrates SA Power Networks lifecycle management of substation power transformers is efficient.

⁹ The AER Regulatory Information Notice reporting does not separately categorise ground outdoor / indoor chamber mounted transformers between substations and HV distribution networks for certain transformer capacity and voltages; this would be applicable to all DNSPs.

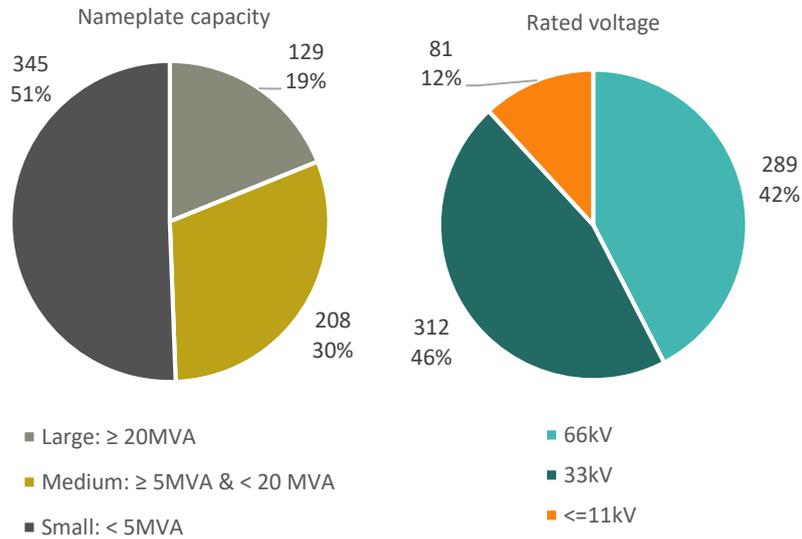


Figure 118: Power transformer capacity and rated voltage distribution

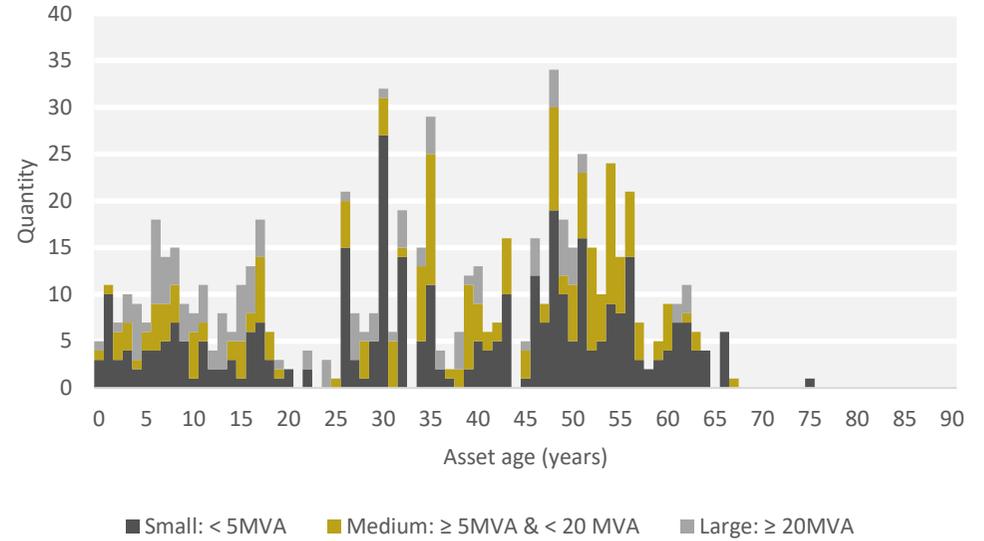


Figure 119: Power transformer age profile

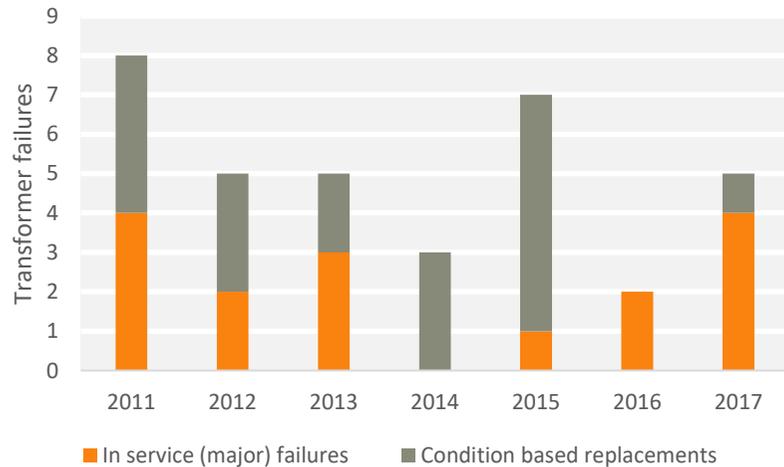


Figure 120: Power transformers failures

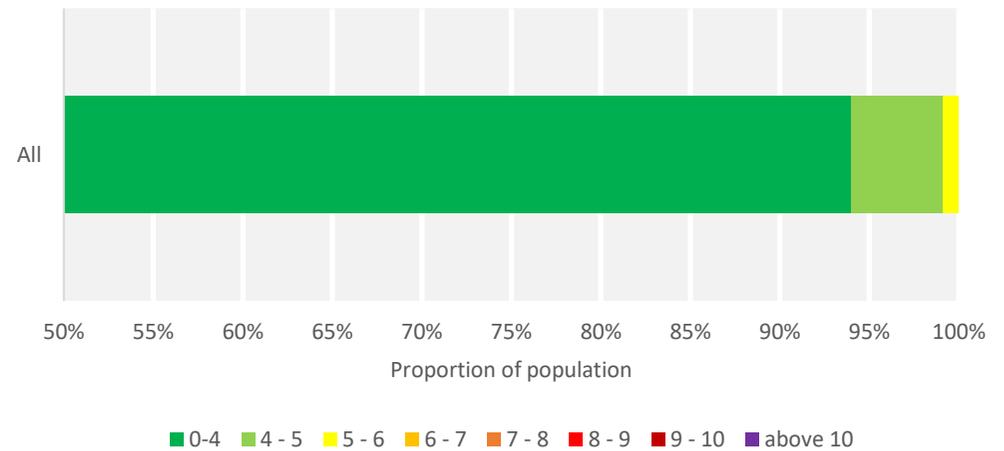


Figure 121: Current power transformer health index distribution

8.4.1.6 Risks

The main risks associated with substation power transformers include:

- potential injury/death of SA Power Networks staff and contractors through accessing and maintaining power transformers;
- potential injury/death of SA Power Networks staff, contractors or the public due to catastrophic failure of the power transformer or components;
- impact on reliability service standards including interruptions and quality of supply due to the large supply areas impacted by power transformers; and
- potential environmental damage because of failures including oil loss and fires.

Cyclic asset inspections, maintenance and condition monitoring play key roles in managing the risks associated with substation power transformers. These assets have been modelled using CBRM to assess the current and future risk and asset health based on available asset and condition data.

Specific power transformer risks are listed below.

- Approximately 35% of the medium sized transformer population are currently older than 50 years. With load-related investment plans not forecast to have significant impact on this population up to 2025, approximately 28% of medium sized transformers will be older than 60 years by 2025.
- Many different On Load Tap Changers (OLTC) makes and models exist on the network and several are beginning to show performance issues (affecting motor control cubicles, control wiring and drive systems) that carry significant risks to equipment reliability and customer service standards. Many of these tap changer models only allow for unidirectional power flow, which significantly de-rates the transformer during reverse flow conditions increasingly encountered by the uptake of PV systems.
- A small population of large 66/11kV transformers purchased of a particular design in 1970 have been shown to have a significantly higher risk of random, catastrophic failure compared to other transformers of similar age, size and condition. To date three of seven units have failed in service (including the most recent at Thebarton substation in October 2017) and this failure mode cannot be condition monitored or economically refurbished.
- Large populations of power transformers have 11kV compound filled cable boxes, which carry significant safety hazards in the event of failure. This construction is subject to compound leaks and moisture ingress and typical failures have resulted in porcelain, insulating compound and metallic debris propelled into the surrounding substation area.
- 66kV synthetic resin bonded paper bushings are known to have a relatively high failure rate and are no longer used in modern equipment in favour of resin impregnated paper bushings, which pose considerably reduced fire and safety risks.
- A large population of power transformers supplied over the period 1996 to 2007 have a specific oil type that contains corrosive sulphur compounds which have been shown to have caused premature, catastrophic failures in affected units.

8.4.1.7 Life cycle management strategy

8.4.1.7.1 Substation power transformers asset creation

Power transformer specifications are continuously reviewed to ensure lessons learned from major failures and operating experience is fed back into future procurement decision making. Examples of continuous improvements include the introduction of resin impregnated paper bushings, the use of biodegradable natural ester insulation for high risk installations and extended tapping range transformers to manage distribution voltages under distributed renewable generation. Other lifecycle cost improvements, such as bolt-on tap changers (ease of maintenance access) and welded lids (reduced risk of moisture ingress/oil leaks) are also under consideration for future equipment specifications.

Period contracts for the supply of standard equipment items, managed through design reviews, manufacturing inspections, audits and witness testing are also undertaken to achieve cost efficiencies.

Planning guidelines for asset creation also ensure power transformers are an efficient match to minimum site requirements, yet able to allow emergency, abnormal load transfers in the network.

8.4.1.7.2 Substation power transformers operations and maintenance strategy

Operational control, protection and monitoring of substation power transformers (including equipment operating temperature, load and voltage levels) are continually monitored through SCADA systems.

Key maintenance strategies for substation transformers are centred around reliability centred maintenance principles informed by condition assessments, periodic routine visual inspections, mechanical overhauls and specific diagnostic tests appropriate to condition and equipment criticality.

Table 48 gives a summary of the routine inspection, maintenance and condition monitoring tasks for power transformers.

Table 48: Substation power transformers inspection, maintenance and condition tasks

Inspection, maintenance and condition monitoring tasks	Frequency
Visual inspections of substation transformers	6 months
Thermographic inspections	Annually
Dissolved gas analysis	1–3 years
Oil quality testing (oil filled transformers only)	3 years
Maintenance, diagnostic testing and overhaul	6–12 years

Further details on maintenance of substation transformers are covered in Section 5.4 (substation oil filled transformers) and Section 5.5 (dry transformers) of the Network Maintenance Manual.

8.4.1.7.3 Substation power transformers renewal/replacement strategy

The high-level renewal/replacement strategy for substation power transformers is to maintain the long-term risk and performance across the asset population, as assets age and deteriorate in service (maintain risk). Evaluation of current risk and future performance of the transformer fleet is modelled using a condition based risk management (CBRM) methodology.

This strategy approach considers the effects of other programs of work such as substation upgrades, unplanned transformer replacements (on failure) and other replacement projects to target critical assets in poorest condition. Delivery of the plan uses an efficient mix of refurbishment and replacement works, with the combined effect of all replacements resulting in approximately 1.4% of the population replaced annually to 2030.

Initial risk control techniques for power transformers include the use of more frequent maintenance and condition monitoring of asset performance.

The decision to refurbish or replace a substation transformer considers:

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

Where more efficient means of risk mitigation (typically decommissioning or asset refurbishment) are not able to be used as an effective risk control, asset replacement is used to manage the risks posed by significantly deteriorated and poor condition transformers.

Figure 122 shows a summary of the substation transformers replacement plan to 2030.

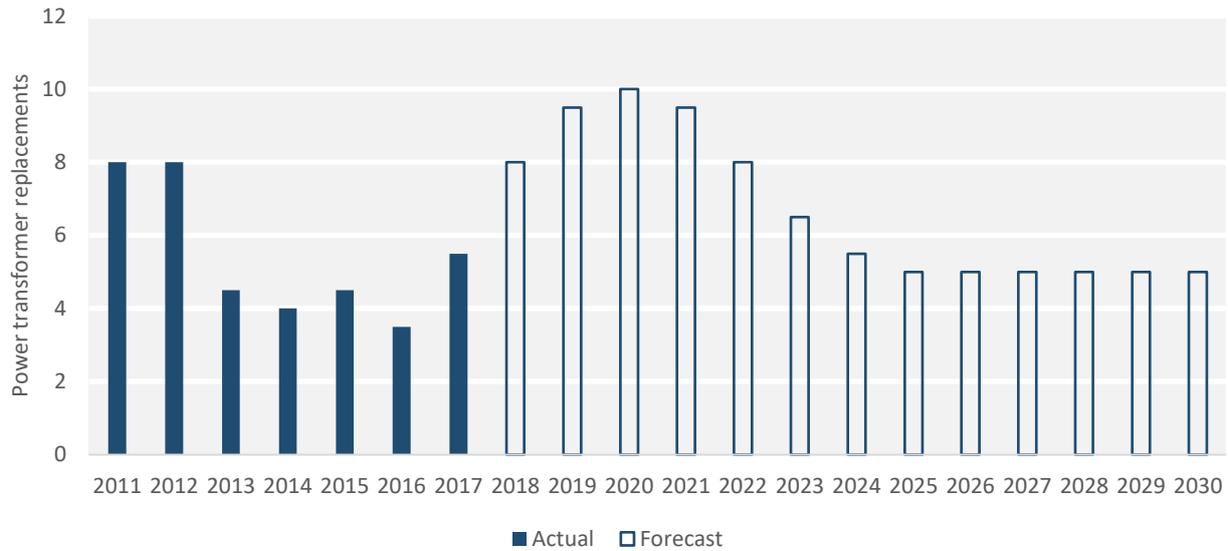


Figure 122: Substation transformers replacement plan

Figure 122 shows the forecast volumes of power transformers to be relatively stable out to 2030. These replacements comprise an ongoing program of unplanned replacements for historical volumes of small, medium and large transformers combined with targeted replacements of the identified unreliable, high-risk power transformer assets. The number of power transformers (and unit cost) refurbished annually varies year on year based on need. Expenditure requirements are thus forecast as an ongoing annual allowance, based on maintaining historical rates of program completion (typically 5-10 power transformers annually).

The performance of the transformer fleet through 2014-2016 was better than anticipated until the end of 2017 when three in-service failures identified additional areas of risk in older power transformers. Some of these failure modes relate to equipment design and manufacture and cannot be mitigated through maintenance and condition monitoring. To address these increased risks, targeted programs of replacement for Tyree design Spec E465 transformers, 66kV SRBP bushings and 11kV compound filled cable boxes are planned from 2018-2024.

The impact of renewal/replacement and refurbishment plans on population risk for substation power transformer assets was modelled using CBRM. Figure 123 shows the current risk for substation transformers and how it is forecast to grow across if assets are allowed to continue to deteriorate without intervention from 2020. The risk for substation transformers would increase by 3% by 2025 and 11% (on 2017 levels) by 2030 if no proactive replacements are undertaken.

Figure 125 shows the resulting risk profile based on the proposed expenditure through to 2030. The completion of all proposed investment programs over the planning period is forecast to maintain current levels of safety, reliability and network performance across the asset class out to 2030. Notwithstanding, from 2025 there will remain a significant number of large and medium transformers entering the high-risk range (> 60 years).

Figure 124 and Figure 126 compare how the health index of the substation power transformer population will change by implementing the proposed renewal strategy. The proportion of power transformers with advanced deterioration (HI >7) remains relatively stable. This suggests that those assets in poorest condition are generally those that present the greatest consequence to the network. There is a notable change in the proportion of power transformer assets with observable to serious deterioration (HI 4–7) increasing from 6% to 15% resulting from the large proportion of significantly aged (>55 years) small and medium sized power transformers that are not planned for renewal through capacity upgrades before 2030.

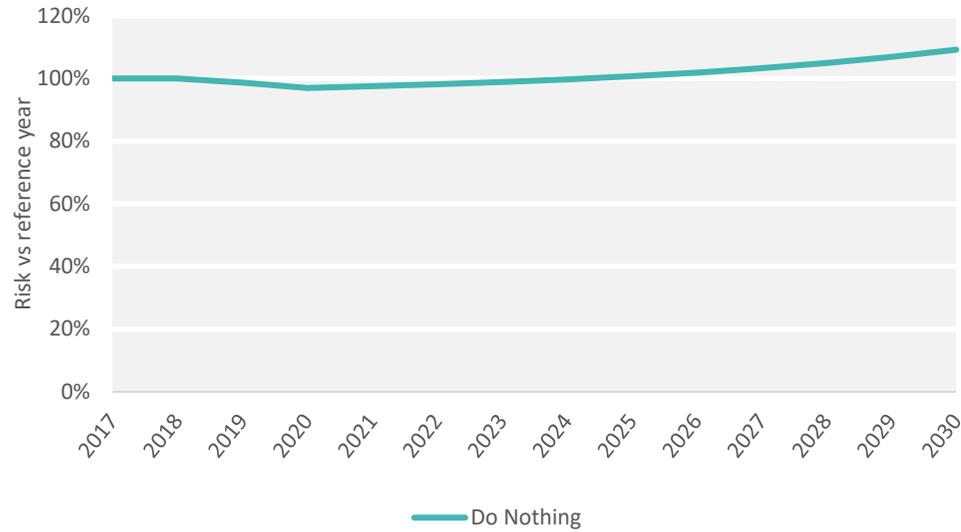


Figure 123: Substation power transformers risk profile — do nothing

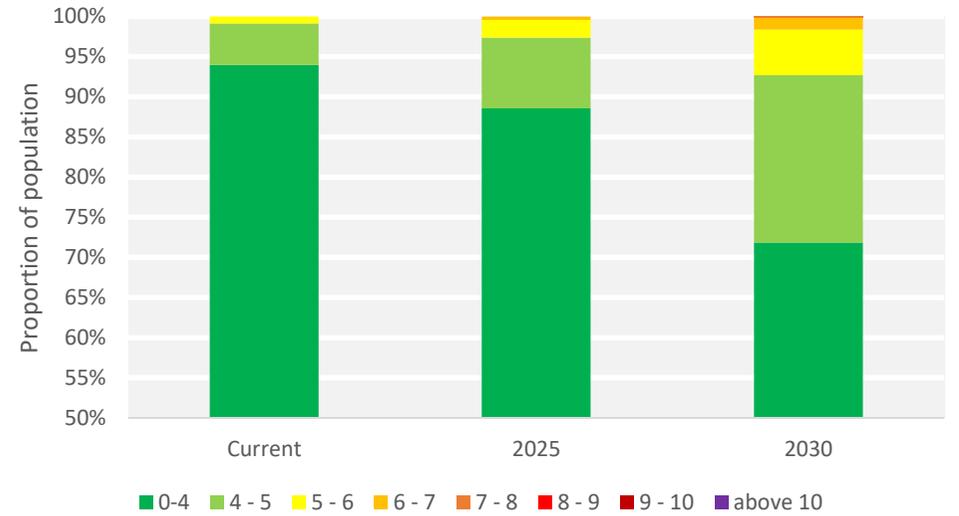


Figure 124: Substation power transformer health index — do nothing

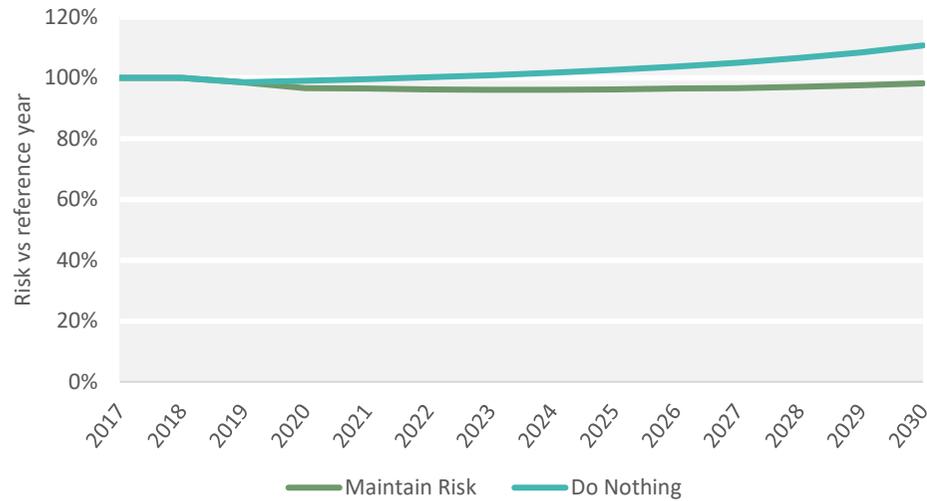


Figure 125: Power transformer risk profile — proposed expenditure

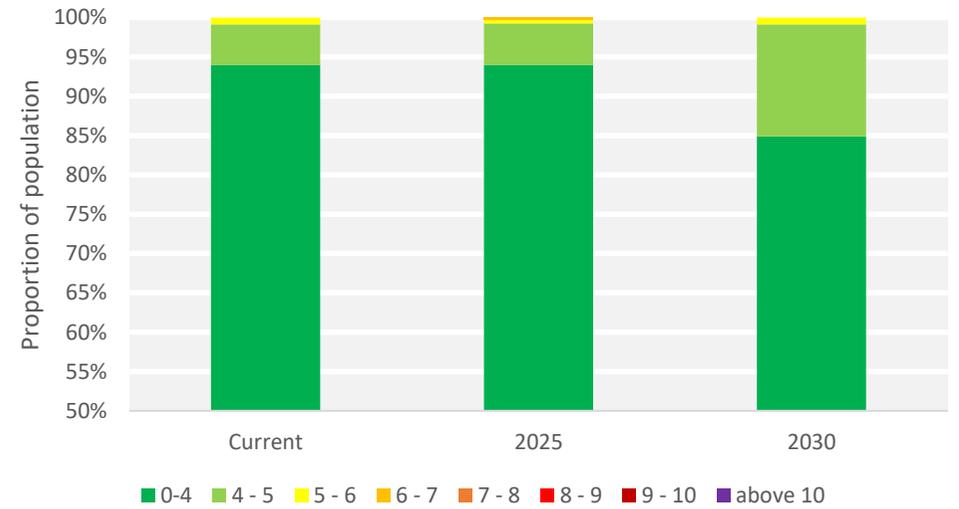


Figure 126: Projected substation transformers health index — proposed expenditure

8.4.1.7.4 Substation power transformers disposal strategy

The disposal of a power transformer includes the decommissioning of the asset after which it may be sold for scrap metal value, salvaged for component spares or refurbished and reused elsewhere as an emergency spare. The decision process is informed by asset condition assessment and need for the individual transformer.

Any power transformers requiring disposal have their oil drained and tested for PCB to ensure disposal in accordance with the Environmental Management Plan. Any asbestos containing components are also disposed of in accordance with the Environmental Management Plan.

8.4.2 Circuit breakers

8.4.2.1 Introduction

Circuit breaker asset's population, age and condition, and the life cycle management approach, are outlined in this section, as are replacement forecasts and resulting risk and asset condition for the planning period. For further information, refer to the substation circuit breakers asset plan.

Asset summary

Circuit breakers act as controlled switching devices within zone substations and control the energisation of electricity distribution equipment. The safe and reliable operation of these assets is critical to network operation as they provide essential control and protection functionality necessary to maintain public safety and the ongoing reliable supply of electricity to our customers. As of December 2017, there were 1,998 in service circuit breakers across the network with a significant proportion (37%) in service for more than 45 years.

Major substation circuit breaker strategies to 2030 include:

- Replace indoor switchgear types in major metropolitan substations and the Adelaide CBD that no longer meet our expectations for safe and reliable service.
- Replace failed and poor condition legacy outdoor circuit breaker types with no spare parts support and historically poor service performance.
- Circuit breaker replacement/refurbishment – targeted programs to address risks related to specific design flaws or performance issues that would otherwise lead to early equipment failure without specific intervention.

Circuit breaker assets have been modelled within CBRM to assess the current health and projected deterioration and failure risk based on current asset and condition data. Current condition data indicates 76% of circuit breakers are currently in good condition, 22% with observable to serious deterioration and <3% with advanced deterioration. The model outputs inform the required forward investment to 2030 to maintain risk across the circuit breaker asset base, allowing for the effects of other replacement programs (such as substation capacity upgrades and unplanned replacements).

8.4.2.2 Circuit breaker asset management objectives

The asset management objectives specific to circuit breakers are summarised in Table 49.

Table 49: Circuit breaker asset management objectives

Level of service category	Circuit breaker asset management objectives
Safety	<ul style="list-style-type: none"> • No injuries/deaths to staff or contractors through installing, operating, inspecting, maintaining/repairing, replacing or decommissioning circuit breakers. • No circuit breaker condition or functional failures resulting in injury/death. • No instances of circuit breakers failing to operate when required.
Reliability and resilience	<ul style="list-style-type: none"> • Minimise planned and unplanned interruption frequency and duration from circuit breaker failures and replacements. • Minimise long term (10-year) equipment major failure rates.
Environment	<ul style="list-style-type: none"> • Minimise the oil loss from circuit breakers entering the environment. • Minimise the volume of SF₆ gas from circuit breakers entering the environment. • Minimise the potential environmental damage from fire or catastrophic switchboard failures.

Level of service category	Circuit breaker asset management objectives
Communication and information	<ul style="list-style-type: none"> • Provide accurate information on restoration times for unplanned outages. • Provide accurate advanced notice of any planned circuit breaker works involving outages.
Efficiency	<ul style="list-style-type: none"> • Minimise circuit breaker life-cycle costs including the cost of installation, operations, maintenance, refurbishment/replacement and disposal. • Continual improvement of circuit breaker CBRM models for life-cycle decision making.

8.4.2.3 Asset description

Circuit breakers are power switching devices installed within substations to selectively control the energisation of high voltage electricity distribution equipment. They provide a vital safety function for the public, personnel and equipment by selectively isolating network faults.

8.4.2.4 Population and age profile

There are 1,998 circuit breakers across the sub-transmission system and HV distribution networks as of December 2017. Figure 128 shows the breakdown of circuit breakers by interrupter type and system. Distribution circuit breakers have a relatively equal split between old bulk oil circuit breakers and more modern vacuum types. For the sub-transmission system, older bulk oil and minimum oil circuit breakers represent a smaller proportion than the more modern circuit breaker types.

Figure 129 shows the age profile of circuit breakers and illustrates the large volume of circuit breakers less than 20 years old installed as a result of strong network growth (new substations and substation upgrades) over the period 2000 - 2015. Asset replacement programs over this period focused on populations of considerably aged (> 60 yrs), poor condition outdoor 33kV and 66kV circuit breakers.

The expected life of a circuit breaker varies but for the current population is typically in the range of 55–65 years. The main factors that influence expected life are the switchgear installation environment, equipment design and operating duty (normal thermal/electrical service stresses and abnormal stresses from switching, lightning over-voltages and interruption of system faults). A significant proportion (35%) of the circuit breaker population now exceeds 45 years of age and installed as legacy indoor oil filled switchgear in substations that supply major metropolitan areas and the Adelaide CBD.

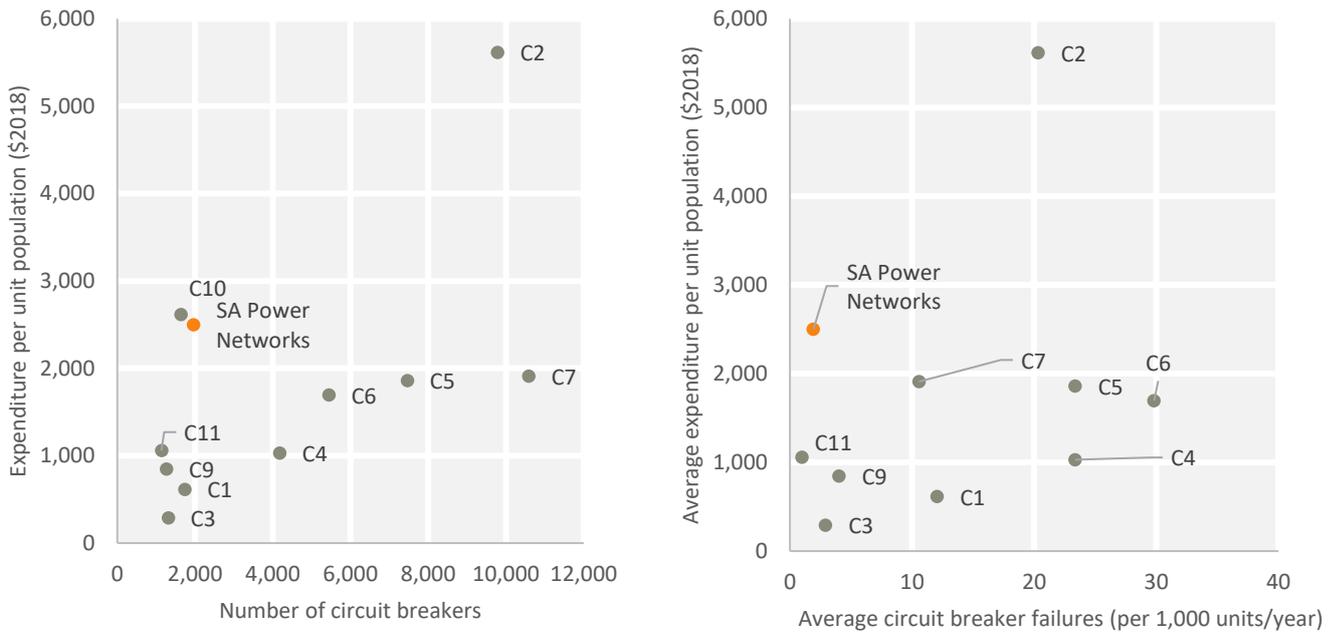
8.4.2.5 Current condition and performance

Figure 130 shows the historical number of in-service circuit breaker failures since 2011. Failures over this period are predominately outdoor sub-transmission circuit breakers, with two switchboard failures in 2011 and 2014 affecting a large number of integrated circuit breakers which could no longer be operated safely.

Relatively poor operational performance of the circuit breaker fleet across 2015-2017 has required ongoing unplanned expenditures to address areas performance issues across a large fleet of problematic 33kV circuit breakers and to manage poor operational performance of aged 11kV indoor switchboards.

Circuit breaker assets have been modelled using CBRM to assess their current health based on current asset and condition data. Figure 131 displays the current HI distribution of circuit breakers and shows 76% of circuit breakers currently in good condition (HI 0–4), 22% have observable to serious deterioration (HI 4–7) and <3% have advanced deterioration (HI>7).

A comparison of circuit breaker performance in contrast to other DNSPs was undertaken analysing data from publicly available Category Regulatory Information Notices (RIN) reported over the period 2013-2014 to 2016-2017 inclusive (outliers excluded). A comparison of average annual renewal expenditure per unit population and failure rate is shown in Figure 117.



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

Figure 127: Circuit breaker benchmarking of SA Power Networks vs other DNSPs (2013-2014 to 2016-2017 data)

Figure 127 shows SA Power Networks currently has one of the highest level of average annual expenditure per circuit breaker coinciding with one of the lowest reported failure rates amongst DNSPs.

These benchmark results come as a consequence of SA Power Networks’ investment focus from 2010-2011 in the renewal of aged (1950s era) high voltage indoor switchboard assets, which provide the replacement of many other asset types (e.g. civil works, high voltage cables and auxiliaries systems) that have not had their replacement expenditures separately reported in Category Regulatory Information Notices. SA Power Networks’ benchmark volumes and expenditures in Figure 127 also exclude the effects of (low value, high volume) replacement programs for distribution recloser circuit breaker asset types.

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

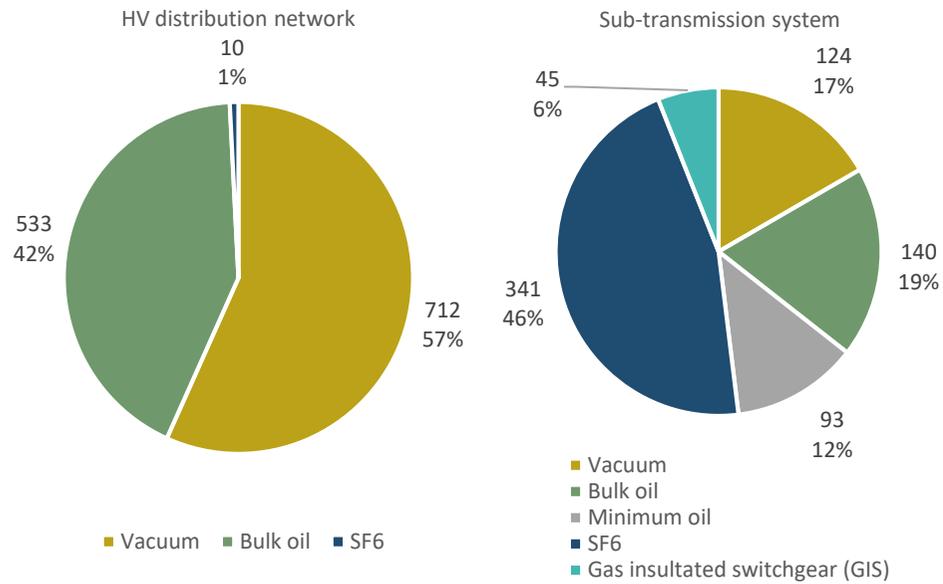


Figure 128: Circuit breaker interruption type

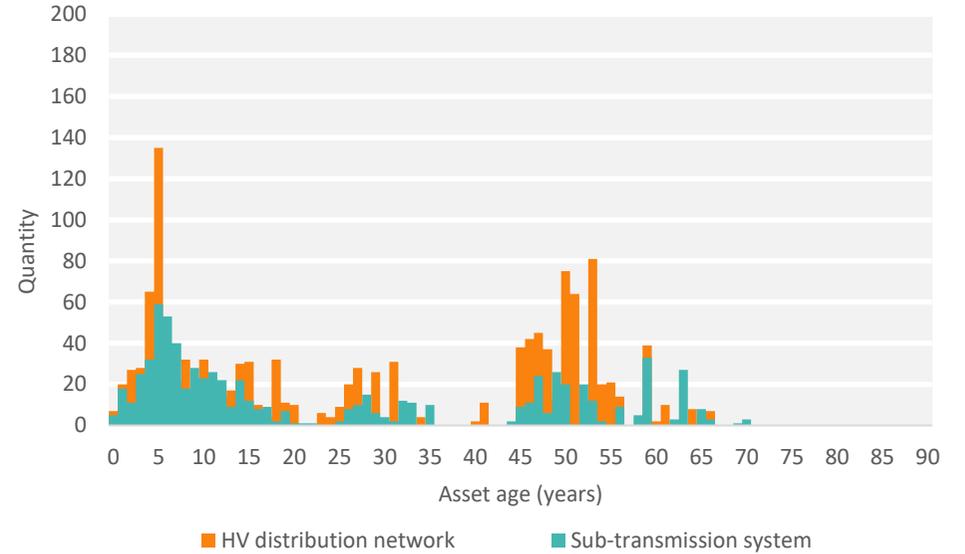


Figure 129: Circuit breakers age profile

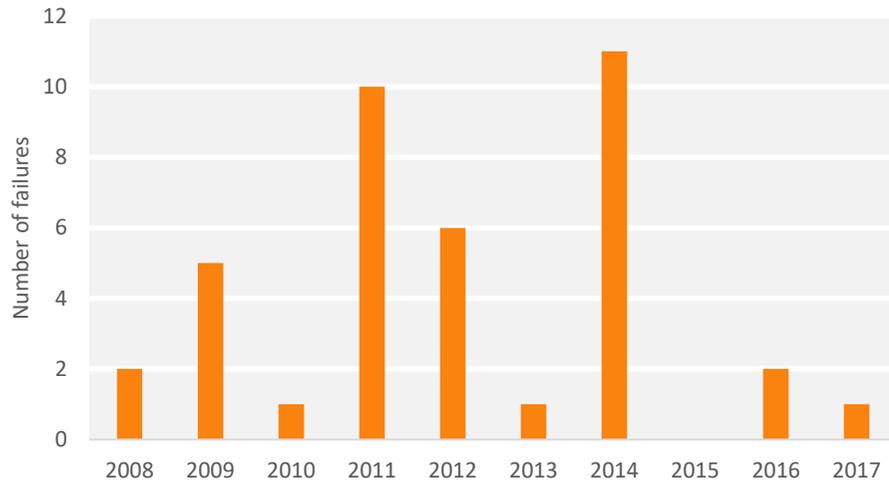


Figure 130: Circuit breakers historical in-service failures

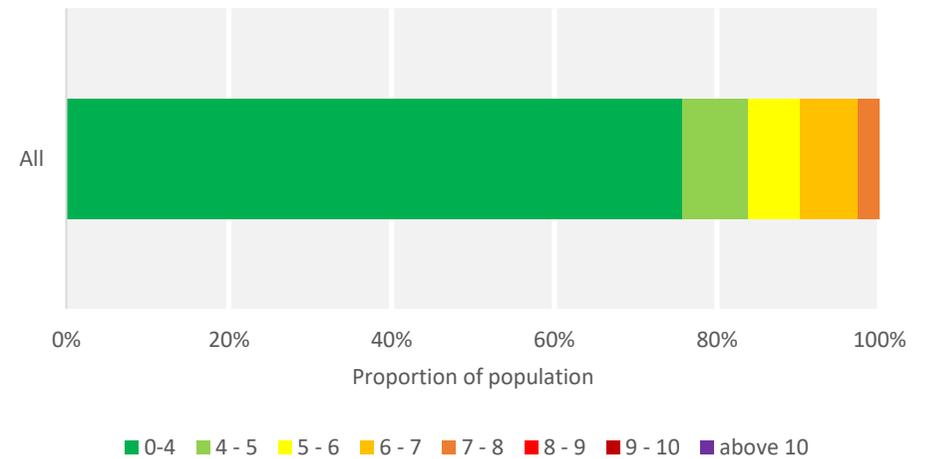


Figure 131: Circuit breakers health index distribution

8.4.2.6 Risks

The main risks associated with circuit breakers include:

- potential injury/death of SA Power Networks staff and contractors through accessing and maintaining circuit breakers
- potential injury/death of SA Power Networks staff, contractors or the public due to catastrophic or functional failure of the circuit breaker or components;
- impact on reliability service standards due to the critical nature and large supply areas served by circuit breakers; and
- potential environmental damage because of failures including oil loss, SF₆ leaks and the potential for fires and catastrophic equipment failure.

Cyclic asset inspections, maintenance and condition monitoring play a key role in managing the risks associated with circuit breakers. These assets have been modelled using CBRM to assess the current and future risk and asset health based on available asset and condition data.

Specific circuit breaker risks are listed below.

- A significant population of aged (> 50years) indoor HV switchgear remains in service in critical network substations and the Adelaide CBD. This switchgear is typically installed in large indoor switchboards or oil insulated Ring Main Units employing withdrawable bulk oil circuit breakers that are forecast to reach the end of their reliable service life by 2030.
- A relatively large proportion (approximately 40%) of the 33kV circuit breaker fleet is comprised of a problematic 33kV circuit breaker model presenting many reliability and performance issues. These circuit breakers are typically installed at transmission connection points and major country substations and require ongoing, proactive intervention to manage failure risks.
- SA Power Networks has a specific model of 66kV SF₆ insulated circuit breaker that is prone to corrosion and gas leaks. Condition monitoring typically identifies 1 – 2 of these circuit breakers per year for repair and refurbishment.
- The 66kV Gas Insulated Switchboard (GIS) at Northfield Connection Point is currently in poor condition, with many areas of external corrosion and flange sealing failures allowing SF₆ gas to be released into the atmosphere. After 30 years in service, the deteriorating mechanical condition of this critical switchboard requires significant intervention in the near term (< 2025) to manage performance and risk of equipment failure (refer Section 8.4.4.1).

8.4.2.7 Life cycle management strategy

8.4.2.7.1 Circuit breakers asset creation strategy

Circuit breaker specifications are continuously reviewed to ensure lessons learned from major failures and operating experience is fed back into future procurement decision making. Examples of continuous improvements include the introduction of SF₆ free circuit breaker technology to 33kV and 66kV equipment and the standardisation of internal arc/fault containment facilities for indoor switchboards to ensure operator and equipment safety in the event of major plant failure.

Period contracts for the supply of standard equipment items, managed through design reviews, manufacturing inspections, audits and witness testing are also undertaken to achieve lifecycle cost efficiencies.

8.4.2.7.2 Circuit breakers operations and maintenance strategy

Operational control, protection and monitoring (including load, fault operations and equipment alarms) of circuit breakers on the network are continually monitored through the SCADA system.

Key maintenance strategies for circuit breakers are centred around reliability centred maintenance principles informed by periodic routine visual inspections, mechanical overhauls and specific diagnostic tests appropriate to condition and equipment criticality.

Table 50 gives a summary of the routine inspection, maintenance and condition monitoring tasks for circuit breakers.

Table 50: Circuit breakers inspection, maintenance and condition tasks

Inspection, maintenance and condition monitoring tasks	Frequency
Visual inspections	6 monthly
Thermographic inspections	Annually
Post fault maintenance	After set number of recorded fault interruption operations depending on voltage and type of circuit breaker
Maintenance, diagnostic testing and overhaul	6–12 years (frequency varies depending on asset type and duty of operation)

Further details on maintenance of circuit breakers are given in Section 5.1 (Substation circuit breakers) of the Network Maintenance Manual.

8.4.2.7.3 Circuit breakers renewal/replacement strategy

The high-level renewal/replacement strategy for circuit breakers is to maintain the long-term risk and performance across asset population as assets age and deteriorate in service (maintain risk), Evaluation of current risk and future performance of the circuit breaker fleet is modelled using condition based risk management (CBRM) methodology.

This approach considers the effects of other programs of work such as substation upgrades, unplanned (on failure) replacements and other planned project works to target critical assets in poorest condition. Delivery of this plan employs prudent investment across refurbishment (service life extension) and replacement works and will result in approximately 1.6% of the asset population replaced annually to 2030.

Initial risk control techniques for Circuit Breakers include the use of more frequent maintenance and condition monitoring of asset performance.

The decision to refurbish or replace a circuit breaker considers:

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

Where more efficient means of risk mitigation (typically decommissioning or asset refurbishment) are not able to be used as an effective risk control, asset replacement is used to manage the risks posed by significantly deteriorated and poor condition circuit breakers.

Figure 132 shows a summary of the circuit breakers replacement plan to 2030, which illustrates the change in focus of asset replacement strategy beginning in 2016 to address deterioration across our populations of aged indoor switchboards (containing many integral circuit breakers).

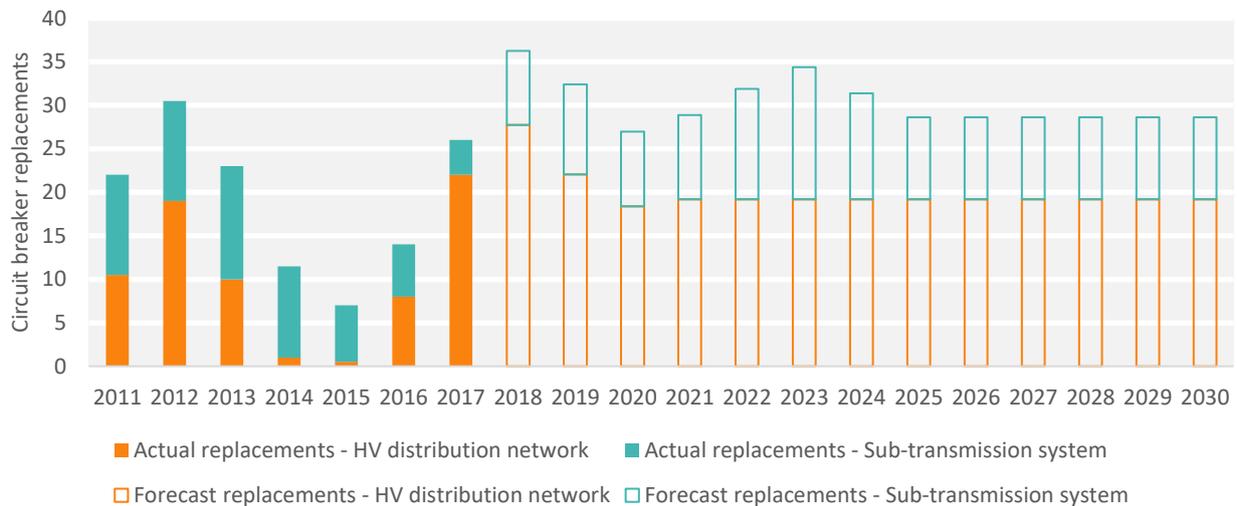


Figure 132: Circuit breakers renewal/replacement plan

To maintain the performance of the HV distribution network circuit breakers, investment plans to 2030 are focused on the large volumes of aged, oil-insulated distribution switchgear expected to reach the end of their reliable service lives by 2030. Expenditure during this period will target populations of indoor oil-insulated switchboards, CBD Ring Main Units and outdoor ‘cubicle style’ circuit breakers that no longer meet provide a safe and reliable service.

The strategy for sub-transmission circuit breakers to 2030 will continue current replacement programs targeting significantly aged, legacy and poor condition outdoor oil-insulated circuit breaker models and enduring risks posed by a large fleet of a problematic 33kV circuit breaker model.

The number of circuit breakers refurbished annually varies year on year based in programs to manage identified risks. Expenditure requirements for these programs are forecast as an ongoing annual allowance, based on completion of current program of Email/Westinghouse indoor oil circuit breaker refurbishment (typically on average 90 circuit breakers refurbished p.a.) and forecast ongoing needs to manage the remaining circuit breaker population

The impact of renewal/replacement and refurbishment plans on the population risk across the circuit breaker assets was modelled using CBRM. Figure 133 shows the current risk for circuit breakers and how this risk is forecast to grow if assets are allowed to continue to deteriorate without intervention from 2020. It shows that the current risk for circuit breakers in both the HV distribution network and sub-transmission system would increase by 50% (on 2017 levels) by 2030 if no proactive replacements are undertaken.

Figure 135 shows the resulting risk profile resulting from proposed expenditures through to 2030. The completion of all proposed investment programs over the planning period is forecast to maintain current levels of safety, reliability and network performance across the asset class out to 2030.

Figure 134 and Figure 136 compare how the HI of the circuit breaker population will change by implementing the proposed renewal strategy.

The proportion of circuit breakers with advanced deterioration (HI >7) increases from <3% to 6% by 2030; predominately in the lower consequence locations in the network. This is largely offset by those circuit breakers in critical locations with observable to serious deterioration (HI 4–7) decreasing from 22% to 17%. The proportion of the circuit breaker population in good condition (HI 0–4) remains relatively stable to 2030.

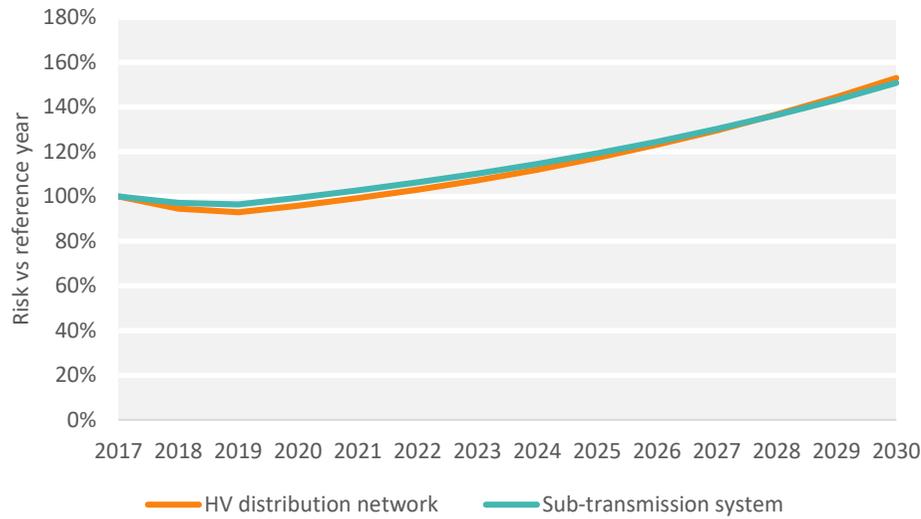


Figure 133: Circuit breakers risk profile — do nothing

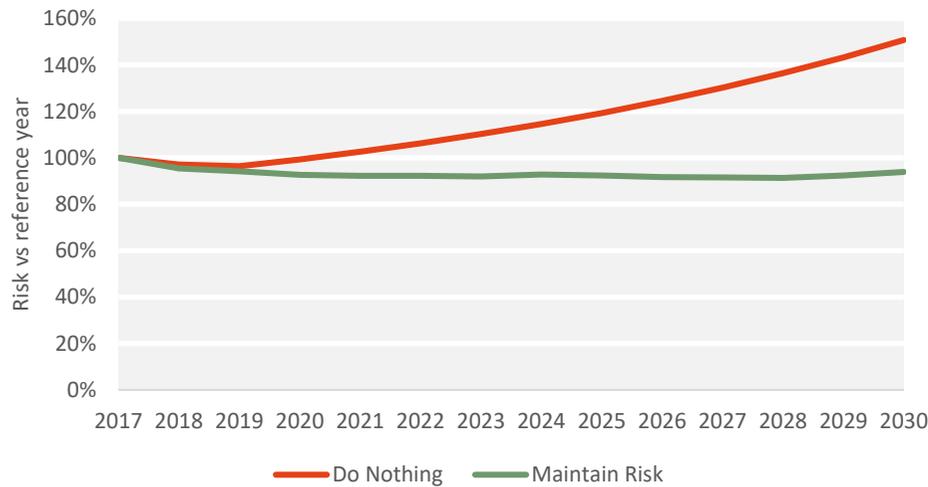


Figure 135: Circuit breakers risk profile — proposed expenditure

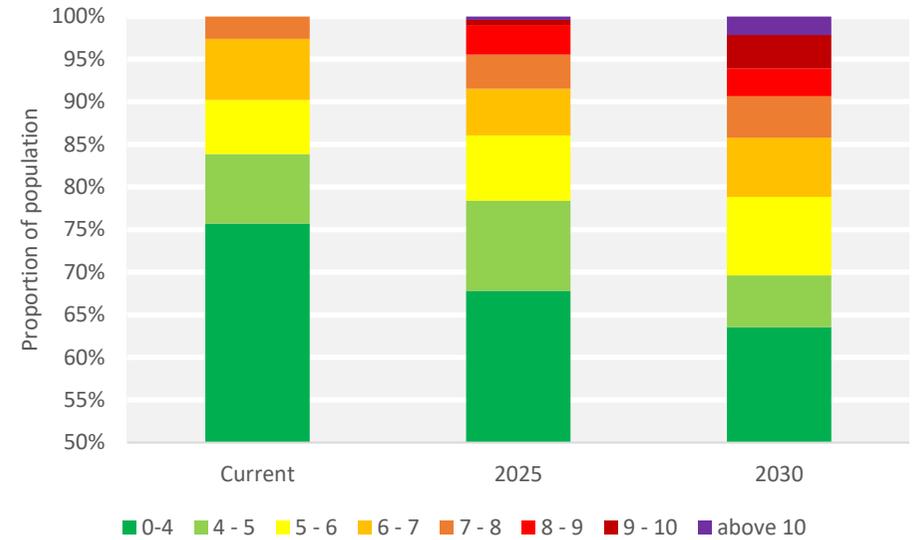


Figure 134: Circuit breakers health index — do nothing

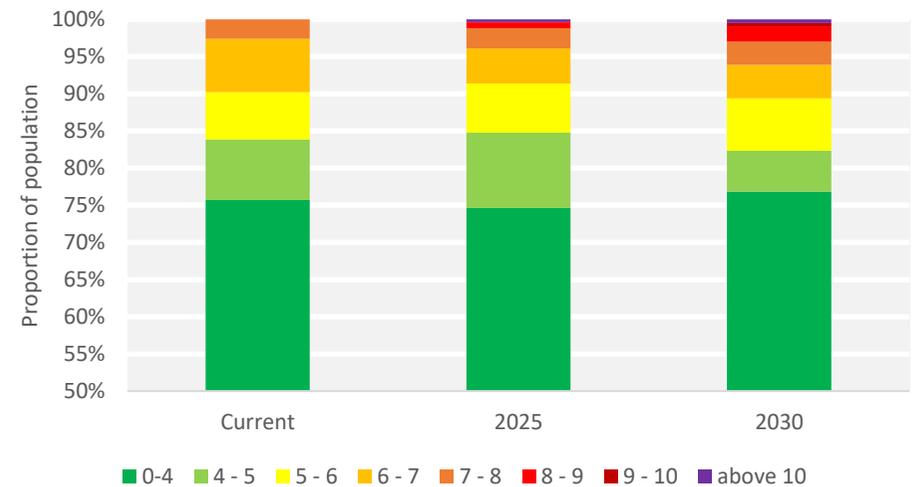


Figure 136: Projected circuit breaker health index — proposed expenditure

8.4.2.7.4 Circuit breaker disposal strategy

The disposal of a circuit breaker includes the decommissioning of the asset and removal from site, after which it may be sold for scrap metal value, salvaged for component spares or refurbished and reused elsewhere as an emergency spare. This decision process is informed by asset condition assessment and need for the individual circuit breaker.

Any oil insulated circuit breakers requiring disposal have their oil drained and tested for PCB to ensure disposal in accordance with the Environmental Management Plan. Any asbestos containing components are also disposed of in accordance with the Environmental Management Plan.

Circuit breakers containing SF₆ insulation gas have their gas extracted and tested for potential re-use. Any SF₆ gas to be disposed of must be in accordance with procedure CB 001/03 Safe Handling of SF₆ and Decomposition Materials.

8.4.3 Other substation assets

8.4.3.1 Introduction

This section provides an overview of the other sub-transmission system and distribution network assets. For further information, refer to the relevant substation asset plans.

Asset summary

The 'other' substation assets include lighting, instrument transformers, surge arrestors, capacitor banks, DC & AC auxiliary supplies, earth grids, buildings & support structures, airbreak disconnect switches, oil containment and other ancillary assets. Their critical support functions include:

- protection, monitoring and ensuring reliable, continuous operation of sub-transmission and HV distribution network equipment within substations;
- ensuring the sub-transmission and HV distribution network equipment in substations maintains a continuous supply within required voltage limits;
- ensuring the sub-transmission and HV distribution network equipment is protected in the event of faults and safely accessible for undertaking, repairs, planned maintenance or other operational activities and to protect public safety;
- preventing unauthorised access, enabling staff and contractors access to our assets and assisting network operations staff with locating faults; and
- minimising the environmental risks of sub-transmission and HV distribution network equipment failure.

These assets are generally monitored and replaced on failure or degraded performance. They have not been modelled using CBRM. Historical expenditures and future performance requirements for these assets informs the required forward investment to 2030.

8.4.3.2 Other substation assets asset management objectives

The asset management objectives that guide day-to-day asset management activities and support the asset management of other substation assets objectives are summarised in Table 51.

Table 51: Other substation assets asset management objectives

Level of service category	Other substation assets asset management objectives
Safety	<ul style="list-style-type: none"> • No injuries/deaths to staff or contractors through installing, operating, inspecting, maintaining/repairing, replacing or decommissioning other substation assets. • No other substation assets failures resulting in injury/death.

Level of service category	Other substation assets asset management objectives
Reliability and resilience	<ul style="list-style-type: none"> Minimise planned and unplanned interruption duration and frequency from failures and replacements of the various other substation assets. Provide resilience of critical systems through major (system-wide) events.
Two-way grid	<ul style="list-style-type: none"> Maintain voltage to the required standard through maintaining the functionality of capacitor banks.
Communication and information	<ul style="list-style-type: none"> Provide accurate information on restoration times for unplanned outages due to failures of other assets within substations resulting in interruption to supply. Provide accurate advanced notice of any planned other asset replacement works within substations involving outages.
Efficiency	<ul style="list-style-type: none"> Minimise the various other asset life-cycle costs including the cost of installation, operations, maintenance, refurbishment/replacement and disposal.

8.4.3.3 Asset description

Table 52 summarises the remaining other asset types within substations.

Table 52: Other substation assets

Asset class	Asset description	Quantities (approx.)
Substation lighting	Provides a safe place of work and site security. Includes substation indoor lighting (standard lights, emergency and exit lighting) and outdoor lighting (standard exterior lighting and floodlights).	Unknown
Instrument transformers	Used with protection and metering devices to monitor the network quality of supply and detect faults.	356 voltage transformers 717 current transformers
Surge arresters	Used to protect major substation equipment (transformers, regulators, cables, capacitors and circuit breakers) from the damaging effects of over-voltage due to lightning and switching surges.	2,268 substation surge arresters
Capacitor banks	Used to store energy for power factor adjustments by compensation of reactive loads on the distribution network which varies with load throughout the day.	111
DC auxiliary supplies	The substation direct current (DC) system provides a stable power supply for critical substation equipment independent of primary alternating current (AC) mains supply.	344
Earth grids	Provide an earthing system in the substation to protect equipment and safe operations 'Earth grid' covers all types of earthing system and may include earth stakes, buried conductors, earthed structures, connections, equipment conducting parts, cable screens and other components.	408
Buildings and structures	House the protection, control, communications and switchgear equipment. Include control buildings, firewalls, equipment support stands and footings, yard surface and stormwater management.	Unknown
Airbreak disconnect switches	Devices used to visually and electrically isolate HV equipment or sections of the network for the purpose of safe access during maintenance, repair, upgrade or network operation.	2,929 switches

Asset class	Asset description	Quantities (approx.)
AC auxiliary supplies	Load distribution of power to lights, power outlets, and critical ancillary systems on major primary plant.	341
Environment protection infrastructure	Includes permanent and interim oil containment bunds and substation noise control measures.	229 substation permanent oil containment solutions 24 substation interim oil containment solutions 11 substation sites with sound control measures
Safety infrastructure	Provides a safe place of work for substations and site security including substation fencing, and indoor and outdoor lighting.	Unknown
Pipework switchyards	A popular method of substation construction for small/medium country substations from the 1940's through to the early 1990's. The style of construction uses readily available materials (galvanised support structures and distribution line equipment) to create a compact overhead switchyard on a small footprint of land.	45 substations
Substation cables and cable terminations	These assets electrically connect substations to the distribution network and provide underground HV distribution between substation assets (power transformers, switchboards etc).	Unknown

8.4.3.4 Life cycle management strategy

The operations and maintenance activity, renewal/replacement strategy for the other substation assets are summarised in Table 53. For further information, refer to the relevant asset plan documents.

Table 53: Other substation assets life cycle strategies

Asset classes	Inspection, maintenance and condition monitoring tasks	Lifecycle management strategy
Substation lighting	Typical inspection activities include: <ul style="list-style-type: none"> visual inspections 6 monthly; 	Risk based replacement/upgrade.
Instrument transformers	<ul style="list-style-type: none"> thermographic inspections 6 monthly or annually depending on asset type; and 	Condition / risk based replacement
Surge arresters	<ul style="list-style-type: none"> other routine testing: 1–18 years depending on asset type. 	Targeted and risk based replacement
Capacitor banks	Further details in Section 5 (Maintenance strategies – Substations) of the Network Maintenance Manual.	Replace on failure
DC auxiliary supplies		Risk based replacement/upgrade
Earth grids		Risk based replacement/upgrade
Buildings and structures		Risk based replacement/upgrade

Asset classes	Inspection, maintenance and condition monitoring tasks	Lifecycle management strategy
Airbreak disconnect switches		Targeted replacement
AC auxiliary supplies		Risk based replacement/upgrade
Environment protection infrastructure		Risk based replacement/upgrade
Safety infrastructure		Risk based replacement/upgrade
Pipework switchyard		Risk based replacement/upgrade
Substation cables and cable terminations		Targeted replacement and replace on failure

8.4.4 Major projects and targeted programs

This section discusses major replacement projects or targeted replacement programs of work within substations.

8.4.4.1 Northfield Gas Insulated Switchgear (GIS) replacement

Northfield substation is a connection point substation shared between the ElectraNet and SA Power Networks. The transfer of power between the two service providers takes place at 66kV and utilises Gas Insulated Switchgear (GIS), owned and operated by SA Power Networks.

The Northfield 66kV GIS is in poor mechanical condition and subject to accelerated ageing, with significant external corrosion present after 30 years of continuous service in an outdoor environment. The corrosion has initiated two flange failures which is currently allowing SF₆ gas to be released into the atmosphere (see Section 4.9.4.2). The estimated timeframe to replace the failed 66kV GIS is expected to take two years, during which time the stability, redundancy and capability of the resulting abnormal network to supply customer load would be significantly reduced.

The investment strategy for the Northfield GIS is based on prudent risk management and proposes a multi-staged approach to address the present and long-term risks associated with the operation of the 66kV GIS at Northfield substation.

For further information, refer to the Northfield gas insulated switchgear asset plan.

8.5 Mobile assets

8.5.1 Introduction

A brief overview of mobile assets, including the types of mobile assets and the life cycle management approach, are outlined in this section.

8.5.2 Asset description

Mobile assets can be moved to different sites for emergency bypass of faulted equipment or maintenance operations. They include:

- **Mobile substations:** 2 x 10MVA 66–33/11kV self-contained trailer substation units primarily used for rapid deployment in response to emergency supply restoration and planned maintenance in the HV distribution system;
- **Compact mobile substations:** 2 x 3.8MVA and 1 x 3 MVA 33/11kV skid mounted substations;
- **Mobile transformers:** 9 x units able to be connected to various voltage lines for emergency response or for reducing the impact of potential extended interruptions;
- **Mobile generators:** 3 x units that provide an additional source of power for emergency or planned operation and maintenance activity;
- **Mobile switchboard:** 1 x 11kV switchboard with 11kV circuit breakers as a backup/emergency switchboard in the event of a switchboard fault at a substation or for planned maintenance or substation upgrades; long term deployment at Port Pirie substation;
- **Ancillary plant and equipment:** includes mobile recloser, regulator, switching cubicles, cable support and bypass cables used in bypass arrangements and for installing and connecting mobile plant including safety and security equipment for temporary sites.

8.5.3 Risks

The risks of the mobile assets are the same as those for the fixed assets performing the same function.

8.5.4 Life cycle management strategy

8.5.4.1 Mobile assets asset creation

The considerations taken into consideration for the creation of new mobile plant is given the same considerations as for the equivalent fixed assets. The mobile assets are typically specified to fulfil a specific functional role within the network. Assets of this nature undergo a separate request for tender, procurement, risk assessment and implementation process.

8.5.4.2 Mobile assets operations and maintenance strategy

The operations strategy for mobile assets adopts the same approach as that for similar fixed assets when in service. The maintenance strategy for the mobile assets (substations, transformers and generators) is based on the need to ensure that they are ready and serviceable at all times. Mobile generators are leased with their operation and maintenance programs covered by third party service agreements.

Table 54 gives a summary of the mobile assets inspection, maintenance and condition monitoring tasks.

Table 54: Mobile assets inspection tasks

Inspection task	Frequency
Routine inspection by operator	Before and after use
Visual inspections of mobile plant and trailer	Annually
Test of connection leads, electrical testing, diagnostic testing	Annually or every 500 hours of use and before and after each use
Major programmed maintenance	Based on above inspections and maintenance strategies for major assets types (e.g. circuit breakers, protection, transformers)

8.5.4.3 Mobile assets renewal/replacement strategy

The renewal/replacement strategy for mobile plant is based on managing risks based on asset condition assessments. The mobile assets are refurbished or replaced applying the same principles as used for the corresponding fixed assets within the networks and substations.

8.5.4.4 Mobile assets disposal strategy

Mobile assets are disposed of with the same principles as used for the corresponding fixed assets within the networks and substations.

8.6 Secondary systems

8.6.1 SCADA and network control

8.6.1.1 Introduction

This section gives an overview of the SCADA and network control assets, including their population, age and condition. It outlines the life cycle management approach and risks for the planning period. For further information, refer to the network security and control asset plan.

Asset summary

The SCADA system enables the SA Power Networks' Network Operations Centre (NOC) to manage and control the network through the advanced distribution management system (ADMS). It gathers, processes and displays information about the status of the network as well as to change the operating state of devices remotely. The system comprises a central master station (or ADMS), numerous field installed remote terminal units (RTUs) and data concentrators which transfer data using the telecommunication assets to the ADMS. The primary ADMS is located in the NOC at SA Power Networks' Keswick office with a fully redundant disaster recovery ADMS on standby at Angle Park.

The RTUs form a large component of the SCADA system with approximately 340 RTUs across the network. Approximately half of the RTU population will exceed the upper end of the expected life range by 2025 if no replacements are made.

As many of the SCADA assets are largely electronic or computer based, their management is largely a fix on failure approach with no routine maintenance. However, as equipment and manufacturer support becomes obsolete in a short time relative to other network assets, replacement of other SCADA assets is targeted to ensure ongoing operability. Proactive targeted programs on RTUs and data concentrators are planned to replace assets that have exceeded their expected life, are no longer supported by manufacturers, or are becoming increasingly difficult to maintain and support.

In addition, SCADA extension programs are ongoing in regional areas to provide network visibility, monitoring and control to a similar level as the metropolitan network. The program will help model the network accurately in the ADMS to optimise the use of the existing network assets and enable more informed decision making.

8.6.1.2 SCADA and network control asset management objectives

The asset management objectives specific to SCADA are summarised in Table 55.

Table 55: SCADA and network control asset management objectives

Level of service category	SCADA and network control asset management objectives
Safety	<ul style="list-style-type: none"> through installing, operating, inspecting, maintaining/repairing, replacing or decommissioning SCADA or network control assets. No SCADA or network control asset failures resulting in injury/death. No SCADA or network control failures resulting in bushfire starts. No SCADA or network control resulting in damage to third party property.
Reliability and resilience	<ul style="list-style-type: none"> Minimise unplanned interruption frequency and duration because of SCADA system failures. Minimise planned interruption frequency and duration for SCADA system replacement works.
Communication and information	<ul style="list-style-type: none"> Provide accurate information on restoration times for unplanned outages through advanced distribution management system (ADMS) visibility of the network operations. Provide accurate advanced notice of any planned asset replacement works involving outages through use of the Network Operating Model.
Efficiency	<ul style="list-style-type: none"> Minimise SCADA and network control asset life-cycle costs including the cost of installation, operations, maintenance, refurbishment/replacement and disposal.

8.6.1.3 Asset description

The SCADA system is a key application used by the SA Power Networks' Network Operations Centre (NOC) to manage and control the network. It is used to gather, process and display information about the status of the network as well as to change the operating state of devices remotely. The system comprises a central master station (or ADMS; see Section 7.5.3.1) and numerous field installed remote terminal units (RTUs) and data concentrators which transfer data using the telecommunication assets to the ADMS. The primary ADMS is located within the NOC at SA Power Networks' office building at 1 Anzac Highway Keswick with a fully redundant disaster recovery ADMS on standby at Angle Park.

8.6.1.4 Population and age profile

The 340 RTUs across the network have a variable expected life, typically around 15 years. The main factors that influence expected life are environmental, for example temperature and moisture ingress. Figure 137 shows the age profile of the RTUs.

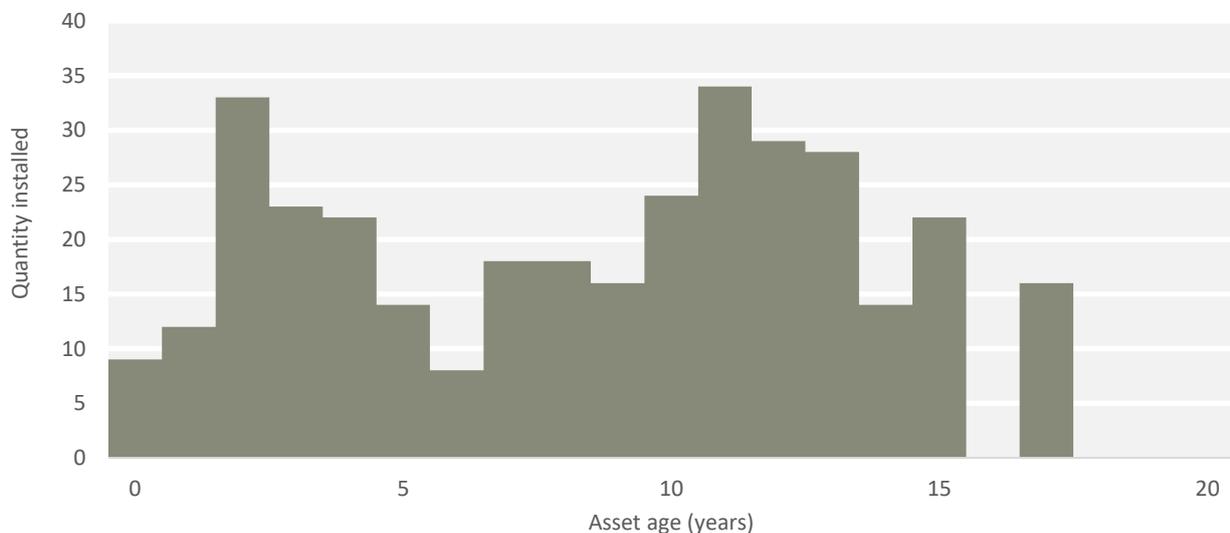


Figure 137: SCADA RTUs age profile

Figure 137 shows that a significant proportion (~42%) of RTUs are currently more than 10 years of age, and more than half will exceed the upper end of the expected life range by 2025 if no replacements are made.

All data concentrators will exceed their expected life of 15 years by 2020.

8.6.1.5 Current condition and performance

As the failure of RTUs and data concentrators is random, no routine or preventative maintenance is undertaken. Condition is therefore not monitored and the units are typically replaced on failure. Based on the age profile of the RTU assets, a significant number of failures will occur in a short timeframe, which would likely result in extended SCADA outages adversely impacting reliability service standards.

8.6.1.6 Risks

The main risks associated with SCADA and network control assets include:

- potential injury/death of SA Power Networks staff, contractors or the public due to:
 - accessing/operating manually operated switches in bushfire risk areas on extreme fire days in the event of SCADA system component failure preventing remote operation, and
 - incorrect network connectivity or settings within ADMS resulting in switching incidents.
- impact on reliability service standards due to:
 - the potential for complete failure of the master station or random failures of various SCADA components decreasing network visibility and control in the event of an outage,
 - many rural substations without SCADA connectivity, limiting visibility in those parts of the distribution network,
 - several rural 11kV and 19kV switches that are manually operated, limiting visibility and control in those parts of the distribution network; and
 - ageing RTU and data concentrators across the distribution network increasing the risk of no visibility and control in those parts in the event of an RTU or data concentrator failure.
- impact on communication and information due to:
 - limited visibility in parts of the rural network where SCADA coverage is limited, and
 - increased probability of failure of ageing RTUs and data concentrators, significantly affecting NOC management of the distribution network.

Specific SCADA and network control risks are:

- switching operations soon to be undertaken primarily within ADMS meaning a high reliance on integrity and availability of SCADA systems; and
- the current OMS not being fit for purpose and unable to cope during major storm events in 2017, which had a significant impact on customer services; also, highly customised and expensive to support.

These risks are being mitigated primarily through the capital works program.

8.6.1.7 Life cycle management strategy

8.6.1.7.1 SCADA assets asset creation

All new substations and network protection devices that are part of network planning projects are installed with SCADA functionality.

The strategy for extending SCADA and network control assets includes:

- SCADA functionality in rural substations and HV distribution network 11kV and 19kV switches will align visibility and functionality with similar switches in the metropolitan Adelaide region; and
- business implementation of ADMS into the NOC and other areas of SA Power Networks will require it.

The specific works programs under this strategy are shown in Table 56.

Table 56: SCADA extension plan

Provide a safe network service; and Deliver a reliable and quality network service.	
Capital programs of work	Benefits and outcomes
HV distribution network	
<ul style="list-style-type: none"> • Extending SCADA to remaining 11kV and 19kV switches: continue a targeted installation program to establish SCADA to all 11kV and 19kV switches and replace old panel mounted switches in substations with push buttons, to accommodate SCADA control and monitoring 	<ul style="list-style-type: none"> • Provide greater visibility of the network, improve reliability levels of service and optimise the ADMS functionality
<ul style="list-style-type: none"> • Extending SCADA to remaining substations: continue a targeted program to extend SCADA to rural substations where, unlike metropolitan areas, SCADA control and monitoring is scarce 	<ul style="list-style-type: none"> • Provide greater visibility of the network, improve reliability levels of service and optimise the ADMS functionality
<ul style="list-style-type: none"> • Network switching: Implement ADMS into the NOC 	<ul style="list-style-type: none"> • Increased efficiency in network monitoring and control

8.6.1.7.2 SCADA and network control operation and maintenance strategy

The operation and maintenance strategy for the ADMS master station includes:

- a network management console to enable ADMS administrators to quickly assess, diagnose and respond to system health anomalies; and
- an ‘evergreen’ support and maintenance agreement (given computer technology software and hardware is only supported by manufacturers for a finite period) to provide continuity of system maintenance, evolution, software assurance and renovation program; includes secure authorised access to the diagnostic system for the manufacturer for remote maintenance and monitoring of the ADMS environment.

The operation and maintenance strategy for RTUs and data concentrators is to replace on failure. As failure modes are random no routine preventative maintenance is undertaken.

8.6.1.7.3 SCADA renewal/replacement strategy

The renewal/replacement strategy for the ADMS master station includes a five-yearly hardware and software upgrade for both the primary and disaster recovery control centres to ensure ongoing manufacturer support.

The renewal/replacement strategy for RTUs and data concentrators includes:

- **RTU replacements:** More than half of the RTUs will exceed their expected life of 15 years by 2025, and are proposed to be replaced with modern day equivalent RTUs. Newer RTUs that randomly fail will also be replaced on failure.
- **TDU replacements:** Telephone dialup units (TDUs) at several distribution sites were due to be replaced by 2025. The introduction of the National Broadband Network has created a low-cost opportunity to replace them immediately using its communication infrastructure.
- **Data concentrators:** Nine data concentrators will exceed their expected life of 15 years by 2025. All data concentrators are proposed to be replaced with modern day equivalent assets by 2025.

The specific works under this strategy are shown in Table 57

Table 57: SCADA replacement plan

Provide a safe network service; and Deliver a reliable and quality network service.	
Capital programs of work	Benefits and outcomes
All systems	
<ul style="list-style-type: none"> Network data capture: Improve the quality of network data on infrastructure drawings and within the GIS, with an initial focus on the CBD. 	<ul style="list-style-type: none"> Improve accuracy of information used for planning network switching operations
<ul style="list-style-type: none"> SCADA improvement project (TDUs and RTUs): Bulk replacement of TDUs and RTUs beyond their expected life 	<ul style="list-style-type: none"> Ensure continuous visibility of the network
<ul style="list-style-type: none"> SCADA data concentrator replacements: Replace data concentrators beyond their expected life 	<ul style="list-style-type: none"> Avoid significant impacts on SCADA visibility across the network in the event of failure
<ul style="list-style-type: none"> ADMS/OMS hardware upgrade: Proactive replacement of servers and computer hardware 	<ul style="list-style-type: none"> Ensure ongoing reliability of the ADMS/OMS system for monitoring the network and responding to network outages
<ul style="list-style-type: none"> ADMS/OMS software upgrade: Proactive replacement of the ADMS/OMS software 	<ul style="list-style-type: none"> Ensure ongoing manufacturer service support of this critical operational platform

8.6.1.7.4 SCADA disposal strategy

The disposal strategy for SCADA and network control assets includes the removal of any data and settings from hard drives before electronic waste disposal.

8.6.2 Protection relays

8.6.2.1 Introduction

Protection relay assets, including their population, age and condition, and the life cycle management approach, are outlined in this section, as are replacement forecasts and resulting risk and asset condition for the planning period. For further information, and for information on control and auxiliary relays, refer to the protection and control asset plan.

Asset summary

Protection relays and control assets in the HV network automatically protect personnel and the network in the event of fault conditions. Of the 5,904 protection relays installed in substations, a significant proportion (~63%) is over 25 years of age

The number of protection relay failures shows an increasing trend in recent years. Their management is based on the outcomes of the visual inspections and diagnostic tests, in addition to responding to any identified faults reported through SCADA or network outages where protection relays failed to operate.

Protection relay assets have been modelled within CBRM to assess their current health and projected deterioration and failure risk based on current asset and condition data. Current condition data indicates 75% of protection relays as currently in good condition, with 25% having observable to serious deterioration and 0% with advanced deterioration. The model outputs inform the required forward investment to 2030 to maintain the risk across the protection relay asset base.

8.6.2.2 Protection relay asset management objectives

The asset management objectives specific to protection relays are summarised in Table 58. As protection relays protect HV plant from damage, some objectives are delivered by ensuring the HV plant is suitably protected.

Table 58: Protection relay asset management objectives

Level of service category	Protection relay asset management objectives
Safety	<ul style="list-style-type: none"> No injuries/deaths to staff or contractors through installing, operating, inspecting, maintaining/repairing, replacing or decommissioning protection relays including protection relays on embedded generator connections. Comply with the National Electricity Rules and SA power Networks requirements for primary and backup clearing times for any single device failure. No protection relay failure results in unnecessary plant damage or exposure to people. No protection relay failure results in high risk of bush fire start.
Reliability and resilience	<ul style="list-style-type: none"> Minimise planned and unplanned interruption frequency and duration from protection relay failures and replacements.
Environment	<ul style="list-style-type: none"> No oil spills or loss of SF₆ gas because of a protection relay fault or functional failure.
Communication and information	<ul style="list-style-type: none"> Install relays with fault recording capability for providing accurate information on outage events. Provide automatic relay fail reporting to facilitate replace on failure asset strategy. Provide supporting info for customer enquiries regarding protection relay operations in response to network faults.
Two-way grid	<ul style="list-style-type: none"> Record, control and protect energised assets during two-way load flows.
Efficiency	<ul style="list-style-type: none"> Minimise protection relay life-cycle costs including the cost of installation, operations, maintenance, refurbishment/replacement and disposal.

8.6.2.3 Asset description

Protection relays and control assets form an integral part of the HV network and automatically protect personnel and the network in the event of fault conditions. The protection relays vary in technology from the earliest electromechanical relays, solid state relays and modern digital protection relays.

8.6.2.4 Population and age profile

There are 5,904 protection relays installed in substations. Figure 138 shows the distribution of the various types of protection relays in use. More than half of all protection relays are the older electromechanical type; the modern digital relays have the second largest population.

Figure 139 shows the age profile of protection relays. A significant proportion (~63%) is more than 25 years of age. They are largely the electromechanical relays installed as part of the original network construction. Protection relays 20–35 years of age are solid state relays; those less than 20 years are typically digital relays. The expected life for electromechanical, solid state and digital relays is 40-60 years, 20–35 years and 15–20 years respectively.

8.6.2.5 Current condition and performance

Protection relay failures can be used as a lag indicator of how the overall protection relay asset base is performing in response to the asset management approach.

Figure 140 shows the historical number of protection relay failures. Protection relay failures have increased since 2014 (before 2014, SA Power Networks reported the failures in regulatory reporting on protection relay schemes rather than individual protection relays). Historically most failures were ‘silent’ failures of old electromechanical relays, which were few in number but resulted in large customer outages. More recently, the higher number of failures cause minimal customer outages given modern digital relays’ alarm on failure.

Protection relay assets have been modelled using CBRM to assess their current health based on current asset and condition data. Figure 141 shows the current HI of protection relays: 75% of protection relays are currently in good condition (HI 0–4), 25% have observable to serious deterioration (HI 4–7) and 0% have advanced deterioration (HI>7).

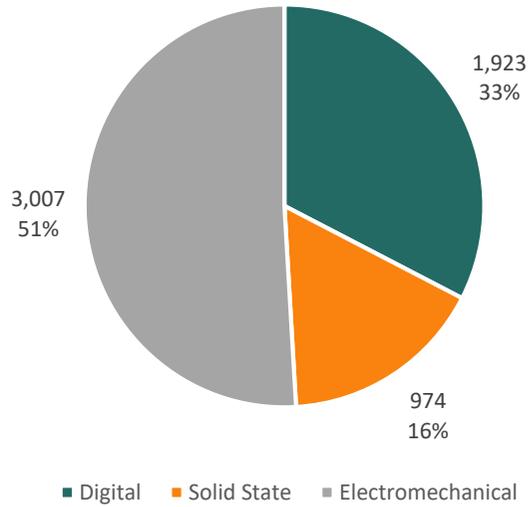


Figure 138: Protection relays type distribution

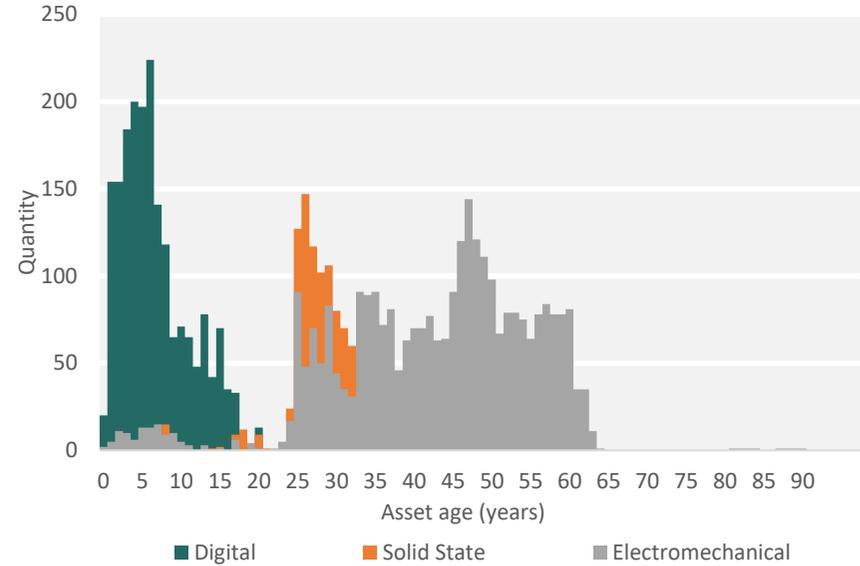


Figure 139: Protection relays age profile distribution

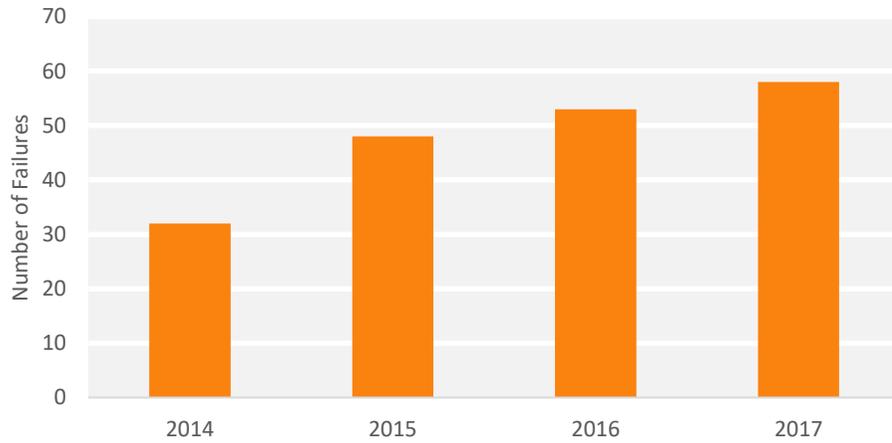


Figure 140: Protection relays historical failures

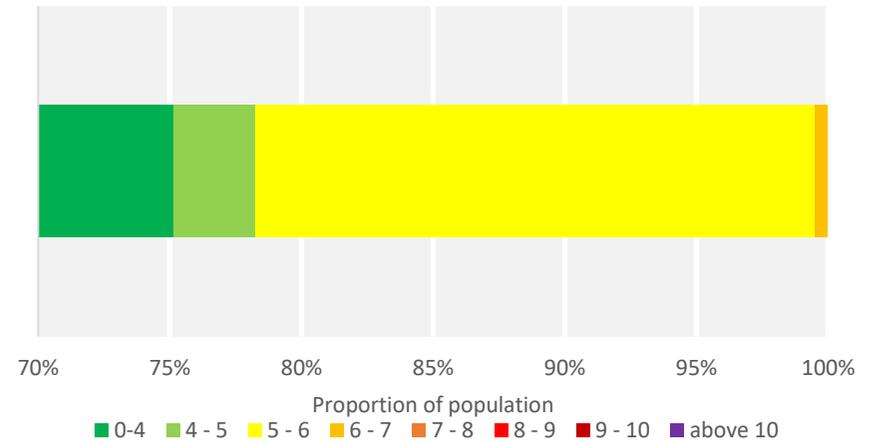


Figure 141: Protection relay health index distribution

8.6.2.6 Risks

The main risks associated with protection relays include:

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

Any protection relays that fail to operate when required during a network fault are investigated reactively with audits and compliance checks undertaken to ensure protection relays are installed and configured with the correct settings. In addition, protection relay assets have been modelled using CBRM to assess the current and future risk and asset health based on available asset and condition data.

Some specific protection relay risks include:

- obsolete makes and models where the unit and/or spares are no longer available internally or from equipment suppliers (includes the LI41, Raza and LPS protection relay models (<1% of the protection relay population));
- ‘silent’ older electromechanical relay failures usually resulting in large customer outages (inability to monitor condition increases the risk from being operated beyond their design life);
- some modern makes/models or protection relays in use in the network reported by other distribution network service providers interstate to have higher failure rates, but not yet evident in the network;
- anticipated increase in unplanned failures due to digital relays with shorter design life than electromechanical relays; and
- inadequate or non-compliant backup protection and fault clearing times on the distribution network presenting higher risks in bushfire risk areas, risk to high value assets and safety risks in densely populated areas. Some assets would have been previously upgraded through substation upgrades for load growth on the network. The extent of growth driven upgrades means fewer non-compliant relays are being replaced.

8.6.2.7 Life cycle management strategy

8.6.2.7.1 Protection relay asset creation

Most new protection relays installed are digital relays. The SA Power Networks protection philosophy is currently being reviewed to assess whether historical and currently applied protection relay requirements are suitable for future network operation. Key considerations are a focus on functionality such as feeder automation requirements as well as compatibility with IEC 61850 Communication Protocol Manual, an international standard defining communication protocols for intelligent electronic devices at electrical substations.

8.6.2.7.2 Protection relay operations and maintenance strategy

Where connected to SCADA, protection relays are monitored to identify any faults. The maintenance strategy for protection relays is a combination of preventative and reactive maintenance based on information obtained from condition assessments. Reactive inspections are undertaken on protection relays where network faults impact large areas, where network outages occur due to a protection relay operating when there was no network fault or where protection relays failed to operate for a network fault resulting in a larger network outage.

Table 59 gives a summary of the inspection, monitoring and maintenance plans for protection relays.

Table 59: Protection relays inspection, monitoring and maintenance plan

Inspection, condition monitoring or maintenance task	Frequency
Automated continuous monitoring of modern digital protection relays	Daily
Visual inspection	6 monthly
Diagnostic checks	2.25–6 years
Maintenance of electromechanical relays	By defect or diagnostic failure

Further detail for the maintenance of protection relays is covered in Section 5.8 (Substation protection and control systems) of the Network Maintenance Manual.

8.6.2.7.3 Protection relay renewal/replacement strategy

The renewal/replacement strategy for protection relays is based on maintaining the long-term risk and performance across the protection relay population. Electromechanical protection relays are refurbished where possible using purchased components or spares from previously replaced units. Refurbishment of electromechanical protection relays significantly extends their life at a much lower cost than complete replacement. Most new protection relays installed are digital relays with the capability to alarm on failure. Wherever possible, protection relays are replaced in conjunction with planned circuit breaker refurbishments/replacements, which require the protection relay system to be recommissioned. Modern distribution circuit breakers include digital protection relays as part of the circuit breaker.

Figure 142 gives a summary of the historical and forecast protection relays renewal/replacement plan to 2030.

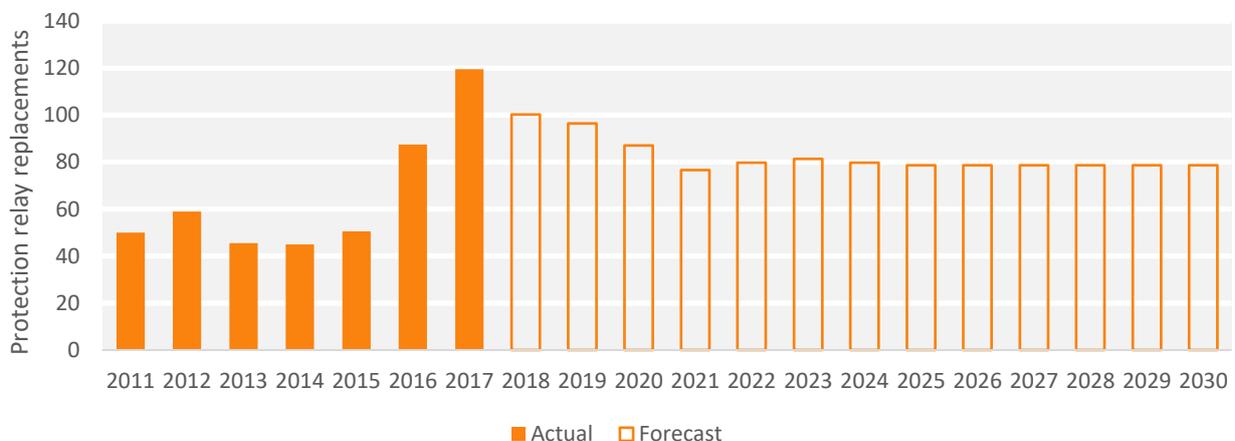


Figure 142: Protection relays renewal/replacement plan

The spike in replacements across 2016 and 2017 (Figure 142) was from a targeted, high volume recall/warranty replacement program based on unacceptably high failure rate.

The impact of the renewal/replacement plan on the risk across the protection relay assets was modelled using CBRM. Figure 143 shows the current risk for protection relays and how this risk would grow across the entire asset class if assets continued to deteriorate without intervention. The current risk for protection relays would increase significantly by more than 300% for protection relays in both the sub-transmission system and HV distribution network and if no replacements were made.

Figure 145 shows the resulting risk profile based on proposed expenditure through to 2030 to maintain a stable level of network risk on the protection relay assets.

Figure 144 and Figure 146 compare how the HI of the protection relay population would change by implementing the proposed renewal strategy. The proportion of protection relays in very poor condition (HI >7) increases from 1% to 12% by 2030; of assets becoming significantly deteriorated (HI 4–7) increases from 23% to 28%; and of protection relay assets in good condition (HI 0–4) decreases from 76% to 60%.

For protection relays, the increasing HI doesn't necessarily correspond with an increase in risk, as modern relays self-monitor and performance does not degrade (e.g. they are either operational or failed). Digital relays can fail with minimal immediate consequence due to redundancy and self-monitoring raising an alarm on failure. Based on protection relay history compiled to date, it is anticipated electronic relay failures will increase in the future. It is necessary to manage relays to keep the failure rate to an average of no more than one relay per week. The failed relay is required to be replaced within five to ten days, depending on level of risk the failed relay is carrying.

8.6.2.7.4 Protection relay disposal strategy

The disposal of a protection relay is determined by assessing the condition and need for the individual protection relay. The assessment includes which components are to be salvaged for future use on other similar units still in service.

Assets that reach the disposal stage usually do not have any economic value beyond their scrap metal value.

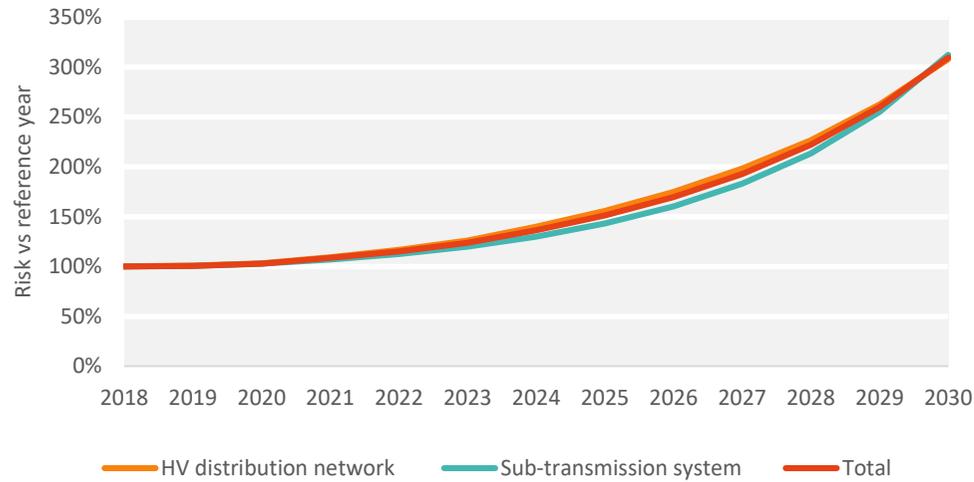


Figure 143: Protection relays risk profile — do nothing

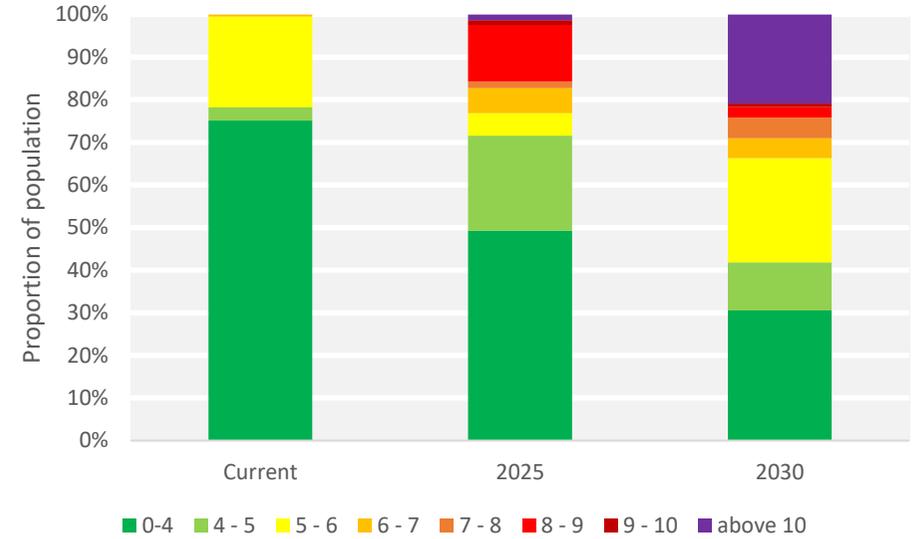


Figure 144: Protection relay health index — do nothing

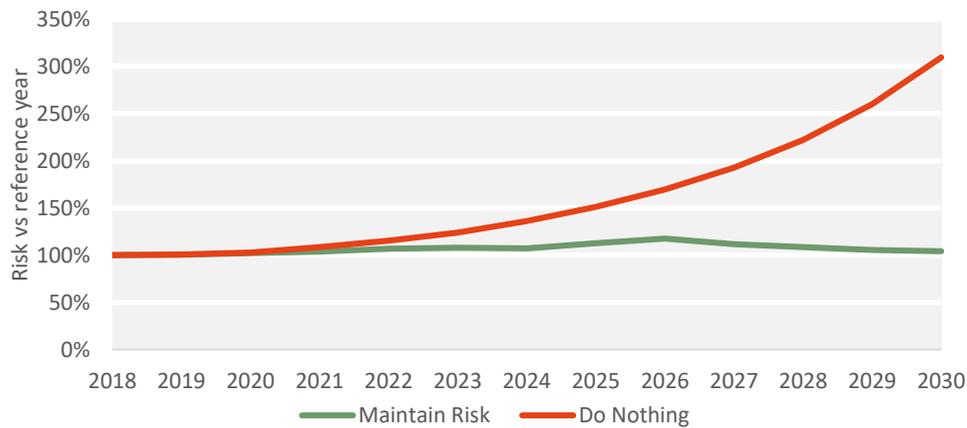


Figure 145: Protection relay risk profile — proposed expenditure

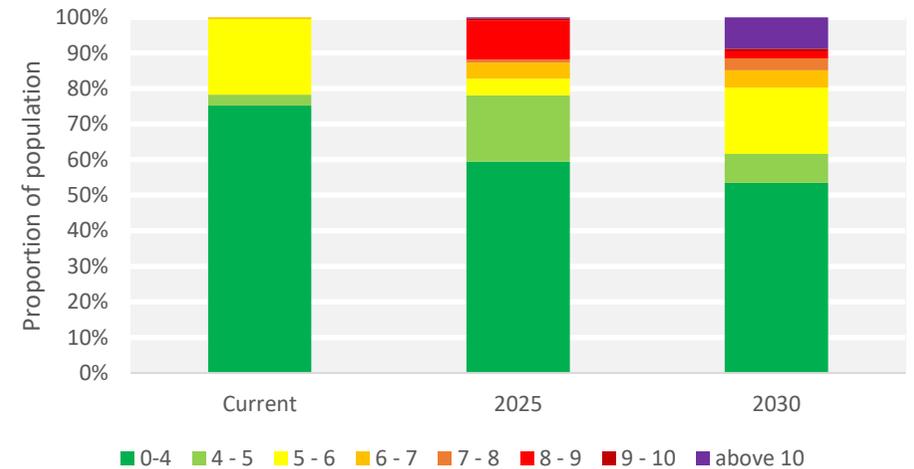


Figure 146: Projected protection relay health index — proposed expenditure

8.6.3 Telecommunication assets

8.6.3.1 Introduction

This section provides an overview of the telecommunication assets, including their population, age and condition. It outlines the life cycle management approach and risks for the planning period. For further information, refer to the suite of telecommunication asset plans.

Asset summary

Telecommunication assets transfer data from across the network to enable its status to be continuously monitored. These assets are broadly classified as:

- **linear communication assets:** copper and fibre optic cables that provide a physical communication line between network assets;
- **other communication assets:** microwave radio, 48V DC power systems, radio systems, private mobile radio network, multiplexers, operational telephony and data network equipment to transfer data and communications across the network;
- **communications monitoring assets:** telecommunications network control (TNC) management systems that ensure data and services are delivered safely and securely across network; and
- **communications site infrastructure:** for mounting or housing communication assets.

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

These assets are typically replaced based on condition and risk of failure. They have not been modelled using CBRM. The historical performance and expenditure of this asset class informs the required forward investment to 2030.

8.6.3.2 Telecommunication asset management objectives

The asset management objectives specific to protection relays are summarised in Table 60.

Table 60: Telecommunication assets asset management objectives

Level of service category	Telecommunication assets asset management objectives
Safety	<ul style="list-style-type: none"> • No injuries/deaths to staff or contractors through installing, operating, inspecting, maintaining/repairing, replacing or decommissioning telecommunications assets. • No telecommunication asset failures resulting in injury/death. • No telecommunication asset failures resulting in bushfire starts.
Reliability and resilience	<ul style="list-style-type: none"> • Minimise unplanned interruption frequency and duration from telecommunication failures and replacements.
Communication and Information	<ul style="list-style-type: none"> • Provide a reliable telecommunications network to supply the NOC and field staff with accurate information on unplanned outages. • Provide accurate advanced notice of any planned telecommunication replacement works involving outages.
Efficiency	<ul style="list-style-type: none"> • Minimise telecommunication life-cycle costs including the cost of installation, operations, maintenance, refurbishment/replacement and disposal.

8.6.3.3 Asset description

Linear communication assets

Linear communication assets include pilot cables (copper wires) and fibre optic cables that make a physical communication line between network assets.

The total length of pilot cables in the network is estimated at 400km, of which about 320km are within the metropolitan area, 40km within the CBD and 40km in country areas. Pilot cables are no longer deployed in the network and will be replaced by fibre cable in the future.

The 3,839 fibre optic cables extending over 2,551km in both overhead and underground installations, are used to provide SCADA, teleprotection, operational telephony, equipment management and monitoring of operational and telecommunications equipment in substations throughout South Australia.

Electrical and electronic communication assets

These assets include microwave radio, 48V DC power systems (batteries, rectifiers and solar installations), radio systems, private mobile radio network, multiplexers, operational telephony and data network equipment such as routers, switches and firewalls. They enable the transfer of data and communications across the network.

Communications monitoring assets

Communications monitoring assets are used to manage, maintain and monitor the various assets in the network to ensure continuous network operations. They include telecommunications network control (TNC) management systems that ensure data and services are delivered across network in the safest and most secure manner.

Communication site infrastructure

Communication site infrastructure includes infrastructure for mounting or housing communication assets and includes towers, masts, poles, fencing and buildings. There are about 140 structures and 40 buildings across the network (excluding substations).

8.6.3.4 Age profile

Linear communication assets

The age profile for the linear communication assets is shown in Figure 147.

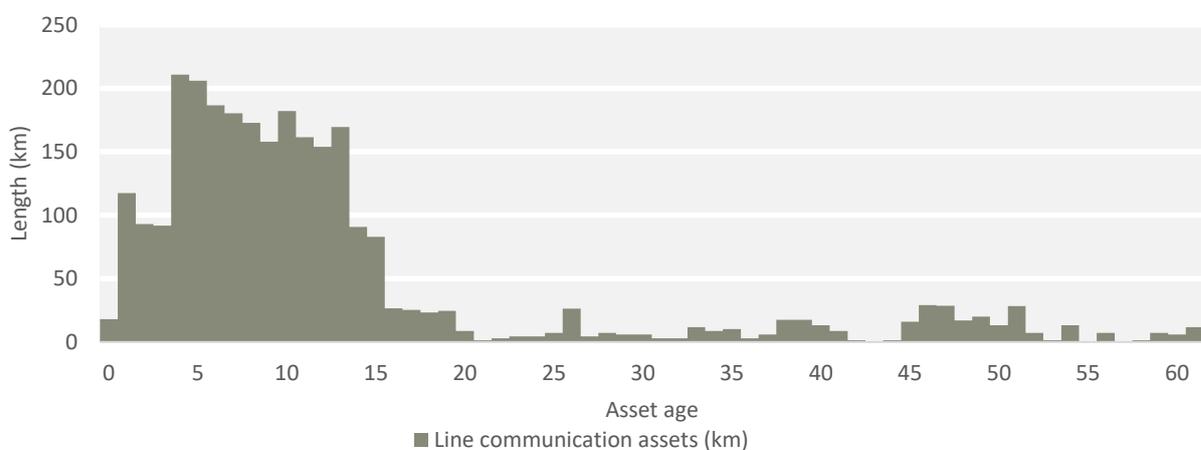


Figure 147: Linear communication assets age profile

Figure 147 shows the combined distances of pilot and fibre cable (overhead and underground). Assets older than about 30 years of age (before 1990) are pilot cable; assets younger than this are predominantly fibre cable with a small percentage of pilot cable installed as faulted section replacement. Based on the age profile, approximately 90% of the linear communication asset length consists of fibre optic cables and approximately 10% pilot cables.

Electrical and electronic communication assets

Figure 148 shows the age profile of the main electrical (48V battery systems) and electronic equipment (multiplexers, routers, switches and modems) installed. Most assets are less than 10–15 years of age which is reflective of the range of expected life for electrical and electronic equipment.

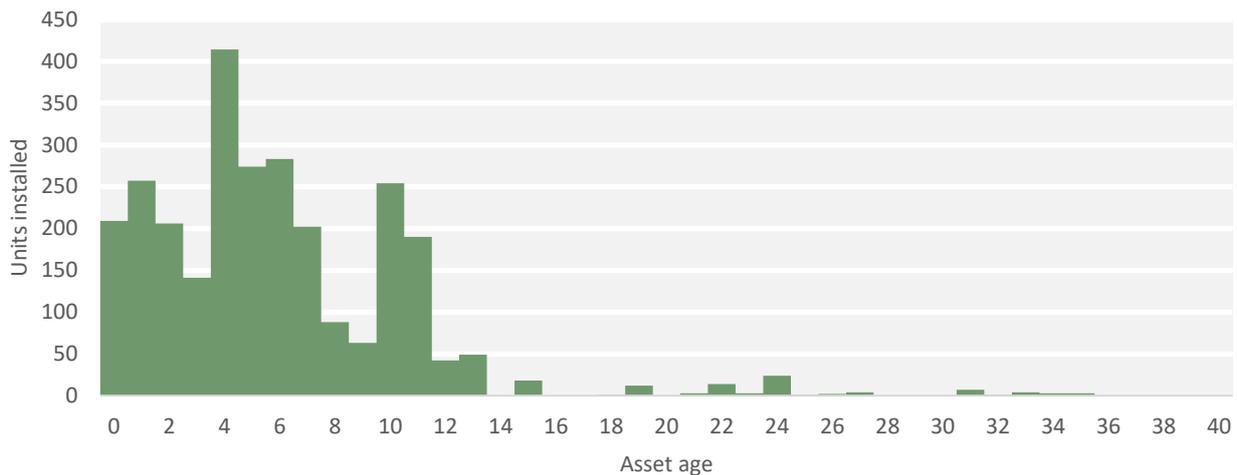


Figure 148: Electrical and electronic communication assets age profile

Communications monitoring assets

The age profile of telecommunications monitoring assets is generally less than five years and in all cases less than seven years. The total number of asset in this class is fewer than 20 systems.

Communication site infrastructure

The age profile of the structural assets is limited. Generally, assets in this class are more than 10 years old but less than 50 years old.

8.6.3.5 Condition/performance

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

8.6.3.6 Risks

The main risks associated with telecommunications assets include:

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

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

Specific telecommunication asset risks are:

- potential for unreliable mobile radio network that doesn't provide essential communications during operations or emergencies; and
- potential failure of Belair radio site causing loss of SCADA and mobile radio traffic.

These identified risks have several controls in place within SA Power Networks risk management framework.

8.6.3.7 Life cycle management strategy

8.6.3.7.1 Telecommunication asset creation

Any new linear communication assets are exclusively fibre optic cables. The electrical, electronic and communications monitoring asset selection focuses on vendors who provide high quality equipment, short lead times, technical support and training, and ongoing support for spare parts and firmware upgrades. Equipment selection and positioning shall consider safety of staff, contractors and the community. The design of equipment shall consider aspects such as radio path (for radio systems) as well as the environmental conditions of the installed equipment, and provide a secure environment against unauthorised access. Telecommunications equipment design is also dependent on the criticality of the data services it is assigned to transport and the anticipated future capacity of the equipment. Telecommunications infrastructure must support the required functionality of other network assets (e.g. HV protection schemes are required to have an independent dedicated telecommunication path so that no common fault interrupts both protection schemes). The telecommunication equipment and frequency assignments shall be licenced with the Australian Communications and Media Authority. Site infrastructure is designed with consideration to physical loading, wind loading, corrosion resistance, and security infrastructure and weather including appropriate lightning protection.

8.6.3.7.2 Telecommunication assets operations and maintenance strategy

Linear communication assets

The maintenance strategy for linear communication assets is a combination of preventative, reactive and corrective maintenance. Annual visual inspections are made on overhead pilot and optic fibre cables. Annual electrical testing is also undertaken on a sample of pilot assets which considers location (e.g. CBD), areas with significant vegetation encroachment where cables are prone to abrasion or areas with a history of defects. Detailed testing is undertaken on optical fibre cables suspected of having potential condition concerns or indications of faults. Any faults identified are scheduled for corrective maintenance. Any failures of linear communication assets that can impact safety or supply are attended to immediately. Pilot cables or protective wrapping installed on linear assets subject to abrasion are repaired where cost effective, otherwise they are scheduled for replacement.

Communications monitoring assets

As most communication assets are electronic they are monitored continuously through their connection to the TNC. TNC systems — computers and software which self-diagnose any impending faults — are used to monitor telecommunication assets.

Electrical and electronic communication assets

Annual visual inspections of communications assets include pre-bushfire checks in high bushfire risk areas. Fans used to cool telecommunications equipment are also inspected and cleaned annually, and battery systems powering the telecommunication systems are also tested annually.

Communication site infrastructure

There is a regulatory requirement to inspect all towers and lattice structures every three years, but in practice it is undertaken in two yearly cycles. There is also a legislative obligation to visually inspect all climbing safety devices annually. Limited preventative maintenance is undertaken on the communication site infrastructure such as painting of towers to protect against rust. Corrective maintenance for the site infrastructure is typically limited to reattaching loose brackets, cables or replacing aircraft warning lights. Reactive maintenance for the site infrastructure is based on the outcomes of the visual inspections. This typically involves minor repairs to concrete footings or installing additional structural steel reinforcement.

8.6.3.7.3 Telecommunication assets renewal/replacement strategy

The replacement strategy for linear communication assets is based on managing risks. Electronic communication assets are replaced to maintain sufficient spare parts due to obsolescence of equipment; battery systems and TNC hardware are typically replaced based on age with condition monitoring used to prioritise replacements.

Site infrastructure is renewed/replaced based on condition with an assessment determining the viability and most cost-effective solution of renewal, upgrading or replacement of the structure.

8.6.3.7.4 Telecommunication assets disposal strategy

The disposal strategy for telecommunication network assets includes the removal of any data and settings from hard drives before electronic waste disposal.

9 Targeted strategies

9.1 Introduction

This section describes the targeted strategies that span multiple asset classes to address legislative or regulatory obligations or are required because of the changing environmental and operating climate. The detailed Asset Plans provide further detail on the strategies developed and resulting in the programs of work.

9.2 Safety

9.2.1 Introduction

Safety strategies applied to managing power network assets are outlined in this section, as are the processes applied to identifying operating and capital investment plans focused on safety to support the safety objectives and levels of service. For further information, refer to the suite of safety asset plans.

Safety summary

Protecting the public, our employees, contractors and the environment from the inherent risks of operating and maintaining a distribution network is SA Power Networks' highest priority.

Consequently, the key objectives of the safety strategies are:

- the safety of SA Power Networks employees and contractors;
- the safety of the public and protection of the environment; and
- compliance with legislative and regulatory requirements.

SA Power Networks has a legislated requirement to deliver a Safety, Reliability, Maintenance and Technical Management Plan (SRMTMP) that is approved by the ESCoSA on the recommendation of the Office of the Technical Regulator. Many safety strategies are required to ensure compliance and continuous improvement, and minimise safety risks associated with the services provided.

The safety strategies applied can be categorised as follows:

- **Work health and safety:** The Safety Management System, the *Safety Strategy 2020*, and the annual Work Health and Safety Management Plans, contain the projects and processes for ensuring hazard identification and risk assessment. They also ensure adequate and regularly monitored controls are in place to undertake the day-to-day activities associated with operating and maintaining the network. The Safety Management System is externally and independently audited and certified to monitor staff and contractor compliance with operating procedures.
- **Safety capital works program:** This targeted capital works program replaces specific assets or installs new assets where other controls are ineffective to reduce safety risks to acceptable levels.

These strategies inform the required forward investment to 2030 to undertake the necessary operational activity and capital works to minimise safety risks, including those presented by potential bushfires, to maintain the safety levels of service.

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graph TD
    AP[Asset Planning] --> ACA[Asset Creation/Acquisition]
    ACA --> AO[Asset Operations]
    AO --> ACM[Asset Condition and Performance Monitoring]
    ACM --> AM[Asset Maintenance]
    AM --> AR[Asset Renewal/Replacement]
    AR --> AD[Asset Disposal]
    AD --> AP
  
```

9.2.2 Safety asset management objectives

The safety asset management objectives are summarised in Table 61.

Table 61: Safety asset management objectives

Level of service category	Safety asset management objectives
Safety	<ul style="list-style-type: none"> Protect SA Power Networks employees, contractors and the community from the risks of operating, condition and performance monitoring and maintenance of the electricity distribution network. Minimise the potential of fires starting from network infrastructure. Minimise the potential of fires starting from vegetation interfering with network infrastructure.
Reliability and resilience	<ul style="list-style-type: none"> Minimise the number of risk line section on the disconnection list leading up to the Fire Danger Season (FDS). Minimise the duration of interruptions resulting from planned disconnections during FDS through automation where the benefits of those works exceed the costs.
Aesthetics	<ul style="list-style-type: none"> Identify and implement alternatives to tree pruning such as tree removal and replacement to minimise fire starts. Select appropriate species for planting near overhead powerlines to minimise fire starts.
Efficiency	<ul style="list-style-type: none"> Minimise life-cycle costs of asset replacements or upgrades for safety driven capital works including the cost of installation, operations, maintenance, replacement and disposal. Identify and implement cost effective capital works for bushfire risk mitigation Minimise vegetation management costs including the cost of scoping, clearance and disposal.

9.2.3 Legislative requirements

SA Power Networks is required to meet many specific safety regulatory obligations as a distribution networks service provider including:

- a duty to comply with the *Work Health and Safety Act 2012* and *Work Health and Safety Regulations 2012*;
- a duty under Section 22 of the *Electricity Act 1996*, to prepare and deliver on the SRMTMP, approved by the Essential Services Commission of South Australia (ESCoSA) on the recommendation of the South Australian Office of the Technical Regulator; includes relevant policy directions, governance, organisational responsibilities and approaches as they apply to network:
 - operations management,
 - maintenance management (including inspections),
 - construction management,
 - safety, reliability and technical performance indicators, and
 - standards compliance requirements.
- a duty under Section 60 of the *Electricity Act*, to take reasonable steps to ensure that infrastructure complies with, and is operated in accordance with, the technical and safety requirements imposed under the *Electricity (General) Regulations 2012*, and is safe and safely operated; and
- a requirement, under *Electricity (General) Regulations*, to adhere to various listed standards (e.g. Australian and industry standards) for infrastructure.

SA Power Networks adheres to these requirements through application of a Work Health and Safety Policy and Directive which are both aligned with the Work Health and Safety Legislation and Federal Safety Commissioner Standards.

Significant management and employee time and effort is focused on workplace safety and is supported by an integrated Work Health and Safety Management System, the SRMTMP and other standards and procedures. In addition to *SA Power Networks Safety Strategy 2020* (see section 9.2.4.3), several operational strategies such as the vegetation management strategy (see Section 7.5.5) and bushfire risk management strategy (see Section 7.5.4.1) are actively applied.

9.2.4 Work health and safety

9.2.4.1 Introduction

Safety for the community, employees and contractors is our highest priority. The development, application and review of work health and safety processes and procedures covering SA Power Networks operational activities is comprehensive and essential due to the high-risk nature of the assets and the services they provide. The systems and processes, which have evolved over many years to address the many risks identified in operating a distribution network, underpin legislative safety obligations.

9.2.4.2 Work Health and Safety Management System

The various elements of the SA Power Networks Safety Management System, which underpins the delivery of services to customers aligned to the SA Power Networks Work Health and Safety Policy, are shown in Figure 149.



Figure 149: Working safely at SA Power Networks

SA Power Networks Safety Management System has the following safety accreditations in place for the processes associated with the inspection, operation, modification and restoration of the electricity distribution network in South Australia:

- Occupational Health and Safety Management System compliant with ISO 18001:2007 Occupational Health and Safety Assessment Series;
- Occupational Health and Safety Management System compliant with AS/NZS ISO 4801:2001 Occupational Health and Safety Management Systems;
- *ReturnToWorkSA* certificate of self-insurance; and
- Federal Safety Commissioner Australian Government Building and Construction WHS Accreditation Scheme.

The registrations also cover the design and construction of electricity distribution infrastructure. These accreditations demonstrate SA Power Networks’ strong commitment to safety by employees and contractors in delivering services to customers. The objectives of the system ensure hazard identification, risk assessment, and adequate and regularly monitored controls are in place. The hierarchy of controls for identified safety risks is shown in Figure 150.

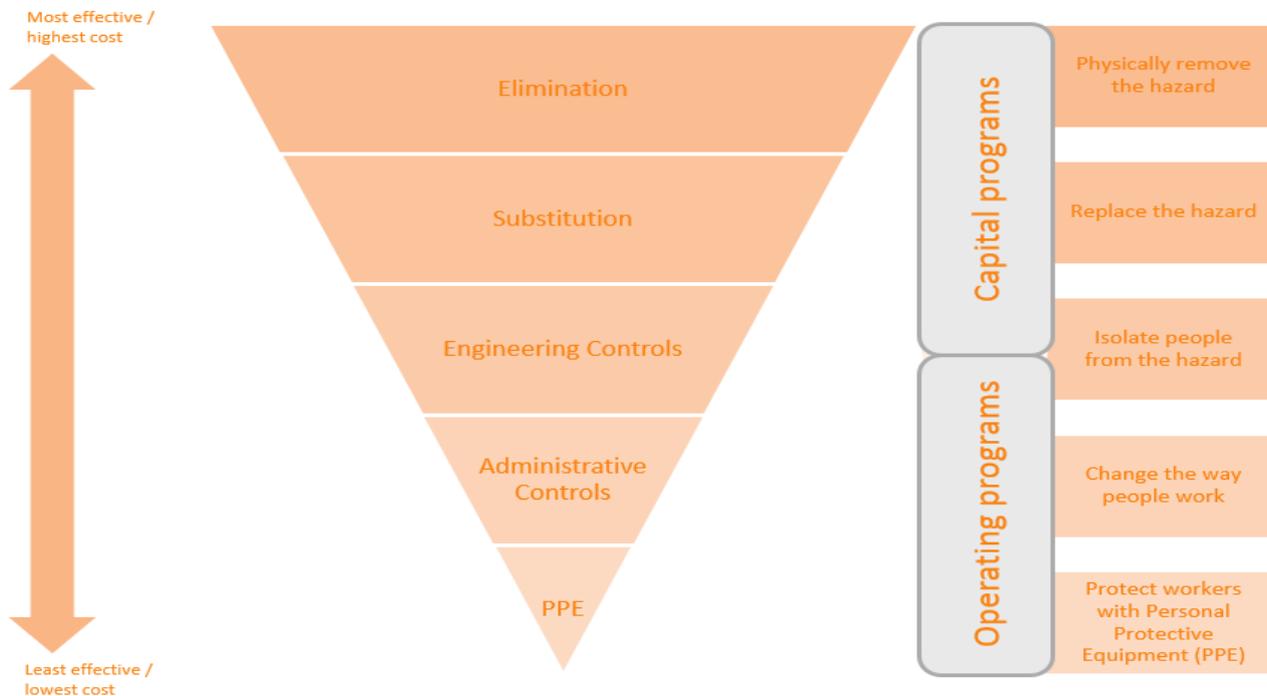


Figure 150: Safety risk management hierarchy of controls vs capital and operating programs

Figure 150 shows that the most effective solutions are typically the most expensive to implement. The decision on the preferred solution leading to operating or capital expenditure is primarily determined on whether the risk is mitigated to an acceptable level in line with the SA Power Networks Risk Management Framework *and* whether the benefits exceed the cost of undertaking those works. The resulting control measures largely inform the forward *Safety Strategy 2020* and the Safety Capital Works Program.

9.2.4.3 Safety Strategy 2020

The forward direction for managing and improving the safety of employees, contractors and the community is outlined in the SA Power Networks *Safety Strategy 2020* which has three key objectives:

- **Keep our people safe and well:** targeted strategies for employees and contractors;
- **Empower leaders:** targeted strategies for capacity and capability; and
- **Continue to improve safety systems and culture**

The objectives and focus areas underpinning the *Safety Strategy 2020* are summarised in Figure 151.

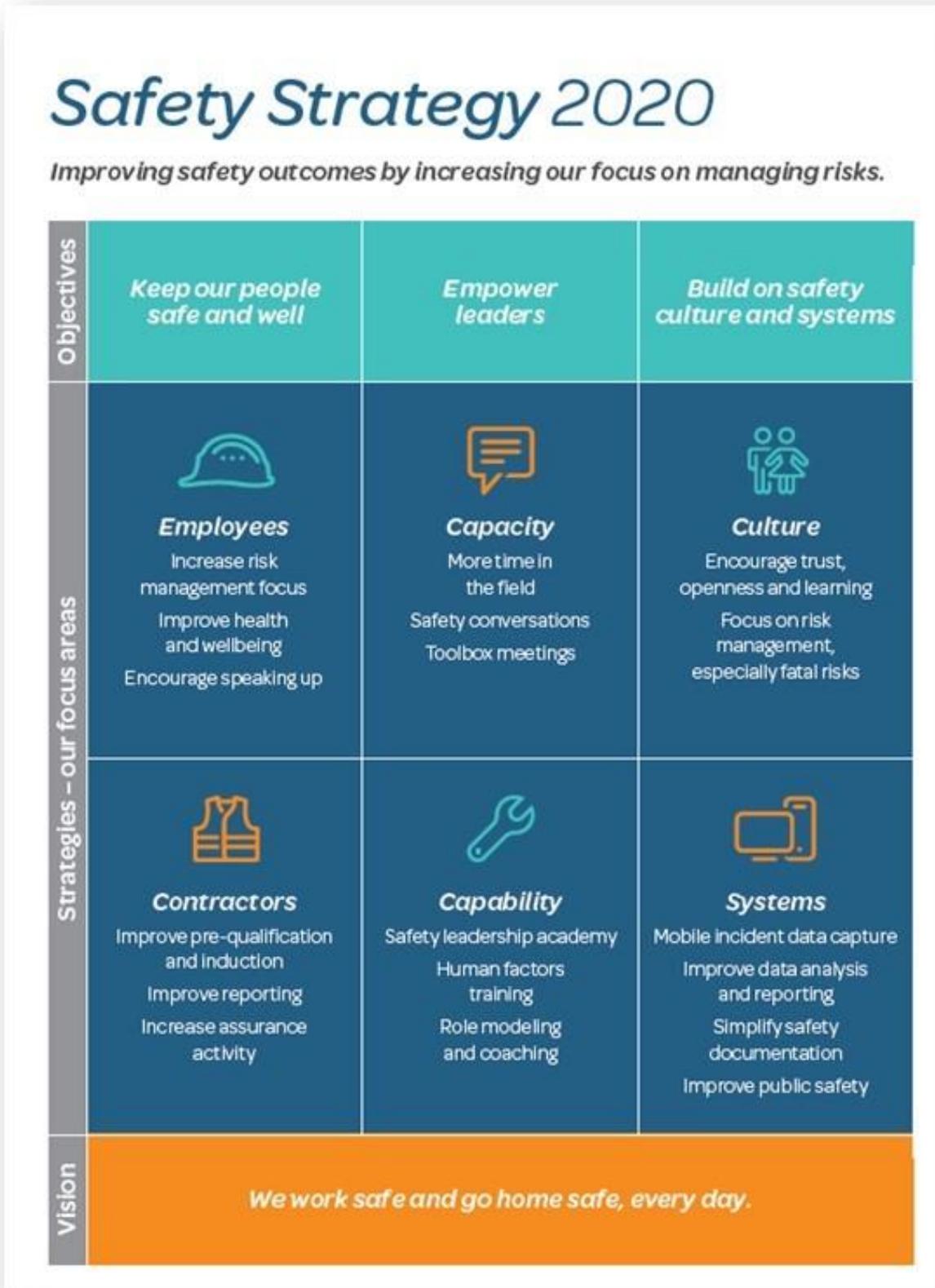


Figure 151: SA Power Networks Safety Strategy 2020

Safety values of teamwork, communication, ownership and management of risk are integral within the Safety Strategy 2020. Several key projects to support these focus areas are briefly described in Table 62.

Table 62: Planned Corporate Safety Programs 2018–2020

Operating programs of work	Benefits and outcomes
All systems	
<ul style="list-style-type: none"> • Safety Management System: Ongoing reviews and updates of processes and procedures as they relate to the safe design, operation and maintenance of the distribution network 	<ul style="list-style-type: none"> • Continue to provide a safe working environment and a safe network service
<ul style="list-style-type: none"> • Look up and live: Targeted community awareness campaign about working near overhead powerlines or excavating near underground assets 	<ul style="list-style-type: none"> • Heightened community awareness of the risks of working near overhead or underground powerlines to minimise potential safety risks from encroaching or contacting powerlines
<ul style="list-style-type: none"> • Switch-on: Safety leadership academy 	<ul style="list-style-type: none"> • Increase safety risk awareness of people leaders, reporting, role modelling, adoption of values and transforming conversations around safe work practices and culture
<ul style="list-style-type: none"> • Enablon: A new risk and incident management system 	<ul style="list-style-type: none"> • New software to enable access anywhere, anytime on any device providing real time visibility and reporting of incidents, other events and assurance activity
<ul style="list-style-type: none"> • Health hub rollout: Early treatment and wellness program for employees 	<ul style="list-style-type: none"> • Resources for the ongoing health and wellbeing of employees

For further details, refer to the SA Power Networks *Safety Strategy 2020*.

9.2.5 Safety capital works program

9.2.5.1 Introduction

Assets are sometimes replaced to ensure they do not pose safety risks to staff, contractors or the community irrespective of the asset condition, if aspects of design, access for operational and maintenance purposes, legislative requirements or current standards mean the asset poses an unacceptable safety risk. If operational measures do not effectively control risk, targeted capital expenditure is often required to control the risk, and/or replace or decommission the asset.

9.2.5.2 Safety Capital Investment Strategy

The strategy for capital investment to minimise safety risk exposure to staff, contractors and the community includes:

- identifying safety hazards;
- assessing the level of risk based on the Risk Management Framework;
- determining potential control measures;
- assessing the residual risk after potential control measures are implemented; and
- determining the most cost-effective solution or control measures that achieve an acceptable risk.

If other controls are not effective to adequately mitigate identified safety risks, targeted capital works programs install new network assets or replace existing network assets that:

- are no longer safe to operate and maintain;
- present a potential public safety risk; or
- can fail catastrophically and are unable to be condition monitored (e.g. instrument transformers).

The specific capital work programs under this strategy are shown in Table 63.

Table 63: Planned Safety Capital Works Programs

Capital programs of work	Benefits and outcomes
Substations	
<ul style="list-style-type: none"> • Substation lighting, security and fencing upgrades: Upgrades of substation lighting and security at sites susceptible to unauthorised access 	<ul style="list-style-type: none"> • Improves safety for staff undertaking works at night and upgraded fencing to minimise risk of unauthorised public access
<ul style="list-style-type: none"> • CBD 33kV substation migration to 11 kV: Phasing out of several 33kV substation assets that are expensive to maintain, do not meet current safety standards, cannot be operated safely while energised or contain asbestos materials in variable condition; to be replaced with modern 11kV equipment (where 11kV capacity is sufficient) 	<ul style="list-style-type: none"> • Replaces or phases out, in a planned cost-effective way, of several ageing 33kV substation assets; also remove confined space entry and improve access/egress to network infrastructure
<ul style="list-style-type: none"> • Protection and compliance: A targeted program to ensure that all protection scheme and fault clearing times will conform with the Network Protection Settings Standard and regulatory requirements 	<ul style="list-style-type: none"> • Ensures all energised high voltage (HV) equipment is protected should any element in the protection system fail to minimise public safety risk from potential bushfire starts or catastrophic HV plant failure due to network faults
<ul style="list-style-type: none"> • Network protection substation audits: An ongoing program to ensure critical protection systems are configured correctly on site and will therefore perform as designed for network high voltage faults 	<ul style="list-style-type: none"> • Minimises the risk of damage to the infrastructure and public safety risk from potential bushfire starts or catastrophic HV plant failure due to network faults
<ul style="list-style-type: none"> • Substation earth grid upgrades: Upgrades to existing ageing earth grid systems at substations identified for remedial works through condition monitoring and testing 	<ul style="list-style-type: none"> • Minimises the risk to human safety and equipment by ensuring adequate earthing systems are maintained
<ul style="list-style-type: none"> • Substation air break disconnect switch replacements: Replacement of switches that don't mechanically 'fail safe', in conjunction with other identified substation safety upgrades (e.g. earthing systems, security, protection relays) 	<ul style="list-style-type: none"> • Minimises the safety risks from potential catastrophic failures of these assets and ensures safe access during maintenance, repair, upgrade or network operation to isolate HV equipment at substations
<ul style="list-style-type: none"> • Instrument transformer upgrades: Replacements of specific makes/models of voltage and current transformers in substations which are unable to have their condition monitored and can fail catastrophically 	<ul style="list-style-type: none"> • Minimises the safety risks from potential catastrophic failures of these assets and ensures a safe and reliable operation of the network
<ul style="list-style-type: none"> • Substation bus pipework replacement program: Substation replacement program due to condition and unsafe design of these old, pipework bus switchyards 	<ul style="list-style-type: none"> • Upgrades substations to a safe, modern day equivalent compliant with current safety standards, with SCADA and metering, remote operation and protection
Distribution network	
<ul style="list-style-type: none"> • Elizabeth transformer stations: Continuation of a long-term program to manage transformers in the first underground network in South Australia; can no longer be maintained as switches are unsafe and present 	<ul style="list-style-type: none"> • Improves the assets to meet current safety standards and minimises the safety risk to staff operating and maintaining these assets through planned replacements

Capital programs of work	Benefits and outcomes
a risk to staff, and their operation has been banned	
<ul style="list-style-type: none"> • Distribution line clearance rectification: A targeted program of distribution line upgrades to ensure minimum overhead conductor clearances from ground level and other structures meet required clearance standards 	<ul style="list-style-type: none"> • Minimises safety risks from conductors near the ground or other structures
<ul style="list-style-type: none"> • CBD line upgrade program: In conjunction with the CBD 33kV substation upgrade program, phasing out several poor condition 33kV cable assets and providing 11kV feeders and loops, and replacing several cable joints to facilitate the transition 	<ul style="list-style-type: none"> • Minimises safety risks to public and staff from cable faults
<ul style="list-style-type: none"> • Ground level switchgear replacements: Targeted removal of switching cubicles which can no longer be operated safely 	<ul style="list-style-type: none"> • Minimises the safety risks to staff accessing switching devices that no longer have safe switching functionality for operations and maintenance purposes
<ul style="list-style-type: none"> • Distribution earthing: Renewal of distribution network earthing systems identified as faulty or missing 	<ul style="list-style-type: none"> • Minimises the risk to human safety and equipment by ensuring adequate earthing systems are maintained on distribution network assets
<ul style="list-style-type: none"> • CBD ducts and manholes: Remedial work of poor condition manholes, manhole covers and cable supports in manholes which deteriorate over time due to moisture ingress and subsidence; injury can result from failed cables causing an explosion or lifting of manhole lids; duct system in the CBD, used for below-ground cable installations, is also ageing with sections of the network nearing capacity with little or no room for future cables; many older ducts also contain asbestos in variable condition; when a cable fails the duct cannot be reused in most cases 	<ul style="list-style-type: none"> • Improves operator safety through improved access to network infrastructure in the CBD • Reduces risk to public safety in areas of high pedestrian traffic
Secondary systems	
<ul style="list-style-type: none"> • Mobile radio network upgrade: Ongoing terminal replacements in field vehicles and the Network Operations Centre for voice communication between the centre and field staff accessing the South Australian Government Radio Network 	<ul style="list-style-type: none"> • Ensures continued safe and reliable communication through access to the SA Government Radio Network without reliance on third party infrastructure (e.g. mobile telephone service providers)
<ul style="list-style-type: none"> • Telecommunication structure upgrades: Renewal/refurbishment of poles, towers and other structures identified as being in poor condition and presenting a safety risk to the public 	<ul style="list-style-type: none"> • Ensures continued safe and reliable communication infrastructure through works to extend the life of the assets where cost-effective

For further information on these programs, refer to the relevant asset plans.

9.3 Environment

9.3.1 Introduction

This section outlines the environmental strategies applied to managing power network assets and the processes applied for identifying operating and capital investment plans focused on environmental management that support the asset management objectives and levels of service. For further information, refer to the suite of environmental asset plans.

Environmental management summary

SA Power Networks is committed to conducting its electricity distribution operations and business activities in a manner that prevents or minimises pollution and other adverse impacts on the environment. Some electricity network assets contain materials defined as pollutants under legislation — an environmental risk that needs to be appropriately managed. SA Power Networks is also required to comply with certain legislative obligations and regulations.

The environmental strategy covers a range of activities to minimise environmental risks and achieve the key objectives of:

- protecting the environment;
- enhancing relationships with shareholders and the community; and
- reducing the risk of litigation related to environmental incidents.

SA Power Networks maintains an environmental management system in line with AS/NZ ISO 14001:2016 Environmental Management Systems that provides employees and contractors with the skills, knowledge and resources to protect and improve the environment. In addition, the Environment Policy, Climate Change Policy and Environmental Management Plan provide direction for minimising environmental risks throughout asset life cycles.

The environmental management operating and capital investment ensures existing performance can be maintained and that sites assessed as having unacceptably high environmental risks can be targeted for capital investment.

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graph TD
    AP[Asset Planning] --> ACA[Asset Creation/Acquisition]
    ACA --> AO[Asset Operations]
    AO --> ACM[Asset Condition and Performance Monitoring]
    ACM --> AM[Asset Maintenance]
    AM --> AR[Asset Renewal/Replacement]
    AR --> AD[Asset Disposal]
    AD --> AP
    
```

9.3.2 Environmental asset management objectives

Asset management objectives specific to environmental management programs are summarised in Table 64.

Table 64: Environmental asset management objectives

Level of service category	Environmental asset management objectives
Environment	<ul style="list-style-type: none"> Minimise the environmental risk of existing network assets through developed policies and procedures captured under the environmental management system. Minimise the environmental impact of new assets throughout their life cycle Comply with environmental and other related legislation administered by the South Australian Environment Protection Authority (EPA), and other state and federal government regulators.
Efficiency	<ul style="list-style-type: none"> Minimise the life-cycle costs of capital works aimed at managing environmental risks across the distribution network including the cost of asset installation, operations, maintenance, replacement and disposal. Minimise waste generation through reuse and recycling of materials where possible.

9.3.3 Legislative requirements

The legislative obligations for environmental management of SA Power Networks as a distribution networks service provider include:

- a general environmental duty under section 25 of the South Australian *Environment Protection Act 1993* to prevent or minimise environmental harm arising from the operation or maintenance of network assets;
- a requirement under the *Environment Protection (Noise) Policy 2007* to manage the maximum allowable continuous noise levels allowed from network assets;
- a requirement under the *Environment Protection (Water Quality) Policy 2015* to manage the risks of potential pollution of surface water, marine water and groundwater arising from network operations;
- a requirement under the *Environment Protection (Air Quality) Policy 2016* to manage the risks of air pollutant emissions arising from network operations;
- a requirement under the *National Greenhouse Energy Reporting Act 2007* (Cwth) for recording and reporting on greenhouse gas emissions from the operation or maintenance of network assets as part of the National Greenhouse Energy Reporting Scheme;
- a requirement under the *Native Vegetation Act 1991* and *Aboriginal Heritage Act 1988* to minimise the impact of network assets and operation on native vegetation and sites of cultural significance; and
- a requirement under the *Environment Protection and Biodiversity Conservation Act 1999* (Cwth) to provide for the protection of the environment, especially for locations of national environmental significance.

9.3.4 Environmental management

9.3.4.1 Introduction

SA Power Networks is committed to conducting its electricity distribution operations and business activities in a manner that prevents or minimises pollution and other adverse impacts on the environment. Some electricity network assets contain materials defined as pollutants under legislation. The environmental risks they present need to be appropriately managed.

The environmental issues covering pollutants, processes and systems of relevance to the network assets are shown in Figure 152. The pollutants of most significance to the network are shaded in grey.

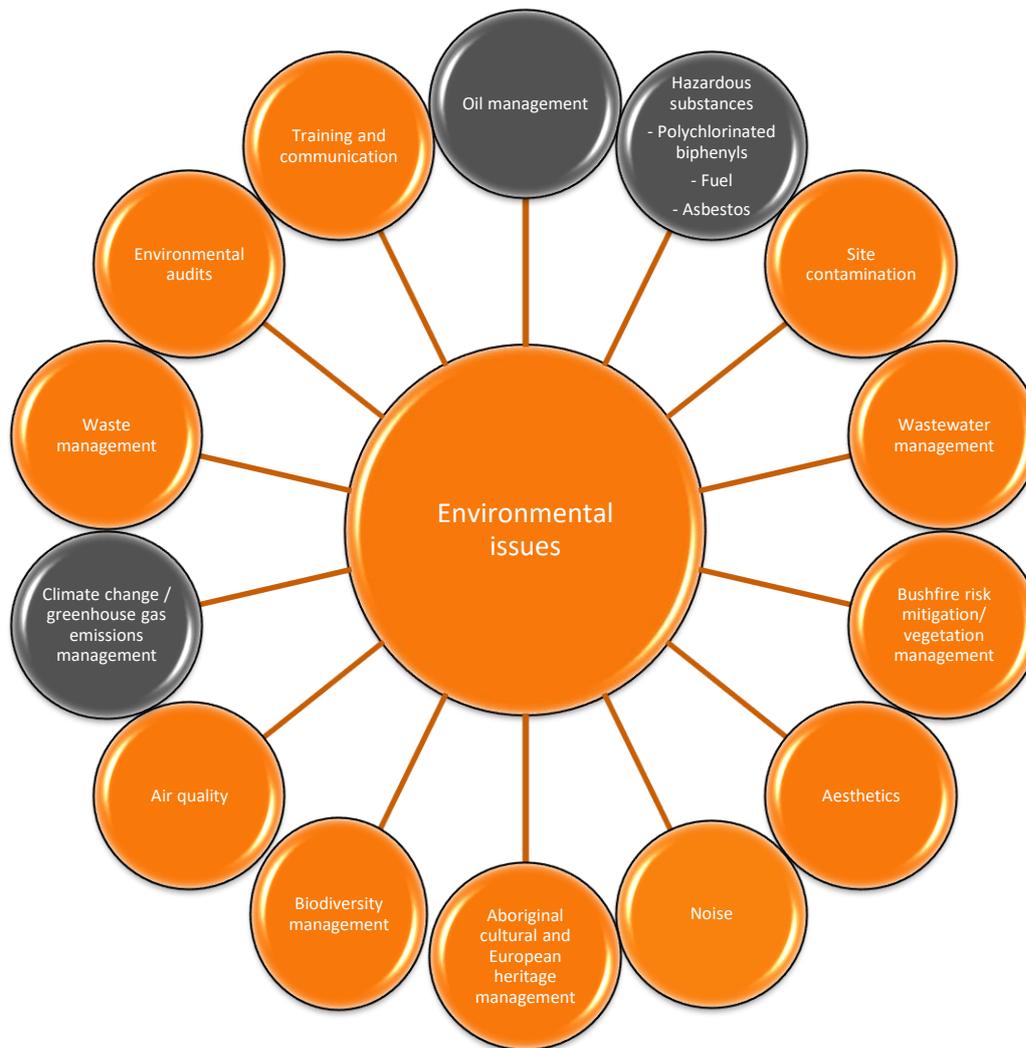


Figure 152: SA Power Networks – environmental issues across the network

The pollutants of most significance arising from the network assets can be described as follows:

- Oil:** Assets including oil filled cables, substation power transformers, distribution transformers, regulators and capacitors can contain oil used as insulation, and to cool equipment that may operate at high temperatures for extended periods. When these assets fail, the oil could enter stormwater, watercourses, groundwater and/or soil. Some oil-containing assets could also contain polychlorinated biphenyl (PCB), an environmental pollutant and probable human carcinogen, added to oil insulated equipment for its fire suppressing properties.
- Hazardous substances:** Operating oil-filled and other power assets requires prudent management of several hazardous chemicals and substances, including PCB, mercury, perchloroethylene, and asbestos. Such management is regulated by state and federal government agencies.
- Greenhouse gas emissions management:** Primarily the very potent greenhouse gas sulphur hexafluoride gas (SF_6), which is used as an insulator (because it is stable and inert) in network and substation gas-insulated switchgear including switching cubicles, overhead switchgear, circuit breakers and substation switchboards. Further, on exposure to electrical arcing or flames, SF_6 decomposes to other compounds including sulphur dioxide (SO_2) and hydrofluoric acid (HF) both of which are toxic and hazardous.

The SA Power Networks environmental strategy covers a range of activities to minimise environmental risks and achieve the key objectives of:

- protecting the environment;
- enhancing relationships with shareholders and the community; and
- reducing the risk of litigation, related to environmental incidents, for SA Power Networks Board and personnel.

9.3.4.2 Environmental Management Strategy

The Environmental Management Strategy can be summarised as follows:

- **Develop and maintain an environmental management system:** This coordinated approach for managing environmental issues across the organisation includes, among others:
 - SA Power Networks' Environmental Policy — overarching principles of environmental management across SA Power Networks;
 - SA Power Networks' Climate Change Policy — direction to SA Power Networks on the commitment to reduce the effects of the operations and assets on climate change, and to manage the impacts of climate change on network operations;
 - Environmental Management Plan — annually approved environmental direction for managing the key issues associated with the network assets including:
 - climate change and environmental sustainability initiatives,
 - Aboriginal cultural heritage management,
 - biodiversity and native vegetation management,
 - management of oil filled assets — substation audits,
 - in-house environment advisory services,
 - site (land) contamination, and
 - environmental incident response;
 - compliance with environmental licences for the Kangaroo Island power station through monitoring to ensure that facilities and functions are managed in accordance with licence conditions;
 - development and maintenance of directives and procedures aimed at minimising environmental risks;
 - environmental incident response: use of the SA Power Networks Incident Management System (Enablon) to capture records of incidents that cause, or have potential to cause, environmental harm including details of the incident and subsequent remedial actions; and
 - active maintenance of an environmental management system encompassing all of the above that ensures the organisation meets legislative requirements, manages environmental issues, and protects employees, the community and the environment.
- **Minimise environmental impacts across the asset life cycle:** The environmental risks of network assets are considered throughout all stages of the asset life cycle from asset planning through to disposal (see Figure 43). This includes avoiding unnecessary disturbance to cultural and natural sites of significance.
- **Education and awareness:** An attitude of care and responsibility and a sense of stewardship for the environment by employees and contractors, is promoted through environmental education and training.

Specific works under this strategy are listed in Table 65.

Table 65: Environmental works programs

Operating programs of work	Benefits and outcomes
All systems	
<ul style="list-style-type: none"> • Environmental management system: Maintain the environmental policies and procedures in the environmental management system to ensure they are applied to managing the environmental risks associated with the network assets 	<ul style="list-style-type: none"> • Minimises environmental risks arising from network assets and operations • Increases employee and contractor awareness of environmental risks and legislated requirements • Increases customer and stakeholder confidence in providing an environmentally sustainable service
<ul style="list-style-type: none"> • PCB management: In line with the EPA approved National PCB Management Plan, SA Power Networks identifies, removes and treats for disposal any PCB contaminated material in its electrical assets 	<ul style="list-style-type: none"> • Manages any PCB still in service responsibly to minimise the potential for release to the environment • Continues to identify, remove and treat for disposal, PCB contaminated material in accordance with the National PCB Management Plan
<ul style="list-style-type: none"> • Fuel management: Manage the handling, use, storage and disposal of fuel for mobile plant and power generation plant 	<ul style="list-style-type: none"> • Minimises environment risks arising from potential fuel spills
<ul style="list-style-type: none"> • Asbestos: Handle, remove and dispose of asbestos contaminated material in an appropriate manner as required under the Environment Protection Act Remove through a variety of capital works projects primarily within the safety category of expenditure 	<ul style="list-style-type: none"> • Minimises the potential for release of asbestos into the environment
<ul style="list-style-type: none"> • Site contamination: Manage the environmental contamination impacts of historical and current operations and land divestment, mainly associated with land holdings for substations and transformer stations, as required under the Environment Protection Act and <i>National Environment Protection (Assessment of Site Contamination) Measure 2013</i> 	<ul style="list-style-type: none"> • Minimises environmental risks from site contamination arising from current or past network operations • Ensures no long-term liabilities for SA Power Networks from the sale or purchase of properties holding network assets
<ul style="list-style-type: none"> • Wastewater management: Manage wastewater produced from asset wash down activities, service pits and generating plant cooling system maintenance as required under the and Environment Protection (Water Quality) Policy 	<ul style="list-style-type: none"> • Minimises environmental risks from wastewater arising from network assets and operations
<ul style="list-style-type: none"> • Native and non-native vegetation management: Manage vegetation near powerlines (Section 9) and other power assets in accordance with the Native Vegetation Act and <i>Native Vegetation Regulations 2017</i> 	<ul style="list-style-type: none"> • Minimises the risk of damaging or destroying protected native vegetation as the result of the construction, maintenance and operation of power assets

Operating programs of work	Benefits and outcomes
All systems	
<ul style="list-style-type: none"> • Aesthetics: Undergrounding of distribution networks as part of new real estate developments and a targeted program of undergrounding existing overhead powerlines through the Power Line Environment Committee program (Section 9.6) 	<ul style="list-style-type: none"> • Minimises the visual impact of assets on the surrounding environment
<ul style="list-style-type: none"> • Noise: Manage noise emissions from network assets, primarily from power transformers in urban substations, in accordance with Environment Protection Act and Environment Protection (Noise) Policy 	<ul style="list-style-type: none"> • Ensures compliance at sites likely to be the subject of noise related complaints from nearby residents
<ul style="list-style-type: none"> • Aboriginal cultural and European heritage management: Manage natural and cultural heritage resources during the designing, planning construction, operation and maintenance of network assets as required under Aboriginal Heritage Act and <i>Heritage Places Act 1993</i>, and Environment Protection and Biodiversity Conservation Act 	<ul style="list-style-type: none"> • Minimises the impact on sites of natural and cultural significance from construction, maintenance and operation of power assets
<ul style="list-style-type: none"> • Biodiversity management: Manage flora and fauna in accordance with state and federal legislation and regulations 	<ul style="list-style-type: none"> • Minimises the impact on biodiversity from construction, maintenance and operation of power assets
<ul style="list-style-type: none"> • Air quality: Manage air pollutant emissions from network assets, primarily from power generating plant, as required under the Environment Protection Act and Environment Protection (Air Quality) Policy 	<ul style="list-style-type: none"> • Minimises environmental risks from power generating emissions • Ensures licence compliance for the Kangaroo Island standby power generation plant including required reporting under the National Pollutant Inventory
<ul style="list-style-type: none"> • Climate change and greenhouse gas emissions management: Monitor and report on direct and indirect emissions from the network assets through the National Greenhouse Energy Reporting Scheme 	<ul style="list-style-type: none"> • Ensures legislative compliance under the National Greenhouse Energy Reporting Act • Reduces the effects of network operations and assets on climate change, and manages the impacts of climate change on network operations
<ul style="list-style-type: none"> • Waste management: Manage various waste materials from managing network assets including hazardous waste, oils, scrap metals, poles, plastics, porcelain, and other solid and liquid wastes as required under the Environment Protection Act and <i>Environment Protection (Waste to Resources) Policy 2010</i> 	<ul style="list-style-type: none"> • Minimises waste generation and maximises recycled materials from network operations
<ul style="list-style-type: none"> • Environmental audits: Periodic, objective, documented and systematic way of checking environmental performance with respect to policy, legislation, and environmental risk 	<ul style="list-style-type: none"> • Ensures staff and contractors are aware of, and are adhering to, environmental policies and procedures to manage environmental risks

Operating programs of work	Benefits and outcomes
All systems	
<ul style="list-style-type: none"> • Training and communication: Providing environment training modules and in-house advisory services to meet the changing legislative requirements placed on the management of its assets and advice and guidance on emerging environmental issues 	<ul style="list-style-type: none"> • Increases employee and contractor awareness of environmental risks • Demonstrates promotion of enforced compliance with legislative requirements

Capital programs of work	Benefits and outcomes
Substations	
<ul style="list-style-type: none"> • Substation oil containment: Continue works to install oil containment infrastructure at high and medium risk substation sites containing oil filled equipment 	<ul style="list-style-type: none"> • Minimises the environmental risk from discharge of oil to stormwater and watercourses, and impact to groundwater from power transformers at substation sites
<ul style="list-style-type: none"> • Substation noise control: Program to install noise attenuation infrastructure in response to customer complaints and where EPA noise levels are not met 	<ul style="list-style-type: none"> • Ensures noise emissions from substation locations near customers do not exceed EPA guidelines
Distribution network	
<ul style="list-style-type: none"> • Distribution network oil and fuel containment: Continue works to address distribution network assets at locations with high risk of environmental impacts (mainly ageing assets containing oil, gas or fuel located near waterways) by installing containment systems (bunds, sumps) at identified high risk locations 	<ul style="list-style-type: none"> • Minimises the environmental risk from discharge of oil to stormwater and watercourses from power transformers at substation sites

For further information on these programs, refer to the relevant asset plans.

9.4 Reliability and resilience – improve resilience

9.4.1 Introduction

This section outlines the reliability and resilience strategies applied to managing power network assets, the process for forecasting the expenditure, and the programs of work that support the reliability objectives and levels of service. For further information, refer to the reliability and resilience performance management strategy.

Reliability and resilience summary

Reliability and resilience is focused on ‘keeping the lights on for South Australians’ with a continuous and reliable supply of electricity for residential customers reliant on electricity for basic everyday needs and business customers reliant on electricity for providing goods and services. During the SA Power directions workshops of 2017, reliability emerged as the highest priority for customers. Reliability standards should not be lowered, and customers supported hardening the network against major storms and ensuring acceptable levels of reliability for all customers.

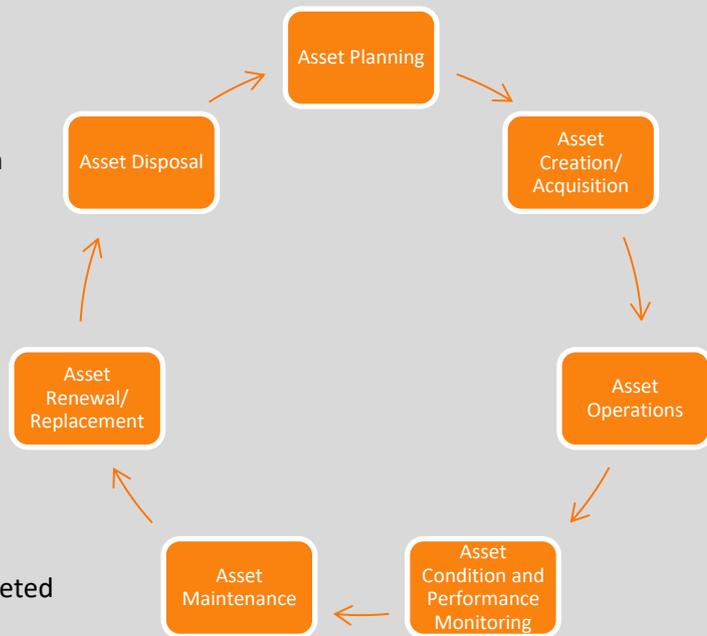
The reliability and resilience programs of targeted work include actions that:

- **prevent** interruptions from occurring;
- **minimise** the number of customers impacted when an interruption does occur; and
- **restore** supply to customers as soon as possible in the safest and most efficient way.

SA Power Networks has one of the most reliable distribution networks in Australia. It consistently benchmarks well against other distribution network service providers in the National Electricity Market through a prudent and efficient targeted reliability strategy.

The SA Power Networks Reliability and Resilience Performance Management Strategy (RRPMS) describes the current strategy for managing network reliability performance. The RRPMS has been developed with the objective of establishing a clear overarching strategy to maintain compliance with the required reliability levels of service set by ESCoSA and address the identified high priority electricity consumer needs for maintaining reliability performance in the most prudent and cost-efficient manner.

Reliability and resilience projects generally target the most cost efficient problematic parts of the network (e.g. where customer benefits exceed costs) to enable the Essential Services Commission of South Australia (ESCoSA) average service standards to be achieved. Targeted reliability investment is prioritised on works that provide the greatest benefit to customers. With the Bureau of Meteorology predicting future increases in severe weather events, this is likely to further impact network performance observed by customers who support increased investment in reliability and resilience programs, particularly for the regional and worst served customers.



9.4.3 Reliability and resilience asset management objectives

The asset management objectives specific to reliability and resilience programs are summarised in Table 66.

Table 66: Reliability and resilience asset management objectives

Level of service category	Reliability and resilience asset management objectives
Safety	<ul style="list-style-type: none"> Minimise the number of switching incidents during the restoration of unplanned or planned interruptions to supply.
Customer experience	<ul style="list-style-type: none"> Meet customer expectations with a reliable service, and timely and accurate information during planned or unplanned outages.
Reliability and resilience	<ul style="list-style-type: none"> Meet ‘best endeavours’ reliability performance standards as defined in the South Australian Electricity Distribution Code. Target improvements in reliability performance on current ESCoSA low reliability distribution feeder customers (only where customer benefits exceed costs or to manage a specific and repeated ongoing customer issue where cost effective and prudent).
Communication and information	<ul style="list-style-type: none"> Provide accurate information on restoration times for unplanned outages. Provide accurate advanced notice of any planned targeted reliability capital works projects involving outages.
Efficiency	<ul style="list-style-type: none"> Outperform forecast guaranteed service level payment costs across each regulatory period. Achieve an overall neutral or better Service Performance Scheme result across each regulatory period.

9.4.4 Legislative requirements

The legislative obligations for SA Power Networks as a distribution network service provider for reliability include:

- system security and performance standards (National Electricity Rules (NER) chapters 4 and 5);
- the Service Target Performance Incentive Scheme (STPIS) (NER clause 6.6.2);
- demonstrated engagement with electricity consumers and addressing relevant concerns identified through the engagement (NER Clause 6.8.2 (c1) (2)); and
- Essential Services Commission of South Australia (ESCoSA) Jurisdictional Service Standards (the South Australian Electricity Distribution Code).

The NER outlines the rules, and ESCoSA service standards are quantitative ‘best endeavours’ measures against which the performance of SA Power Networks is measured. The STPIS incentivises SA Power Networks to improve or maintain performance for the benefit but not at the expense of customers.

In addition, SA Power Networks also has an obligation under the above legislation to manage the risks associated with current and forecast weather trends in South Australia as identified in the Bureau of Meteorology’s report “Climate extremes analysis update for South Australian Power Network operations” published July 2018 which predicts future increases in severe weather events which is likely to further impact network performance.

9.4.5 Service Standard Framework

The Service Standard Framework (SSF) prescribes network reliability targets and customer service responsiveness targets in South Australia. The current SSF for SA Power Networks comprises three interrelated elements:

- average reliability and customer service standards and targets (set by ESCoSA);
- a symmetrical financial incentive scheme that provides rewards/penalties to SA Power Networks for achievement against reliability and customer service targets (set by the Australian Energy Regulator, AER); and

- a Guaranteed Service Level Scheme (GSL Scheme) that provides payments to customers receiving service levels below pre-determined threshold levels within any single year (set by ESCoSA).

Since mid-2017, SA Power Networks has worked closely with ESCoSA on its SSF 2020–2025 review. ESCoSA was involved with SA Power Networks in early customer engagement, which was used as inputs to ESCoSA’s study into the reliability of electricity in South Australia. The outcomes of the study will inform ESCoSA’s determinations on the reliability performance expected of the distribution network from 1 July 2020 (see Section 4.9.3).

9.4.5.1 ESCoSA Service Standards

ESCoSA is the independent regulatory body that determines electricity reliability and service standards (targets) in South Australia. The average annual reliability of the distribution network is measured by the frequency and duration of unplanned interruptions using system average interruption duration index (SAIDI) and system average interruption frequency index (SAIFI) targets. These targets exclude the impacts of major event days (MEDs) but include effects of other severe weather (that does not meet the MED classification threshold).

The reliability service standards are set to reflect differences in the levels of interconnection and redundancy across the distribution network. From July 2015, SA Power Networks’ feeders were divided into four broad categories for the purposes of monitoring network reliability as shown in Table 67. A feeder, for these purposes, is defined as a high voltage (HV) conductor or cable and associated equipment which the distributor uses to distribute electricity.

Table 67: SA Power Networks’ feeder categories

Feeder	Definition
CBD feeder	A feeder supplying predominantly commercial, high-rise buildings, through a predominantly underground distribution network containing significant interconnection and redundancy when compared to urban areas
Urban feeder	A feeder, which is not a CBD feeder, with actual maximum demand over the reporting period per total feeder length greater than 0.3MVA/km
Short rural feeder	A feeder, which is not a CBD or urban feeder, with a total feeder length less than 200km; may include feeders in urban areas with low load densities
Long rural feeder	A feeder, which is not a CBD or urban feeder, with a total feeder length greater than 200km

SA Power Networks must use its best endeavours to meet the service standards set by ESCoSA. The standards are annual targets, but quarterly performance updates are provided to and published by ESCoSA on its website. SA Power Networks’ end of year performance results are also reported in full in the Energy Networks’ Regulatory Performance Report published annually by ESCoSA. The current regulatory period performance of the feeder category reliability standards is shown in Table 68.

Table 68: ESCoSA 2015–2020 supply restoration and reliability standards vs actual performance¹⁰

Feeder category	2015–2020 ESCoSA target		2015–16 Actual		2016–17 Actual		2017–18 Actual	
	USAIDI _n	USAIFI _n	USAIDI _n	USAIFI _n	USAIDI _n	USAIFI _n	USAIDI _n	USAIFI _n
CBD feeder	15	0.15	2	0.02	16*	0.11	43	0.41
Urban feeder	120	1.30	98	1.04	111	1.12	96	1.06
Short rural feeder	220	1.85	175	1.48	230*	1.71	155	1.20
Long rural feeder	300	1.95	289	1.70	264	1.43	269	1.48
Implied state-wide	165	1.50	139	1.20	151	1.24	132	1.142

* SA Power Networks assessed by ESCoSA as having used best endeavours in attempting to meet targets ('best endeavours' means to act in good faith and use all reasonable efforts, skill and resources)

Table 68 shows that SA Power Networks has met the ESCoSA reliability service standards in the current regulatory period. However, the 2016–2017 SAIDI actual result for the CBD was marginally above target and the 2017–2018 SAIDI performance for the CBD was well above the reliability target primarily due to several 11kV underground cable faults (see Section 8.2.9.1).

Figure 153 shows the proportion of causes contributing towards SAIDI performance. Note this includes the contribution of planned interruptions experienced by customers in addition to the unplanned SAIDI causes but excludes MEDs.

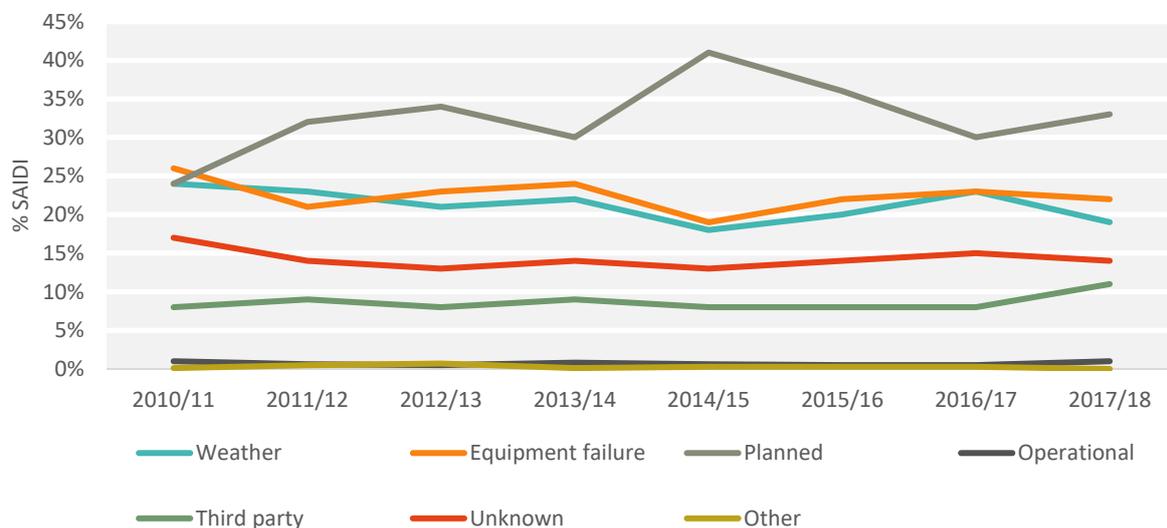
**Figure 153: SAIDI cause contribution (excluding MEDs) (2010/11 to 2017/18)**

Figure 150 shows that equipment failure (primarily an increase in cable faults) and weather contributions to SAIDI across 2014–2015 and 2015–2016 corresponded with an increase in interruption duration experienced by customers; conversely the contribution of weather related causes in 2017–2018 also corresponded with a reduction in interruption duration experienced by customers.

¹⁰ Reliability targets exclude SA Power Networks' performance during severe or abnormal weather events through the application of the Institute of Electrical and Electronic Engineers MED exclusion methodology. This approach allows the impact of MEDs to be studied separately from SA Power Networks' daily operations, and in the process, to better reveal trends in daily operation that would be hidden by the large statistical effect of major events.

The South Australian Electricity Distribution Code (Essential Services Commission of South Australia, 2015) and the Energy Networks’ regulatory performance report for 2016-2017 (Essential Services Commission of South Australia, 2017) have further information on regulatory targets and performance against the regulatory targets.

9.4.5.2 Service Target Performance Incentive Scheme

SA Power Networks is required to operate within a national STPIS in accordance with NER. The STPIS is referred to interchangeably with the Service Performance Scheme. The STPIS is a component of the AER’s revenue determination for SA Power Networks. The revenue at risk under the scheme is +/- 5% and therefore caps the potential rewards and penalties for SA Power Networks under the STPIS.

The two key targets set by the AER under the STPIS scheme are:

- a reliability target based on SAIDI and SAIFI for each feeder category; and
- a call centre target.

For the reliability target, the STPIS excludes interruptions associated with:

- planned interruptions;
- interruptions of less than one minute;
- interruptions during MEDs; and
- upstream generation or transmission line interruptions.

The STPIS applies a monetary penalty rate for every unplanned outage on the distribution network for both an interruption occurring and the duration of that interruption. Incentive rates are calculated by reference to the value that customers place on supply reliability or an amount of money that the customer would be willing to pay to have avoided that interruption (termed the value of customer reliability), along with other parameters such as consumer price index, energy consumption and annual revenue.

The AER sets the revenue at risk for each regulatory period. For the 2015–2020 period this figure is capped at $\pm 5\%$ of the total annual regulatory revenue. A neutral STPIS result for any given regulatory year would mean the annual performance across the network was equal to the average performance of a preceding five-year target setting period (e.g. in line with the average 2009–2010 to 2013–2014 performance). Any departure from the STPIS reliability targets will result in a reward or penalty to SA Power Networks through a distribution revenue adjustment. The intent of the STPIS is therefore to provide SA Power Networks with a financial incentive to maintain or improve reliability performance to customers.

Table 69 shows the applied (and simplified) 2017–2018 STPIS rates applied to each unplanned interruption on the distribution network to determine the STPIS impact of an interruption. These rates are adjusted annually as they consider the annual regulatory revenue adjusted for CPI and the number of customers supplied.

Table 69: SA Power Networks 2017–2018 STPIS rates

Feeder	SAIDI cost/customer/minute	SAIFI cost/customer
CBD feeder	\$4.77	\$406
Urban feeder	\$0.49	\$45
Short rural feeder	\$0.46	\$60
Long rural feeder	\$0.42	\$71

Each year, SA Power Networks determines the projected STPIS performance (ie annual dollar budget) to maintain the average historical levels of reliability based on the preceding target setting period (ie 2009–2010 to 2013–2014) and the forecast annual revenue. The projected STPIS target is based on:

- calculation of each calendar month revenue contribution (%) based on the respective incentive rates and previous five years' average monthly reliability performance;
- multiplying the five-year average monthly revenue contribution (%) by the forecast annual revenue (\$); and
- calculating the STPIS penalty/reward operating bands through applying the $\pm 5\%$ of the total annual AERs regulatory revenue at risk either side of the STPIS target trendline.

The slight difference between the ESCOSA and AER STPIS targets as shown in Table 70 is due to a change in the calculation of the MED exclusions method applied in setting SA Power Networks performance targets for the STPIS.

Table 70: Comparison of ESCOSA and STPIS SAIDI/SAIFI targets

Feeder	2015-2020 ESCoSA target		2015–2020 STPIS target	
	USAIDI _n	USAIFI _n	USAIDI _n	USAIFI _n
CBD feeder	15	0.15	12.5	0.132
Urban feeder	120	1.30	121.5	1.353
Short rural feeder	220	1.85	231.1	1.930
Long rural feeder	300	1.95	311.7	2.027
Implied state-wide	165	1.50	167.9	1.539

Table 70 shows that, in general, if ESCOSA targets are achieved, STPIS targets are also achieved (apart from possibly CBD). It is important to note that these reliability targets are fixed across the regulatory period whereas the STPIS rates change due to annual variations in annual regulatory revenue and number of customers supplied.

9.4.5.3 ESCoSA Guaranteed Service Level Scheme

The GSL Scheme provides payments to customers receiving a service below pre-determined threshold levels set by ESCoSA. GSL payments are made:

- for interruptions to electricity supply including those during MEDs;
- for late attendance at an appointment;
- for delays in providing a new connection; and
- where customers report street light outages that are not fixed in a timely manner (for street lights owned by SA Power Networks).

The GSL scheme excludes payments because of:

- interruptions caused by transmission and generation failures;
- disconnections required in an emergency (e.g. bushfire);
- single customer faults caused by that customer;
- interruptions of a duration less than one minute;
- planned interruptions; and
- events beyond the control of SA Power Networks (e.g. bushfire, storm, flooding and it is unsafe to restore supply).

The GSL rates applicable to the frequency and duration of interruptions are shown in Table 71 and Table 72 respectively.

Table 71: GSL thresholds and payment amounts 2015–2020 — frequency of interruptions

	Threshold 1	Threshold 2	Threshold 3
Number of interruptions in a regulatory year ending 30 June	>9 and ≤12	>12 and ≤15	>15
Payment	\$100	\$150	\$200

Table 72: GSL thresholds and payment amounts 2015–2020 — duration of interruptions

	Threshold 1	Threshold 2	Threshold 3	Threshold 4	Threshold 5
Duration of an interruption (hrs)	>12 and ≤15	>15 and ≤18	>18 and ≤24	>24 and ≤48	>48
Payment	\$100	\$150	\$200	\$405	\$605

The more frequent or longer the duration of interruptions, the higher the GSL payment. The SA Power Network’s GSL annual payment regulatory allowance is included in the AER’s revenue determination and is based on the GSL payments made in the revealed year before the regulatory submission.

GSL payments do not provide compensation for individual loss or damage that a customer might suffer. SA Power Networks’ administers its separate customer compensation scheme for any damage or losses resulting from an incident associated with SA Power Networks’ electricity distribution network.

The majority of GSL reliability payment amounts are duration payments as shown in Figure 154.

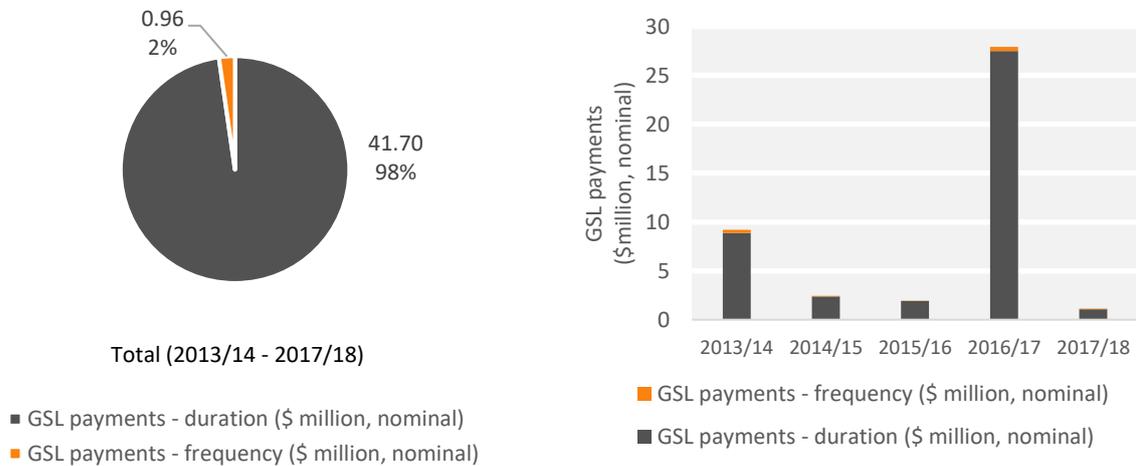


Figure 154: SA Power Networks amount of GSL payments – 2013/14 to 2017/18 performance

Figure 154 shows that duration GSL payment amounts dwarf the frequency payment amounts and shows a significant increase in the GSL payment amounts for duration in 2016-2017, largely due to nine MEDs compared to a typical range of three to four MEDs per annum with zero MEDs in 2017-2018.

The majority of GSL reliability payments are related to duration of interruptions as shown in Figure 155.

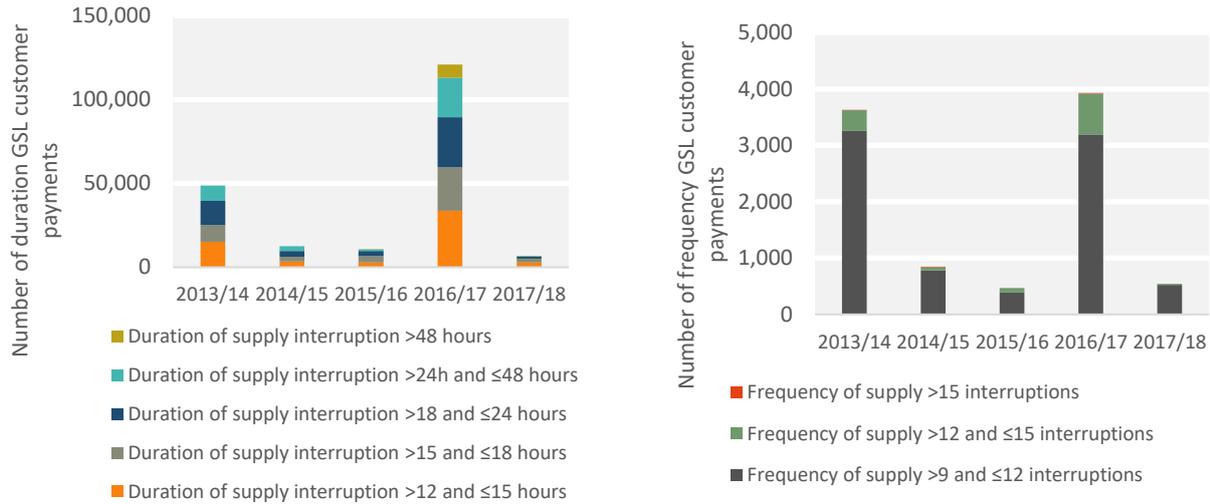


Figure 155: SA Power Networks number of GSL payments – 2013/14 to 2017/18 performance

Figure 155 shows that the number of duration GSL payments also dwarf the number frequency payments and shows and like the GSL payment amounts in Figure 154 is strongly linked to MEDs. These MEDs accounted for more than 90% of the duration payments made during the 2016-2017 regulatory year. This is likely driving customer support for hardening of the network (see Section 4.5) due to the large number of customers impacted by prolonged durations.

The impact of MEDs on customer GSL duration payments is shown in Figure 156.

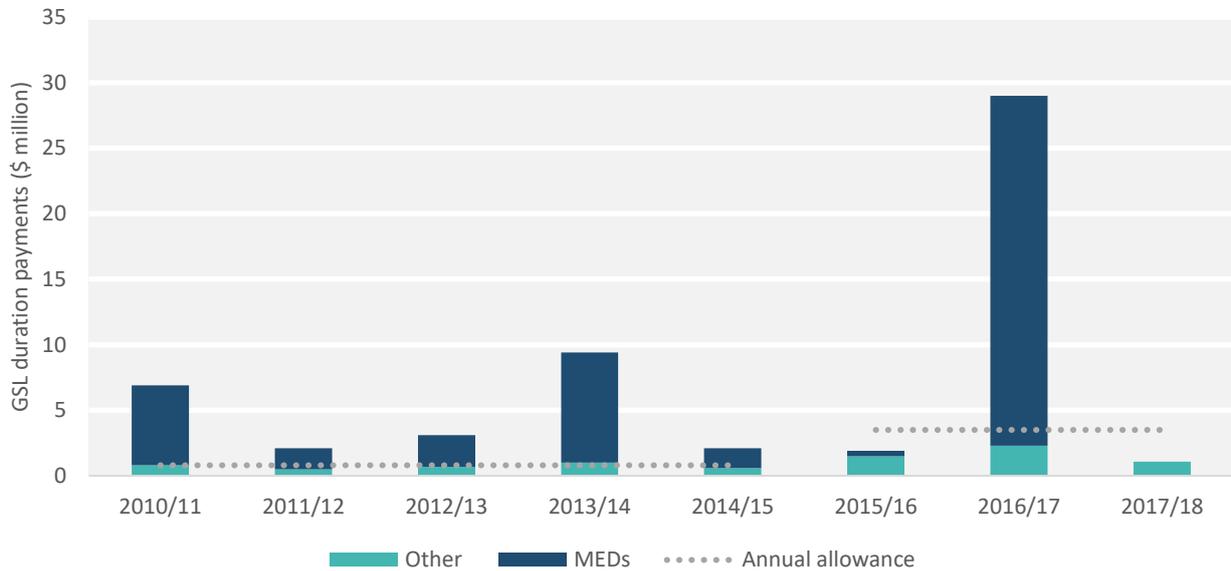


Figure 156: GSL duration payments to customers (2010/11-2017/18)

Figure 156 shows that because of severe weather events, customers are experiencing longer duration interruptions resulting in an escalation of the GSL duration payment to customers, the cost of which in the long term is borne by all South Australian electricity customers.

The South Australian Electricity Distribution Code (Essential Services Commission of South Australia, 2015) has further information on the current GSL scheme.

9.4.6 Overall network performance

The reliability levels of service (see Section 4.9.3) exclude the impact of MEDs and the overall reliability performance of the network as observed by customers and stakeholders. SA Power Networks has observed a marked deterioration in performance of the network during MEDs since 2010 although it is highly variable. The increasing trend and significance of MEDs on duration of supply interruptions experienced by customers compared to the underlying SAIDI performance is shown in Figure 157.

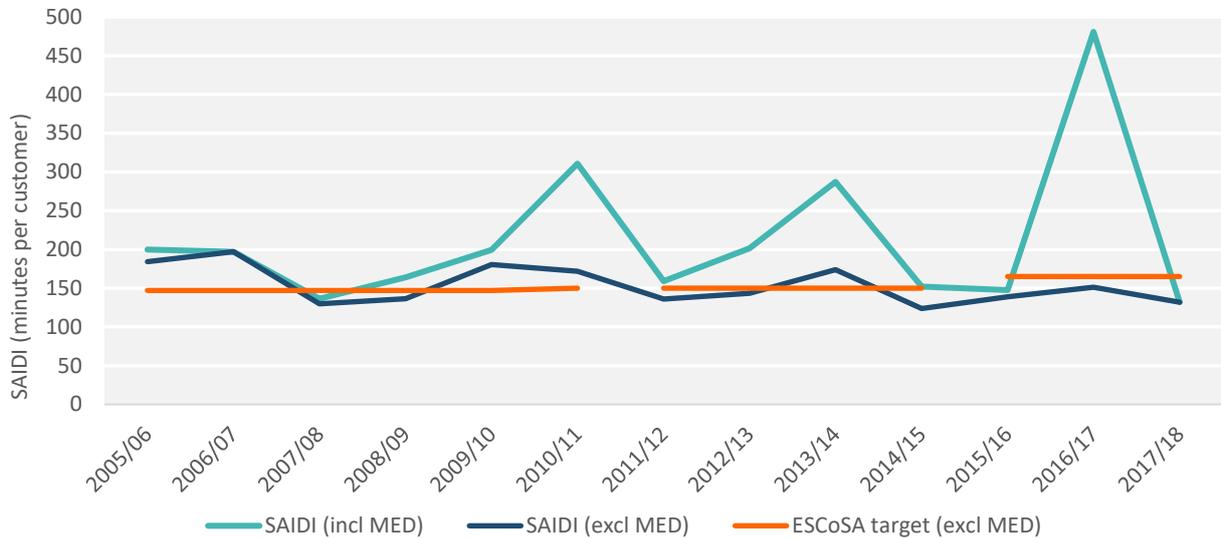


Figure 157: Annual SAIDI impact with and without impact of major event days (2010/11 to 2017/18)

Figure 157 shows that the impact of MEDs can in some years more than double the SAIDI experienced by customers. It shows severe weather events are the major cause of prolonged interruptions to power supply in South Australia. The challenge of maintaining overall reliability of the network under changing climatic conditions remains high.

Figure 158 shows the weather type that has historically caused most outages during MEDs and their contribution to the State SAIDI.

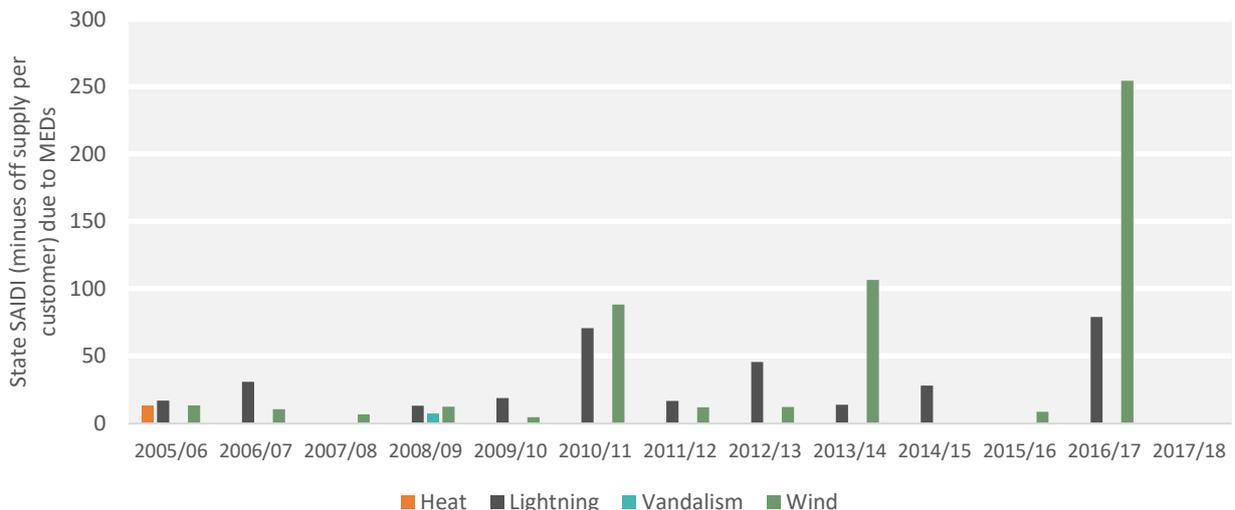


Figure 158: Annual unplanned SAIDI impact on network due to MEDs (2005/06 – 2017/18)

Figure 158 shows that the performance of the of network is severely impacted during MEDs and has adversely impacted customer supply particularly since 2010 and is highly variable. SA Power Networks’ overall performance (as would be observed by customers) including MEDs has therefore deteriorated significantly through greater intensity storm events.

9.4.7 Reliability management strategy

9.4.7.1 Introduction

Reliability and resilience of the network is about providing a continuous supply of electricity to customers and being able to restore supply quickly when a network fault (outage) occurs.

The SA Power Networks Reliability and Resilience Performance Management Strategy (RRPMS) describes the current strategy for managing network reliability performance. The RRPMS has been developed with the objective of establishing a clear overarching strategy to maintain compliance with the required reliability levels of service set by ESCoSA and address the identified high priority electricity consumer needs for maintaining reliability performance in the most prudent and cost-efficient manner.

Reliability strategies often provide a cost-effective solution ahead of major asset renewal/replacement and so are considered for localised reliability issues, irrespective of asset condition. Reliability programs are mainly capital solutions, along with a combination of operational solutions, to minimise the frequency and duration of network faults and enable faults to be located and restored more quickly after network outages.

Historically, the top four reported impacts on reliability performance are:

- **Unknown** — the cause of the interruption is not found following a line patrol;
- **Vegetation** — branches falling from vegetation overhanging wires from outside clearance zones;
- **Lightning** — to which the network is susceptible; and
- **Cable insulation breakdown** — underground cable faults.

While the average underlying reliability performance of SA Power Networks (excl. MEDs) remains consistent and a national high performer, recent trends across the networks that have affected the reliability of customer supply include:

- **Black system event:** On 28 September 2016, damage to several ElectraNet transmission lines caused a complete failure of supply to South Australians. This storm event also extensively damaged SA Power Networks infrastructure and flattened numerous battery supplies used to power major substation plant. Restoration times were thus delayed for some parts of the network.
- **Increased storm frequency:** In 2016–2017, nine MEDs caused widespread storm damage, and thus widespread outages across the state. The average is 3–4 MEDs per annum. Customers are experiencing significantly more extended interruptions because of the distribution network assets being repeatedly damaged and GSL payments as a result. As mentioned in section 9.4.4, the Bureau of Meteorology predicts future increases in severe weather events which is likely to further impact network performance.
- **CBD reliability:** Many network faults, primarily on the underground 11kV cable network within the regulatory CBD region predominantly during November–December 2017, affected commercial business, offices, hotels and high-rise apartment buildings.
- **Low reliability feeders:** ESCoSA and customers have become more focused on poor reliability feeders where the cost to undertake any enhancement works does not exceed the STPIS benefit. The number of low reliability feeders and worst served customers identified whose performance has been consistently far worse than the targets prescribed in the South Australian Electricity Distribution Code is escalating.
- **Increasing HV interruptions from vegetation outside clearance zone:** The number of interruptions from vegetation has doubled over the past 10 years mainly due to vegetation falling from outside the prescribed clearance zone.
- **Grey headed flying foxes:** An increase of >600% of flying fox interruptions on the distribution network was observed between 2015 and 2018 with contact across rod air gaps contributing 50% of such interruptions. The flying fox population is forecast to double between 2018 and 2030.

9.4.7.2 Reliability and resilience strategy

The reliability management strategy specifically focuses on maintaining the network reliability through:

- **supply restoration to customers:** as quickly as possible using safe, cost efficient supply restoration technologies and procedures;
- **monitoring and review of network performance:** identify targeted reliability improvements through:
 - monitoring the performance of the network,
 - identifying low reliability distribution feeders,
 - investigating abnormal operations following a network outage, and
 - investigating operational switching errors;
- **improving information:** accurate and timely information for customers through:
 - key process and system improvements, and
 - use of network monitoring devices and SCADA to provide real-time information on network outages;
- **research and innovation:** assess new and emerging technology, innovation and research projects for application on the distribution network;
- **employee awareness:** communication, culture, education and employee engagement plan
- **capital programs of work:** solutions for repeat interruptions through:
 - modifying the network at specific locations to maintain the underlying reliability performance,
 - modifying the network to improve reliability on low reliability distribution feeders,
 - hardening the network against storms,
 - providing alternate power supplies, and
 - strengthening existing network protection and response management (e.g. ensuring existing protection and control devices operate as required).

The projects delivered through the capital and operating programs are identified through ongoing monitoring and reviews of network performance. They address performance degradation, escalating underlying causes, regional performance and localised customer issues. The proposed expenditure is largely based on historical trends where the historical performance is to be maintained. In addition, targeted reliability projects are only undertaken when the customer benefit exceeds the cost. That is, assessing the cost of the proposed works against the benefit which is calculated mainly based on forecast STPIS benefits (over five years) or for hardening parts of the network supplying the worst served customers, based on value of customer reliability over a 15-year period.

The specific works under this strategy are shown in Table 73.

Table 73: Reliability and resilience works programs

Operating programs of work	Benefits and outcomes
HV distribution networks	
<ul style="list-style-type: none"> • Supply restoration: Mobilisation of field resources to attend to network outages and restore supply to customers as quickly as possible All network switching for safely isolating the fault and restoring service coordinated by network operations centre and implemented by Field Services 	<ul style="list-style-type: none"> • Faster response times to unplanned network outages to reduce SAIDI and CAIDI impacts
<ul style="list-style-type: none"> • Network performance monitoring: Ongoing monitoring and review of network faults to identify emerging issues or trends to optimise use of available resources 	<ul style="list-style-type: none"> • Achieves service standard (or demonstrates 'best endeavours' where targets not met) • Increases regulator and stakeholder confidence
<ul style="list-style-type: none"> • Information, innovation and employee awareness: Improved information and technologies to improve employee 	<ul style="list-style-type: none"> • Changes in work practices and processes to more rapidly identify, locate and restore unplanned network outages

Operating programs of work	Benefits and outcomes
HV distribution networks	
awareness of importance of responsiveness to network outages	

Capital programs of work	Benefits and outcomes
HV distribution network	
<ul style="list-style-type: none"> • Maintain reliability: Reliability enhancement programs to maintain the average performance and achieve ESCoSA service standards. Works include reinsulating on high voltage distribution feeders prone to lightning damage or the effects of ‘tracking’ from salt near the ocean, installing infrastructure to transfer customers to more reliable nearby feeders, animal guards and new technologies to minimise interruptions or assist with more rapid restoration of service 	<ul style="list-style-type: none"> • Maintains underlying network reliability (excluding MEDs) through continued targeted reliability enhancement programs works • Reduces time for locating and repairing faults
<ul style="list-style-type: none"> • Network hardening: Harden the most vulnerable sections of the distribution network against storms and lightning to reduce the impact during storms and MEDs Works include vegetation solutions (install insulated uncovered conductors, conductor line covers and targeted vegetation removal) and surge diverters in selected locations 	<ul style="list-style-type: none"> • Improves overall network reliability (including storms and MEDs) through reduced frequency and duration of interruptions particularly prone to storm events, including MEDs
<ul style="list-style-type: none"> • Low reliability feeders: Works to improve performance to customers who repeatedly experience extremely poor reliability performance below ESCoSA targets Targeted at feeders within a particular region/feeder category which have exceeded 2.1 times the SAIDI service standard for that region/feeder category for two consecutive financial years Works typically additional mid-line devices (reclosers and sectionalisers) and additional line fault indicators 	<ul style="list-style-type: none"> • Targets improvement in the performance of low reliability feeders and supply to worst served customers (where customer benefits exceed costs or to manage a specific and repeated ongoing customer issue where cost effective and prudent) • Reduces SAIDI impact of network faults through providing increased operational flexibility in the network
<ul style="list-style-type: none"> • Major event day supply restorations: Invest in new technologies to assist restoration crews during widespread storm events including the ability to remotely restore supply (e.g. connection of reclosers to SCADA) 	<ul style="list-style-type: none"> • Reduces SAIDI impacts from widespread storm events

Capital programs of work	Benefits and outcomes
Substations	
<ul style="list-style-type: none"> • Network protection management: An ongoing program to manage and maintain the existing reliability and performance of the protection and control assets installed on the network Includes reviewing the performance of protection systems to identify non-compliance or settings with potential for inadvertent operation to impact reliability 	<ul style="list-style-type: none"> • Ensures that the network remains compliant with the NER and electricity distribution code
<ul style="list-style-type: none"> • Air conditioning relay rooms: Targeted installation of air conditioners in substations with digital protection relays (failure rate of digital protection relays at sites without air conditioning observed to be higher than in air-conditioned rooms) 	<ul style="list-style-type: none"> • Ensures digital protection relays function as required to minimise SAIDI impacts • Extends the expected life of digital protection relays

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9.5 Future Network Strategy – enabling the energy transition

9.5.1 Introduction

Section 1.1 of this Power Asset Management Plan outlines the principles and processes used for the real-time management and operation of the existing distribution network. Chapter 7 outlines the strategies for the renewal and extension of SCADA and network control assets. This section describes the strategies in response to the changing use of the distribution network and the operating and capital investment plans to support the asset management objectives and levels of service.

Future Network Strategy summary

South Australia is at the forefront of an electricity industry in transition. The state’s rooftop solar penetration, already the highest in the world at more than 30% of customer and business premises, continues to increase, and the battery storage market is beginning to accelerate as prices fall faster than expected. Government, Australian Energy Market Operator and industry are grappling with emerging challenges to stability and security of supply as baseload generation is displaced by intermittent renewable energy and system inertia reduces. New energy products and services are emerging to service customers seeking empowerment in the face of rising prices. The global transition to electric vehicles is well underway, with Australia’s electric vehicle market poised to develop in the next five years.

The Future Network Strategy is a response to these changes. Developed in alignment with our *Future Operating Model* and the Energy Networks Australia and CSIRO *Electricity Network Transformation Roadmap*, it sets out six core strategies to adapt our network business to a more diverse, dynamic and distributed energy future.

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graph TD
    A[Asset Planning] --> B[Asset Creation/Acquisition]
    B --> C[Asset Operations]
    C --> D[Asset Condition and Performance Monitoring]
    D --> E[Asset Maintenance]
    E --> F[Asset Renewal/Replacement]
    F --> G[Asset Disposal]
    G --> A
    
```

9.5.2 Future network asset management objectives

The asset management objectives specific to the future operating model are summarised in Table 74.

Table 74: Future Network Strategy asset management objectives

Level of service category	Future network asset management objectives
Reliability and resilience	<ul style="list-style-type: none"> Increased visibility and understanding of the capacity of the distribution network to limit customer PV systems on network reliability.
Two-way grid	<ul style="list-style-type: none"> Optimised use of the network to cater for small embedded generators where network capacity exists.
Efficiency	<ul style="list-style-type: none"> Minimised life-cycle costs of required replacements or upgrades for network assets with optimised use of the existing network for two-way flow through the cost of installation, operations, maintenance, replacement and disposal. Increased use of non-network solutions to defer network augmentation expenditure where this is efficient.

9.5.3 Future Network Strategy

Many technological changes are influencing the way consumers use electricity (see Section 7.3.3). In the absence of new approaches, these changes could:

- **overload existing assets:** particularly at times of peak export or unconstrained orchestration;
- **exceed quality of supply (voltage) tolerances:** risking damage to customer equipment, causing customers' inverters to disconnect, and increasing transient variations and flicker; and/or
- **reduce the resilience of the network to faults:** whereby relatively small network perturbations could place the stability of large portions of the network at risk.

Equally, this new future also presents opportunities for:

- **improved network efficiency:** through leveraging distributed energy resources (DERs) for network support;
- **supporting new markets:** by providing a robust platform to enable customers to share and trade energy using their DERs and enabling electric vehicles; and
- **a new role for networks:** to add greater value as an active distribution system operator.

In 2017, Energy Networks Australia and CSIRO released the *Electricity Network Transformation (ENTR) Roadmap* to guide a structured transition over the 2017–2027 decade. The SA Power Networks Future Network Strategy broadly aligns with the *ENTR Roadmap*.

The six key strategies arising from the Future Network Strategy are shown in Figure 159.

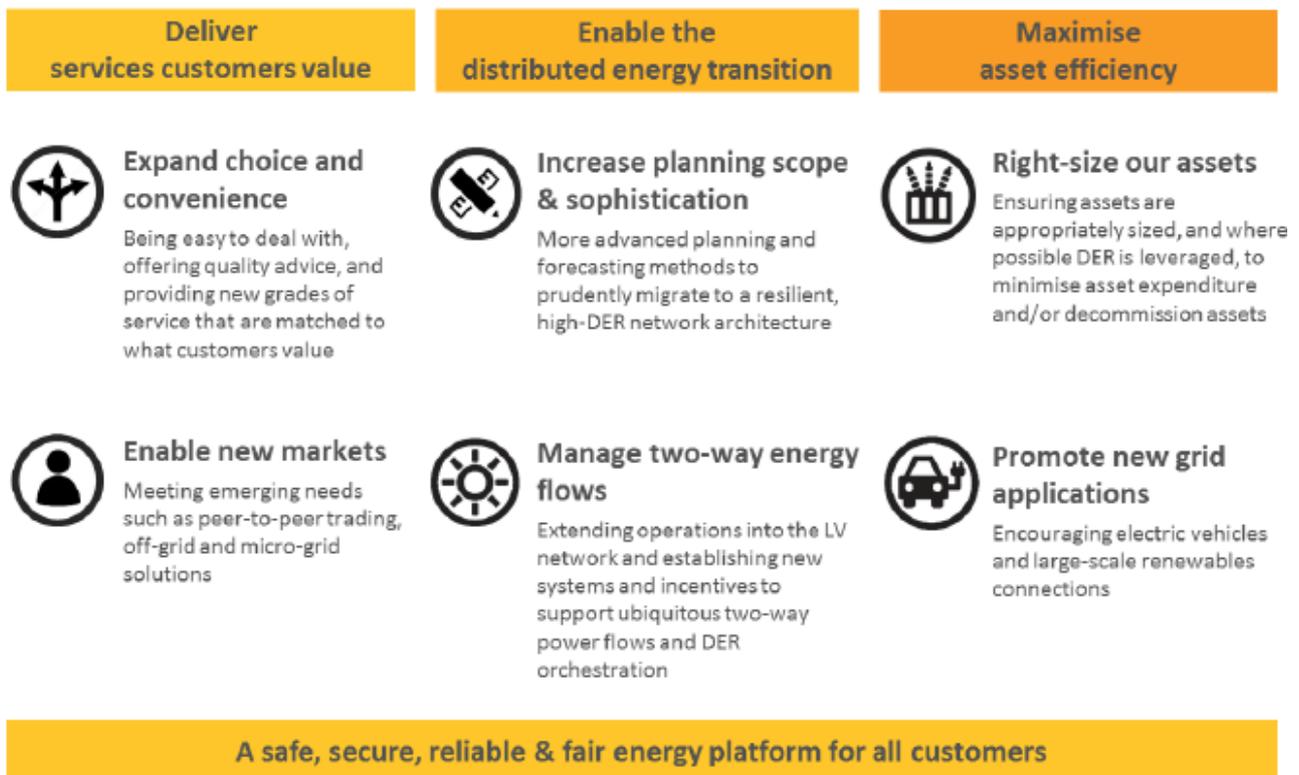


Figure 159: SA Power Networks Future Network Strategy – Core strategies

The most significant works program to be progressed under the Future Network Strategy is the low voltage (LV) management program centred around building an LV network model, achieving visibility of the LV network through monitoring, and the transition to more proactive planning and operational management of the LV network (see Section 7.3.6.4). Further information on the other planned initiatives are discussed in the Future Network Strategy document.

9.6 Power Line Environment Committee — undergrounding of powerlines

9.6.1 Introduction

This section outlines the undergrounding of powerlines through the Power Line Environment Committee (PLEC) strategy, SA Power Networks requirements, and how works are prioritised and funded to support the asset management objectives and levels of service.

PLEC summary
 SA Power Networks, like most other distributors worldwide, operates a predominantly overhead distribution network. Cost is the main reason for not adopting an extensive undergrounding program.

SA Power Networks has a legislative requirement to contribute two-thirds of funding towards an annual Power Line Environment Committee (PLEC) program to enhance the aesthetics of targeted locations by undergrounding powerlines. The total amount of work under this program is capped by legislation, adjusted annually for inflation. This determines the extent of work to be delivered.

The committee seeks proposals and assesses them according to the aesthetics of an area, the benefit of the general community, regard for road safety, and the provisions for electrical safety of the *Electricity Act 1996*. The committee operates under a charter which defines the scope of its activities, its composition, financial arrangements, reporting requirements and associated administrative processes. The Minister responsible for the *Electricity Act 1996* approves the list of projects.

The resulting approved PLEC program is a targeted program of project works for undergrounding of powerlines for the greatest benefit to the South Australian community. Once constructed and tested to SA Power Networks requirements, the assets are gifted to SA Power Networks and become part of the regulated asset base.

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graph TD
    AP[Asset Planning] --> ACA[Asset Creation/Acquisition]
    ACA --> AO[Asset Operations]
    AO --> ACM[Asset Condition and Performance Monitoring]
    ACM --> AM[Asset Maintenance]
    AM --> AR[Asset Renewal/Replacement]
    AR --> AD[Asset Disposal]
    AD --> AP
    
```

9.6.2 PLEC asset management objectives

The asset management objectives specific to the PLEC program are summarised in Table 75.

Table 75: PLEC asset management objectives

Level of service category	PLEC asset management objectives
Safety	<ul style="list-style-type: none"> Improved road safety through removal of Stobie poles adjacent to roadways and public lighting compliant with Australian Standards.
Efficiency	<ul style="list-style-type: none"> Minimised cost of underground works through a competitive, open tender process and in conjunction with council streetscaping projects where possible. Deliver the PLEC program to achieve the annual legislated expenditure targets.

9.6.3 Legislative requirements

The legislative obligations that SA Power Networks is required to meet as a distribution network service provider specifically for PLEC include requirements under:

- Section 56A of the *Electricity Act 1996* for a program of undergrounding of powerlines to be carried out by SA Power Networks; and
- Part 9 of the *Electricity (General) Regulations 2012* which outlines the prescribed annual PLEC expenditure.

9.6.4 PLEC strategy

9.6.4.1 Introduction

SA Power Networks, like most other distributors worldwide, operates a predominantly overhead distribution network as they are the most cost-effective way to distribute power over long distances. Since the early 1970s, powerlines in new residential areas of South Australia have been placed underground. Land developers pay the cost, which is included in the price of the land, with the distribution assets gifted back to SA Power Networks. The total cost to underground the thousands of kilometres of existing overhead powerlines in South Australia would be in the tens of billions of dollars; the main reason for not adopting a more extensive undergrounding program.

A targeted approach is therefore taken in selected locations where undergrounding of powerlines provides greatest benefit to the community, with regard to road safety and the provisions for electrical safety pursuant to the Electricity Act. Undergrounding can enable tree establishment and streetscaping projects thereby significantly improving the visual appearance of a locality.

The improvements in visual amenity are largely achieved through the PLEC program and its associated committee which was established in 1990. The eight committee members come from various stakeholders including SA Power Networks, local councils, Department of Planning, Transport and Infrastructure, and other bodies responsible for the care, control or management of roads who oversee the PLEC program. The committee operates under a charter which defines the scope of PLEC activities, its composition, financial arrangements, reporting requirements and associated administrative processes.

The annual expenditure on the legislated PLEC program is capped but is adjusted annually for inflation with the prescribed amount legislated under section 44 of the Electricity (General) Regulations 2012. This determines the extent of work (number of project applications) that can be delivered. While the PLEC program is an 'un-scoped allowance' in accordance with the Regulations, the program can be considered prudent as it is managed within a legislated framework and is efficient as construction is predominantly completed through a competitive tender process.

9.6.4.2 PLEC strategy

The PLEC strategy can be summarised as follows:

- The committee requests biannual proposals from bodies responsible for the care, control or management of roads to submit proposals for undergrounding powerlines.
- A council responsible for the area concerned, or Department of Planning, Transport and Infrastructure, in partnership with a local council, submits a proposal for PLEC funding towards a project.
- On receiving the proposal, SA Power Networks provides indicative costs to the committee to help applicants decide whether to proceed with a project on a cost sharing basis of two-thirds SA Power Networks, one-third the council.
- Following confirmation from council that they wish to proceed with the project, SA Power Networks designs and makes estimates for undergrounding the network.
- The applicant combines designs for traffic, public lighting, tree planting and parking with the proposed below ground network infrastructure design.
- The applicant submits their formal application to PLEC for consideration.

- The committee considers applications according to the PLEC Charter which includes assessing the aesthetics of an area for the benefit of the general community, having regard to road safety and the provisions for electrical safety pursuant to the Electricity Act.
- The Minister responsible for the Electricity Act approves the PLEC program on recommendation of the committee.
- Formal agreements are signed committing the parties to delivering the approved project.
- Representatives of the committee are responsible for assessing tenders and estimates submitted for each PLEC project.
- SA Power Networks project manages the delivery of the distribution network component of the works (civil works, powerline assets and connection works beyond the customer meter) with a project team involving the key stakeholders.
- At the completion of the project, the underground assets are tested, commissioned and transferred to SA Power Networks ownership.

The Essential Services Commission of South Australia website has further information on the PLEC program.

Figure 160 shows the historical prescribed and actual annual expenditure for the PLEC program.

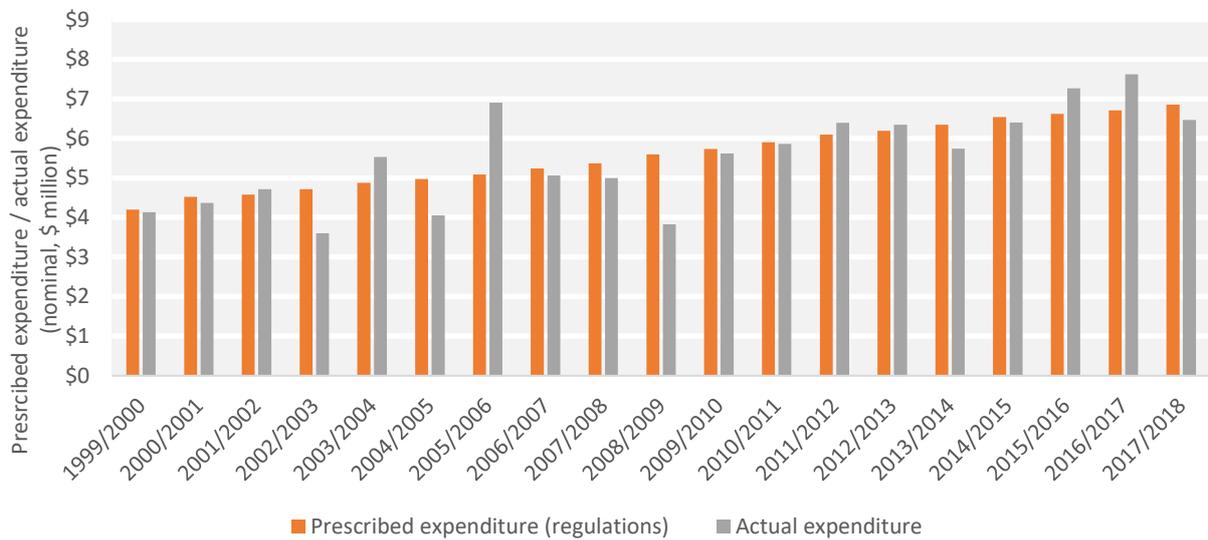


Figure 160: PLEC prescribed expenditure vs actual expenditure (1999/00 – 2017/18)

Figure 160 shows the PLEC program has historically aligned very closely with the legislated expenditure levels. While some minor annual variations occur (typically outside of SA Power Networks control); any over/under spends are carried forward and addressed in subsequent years (and vice versa).

The specific works under this strategy are shown in Table 76.

Table 76: PLEC works programs

Programs of work	Benefits and outcomes
Sub-transmission system, HV distribution network, LV network	
<ul style="list-style-type: none"> • Undergrounding of powerlines: Continued program of undergrounding of existing powerlines in specific areas under the State Government’s PLEC scheme 	<ul style="list-style-type: none"> • Improves the aesthetics of an area for the benefit of the general community having regard to road safety and the provisions for electrical safety in selected areas

Once constructed and tested to SA Power Networks requirements, the assets are gifted to SA Power Networks and become part of the regulated asset base.

10 Asset information

10.1 Introduction

This section outlines the information (data) used to support asset management and how it is managed, the types of asset information, the sources of information, how the information is stored and how it is utilised to support asset management decision making. It also identifies key asset information improvement areas.

Historically, the limited information on asset locations was held in disparate data sets at various physical locations. Significant data capture projects, recently completed or currently underway, are developing systems to manage the data efficiently and provide ready access to users.

The Network Management Group develops and maintains the asset information systems, and standards to ensure compliance with regulations and industry standards, and enable effective asset management decision making.

10.2 Asset information types

Table 77 summarises the key types of information collected on network assets.

Table 77: Asset information types

Data type	Description	Example
Description data	Required to identify an asset	Unique ID, descriptive details from nameplate; manufacturer, common name, serial number, model number
Physical data	Describes the physical characteristics of the asset	Dimensions – height, length, depth, weight, steel thickness, volume
Location data	Identifies the location of an asset, including geospatial coordinates, map grid references, plan grid references	Latitude, longitude, bushfire risk area, corrosion zones, suburb, postcode
Condition data	Records the physical health of the asset	Condition rating, condition measurements, expected life
Maintenance data	Identifies the work planned to be completed and work completed against an asset	Activity type, order no, order status, date, task details, cost, labour hours
Performance data	Shows how assets are performing for the service they are required to deliver	Strength, amps, volts, temperature, compliance
Demand data	Shows the demand on assets	Strength, capacity, operational status, availability
Connectivity data	Depicts the electrical connectivity of assets Consists of node to node connections containing relevant assets	Switching zones, feeder
Customer data	Customer information required to associate assets to the customer(s) they service	Number of upstream and downstream customers, customer type, address, access details
Financial data	Related to the asset finances	Asset value, ownership, purchase price
Electrical data	Specific electrical ratings and settings, attributes of assets usually for operations and strategic planning purposes	Some dynamic ratings such as emergency and environmental ratings
Contract management data	Related to contract management	Asset related contractual information, vendor information, third party agreement, contract administration information

10.3 Asset information sources

The sources of asset information include the following:

- **As-constructed drawings:** Show the physical and functional details of the assets constructed. This data is used to populate information in the key asset information systems (GIS and SAP) on creation of new assets.
- **Asset inspections:** Information is collected through routine asset inspections on asset defects, asset condition, and other asset data collected includes description, physical, location data.
- **Network monitoring equipment:** Various monitoring equipment records, for example, current flows, voltage levels, asset availability, number of operations.
- **Data collection programs:** Targeted asset data collection programs collect data where none currently exists or to validate and update the quality of existing data sets. This includes vegetation management scoping and trimming.
- **Easement register:** This database registers the value and location of easements.
- **Asset change forms:** No drawings are made of emergency works; asset change forms are used to record information on any emergency works undertaken on the assets.
- **Substations management systems:** A repository of drawings is kept for the source of substation assets.
- **Switching diagrams:** Drawings of the distribution network are maintained through information provided from sources such as line construction and maintenance crews, asset inspectors, the Network Operations Centre and several other areas throughout SA Power Networks.
- **Customers:** Customers relay information directly through the call centre, consultations, website and social media channels on the performance of assets, e.g. asset defects, voltage issues, network outages, ability to export into grid.
- **Various other documents and spreadsheets:** Abundant asset data is kept by staff, electronically or in hard copy form, but not centrally accessible.
- **Institutional knowledge:** Staff knowledge obtained through experience is not usually documented.

10.4 Asset information management systems

Table 78 gives a summary of the key systems used to manage the asset information. The architecture has been designed to ensure integration between all systems. Data management plans are implemented to ensure the flow of asset information into and between information systems.

Table 78: SA Power Networks asset information systems

System	Description of system
Works management system (SAP)	This software package contains a register of the assets and data associated with individual assets (physical details, installation dates, costs), defect and failure information, preventative, corrective and reactive maintenance history, condition data, inventory and materials management
Geographic information system (GIS)	This collection of specialised systems and applications is for maintaining spatial and (electrical) connectivity information for assets GIS systems and applications include G/Tech, Esri ArcGIS, GeoMedia and GEO Cortex
Centralised Asset Mapping System	This mapping system enables accurate location and description of underground asset data, helping deliver the Dial-Before-You-Dig service
Interactive Voice Response System	The system allows customers to report supply interruptions and faulty street lights, and gain direct access to call centre agents; it gives dynamically updated real-time outage details and current outage status
Outage management system	This Microsoft Windows based interfaced system enables fault (outage analysis) management including fault records, dispatch of field crews and job close out
Advanced distribution management system (ADMS) including the Supervisory Control and Data Acquisition (SCADA)	The main operational tool used by Network Operations Centre to manage the high voltage distribution network, provides real time monitoring and visibility of alarming, metering and operational status of remote substations
Protection Settings Database	This database stores the programmable parameters and settings for the protection relays employed throughout the distribution network
CNMS-NG & Connect Master	The main operational tool used by the Telecommunications Network Operations Centre, manage the telecommunications network providing real time alarming and control
RIVA	This risk-based software uses information from the SAP system to assess the risk profile of various asset classes and undertake long term renewals investment forecasting and scenario modelling
Customer Information System – Open Vision	This customer billing system contains information on customer relationship management, meter data and meter locations
Power Transmission System Planning Software	This software is used to model the electricity transmission and distribution network
Intranet site	All employees have access to information ranging from corporate policies through to work field instructions, on a central intranet site
Survey and Engineering Applications	Network Management uses Caddsmen as the primary drafting package for producing most design, construction and electrical drafting products The Linscad package is used for processing electronically captured survey data and terrain modelling for export to Caddsmen
Substation Load	This internally developed software package displays historical SCADA metering data grouped by the relevant substation name; within each substation, the various load readings are displayed according to the name associated with each individual item of equipment
Distribution drawings management system	The 3D software known as Pro/ENGINEER is used to produce distribution construction drawings and can construct various models and develop complete final distribution construction standard E-drawings

10.5 Asset information use

Asset information is used to support key decisions such as:

- financial management;
- risk management;
- operations (including switching operations and reliability investigations);
- maintenance planning (including asset inspections and condition monitoring);
- renewals and augmentations planning;
- levels of service monitoring and assessment;
- asset depreciation;
- life cycle optimisation analysis; and
- regulatory reporting.

10.6 Current asset information and systems improvements

Several projects currently underway are aimed at improving asset information and supporting systems to better support decision making. The key projects are:

- **assets and works project:** adding breadth (covering more assets) and depth (covering more characteristics and measuring points) to asset information;
- **works manager:** part of a broader field mobility program of work, and aiming to significantly improve the systematisation of data collection; implementation of asset condition assessments through this project will drive further benefits in asset-work history and asset metadata; and
- **RIVA:** software using condition-based modelling, and real-time data from the key asset information systems (GIS and SAP), to assess asset risks and develop renewal budget forecasts.

11 Continuous improvement plan

The Power Asset Management Plan (PAMP) will evolve over time in response to the changing needs of its stakeholders and customers, the changing condition and performance of the network assets, and the changing competitive environment.

Currently SA Power Networks is planning improvements to its asset management processes and practices to align the business with ISO 55000:2014 Asset Management.

Table 79 provides a summary of the future improvements to asset management that have been identified throughout this plan.

Table 79: SA Power Networks improvement plan

Chapter	Improvement action reference	Improvement action	Improvement action description	Responsibility	Key teams	Timeline
2. Network and asset overview	1	Match information held on assets in the two main asset information systems (GIS and SAP)	Make asset information consistent — currently some asset information held in the two main asset management systems (GIS and SAP) doesn't match	Strategic Asset Management Manager Network Records Manager	Strategic Asset Management, Network Planning, Network Records, IT	2018–2020
	2	Improve the accuracy of the key asset information held in GIS and SAP	Improve the accuracy and completeness of asset information held in GIS and SAP — currently some key asset information held in GIS and SAP is not accurate nor complete (e.g. age profiles of conductors).	Strategic Asset Management Manager Substations Planning Manager Protections and Control Planning Manager Network Records Manager	Strategic Asset Management, Network Planning, Network Records, Network Planning, IT	2018–ongoing
	3	Link asset defects/faults to individual assets in SAP	Link asset defects/faults not currently linked to their respective assets to facilitate analysis of asset risks	Asset Assessment Manager Operational Asset Management Manager Substations Planning Manager Protections and Control Planning Manager Network Records Manager	Operational Asset Management, Strategic Asset Management, Network Planning, Network Records, IT, Strategic Initiatives, Asset Assessment	2018–ongoing
3. Levels of service provided to customers and stakeholders – understanding customers	1	Develop a performance reporting framework on levels of service	Develop a framework for the levels of service clearly outlines the level of service measures purpose and discussion leading to development of the measures, data sources, data quality, assumptions, other levels of service measures considered but excluded with reasoning and explore the viability and implementation of dashboard reporting	Strategic Asset Management Manager	Strategic Asset Management, Network Planning, Customer Solutions, Customer Relations	2018–ongoing
	2	Expand further the levels of service targets to various asset systems and classes	Break down the current targets for a number of the levels of service measures to the relevant asset systems and classes	Strategic Asset Management Manager	Strategic Asset Management, Network Planning	2019
	3	Investigate the shock reports and consider the value of possible proactive monitoring and replacements of old aluminium neutral wires on service mains	Investigate the reported shocks in the powerlines, which have increased in the last two years and are believed to be due to the poor condition of the aluminium steel wires in service lines Identify and implement remedial measures to ensure safety of staff, contractors and the public	Operational Asset Management Manager	Operational Asset Management, Strategic Asset Management	2018
4. Risk – assets and operations	1	Model the asset risks for the remaining asset classes	Expand on current CBRM models to finalise (conductors, cables, switching cubicles) and progress development of other critical network assets including distribution transformers and service lines, using the Condition Based Risk Modelling methodology	Strategic Asset Management Manager	Strategic Asset Management Network Planning	2020
	2	Refine the asset risk assessment methodology	Refine the Condition Based Risk Modelling methodology for assessing the asset risks to outline how risk is evaluated, composition of	Strategic Asset Management Manager	Strategic Asset Management Network Planning	2018–ongoing

Chapter	Improvement action reference	Improvement action	Improvement action description	Responsibility	Key teams	Timeline
			risks by asset types, condition vs not condition risk and links to levels of service.			
	3	Make consistent the factors and methodologies used to assess asset failure consequences in valuing work and in assessing asset risks as per the CBRM methodology in RIVA	Align the asset failure consequence factors and methodologies used in assessing risks as per the CBRM methodology in RIVA and those used in valuing work to ensure consistency in asset management decisions made in the short, medium and long term	Strategic Asset Management Manager Strategic Initiatives Manager	Strategic Asset Management Strategic Initiatives	2018–2019
5. Asset management framework	1	Prioritisation and ranking of capital works projects	Document the processes used to rank projects within capital programs to prioritise works and consideration of business tools to be applied to make project timing, ranking and forecast information centrally accessible.	Operational Asset Management Manager Substation Planning Manager Distribution Planning Manager Transmission and Generation Planning Manager Protection and Control Manager Quality of Supply Manager Telecommunications Planning & Engineering Manager Reliability Operations Manager	Operational Asset Management Network Planning (all teams) Reliability Operations	2019-2020
	2	Progression of the Asset Management System to align with ISO 55000 requirements	Undertake a gap analysis of the existing Asset Management System and identify gaps and required actions towards achieving alignment.	Strategic Asset Management Manager	Operational Asset Management Network Planning (all teams) Reliability Operations	2019-2020
6. Asset lifecycle management	1	Forecast minimum demand to plan for impact of reverse flows	Develop network models to forecast the impacts of reverse flows during minimum demand periods	Distribution Planning Manager	Distribution Planning	2018
	2	Improve the accuracy of forecasts for zone substations and connection points subject to large holiday loads (e.g. Fleurieu, Yorke Peninsula, Robe)	Improve current demand forecasts to accurately represent the significant impact of transient holiday loads on the peak demand	Distribution Planning Manager	Distribution Planning	2019
	3	Monitor demand against projections and adjust future plans as needed	Monitor actual demand in the coming years against the future electricity demand forecast in this PAMP and in the Distribution Annual Planning Report, and adjust projections as needed	Distribution Planning Manager	Distribution Planning	Ongoing
	4	Improve the customer connection process	Provide customers with greater access and visibility to information on new or altered connection applications and embedded generator applications	Manager Customer Solutions	Customer Solutions Network Planning	2019-2021

Chapter	Improvement action reference	Improvement action	Improvement action description	Responsibility	Key teams	Timeline
7. Asset class strategies	1	Review and update the asset condition assessment strategy	Consolidate the condition assessment strategy to build on the detailed inspection cycles for the various assets in the Network Maintenance Manual	Strategic Asset Management Manager	Strategic Asset Management, Operational Asset Management, Network Planning	2018
	2	Review the Network Maintenance Manual to ensure the assets inspection cycle details are up to date and reflective of current practices	Update the out-of-date asset inspection and maintenance tasks and cycle frequency details in the Network Maintenance Manual	Operational Asset Management Manager Substation Planning Manager Asset Assessment Manager	Operational Asset Management, Substations Planning, Asset Assessment	2018
	3	Review the life cycle strategies for key assets, with particular focus on ensuring clear and robust linkages to the levels of service delivered to customers	Ensure linkages are clear to the levels of service delivered in a review of asset life cycle strategies so they are not only aimed at managing risks	Strategic Asset Management Manager Operational Asset Management Manager Substation Planning Manager Protection and Control Planning Manager	Strategic Asset Management, Operational Asset Management, Substations Planning, Protection and Control Planning	2019–2020
	4	Review the renewal vs maintenance decision criteria for conductors and underground cables	Review the current practice of patching most faulty conductors and underground cables, which is in many cases the most cost-efficient approach, to ensure the balance between patching and replacement of sections that have failed; both conductors and underground cables are very critical assets that could have significant reliability consequences when they fail	Operational Asset Management Manager	Operational Asset Management Strategic Asset Management	2019
	5	Extend the application of 'value and visibility' to substation assets	Extend the value and visibility project to include substations assets, in addition to the current distribution assets	Strategic Initiatives Manager Network Planning	Strategic Initiatives, Network Planning	2018–2019
9. Asset information	1	Review and improve the quality of key asset information	Undertake a major review of the quality of the key information that supports the key decisions, beyond the projects currently underway (Assets and Works, Works Manager) are aimed at improving the quality of the key information	Strategic Asset Management Manager	Strategic Asset Management, Asset Assessment, Substations Planning, Protection and Control, Network Records	2018–ongoing
	2	Improve asset information availability by, e.g. automated reporting and improved accessibility	Investigate automated reporting and other options for making asset information in the asset management systems, including GIS, SAP and ADMS, more readily accessible and available to decision makers	Operations Asset Management Manager Network Quality and Operational/NECF Reporting Manager	All network management teams	2018–ongoing
	3	Centralise and align various key asset information data sources	Centralise and align asset information held in various places, including GIS, SAP, spreadsheets and in the minds of staff, to	Manager Network Asset Management Network Records Manager	Strategic Asset Management, Network Records, Substation	2018–ongoing

Chapter	Improvement action reference	Improvement action	Improvement action description	Responsibility	Key teams	Timeline
			enable its efficient support to the decisions made around asset management	Substation Planning Manager Protection and Control Planning Manager	Planning, Protection and Control Planning	
	4	Document key asset information processes (from data sourcing to final utilisation)	Documented processes for the key asset information flow to ensure information consistency and no loss of critical information	Strategic Asset Management Manager Network Records Manager	Strategic Asset Management, Network Records, Substation Planning, Protection and Control Planning	2019
11. Capital and operating programs and financial forecasts	1	Review the asset unit replacement costs	Review asset unit replacement costs, currently largely based on the estimates derived from the RepEx model and staff knowledge, to ensure they reflect reality	Strategic Asset Management Manager	Strategic Asset Management, Substation Planning, Protection and Control Planning	2019
	2	Review asset useful lives	Review asset useful lives, currently largely based on the estimates derived from the RepEx model, to ensure they reflect reality	Strategic Asset Management Manager	Strategic Asset Management, Substation Planning, Protection and Control Planning	2019-2020
	3	Review expenditure forecasts with a particular focus on ensuring clear and robust linkages to levels of service	Review current financial forecasts to ensure clear linkages to the levels of service delivered, as well as for managing risks	Strategic Asset Manager	All network management teams	2019-2020

12 Capital and operating programs and financial forecasts

12.1 Introduction

This section summarises the capital and operating programs and the financial forecasts required to deliver the various strategies and ensure agreed services are delivered to customers now and into the future. The works proposed include high level commentary and context for the forecasts including key assumptions. All figures and discussion are based on forecasts as of early December 2018 and inclusive of all business overheads.

Financial forecast summary

The total forecast expenditure for managing our power assets over the period 2018 to 2030 is \$6.51 billion comprising \$4.21 billion (65%) in capital expenditure and \$2.30 billion (35%) in operating expenditure. This reflects the underlying network needs discussed in this PAMP. The largest areas of capital investment are for the renewal/replacement of ageing assets on our sub-transmission system and distribution networks (\$1.26 billion or 30% of forecast capital expenditure) and customer connections (\$1.18 billion or 28% of forecast capital expenditure). The largest areas of operational expenditure are for vegetation management (\$576 million or 25% of forecast operating expenditure) followed by supply restoration (\$456 million or 20% of forecast operating expenditure).

Total annual expenditure is forecast to remain between \$480 million to \$527 million per annum from 2018 to 2030.

The forecast budgets required to manage the power network assets are broadly classified into two categories for the purposes of this Power Asset Management Plan:

- **capital expenditure (capex):** expenditure required to create, upgrade, extend or replace network assets; and
- **operational and maintenance expenditure (opex):** expenditure required to operate and maintain the existing network assets.

12.2 Capital expenditure programs

The capital programs are categorised to ensure that all network risks are adequately identified and managed in accordance with the business risk profile. The capital program categories are as follows:

- **Asset replacement/refurbishment** is the replacement or refurbishment (life extension) of assets to enable SA Power Networks to maintain an acceptable level of distribution system safety and reliability by addressing identified defects in, and the degradation of, ageing network assets to meet jurisdictional service standards and to comply with other regulatory obligations as outlined in the SRMTMP. It covers the replacement of assets that have reached the end of their service life, and those that are about to fail, or have failed, before the completion of their nominal service life. The former is the proactive plan to minimise the network performance deterioration by targeting assets assessed to be past their service life (based on condition and performance) that are also strategically important. The latter (unplanned), is a driver of network performance and reliability, and is trending upwards.
- **Capacity upgrades** is indirectly driven by customer activity, where the network requires an upgrade to cater for general load growth. When forecasted load through a network asset exceeds the rating of that asset in accordance with SA Power Networks planning standards, the asset is then considered for upgrading. These planning standards are published each year on SA Power Networks website (in accordance with regulatory requirements). No customer contribution is derived for this expenditure.
- **Customer connect** is driven by customer demand for electrical energy, with the customer contributing towards the cost of the work. Customer connect planning includes the required connection works between the customer and the distribution network, extension of the network to the customer's location and any network augmentation required within two years of the customer's connection to

meet SA Power Networks planning standards. Forecasts are based on historical expenditure, modified by known customer economic activity and changes to regulations (ie National Electricity Rules). This expenditure is generally ‘non-discretionary’ in nature (customer driven).

- **Reliability and resilience** is driven by the need to meet regulated supply reliability and customer service standards, meet customer service expectations, and maximise business performance. Reliability expenditure is generally based on strategic planning and historical values focused on maintaining regulated service standards. The performance degradation is due to the, ageing profile of the assets and increasing intensity of weather events and escalation vegetation and of animal related outages.
- **Safety** ensures that the electrical distribution network is operated in a safe manner for customers, SA Power Networks employees and contractors.
- **Environment** is for managing requirements under the *Environment Protection and Biodiversity Conservation Act 1999*, and other environmental Acts.
- **Network control** covers activities required by the organisation to operate and report on the network performance e.g. outage management system. The budget category covers specific major projects.
- **Power Line Environment Committee (PLEC)** is mandated under the *Electricity Act 1996* and *Electricity (General) Regulations 2012* to underground overhead mains as determined and agreed with the PLEC committee. For operational efficiencies, the plan allows for the gross cost of the work, with the offset later by the contributions from the relevant local council (one-third of the cost).
- **Strategic Network Investment** includes condition monitoring equipment, development of innovative technologies for optimising the management of network assets.

12.3 Operating expenditure programs

The operational programs are largely based on historical expenditure and/or tasks. Being reactive, the unplanned operating expenditure, consisting of emergency response and asset restoration including responding to catastrophic events, is modelled on trends considering failure rates over the past five years to determine a sensible expected expenditure over the asset classes for subsequent years.

Like capital expenditure, the operational program categories ensure that all network risks are adequately identified and managed in accordance with the business risk profile.

Operational program categories:

- **Line maintenance (preventative and defective):** The plan outlined for line maintenance, is to meet the strategies published by SA Power Networks as part of the SRMTMP, a plan required under the Electricity Act and Regulations. The defective component of line maintenance is based on historical values and CBRM modelling; preventative maintenance is based on manufacturers’ recommendations, industry standards or SA Power Networks experience.
- **Substation maintenance (preventative and defective):** This maintenance program covers distribution network assets within substations (including the perimeter fence) and the two mobile substations owned and operated by SA Power Networks. The plan and its drivers are similar to that for line maintenance.
- **Telecommunications maintenance (preventative and defective):** The operational plan and its drivers are similar to that for line maintenance.
- **Asset inspection:** This plan generally initiates the maintenance plans and is therefore driven by the same factors.
- **Supply restoration (emergency response and asset restoration):** This category is primarily unplanned, with the response being predominantly reactive to events as they arise. Typically, the events are weather driven and, to a lesser extent, influenced by the outcomes of other plans, e.g. maintenance, capacity upgrade. The plan strives to achieve regulated supply reliability and customer service standards and therefore maximise business performance. The costs are based on historical values, adjusted to reflect the current performance of the network.

- **Ancillary services:** Minor incidental work undertaken by SA Power Networks and its contractors, e.g. high load escorts, drawing maintenance, load transfers, is generally not customer driven. The costs are based on historical values.
- **Services (operations including local power stations):** This program covers minor incidental works undertaken by SA Power Networks and its contractors that are customer service driven, e.g. temporary disconnections and reconnections.
- **Vegetation management:** SA Power Networks clears and manages vegetation to meet the requirements of the Electricity Act and Regulations for cyclic and emergency vegetation clearance work.
- **Other operational costs:** Other operational activities include regulatory compliance, systems support and asset management operational costs.

12.4 Forecast expenditure summary

Figure 161 the historical and forecast expenditure profile and split of forecast total capex and opex expenditure for the period 2018–2030.

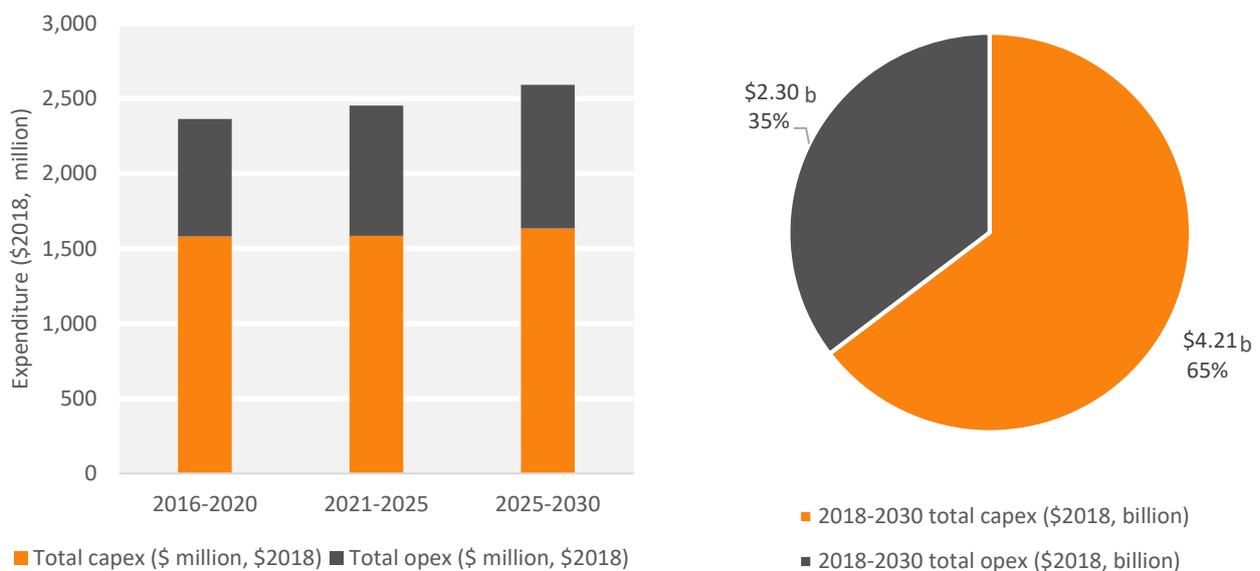


Figure 161: Total historical and forecast expenditure (\$2018, including overheads)

In summary, over the period 2018–2030 a forecast expenditure of \$6.51B is required comprising:

- \$4.21B in capital expenditure; and
- \$2.30B in operations and maintenance expenditure.

The distribution of this expenditure across the capital and operating programs is discussed below.

12.5 Capital historical and forecast expenditure

The forward capital expenditure is developed using a risk-based approach to enable the power network to:

- achieve acceptable levels of safety risk to the public and employees;
- meet forecast demand;
- comply with all applicable regulatory obligations;

- deliver the required levels of service; and
- achieve acceptable levels of business risk.

The historical capital program expenditure and the total forecast \$4.21B capital expenditure for 2018–2030 is distributed across the programs discussed in Section 12.2 and is shown in Figure 162.

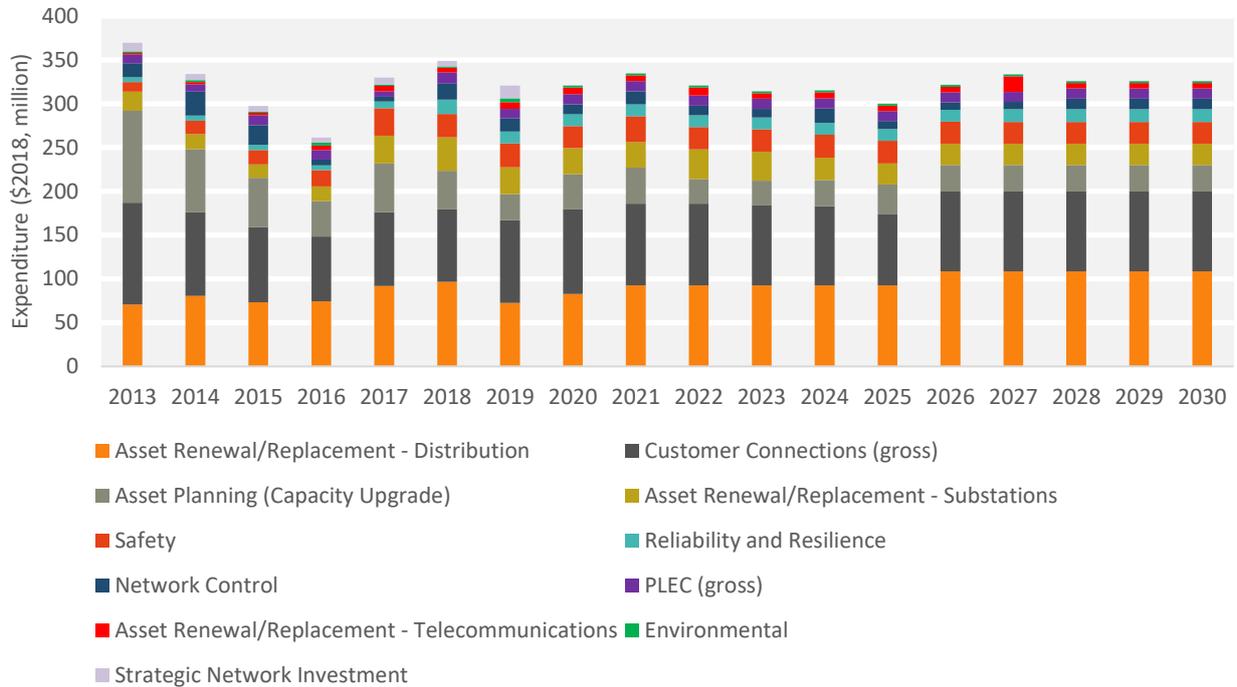


Figure 162: Capital expenditure programs 2013–2030 (\$2018, including overheads)

Figure 162 shows a decline in capital expenditure over 2013-2016 largely due to reductions in the required connections and capacity upgrade expenditure due to a downturn in economic development activity and increased PV offsetting the need for network capacity augmentations. The increase in capital expenditure since 2016 is due to an increased rate of asset renewal/replacement programs on ageing assets in response to an increased rate of defects and poor condition assets being identified combined with an upturn in customer connection works.

Figure 163 shows the total capital expenditure by capital program for 2018-2030.

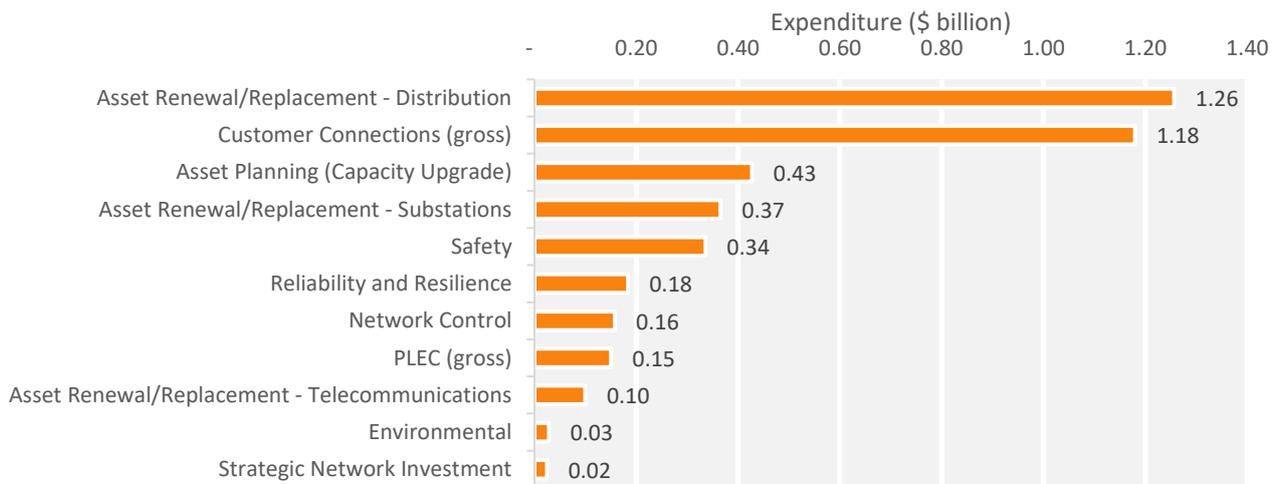


Figure 163: Forecast capital expenditure programs (\$2018, including overheads)

Figure 163 shows:

- the distribution renewal/replacement forecast (including works in the sub-transmission system) is the largest area of capital investment; and

- the forecast distribution renewal/replacements and customer connections gross expenditure make up approximately 60% of the forecast total capital expenditure to 2030.

For further detail on the proposed capital forecasts and programs of work, see Appendix 12.2

12.5.1 Asset renewal/replacement historical and forecast expenditure

Figure 164 shows the total historical and forecast renewal/replacement expenditure program profile split by system.

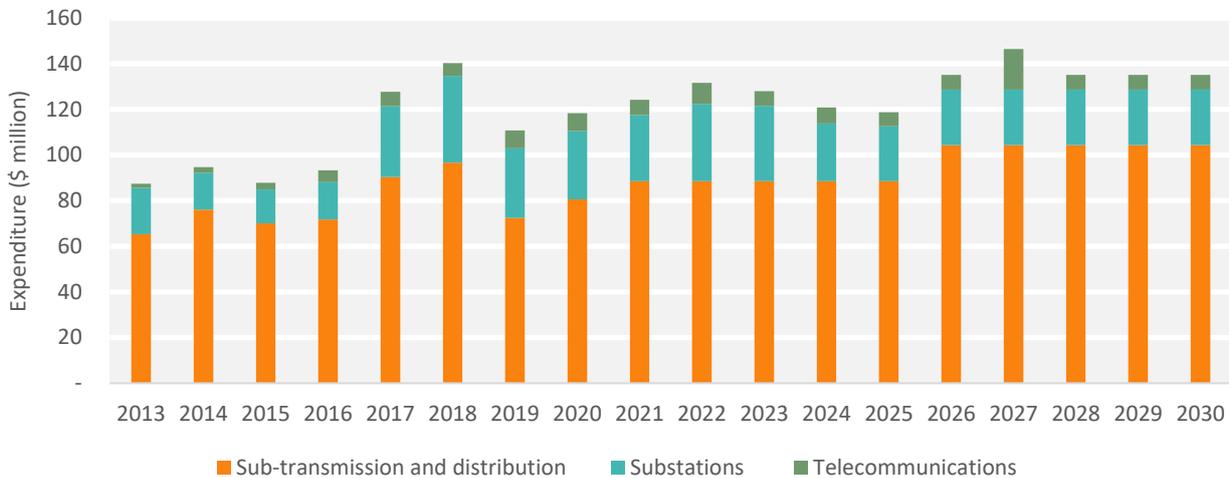


Figure 164: Asset renewal/replacement historical and forecast expenditure profile (\$2018 million, including overheads)

Figure 164 shows an increase in expenditure across substation and line assets in 2017 and an increase in 2018 to approximately \$140 million per annum and reducing to around \$120 million per annum to 2025 largely driven through expensing cable and conductor repairs and then increasing to around \$135 million per annum thereafter largely driven by forecast repex expenditure increases for poles and pole top structures.

Figure 165 shows the proportion of forecast capital expenditure from Figure 164 for the period 2018–2030 split by system and asset class for the renewal/replacement expenditure program.

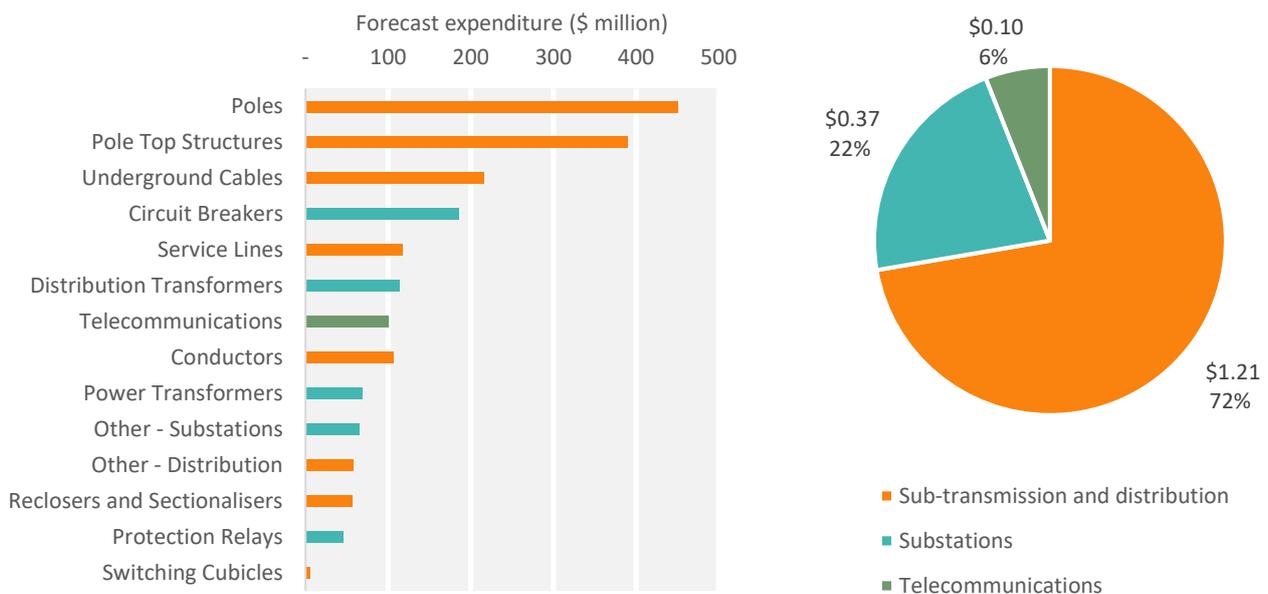


Figure 165: Asset renewal/replacement expenditure forecast 2018–2030 – asset class expenditure and proportion of asset renewal/replacement expenditure by system (\$2018, including overheads)

Figure 165 shows:

- approximately 76% of asset renewal/replacement program expenditure is within the sub-transmission system and distribution networks; and
- expenditure in poles, pole top structures and cables represents approximately half of the forecast 2018-2030 renewal/replacement expenditure.

12.5.1.1 Sub-transmission and distribution system assets

Figure 166 shows the total historical and forecast renewal/replacement expenditure profile for sub-transmission system and distribution networks split by asset class.



Figure 166: Sub-transmission and distribution asset renewal/replacement historical and forecast expenditure profile (\$2018 million, including overheads)

Figure 166 shows:

- a notable increase in expenditure from 2016-2021 mainly driven through an increase in poles, pole top structure, cable and conductor replacements increasing to 2021 and then stabilising; and
- pole top structures and poles comprise approximately 42% of the sub-transmission system and distribution network renewal/replacement proposed expenditure for 2018–2030.

12.5.1.2 Substation assets

Figure 167 shows the total historical and forecast renewal/replacement expenditure profile for substation assets split by asset class.



Figure 167: Substation asset renewal/replacement historical and forecast expenditure profile (\$2018 million, including overheads)

Figure 167 shows:

- a decline in substation renewal/replacement expenditure from approximately \$38 million in 2018 down to \$25 million in 2025 mainly driven through a decrease in forecast expenditure on circuit breakers and power transformers;
- circuit breakers and power transformers comprising approximately 70% of the forecast substation asset renewal/replacement expenditure for 2018-2030.

12.5.1.3 Telecommunication assets

Figure 168 shows the total historical and forecast renewal/replacement expenditure profile for telecommunication assets.

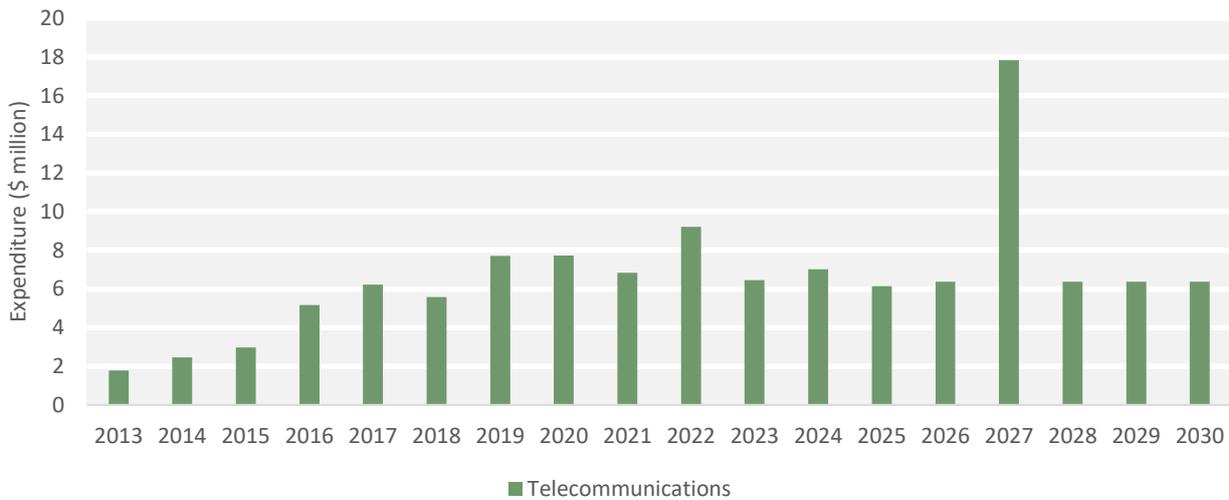


Figure 168: Telecommunications asset renewal/replacement historical and forecast expenditure profile (\$2018 million, including overheads)

Figure 168 shows:

- a relatively stable long-term expenditure profile generally \$6–\$8 million per annum from 2019-2030; and
- notable increase in expenditure in 2027 due to several major system upgrades including the utility private automatic exchange business telephone network, Telecommunications Network Operations Centre management systems and operational technology cyber security.

12.5.2 Customer connections historical and forecast expenditure

Figure 169 to Figure 171 show the total historical and forecast expenditure profile of the forecast customer connection expenditure (gross, contributions and net) for new connections, alterations of existing connections and real estate developments split by connection type. In the absence of any long-term forecast data, the 2026-2030 connection forecasts are based on an average of the forecast 2021-2025 expenditure for each connection category.

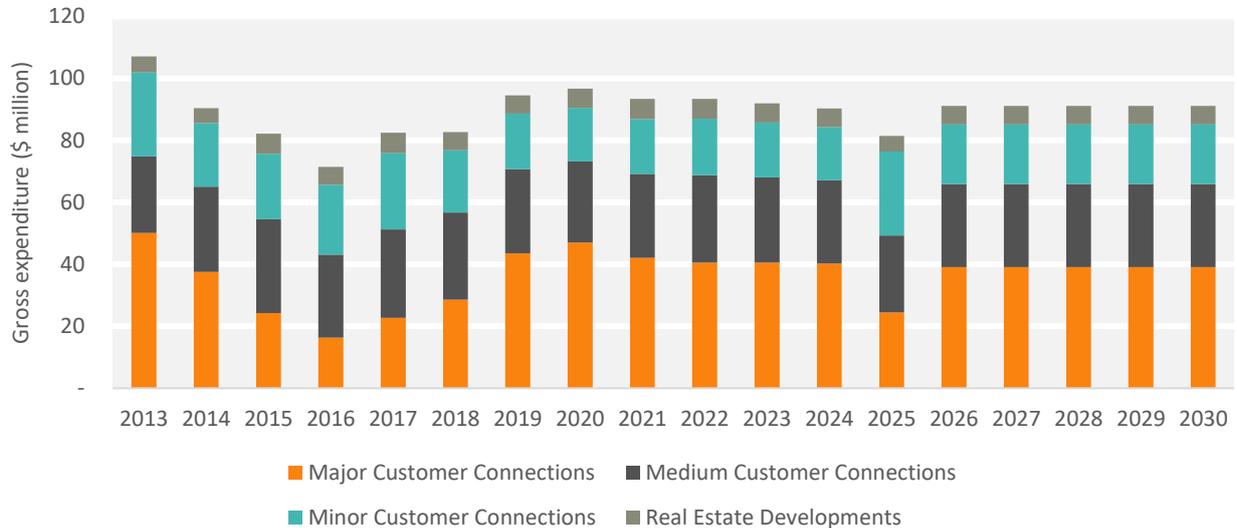


Figure 169: Customer connection historical and forecast expenditure profile (gross) (\$2018 million, including overheads)

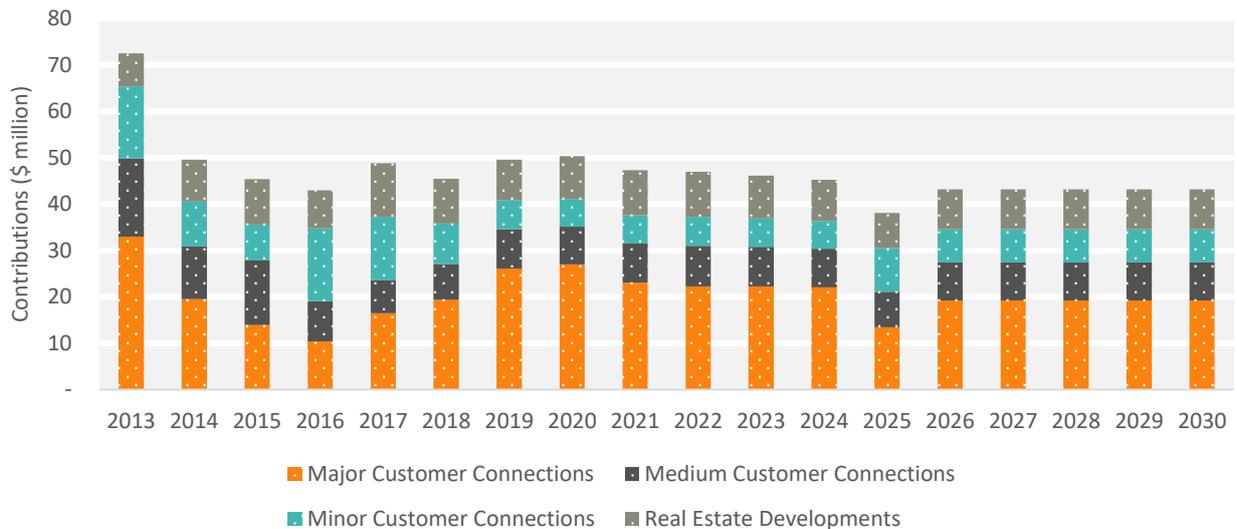


Figure 170: Customer connection historical and forecast expenditure profile (customer contributions) (\$2018 million, including overheads)

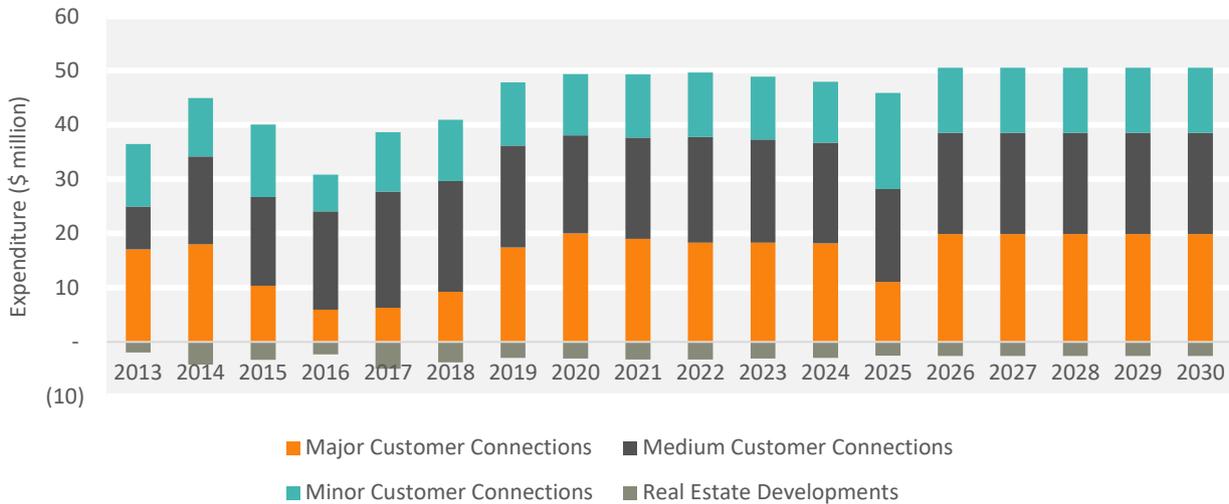


Figure 171: Customer connection historical and forecast net expenditure profile (\$2018 million, including overheads)

Figure 171 shows an increase in connections net expenditure from 2016 to 2020 before a slight decline in 2025 and plateauing around \$48 million per annum net expenditure mainly due to the forecast fluctuations in major connections expenditure in the forecast economic outlook out to 2026 (BIS Oxford Economics, 2018).

12.5.3 Network augmentation historical and forecast expenditure

Figure 172 shows the total historical and forecast asset augmentation (capacity upgrade) expenditure profile split by asset class.

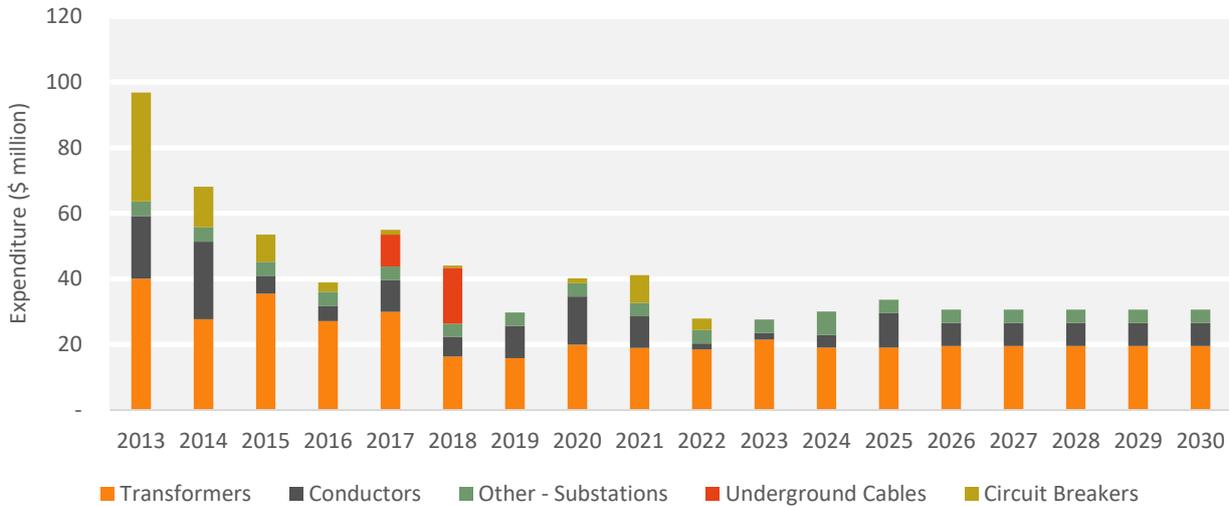


Figure 172: Assets augmentation historical and forecast expenditure profile (\$2018 million, including overheads)

Figure 172 shows:

- a sharp decrease in augmentation expenditure since 2013 due to fewer network constraints to meet required capacity (see Section 7.3).
- a reduction in forecast augmentation expenditure from 2019 due to completion of the second submarine cable to Kangaroo Island; and
- a relatively stable level of capacity upgrade expenditure of \$30–\$40 million per annum from 2019.

12.5.4 Safety historical and forecast expenditure

Figure 173 shows the total historical and forecast safety expenditure profile split by asset class.

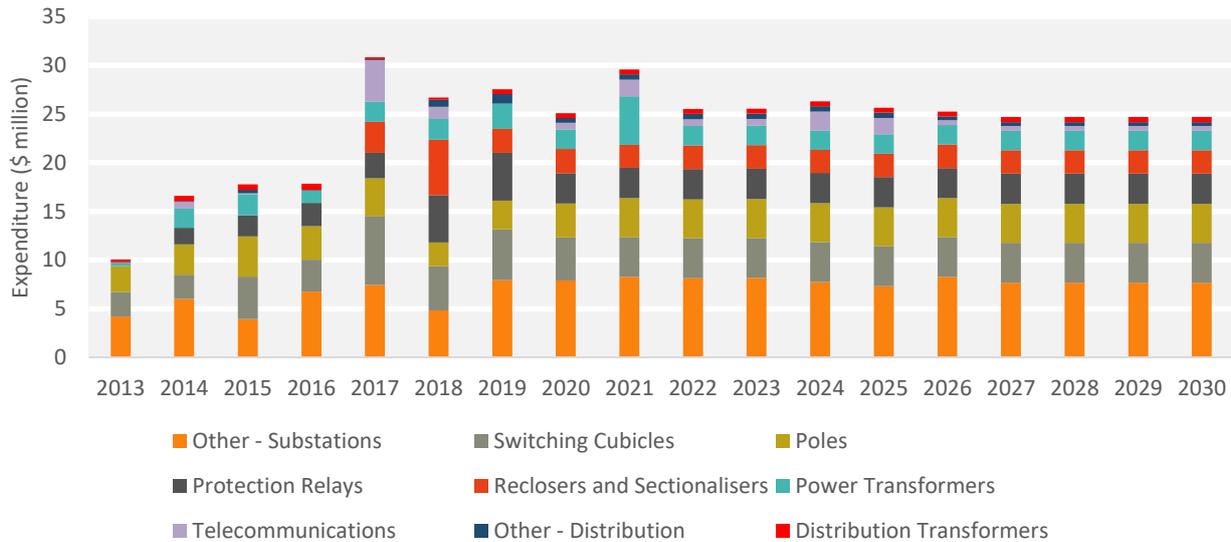


Figure 173: Safety historical and forecast expenditure profile (\$2018 million, including overheads)

Figure 173 shows:

- several peaks in annual expenditure in 2017 (\$31 million) and 2021 (\$30 million) but otherwise between \$25 to \$28 million per annum; and
- a variety of substation plant (substation – other) combined with switching cubicles comprising almost 50% of the proposed forecast safety program expenditure to 2030. The expenditure on other substation assets covers safety upgrades to security fencing, lighting and earth grids and on ongoing program of pipework switchyard rebuilds at several high-risk substation locations while a significant backlog of out of service switching cubicles that cannot be safely operated are planned for replacement.

12.5.5 Reliability and resilience historical and forecast expenditure

Figure 174 shows the total historical and forecast reliability and resilience expenditure profile.

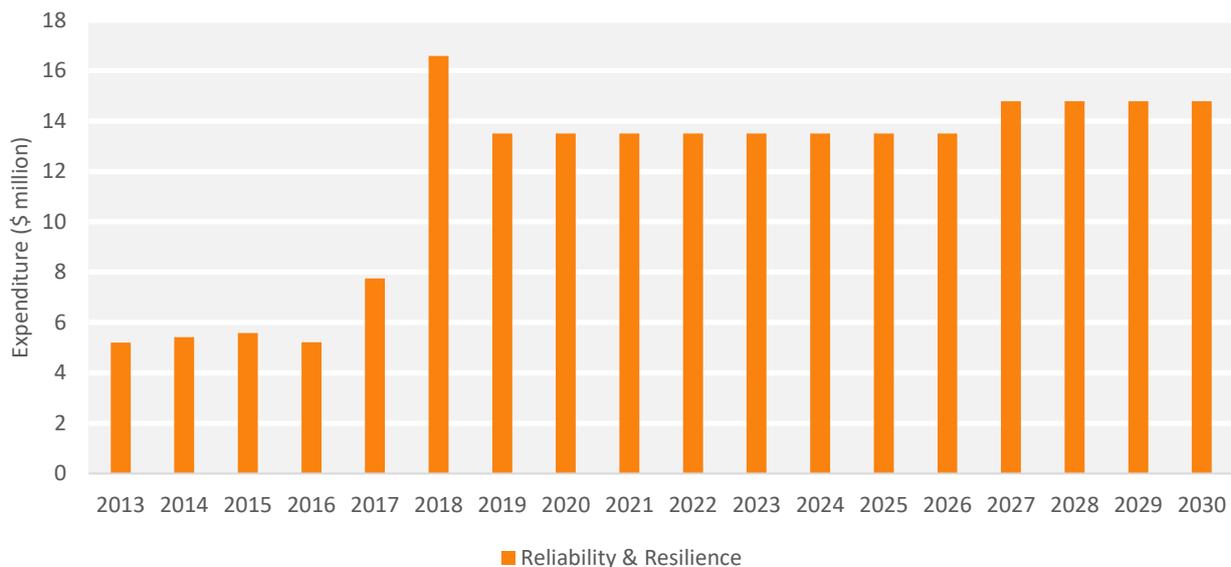


Figure 174: Reliability and resilience historical and forecast expenditure profile (\$2018 million, including overheads)

Figure 174 shows an increase in expenditure to approximately \$17 million during 2018 then plateauing to \$13–\$15 million per annum thereafter to 2030.

12.5.6 Network control historical and forecast expenditure

Figure 175 shows the total historical and forecast network control expenditure profile.

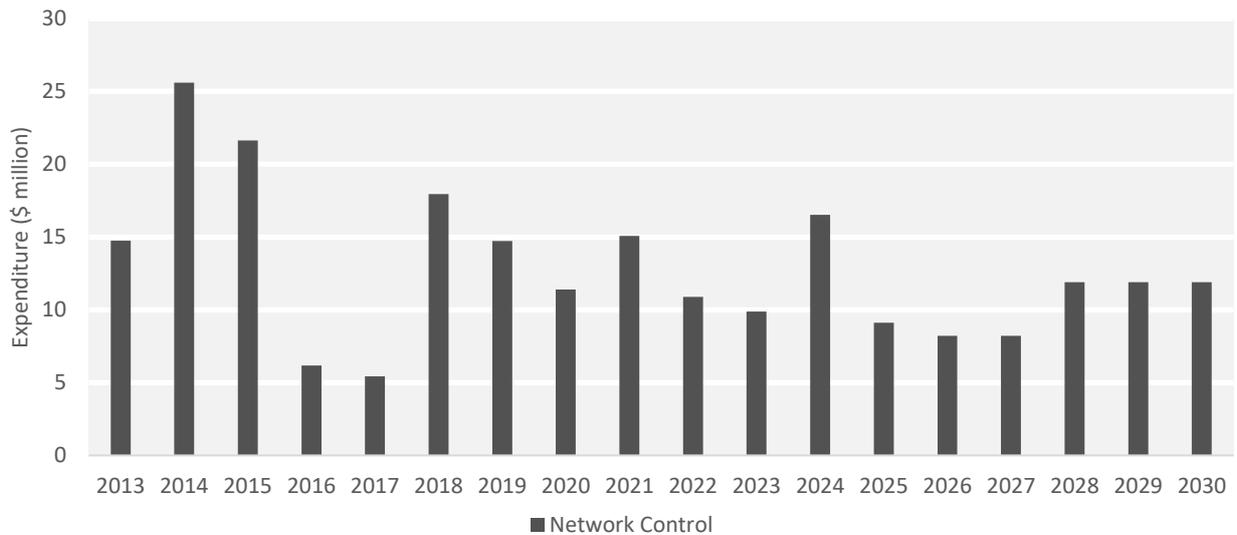


Figure 175: Network control historical and forecast expenditure profile (\$2018 million, including overheads)

Figure 175 shows:

- generally, a relatively stable level of expenditure of \$10-\$15 million per annum; and
- an increase above this level over the period of 2018-2021 due to the OMS replacement project and ADMS/OMS software and hardware upgrades as well as increased capital expenditure as part of the low voltage management strategy commencing from 2020.

12.5.7 Powerline Environment Committee historical and forecast expenditure

Figure 176 shows the total historical and forecast Powerline Environment Committee (PLEC) expenditure profile.

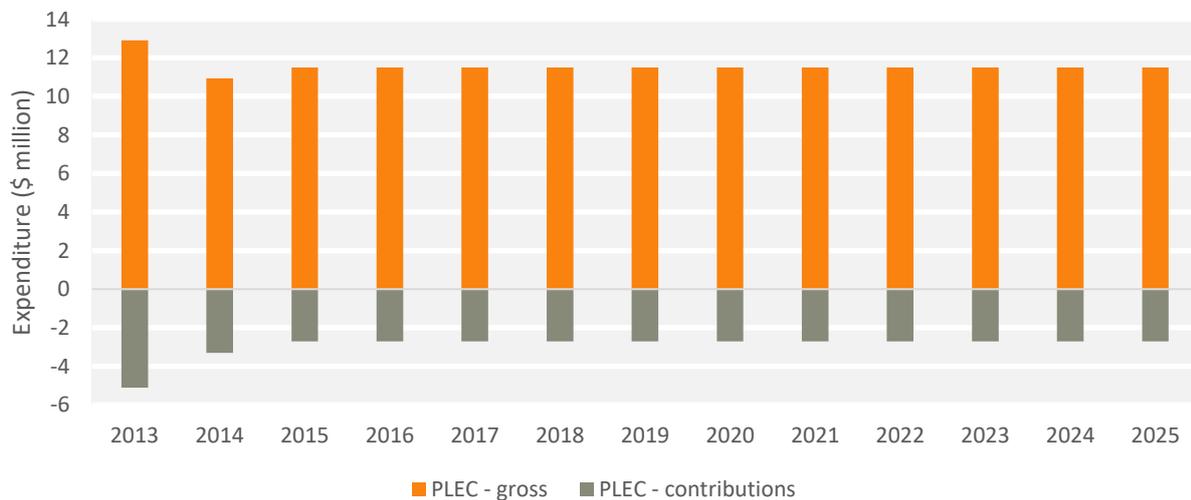


Figure 176: PLEC expenditure forecast 2018–2030 (\$2018 million, including overheads)

Figure 176 shows a stable level of SA Power Networks investment of \$11.5 million per annum out to 2030 (two-thirds contribution) in line with the *Electricity Act 1996* obligations.

12.5.8 Environmental historical and forecast expenditure

Figure 177 shows the total historical and forecast environmental expenditure.

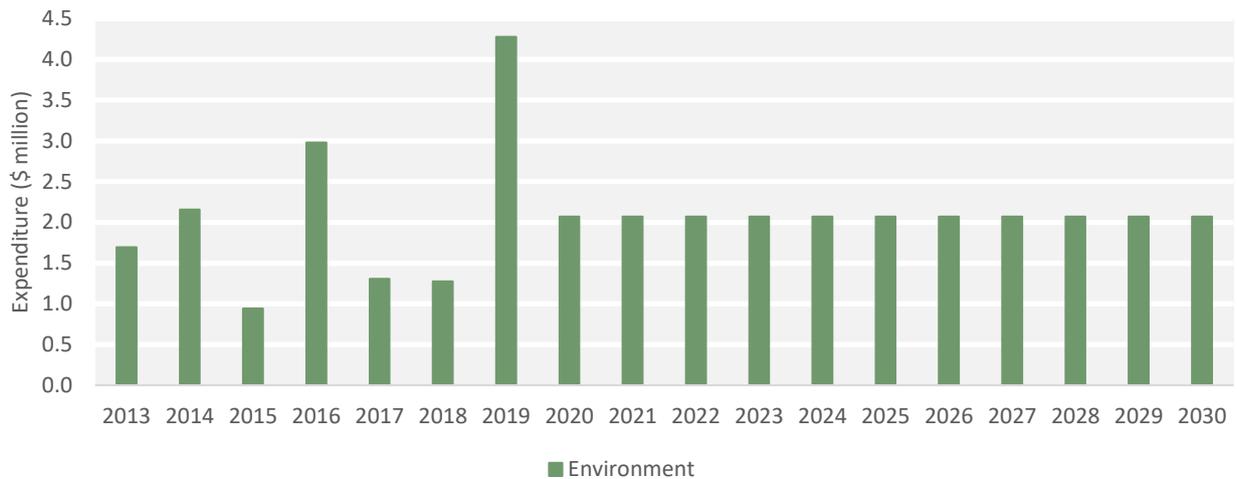


Figure 177: Environmental expenditure forecast 2018–2030 (\$2018 million, including overheads)

Figure 177 shows:

- a spike in expenditure during 2019 as a result of a 2018 fire at the Thebarton substation leading to oil contamination of the River Torrens with a subsequent desktop review finding four sites with concealed drainage systems which are being addressed during 2019; and
- an otherwise stable level of investment of approximately \$2 million per annum out to 2030.

12.5.9 Strategic network investment historical and forecast expenditure

The historical and forecast expenditure is largely for:

- development of and application of innovative technologies and trials for management of the network assets; and
- condition monitoring equipment.

12.6 Operations and maintenance historical and forecast expenditure

shows the historical expenditure (escalated to \$2018) and proposed forecast expenditure for operation and maintenance expenditure on the power assets from 2018 to 2030. While the operations and maintenance budgets are set annually, the forecast expenditure to 2030 is based on the 2018 forecasts remaining constant in real terms.

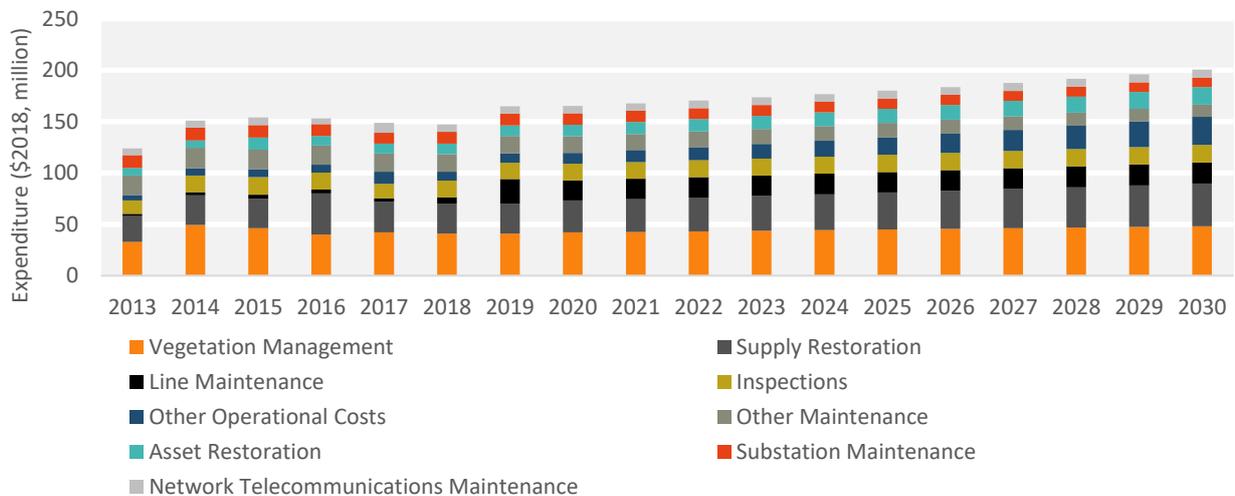


Figure 178: Operations and maintenance historical and forecast expenditure 2018–2030 (\$2018 million, including overheads)

Figure 178 shows:

- a slight decrease (in real terms) to 2018 in operation and maintenance expenditure from the 2015 peak;
- an increase in operation and maintenance expenditure from 2019 with cable and conductor repairs expensed; and
- an otherwise relatively stable level of investment across the various operations and maintenance activities since 2014; and
- vegetation management and supply restoration account for approximately half of the total operations and maintenance costs.

Figure 179 shows the total operations and maintenance expenditure by operations and maintenance activity for 2018-2030.

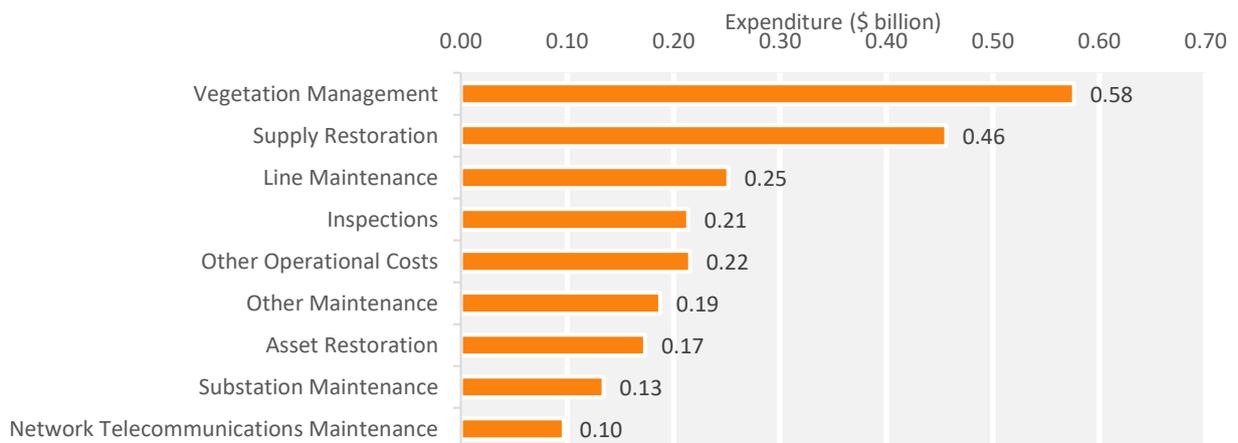


Figure 179: Forecast operations and maintenance expenditure programs (\$2018, including overheads)

Figure 179 shows:

- vegetation management is the highest operational cost for managing network assets; and
- line, substation and telecommunication maintenance are collectively less than 20% of the total operations and maintenance costs.

For further detail on the proposed operations and maintenance forecasts and programs of work, see Appendix 12.3.

13 Appendices

13.1 Corporate risks and controls for the power network

WARNING: Printed copies of this document ARE DEEMED UNCONTROLLED. The most up-to-date version is located on the Intranet/Internet.

Risk description	Risk Category	Inherent Risk	Controls	Residual Risk Ranking
Injury or death of our staff, contractors or the public	Operational/ Asset	High	<p>Training: Employees are adequately prepared with the skills they need to undertake work and respond appropriately during a bushfire</p> <p>Governance: Formal guidance and policies and procedures are provided to workers to promote awareness of key processes</p> <p>Contractor management: A number of key processes are in place to manage the safety of contractors</p> <p>Operational controls: Operational measures exist that are designed to identify safety related issues and effectively mitigate safety risk</p> <p>Protective equipment: Workers are provided with protective equipment to safely undertake their role in each specific scenario</p> <p>Dedicated resources: The business has a dedicated Work Health and Safety (WHS) Branch, with resources focused on WHS; other resources are focused on other aspects of safety, such as workers compensation and rehabilitation</p>	High
A bushfire event caused by SA Power Networks assets, staff or operations	Operational/ Asset	High	<p>Training: Employees are adequately prepared with the skills they need to undertake work and respond appropriately during a bushfire</p> <p>Policies and procedures: A number of policies and procedures cover the operational aspect of working in a bushfire area, as well as the management of bushfire events</p> <p>Asset management: A number of processes exist to ensure adequate asset inspection and maintenance</p> <p>Communications: Preparation for bushfire events, as well as communicating to workers effectively in the event of a bushfire</p> <p>Vegetation management: A formal approach to ongoing vegetation management, in line with legislative/regulatory requirements</p> <p>Governance: Several committees and groups across the business are dedicated to the ongoing management and review of bushfire mitigation/management activities</p> <p>Operational controls: A number of operational controls are aimed at identifying and managing potential and actual bushfire event risks</p> <p>Insurance: Management of financial risk through placement of bushfire insurance coverage</p>	High
Lack of appropriate crisis and emergency management and business continuity planning resulting in an inability to adequately respond in a crisis or emergency and ensure the continuity and performance of the business	Operational	Extreme	<p>Training: Staff understand their role in a crisis/emergency, with training developed to encourage and facilitate critical thinking</p> <p>Policies and procedures: A number of policies and procedures cover the operational aspect of crisis, emergency and business continuity management</p> <p>Resourcing: Dedication of personnel and budget focused on crisis, emergency and business continuity management (ongoing and during events)</p> <p>Operational controls: A number of operational controls are aimed at identifying and managing potential emergency and crisis situations</p> <p>Governance: A number of committees and groups across the business are dedicated to the ongoing management and review of crisis and emergency events</p> <p>Communication: Preparation for crisis and emergency management events, as well as communicating to workers effectively during events</p>	Medium
Failure to supply energy services that customers value, adversely impacts our reputation, financial performance and our positioning for the future	External/ Operational/ Asset	Extreme	<p>Training: Staff are trained in customer service</p> <p>Standards and reporting: Customer service performance is tracked, acted upon and reported on an ongoing basis</p> <p>Strategy: The business has the customer as a key focus in a number of its strategic documents</p> <p>Customer interaction and communication: A number of systems and processes exist to manage interactions with customers</p> <p>Policies and procedures: The management of customers is formally documented</p> <p>Market understanding: The business scans the external environment to determine what customers value</p>	High
Failure to meet the financial objectives of the business and the expectations of shareholders	Operational	High	<p>Resourcing: Adequate resourcing, in conjunction with external assistance, facilitates the achievement of financial objectives</p> <p>Strategy and budgeting: A number of strategy, programs and projects are in place to ensure a focus on strong financial performance</p> <p>Risk management: The level of risk the Board is willing for SA Power Networks to take is formally documented</p> <p>Operational controls: A number of operational controls are in place aimed at meeting financial objectives of the business</p> <p>Communications: Ongoing communications with management and shareholders to confirm budget, returns and financial performance</p> <p>Policies and procedures: The management and treatment of core financial processes is formally documented</p>	Low
Inadequate or inappropriate workforce planning and training for all employees results in insufficient skills and/or resourcing levels, impacting SA Power Networks safe and reliable delivery of operations	Operational	Extreme	<p>Training: A formal and structured approach to training and professional development</p> <p>Strategy: Planning and strategy form the basis of workforce planning</p> <p>Resources: Dedicated resources allow for training and workforce planning to be a key focus</p> <p>Operational controls: A number of operational controls are aimed at effective workforce planning and training</p>	Medium
Failure to comply with legal, statutory or regulatory obligations resulting in fines, penalties, investigations, prosecution (civil and criminal), loss of distribution licence	External/ Operational	High	<p>Identification: A number of controls are in place to identify legal, statutory and regulatory obligations</p> <p>Review & communication: Legal, statutory and regulatory requirements are analysed by dedicated resources and communicated throughout the business</p> <p>Monitoring: Compliance is monitored on an ongoing basis</p> <p>Reporting: Compliance reporting is provided to a number of internal and external stakeholders</p>	Medium

Risk description	Risk Category	Inherent Risk	Controls	Residual Risk Ranking
and/or financial and reputational impacts				
Major loss of supply through ineffective operations, asset management or external factors (including loss of the interconnector)	External/ Operational/ Asset	High	<p>Policies and procedures: The management of assets and loss of supply events are formally documented</p> <p>Training: A formal and structured approach to training and professional development</p> <p>Resourcing: A number of resources across the business are dedicated towards ongoing management of emergency and crises</p> <p>Technology: A number of systems provide visibility of supply events</p> <p>Asset management: There is a formal approach to understanding our assets, and managing and maintaining them</p> <p>Management of loss of supply: When a major loss of supply occurs a number of plans and resources are utilised and mobilised</p> <p>Operational controls: A number of operational controls are aimed at mitigating major loss of supply</p>	High
Inadequate consideration of the impacts and opportunities arising from new technologies and business, including safety, financial, customer and operational	External/ Operational	High	<p>Strategy: A formal strategic direction and framework is in place to ensure consideration of potential opportunities and their impacts</p> <p>Resourcing: Skilled resources are dedicated to the execution of initiatives to pursue non-traditional and emerging business opportunities</p> <p>Risk management: The level of risk the Board is willing for SA Power Networks to take is formally documented</p> <p>Operational controls: A number of operational controls are in place aimed at considering impacts and opportunities arising from new technology/business</p>	High
Lack of appropriate or effective IT systems and processes to support the business	Operational	High	<p>Strategy: IT within the business is aligned to a long term corporate strategy</p> <p>Governance: Several committees and groups in place for providing support to the management of IT programs</p> <p>Resourcing: Dedicated resources across the organisation provide support to staff with their IT requirements (current and future)</p> <p>Operational controls: There are a number of operational controls in place aimed at providing effective systems and processes</p>	Medium
Inability to restore supply within expected timeframes results in guaranteed service level (GSL) impacts	Operational	High	<p>Policies and procedures: The management of assets and loss of supply events are formally documented</p> <p>Training: A formal and structured approach to training and professional development</p> <p>Resourcing: A number of resources across the business are dedicated towards ongoing management of reliability with increased resourcing on high risk days</p> <p>Technology: A number of systems provide weather forecasting to identify parts of the network most at risk and visibility of network outages when they occur</p> <p>Asset management: There is a formal approach to understanding our assets, and managing and maintaining them</p> <p>Management of loss of supply: When a loss of supply occurs a number of plans and resources are utilised and mobilised</p> <p>Operational controls: A number of operational controls are aimed at mitigating GSL impacts including an escalation procedure</p>	High
Uncapped GSL payment liability and reputational damage arising from major weather event	External	High	<p>Policies and procedures: The management of assets and loss of supply events are formally documented</p> <p>Training: A formal and structured approach to training and professional development</p> <p>Resourcing: A number of resources across the business are mobilised to areas forecast to be most impacted by major weather events with the SA Power Networks' Network Operations Centre (NOC) resourced on 24/7 basis</p> <p>Technology: There are a number of systems that provide weather forecasting to identify parts of the network most at risk and visibility of network outages when they occur</p> <p>Asset management: There is a formal approach to manage major assets to enable load transfers across the network for abnormal operating conditions and the use of mobile plant to provide emergency supply</p> <p>Management of loss of supply: When a loss of supply occurs a number of plans and resources are utilised and mobilised</p> <p>Operational controls: A number of operational controls exist aimed at mitigating GSL impacts including an escalation procedure once a duration time is exceeded</p> <p>Communication: Dedicated resources using a number of communication channels and platforms to inform customers of network outages during major event days</p>	High
Extended summer heatwave conditions cause extended outages	External	High	<p>Policies and procedures: The management of assets and loss of supply events are formally documented</p> <p>Training: A formal and structured approach to training and professional development</p> <p>Resourcing: A number of resources across the business are dedicated towards ongoing management of emergency and crises and communication to customers during extended heatwave outages</p> <p>Technology: A number of systems provide weather forecasting and visibility of network loads, supply events and locating network faults</p> <p>Asset management: There is a formal approach to manage major assets to enable load transfers across the network for abnormal operating conditions, the use of mobile plant, and South Australian Government battery storage and turbine generators to provide emergency supply</p> <p>Management of loss of supply: When a major loss of supply occurs a number of plans and resources are utilised and mobilised</p> <p>Operational controls: A number of operational controls are aimed at mitigating impacts of extended outages during heatwaves</p> <p>Communication: Dedicated resources using a number of communication channels and platforms to inform customers of network outages during heatwaves</p>	High
Failure to maintain a reliable network or restore supply in a timely manner resulting in financial penalties (e.g. Service Target Performance Incentive Scheme (STPIS) penalties)	Operational	Extreme	<p>Policies and procedures: The management of assets and loss of supply events are formally documented including reviews of major outages</p> <p>Training: A formal and structured approach to training and professional development</p> <p>Resourcing: A number of resources across the business are dedicated towards ongoing management of reliability and STPIS impacts</p> <p>Technology: A number of systems provide weather forecasting and visibility of supply events and locating network faults</p> <p>Asset management: There is a formal approach to understanding our assets, and identifying assets where reliability enhancement programs can provide a cost effective improvement to reliability service standards</p>	High

Risk description	Risk Category	Inherent Risk	Controls	Residual Risk Ranking
Unauthorised access to property, substation or transformer/regulator station resulting in injury, damage or interruption of supply to third parties	External	High	<p>Management of loss of supply: When a major loss of supply occurs a number of plans and resources are utilised and mobilised</p> <p>Operational controls: A number of operational controls and plans are aimed at mitigating STPIS impacts</p> <p>Policies and procedures: The management of authorised access to access or inspect assets are formally documented</p> <p>Training: A formal and structured approach to training and professional development</p> <p>Resourcing: A number of resources across the business are dedicated towards ongoing management of authorised access and responding to unauthorised access</p> <p>Technology: A number of systems provide visibility of authorised site access</p> <p>Asset management: There is a formal approach to the installation and management of security infrastructure at high risk sites</p> <p>Operational controls: A number of operational controls are aimed at preventing and responding to unauthorised access to network assets</p> <p>Communication: A formal communication process for access to major network assets between field staff and the NOC</p>	High
Inability to meet load demands during outages due to insufficient system capacity	Asset	High	<p>Policies and procedures: A formal customer connection process and periodic reviews of system forecast loads and network constraints</p> <p>Training: A formal and structured approach to training and professional development</p> <p>Resourcing: Dedication of personnel and budget focused on crisis, emergency and business continuity management (ongoing and during events)</p> <p>Technology: A number of systems provide visibility of network loads and loss of supply events</p> <p>Asset management: There is a formal approach to understanding our assets, and managing and maintaining them</p> <p>Management of loss of supply: When a major loss of supply occurs a number of plans and resources are utilised and mobilised</p> <p>Operational controls: A number of operational controls and contingency plans exist aimed at mitigating loss of supply and transfer of load across the network</p>	Medium
Unreliable mobile radio network doesn't provide essential communications during operations or emergencies	External/ Operational	High	<p>Policies and procedures: The management of assets and loss of supply events are formally documented</p> <p>Resourcing: Dedication of personnel and budget focused on crisis, emergency and business continuity management (ongoing and during events)</p> <p>Asset management: There is a formal approach to understanding our telecommunications assets, and managing and maintaining them</p> <p>Operational controls: A number of operational controls are aimed at mitigating loss of mobile radio communications including use of mobile phones and landlines</p>	High
Assets or activities causing environmental harm to air, land, water, flora and fauna, with remediation costs >\$5,000	Asset	High	<p>Policies and procedures: The management of environmental issues arising from assets within an environmental management system</p> <p>Training: A formal and structured approach to training and professional development including awareness of the environmental management system</p> <p>Resourcing: Dedication of personnel and budget focused on environmental management (ongoing and during events)</p> <p>Asset management: There is a formal approach to understanding and managing the environmental risks posed by assets including installation of new infrastructure and decommissioning and disposal of assets</p> <p>Operational controls: A number of operational controls are aimed at mitigating environmental risks</p>	Medium
Changes to energy market structures, laws and regulations could preclude SA Power Networks from earning a fair return on investment within the network business or otherwise constrain the non-regulated areas of the business	External	High	<p>Strategy: A formal strategic direction and framework is in place to ensure consideration of potential opportunities and their impacts</p> <p>Resourcing: Skilled resources are dedicated to the execution of initiatives to pursue non-traditional and emerging business opportunities</p> <p>Risk management: The level of risk the Board is willing for SA Power Networks to take is formally documented</p> <p>Operational controls: A number of operational controls in place aimed at considering impacts and opportunities arising from new technology/business</p>	High

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