Monitoring, evaluation, and compliance strategy

June 2025

SA Power Networks

Empowering South Australia

Contents

Document Control

Version	Date	Author	Notes
1	June 2021	Grant Cox	First version of the MECS
2	June 2022	Grant Cox	It is substantially the same as we published last year, with updates only in Section 3.6e (our 'Value and visibility' approach to maintaining assets) Section 6.5 (Reliability Performance focus areas) and section 7 (to include actual 2020/21 performance outcomes)
3	June 2023	Grant Cox	Update to Sections 3.1 (distribution system asset breakdown) and 7 (includes 2021-22 performance), new Sections 3.2 Safety Reliability Maintenance and Technical Management Plan (SRMTMP), 6.5.e Rural Network Restoration Performance and 3.7 Reliability Management.
4	June 2024	D Kurbatfinski / Grant Gox	2024 Update
5	June 2025	D Kurbatfinski / Grant Gox	2025 Update. Includes EDC 14.1 updates.

1. Introduction

About SA Power Networks

As South Australia's primary electricity distribution network service provider, SA Power Networks plays a vital role in powering our state. We manage the distribution network that delivers electricity to over 900,000 homes and businesses across South Australia, ensuring a safe, reliable, and efficient supply of energy.

Our network spans over 178,000 km², with a total route length exceeding 90,000 km and an estimated replacement value of $65 billion. This extensive infrastructure enables us to deliver electricity to almost every corner of the state, supporting the daily lives of South Australians and the growth of our economy.

We provide a fully managed electricity distribution service, which includes:

- Monitoring the network 24/7 to ensure safety and reliability;
- Connecting new customers and supporting growing demand for load and export services;
- Managing safety risks and addressing reliability and quality of supply issues;
- Promptly restoring power during outages and keeping customers informed; and
- Complying with all relevant Acts, regulations, and service standards.

Adapting to Change and Meeting Challenges

The energy landscape is evolving rapidly, and so are the expectations of our customers and stakeholders. As we commence the next regulatory control period (2025–30), we are committed to balancing the investment needed to maintain a safe and reliable network with the need to keep costs down. This includes accommodating the changing ways customers use energy, such as increased renewable energy exports, while enabling the clean energy transition and ensuring equity for all South Australian customers.

Our **Monitoring, Evaluation, and Compliance Strategy** (**MECS**) outlines how we monitor and evaluate our performance, ensuring compliance with the customer service and reliability standards set out in the **Electricity Distribution Code** (**EDC**). From 1 July 2025, a revised EDC (V14/1) will come into effect. Section 2 of this document summarises the key changes in the new EDC.

We also address the challenges of managing our network assets, improving our asset management capabilities, and responding to emerging trends, such as climate change and technological advancements.

Customers and Stakeholders

Our customers and stakeholders are diverse, widespread, and evolving. We serve almost the entire population of South Australia, and as the state grows, so does the number of customers we support. Technological advancements are transforming the energy industry, and our customers' expectations are changing just as quickly. Customers want:

1. A safe and reliable electricity supply;
2. High-quality service;
3. Support for the clean energy transition; and
4. Affordable prices, with a focus on equity.

They also want better information about outages and restoration times, as well as greater transparency around costs. We are committed to meeting these expectations while enabling customers to use the network in new ways, including as both consumers and exporters of energy.

Purpose of this Document

SA Power Networks is required by our electricity distribution licence to comply with the South Australian EDC. Clause 2.6 of the EDC requires us to prepare an annual MECS, which explains how we plan to meet the service standards defined in Clauses 2.1 to 2.4 of the EDC. These standards include:

- Customer service measures (Clause 2.1),
- Reliability measures (Clause 2.2),
- Guaranteed Service Level (GSL) payments (Clause 2.3), and
- Reconnection after disconnection (Clause 2.4).

This document outlines our approach to achieving these standards and is structured as follows:

- Section 1: Introduction
- Section 2: Our service standard obligations
- Section 3: Maintaining our network
- Section 4: Environmental and external factors
- Section 5: Current issues impacting network reliability
- Section 6: Emerging trends impacting network reliability
- Section 7: Use of best endeavours
- Appendix A: Our risk management framework

This document complements the public version of our Annual Operational Performance Report, which details our performance against prescribed service standards over the past regulatory year, and our **Distribution Annual Planning Report** (**DAPR**)[1] which provides a summary of our proposed works for the five years forward planning period.

2. Service standard obligations

SA Power Networks is required by its distribution licence to comply with the service standards contained in the EDC. The EDC requires us to use 'best endeavours' to achieve the service standard targets for each year ending 30 June.

The EDC Clause 1.5.1 defines best endeavours as 'to act in good faith and use all reasonable efforts, skill and resources'. As the service standard obligation is to use best endeavours, we can still comply with a service standard obligation, despite not achieving the target, providing we can demonstrate we have used best endeavours.

The **Essential Services Commission of South Australia** (**ESCoSA**) periodically reviews the EDC service standards, normally in the lead up to the **Australian Energy Regulator's** (**AER's**) regulatory reset for SA Power Networks. The service standard measures and targets for the 2025-30 EDC came into effect 1 July 2025.

The key elements to the revised EDC include:

- Retention of the existing network reliability and restoration service standards, and existing regional performance reporting requirements.

[1] Distribution Annual Planning Report (sapowernetworks.com.au)

- Inclusion of two new customer service standards related to telephone responsiveness and first contact resolution on the General Enquiries phone line and the Builders and Contractors' phone line, and limit the existing customer service standard for telephone enquiry responsiveness to SA Power Networks' other telephone lines (most significantly, the Faults and Emergencies line). This will come into effect 1 July 2028.
- Removal of the street light fault repair service standard and the street light repair **Guaranteed Service Level** (**GSL**) payment and expand annual reporting on street light fault repairs to monitor the impact of those changes. A street light repair service level is included in the SA Power Networks' Public Lighting Service Framework.

SA Power Networks is also required by its distribution licence to provide information to ESCoSA and the **Office of the Technical Regulator** (**OTR**) in accordance with the Electricity Industry Guideline 1[2]. Notable changes in Electricity Guideline No. 1 include:

- the addition of reporting requirements related to the new customer service standards, complaint responsiveness and escalation, SA Power Networks' performance delivering the CBD reliability improvement program, and street light fault repair.
- the retention of Technical Regulator reporting requirements, with a new requirement that this reporting is provided directly to the Technical Regulator.
- removal of reporting requirements related to the street light repair GSL payment and generation embedded within the distribution network.

3. Monitoring, evaluation and compliance strategies

SA Power Networks' objective is to achieve the service standards specified in the EDC Clauses 2.1 to 2.4 for each year ending 30 June.

SA Power Networks has implemented, and continuously improves, its procedures and practices to monitor and evaluate our performance, implement improvements to address any long-term decline in performance (i.e. to maintain historic performance) and to improve historic performance where the benefit to customers exceeds the costs of those improvements. Further, where the reliability of a power line declines, we will implement improvements to correct that decline (i.e. return to reliability levels that existed prior to the decline).

The following sections summarise the four categories of service standards and targets (where specified), for the 2025-30 **Regulatory Control Period** (**RCP** – i.e. 1 July 2025 to 30 June 2030), along with the strategies we have in place to monitor and evaluate our performance against these standards.

3.1 Board commitment to compliance

SA Power Networks' Board Compliance Policy outlines our commitment to conducting business activities in full compliance with all relevant legal, regulatory, and contractual obligations, as well as internal policies, directives, procedures, and guidelines. The Policy states:

SA Power Networks will conduct its business activities in compliance with all relevant legal, regulatory and contractual obligations as well as policies, directives, procedures and guidelines.

[2] ESCoSA, Electricity Regulatory Information – Requirements – Distribution, Electricity Industry Guideline 1 Ver G1/14

The Policy provides a detailed framework to ensure compliance and minimise the risk of non-compliance. This is achieved through a structured compliance system that includes the following key elements:

- identification of obligations;
- designation of responsibility for compliance with those obligations;
- implementation of processes, procedures and other controls where applicable to ensure compliance;
- information and education about those obligations;
- the promotion of the importance of compliance;
- monitoring assessment of compliance;
- reporting on compliance and non-compliance; and
- management and independent review via Head of Audit, Risk and Compliance of the compliance system.

This systematic approach ensures that risks associated with non-compliance including financial loss, regulatory or legislative penalty and reputational consequences are mitigated. The approach supports a compliance culture throughout the business, demonstrates SA Power Networks' commitment to being a good corporate citizen and enhances the relationships with key stakeholders.

3.2 Customer service measures

There are two customer service standards defined in the EDC relating to communication with our customers:

- Time to respond to telephone calls; and
- Time to respond to written enquiries.

These standards measure how quickly we respond to customer enquiries by both telephone and written responses.

From the 1 July 2028 onwards, SA Power Networks will be required to achieve:

- separate customer service standards for telephone responsiveness and first contact resolution on its general enquiries phone line, and
- separate customer service standards for telephone responsiveness on its builders and contractors phone line and an additional customer service quality measure for builders and contractors.

The performance targets for these service standards will be established based on our performance during the period 1 July 2025 to 30 June 2027 and will be published on ESCoSA's website prior to 1 July 2028.

3.2.1 Responding to telephone calls

Service standard definition

SA Power Networks is required to use best endeavours to meet the service standard for responding to telephone calls as set out in Table 1 for each year ending 30 June.

Table 1: Customer service measures and targets

Category	Customer service to measure	Target
Customer service – telephone responsiveness	Time to response to telephone calls - all telephone lines	85% within 30 seconds

The EDC defines responding to telephone calls as:

a) answering a customer's telephone call in person, or

b) answering a customer's telephone call after they have used an Interactive Voice Response system to elect to talk to an operator (with monitoring of the call waiting time commencing when the caller selects the relevant operator option and covers the time from this point until an operator picks up the call to deal with the caller's issue), or

c) answering a customer's telephone call by providing access to a computer/telephony based interactive service which can process calls by providing information or direct calls to a service officer, but does not include the answering of a call by being placed in an automated queue to wait for any one of the options above.

When responding to telephone calls, SA Power Networks must always use its best endeavours to ensure that all of the information provided, including that which is provided by means of a computer/telephony based interactive service, is current and accurate and that vital information for customers is not omitted.

Our strategy

SA Power Networks aims to optimise call handling processes, manage resources efficiently, and enhance the overall customer experience by answering calls within 30 seconds. To best maintain this standard, we use efficient workforce management utilising a mix of base contact centre agents and overflow members when necessary.

Real-time monitoring and reporting also identifies trends or issues as they arise, coupled with performance dashboards visible during operating hours. Training and development focussed on continuous improvement of our knowledge management system is also utilised as well as call back and queue management processes if agents are not able to action the enquiry within the call.

Faults and emergency contact centre

SA Power Networks' Faults and Emergency Contact Centre (i.e. 13 13 66) is staffed 24/7 to ensure that customers can contact us to report interruptions to their electricity supply and report emergencies (e.g. wires down).

Satellite contact centre

In addition to our regular Faults and Emergency Contact Centre we have established a capability to quickly establish a **Satellite Contact Centre** (**SCC**) during major events when call volumes are very high, to ensure that all faults and emergency calls are handled promptly. We ensure that we have sufficient employees trained to be called on to staff the SCC. The SCC generally takes inbound calls from the Faults and Emergencies line (13 13 66) but may also make outbound calls to Life Support Customers or the worst affected customers during an event to better understand customer impacts/priorities.

How we monitor and evaluate our performance

To ensure we answer telephone calls within the defined service standard we use a range of methods for monitoring our performance, we use intraday, daily and monthly reporting to identify trends as they arise. Within the contact centre there are large displays of the current day performance to provide real-time visibility to leaders and agents, dashboard style applications with daily results for leaders and managers, and end of month reporting for general reporting in the business. Additional reviews of accuracy are completed at the same time end of month reports are collated.

Should a problem with data from our telephony systems be identified, managers are notified and the issue is resolved with vendor support if required.

3.2.1 Responding to written enquiries

Service standard definition

SA Power Networks is required to use best endeavours to meet the service standard for responding to written enquiries as set out in Table 2 for each year ending 30 June.

Table 2: Customer service measures for written enquiries

Category	Customer service to measure	Target
Customer service – written enquiry responsiveness	Time to respond to written enquiries	95% within 5 business days after receipt of the written enquiry

A written enquiry is an enquiry from a customer by the use of:

- Email;
- Fax;
- SA Power Networks' website;
- Direct messaging on SA Power Networks' social media channels; or,
- a letter sent by a customer to SA Power Networks, via nominated enquiry channels, requesting information from us and/or making a complaint about an action of SA Power Networks.

A response to such an enquiry means direct or telephone contact or a written response in which we either answer the enquiry or acknowledge receipt of the enquiry and indicate the process and timetable to be followed in dealing with the enquiry.

Our strategy

We have established systematic processes to ensure all emails, social media and other written enquiries are responded to in order to meet or exceed the established service standard. We have contact centre agents who are multi-trained and utilise queue management techniques to triage customer enquiries.

How we monitor and evaluate our performance

Real-time monitoring and dashboards enable SA Power Networks to understand workflows and ensure this standard is met. We provide daily, weekly, and monthly reports on this target to continually optimise our processes and systems.

3.3 Reliability measures

There are three reliability measures for SA Power Networks' distribution system:

- **Unplanned System Average Interruption Duration Index** (**USAIDI**) — measures the average time in minutes that customers are without their electricity supply because of unplanned interruptions on the distribution system in the year ending 30 June;
- **Unplanned system average interruption frequency index** (**USAIFI**) — measures the average number of unplanned interruptions customers experience to their electricity supply in the year ending 30 June; and
- **Restoration of supply** — measures the percentage of customers who will on average have an unplanned interruption to their electricity supply where the duration exceeds a specified number of hours in the year ending 30 June.

To measure the distribution system's performance in a like for like manner, SA Power Networks' power line feeders are allocated into four categories defined by the EDC, as follows:

- **Central Business District** (**CBD**)– means a high voltage overhead powerline or underground cable in the CBD area supplying predominantly commercial, high-rise buildings, supplied by a predominantly underground distribution network containing significant interconnection between high voltage feeders;
- **Urban**– means a high voltage overhead powerline or underground cable, which is not a CBD feeder, and supplies a three-year average maximum demand over the three-year average feeder route length of greater than 0.3 MVA/km;
- **Rural Short** (**RS**) – means a high voltage overhead powerline or underground cable which is not a CBD feeder or urban feeder with a total feeder route length less than 200 km; and
- **Rural Long** (**RL**) feeder – means a high voltage overhead powerline or underground cable which is not a CBD feeder, urban feeder or a rural short feeder.

Table 3 below summarises information about each feeder category.

Table 3: EDC feeder category metrics

Feeder	CBD	Urban	Rural Short	Rural Long
Areas supplied	Part of the Adelaide square mile.	Greater Adelaide Metro Area and some parts of large regional towns	Eastern Hills (50%), Fleurieu Peninsula, Riverland and parts of large and medium regional towns.	Barossa, Eastern Hills (50%), Most of Eyre Peninsula, KI, Mid-North, Murraylands, Southeast, Upper North
% of customers	0.8%	69%	15%	15%
Circuit length of powerline (km)	320	26,500	14,120	49,500
Annual Consumption (GWh)	560	6,600	1,300	1,300

Due to large annual variations in feeder category reliability performance, the reliability service standards include a reporting threshold, which represents the expected variation in reliability for a feeder category.

SA Power Networks must demonstrate the use of best endeavours where the reliability of a feeder category is worse than the reporting threshold. The reporting threshold has been established at a level that, with normal variation in reliability, it should typically require SA Power Networks to demonstrate the use of best endeavours once every five years.

3.3.1 Network reliability standards

Service standard definition

SA Power Networks must use its best endeavours to achieve the minimum network reliability standards set out in Table 4, during every regulatory year ending 30 June. However, SA Power Networks is only required to report on how it applied *best endeavours* if we fail to meet the reporting threshold.

Table 4: SA Power Networks' minimum reliability service standard targets and reporting thresholds

Measure		CBD	Urban	RS	RL
USAIDIn (average minutes off supply per customer per annum)	Target Reporting threshold	15 20	110 125	200 220	290 330
USAIFIn (average number of supply interruptions per customer per annum)	Target Reporting threshold	0.15 0.20	1.15 1.35	1.65 1.85	1.75 2.10

These measures exclude planned interruptions and unplanned interruptions due to failures of the transmission network, generation failures, load shedding and failures in a customer's electrical installation.

The reliability service standard targets exclude interruptions that occur on a **Major Event Day** (**MED**)[3] which normally result from extreme weather events. The normalised reliability targets which exclude MEDs are designated with an 'n' (eg USAIDIn).

Our strategies

SA Power Networks operates and maintains the electricity infrastructure in accordance with its distribution licence obligations to ensure that:

- The network performance meets the **National Electricity Rules** (**NER**) and the South Australian EDC relating to system security and performance standards;
- Quality of supply is maintained to customers;
- Operational risks and hazards are identified and managed;
- The electricity infrastructure is secured to prevent unauthorised access; and
- Response to the risks presented by accidents and incidents involving electricity infrastructure is adequate and timely.

We employ many strategies to maintain a safe and reliable distribution network. The major activities we undertake to ensure our network is safe and reliable, include:

- **Network operations** – to efficiently control our distribution network (see Network Operations Centre below);
- **Asset inspection** – to understand the condition of our network;
- **Vegetation management** – to minimise obstructions on our network;
- **Asset maintenance** – to keep assets working in good order;
- **Asset refurbishment** – to extend asset life where feasible;
- **Asset replacement** – to replace assets prudently with minimal disruption to network operations;
- **Network augmentation** – to ensure sufficient capacity to supply customers, this can include implementation of distributed energy resources management strategies; and
- **Reliability programs** – targeted reliability programs such as improving services to those who experience poor reliability, hardening the network against the impacts of severe weather and other

[3] A MED is any day where the contribution to distribution system USAIDI exceeds an annually calculated threshold which is around six minutes due to unplanned interruption that commence on a calendar day (i.e. midnight to midnight), this compares to an average for a non-MED of about 0.4 minutes.

emerging issues affecting our network. For example, management of the grey-headed flying fox population.

Our **Safety, reliability, maintenance, and technical management plan** (**SRMTMP**[4]) details the management framework, key procedures and associated performance indicators for the safety and technical management of SA Power Networks' electricity infrastructure throughout its life cycle.

SA Power Network also has a corresponding Asset Management System.

Safety, reliability, maintenance, and technical management plan

The *Electricity Act 1996* specifies that a licence issued to the operator of a distribution network must include a condition that the operator prepare and periodically revise a SRMTMP, which deals with matters that are prescribed by regulation. The operator must also comply with the plan, annually audit its compliance with the plan and report the results of the audits to the OTR.

SA Power Networks' SRMTMP details the management framework used to ensure that the network is operated and maintained in a safe and effective manner. This is supported by several manuals covering policies, strategies, operating processes and standards.

The SRMTMP sets out a management framework which ensures that:

- The electrical system is in a stable condition at all times;
- Reliability of the network is maintained to customers;
- Operational risks and hazards are identified and managed;
- The electricity infrastructure is secured to prevent unauthorised access; and
- Responses to the risks presented by accidents and incidents involving electricity infrastructure are adequate and timely.

Asset Management System

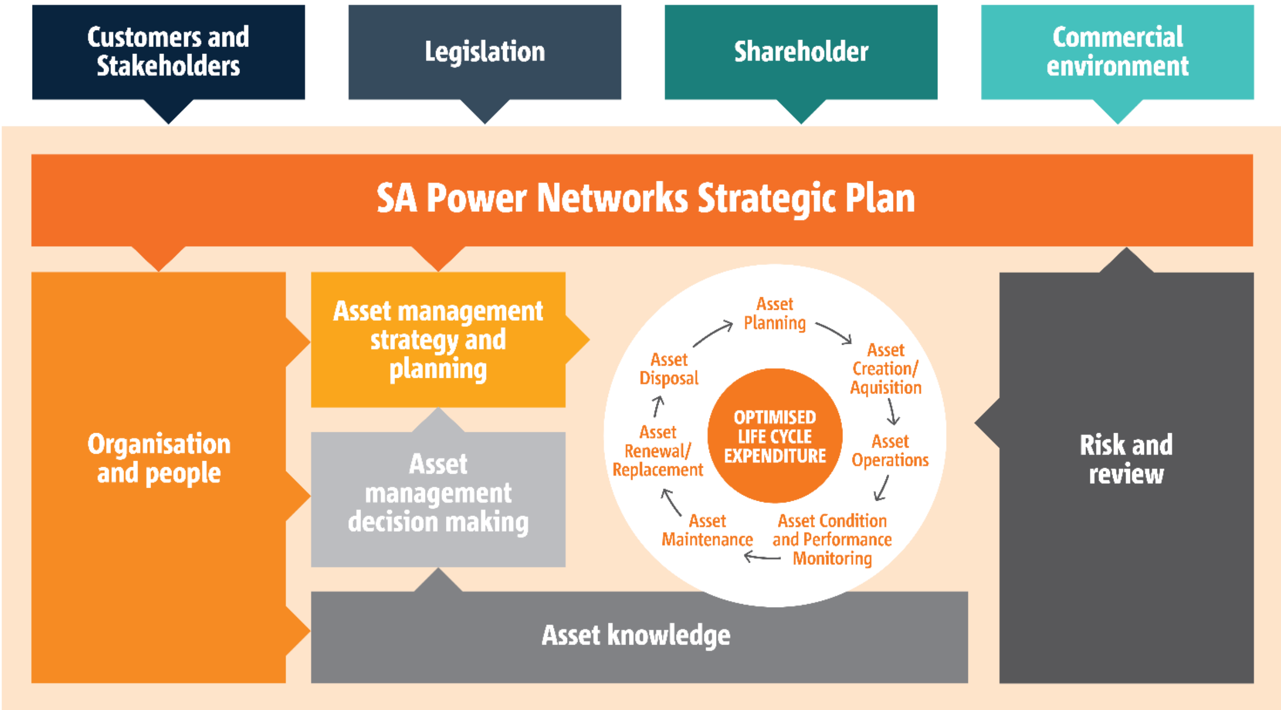
To deliver effective asset management, we evolved and continue to develop an **Asset Management System** (**AMS**). The AMS ensures the many aspects of asset management are addressed, risks are identified and managed, asset management activities are integrated with other business planning functions and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

- strategic asset management documentation including the Strategic Asset Management Plan and supporting detailed strategies, asset plans, manuals, processes and procedures with line of sight to the Corporate Strategic Plan;
- comprehensive, centralised management of asset information and standards;
- specific strategies for managing all classes of assets and all operating environment issues;
- a risk management process;
- systemised relationship management to ensure asset management activity integrates fully with other departments;
- effective management of life-cycle delivery mechanisms; and
- work process documentation including provision for review and improvement.

[4] The SRMTMP is annually approved by the Office of the Technical Regulator (SA Government).

Like many other utilities, our AMS is based on the conceptual model shown in Figure 1– which shows that the elements of the AMS are integrated and reliant on each other, with the performance of any one element affecting other elements.

Figure 1: Asset management system structure



Source: Institute of Asset Management, 2015

Asset management improvement

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

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

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

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

The AMTP is a multi-year program of work aiming to improve the way SA Power Networks undertakes the whole lifecycle of asset management from planning and execution to ongoing monitoring and review. The AMTP ultimately aims to ensure that all asset work performed meets the needs of SA Power Networks' customers, while balancing risk, performance and cost.

Asset inspections

Asset inspections and condition monitoring are designed to identify defects or issues before assets fail. This process helps determine whether maintenance, renewal, or replacement is required.

We use a variety of techniques to assess asset condition, including visual inspections, thermography, partial discharge tests, and other diagnostic methods. Inspections are conducted on a cyclic basis, with frequency determined by:

- Corrosion zones: How quickly the asset is likely to deteriorate.
- Bushfire risk zones: The potential consequences of asset failure.
- Asset criticality: The number of customers relying on the asset.

Inspection cycles are continually optimised, and we monitor network reliability to identify and address emerging trends.

Inspections also gather valuable data to improve our understanding of the asset base. When significant or unexpected failures occur, we conduct detailed investigations to learn more about failure causes. This helps us link asset failures to their observed conditions during inspections, improving our understanding of asset risks and shaping our policies, strategies, and practices.

Various trials are currently underway to adopt new technologies and/or leverage existing technologies. These include running trials for the use of drones 'beyond visual line of sight' to provide greater flexibility in the inspection program, and trialing drones with thermal cameras to identify hot joints during times of higher load (i.e., in the evenings). We currently use advanced tools and technologies to enhance inspections, including:

- Autonomous drones,
- Fixed-wing aircraft,
- Specialised condition monitoring equipment,
- Light Detection and Ranging (LiDAR) technology.

We are also exploring new data collection methods, such as input from field crews, customers, and emerging technologies, to improve the timeliness and accuracy of our data.

We are moving towards condition-based inspections, focusing on asset condition rather than fixed schedules. This involves expanding our inspection tools to support more field-based activities, including:

- Vegetation management audits,
- Pre-bushfire patrols,
- Substation inspections,
- Bulk lights,
- DC batteries,
- Thermographic inspections.

All staff and contracted inspectors are trained and accredited to Certificate II in asset inspection. Defect rectification is prioritised using SA Power Networks' Asset Management System, which assigns a risk value to each defect. This value is based on:

- The likelihood of failure within a specific timeframe,
- The potential consequences of failure (e.g., reliability, safety, environmental impact),
- Factors such as asset age, condition, incident history, and industry experience.

Risk scores are calculated by summing all potential adverse consequences of a failure. For example, a single failure might impact reliability, safety, and the environment. This comprehensive risk assessment ensures maintenance and repairs are prioritised effectively to minimise adverse outcomes.

Vegetation Management

The vegetation management program aims to minimise risks associated with vegetation contacting powerlines, which can lead to bushfires, public safety hazards, and electricity supply interruptions. A key focus is maintaining statutory clearances between trees and powerlines as part of bushfire risk mitigation. This includes clearing vegetation from public supply lines and naturally occurring vegetation from private supply lines, in line with the *Electricity Act 1996* Regulations and the *Native Vegetation Act 1991*.

SA Power Networks' power lines are inspected on an appropriate cycle[5] in bushfire risk areas and up to three-year cycles in non-bushfire risk areas to identify vegetation cutting needs to comply with clearance zones specified in the Vegetation Clearance Regulations and scope cutting work as specified in Vegetation Services Work Instructions.

SA Power Networks' vegetation clearance scoping and cutting is carried out by our vegetation clearance contractors. This work is audited by an external party and by SA Power Networks' Officers to ensure that vegetation has been cleared in compliance with the Electricity (Principles of Vegetation Clearance) Regulations.

Asset maintenance

SA Power Network undertakes cyclic asset maintenance (similar to servicing a vehicle) on priority equipment, mostly substation assets.

Asset refurbishment

Where possible and prudent to do so, we repair or refurbish assets to extend their service lives. In addition to 'patching' in-service assets (e.g. pole plating), we deploy refurbished transformers, switching cubicles and circuit breakers. Our refurbishment programs have allowed us to extend the life of our assets and reduce the investment required to minimise risk and maintain service levels.

Asset replacement

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

When determining if to replace (or renew) the asset we consider the *benefit* of replacing the asset which is typically the risk removed. On failure, an asset may pose a risk to the public, network workers, the network itself or any other stakeholder in the electricity system. This is summarised by the Risk Cost, which is a measure

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[5] The cycle is determined based on vegetation growth rates and the extent that SA Power Networks is able to clear vegetation away from powerlines to keep vegetation outside the clearance zone until the next scheduled inspection cycle.

of the expected monetised value of the risk event. At its highest level, the Risk Cost is made up of three components as follows:

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

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

Our key repex programs and their replacement strategies are summarised below.

Overhead conductors

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

The life expectancy of conductors varies but is typically 65–95 years. The main factors that influence expected life are distance to coast, material type and diameter.

Our historic, overhead conductor approach of 'fixing on fail' with little proactive replacement, will deteriorate the reliability and safety of our distribution network. We have recently been replacing on average less than 150km of overhead conductor per year under our replacement program. This results in a total effective annual volume of less than 0.1% of the population (175,000km) replaced each year. With this replacement rate it would take well over 1,000 years to replace the entire conductor population. This replacement rate may be appropriate, efficient and prudent, when the assets are relatively young but is clearly unsustainable in the long term and is now resulting in increased failures.

We are proposing to prudently increase our average proposed replacement rate over the 2025-30 RCP to 340km per year. It is forecast that further increases in replacement rates will be required in future periods.

Underground cables

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

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

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

Over the 2020-25 RCP, we replaced on average approximately 6km of underground cable per year under our replacement program, out of a total population of more than 18,000km. This results in a total effective annual volume of 0.03% of the underground cable population. At this rate, it would take 3,000 years to replace the entire underground cable population. We are now seeing an increase in failures in the CBD, which contains our oldest population of cables, and this is impacting on reliability.

The majority of proactive cable replacement is forecast in the Adelaide CBD region to meet the jurisdictional service standard reliability target for the CBD. Our cable replacement plan has been optimised together with augmentation solutions to meet the target at lowest overall cost (repex plus augex), as discussed in section 5.2.

Pole replacements

Poles serve as the support structures for overhead conductors, maintaining a safe height above ground and ensuring prescribed safety clearances from other objects. They also support other network equipment such as pole top structures, transformers, reclosers, and voltage regulators. Stobie poles are used almost exclusively across our network and consist of a concrete core with two outer steel beams connected by bolts to ensure strength. This asset class includes a small number of municipal tramway poles (mainly within the LV network) and wooden poles (former Telstra poles with only our assets attached).

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

On average, we have been replacing less than 1,000 poles per year under our replacement program, while deferring 3,000-4,000 replacements through plating. At this replacement rate, it would take approximately 600 years to replace the entire pole population. Given the average life of a pole is expected to be less than 100 years, this would suggest this replacement rate is below a sustainable rate. However, the recent performance of our pole assets does not suggest an increase in replacement rates is necessary for this asset class in the near term. Our risk modelling shows that a continuation of our current rate of replacement will maintain the current impact on customer reliability and safety risk (including bushfire risk) from our pole assets.

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

Pole top structures

Pole top structures enable overhead conductors to be securely attached to their support structures, support other pole mounted equipment, and connect the overhead conductors to other equipment. Pole top structures include cross arms, insulators, overhead switchgear, joints and taps, and other components. As this asset class comprises a very large number of small assets, we have limited data on this asset population.
Our BAU approach to pole top structures is to replace or refurbish on a benefits versus costs approach where we identify a defective asset, as well as replacing on failure.

Circuit breakers

Our historic circuit breakers BAU approach has been to proactively manage this equipment based on condition and risk and, where efficient, we continue to extend their life via refurbishment. We assess that maintaining our BAU approach and our historic repex spend level is likely sufficient. The alternative of 'run-to-fail', would degrade service.

Hindley Street substation 66kV switchgear

This key CBD substation is deteriorating. A do-nothing option (no capex investment) presents a reliability risk, with the deteriorated condition of circuit breakers posing risk of catastrophic failure and resulting safety risk. SA Power Networks is proposing to replace the Hindley Street substation 66kV switchgear during the 2025-30 period.

Northfield 66kV GIS switchboard replacement

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

We have commenced preparation to construct a new Northfield 66kV **air insulated switchgear** (**AIS**), as the preferred option which satisfies the RIT-D. This option involves constructing a new 66kV outdoor AIS immediately south of the existing Northfield substation with three 66kV bus sections supplying all existing seven 66kV lines as well as supplying the two 66/11kV transformers at the existing Northfield substation. This project is expected to be completed late 2026.

Mobile substations project

A base case of only doing minor refurbishment and regular maintenance of our mobile substations poses risks that defects in these substations will increase the risk to reliability. SA Power Networks is proposing to to replace two 10MVA mobile substations, one 11kV mobile switchboard in the 2025-30 period.

Other asset replacement programs

These comprise a broad range of asset classes each of which contribute less than 10 percent to total forecast repex. They include high volume assets, with the forecast based on: volumetric risk-based modelling for work that is condition-based; historic spend for reactive work; and historic spend for high volume assets for which there is insufficient data for modelling.

Network augmentation

SA Power Networks must comply with the requirements relating to reliability and system security contained in Schedule 5.1 of the NER and with the service obligations imposed by the EDC. We have developed our 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 (i.e. a network constraint) a suitable solution is developed which may involve a major network augmentation, a deferral solution or a suitable contingency plan taking all risks and their associated consequences into consideration.

For the 2025-30 RCP we are proposing to adopt a hybrid approach. The hybrid approach combines *probabilistic* and *deterministic* methodologies to produce targeted investment in two distinct categories:

1) projects required to avoid unserved energy risks forecast at a 10 POE level under normal operating conditions; and
2) projects required to address contingency (N-1) scenarios that are NPV-positive to deliver in 2025-30, identified via the application of probabilistic (economic) analysis.

This presents a balanced approach to expenditure over the 2025-30 RCP that recognises and assists with the general affordability concerns expressed by our customers; and provides an opportunity for the maturation of non-network solutions and other developing technologies (e.g. flexible load connections) to address the demand forecast. Our planning methodology is discussed in detail within our DAPR[6].

Maintaining reliability

The reliability of customer's supply (due to unplanned activities) is driven by various factors, including:

- unplanned network outages, which can be due to many causes including asset failure due to their age/condition, vegetation and animals contacting the network, lightning, and third parties contacting or damaging the network; where storm activity can be a significant driver of many of these causes;
- network protection and switching arrangements, particularly where switches are located on the network, and the method to switch (e.g. via manual actions requiring a field trip, remote switching from the control room, or automatic switching or reclosing), which affects how many customers are interrupted due to a network outage, how fast the network can be rearranged to restore some or all interrupted customers, or whether the switch can automatically restore the network if the outage was only temporary;
- fault response arrangements and practices, which affects how network outages are identified and responded to, including addressing or repairing specific causes of outages, and restoring supply to interrupted customers; and
- where a customer is located on the network, how far a customer is located from a bulk supply point and the length of line that supplies a customer from the bulk supply point and the terrain the lines traverse.

Furthermore, reliability patterns change over time, driven by:

- internal factors, such as the aging of the network assets; and
- external factors, such as the changing environment of the network and changing customer patterns.

These changes result in new issues emerging that cause outages, or changes in the pattern of outages, or changes in the customers who receive poor performance (compared to other similar cohorts).

We have BAU programs to mitigate these ongoing changes (e.g. our network inspection, maintenance and repex programs address the ageing of the network assets). Nonetheless, historically, we have always required ongoing reliability programs to maintain reliability and improve it where appropriate. The works undertaken under the reliability programs typically involve:

- addressing outage causes (excluding those addressed through the other BAU programs) by upgrading the network to make it less prone to certain outage causes (e.g. replacing bare wire overhead spans with covered conductor or undergrounding);
- reduce the number of customers interrupted due to a network outage by adding mid-line switches to feeders; and
- reducing the restoration time of interruptions by enhancing operational practices, installing remote controlled switches and automation, and fault locating devices.

The Reliability Management Programs are required to:

- maintain underlying reliability of the supply to SA Power Networks' customers at historical levels (consistent with the STPIS setting for the next regulatory period); and
- improve the reliability of supply to the worst served areas of the SA Power Networks network where the **Service Targeted Performance Incentive Scheme** (**STPIS**) does not provide sufficient incentive to undertake the investment.

[6] The DAPR can be found on SA Power Networks' website here

The improvement programs include some elements where it is expected that our network could exceed jurisdictional reliability service standards applicable in the next regulatory period. However, the reliability improvement component only includes programs supported by our customers that can be demonstrated to provide a net-benefit to customers. [7]

These improvement programs are focused on improving the supply reliability for the following worst served customers:

- CBD improvement program - customers in the CBD, where the reliability of the network has been declining significantly over the recent regulatory period and is now expected to exceed the jurisdictional service standards applicable for the next regulatory period; [8]
- supply restoration time improvement program - customers supplied from rural feeders whose average time to restore supply following an interruption has been declining and is expected to exceed the jurisdictional service standards associated with maximum restoration times applicable for the next regulatory period;
- low reliability feeder improvement program - customers supplied from a feeder whose reliability performance over the last five years has been consistently much poorer than the regional average resulting in the feeder being defined as a 'low reliability feeders' on multiple occasions under the jurisdictional service standard arrangements[9]; and
- regional improvement program - customers in those regions that have the worst reliability compared to the overall regional average or regions where reliability has seen an appreciable decline recently.

Maintaining reliability to achieve service targets, must take priority over expenditure on reliability improvement programs for worst served customers.

Service target performance incentive scheme

SA Power Networks is required to operate within a STPIS, in accordance with the NER. The intent of the STIPS is to provide SA Power Networks with a financial incentive to maintain and improve reliability and customer service (telephone response – maximum of 0.5%) performance. The revenue at risk under the STIPS is ± 5% of SA Power Networks' annual revenue, or around $52 million per annum on average (i.e. $260 million over the five-year regulatory period).

The STPIS is based on SA Power Networks' annual unplanned SAIDI and SAIFI performance against targets set in four feeder categories CBD, Urban, Rural Short and Rural Long, measured over each financial year.

The STPIS targets exclude:

- Transmission/generation/emergency disconnections;
- Momentary interruptions (duration is ≤ 3 minutes);
- Planned interruptions; and
- Interruptions commencing on MEDs, where the daily SAIDI exceeds 4.718 minutes (this is the threshold for the regulatory year 2024-25).

[7] Though the ESCOSA review, we will later determine the extent to which some of these programmes may be required on regulatory compliance grounds.

[8] These standards are currently being reviewed by ESCOSA and will be defined in South Australian Electricity Distribution Code. ESCoSA has highlighted the poor performance of CBD feeders in its Issues Paper pg 7, available via [www.escosa.sa.gov.au] last accessed 24/1/2024.

[9] The definition of a 'low reliability feeder' under the jurisdictional service standard arrangements is defined in the South Australian Electricity Distribution Code and is summarised further in this forecasting approach document.

Any departure from these performance targets will result in an incentive or penalty to SA Power Networks via a distribution revenue adjustment. A distribution revenue adjustment (increment or decrement) can be delayed in any one regulatory year to smooth customer price variations (referred to as the 's-bank' mechanism).

SA Power Networks has not been funded to a level sufficient to maintain BAU reliability performance through the 2025-30 period and undertake all of our proposed reliability improvement programs. Reliability improvement programs such as improving worst performing feeders, will need to be balanced with BAU programs in order to maintain the network to achieve the maximum customer benefit (assuming average weather performance over the regulatory period).

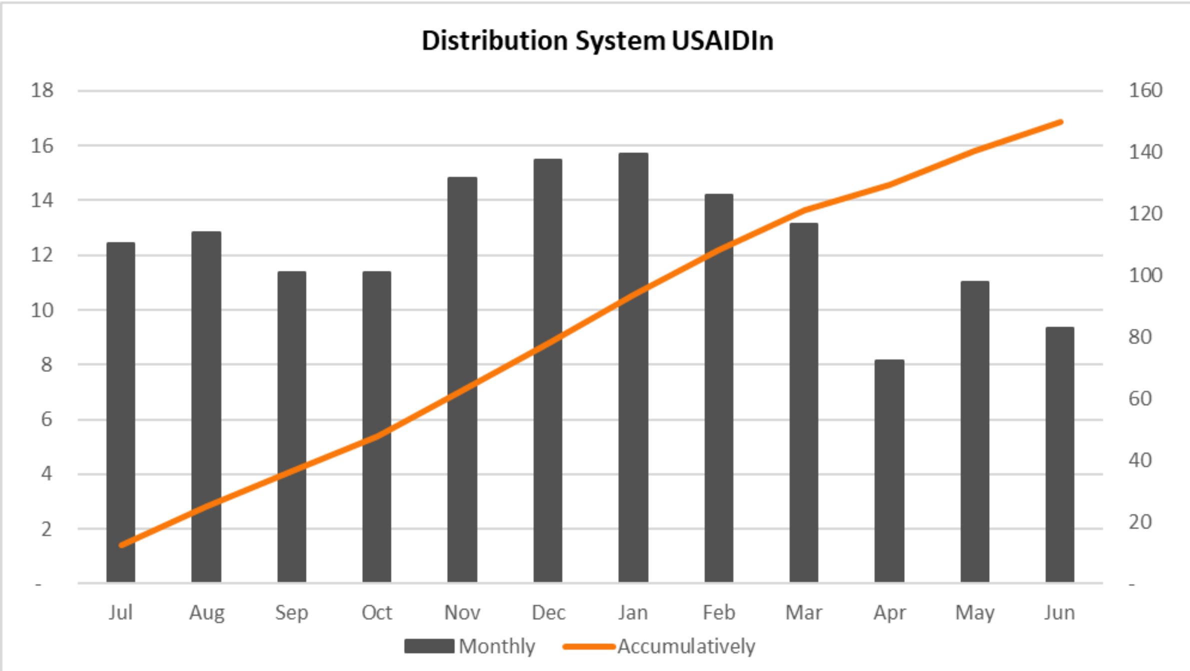
Decisions from SA Power Networks' STPIS Steering Committee[10] inform the **Reliability Management Plan** (**RMP**).

How we monitor and evaluate our performance

To effectively monitor our performance against the service standards, we calculate the historical average monthly performance to develop a twelve-month profile (based on outage data for the 10-year target setting period) that tracks service performance with the service standard targets. These profiles are not linear and can have significant monthly variations.

For example, the monthly distribution system total USAIDIn is shown in Figure 2 below. It highlights that the contribution to USAIDIn from unplanned electricity supply interruptions on average is the highest in January (i.e. just under 16 minutes) and the lowest in April (i.e. just over 8 minutes).

Figure 2: Distribution system monthly USAIDIn

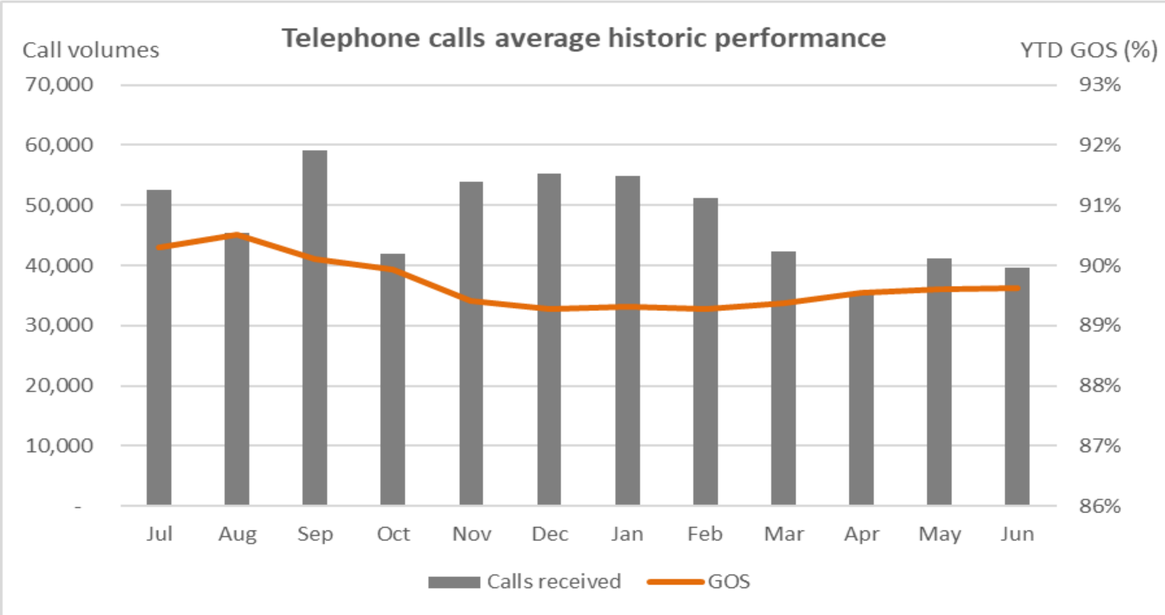


The following graph shows the monthly variability in telephone call volumes and the associated impact on the year-to-date **Grade of Services**[11] (**GOS**).

[10] The SPS Steering Committee meets monthly and comprises senior Asset Management and Operations personnel.

[11] The percentage of telephone calls answered within 30 seconds from five published telephone lines.

Figure 3: Telephone call response



These monthly profiles enable us to monitor and determine if the service standard targets will be achieved by 30 June. They enable the identification of any negative variations in performance during the year that require investigation to determine the cause(s) and whether they are systemic or one-off causes. Generally, most variations from the profiles are due to one-off faults or the number and/or severity of significant weather events that do not result in a MED exclusion.

Operational managers and their teams are tasked with monitoring service standard performance on a daily/weekly basis and must report monthly to the **Executive Leadership Team** (**ELT**)[12]. Any negative deviations from the service standards profiles are highlighted for further investigation and rectification where the cause is systemic. Reliability performance is monitored at an individual feeder level, to identify poor reliability and correct it to previous historic levels. Any customer enquiries or complaints about service standard performance are fully investigated to determine if cost effective actions can be taken to improve the performance seen by customers. Further, we will initiate service improvements where the benefit to customers exceeds the costs.

Evaluating and correcting poor service performance

As highlighted above, SA Power Networks investigates any negative deviation from the monthly service standard performance profiles to determine the cause(s). Once the cause is found, potential options are considered for addressing the performance decline. Once the option is selected, remedial actions are implemented. We note this may require redesign of infrastructure and may take some time to implement. Where it involves a systemic or age-related deterioration with a class of asset, a program to replace all those assets over several years may be instigated.

If the cause is potentially associated with a systemic equipment component failure, then other similar failures are investigated to determine if we need to monitor this type of equipment more closely or to develop a programme to replace that equipment across the distribution system.

Operational personnel monitor the performance of individual feeders to ensure that there has not been a gradual decline in the historic performance. Where historic performance is declining, the causes of

12 The Executive Leadership Team includes all Departmental Chief Executive Officers.

interruptions are investigated to determine what improvements can be implemented to return the feeders performance to historic levels.

SA Power Networks has established its STPIS Committee (see below), to monitor the performance of the four feeder categories, identify emerging systemic issues and monitor improvement projects and programmes to remedy those systemic issues. The committee meets monthly to monitor these matters.

Service performance scheme steering committee
As mentioned above, SA Power Networks is required to operate within a STPIS in accordance with the NER. A STPIS Steering Committee has been formed to maximise opportunities and reduce risk arising with respect to the Scheme. The Committee's purpose is to:

- Improve network reliability and customer service levels;
- Deliver optimal STPIS outcomes for SA Power Networks;
- Monitor progress, performance and trends;
- Review high impact events and causes;
- Consider and approve mitigation strategies;
- Identify STPIS opportunities and threats;
- Seek strategic management solutions, projects, ideas and innovations;
- Challenge the current norms; and
- Facilitate agreement and provide endorsement.

The Committee meets monthly and comprises senior Asset Management and Operations personnel.

Asset performance review committee
The purpose of the **Asset Performance Review Committee** (**APRC**) is to manage and monitor asset performance trends, develop and endorse mitigation strategies and to report the findings to the Asset Management steering committee. The APRC is responsible for reviewing:

- Performance against Asset Management Objectives (AMOs);
- Asset Performance issues as referred by the SPS Steering Committee;
- Asset Performance issues as referred by the AM&O Risk Working Group;
- Equipment failure investigations; and
- Asset inspection results.

The APRC assists the SPS Steering Committee in the development of a rapid response to asset performance issues.

3.3.2 Network restoration measures

Service standard definition
EDC Clause 2.2.2 requires SA Power Networks to use its best endeavours to achieve the minimum network restoration time targets. The proportion of the customers in each feeder category that experience unplanned interruptions that exceed the defined time periods, in hours, are set out in Table 5 for each year ending 30 June.

Table 5: SA Power Networks' network restoration targets

Target	Single interruption duration	CBD	Urban	RS	RL
Percentage of total customers in each feeder category per annum	Interruption equal to or greater than 1 hour	11			
	Interruption longer than 2 hours	4	27		
	Interruption longer than 3 hours		11	27	
	Interruption longer than 4 hours				30
	Interruption longer than 5 hours			8	
	Interruption longer than 7 hours				10

SA Power Networks is only required to report on how it has applied its *best endeavours* if its performance is worse than the reporting thresholds set out in Table 6.

Table 6: Interruption reporting threshold

Reporting threshold	Interruption duration	CBD	Urban	RS	RL
Percentage of total customers in each feeder category per annum	Interruption equal to or greater than 1 hour	13.5			
	Interruption longer than 2 hours	6.5	29.5		
	Interruption longer than 3 hours		13.5	29.5	
	Interruption longer than 4 hours				32.5
	Interruption longer than 5 hours			10.5	
	Interruption longer than 7 hours				12.5

Clause 2.2.3 requires SA Power Networks to use its best endeavours to minimise interruptions to supply. Whilst there are no specific measures in addition to the requirements listed above, we must use our best endeavours to:

- Minimise planned interruptions or limitations to supply and unplanned interruptions or limitations caused by:
    - carrying out maintenance or repair work to the distribution network;
    - connecting a new supply address to the distribution network; or
    - carrying out augmentations or extensions to the distribution network, and
- restore supply as soon as reasonably practicable.

Our strategies

To manage network access, outages and/or major incidents we make use of a number of strategies. The primary policies and strategies are summarised below.

Network Operations Centre

To efficiently manage our distribution network and to minimise interruption of supply, SA Power Networks operates a **Network Operations Centre** (**NOC**) on a 24 hour x 7 day basis. SA Power Networks NOC 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 SA Power Networks related work; and third party 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 central, integrated and dynamic system used by the NOC for managing and monitoring our entire distribution network is the **Advanced Distribution Management System** (**ADMS**), see below.

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 (e.g. **Supervisory Control and Data Acquisition** (**SCADA**)) 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. The NOC staff direct field crews during the supply restoration process to ensure safe operational procedures are followed while maintaining reliability of the network.

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.

Advanced distribution management system

The ADMS is a central, integrated and dynamic system used for managing and monitoring our 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 the **Australian Energy Market Operator** (**AEMO**) as well as for expediting the feeder disconnection process during high-risk fire days.

The ADMS provides:

- real-time execution and operations: visibility and control across the distribution network settings,
- a network operational model: a digital representation of the electrical transmission network, sub-transmission system and distribution network that illustrates 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 HV switching. Performing electronic HV switching on a connected network model in ADMS leads to increased visibility of the real-time state of the network, leading to more efficient supply restoration times and a decrease in HV switching incidents.

Maximum restoration supply policy

We do everything within our control to restore electricity supply to all customers as soon as possible following an unplanned interruption. SA Power Networks has a maximum restoration time policy where our field crews or work dispatchers are responsible for escalating any unplanned interruption where the number of customers or/and the forecast restoration time exceed a specified threshold.

Where an unplanned interruption is escalated, a leader is responsible for resolving any resourcing (e.g. labour, materials, vehicles) issues (within authority levels), in an attempt to achieve or better these thresholds.

If it is confirmed that the interruption time will exceed the threshold then the leader must ensure that the matter is promptly escalated to their Operations Managers, the department 'Head of' and the **Incident Response Manager** (**IRM**).

Where it is apparent that the thresholds are not achievable, the Operations Manager, or their delegate, are responsible for advising Customer Relations and Media Relations. In conjunction with these groups, the customer and media management strategies will be implemented.

Management of emergency response (including major event days)
SA Power Networks' **Emergency Response Manual** sets out our procedures for emergencies associated with our distribution network. It specifies the roles and responsibilities for all groups that respond to network emergencies, including outages to supply, network security, and environmental incidents.

SA Power Networks has four response levels, from the lowest being emergency response level zero (ERL0) for normal daily operation, to the greatest being ERL3 (see Table 7 below). There are four phases associated with emergency response being: preparation, pre-Event, during the Event and post-Event (i.e. review).

The **Emergency Management Team** (**EMT**) responsibilities are to develop a suitable emergency operational response plan, implement it, monitor its progress, and ensure that supply is restored within agreed corporate objectives and priorities.

Table 7: Emergency response levels

Network emergency level	Event characteristics	Summary response
ERL0	• Normal daily operation	• Normal response
ERL1	• Localised strong to gale force winds ≤ two days high (maxima, minima) temperatures • Localised Severe lightning	• Resources increased in impacted areas • Resources placed on standby
ERL2	• Widespread gale or strong winds > two days high (maxima, minima) temperatures • Widespread Severe lightning	• Incident Response Manager (IRM) convenes Emergency Management Team (EMT) • EMT prepares operational response plan • Continuous shift rostering
ERL3	• Widespread, protracted, multi-day Network restoration event	• Continuous shift for all operational staff including EMT, Call Centre and field crews • IRM convenes EMT • CMT[13] is convened

Restoration prioritisation
Responding to a major significant weather event is a complex exercise entailing a multitude of information sources and decisions that reflect many trade-offs. To assist in this endeavour, SA Power Networks operates according to restoration priorities.

The restoration priorities are provided in the table below and were developed in conjunction with State Government emergency service organisations in 2011[14]. It should be noted, however, that the overriding priority across all jobs is the safety of people, of both powerline workers and the wider community. Accordingly, prioritisation of work is assessed with primary regard to reports of wires down that may otherwise pose a risk to the community.

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[13] CMT ≡ corporate Crisis Management Team
[14] The restoration of supply priorities are currently being reviewed with these organisations.

In practice, outage jobs are categorised into operational work areas and issued to available crews based on the priorities listed below. Re-prioritisation may occur in response to new outages, or as new information becomes available.

Table 8: Restoration of supply prioritisation

Priority	Customer / Load
1	State Electricity Grid
2	Communications
3	Water for drinking
4	Wastewater
5	Hospitals, Aged care
6	Bulk transport
7	Major Shopping Centres
8	Emergency Services Control Centres
9	Correctional Services
10	Major Industrial customers
11	Residential customers

An interruption affecting large numbers of customers is typically given priority over an interruption affecting a small number of customers. However, consideration is also given to restoring an interruption affecting small numbers of customers where those customers have been without supply for a longer period.

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 (**ERL**) or fire danger level response is initiated. For escalated or forecast emergency situations, an EMT 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 EMT are recorded and all significant emergency response efforts are reviewed to identify opportunities for improvement.

Social media

SA Power Networks employs Facebook, Twitter, Instagram and the media to keep customers informed during major significant weather events. In addition, we use our 'Power at My Place', to send SMS messages to customers about interruptions to their electricity supply and updates of estimated supply restoration times. We provide 'posts' to customers about delays in restoration times and photographs of the types of damaged to infrastructure.

How we monitor and evaluate our performance

Our reliability performance monitoring is set out in Reliability measures, above.

3.4 Guaranteed service level scheme

SA Power Networks is required to make **guaranteed service level** (**GSL**) payments where we do not:

- connect a new supply address on the date agreed or within six business days after the customer has met all the necessary preconditions, and
- minimise the frequency and the total duration of unplanned supply interruptions[15].

3.4.1 Connection of a new supply address

Service standard definition

EDC 2.3.1(a) specifies that SA Power Networks is required to connect a customer's electricity supply to new supply address within the EDC specified timeframes. We must use best endeavours to provide infrastructure to enable a connection for a customer's new supply address either:

- on a date agreed with the customer, or
- where no date has been agreed with the customer, within 6 business days after the customer has met all the necessary pre-conditions for connection and supply is readily available adjacent your premises.

SA Power Networks must pay the customer $65 (including GST) for each day it is late in connecting the customer, up to a maximum of $325 (including GST).

This GSL payment only applies in situations where any required extension and/or augmentation of the distribution network to affect the connection has been completed.

Our strategies

SA Power Networks has established systems and process to set a date (referred to as the agreed date) with a customer who is receiving a basic connection service. The date for connection is set and recorded in our systems and the date when the premises is connected is also recorded in our systems. Where actual date of connection is after the agreed date, then the customer is paid a GSL payment up to a maximum of $325 based on the number of days between the agreed date and the actual connection date.

3.4.2 Reliability GSL payments

Service standard definition

EDC Clause 2.3.1(c) specifies that SA Power Networks must use its best endeavours to minimise the frequency and duration of supply interruptions to a customer's supply address. If the total number of interruptions and/or the total duration of all interruptions across a regulatory year exceeds the thresholds in the following Table 9 and Table 10 below, we must make payments (GSL reliability payments) to customers experiencing interruptions as set out in those tables.

Table 9: Thresholds and payment amount - Frequency of interruptions

	Threshold
Number of unplanned interruptions in a regulatory year	> 9
Payment (including GST)	$100

[15] For the purpose of EDC clause 2.3, the term interruption is defined as a planned or unplanned interruption of, or restriction to, supply of at least three minutes in duration, other than an interruption or restriction due to an emergency, or an interruption on a CBD feeder, urban feeder, rural short feeder or rural long feeder (but not on a SAPS feeder) due to a generation failure or a transmission failure.

Table 10: Threshold and payment amounts - Total annual duration of interruptions

	Threshold 1	Threshold 2	Threshold 3
Total annual duration (hrs) of unplanned interruptions	> 20 and ≤30	> 30 and ≤60	> 60
Payment (including GST)	$100	$150	$300

Customers' electricity accounts will be credited with their eligible reliability GSL payments in the quarter following the end of the regulatory year (i.e. typically in August each year). Payments will be made in respect of the supply address, not the customer. The resident of the supply address will receive a SMS or letter advising them of the reliability GSL credit that has been applied to their electricity account.

For the purposes of the EDC clause 2.3, the term interruption is defined as a planned or unplanned interruption of, or restriction to, supply of at least three minutes in duration, other than an interruption or restriction due to an emergency, or an interruption on a CBD feeder, urban feeder, rural short feeder or rural long feeder (but not on a SAPS feeder) due to a generation failure or a transmission failure, the above scheme also excludes:

(i) interruptions caused by disconnection required by law;
(ii) Interruptions caused by single customer faults caused by that customer;
(iii) planned interruptions, and
(iv) partial interruptions to a supply address such as:
    (A) interruptions that affect only one or two phases of supply at a supply address with three phase supply, and/or
    (B) interruptions to one connection point where the supply address has multiple connection points.

Our strategies

SA Power Networks seeks to minimise the frequency and duration of supply interruptions for all customers across our distribution network. Noting this, we acknowledge we are not always able to maintain reliability of supply or restore supply within the timeframes. For example, reliability GSL payment include interruptions on MEDs, which can result in significant variation in reliability GSL payments. For example, a total of $1.6M was paid to customers for reliability GSL payments in 2020-21 and a total of $14.7m in 2022-23. The main reason for this significant variation results from the number and severity of the MEDs in 2020-21compared to2022-23. There were three MEDs contributing 30 minutes to USAIDI in 2020-21 and six MEDs contributing 262 minutes to USAIDI in 2022-23.

SA Power Networks has systems and process in place to record the number of interruptions and the duration of each interruption that are experienced by customers. This same reliability data is used to report annually to ESCoSA and the AER on the reliability performance by feeder category. This same data is used to report on the AER's STPIS. The reliability data is audited annually by an external auditor, who verifies the accuracy of the reliability data.

SA Power Networks has developed reports which interrogate this reliability data to determine which premises (supply address) are eligible for a reliability GSL payment. These reports are run after internal quality checks of the reliability data. Payments are then credited to the current customers electricity accounts. SA Power Networks notifies customers using electronic communication that they should have received their reliability GSL payment for the year ending 30 June in October/November each year.

3.4.3 Interruptions outside control of SA Power Networks

If an interruption arises from one or more events or circumstances that are not caused by and are outside the control of SA Power Networks and we are prevented from restoring supply for reasons outside of our control or reconnection may result in serious harm, the period for which we cannot reinstate supply will not be counted within the GSL timeframes.

SA Power Networks must use best endeavours to provide prompt notice to affected customers including details of the event, an estimate of likely duration, the extent to which obligations are affected and the steps taken to remove, overcome or minimise those effects. However, we do not have any reporting obligations relating to these supply interruptions.

For further information refer to EDC Clause 2.3.2.

Our strategies

In order for SA Power Networks to use best endeavours to provide prompt outage notification to customers during supply outages beyond our control, we employ the use of social media and text messaging to promptly inform affected customers of our supply restoration progress, see Social media above.

To manage major outages or incidents efficiently and safely we make use of a number of strategies. These are set out in Network restoration measures, above.

3.5 Reconnection after disconnection

In summary, EDC Clause 2.4.1 specifies that where the **National Energy Retail Rules** (**NERR**) require SA Power Networks to reconnect a previously disconnected customer's premises, we must:

- reconnect on the same business day in the Adelaide Business Area and the Major Metropolitan areas, provided the request is received by us prior to 5pm on the business days; and
- use best endeavours to reconnect on the same business day but in any event on the next business day, where the request is received after 5pm.

The EDC clause 2.4.1 details all the possible scenarios for a customer requesting reconnection and the timeframes required for reconnection or customer payment required to achieve those timeframes.

Under the deemed standard ongoing contract, under which reconnections are performed, the obligation to reconnect lapses if the customer does not request a reconnection within 10 business days of their disconnection. Therefore, the reconnection timeframes only apply if a customer has requested a reconnection of their premises within 10 business days of the disconnection.

Under the AER **National Energy Retail Law** (**NERL**) compliance framework, SA Power Networks is required to report quarterly any failures with our reconnection obligations to the AER.

Our strategies

SA Power Networks has mature processes and procedures in place to ensure compliance with this obligation. Where a reconnection is not performed within the timeframe specified an investigation is instigated and corrective action take to eliminate any further non-compliance.

How we monitor and evaluate our performance

Non-compliances are typically detected by receipt of a customer complaint that a reconnection has not occurred. We then take action to remedy that breach as soon as practical.

4. Environmental/external factors

This section explains the external factors that influence the reliability of the distribution network.

4.1 Interruption to supply causes

The causes listed in Table 11 are used to classify unplanned interruptions to supply. We use this information to monitor our network performance and to identify trends in performance. It is important that detailed information is recorded against each unplanned outage to determine the cause so that trends can be determine and where required actions take to address a specific cause trend.

Table 11: Unplanned outage cause categorisation

Guideline No.1 cause	Simple Cause	Internal cause	Sub-cause
Equipment Failure	Equipment failure	Cable Fault	Cable Insulation Breakdown
Equipment Failure	Equipment failure	TF Failed	Internal Fault
Equipment Failure	Equipment failure	TF Failed	TF Failed (Age)
Equipment Failure	Equipment failure	Regulator Faulty	Internal Fault
Equipment Failure	Equipment failure	Conductor Failed	High Resistance Joint (Hot Joint)
Equipment Failure	Equipment failure	Conductor Failed	Corrosion
Equipment Failure	Equipment failure	Conductor Failed	Vibration
Equipment Failure	Equipment failure	Tap Failed	High Resistance Joint (Hot Joint)
Equipment Failure	Equipment failure	Tap Failed	Corrosion
Equipment Failure	Equipment failure	Tap Failed	Vibration
Equipment Failure	Equipment failure	Line Plant Failed	Wear or Abrasion
Equipment Failure	Equipment failure	Sectionaliser Faulty/ Damaged /Did not operate	Failed to Operate
Equipment Failure	Equipment failure	Recloser Faulty / Damaged / Did Not operate	Failed to Operate
Equipment Failure	Equipment failure	Switching cubicle failed	Internal Fault
Equipment Failure	Equipment failure	Pole Failure	Corrosion
Equipment Failure	Equipment failure	Substation plant failed	Internal Fault
Equipment Failure	Equipment failure	Wood Rot	Wood Rot
Equipment Failure	Equipment failure	Mechanical	Age
Equipment Failure	Equipment failure	Mechanical	Mechanical Overload
Equipment Failure	Equipment failure	Mechanical	Gasket Failure
Equipment Failure	Equipment failure	Design / Standards / Installation	UV Degradation
Operational	Other	Switching Error	Switching Error
Operational	Other	Overload	Electrical Overload
Operational	Other	Forced Interruption (Emergency or 15 Minute Rule)	Check / Inspect Equipment
Other	Other	Protection Issue	Protection Settings
Other	Other	Conductor Clearance Issue	Clearances Insufficient
Other	Other	Design / Standards / Installation	Faulty Workmanship
Other	Other	Design / Standards / Installation	Non Standard - Connections
Other	Other	Design / Standards / Installation	Not to current - Standards
Third Party	Other	Work Procedure Error	Human Error (Switching Error)
Third Party	Other	Foreign Object	Object on Mains
Third Party	Other	Animal	Rats, Snakes, Cats - Misc Animals & Insects
Third Party	Other	Animal	Bees
Third Party	Other	Animal	Birds
Third Party	Other	Animal	Possums
Third Party	Other	Animal	White Ants
Third Party	Other	Animal	Bats & Flying Foxes
Third Party	Other	Bushfire Damage	Vandalism
Third Party	Other	Bushfire Damage	Bushfire

Guideline No.1 cause	Simple Cause	Internal cause	Sub-cause
Third Party	Other	Tree Felling	Tree Felling
Third Party	Other	Animal Nesting	Animal nesting
Third Party	Other	Third Party	U/G Cable Dug Up
Third Party	Other	Third Party	Vandalism
Third Party	Other	Third Party	Vehicle/Machinery/Crane etc Hit ETSA Eqp
Unknown	Weather	No Cause Found	Feeder/Line Patrolled - No Cause Found
Unknown	Weather	No Cause Found	Nothing found/suspected
Unknown	Weather	No Cause Found	Suspect Animal / Bird
Unknown	Weather	No Cause Found	Suspect Vegetation
Unknown	Weather	No Cause Found	Suspect Weather
Weather	Weather	Vegetation	VEG detached - INSIDE clearance zone
Weather	Weather	Vegetation	VEG detached - OUTSIDE clearance zone
Weather	Weather	Vegetation	VEG attached - INSIDE clearance zone
Weather	Weather	Vegetation	VEG attached - OUTSIDE clearance zone
Weather	Weather	TF Failed	Lightning
Weather	Weather	Regulator Faulty	Lightning
Weather	Weather	Conductor Failed	Lightning
Weather	Weather	Tap Failed	Lightning
Weather	Weather	Lightning	Lightning
Weather	Weather	Foreign Object	Wind Blown Debris
Weather	Weather	Insulator Failed	Lightning
Weather	Weather	Insulator Failed	Lightning from previous storm
Weather	Weather	Insulator Failed	Pollution
Weather	Weather	Bushfire Damage	Lightning
Weather	Weather	Pole Failure	Erosion or Subsidence
Weather	Weather	Flooding	Flooding

The major causes of unplanned interruptions are:

- Equipment failure
- Animal
- Third Party
- Weather (including lightning)
- Vegetation;
- ‘Other’ and
- Unknown.

4.2 Monitoring

SA Power Networks monitors the reliability of feeders on a daily basis to detect systemic issues on specific feeders that require action to improve the feeder’s reliability performance.

4.3 Reliability improvement methods

SA Power Networks has developed remedies for the major causes of environmental based outages, summarised below.

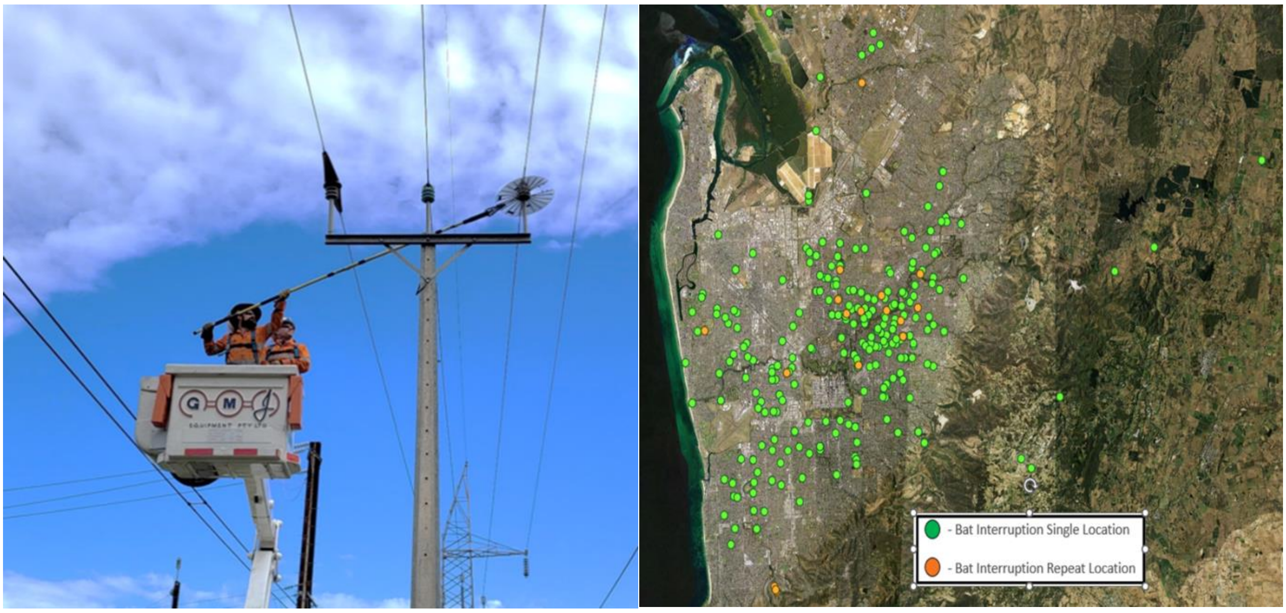
Lightning

As highlighted earlier, SA Power Networks is gradually replacing its high voltage porcelain insulators to lightning resistant resin-based insulators, as porcelain insulators are susceptible to damage from lighting strikes. SA Power Networks' strategy is to replace porcelain insulators in known lightning prone areas (i.e. where lightning has damaged porcelain insulators previously). Where an insulator fails due to lightning, we replace all of the porcelain insulators on the pole with lightning resistance insulators and also those on the immediately adjacent poles. In some cases, we may replace a section of a feeder with lightning resistance insulators, in areas that have experienced significant repeat lightning strikes.

Animals

SA Power Network is installing protective covering on the distribution network in areas where bats are impacting reliability. Figure 4 below shows field crews installing the covering (known as a frisbee). The second photo shows the extent of the bats and whether it was a single interruption (green dot) or repeat locations (orange dot). Frisbees are installed where we have experienced repeated interruptions.

Figure 4: Equipment covers to reduce the impact from bats



We have developed other guards to prevent birds and other animals (e.g. possums) from bridging across the active conductors to earth (i.e. from the conductor to the crossarm). These guards are installed in known problem areas or on feeders where repeat outages occur due to animals.

Vegetation

We install covered conductor or cover the existing bare conductor with a covering to prevent outages in known areas where vegetation impacts our powerlines, resulting in an unplanned outage. We also undertake vegetation clearance activities in accordance with our obligations under the Electricity Act. Noting that in **non-bushfire risk areas** (**NBFRA**), we are not permitted to clear vegetation above the powerline.

Feeder Automation (self-healing networks)

SA Power Networks has been using self-healing networks for almost a decade and we are continuing to roll **distribution feeder automation** (**DFA**) across our network. A self-healing network identifies a network fault and switches the network automatically to isolate the feeder section (i.e. between remote controlled switches) where the fault is located. It then restores supply to other parts of the network with no fault. This minimises the number of customers affected by the fault and the unplanned interruption. The reconfiguration of the network typically takes less than one minute. Figure 5 below highlights the improvement in the distribution network USAIDIn from DFA.

DFA is only effective where there are alternative sources of supply to reroute power to customers. It also relies on those sources having suitable capacity to supply the additional customer load.

Figure 5 - Benefits in Distribution Network USAIDIn due to Distribution Feeder Automation (DFA) by simple cause.

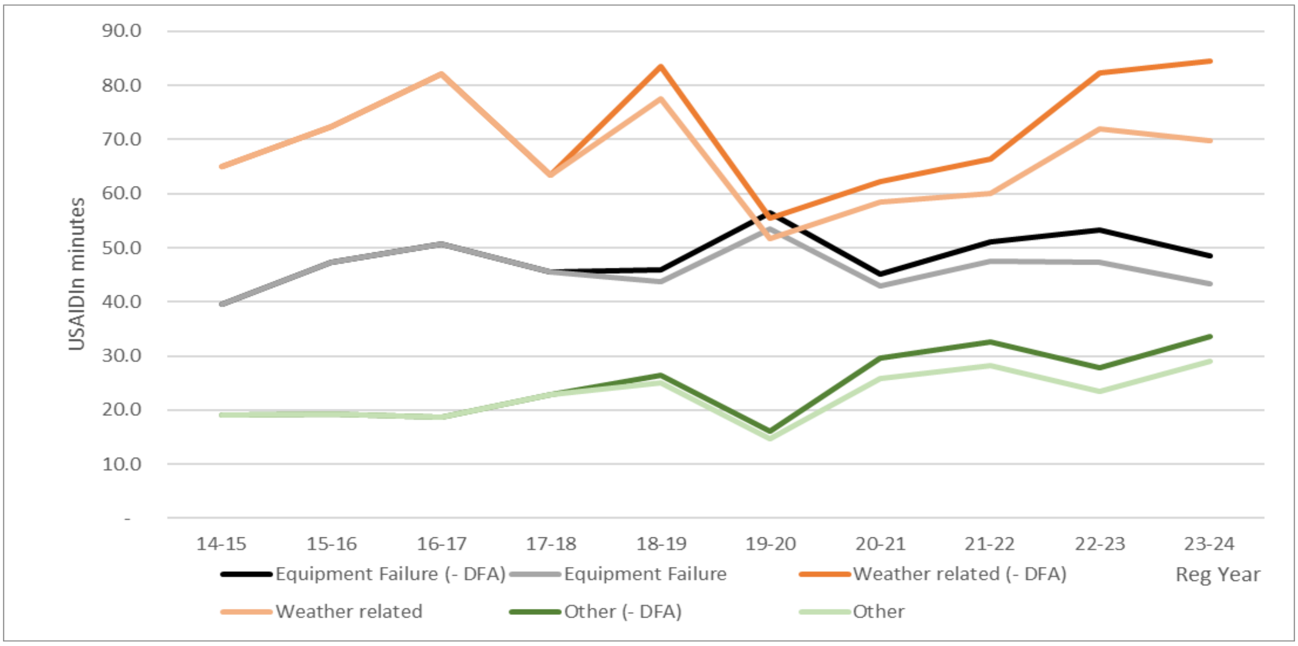


Figure 5 also highlights that DFA is masking the decline in reliability performance due to weather (lightning), other (grey-headed flying foxes) and the marginal decline in equipment failure (due to aging of the distribution system).

Installing additional protective devices

The other tool used to improve or mitigate the impact of outages (i.e. number of customers affected) is to sectionalise the feeder to limit the customers affected to a smaller part of the feeder instead of the whole or a larger section of the feeder. This has been effective, except on 19kV SWER powerlines where recently the proliferation of Solar PV has meant that the sectionaliser no longer works as originally intended (see Section 5 below).

4.4 Effectiveness of Remedies

We conducted a post implementation review to determine the effectiveness of the reliability improvements SA Power Networks undertook from 2017/18 to 2021/22. Table 12 below highlights the costs and benefits of the reliability improvement programs.

Table 12: Analysis of historical reliability improvement works for significant reliability projects undertaken between 2017/18 to 2021/2022 $m, June 2025

Improvement	Line type	Improvement project	Customers	Augex 2018-2022 ($M June 2025)	State SADI improvement pa	State SAIFI improvement pa	Augex investment to save 1 SADI min $M	Ave customer improvement in minutes pa	Ave customer improvement in interruptions pa
Automation	33&11kV	212	418,373	41.81	20.7	0.280	1.97	47	0.64
Segmentation	11kV	31	20,636	3.11	1.1	0.015	2.88	50	0.71
Segmentation	19kV	136	10,401	0.70	-1.0	0.000	-0.73	-87	-0.04
Insulator upgrade	33kV	12	25,466	2.76	2.8	0.015	0.99	104	0.57
Insulator upgrade	11kV	9	6,350	4.08	0.8	0.006	5.28	116	0.91
Insulator upgrade	19kV	21	1,769	10.66	0.5	0.002	19.49	294	1.01
Vegetation solutions	11kV	6	7,006	3.47	0.5	0.005	6.73	70	0.70
Animal guards	11kV	4	7,665	0.79	0.5	0.004	1.55	63	0.53
Animal guards	33kV	2	7,750	0.52	0.8	0.007	0.66	97	0.81
TOTAL		**433**	**505,416**	**66.9**	**26.8**	**0.334**	**2.50**	**50**	**0.63**

Note :

- This is based on actual improvement on the feeder after the augex expenditure.
- This compares the actual customer experience pre and post the improvement.
- Distribution network customers numbers of 929,485 as at May 2024.

In summary, the reliability improvements tabulated above have effectively reduced the underlying SAIDI by 26.8 minutes per annum. However, the allocated expenditure and the number of improvements has not been sufficient to counteract the performance decline, primarily driven by a significant increase in weather and vegetation related causes such as lightning strikes and branches blowing on to powerlines, and third party causes such as the increase in the Grey Headed Flying Fox population.

The customers supplied by the feeders included in these projects, have had an average reduction of 0.63 interruptions per annum in underlying SAIFI and a reduction of 50 minutes due to supply interruptions per annum. The average cost to improve one minute of USAIDI is approximately $2.5m.

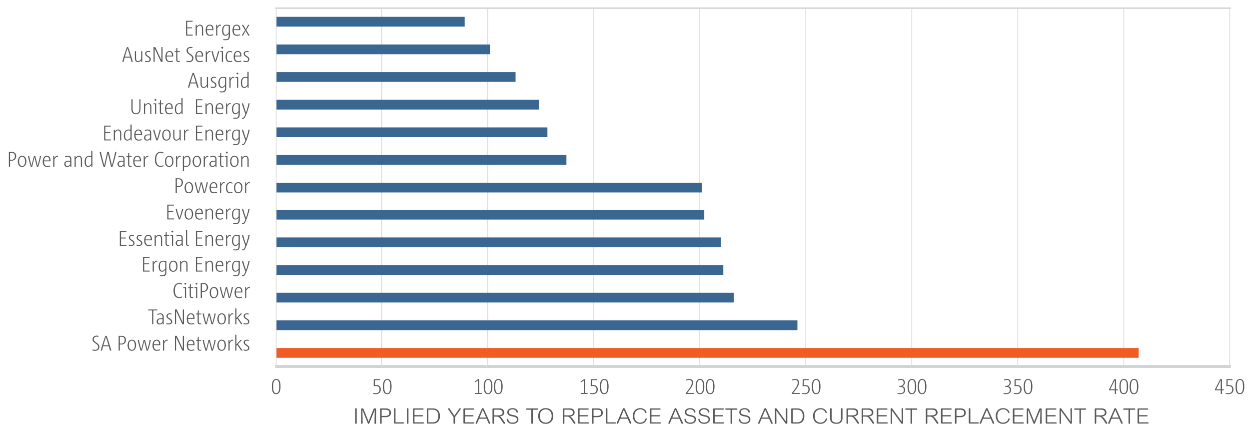
Please note that the analysis above excludes 'spot' improvements, such as the installation of animal guards at specific locations to mitigate single and recurring interruptions and animal fatalities. A random sample of 211 spot improvements implemented between 2017/18 and 2021/2022 reveals that, before improvement, there were 319 interruptions at these sites, which reduced to 13 interruptions after improvement, showing a 96% reduction in outages where spot improvements were implemented.

5. Current issues impacting network reliability

5.1 Underlying concerns for service performance are beginning to manifest

While long-term service performance has been sound, we are concerned about the impact on service in coming years if inadequate action is taken. This is with particular regard to the service risk posed by the condition of our network assets, noting we have the oldest asset fleet in the NEM and we face a critical time in which assets reach the end of their economic service life. See Figure 6 below.

Figure 6: Implied asset lives – years implied to replace assets and current replacement rate



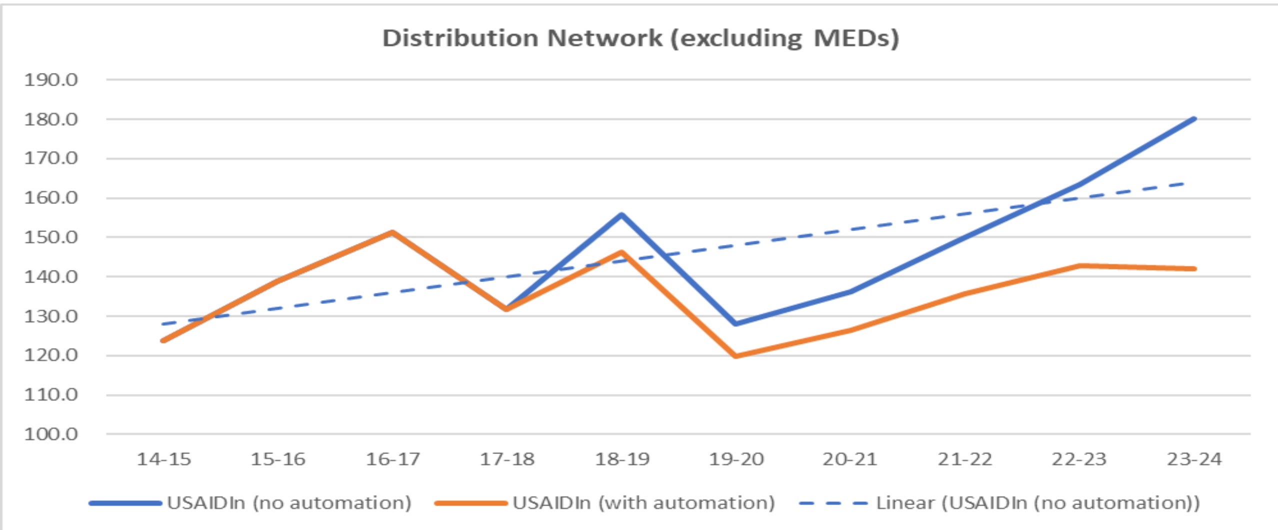
Our underlying concern arises from us considering:

1. **backward indicators**: recent service performance indicators and how they should be interpreted; and
2. **forward risk indicators**: our detailed and vastly improved modelling of the probability, likelihood and monetised cost for customers of poorer service outcomes in relation to reliability and safety (including bushfire risks) arising from:
    - asset condition-based failures across our entire network asset fleet; and
    - ongoing trends in non-asset condition effects on reliability such as weather and animal contact, and ongoing bushfire safety risk.

Looking backward across our overall distribution network service performance, we see that underlying reliability has gradually deteriorated since the start of 2020-25 as shown in Figure 7, via a combination of: more frequent and severe weather and outages caused by grey-headed flying foxes (i.e. bats), and network asset failures.

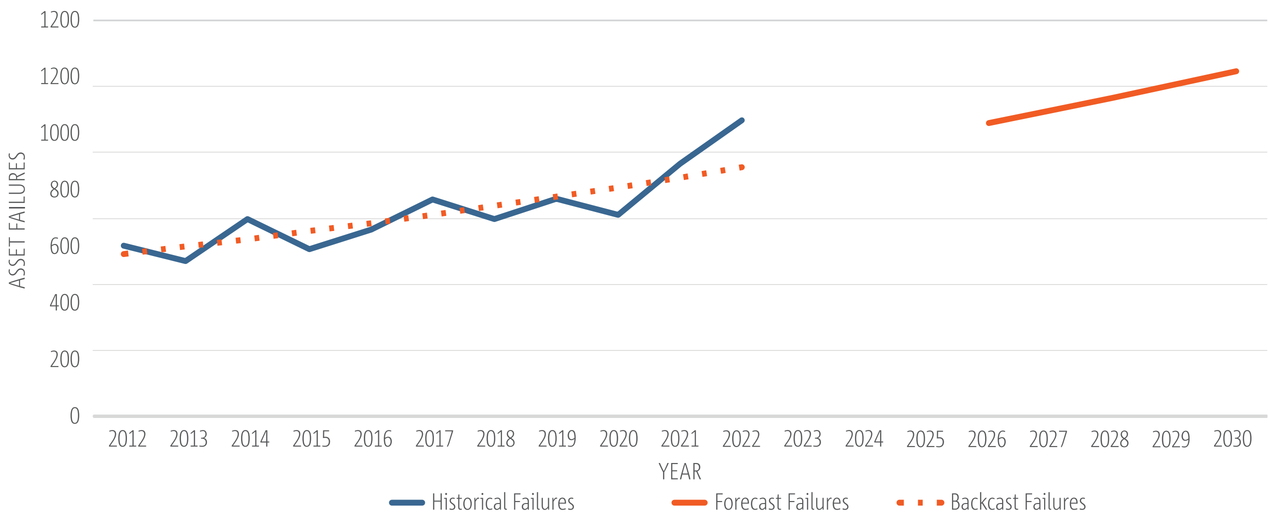
This deterioration has been masked by the implementation of DFA, implemented and expanded since 2018/19, which reduces the number of customers affected by network outages by segmenting the network and automatically re-routing supply in meshed areas of our network where feasible. If not for this program, reliability would have been materially worse as can be seen in Figure 7 below.

Figure 7: Distribution system interruption duration (USAIDIn)—with and without DFA



A key driver of the deterioration in underlying performance is increasing asset failures across asset classes, such as displayed in Figure 8 for our overhead conductors. Figure 8 demonstrates a material decline in asset condition, supporting anecdotal feedback from our staff that condition related asset failures are significantly increasing. This actual failure data has also been used to ground and validate our view of forecast risk underpinning our proposed repex, by back-casting our forecasts against actual failures where data permits.

Figure 8: Historical and forecast asset failures - overhead conductors[16]



This data is particularly concerning as we enter the 2025-30 period, given that DFA solutions have now been deployed across most of the meshed network where these solutions are the most valuable and efficient. Figure 5 in section 4.3 above, highlights the deterioration of the distribution network asset, if not for DFA. This deterioration will increase so that in the longer term it will not be masked by the DFA, so customers will see a decrease in reliability performance. To address this deterioration in performance, we are forecasting an increase in expenditure from 2025.

In our modelling we have identified where it is more efficient to address the underlying cause of an outage rather than just mitigate its impact.

5.2 CBD reliability

For the purpose of reporting, the 'CBD' is the Adelaide Central Business District which includes significant commercial, government, residential, cultural and entertainment customers and development. Reliability performance targets for the CBD are established by ESCoSA in the EDC.

Since 2017/18, our performance against CBD reliability targets has been varied. While we have met the targets in some years, we have fallen short in others. Overall, CBD reliability has gradually declined, primarily due to underground cable failures and faults. This is largely because a significant portion of the high-voltage cables in the CBD are now over 50 years old. A substantial part of the CBD network is expected to reach the end of its service life within the next 20 years.

ESCoSA expects SA Power Networks to invest appropriately to meet the minimum network performance standards for CBD feeders. Although the AER did not approve all our proposed expenditure for CBD reliability improvements, we plan to prioritise planned cable replacements, as this is the main factor impacting CBD reliability. However, even with this focus, it is unlikely we will meet the CBD reliability target by 2029/30. As

16 Overhead conductors are assets that transmit electricity between substations, and from substations to customers. We have approximately 175,000km of conductors across our network over a route length of approximately 70,000.

in recent years, we expect performance to fluctuate throughout the 2025–30 RCP, with some years meeting the target and others falling short.

Furthermore, the AER did not allocate specific funding for feeder automation in the CBD, instead it provided an overall allowance for maintaining reliability across the entire network where DFA can be implemented where it delivers the greatest economic benefit for customers. Given the significant reduction in the Value of Customer Reliability for business and commercial customers, we anticipate fewer DFA projects will be undertaken in the CBD during the 2025–30 RCP.

Cable faults in the CBD are mostly seen on paper insulated lead cables (**PILC**) with aluminium conductor. Modelling of cable type, age, failure history and other fault contributing factors, has been undertaken to generate a probability of failure for each cable in the CBD. This data along with known consequence information (such as customers effected by an outage), is used to take a risk-based approach to a proactive replacement program of cable within the CBD.

The CBD Program Steering Committee meets regularly to ensure the reliability and safety performance objectives of the CBD are achieved. A key focus of the committee is to provide governance and oversight of the CBD cable replacement program, which plays a critical role in meeting ESCoSA reliability targets and maintaining safety performance standards.

5.3 Grey Headed Flying Fox (GHFF)

The **Grey-headed Flying Fox** (**GHFF**), Australia's largest bat and one of the largest in the world, is a protected species listed as vulnerable. A significant group of flying foxes arrived in 2010 from the eastern states and established a permanent colony in the Adelaide Botanic Gardens near the zoo. Since then, their population has grown from around 10,000 to over 50,000. This increase in numbers has coincided with a rise in power outages across our network. Prior to 2010, there was no GHFF colony in South Australia. The size of the colony fluctuates based on food availability and ambient temperatures.

Flying foxes cause outages when they come into contact with powerlines or pole-top equipment, such as insulators, transformers, switches, or lightning arrestors. These incidents can result in outages lasting anywhere from 60 seconds to 2 hours, depending on whether an inspection of the powerlines is required.

The bats are most active at night while foraging for food, such as nectar, pollen, and fruit. They travel 20–30 km from their colony, covering much of metropolitan Adelaide and nearby horticultural areas. Without specific flight paths, they follow food sources, making their impact widespread and difficult to predict or target. Outages are most common in January and February, as juvenile bats, with shorter flight ranges, land more frequently on pole-top infrastructure.

The random nature of GHFF-related outages across our extensive distribution network in Adelaide makes it challenging to eliminate or significantly reduce their occurrence. To address the issue, we have implemented several strategies:

- **Animal Guards and Insulation:** Installing guards and insulation coverings on overhead equipment in areas with repeat outages.
- **Self-Healing Networks:** Investing in technology to minimise the number of customers affected by GHFF-related outages.
- **Pole-top Covers (Frisbees):** Installing covers opportunistically during any pole-related work in the Adelaide Metropolitan Area to maximise coverage at minimal cost.

We continue to explore new strategies to reduce the impact of flying fox-related outages. While GHFF have negatively affected the reliability of Urban feeders and the Greater Adelaide Metropolitan Area (GAMA), other reliability improvements have ensured that reliability targets are still being met.

Recent GHFF-related outages have been reported in the Southeast. If a colony becomes established in this region, it could lead to an increase in outages. We are monitoring outage causes in the Southeast and will consider implementing preventive measures, similar to those in Metropolitan Adelaide, if necessary.

Our efforts remain focused on balancing the protection of this vulnerable species with maintaining reliable electricity supply for our customers.

6. Emerging trends

As explained in Section 4, improving reliability performance typically takes time. For this reason, it is very important for SA Power Networks to monitor emerging trends in order to implement rectification measures as early as possible.

6.1 Decline in reliability performance of Long Rural feeders

There are a number of causes for the poor USAIDIn and restoration of supply performance of Long Rural feeders over 2023/24 and 2024/25. The major causes for the increase contribution to USAIDIn are:

1. An increase in weather related interruptions which is caused by the significant increase in lightning[17] activity in the 2020-25 RCP;
2. The decline in the performance of 19kV SWER feeders. Sectionalisers are not operating due to the feed in voltage from distributed energy resources (e.g. solar pv); and
3. An increase in animal and vegetation related interruptions in 2023-24 and 2024-25.

Note: the 2024-25 Long Rural reliability performance was significantly impacted by environmental factors (e.g. no rain permitted dust and salt build up on insulators) which led to significant increase in unplanned outages.

Decline in 19kV SWER performance

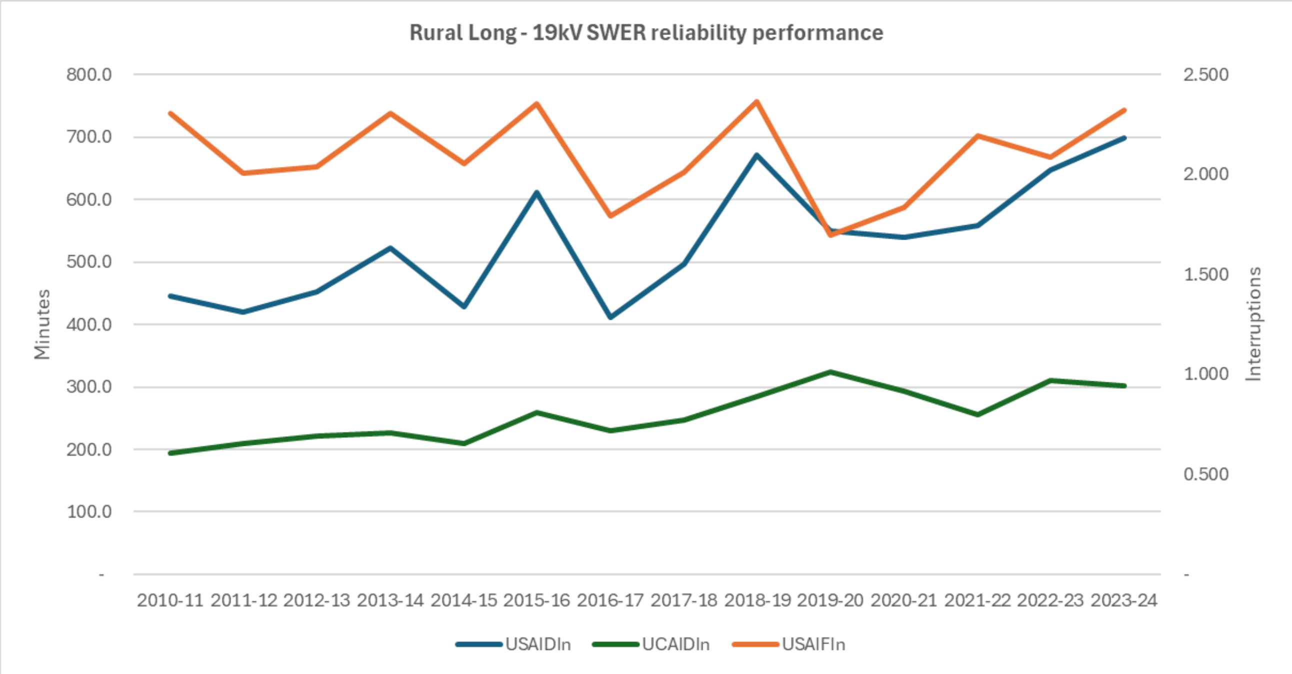
Figure 9 below highlights the decline in both USAIDIn and UCAIDIn in Rural Long 19kV SWER feeders since 2010-11. The decline is due to several factors which include:

1. The proliferation of Solar PV which results in our sectionalisers being ineffective during daylight hours which leads to extended timeframes to locate and repair the fault on long lines;
2. Ageing of the 19kV SWER network which is now 50-60 years old; and
3. Operational and safety factors which are delaying the restoration of supply.

It highlights that the % of customers affected by outages has remained consistent but with a decline in UCAIDIn and consequently USAIDIn.

[17] The distribution system was initially designed for a low isokeraunic levels (i.e. South Australia historic lightning levels were low)

Figure 9: Rural long 19V SWER feeder reliability performance (excluding MEDs)



Sectionalisers and Solar PV

Sectionalisers are used to mitigate the impact of outages, as it limits the number of customers affected by a fault on the feeder to those customers downstream of the sectionaliser, with other customers supplied by the feeder seeing a momentary interruption. For a sectionaliser to work it must have zero voltage on the downstream side of the recloser. However, downstream Solar PV installations are preventing the voltage from decreasing to zero[18], so the sectionaliser no longer works. This results in longer patrol times to locate and then repair the fault, as the whole feeder must be patrolled instead of just the section downstream of the sectionaliser.

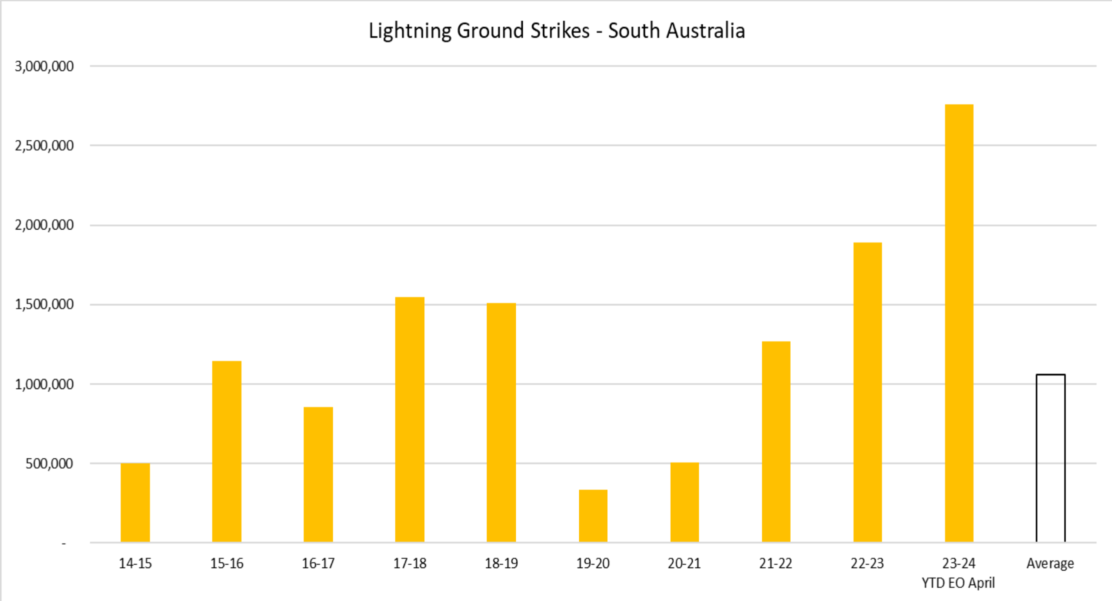
We have investigated solutions to replace sectionalisers and remedy the Solar PV issue. We have commenced replacing sectionalisers with reclosers, prioritising high USADI feeders. We plan to replace 100 sectionalisers in 2025 and a further 80 in 2026. This should over time improve our Long Rural USAIDIn and the restoration of supply performance.

Increase in weather related outages

Lighting strikes have significantly increased during the 2020-25 RCP with 2023-24 being the greatest number in recent history see below Figure 10. These lightning strikes have significantly increased the contribution to USAIDIn from weather caused interruptions for Long Rural feeders.

[18] Inverters on Solar PV systems are supposed to disconnect from the distribution network within 2 seconds of seeing no supply, however, it is taking around five seconds for inverters to disconnect. This longer time frame results in the sectionaliser failing to open due to voltage being present. It is unclear if this is a non-compliance with our requirements or because of other Solar systems giving the appearance of the system supply still being available.

Figure 10: Number of lightning strikes in South Australia



Operational and other factors

There are a number of operational and other factors which are delaying restoring customer supplies on 19kV SWER feeders, which include:

- Greater damage to infrastructure requiring more work, and consequently longer to restore supply.
- Full patrol of the feeder versus previously part patrols, mainly during the fire danger season, to prevent fire starts.
- Customers locking gates/access points or requiring phone calls prior to enter, which is extending the duration of patrols and consequently delaying restoring customers electricity supply.
- Installation of SCADA on SWER feeders reclosers which identifies immediately when supply is lost. Previously, customers would typically wait until the morning to advise that they had lost electricity supply (i.e. crews were already available to respond). The mobilisation of crews to respond delays restoration time compared to crews being at work and available to respond.

In 2024 we established a project team to investigate the cause of our declining rural long (SWER) feeder performance. To address this decline we are implementing the following measures over 2025 and 2026:

- Replacing 180 SWER sectionalisers with reclosers;
- Installing SWER fault indicators at 776 locations;
- Installing lightning resilient insulators on 3,400 poles;
- Installing 11kV mid-line reclosers at 27 locations; and
- Installing 33kV mid-line reclosers at 10 locations (in 2026).

For the 2025-30 period, the AER have approved a reliability allowance for regional customers under the 'Worst Served Customers' program which will improve some rural long performance outcomes. This program recognises that improving reliability for regional customers is often un-economic under STPIS.

The implementation of improvement measures will take time due to the vastness of the SWER network and the limited availability of resources. Incremental improvements should be seen over 2025/26 with a more material improvement seen from 2026/27.

7. Demonstration of Best Endeavours

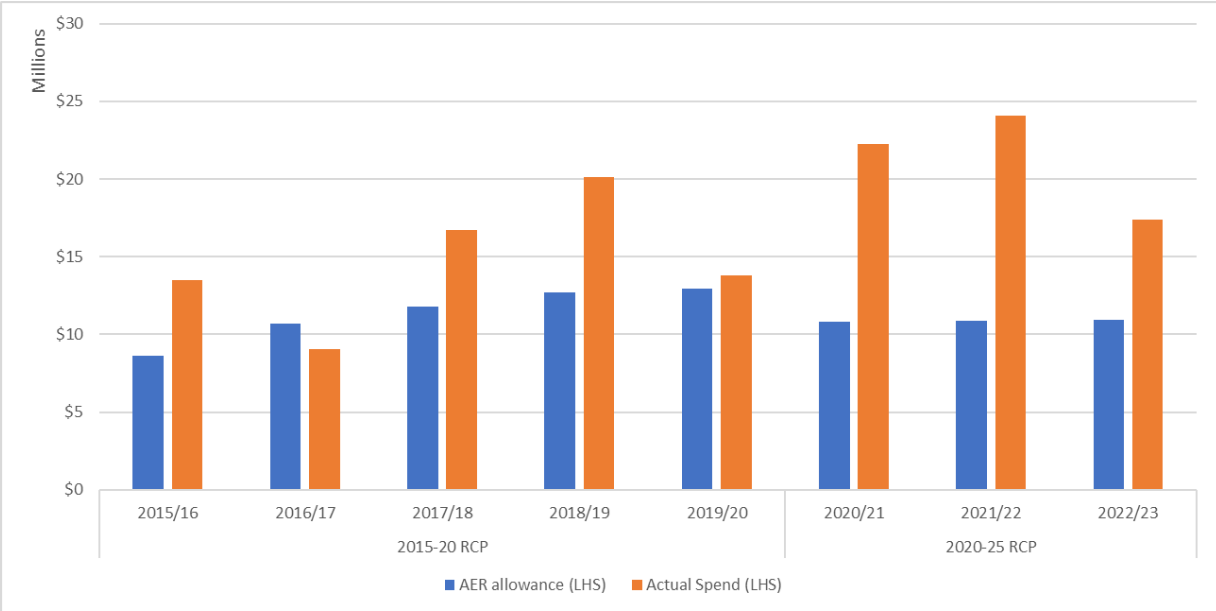
The EDC requires SA Power Networks to use best endeavours to achieve the customer service and reliability standards detailed in the EDC. Best endeavours:

“means to act in good faith and use all reasonable efforts, skill and resources.”

The AER includes an allowance for maintaining historic reliability performance in its Distribution Determination for SA Power Networks.

One way to assess the use of best endeavours is by examining the resources or expenditure SA Power Networks is employing to maintain reliability. Figure 11 below highlights that SA Power Networks is using considerably more resources than that provided within our AER allowances to maintain reliability. However, despite increased expenditure, the reliability performance of some feeder categories, such as Long Rural feeders, is declining.

Figure 11: SA Power Networks – Reliability expenditure versus allowance



As explained previously, the EDC defines best endeavours as ‘to act in good faith and use all reasonable efforts, skill and resources’. As the service standard obligation is to use best endeavours, SA Power Networks can still comply with a service standard obligation, despite not achieving the target, providing we can demonstrate we have used best endeavours.

SA Power Networks monitors the performance of the EDC customer service and reliability standards on a daily and monthly basis. Where monitoring indicates a customer service measure’s target is unlikely to be achieved, it is often possible to adjust performance to achieve the target. However, it is generally not feasible to immediately rectify a reliability measure’s performance to achieve the target within the remaining timeframe of the year.

Poor performance for a customer service measure can be corrected by focusing more effort and resources to improve the performance for the remainder of the year. However, achieving our reliability targets is not just a matter of adding additional resources. .

The improvement of reliability typically takes several years to rectify where the 'poor' performance is due to systemic issues. This is because remediation generally requires at least several of the following activities:

- Analysing the faults that result in interruptions to determine options to remedy/reduce interruptions. Determine the cause of the poor performance and determine options to remedy. In some instances research is required to determine the options;
- Researching new equipment, or new methods to resolve a systemic issue;
- Trial different solutions;
- Design the remedy, which may involve replacing poles or equipment, restring sections of power lines etc and the best location(s) for the remedy;
- Plan and schedule the work;
- Source materials and equipment; and
- Organise the outage, notify customers and complete the work.

In addition, any remediation to improve reliability needs to be performed at an individual feeder level, so to achieve any material improvement requires improvement on many feeders. There are in excess of 1,500 high voltage powerline feeders in SA Power Networks distribution system.

Normal variation in reliability performance

The tables below highlight the variation in reliability performance over the 10-year period (the **Target Setting Period** (**TSP**)) used to establish the EDC Reliability Targets.

Table 13 - USAIDIn and USAIFIn EDC Targets and variation in performance during TSP

	USAIDIn					USAIFIn				
	CBD	Urban	Short Rural	Long Rural	Dist Nwk	CBD	Urban	Short Rural	Long Rural	Dist Nwk
EDC Target	15	110	200	290		0.15	1.15	1.65	1.75	
Average	16	108	199	289	150	0.15	1.17	1.63	1.75	1.32
Maximum	44	132	283	351	181	0.39	1.39	2.21	2.28	1.65
Minimum	4	94	143	239	124	0.04	0.95	1.19	1.43	1.12
RT	20	125	220	330	175	0.20	1.35	1.85	2.10	1.50
Exceeded RT (times)	1	1	2	3	1	1	2	2	2	2

Table 14 - Restoration of supply EDC targets and variation in performance during TSP

	Restoration of Supply (1st Target)				Restoration of Supply (2nd Target)			
	CBD ≥ 1 Hr	Urban > 2 Hrs	Short Rural > 3 Hrs	Long Rural > 4 Hrs	CBD > 2 Hrs	Urban > 3 Hrs	Short Rural > 5 Hrs	Long Rural > 7 Hrs
EDC Target	11%	27%	27%	30%	4%	11%	8%	10%
Average	10.6%	27.1%	27.3%	30.0%	4.5%	11.1%	8.1%	9.5%
Maximum	29.5%	33.9%	46.1%	36.4%	16.9%	13.4%	10.1%	13.9%
Minimum	3.4%	22.9%	21.5%	20.6%	0.6%	7.9%	5.0%	6.3%
RT	13.5%	29.5%	29.5%	32.5%	6.5%	13.5%	10.5%	12.5%
Exceeded RT (times)	3	3	1	3	1	0	0	1

For example, the variation in USAIDIn performance for Long Rural was from a best of 239 to a worst of 351 minutes with an average of 289 minutes (i.e. a 17% variation below and a 21% variation above the average) and the variation in USAIFIn was from a best of 1.43 to a worst of 2.28 (i.e. a 18% variation below and a 31% variation above the average). This sort of variation is normal and should be considered when determining whether or not SA Power Networks has used best endeavours when a reliability outcome is worse than the target.

SA Power Network has in place daily monitoring system, that analyses performance at a feeder level to determine which feeders need improvement. We have developed methods to improve reliability where reliability has deteriorated or the overall feeder category needs improvement. We establish work project teams to analyse specific issues that arise to consider all possible methods to improve reliability where there has been a long-term deterioration (e.g. CBD and Long Rural feeders). We then implement work plans to improve the reliability to achieve the reliability standards.

A. Risk management framework

SA Power Networks applies a risk management approach to all business activities in order to not expose the business to unacceptable levels of risk. This includes:

- a corporate Risk Management Framework which provides the structure and tools to be used by the organisation in order to achieve the desired outcomes;
- a Risk Appetite Statement that provides a view of the Board's risk appetite for key strategic areas of the business;
- an annual risk profiling process;
- regular review of the risk profile data;
- regular report to the Risk Management & Compliance Committee providing an analysis of the risk profiling data;
- ongoing audits of the risk profile data including the control regimes to facilitate best practice; and
- the appropriate training in risk management techniques and the policy requirements, in accordance with the approved annual training plan.

SA Power Networks' Risk Management Framework is aligned with the Australian Standard on Risk Management AS ISO 31000. Risk management considerations are incorporated into the planning, design, construction and operational phases of all activities. The management of risks includes the purchase of insurance to cover potential losses associated with some risks.

Managing risk

The electricity network carries inherent risks, including the potential to ignite a major bushfire, cause widespread property damage, and result in injury or loss of life to 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.

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.

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.

Managing asset risk

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, have their risk quantified and the estimated cost to repair or replace the defect determined through the value and visibility process. 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.

CBRM decision support tools assist in allocating limited funding to maximise the reduction in asset risk. 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.

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 CBRM. This transition requires good asset condition data combined with improved analytical techniques enabling asset risks to be quantified. Increased condition monitoring will provide better knowledge on the condition of the assets to enable better asset decisions, such as replacement time and maintenance intervals and to manage risks associated with asset operations.