Distribution Annual Planning Report

2023/24 to 2027/28

January 2024

SA Power Networks

Empowering South Australia

Contents

Introduction

SA Power Networks is pleased to present this iteration of the Distribution Annual Planning Report (DAPR) for 2023-24 to 2027-28.

We are a key player in South Australia's energy industry as the state's sole electricity distributor. We have the primary responsibility for planning, building, operating and maintaining South Australia's distribution network. Each year, as part of our responsibilities we produce the DAPR to inform stakeholders about our plans for the future. These plans are based on our review of the capability of South Australia's distribution network to meet customer needs under a range of future operating scenarios.

Since the publication of the previous year's DAPR we have finalised the regulatory assessment process for several large projects which include:

- **Northfield GIS Project**

  Northfield 66kV substation's gas insulated switchgear (GIS) is in poor mechanical condition and has deteriorated to the extent that there is a material risk of asset failure. The regulatory investment test concluded that the preferred option is to construct a new Northfield 66kV outdoor Air Insulated Switchyard.

- **Southern Outer Metro 66kV Line Upgrades**

  The Southern Outer Metro (SOM) 66kV loop is the 66kV line source for the McLaren Flat, Willunga, Aldinga and Seaford substations within the Metro South region. It has been identified that components of the SOM loop will be overloaded under certain conditions. The regulatory investment test concluded that the preferred option is to replace all SOM loop underrated conductor sections with a higher capacity HTLS (High Temperature Low Sag) conductor.

- **Voltage Management and Under Frequency Load Shedding Emergency Standards Project**

  SA Power Networks is required to comply with standards that are targeted to address power system issues associated with the continued uptake of Consumer Energy Resources, predominately rooftop solar systems. In order to continue to meet these standards the regulatory investment test concluded that the preferred and only option is to implement voltage management services and the amendment or installation of prescriptive Under Frequency Load Shedding (UFLS) infrastructure.

These projects, combined with increasing replacement and capacity expenditure, respond to asset-condition based risks and are required to meet the strong increases in forecast load demand supporting South Australia's energy transition.

This year's DAPR has been re-organised around the key themes of:

- how we are responding to current challenges,
- our network forecasts for the future period,
- investing in the network, whilst also exploring demand management and non-network opportunities,
- managing our assets,
- assessing the performance of our assets,
- investing in non-network infrastructure, and
- our planning processes.

Attachments to DAPR

The following attachments form part of our Distribution Annual Planning Report and are available via the relevant links on our website.

Network Visualisation Portal	This portal complements the DAPR by directing users to useful sources of network data, such as our load forecasts, and providing a visual indication of network capacity for importing and exporting to the distribution network. The Network Visualisation Portal is accessible with a simple registration and is available to all customers.
System Limitation Templates	Excel file listing augmentation works and asset replacements projects where the unit cost of the asset exceeds $200,000 for each year of the 2024-28 period
Load Forecast Dashboard	Provides various forecasts for connection points, substations and sub-transmission lines for the 2024-28 period
C-Projects with Changed Dates	Key projects' timings for the 2024-28 period

Purpose of Distribution Annual Planning Report

This DAPR has been prepared by SA Power Networks to comply with the NER clause 5.13.2. This report is published annually on our website in accordance with clause 5.13.2(a)(2) and provides the information specified in NER Schedule 5.8.

The DAPR is intended to inform regulators, market participants in the NEM, and other stakeholders about existing and forecast system limitations on our distribution network together with details related to our asset replacement programs and network performance within the forward planning period from 2023/24 to 2027/28.

Guide to this Document

SA Power Networks is pleased to present this iteration of the Distribution Annual Planning Report (DAPR). The DAPR is organised based around the following chapters.

About SA Power Networks

Provides an overview of our business structure and the frameworks we are required to work within, as well as a description of our distribution network and assets.

Factors impacting our Network and Future Challenges

SA Power Networks must act to respond to the various factors that influence our network and the future challenges we are facing, including those challenges relating to climate change, cyber security threats, the transition to CER, and rapid changes in network technology.

Changes since the previous DAPR

Details the changes both to SA Power Networks projects and the Rules since the DAPR was last published, to inform external stakeholders of changes impacting the network.

Network Demand and Limitations

Details the network constraints resulting from forecast demand growth, asset retirements and asset de-ratings. Includes the system constraints at zone substations and primary feeders, and details consideration for possible regulated SAPS solutions. The forecasting methodology used to identify constraints is detailed in Appendix C.

Networks Investment

Provides information on the prudent and efficient network investment we are planning in response to the forecast network constraints.

Demand Management and Non-Network Opportunities

This chapter describes how market participants can provide feedback and alternative non-network demand management solutions to address the network limitations described in Chapter 3. It also, provides information on the different demand management solutions SA Power Networks currently has in progress and those under consideration for future needs.

Asset Management

SA Power Networks' asset management approach is discussed together with our asset class and life cycle strategies.

Network Performance

This chapter provides a review of the network reliability and quality of supply performance.

Information and Communications Technology Systems Investments

Details the information and communications technology system projects related to management of network assets in the forward planning period.

Planning

This section details the joint planning currently undertaken with ElectraNet, the principal Transmission Network Service Provider in South Australia. Regional development plans are detailed in Appendix D.

Appendices

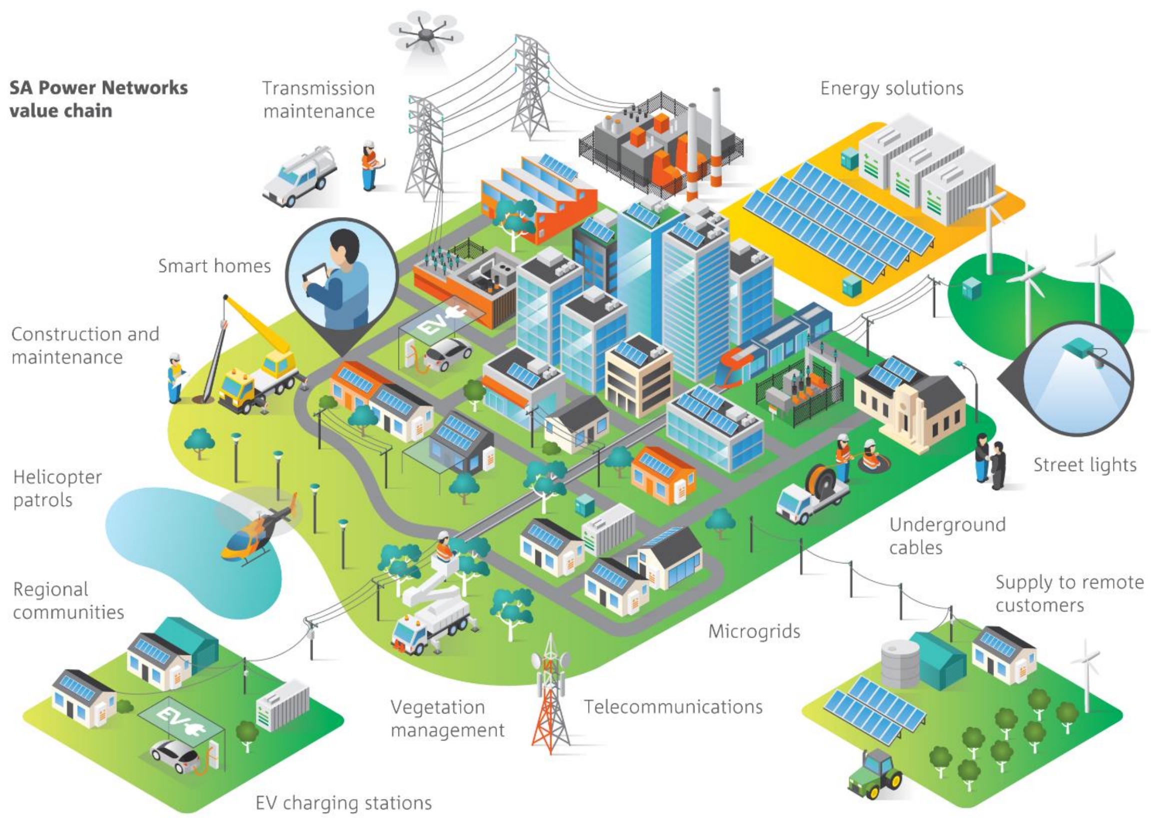
Appendices have been included for the relevant contact people, compliance checklist, forecasting methodology and detailed regional network plans.

1. About SA Power Networks

SA Power Networks has always valued its key role in ensuring the South Australian electricity distribution network supports the needs and development of South Australia and its communities. SA Power Networks has proudly served South Australians since 1946, initially as part of the Electricity Trust of South Australia, and then as a stand-alone distribution business, established in 1999, when the electricity supply industry was transformed by a new regulatory framework. As the registered DNSP in South Australia, our primary responsibility is planning, building, operating and maintaining the South Australian electricity distribution network — an essential community asset and core component of the State's energy infrastructure. SA Power Networks does this in a safe, reliable, efficient and prudent manner.

SA Power Networks is a limited liability partnership which is 51 percent owned by Cheung Kong Infrastructure Holdings Limited and Power Assets Holdings Limited, and 49 percent owned by Spark Infrastructure SA Pty Ltd.

Figure 1. Our Role in the Community



1.1. Our Statutory and Regulatory Framework

SA Power Networks is regulated by multiple statutory and legislative requirements across areas of energy, occupational health and safety, environmental, industrial, competition, consumer protection and national security laws.

Electricity regulation of the National Electricity Market (NEM) is primarily through the National Electricity Rules, enabled by the National Electricity Act (the Act) and the National Electricity Law (a schedule to the Act).

The National Electricity Law established the key regulatory bodies of the NEM and set out the National Electricity Objectives (NEO), which promote efficient investment in, and efficient operation and use of, electricity services for the long-term interests of consumers of electricity with respect to:

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

SA Power Networks aims to meet these objectives through investments that promote:

- reliability and safety,
- choice and empowerment for customers,
- support our state's nation leading energy transition, and
- affordability and equity.

Our planned investments are assessed by the Australian Energy Regulator (AER) as part of their economic regulatory role through the revenue proposal process.

We must also comply with the conditions of our Distribution License, Distribution Code and Transmission License which are provided by the State-based regulator, the Essential Services Commission of South Australia, who also retain responsibility for setting service levels., Whilst the Office of Technical Regulator is responsible for setting and overseeing the safety and technical regulation of the energy industry in South Australia.

1.2. Our electricity distribution network

Schedule 5.8(a)(1) of the NER requires SA Power Networks to provide a description of our electricity distribution network.

The electricity distribution network in South Australia is vast, covering more than 178,000km^2 along a coastline of over 5,000km. We supply electricity to around 919,000 customers ranging from isolated farms in rural areas to industry precincts, regional and metropolitan residential homes, businesses, and city centres.

South Australia is very sparsely populated except for the coastal area with approximately 70% of customers residing in major metropolitan areas but only serviced by 30% of the network infrastructure in terms of circuit length. This results in the remaining 30% of customers being serviced by 70% of the network infrastructure in terms of circuit length. Therefore, the average customer density per kilometre of distribution line in South Australia is the lowest amongst the DNSPs in the NEM.

1.2.1. Network configuration

Our distribution network is predominantly a three-phase system, with some single-phase components used mostly in rural and remote areas. The sub-transmission network supplies and connects zone substations, operating at 66kV and 33kV. In rural and remote areas, the single-phase system predominantly operates at 19kV. Thirty percent of our network is comprised of these long 'single wire earth return' (SWER) lines. In higher density rural and urban locations, the three-phase distribution feeder system most commonly operates at 11kV, however some 7.6kV distribution feeders still exist.

This 7.6kV voltage is a legacy voltage level, being phased out of the network. The standard low voltage customer supply is 230V at 50Hz.

1.3. Our network operating environment

Schedule 5.8(a)(2) of the NER requires SA Power Networks to provide a description of our operating environment.

The network is centred around Adelaide and supplies electricity to the south-east coastal region of South Australia and north towards inland South Australia as shown in the below Figure which also the demonstrates extent of our overhead network in South Australia.

Adelaide and much of South Australia has a dry climate featuring greater extremes of summer temperature than most other Australian capitals. Extended periods of heatwave conditions can occur in summer. During these heatwave periods, summer daytime temperatures can exceed 40°C for several days in a row and overnight minimums can remain above 30°C for some of those days. South Australia, as a result has one of the peakiest electricity demands in the world driven by the extraordinary demand for cooling during our hot summers.

Figure 2. Map of the Network

1.4. Our Network Distribution Assets

In accordance with Schedule 5.8(a)(3) of the NER, this section presents a summary of the number and types of distribution assets in our network.

Our network extends for over 90,000km, and includes around 400 zone substations, 77,500 street transformers, more than 620,000 Stobie poles and 200,000km of overhead conductors and underground cables. Our assets also include switches, meters, and many ancillary systems as well as fleet and depot facilities spread across the State.

1.4.1. Sub-transmission network

The SA Power Networks sub-transmission network includes transmission connection point substations, sub-transmission lines, zone substations and associated protection systems to ensure the safety and operability of the network.

Transmission connection point substations

SA Power Networks' sub-transmission system is supplied by 52 transmission connection point substations. While there are some exceptions, in most cases these connection point substations are jointly managed by ElectraNet and SA Power Networks and they typically operate at either 275/66kV, 132/66kV or 132/33kV.

Transmission connection points are categorised according to the different levels of reliability and security of supply, specified by ESCoSA within the ETC.

Metropolitan 66kV sub-transmission lines

SA Power Networks' metropolitan 66kV sub-transmission network consists of five 66kV meshed systems supplied from the associated connection point substations, which in turn supply SA Power Networks' metropolitan zone substations. Each of these meshed systems contains multiple connection point substations. The fifth region, the Adelaide Central Region (ACR) was most recently created by ESCoSA within the ETC to define the area containing the larger Adelaide CBD. The ACR is independently planned even though it is meshed within the larger Metro East region.

The supply capacity of the metropolitan meshed 66kV networks is dependent on the rating of the individual lines and circuit breakers within the network. The network planning criteria for these systems stipulate that no load will be lost for a single 66kV line outage or a single ElectraNet transformer outage (N-1 condition) under 10% Probability of Exceedance (10 PoE) conditions. The ETC refers to these connection points as 'category 4' and 'category 5' (for the ACR only) and requires 100% N-1 transmission line and connection point transformer capacity to be continuously available by the transmission network service provider (TNSP).

Consequently, SA Power Networks' metropolitan meshed sub-transmission lines are planned such that their emergency rating exceeds the load through the line under contingent conditions at a 10 PoE level of demand. These lines are also planned such that their normal rating exceeds the 10 PoE load under normal conditions (ie all equipment in-service).

The metropolitan sub-transmission network consists primarily of overhead power lines, except for the CBD network which is predominantly supplied by underground cables. In total, around 8% of SA Power Networks' metropolitan sub-transmission system is underground.

Country 66kV and 33kV sub-transmission lines

SA Power Networks’ country 66kV and 33kV sub-transmission lines are predominantly radial systems, designed to carry normal loads under 10 PoE conditions. They are generally not designed to N-1 standards as most of these lines are radial in nature and predominantly consist of overhead construction, with a repair time of typically 12 to 24 hours.

Country radial sub-transmission lines are considered for de-radialisation where the load exceeds 30 MVA and / or where the performance of a RIT-D indicates a positive net market benefit.

Meshed 66kV and 33kV sub-transmission lines, which do exist within country regions, are planned to a N-1 standard as per the metropolitan 66kV sub-transmission network.

Zone substations

SA Power Networks’ distribution network is supplied by 359 zone substations.

Zone substations are supplied by sub-transmission lines. While there are some exceptions in rural areas, metropolitan zone substations are typically supplied by two (sometimes more) sub-transmission lines that are connected to the substation bus via a series of circuit breakers and disconnectors. Under the NER definitions, zone substations are classified as sub-transmission assets.

SA Power Networks usually receives supply from the ElectraNet transmission connection point at a voltage level that is approximately 100% of the nominal voltage. This voltage then falls as power is distributed along SA Power Networks’ 66kV and 33kV sub-transmission lines to its zone substations. The majority of zone substation transformers have on-load tap changers (OLTC) that have the ability to raise or lower voltage levels in response to demand changes to maintain nominal voltage. Alternatively, 11kV voltage regulators may be also used to regulate the output voltage where the transformers are not equipped with OLTCs.

SA Power Networks’ zone substations are designed to supply the forecast 10 PoE load based on a normal cyclic rating, and 50 PoE load following the worst single substation contingency condition based on the zone substation’s emergency cyclic rating.

Sub-transmission protection

SA Power Networks uses best endeavours to coordinate the protection systems across the network to protect our assets, employees and the general public against all credible faults. Protection devices must be set such that network security is maintained or improved and fault clearing times are selected with due consideration to supply security and safety. The integrity of these settings also relies on customers / generators informing SA Power Networks where they wish to alter previously agreed settings.

Sub-transmission protection settings are selected with consideration to future network capacity requirements and fault levels applicable for the normal operation of the network. Generally, SA Power Networks’ protection philosophy is to protect the distribution network from faults, not network overloads.

1.4.2. Distribution network

The distribution network typically operates at 19kV single phase in rural and remote locations and at 11kV three phase in higher customer density rural and urban locations. The standard LV customer supply voltage is 230 Volts single phase or 400 Volts three phase at 50Hz.

The distribution network consists of overhead and underground assets. The overhead distribution assets are supported by approximately 530,500 poles. These poles are constructed in house by SA Power Networks from steel and concrete and are known as Stobie poles.

11kV and 7.6kV feeders

SA Power Networks' 11kV and 7.6kV feeders are largely three-phase radial feeders that provide supply to distribution substations, which transform the voltage down, to either 400V three-phase or 230V single-phase. Feeder capacity may be limited by the zone substation's 11kV or 7.6kV circuit breaker or recloser rating, the feeder's underground cable exit rating or the overhead conductor rating comprising the feeder's backbone.

19kV SWER systems

SA Power Networks' 19kV SWER systems consist of a single-phase conductor that supplies single-phase power to distribution substations. SWER systems typically operating at 19kV have traditionally been used to supply small amounts of load over long distances, such as to supply farms in remote areas. The largest SWER isolating transformer used by SA Power Networks has a capacity of 200kVA.

Distribution substations

Distribution substations convert the voltage from HV to LV and may be connected to SA Power Networks' network at 33kV, 19kV, 11kV or 7.6kV. The secondary voltage of the distribution substation may (nominally) be either 400V (three-phase), 460V (single phase) or 230V (single-phase) and can supply either a single customer or a LV distribution system from which multiple customers may be connected.

Low voltage network

The LV distribution systems operated by SA Power Networks are either radial three-phase 400V (three-phase) or 460/230V (single-phase) systems used to supply multiple customers from a single distribution substation.

1.4.3. Asset summary

A summary of our assets can be found in the AER's Regulatory Information Notice for SA Power Networks available on the AER website via this link.

2. Factors impacting our Network and Future Challenges

This section provides details of SA Power Networks operating environment and descriptions of factors that may have a material impact on our network as per Schedules 5.8(a)(2), 5.8(b)(5) of the NER.

2.1. Factors Impacting our Network

Schedule 5.8(b)(5) of the NER requires SA Power Networks to provide a description of any factors that may have a material impact on its network, including factors affecting;

1) fault levels;
2) voltage levels;
3) other power system security requirements;
4) the quality of supply to other Network Users (where relevant); and
5) ageing and potentially unreliable assets.

2.1.1. Fault Levels

The fault level rating in a specific section of the network is equivalent to the fault current that would flow from a fault in that section of the network. Equipment installed on the distribution network is designed to a maximum fault level. If the fault level exceeds this rating, then secondary equipment damage may occur during a fault. Our maximum design fault levels for the distribution network are outlined below:

- 7.6kV and 11kV: 20,000A
- 33kV: 25,000A
- 66kV: 31,500A

It should be noted that the values above represent SA Power Networks' ultimate fault level ratings. In some locations, for historic reasons, the fault rating of equipment may be lower than these values, thereby placing localised constraints on the connection of equipment which may increase fault levels beyond the capability of the existing plant (eg synchronous generators). Where this is the case, augmentation or some other method of fault level mitigation will be required before any such connection can proceed.

The installation of new embedded generation on the distribution network has the potential to increase fault levels. Generally, the fault levels throughout most of the distribution network are well within limits, however in the Adelaide CBD, the three phase and phase to phase fault levels are close to the rating of the installed equipment on the 11kV network. This limits, the amount of synchronous embedded generation that can be installed on our CBD 11kV distribution network without the provision of additional fault current limiting equipment by any generation proponent.

Similarly, 66kV fault levels in the Metro West 66kV sub-transmission network are such that the connection of any additional synchronous generation at 66kV level in this region, particularly on or near the LeFevre Peninsula is likely to require significant fault level mitigation works.

2.1.2. Voltage levels and Quality of Supply

SA Power Networks aims to comply with the power quality requirements (including voltage levels) specified within the NER and relevant Australian Standards. Voltage levels and QoS can be affected by several factors including:

- Installation and switching of customer loads;
- Installation and switching of distributed energy resources and forms of embedded generation;
- Switching of network equipment such as reactive plant; and
- Disturbances upstream of SA Power Networks' system (e.g. transmission network).

We presently take an approach to managing QoS which includes both pro-active and reactive activities. SA Power Networks pro-actively monitors the voltage levels at zone substations using permanently installed monitoring equipment in the major rural and metropolitan zone substations and using portable equipment to undertake cyclic monitoring of smaller rural zone substations.

We also respond to between 2500 to 4500 requests each year to investigate QoS related queries. In situations where a customer's electricity supply is found to be outside the relevant Australian Standard due to SA Power Networks, we undertake remedial works to meet the relevant standards.

2.1.3. Power system security

The NER clause 4.3.4 outlines certain obligations that SA Power Networks must comply with in relation to system security. This includes the requirement to maintain Under Frequency Load Shedding systems (UFLS), that can automatically interrupt load in response to a sudden loss of system generation.

Due to the high Consumer Energy Resources (CER) within South Australia, a significant number of feeders and lines included within the UFLS scheme are net exporters of energy at certain times of the day. The shedding of these feeders and lines by the UFLS system at these times will exacerbate rather than arrest an under-frequency event.

In late 2021 the South Australian Government gave new powers to the Office of the Technical Regulator to make new emergency service standards. The OTR published standards which required SA Power Networks to augment Underfrequency Load Shedding capabilities to address the aforementioned limitations.

The OTR have also developed the Technical Regulator Guidelines - Distributed Energy Resources which requires that all new electricity generator plant is able to be dynamic export capable with limits to be remotely communicated by SA Power Networks. The guideline requires:

- registration of the site with SA Power Networks,
- the communication and application of site level dynamic exports communicated by SA Power Networks

- the ability to apply a fall back export limit in the events of a communication failure,
- emergency curtailment in the event of distributed generation resulting in system wide events, and
- the capability for measurement and reporting of metering parameters to SA Power Networks.

This guideline was developed together with the solar industry and SA Power Networks and its flexible exports program. The flexible exports program enables SA Power Networks with customer agreement to adjust solar exports to match the available capacity on the network, avoiding unstable electricity supply, local voltage issues and potentially wider issues.

ElectraNet has identified that the flow of capacitive reactive power from the distribution system is contributing to the occurrence of high voltage levels on the SA transmission system, especially at times of low state demand. Continuation of this trend could cause widespread over-voltages on the SA electricity system that exceed equipment ratings if a critical contingency event occurred during a time of low demand. SA Power Networks are working with ElectraNet to better understand connection point power factor ranges and the importance of these in maintaining system security. Refer to section 5.1.3 for more information.

2.1.4. Ageing assets

SA Power Networks has a high focus on asset management and employs good electricity industry asset management practices. During the forward planning period, we plan to continue working towards the alignment of our asset management practices with the latest asset management industry standard, ISO 55001. We also continue to develop more sophisticated economic risk evaluation and investment forecasting capabilities for replacement expenditure aligned with the AER guidelines and as part of our AER approved Assets and Work program.

We have one of the oldest distribution networks in the NEM, with a large proportion of our network installed between the 1950s and 1970s. We are, however, only in the early stages of replacing many of these assets. Consequently, replacement levels have been increasing recently to offset poor condition due to age and to manage overall network risks.

SA Power Networks seeks to prudently manage our asset portfolio risk to the level that is required for compliance with our regulatory obligations and requirements under the SRMTMP, as endorsed by the OTR.

2.1.5. Network Condition

SA Power Networks' overhead power line network is predominantly situated along the coast, which results in high exposure to a saline environment. We acknowledge the impact of corrosion on our assets, by identifying different corrosion zones within South Australia. We have identified three levels of corrosion zones: low; severe; and very severe. Severe corrosion zones extend further inland due to the transfer of airborne salts by the atmosphere.

To effectively manage our asset portfolio and the impact of corrosion SA Power Networks specifies and considers the corrosion zone level for each asset in our Asset Management Database. The different corrosion zones are provided in Figure 3 below.

Figure 3. Atmospheric corrosion zones map in South Australia

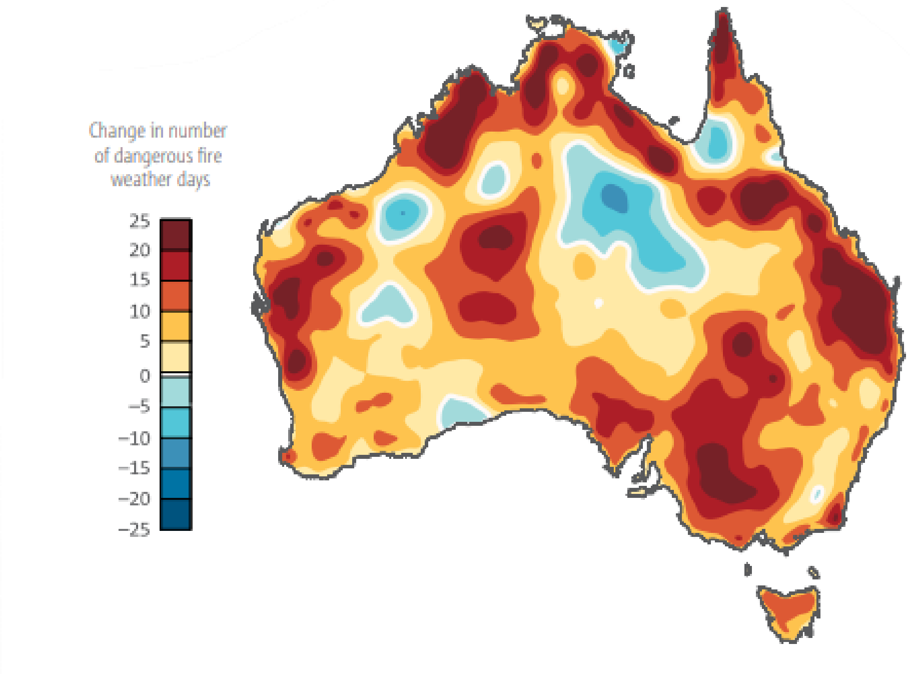
2.2. Future Challenges

2.2.1. Climate change

Bushfires

Climate change is likely increasing the risk and intensity of bushfires in South Australia by affecting the dryness of the environment and fuel loads through changes in rainfall, air temperature and atmospheric moisture content. This is evident in the figure below, showing the change in the number of dangerous fire weather days from the 2022 State of the Climate report, published by The Bureau of Meteorology (BoM) and the Commonwealth Scientific and Industrial Research Organisation (CSIRO).

Figure 4. Change in the number of dangerous fire weather days, *Source: BoM, State of the Climate 2022*

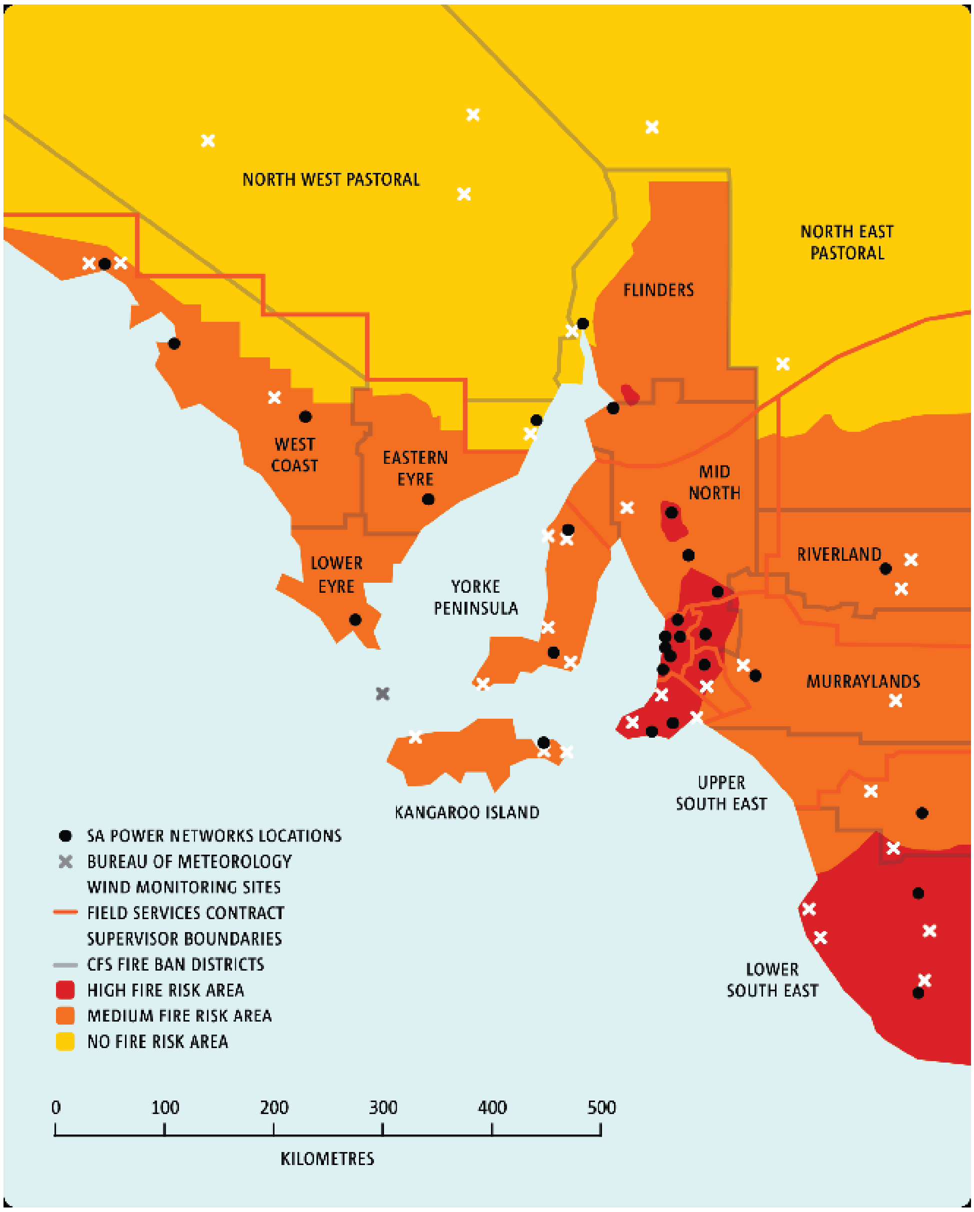


Our distribution network traverses bushfire risk areas where an electrical fault could result in a fire ignition, subject to the conditions. We recognise the importance of minimising any risk associated with operating the distribution network in bushfire prone areas by identifying and categorising risk levels associated with specific areas.

These include high bushfire risk areas (HBFRAs), medium bushfire risk areas (MBFRAs) and non-bushfire risk areas (NBFRAs). HBFRAs include the Adelaide Hills, Fleurieu Peninsula, Clare, Lower South East, parts of Kangaroo Island, parts of the Eyre Peninsula and Wirrabara Forest in the Mid North. MBFRAs reflect fringe bushland areas across the state whilst NBFRAs consists of the metropolitan area, and North West and East Pastoral districts. These bushfire risk areas are identified in Figure 5 below.

In addition to our existing rigorous bushfire management practices, SA Power Networks has undertaken extensive analysis using experts from the CSIRO and developed a model that allows us to quantify the bushfire risks arising from different parts of our network. This model has enabled us to identify assets with the highest bushfire risk so we can implement additional measures to further mitigate bushfire risk.

Figure 5. Bushfire risk areas in South Australia



Severe weather events

The BoM have stated the severity of severe weather events (SWE) will increase as a result of climate change; we have also observed this from our long-term patterns of historical weather-driven reliability outcomes. SWEs are the major cause of prolonged interruptions to power supply in South Australia.

Lightning and high winds cause the most damage, lightning strikes directly damage network equipment, whilst high winds can blow limbs or whole trees onto power lines. Power interruptions as a result, can be extended, especially for customers in remote areas where the network is sparser and radial lines are longer.

When the impact of a weather event exceeds a specified magnitude on a given day, it is classified as a Major Event Day (MED). The number of MEDs can vary considerably from year to year. For example, in 2016/17 there were nine MEDs. This is the highest MED count recorded to date.

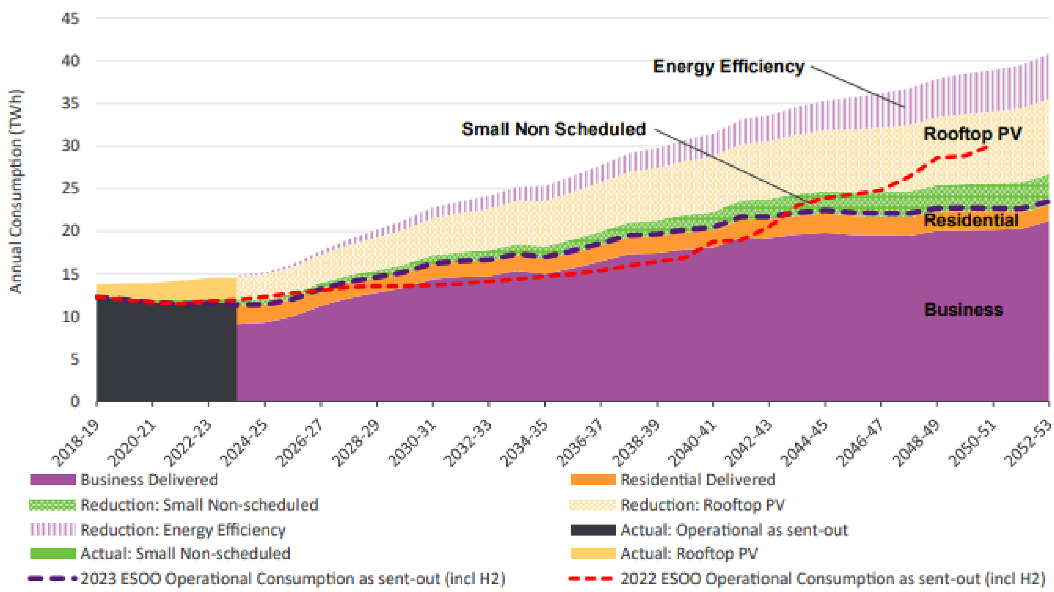
The MEDs of 2016/17 represented the most significant in South Australian distribution reliability events recorded to date by far, totalling a record high of 329.4 minutes, with the previous maximum being 138.5 minutes in 2010/11. In comparison, there were on average 3 MEDs annually over the 10-year period 1 July 2005 to 30 June 2015, totalling 43.0 minutes per year on average and no MEDs in 2006/07 or 2017/18. In 2022/23 we experienced six MEDs, totalling 263.2 minutes, due to severe weather.

2.2.2. Consumer Energy Resources

Australia's transition towards a net zero emission economy by 2050 is a key factor influencing consumption and demand forecasts.

Customers are moving more of their energy needs to electricity through the increased use of electric vehicles and the transition away from gas for hot water, heating and cooking. This energy transition can be seen in the below forecast from AEMO which predicts an increase in electricity consumption. However, it is predicted this increase in consumption will be largely offset by the increase of Consumer Energy Resources (CER) such as rooftop solar PV and household batteries.

Figure 6. Actual and forecast South Australia electricity consumption, ESOO Central Scenario (TWh), *Source: AEMO, ESOO 2023*



South Australia has high levels of CER in the NEM with around 37% of residential customers having solar PV installed. The strong growth in solar PV installations is expected to continue, and beyond that, other new CERs such as battery storage and EVs will increase. Furthermore, South Australia also has significant transmission connected renewable energy resources. CER is having a material impact on the network which was not designed for complex two-way flows of energy, with asset ratings being potentially exceeded during times of minimum demand.

Our current connection rules allow residential customers to export up to 5kW per phase from their CER installations in most areas. However, some customers are eligible for the flexible exports connection option which allows access to higher export limits when the network has adequate capacity. Further details are provided in section 6.5.

During periods of high solar generation, on weekends and public holidays, when there is low underlying demand there, is a risk that operational limits of the network could be breached resulting in:

- The overload of existing network assets resulting in outages to customers;
- Reduced resilience of the network to faults, whereby relatively small network disturbances could place the stability of large portions of the network at risk; and
- Exceedance of quality of supply (voltage) tolerances, risking damage to customer equipment, causing customers' inverters to disconnect and increasing transient variations and flicker.

Despite these challenges, SA Power Networks is committed to enabling a continued uptake of CER, acknowledging that it presents significant opportunities for:

- Improved network efficiency, by leveraging consumer resources for network support;
- Placing downward pressure on electricity prices;
- Providing more customers access to low cost, low carbon energy;
- Supporting the electrification of transport through electric vehicles; and
- Optimising whole of system security and reliability outcomes.

The solutions being implemented to enable the continued integration of CER with the distribution network include:

- The flexible exports program as discussed in section 6.5;
- Time of use tariffs providing price signals to customers to consume more electricity during periods of high solar output;
- The rollout of Line Drop Compensation equipment to substations to enable dynamic voltage management;
- Modification of the connection standard requiring new generation sources to utilise the capability of their inverters to assist negating the impact of their export on the local voltage;
- The use of Low Voltage regulators;
- Voltage regulating distribution transformers, extending the tap range of targeted zone substation transformers and/or installation of reactive plant in zone substations; and
- Increased monitoring and control of the distribution network down to the Low Voltage network.

We are working with ElectraNet on the co-ordination of voltage management issues in both the transmission and distribution networks due to the impact of the rapid increase in CER connections. Furthermore, we are also working with the South Australian Government and AEMO to enable 'emergency backstop' measures to help protect the stability of the power system during major incidents.

2.2.3. Cyber threats to our network

Recent cyber events affecting large corporations have demonstrated the growing importance of cyber security. We have an obligation under the Commonwealth Security of Critical Infrastructure Act 2018 as an operator of critical infrastructure to maintain the cyber security and resilience of the network. We are taking active steps to ensure our network and Information Communication Technology systems are protected in accordance with industry best practices and compliant under the Commonwealth Security of Critical Infrastructure Act 2018.

3. Changes since the previous DAPR

Schedule 5.8(a)(5) of the NER requires SA Power Networks to provide analysis and explanation of any aspects of its forecasts and information provided in this DAPR that have changed significantly from previous forecasts and information provided in the preceding year.

3.1. Changes to the NER and Schedule 5.8

NER Schedule 5.8, governing the requirements for the DAPR has been amended significantly by rule changes (Table 10) since the publication of the 2022 DAPR. This has led to a requirement for some sections of the DAPR to be amended as well as the creation of entirely new sections within the document.

Notable changes to the content and structure of the DAPR include:

- Amendments to the layout of the DAPR as detailed below to enable simplification and grouping of key concepts.

Table 1. DAPR Amendments

Previous DAPR Reference	New DAPR Reference
Sections 1.1 to 1.2	Purpose of Distribution Annual Planning Report
Sections 2.1 to 2.3 and 2.5	About SA Power Networks
Section 2.6	Guide to this Document
Sections 3.6 and 2.4	1. Future Challenges
Section 2.7	2. Changes since the previous DAPR
Sections 3.2 to 3.4, and 5 to 7	3. Network Demand and Limitations
Sections 8 to 9 and 17	4. Network Investment
Sections 14 and 18	5. Demand Management and Non-Network Opportunities
Section 13	6. Asset Management
Section 12	7. Network Performance
Section 15	8. Information and Communications Technology Systems Investments
Sections 10, 11 and 16	9. Planning
Appendix A	Appendix A
Appendix B	Appendix D
Section 3.1	Appendix C
Section 16	Network Visualisation Portal

Table 2. Rule Changes since the previous DAPR publication

Rule Change	Effective Date
Material changes in network infrastructure project costs – which amended the rules to provide greater clarity concerning the process for determining if there has been a material change in circumstances during the Regulatory Investment Test process.	9 October 2022
Improving consultation procedures in the rules – which amended the rule change processes to expedite processes and flexibility when complex issues arise.	11 August 2022

3.1.1. Regulatory Investment Test for Distribution

SA Power Networks has not initiated the RIT-Ds process for any new projects since the publication of the 2022 DAPR.

Details about all RIT-Ds currently in progress, as well as projects SA Power Networks is forecasting as potentially requiring a RIT-D in the future, can be found in section 5.

3.1.2. Network Visualisation Portal

SA Power Networks Load Forecast Dashboard as well as the Regional Development Plans have been replaced by the network visualisation portal.

The network visualisation portal can be found on our website: Annual network plans - SA Power Networks.

4. Forecasts for the forward planning period

4.1. Demand and Capacity Augmentation Forecasts

In adherence to Schedule 5.8(b)(2) and (2A) of the NER, we provide forecasts for the forward planning period. These forecasts comprehensively cover load predictions and the expected utilisation of distribution services by embedded generation units at transmission connection points, sub-transmission lines, and zone substations. The relevant details, where applicable, are made accessible through our Network Visualisation Portal and Load Forecast Dashboard.

A detailed account of the forecasting methodology employed, the sources of input information utilised, and the assumptions applied in generating the forecasts are presented in Appendix C – Forecasting Methodology.

4.1.1. Load Forecasts

The daytime minimum demand forecasts provided are specifically designed to offer our customers information for evaluating network conditions during periods of peak Embedded Generating Unit (EGU) exports to the distribution network.

Furthermore, SA Power Networks has presented export capacity forecasts for Embedded Generating Units (EGUs) across sub-transmission, connection points, zone substations, and 11kV feeders, encompassing PV, ESS, and non-IES installed capacity.

4.1.2. Future transmission – distribution connection point forecast

ElectraNet and SA Power Networks do not forecast a requirement for the establishment of any new transmission connection point substations or associated sub-transmission lines in South Australia within the forward planning period.

4.1.3. Forecasts of performance against STPIS reliability targets

This information is presented in section 8.1.1 Reliability Performance Forecast.

4.2. Network asset retirements that result in a system limitation

Schedule 5.8(b1) and (b2) of the NER requires SA Power Networks to provide information on all asset retirements that would result in a system limitation, in the forward planning period.

The vast majority of our asset replacement (retirement) programs involve assets that have a replacement unit cost of less than $200,000. Details of these programs are set out below.

For asset replacement projects consisting of assets greater than $200,000, a system limitation template has been prepared. The system limitation templates can be found in Network Visualisation Portal

Conductor replacement program

The overhead line conductor replacement program involves the modern equivalent replacement of conductors that have reached their end of life and cannot be economically maintained or refurbished.

Conductors are replaced when their poor condition presents unacceptable risk to safety, reliability and network security. The methodology for determining whether conductor needs to be replaced is by undertaking routine inspections. This usually involves Overhead Component Inspections (OCI) and Ground level Component Inspections (GCI).

Conductor replacement activities will be undertaken at various locations in South Australia throughout the forward planning period. Note, conductor replacement is both planned and unplanned.

Underground cable replacement program

The underground cable replacement program involves the replacement of high voltage and low voltage cables that have been identified as having a high risk of failure. The identification process consists of performing online and offline tests (only for HV cables), historical data based on test results, location of failure, type of failure, date of failure where available as well as local knowledge from various depot personnel.

Underground cables are replaced due to poor condition and health index, known environmental risks and when the cable is at the end of its expected life (high level of cable deterioration). The methodology for identifying whether an underground cable needs to be replaced is a combination of the following:

- Historical failure;
- Operational inspection by online and offline cable testing;
- Failure trend analysis especially on cable sections that have failed numerous times within a short period of time; and
- Cables that have experienced historical high loads.

The underground cable replacement program consists of both planned and unplanned works and are undertaken at various locations across South Australia.

The majority of planned cable replacement is in the Adelaide CBD where failures of paper insulated lead cable (PILC) has resulted in a failure to achieve our regulatory reliability targets for the past three years. Only those cable segments that are economic to be replaced are planned for the forward planning period.

We are continuing to monitor and maintain the Whitmore Square to Magill 66kV sub-transmission oil-filled underground cable which has a history of oil leaks. In 2020, we applied an innovative cable oil leak detection technology that allowed for faster identification of the location of leaks. A project to reduce the oil pressure in the cable and replace the section of cable that has experienced the most faults is planned for the forward planning period. It is anticipated that this will enable the full replacement to be deferred to a future planning period. The full cable replacement project when required will be subject to the RIT-D process.

Pole renewal program

The pole renewal program involves the 'like for like' replacement of poles that have reached their end of life and pole plating or re-plating (refurbishment) where the base of the pole is reinforced with steel plates. Most of the pole renewal program expenditure involves the replacement of Stobie poles. However, the majority of the assets renewed are through the pole plating (refurbishment) program to extend the life of corroded Stobie poles. A Stobie pole of SA Power Networks' design and construction consists of a concrete core with two outer steel beams interconnected by bolts to ensure pole strength.

Poles are renewed owing to their poor condition. For a Stobie pole, the failure mode is typically due to ground level corrosion. The methodology for determining whether an individual pole needs to be replaced or refurbished is performed by undertaking a visual condition assessment and measurement of steel corrosion at the base of the pole.

Pole renewal activities are undertaken at various locations across South Australia throughout the forward planning period.

Insulator (pole top) replacement program

The overhead line re-insulation program involves the replacement of existing insulators that have reached their end of life and cannot be maintained or refurbished with the modern equivalent. Much of the program involves the replacement of overhead insulators and cross arms.

Insulators are replaced when their poor condition presents unacceptable risk to safety, reliability and network security. The methodology for determining whether an insulator needs to be replaced is by undertaking routine inspections.

Insulator replacement activities are undertaken at various locations in South Australia throughout the forward planning period. In some instances, a specific project is undertaken where a significant portion of the powerline has damaged insulators.

The replacement of pole top structures (including insulators) is through a risk-based approach. Defects identified through the OCI are reviewed and a work value (risk) determined with and an estimated cost to repair/replace. Works are then prioritised based on a risk vs cost approach. Replacements are both planned and unplanned.

Recloser renewal program

The recloser renewal program involves the replacement or refurbishment of high voltage reclosers ranging from 7.6kV to 33kV, that are obsolete, or have reached the end of their expected life. Refurbishments are undertaken where possible otherwise the reclosers are replaced.

Reclosers are small self-contained circuit breakers that are typically mounted on a pole. They are designed to protect powerlines with more intelligence than fuses. All reclosers can sense different types of faults and are able to open and reclose a circuit in the event of transient faults. Reclosers are typically located in substations and mid-line whilst remote controllable units have been installed more recently at bushfire risk area boundaries.

Reclosers are renewed due to their poor condition, protection limitations, being no longer being supported by manufacturers and/or they are at the end of their useful life. Recloser renewal activities are both planned and unplanned and are undertaken at various locations across South Australia. The methodology for identifying whether a recloser needs to be renewed is a combination of the following:

- Operational inspection;
- Recloser counter reading; and
- Historic failure rates for unplanned replacements.

For example, we have identified an increasing failure rate of old, legacy hydraulic reclosers. These assets do not have the facility for recommissioning on site or changing coil size on site and therefore present a known risk that cannot be effectively managed through cyclic inspection or counter reading.

Recloser renewal activities are undertaken at various locations across South Australia throughout the forward planning period.

Voltage regulator replacement program

The voltage regulator replacement program involves the replacement of HV voltage regulators (ranging from 7.6kV to 33kV), that are at the end of their useable life, are obsolete, unable to be refurbished or have failed in service.

Voltage regulators are designed to maintain a constant voltage level. They differ from transformers in that the active conductors on either side of the voltage regulator are at the same nominal voltage level. Voltage regulators are mounted on poles or ground mounted and are usually located mid feeder.

The methodology for identifying whether a voltage regulator needs to be replaced is a combination of the following:

- Operational inspection;
- Condition monitoring; and
- Historic failure rates for unplanned replacements.

For example, we have identified an increasing failure rate of existing, legacy voltage regulators. These assets do not have the facility for oil sampling and therefore present a known risk that cannot be effectively managed through inspection and condition monitoring.

Voltage regulator replacement activities are undertaken at various locations across South Australia throughout the forward planning period.

Ground level switchgear renewal program

The ground level switchgear renewal program involves the replacement of medium voltage (7.6kV to 33kV) ground level switchgear that are approaching the end of their expected life and cannot be maintained. Some types of switchgear are also refurbished using spare parts or availability of new components for specific makes/models.

Switchgear is renewed due to age and deterioration which typically results in operational restrictions on the network, obsolescence and inability to source spare parts which can result in unacceptable risk to the safety, reliability and security of the network.

The methodology for determining the renewal of ground level switchgear is based on:

- Condition monitoring through inspection;
- Historical performance and known failure rates;
- Operational restrictions affecting network performance; and
- Obsolescence leading to future restrictions.

Ground level switchgear renewal activities are widespread throughout the underground network in South Australia.

33kV and 66kV substation circuit breaker replacement program

Substation circuit breakers provide an essential role within SA Power Networks' network, providing controlled switching and fault isolation for both the high voltage sub-transmission and distribution networks. The safe and reliable operation of these assets is critical to network operation as they provide essential control and protection functionality necessary to maintain public safety and the ongoing reliable supply of electricity to our customers. The consequences of in-service failures of these assets range from wide scale supply interruptions, hazards to the environment and public safety, catastrophic fires and collateral damage to major substation assets.

Replacement of circuit breakers is planned as their performance degrades and approach the end of their economic life which presents unacceptable risks to safety and network security.

Planned circuit breaker replacements are determined using a risk-based approach that considers age, condition, performance and failure consequences for individual assets. Circuit breaker replacement activities include both planned and unplanned replacement projects and are undertaken at various locations across South Australia. An allowance for two additional unplanned circuit breaker replacements per year is also included in the forward planning period.

The planned and unplanned circuit breaker replacement program are continuous throughout the forward planning period.

Substation surge arrester replacement program

A surge arrester is a relatively low-cost device used to protect major substation equipment (ie power transformers, regulators, cables, capacitors and circuit breakers) from the damaging effects of over-voltage due to lighting and switching surges.

Surge arrester replacement activities include both planned and unplanned replacement projects and are undertaken at various locations across South Australia. Site specific replacements of surge arresters are scheduled approximately six months in advance to align with access provided by other substation maintenance works, eg transformer maintenance.

Surge arrestor replacements are determined using a risk-based approach that considers age, condition, arrestor technology and failure consequences for individual assets. Replacement priority is based on removal of old technology silicon carbide (gapped type) arresters and management of population at end of life.

We are proposing to replace approximately 10 sets of surge arresters per year in the forward planning period.

Instrument Transformer replacement program

Current transformers (CTs) and voltage transformers (VTs) are collectively known as instrument transformers. Within substations, they are predominantly used with protection and metering devices to control and monitor the network and detect faults. In this application, they are essential to maintaining a safe reliable operation of the electricity supply network.

CTs are a fundamental component of protection systems, allowing measurement of HV electrical currents and isolation from the HV network. VTs allow a directional aspect of protection in addition to voltage sensing, metering and load shedding functions.

Replacement of instrument transformers is required as they approach the end of their economic life and present unacceptable risks to safety and network security. The replacements are determined using a risk-based approach that takes into account the age, condition, performance and failure consequences for individual assets.

Instrument transformer replacement activities include both planned and unplanned replacement projects and are undertaken at various locations across South Australia. It is planned to replace approximately three sets of instrument transformers per year in the forward planning period.

Substation Direct Current (DC) supplies replacement program

Substation DC systems are required to provide supply for critical substation protection, control and annunciation requirements, independent of primary AC mains. DC electrical requirements include control and protection relays and circuit breakers. At sites without a dedicated telecommunications (48V) DC system, the substation (110V) DC system is also used to supply communications SCADA equipment.

All major substations are provided with at least one DC system, comprising of batteries, a charger and DC distribution panel. A substation AC panel provides the input to the battery charger which supplies the substation DC Bus and energy source for battery charging.

The batteries used in SA Power Networks' DC systems have a 10-year functional life and must be replaced on a regular basis under a scheduled program of works. Due to significant network operational and safety issues identified by the 2016 state-wide blackout and subsequent prolonged network outages, a DC "hardening" program is being implemented to ensure adequate survival times and remote monitoring capabilities at critical sites. This program is planned to be completed by 2025.

DC supply replacement activities include both planned and unplanned replacement projects and are undertaken at various locations across South Australia. We propose to replace approximately 30 sites per year in the forward planning period.

Substation AC Auxiliary supplies replacement program

The AC auxiliary system consists of a distribution panel, located in a substation's control building, supply transformers, fuses and associated low voltage distribution circuits. It is the source for low voltage electrical power for all auxiliary equipment and DC storage systems required to provide safe and reliable operation of substation primary assets.

Replacement of part or whole of the AC Auxiliary system is required as they approach the end of their economic life or when they are no longer capable of providing a level of substation supply security that ensures safe and secure network performance.

AC auxiliary supplies replacement activities include both planned and unplanned replacement projects and are undertaken at various locations across South Australia. We propose to replace approximately two sites per year in the forward planning period.

Substation disconnector replacement program

Substation air break disconnect switches are devices used to visually and electrically isolate HV equipment or sections of bus-work to facilitate safe access during maintenance, repair, upgrade or network operation. The basic construction of a disconnect switch consists of a mechanically driven moving conductor supported by insulators on a metal support frame. Many disconnectors are now suffering age related failure modes, posing a significant risk to substation switching operators who stand directly below the disconnector when switching and significantly impeding network access for repairs and supply restoration.

A significant increase in age related substation disconnector failure has recently been observed. Substation disconnector replacements are consequently increasing across South Australia. Approximately fifty sets of failed disconnectors per year are being replaced in the forward planning period.

Pipework Switchyard replacement program

Pipework style substation switchyard construction was popular within many small country substations from the 1940's through to the early 1990's. Whilst meeting the minimum construction standards of the time, this style of construction is plagued with safety, reliability and operational issues that cannot be adequately managed without significant remediation works.

This program was initiated in 2015 to address inherent safety, reliability and operational issues of this type of small country substation and improve service delivery outcomes for rural customers. Replacement activities include planned replacement projects at various locations across South Australia and it is planned to upgrade approximately two sites per year in the forward planning period.

Protection replacement (planned and unplanned)

The relay replacement program involves the replacement of existing relays with their modern equivalent.

Relays are replaced owing to their poor performance, limited functionality or where they are no longer supported by the manufacturer.

The methodology for determining whether a relay needs to be replaced is based on the risk calculated by Risk Cost Model (RCM) model. The RCM for protection relays uses age, expected relay life, failure rates and known failure modes for specific relay types to develop a relay health index and in turn a probability of failure. The total risk depends on the safety, bushfire start, and financial consequences associated with such relay failure.

Protection relays replacement activities are undertaken at various substations across the South Australian network throughout the forward planning period.

Rural Feeder Protection Program

The rural feeder protection program involves the installation of fault clearing devices to address identified inadequacies on the rural 19kV network. Typically, this may include the installation of fuses and reclosers. Without adequate backup and overreach protection, there is a risk should the primary protection device fail. Under fault conditions, clearing times would otherwise be excessive.

4.3. System limitations resulting from asset de-ratings

Schedule 5.8(b1) and (b2) of the NER requires SA Power Networks to provide information on all asset de-ratings that would result in a system limitation, for the forward planning period.SA Power Networks does not forecast any asset de-ratings that would result in a system limitation in the forward planning period.

4.4. System limitations for sub-transmission lines and zone substations

Schedule 5.8(c) of the NER requires SA Power Networks to provide information on system limitations for sub-transmission lines and zone substations for the forward planning period.

4.4.1. System limitations for sub-transmission lines

SA Power Networks’ sub-transmission line system limitations forecast for the forward planning period are outlined below. Where the anticipated solution expenditure is greater than $200,000 corresponding system limitation templates[1] are available via the network visualisation portal.

[1] System limitation templates have not been provided for projects >$200,000 that are committed.

CER Management, Load transfers and Monitoring Program

Where possible, SA Power Networks considers it prudent and efficient to monitor and where possible perform minor load transfers to defer the need for major upgrades. The unit costs for such works are less than $200,000. Details of these programs are set out below.

Table 3. Load transfers and monitoring program sub-transmission constraints list

Constrained Asset	Region	Limitation	Constraint (MVA)	Year of Constraint
Mobilong Distribution to Murray Bridge South 33kV	Murraylands	N Overload	0.27	2023/24
Linden Park to Linden Park Tee	Metro East	N-1 Overload	0.1	2026/27
Lucindale to Kingston SE	South East	N Overload	0.1	2026/27

For constraints due to export flows during periods of minimum demand, SA Power Networks will attempt to mitigate all overloads by implementing export limits on any existing embedded generation that has SCADA control. In locations where these constraints are driven by CER <200kW, which do not have SCADA control capability, SA Power Networks has commenced the introduction of reduced fixed export limits and flexible export limits for all CER <200kW. Where there is sufficient curtailable export generation for CER <200kW, fixed export limits will cap the contribution of these systems to reverse constraints, and flexible exports will provide the capability for SA Power Networks to reduce exports at times when the network is constrained. These new connection arrangements are described further in section 6.5.

The following table details those constraints caused by export flows. Embedded generation proponents are strongly encouraged to view the connection point, zone substation and Sub-transmission line minimum demand forecasts. Where a proponent's proposal will result in a reverse constraint, that proponent will be responsible for funding either appropriate protection schemes (ie run-back) or network upgrades.

Table 4. Sub-transmission line export constraint list

Constrained Asset	Region	Limitation	Constraint (MW)	Year of Constraint
Bungama to Port Broughton Tee 33kV Sub-Tx line	Upper North	Reverse N Overload	0.25	2025

NB: the timing of constraints for reverse flows stated is as at 1 July of the stated year.

Port Noarlunga to Seaford and Seaford to Aldinga 66kV sub-transmission lines

The Port Noarlunga to Seaford and Seaford to Aldinga 66kV sub-transmission lines form part of the meshed 66kV sub-transmission network that supplies the southern suburbs and Fleurieu Peninsula. These sub-transmission lines are forecast to be overloaded following a N-1 event (loss of the Morphett Vale East to McLaren Flat to Willunga 66kV line) under 10 PoE conditions.

Recent forecasts have indicated that the lines are already at risk of overload and in breach of the planning criteria under contingent conditions.

Given the forecast and measured actual loads confirmed the need for remedial action, in 2021 SA Power Networks commenced initial design works to investigate possible network solutions and obtain construction estimates for these solution options. These works were performed in preparation for the performance of a RIT-D to consider the network and non-network solutions to address the identified constraint. The RIT-D evaluation was initiated in 2022, with publication of the Options Screening Report (OSR), Draft Project Assessment Report (DPAR) and Final Project Assessment Report (FPAR) all now complete. The intention is to resolve this constraint prior to December 2025.

In the interim period, until the resolution of this constraint, SA Power Networks will consider the use of other post contingent measures to mitigate the severity of the overload such as the use of SA Power Networks' 8MW power station on Kangaroo Island to reduce load supplied by this line under contingent conditions.

The forecast overloads are outlined in the following table.

Table 5. Limitation for the Port Noarlunga to Seaford & Seaford to Aldinga 66kV sub-transmission lines

66kV sub-transmission line	N-1 Rating (MVA)	2023/24 N-1 Overload (MVA)	2024/25 N-1 Overload (MVA)	2025/26 N-1 Overload (MVA)	2026/27 N-1 Overload (MVA)	2027/28 N-1 Overload (MVA)
Port Noarlunga to Seaford	93.0	17.0	20.1	23.2	27.0	30.1
Seaford to Aldinga	93.0	6.0	7.5	9.0	12.2	14.9

Morphett Vale East to McLaren Flat & McLaren Flat to Willunga 66kV sub-transmission lines

The Morphett Vale East to McLaren Flat and McLaren Flat to Willunga 66kV sub-transmission lines are part of the meshed 66kV sub-transmission network that supplies the southern suburbs and Fleurieu Peninsula. These sub-transmission lines forecast to be overloaded following a N-1 event (loss of Port Noarlunga to Seaford to Aldinga 66kV line) under 10 PoE conditions.

These line constraints are directly related to the Port Noarlunga to Seaford and Seaford to Aldinga line constraints in so far as these lines form either side of the same loop within the meshed system such that loss of one, constrains the other.

Recent forecasts have indicated that this line is already significantly overloaded and in breach of the planning criteria. Given the volatility of the forecasts in 2020, SA Power Networks further monitored the loads in 2021 to provide a higher degree of confidence in the forecast before committing to any augmentation.

In 2021 SA Power Networks commenced initial design works to investigate possible network solutions and obtain construction estimates for these solution options. These works were performed in preparation for the performance of a RIT-D to consider the network and non-network solutions to address the identified constraint. The RIT-D evaluation was initiated in 2022, with publication of the Options Screening Report (OSR), Draft Project Assessment Report (DPAR) and Final Project Assessment Report (FPAR) all now complete. The intention is to resolve this set of constraints prior to the summer of 2024/25 (subject to external approvals, eg SCAP).

In the interim period, until the resolution of these constraints, SA Power Networks will consider the use of other post contingent measures to mitigate the severity of the overload such as the use of SA Power Networks' 8MW power station on Kangaroo Island to reduce load supplied by this line under contingent conditions.

The forecast overload is outlined in the below table.

Table 6. Limitation for the Morphett Vale East to McLaren Flat and McLaren Flat to Willunga 66kV sub-transmission lines 66kV sub-transmission line

66kV sub-transmission line	N-1 Rating (MVA)	2023/24 N-1 Overload (MVA)	2024/25 N-1 Overload (MVA)	2025/26 N-1 Overload (MVA)	2026/27 N-1 Overload (MVA)	2027/28 N-1 Overload (MVA)
Morphett Vale East to McLaren Flat	92.0	15.6	18.4	21.2	23.9	26.9
McLaren Flat to Willunga	92.0	4.9	7.4	9.9	12.2	14.9

North Unley to Whitmore Square Tee 66kV sub-transmission line

The North Unley to Whitmore Square Tee 66kV sub-transmission line is part of the meshed 66kV sub-transmission network that supplies the inner loop of the Southern Suburbs. The overhead sub-transmission line consisting of ACSR 54/7/0.139 is forecasted to be overloaded following an N-1 event under 10 PoE conditions.

The previous forecast for the region indicated the line was only marginally overloaded and it was proposed that SA Power Networks would investigate and monitor the loads over the 2022/23 summer period. Based on the latest available forecast, there has been a significant increase in the existing N-1 overload.

In 2026, a project is proposed to uprate approximately 2.9km of the existing overhead line from T80 to T100. The proposed solution for this sub-transmission line is expected to be less than $6 million, and therefore a RIT-D is not expected for this project.

The forecast overload is outlined in the following table.

Table 7. Limitation for the North Unley to Whitmore Square Tee 66kV sub-transmission line

66kV sub-transmission line	N-1 Rating (MVA)	2023/24 N-1 Overload (MVA)	2024/25 N-1 Overload (MVA)	2025/26 N-1 Overload (MVA)	2026/27 N-1 Overload (MVA)	2027/28 N-1 Overload (MVA)
North Unley to Whitmore Square Tee	109.0	7.8	14.3	20.7	23.2	25.7

Metro West 66kV sub-transmission system

The metro west 66kV sub-transmission network consists of more than 30 lines operated in a meshed configuration. The system supplies the western portion of the Adelaide metropolitan area. Based on the most recent forecast, five lines within this system will be overloaded for N-1 events under 10 PoE conditions. The location of the five lines correspond to three separate important arterial positions within the sub-transmission network.

Given the meshed nature of the network, the level of load reduction required to mitigate the constraints are not simply equivalent to the level of overload in MVA. For example, although the 10 PoE load exceeds the rating of the New Osborne to Glanville line by 12.8MVA (in 2023/24), closer to 40MVA of load actually needs to be shed to bring the load in this line to within its rating. The overloads are also highly dependent on the output of three 66kV connected power stations in the system, namely OCPL, Dry Creek and Quarantine. Whilst officially connected to the TNSP's network, they have a direct influence on 66kV line flows within SA Power Networks' sub-transmission network.

These line constraints place a high operational burden on SA Power Networks. Both the ability to remove assets from service for maintenance as well as connecting future load and generation in the region will be severely inhibited. The 2022 and 2023 ESOO forecasts continued positive growth in this region. Combined with the closure deferral of the OCPL power station to 2026 – and possibly beyond – the limitations will only worsen.

A project to construct a new 66kV sub-transmission line between Athol Park and Woodville substations is proposed in 2028 to address the system limitation. As the network solution is expected to exceed $15 million, SA Power Networks will undertake the formal RIT-D process in advance of any augmentation. The RIT-D process is planned to commence in 2026.

The forecast overloads are outlined in the following table. The OCPL closure is not reflected in these figures.

Table 8. Limitation for the Metro West 66kV sub-transmission lines

66kV sub-transmission line	N-1 Rating (MVA)	2023/24 N-1 Overload (MVA)	2024/25 N-1 Overload (MVA)	2025/26 N-1 Overload (MVA)	2026/27 N-1 Overload (MVA)	2027/28 N-1 Overload (MVA)
New Osborne to Glanville	144.0	12.8	15.5	18.1	20.7	24.3
Glanville to Queenstown	137.0	6.8	9.7	12.5	15.3	17.9
Blackpool to Fulham Gardens	142.0	0.0	2.6	5.8	8.9	11.8
Croydon Park Tee to Croydon	144	0.0	0.0	0.0	1.7	4.6
Woodville to Queenstown	137	0.0	0.0	0.0	0.0	0.7

Elizabeth Downs to Smithfield West 66kV sub-transmission line

The Elizabeth Downs to Smithfield West 66kV sub-transmission line is part of the meshed 66kV sub-transmission network that supplies the northern suburbs. This sub-transmission line is designed for operation at its ultimate operating temperature of 100°C (T100) and is forecast to be overloaded following a N-1 event under 10 PoE conditions.

In 2021, as part of a customer connection project new a section of 66kV line was constructed between Virginia and Angle Vale substations. Whilst not meshed, this new 66kV line section can provide some support to relieve the Elizabeth Downs to Smithfield West line under contingent conditions and will enable mitigation of this constraint following manual restoration.

Despite construction of this 66kV line, it is forecasted that there will be an increasing load at risk on the Elizabeth Downs – Smithfield West 66kV line. As such, SA Power Networks proposes to alleviate this constraint in 2028 by installing new 66kV switchgear at the ends of the 66kV line at Virginia and Angle Vale substation respectively enable the line to become permanently meshed. The proposed solution for this sub-transmission line is expected to be less than $6 million, and therefore a RIT-D is not expected for this project. However, we will consider non-network options to address this system limitation in addition to the proposed network solution outlined above.

The forecast overload is outlined in the following table.

Table 9. Limitation for the Elizabeth Downs to Smithfield West 66kV sub-transmission line

66kV sub-transmission line	N-1 Rating (MVA)	2023/24 N-1 Overload (MVA)	2024/25 N-1 Overload (MVA)	2025/26 N-1 Overload (MVA)	2026/27 N-1 Overload (MVA)	2027/28 N-1 Overload (MVA)
Elizabeth Downs to Smithfield West	92.0	3.5	6.8	10.1	13.3	16.6

East Terrace to Norwood 66kV sub-transmission line

The East Terrace to Norwood 66kV sub-transmission line is part of the meshed 66kV sub-transmission network that supplies the CBD and Eastern Suburbs. The 0.3 Cu overhead section of this sub-transmission line is designed for operation at its ultimate operating temperature of 100°C (T100) and is forecast to be overloaded following a N-1 event under 10 PoE conditions.

The previous forecast for the region indicated the line was overloaded and it was proposed that SA Power Networks would investigate potential feeder load transfers to reduce the overload experienced by this line under contingent conditions. Based on the latest available forecast, there has been a significant increase in the existing N-1 overload that cannot be alleviated with load transfers.

In 2026, a project is proposed to rebuild the overloaded section of overhead line with 2km of 508 ACSR conductor to alleviate the N-1 constraint. The proposed solution for this sub-transmission line is expected to be less than $6 million, and therefore a RIT-D is not expected for this project. However, we will consider non-network options to address this system limitation in addition to the proposed network solution outlined above.

The forecast overload is outlined in the following table.

Table 10. Limitation for the East Terrace to Norwood 66kV sub-transmission line

66kV sub-transmission line	N-1 Rating (MVA)	2023/24 N-1 Overload (MVA)	2024/25 N-1 Overload (MVA)	2025/26 N-1 Overload (MVA)	2026/27 N-1 Overload (MVA)	2027/28 N-1 Overload (MVA)
East Terrace to Norwood	100.0	10.0	12.9	15.8	18.7	21.8

Waterloo Distribution to Riverton Tee 33kV sub-transmission line

Riverton and Auburn Zone Substations are supplied by a common 33kV sub-transmission line section from Waterloo Connection Point. This sub-transmission line is designed for operation up to a temperature of 50oC (T50) and it is forecast to be overloaded under 10 PoE conditions in 2023/24.

There are no available tie points that would offer a suitable alternate option to supply Riverton and Auburn Zone Substations. In 2026, a project is proposed to thermally uprate this line from its present operating temperature of T50 to T60.

The proposed solution for this sub-transmission line is expected to be less than $6 million, and therefore a RIT-D is not expected for this project. However, we will consider non-network options to address this system limitation in addition to the proposed network solution outlined above.

The forecast overload (and load reduction required to defer the limitation) is outlined in the following table.

Table 11. Limitation for the Waterloo to Riverton Tee 33kV sub-transmission line

33kV sub-transmission line	N Rating (MVA)	2023/24 N Overload (MVA)	2024/25 N Overload (MVA)	2025/26 N Overload (MVA)	2026/27 N Overload (MVA)	2027/28 N Overload (MVA)
Waterloo Distribution to Riverton Tee	6.20	0.33	0.44	0.55	0.66	0.76

Freeling to Kapunda 33kV sub-transmission line

Kapunda Zone Substation is supplied by a 33kV sub-transmission line from Templers Connection Point. This sub-transmission line is designed for operation up to a temperature of 50oC (T50) and it is forecast to be overloaded under 10 PoE conditions in 2024/25.

There are no available tie points that would offer a suitable alternate option to supply Kapunda Zone Substation. Freeling to Kapunda 33kV line is divided into Freeling – Freeling North Tee and Freeling North Tee – Kapunda 33kV lines. Freeling to Freeling North tee is under further investigation with a survey being undertaken in 2024. In 2026, a project is proposed to thermally uprate Freeling North Tee - Kapunda from its present operating temperature of T50 to T60.

The proposed solution for this sub-transmission line is expected to be less than $6 million, and therefore a RIT-D is not expected for this project. However, we will consider non-network options to address this system limitation in addition to the proposed network solution outlined above.

The forecast overload (and load reduction required to defer the limitation) is outlined in the following table.

Table 12. Limitation for the Freeling to Kapunda Tee 33kV sub-transmission line

33kV sub-transmission line	N Rating (MVA)	2023/24 N Overload (MVA)	2024/25 N Overload (MVA)	2025/26 N Overload (MVA)	2026/27 N Overload (MVA)	2027/28 N Overload (MVA)
Freeling to Kapunda	7.0	3.41	3.67	3.94	4.21	4.47
Freeling North Tee to Kapunda	7.0	0.00	0.07	0.25	0.44	0.62

Tailem Bend to Pinnaroo 33kV sub-transmission line

The sub-transmission line from Tailem Bend to Geranium and Geranium to Lameroo is designed for operation up to a temperature of 60oC (T60) and the line from Lameroo to Pinnaroo is designed for operation up to a temperature of 50oC (T50).

The approximate 120km of 33kV sub-transmission line between the Tailem Bend Connection Point and the end of line zone substation Pinnaroo, has six zone substations and three 33kV voltage regulators. With a committed load increase downstream of Geranium, the existing voltage management capability on the 33kV system would be unable to support the forecast peak load. During peak load conditions, Geranium voltage regulator would reach top tap. Insufficient voltage regulation could lead to voltage collapse.

To mitigate this voltage constraint, a demand management (DM) scheme with a customer in Parilla was established through a 3-year Network Support Service Agreement. The solution was commissioned in November 2023 and defers the need for augmentation for 3 years. To solve the constraint in 2026, the most favourable solution is a STATCOM at Pinnaroo which is included in our 2025-2030 regulatory proposal. SA Power Networks will continue to work with non-network service providers to understand if there is a suitable non-network service that can defer or avoid the need for a network solution to resolve the constraint.

Any potential remediation solutions for this sub-transmission line are expected to be less than $6 million, and therefore a RIT-D is not expected for this project. SA Power Networks is exploring both network and non-network solutions to address this constraint.

Table 13. Tailem Bend to Pinnaroo 33kV sub-transmission line[2]

33kV sub-transmission line	N Rating (MVA)	2023/24 N Overload (MVA)	2024/25 N Overload (MVA)	2025/26 N Overload (MVA)	2026/27 N Overload (MVA)	2027/28 N Overload (MVA)
Tailem Bend to Sherlock	13.80	0.00	0.00	0.00	0.41	1.14
Sherlock to Geranium	9.80	0.00	0.00	0.00	1.03	1.54
Geranium to Lameroo	5.83[3]	0.00	0.00	0.00	2.04	2.34
Lameroo to Pinnaroo	3.94	0.00	0.00	0.00	1.20	1.37

Penola Tee to Penola 33kV sub-transmission line

Penola Zone substation is supplied by 33kV sub-transmission line section from Penola West Connection Point. This sub-transmission line consists of ACSR 6/0.186-7/0.062 conductor designed for operation up to a temperature of 50oC (T50) and it is forecast to be overloaded under 10 PoE conditions in 2023/24.

There are no available tie points that would offer a suitable alternate option to supply Penola Zone Substation. In 2025, a project is proposed to thermally uprate this line from its present operating temperature of T50 to T60.

The proposed solution for this sub-transmission line is expected to be less than $6 million, and therefore a RIT-D is not expected for this project.

The forecast overload is outlined in the following table.

Table 14. Limitation for the Penola Tee to Penola 33kV sub-transmission line

33kV sub-transmission line	N Rating (MVA)	2023/24 N Overload (MVA)	2024/25 N Overload (MVA)	2025/26 N Overload (MVA)	2026/27 N Overload (MVA)	2027/28 N Overload (MVA)
Penola Tee to Penola	6.2	0.16	0.29	0.41	0.53	0.64

Hatherleigh-Robe 33kV sub-transmission line

Robe Zone substation is supplied by a 33kV sub-transmission line from Snuggery Connection Point. The sub-transmission line section between the Beachport Tee and Robe substation consists of 65km of 0.06 ACSR conductor designed for operation up to a temperature of 50oC (T50) and it is forecast to be overloaded under 10 PoE conditions in 2023/24 (and by 2025 under 50 PoE conditions).

[2] These values include the DM scheme at Parilla for which the NSSA concludes in 2026.

[3] This value is based on the voltage constraint at Geranium voltage regulator.

The most recent forecasts have indicated that the line is already at risk of overload. Connection applications in 2023 have further supported the growth in the region.

There are no available tie points that would offer a suitable alternate option to supply Robe Zone Substation, and as such a network or non-network solution is needed to mitigate the risk of overload.

Considering the significant number of customers directly connected to the 33kV sub-transmission line, along with those supplied from the Robe substation, the implementation of any augmentation solution requires careful consideration of constructability factors. This involves ensuring the ability to supply customers during the works and consideration of local conditions that may impact the feasibility of the project at specific times of the year.

In 2029 a project is proposed to install an additional 33kV sub-transmission line that runs parallel to the existing sub-transmission line between the Hatherleigh 33kV Regulator and the Robe substation. SA Power Networks are actively seeking alternative options for the interim period to defer the network augmentation to 2029.

The proposed project is expected to exceed the RIT-D threshold of $6 million and therefore, we will consider non-network options to address this system limitation in addition to the proposed network solution outlined above. SA Power Networks plans to initiate the RIT-D evaluation process in 2027.

The forecast overload is outlined in the following table.

Table 15. Limitation for the Hatherleigh to Robe 33kV sub-transmission line

33kV sub-transmission line	N Rating (MVA)	2023/24 N Overload (MVA)	2024/25 N Overload (MVA)	2025/26 N Overload (MVA)	2026/27 N Overload (MVA)	2027/28 N Overload (MVA)
Beachport Tee to Robe	5.1	0.9	1.1	1.3	1.5	1.7

Keswick to New Richmond Tee, New Richmond Tee to Plympton and Kingswood to North Unley 66kV sub-transmission Lines

The Keswick to New Richmond Tee, New Richmond Tee to Plympton and Kingswood to North Unley 66kV sub-transmission lines are part of the Southern Inner Metro (SIM) region of the Southern Suburbs meshed 66kV network. According to the most recent forecast the three 66kV sub-transmission lines are to be overloaded following a N-1 event under 10 PoE conditions. In addition, some large load connection applications have been received which will both further exacerbate the N-1 overloads.

In 2028, SA Power Networks proposes to create a new 66kV loop in the southern suburbs meshed sub-transmission system to alleviate the N-1 constraints. The reinforcement project will include the rebuild of the Keswick to Clarence Gardens 66kV line and a new three ended 66kV line between Clarence Gardens, Ascot Park and Panorama substations.

The proposed project is expected to exceed the RIT-D threshold of $6 million. As such, SA Power Networks plans to initiate the RIT-D evaluation process in 2027. The intention is to resolve this set of constraints prior to the summer of 2028/29.

The forecast overload is outlined in the following table.

Table 16. Limitation for the Southern Suburbs 66kV sub-transmission lines

66kV sub-transmission line	N-1 Rating (MVA)	2023/24 N-1 Overload (MVA)	2024/25 N Overload (MVA)	2025/26 N Overload (MVA)	2026/27 N Overload (MVA)	2027/28 N Overload (MVA)
Keswick to New Richmond Tee	142	0.0	1.05	6.90	10.08	13.27
New Richmond Tee to Plympton	144	0.0	0.0	3.8	6.92	10.03
Kingswood to North Unley	109	0.0	0.0	1.0	3.08	5.17

Davenport West – Port Augusta 33kV sub-transmission line

Port Augusta Zone Substation is supplied by an interconnected/meshed 33kV sub-transmission line from Davenport West Connection Point. This line has a section of underground cable which is approximately 150m long. A thorough cost-benefit analysis demonstrated that upgrading the line to the extent necessary for continuous N-1 (supply redundancy) is not a prudent investment.

Nonetheless, the radial section of cable raises concerns regarding the security of supply. In the event of a cable failure during summer 10 PoE conditions this would present an unserved energy risk, leaving Port Augusta Zone Substation, Port Augusta West Zone Substation, and numerous direct connect customers without supply during a potentially extended repair period. SA Power Networks has proposed the installation of a second 33kV cable to offer N-1 backup (redundancy) for the existing cable. The design of this solution is underway and is expected to be completed by October 2024.

The remediation cost for this sub-transmission line will not exceed $6 million, and therefore a RIT-D will not be required for this project.

4.4.2. System limitations for zone substations

SA Power Networks' zone substation system limitations forecast for the forward planning period are outlined below. Where the anticipated solution expenditure is greater than $200,000 a corresponding system limitation templates[4] are available via the network visualisation portal.

CER Management, Load transfers and Monitoring Program

There are several substations that are forecast to be marginally overloaded in the forecast planning period. Where available, SA Power Networks considers it prudent and efficient to monitor and perform minor load transfers prior to the relevant summer to defer the need for major upgrades. For N-1 overloads in particular, where continued monitoring confirms that constraints do indeed exist and given that by their very nature, all available transfers have already been considered, upgrades will be performed.

[4] System limitation templates have not been provided for projects >$200,000 that are committed.

Should the cost of these upgrades be estimated to exceed the RIT-D threshold, a RIT-D will be undertaken.

For constraints due to export flows during periods of minimum demand, SA Power Networks will attempt to mitigate all overloads by implementing export limits on any existing embedded generation that has SCADA control. In locations where these constraints are driven by CER <200kW, which do not have SCADA control capability, SA Power Networks has commenced the introduction of reduced fixed export limits and flexible export limits for all CER <200kW. In substations, where there is sufficient curtailable export generation for CER <200kW, fixed export limits will cap the contribution of these systems to reverse constraints, and flexible exports will provide the capability for SA Power Networks to reduce exports at times when the network is constrained. These new connection arrangements are described further in section 6.5.

In some instances, the export rating of SA Power Networks' zone substation transformers is limited due to the OLTC's design such that the import and export ratings vary significantly. Where constraints in the reverse direction are driven by these OLTC limitations, SA Power Networks will look to implement revised OLTC settings which will increase the export rating by essentially bypassing the OLTC. SA Power Networks are referring to this program as "OLTC Blocking". Further details of those sites included within the OLTC Blocking program are detailed in the following section.

Details of the load monitoring and transfer program are set out in Table 17 whilst those substations subject to the Flexible Exports program and/or management of SCADA controlled CER to mitigate export constraints are detailed in Table 18.

Table 17. Load transfers and monitoring program substation constraints list

Constrained Asset	Region	Limitation	Constraint (MVA)	Year of Constraint
Clearview 11kV	Metro East	N Overload	0.75	2026/27
Gumeracha Weir 11kV	Eastern Hills	N Overload	0.01	2023/24
Hackham 11kV	Metro South	N-1 Overload	0.08	2025/26
Lower Mitcham 11kV	Metro South	N Overload	0.15	2027/28

Table 18 details those constraints caused by export flows. Please note that this table does not list N-1 limitations for single transformer sites. This table is arranged according to year of overload followed by the substation name alphabetically.

Embedded generation proponents are strongly encouraged to view the connection point and zone substation minimum demand forecasts. Where a proponent's proposal will result in a reverse constraint, that proponent will be responsible for funding either appropriate protection schemes (ie run-back) or network upgrades.

Table 18. Substation export constraints list

Constrained Asset	Region	Limitation	Constraint (MW)	Year of Constraint
Meadows Substation	Eastern Hills	Reverse N-1 Overload	0.29	2023
Streaky Bay	Eyre Peninsula	Reverse N-1 Overload	0.05	2024
Nairne	Eastern Hills	Reverse N-1 overload	0.06	2027

Note, the timing of constraints for reverse flows stated is as at 1 July of the stated year.

OLTC Blocking Program

Some of SA Power Networks' zone substation transformers have OLTCs which due to the nature of their design, limits the amount of power which can be accommodated by them whilst operating in the reverse direction. This limitation therefore becomes the inherent restriction in the rating of the transformer when power is being exported to the network. This restriction is often orders of magnitude less than the unit's nameplate rating when operating in the forward direction. As a result of this, many of the sites containing these transformers are forecast to become constrained within the forward planning period.

Where possible (based on the capability of the existing OLTC control relay), we propose to remove the effects of the OLTC from the circuit by temporarily locking the OLTC in its present tap position and prevent it from operating whenever power flows near the export rating. Locking the tap position is only enacted at times of high reverse power flow as the OLTC is required to regulate voltage. OLTC blocking increases the export rating significantly (at the expense of voltage control) and thereby mitigates the constraint in the short term. The following is a list of those transformers presently limited by their OLTC which are proposed to have OLTC Blocking enabled in 2024. The ratings provided represent the substation's present total normal and N-1 export ratings together with these same ratings once OLTC Blocking has been enabled.

The OLTC restricted substations are listed in Table 19.

Table 19. OLTC restricted substations

Substation	Transformer Nos	Present Normal Export Rating (MVA)	Present N-1 Export Rating (MVA)	Future Normal Export Rating Post OLTC Blocking (MVA)	Future N-1 Export Rating Post OLTC Blocking (MVA)
Blackpool	TF2	-10.37	-5.60	-31.20	-18.75
Clare	TF1 & TF2	-4.48	-2.50	-11.84	-7.10
Croydon Park	TF2	-10.37	-5.50	-24.53	-14.26
Fulham Gardens	TF2 & TF3	-18.95	-10.10	-50.10	-28.50
Golden Grove	TF2	-27.22	-19.90	-87.90	-56.65
Ingle Farm	TF2	-21.36	-12.40	-48.99	-27.70
Kadina	TF1 & TF2	-4.49	-2.50	-17.36	-9.20
Murray Bridge North	TF1 & TF2	-6.27	-3.50	-26.10	-14.80
Murray Bridge South	TF1 & TF2	-6.82	-3.80	-28.41	-15.00
Oaklands	TF1 &TF2	-17.84	-9.90	-52.26	-30.48
Pyap	TF1 & TF2	-4.75	-2.80	-13.65	-7.50
Tea Tree Gully	TF1 & TF2	-17.70	-9.90	-44.88	-26.50
Wallaroo	TF1 & TF2	-4.50	-2.50	-16.03	-9.38

Smithfield West N-1 Substation Upgrade

Smithfield West Zone Substation consist of a single 32MVA 66/11kV transformer supplying approximately 10,000 customers in the surrounding suburbs of Munno Para, Munno Para West, Andrews Farm and Smithfield Plains. The area is experiencing significant load growth from land re-zoning and the connection of large residential developments. Upon losing the single transformer at Smithfield West substation, under 50% PoE conditions, supply cannot be restored to all customers after performing the available load transfers. A deferral solution was performed in 2023, creating a new feeder tie point to Angle Vale to increase load transfer capability for the substation.

Post completion of the deferral solution there still remained an emerging risk of unserved energy triggering the need for the upgrade of the Smithfield West substation. SA Power Networks proposes to undertake a project in 2026 to install a second 32MVA 66/11kV power transformer.

The proposed network augmentation to alleviate the constraint is expected to breach the RIT-D threshold of $6 million. As a result, SA Power Networks plans to initiate the RIT-D evaluation process in early 2025.

The forecast overload is outlined in the following table.

Table 20. Smithfield West N-1 overload

Substation	N-1 Rating (MVA)	2023/24 N-1 Overload (MVA)	2024/25 N-1 Overload (MVA)	2025/26 N-1 Overload (MVA)	2026/27 N-1 Overload (MVA)	2027/28 N-1 Overload (MVA)
Smithfield West 11kV	0.00	4.11	5.18	5.97	7.27	7.82

Northfield Substation Upgrade

Northfield Zone Substation consists of two 10MVA 66/11kV transformers, supplying 6,200 customers in the surrounding suburbs of Northfield and Northgate. The area is experiencing significant load growth predominantly from adjacent residential developments. There is subsequently an emerging constraint under 10% PoE conditions forecast for 2025/26.

In 2027, SA Power Networks proposes to upgrade Northfield substation replacing the 2 x 66/11kV 10MVA transformers with 2 x 66/11kV 32MVA transformers, a new 11kV switchboard and associated protection and control. Prior to the completion of the upgrade, temporary load transfers to adjacent substations will enable the residential development to commence uptake of their requested load.

The proposed network augmentation to alleviate the substation constraint is expected to breach the RIT-D threshold of $6 million. As a result, SA Power Networks plans to initiate the RIT-D evaluation process in early 2026.

The forecast overload is outlined in the following table.

Table 21. Northfield N overload

Substation	N Rating (MVA)	2023/24 N Overload (MVA)	2024/25 N Overload (MVA)	2025/26 N Overload (MVA)	2026/27 N Overload (MVA)	2027/28 N Overload (MVA)
Northfield 11kV	26.53	0.00	0.00	0.44	2.09	3.49

McLaren Vale Vineyard Substation Reconfiguration

McLaren Vale Vineyard substation is 33/11kV 150kVA pole top transformer supplied from the Willunga – McLaren Vale 33kV line. The substation supplies a single feeder with five customers. As part of an asset replacement program to remove the aged Willunga 66/33kV and McLaren Vale 33/11kV substations, this substation will be decommissioned and will be reconfigured as part of an existing 11kV distribution feeder. Works have commenced with project completion expected in Q1 2024.

Ascot Park Substation

Ascot Park Zone substation consists of a single 66/11kV 21MVA transformer that supplies over 11,000 customers in the surrounding suburbs of Ascot Park, Park Holme, Plympton Park and Edwardstown. Based on the latest substation forecast, the zone substation is expected to be overloaded in the summer of 2026/27 under both N and N-1 conditions.

To defer the substation capacity upgrade, in 2026 SA Power Networks proposes to build a new 11kV feeder out of Morphettville Zone substation that will alleviate some load out of Ascot Park and also provide additional load transfer capability.

The forecast overload is outlined in the following table.

Table 22. Ascot Park N overload

Substation	N Rating (MVA)	2023/24 N Overload (MVA)	2024/25 N Overload (MVA)	2025/26 N Overload (MVA)	2026/27 N Overload (MVA)	2027/28 N Overload (MVA)
Ascot Park 11kV	23.9	0.00	0.00	0.00	0.25	0.44

Kingston SE Substation

Kingston SE Zone substation is supplied from the South East region and consists of two 33/11kV 1.5MVA transformers. Based on the latest 10% PoE forecast, the normal rating of the substation is expected to be exceeded in the summer of 2025/26.

The two existing 11kV feeders supplied from Kingston SE do not have any available feeder tie to other substations. As such in 2025, SA Power Networks proposes to upgrade the substation capacity by replacing the existing transformers with two new 33/11kV 3MVA transformers and upgrading the existing voltage regulator to a 300A rating.

The forecast overload is outlined in the following table.

Table 23. Kingston SE N overload

Substation	N Rating (MVA)	2023/24 N Overload (MVA)	2024/25 N Overload (MVA)	2025/26 N Overload (MVA)	2026/27 N Overload (MVA)	2027/28 N Overload (MVA)
Kingston SE 11kV	3.87	0.00	0.00	0.06	0.15	0.21

Kalangadoo Substation

Kalangadoo Zone substation is located in the South East region and consists of a single 33/11kV 0.5MVA transformer. Based on the latest 10% PoE forecast, the normal rating of the substation is expected to be exceeded in the summer of 2025/26.

In 2025, SA Power Networks proposes to upgrade the substation capacity by replacing the existing transformer with two new 33/11kV 3MVA transformers.

The forecast overload is outlined in the following table.

Table 24. Kalangadoo N overload

Substation	N Rating (MVA)	2023/24 N Overload (MVA)	2024/25 N Overload (MVA)	2025/26 N Overload (MVA)	2026/27 N Overload (MVA)	2027/28 N Overload (MVA)
Kalangadoo 11kV	0.65	0.00	0.00	0.02	0.04	0.06

Mount Burr Substation

Mount Burr substation is a single 0.5MVA pole top 33kV/11kV transformer supplied from the Snuggery to Kalangadoo 33kV sub-transmission line located in the South East region. According to the latest 10% PoE substation forecast, the substation is at risk of overload in this summer of 2023/24.

In 2025, SA Power Networks proposes to upgrade the substation capacity by replacing the existing transformer with a new 33/11kV 1MVA pole top transformer.

The forecast overload is outlined in the following table.

Table 25. Mount Burr N overload

Substation	N Rating (MVA)	2023/24 N Overload (MVA)	2024/25 N Overload (MVA)	2025/26 N Overload (MVA)	2026/27 N Overload (MVA)	2027/28 N Overload (MVA)
Mount Burr 11kV	0.36	0.04	0.05	0.06	0.07	0.08

Portee Substation

Portee Zone Substation is located in the Riverland region which consists of a single 66/11kV 0.5MVA transformer. Based on the latest 10% PoE forecast, the normal rating of the substation is expected to be exceeded in the summer of 2026/27. Portee substation supplies a single 11kV feeder that does not have any feeder tie to other substations.

In 2026, SA Power Networks proposes to upgrade the substation capacity by replacing the existing transformer with a new 66/11kV 2.5MVA transformer and new 66kV circuit breaker with associated protection and control.

The forecast overload is outlined in the following table.

Table 26. Portee N overload

Substation	N Rating (MVA)	2023/24 N Overload (MVA)	2024/25 N Overload (MVA)	2025/26 N Overload (MVA)	2026/27 N Overload (MVA)	2027/28 N Overload (MVA)
Portee 11kV	0.70	0.00	0.00	0.00	0.02	0.03

Qualco Substation

Qualco Zone substation is located in the Riverland region which consists of a single 66/11kV 2.5MVA transformer. Based on the latest 10% PoE forecast, the normal rating of the substation is expected to be exceeded in the summer of 2027/28.

In 2027, SA Power Networks proposes to upgrade the substation capacity by replacing the existing transformer with a new 66/11kV 6.25MVA transformer and new 66kV circuit breaker with associated protection and control.

The forecast overload is outlined in the following table.

Table 27. Qualco N overload

Substation	N Rating (MVA)	2023/24 N Overload (MVA)	2024/25 N Overload (MVA)	2025/26 N Overload (MVA)	2026/27 N Overload (MVA)	2027/28 N Overload (MVA)
Qualco 11kV	3.25	0.00	0.00	0.00	0.00	0.04

Spalding Substation

Spalding Zone substation is located in the Mid North region which consists of two 33/11kV 1MVA transformers (with TF1 on hot standby) and a single 1MVA 11kV regulator. Based on the latest 10% PoE forecast, the normal rating of the substation is expected to be exceeded in the summer of 2027/28.

In 2027, SA Power Networks proposes to increase the substation capacity by recommissioning and loading up the existing TF1 33/11kV 1MVA transformer and upgrading the existing voltage regulator to a 200A pole top voltage regulator.

The forecast overload is outlined in the following table.

Table 28. Spalding N Overload

Substation	N Rating (MVA)	2023/24 N Overload (MVA)	2024/25 N Overload (MVA)	2025/26 N Overload (MVA)	2026/27 N Overload (MVA)	2027/28 N Overload (MVA)
Spalding 11kV	1.24	0.00	0.00	0.00	0.00	0.01

4.5. Overloads and System Limitations for Primary Feeders

4.5.1. Overloaded primary distribution feeders

Schedule 5.8(d) of the NER requires SA Power Networks to provide details of any primary distribution feeders for which it has prepared forecasts of maximum demands under clause 5.13.1(d)(1)(iii) and which are currently experiencing an overload or are forecast to experience an overload in the next two years.

SA Power Networks has several primary distribution feeders that is forecast to be overloaded and for which augmentation works are proposed to address the constraint in the forward planning period. In addition, there are several feeders that are forecast to be marginally overloaded in the next two years. SA Power Networks considers it prudent and efficient to monitor and perform minor load transfers prior to summer to defer the need for major upgrades on these feeders. All overloads stated would need to be mitigated prior to November of the summer stated.

Load transfers and Monitoring Program

The following table sets out our proposed load transfers and monitoring program for our constrained distribution feeders.

Table 29. Load transfers and monitoring program primary distribution feeders constraints list

Constrained Asset	Region	Limitation	Constraint (MVA)	Year of Constraint
Cordola 11kV	Riverland	N Overload	0.2	2023/24
Port Broughton 11kV	Upper North	N Overload	0.1	2023/24
Victor Harbor 11kV	Fleurieu Peninsula	N Overload	0.1	2023/24
Victor Harbor East 11kV	Fleurieu Peninsula	N Overload	0.04	2023/24
Port Pirie South 11kV	Upper North	N-1 Overload	1.6	2023/24
Ridleyton 11kV	Metro West	N Overload	0.34	2023/24
Loxton North 11kV	Riverland	N Overload	0.1	2024/25
Salisbury Plains 11kV	Northern Suburbs	N Overload	0.02	2024/25
Windsor 11kV	Mid North	N Overload	0.04	2024/25

Mount Barker (MTB12) 11kV feeder

Mount Barker 11kV feeder supplied from Mt Barker Distribution Substation is forecast to be overloaded by 1.2MVA under N conditions in the 2023/24 summer according to the 10 PoE forecast. SA Power Networks is planning to construct a new 11kV feeder in 2024 transferring load from Mount Barker 11kV and Bugle Ranges 11kV.

Bugle Ranges (MTB13) 11kV feeder

Bugle Ranges 11kV feeder supplied from Mt Barker Distribution Substation is forecast to be overloaded by 0.34MVA under N conditions in the 2023/24 summer according to the 10 PoE forecast. SA Power Networks is planning to construct a new 11kV feeder (the same feeder as stated in 4.4.2) in 2024 to take some load from Mount Barker 11kV and Bugle Ranges 11kV.

Strathalbyn East (ST12) 11kV feeder

Strathalbyn East 11kV feeder supplied by Strathalbyn substation is forecast to be overloaded by 0.23MVA under N conditions in the 2023/24 summer according to the 10 PoE forecast. SA Power Networks is planning to upgrade 2.5km of feeder backbone in 2024 to resolve this constraint. A system constraint template has been provided and can be found in our network visualisation portal.

Loxton West (LX51) 11kV Feeder

Loxton West 11kV feeder is supplied from Pyap zone substation and is forecasted to be overloaded by 0.6MVA under N conditions in the summer of 2023/24 summer based on the latest 10 PoE forecast. SA Power Networks proposes to upgrade 2.6km of overhead conductor to alleviate the constraint and increase the feeder exit rating of LX51.

Loxton (LX43) and Loxton West (LX51) 11kV Feeder

Loxton 11kV feeder and Loxton West 11kV feeder tie to one another thus serve as an option for alternate backup supply for one another. Due to a low rated overhead conductor near the feeder tie, the two feeders are forecasted to be overloaded under N-1 conditions in the 2023/24 summer. Based on the 50 PoE forecast, the load at risk for Loxton 11kV feeder is approximately 3.1MVA and 1.5MVA for Loxton West 11kV feeder. SA Power Networks proposes to replace 100m of 95mm^2 XLPE cable to 300mm^2 XLPE cable and uprate overhead backbone conductors on Loxton 11kV feeder (subject to confirmation of design temperature rating from line design surveys). The proposed works will increase the N-1 transfer capacity of Loxton 11kV feeder to Loxton West 11kV and vice versa.

Renmark (BM51) 11kV feeder

Renmark 11kV feeder from Renmark zone substation supplies over 850 customers and its overhead backbone conductor is forecasted to be overload under N-1 conditions in the summer of 2024/25. Based on the latest 50 PoE forecast, the load at risk for Renmark 11kV feeder is approximately 2MVA to alleviate the constraint. SA Power Networks proposes to restring approximately 700m of overhead conductor with a higher rated conductor (current carrying capacity of at least 480A).

Trott Park (NL451C) 11kV feeder

Trott Park 11kV feeder from Sheidow Park zone substation and its overhead backbone conductor from the intersection of Candy / Tripoli Roads to Herrings Lane / Bishops Hill Road is forecasted to be overloaded by 0.1MVA under N conditions in the summer of 2024/25 based on the latest 10 PoE forecast. Approximately 2,100 customers out of a total of 2,700 are impacted. To alleviate the constraint, SA Power Networks proposes to restring approximately 1.3km of 7/.144 AAC conductor with a higher rated conductor (current carrying capacity of at least 480A).

4.6. Primary distribution feeders experiencing a system limitation from embedded generation

Schedule 5.8(d1) of the NER requires SA Power Networks to provide details of any primary distribution feeders for which it has prepared forecasts of demand for distribution services by embedded generating units under clause 5.13.1(d1)(3) and which are currently experiencing a system limitation or are forecast to experience a system limitation in the next two years.

SA Power Networks does not have any 11kV distribution feeder system limitations caused by export flows, during periods of daytime minimum demand, in the forward planning period.

SA Power Networks' strategy to mitigate system limitations caused by export flows includes implementing export limits on any existing embedded generation that has SCADA control. In locations where these constraints are driven by CER <200kW, which do not have SCADA control capability, SA Power Networks has commenced the introduction of reduced fixed export limits and flexible export limits for all CER <200kW. Fixed export limits will cap the contribution of these systems to reverse constraints, and flexible exports will provide the capability for SA Power Networks to reduce exports at times when the network is constrained.

4.7. System limitations with the potential for a regulated SAPS

Schedule 5.8(d2) of the NER requires SA Power Networks to provide details of any system limitations in the forward planning period for which a potential solution is a regulated SAPS and to include at least the following information;

1) estimates of the location and timing (month(s) and year) of the system limitation; and

2) a brief discussion of the types of potential stand-alone power systems that may address the system limitation;

For the upcoming forward planning period, SA Power Networks does not have any system limitations that can potentially be resolved by a regulated SAPS solution.

5. Network Investment

5.1. Regulatory Investment Test for Distribution projects

This Section provides details of SA Power Networks' RIT-D projects that have been completed in the preceding year or which are in progress.

Schedule 5.8(e) of the NER requires SA Power Networks to provide a high-level summary of each RIT-D project for which the regulatory investment test for distribution has been completed in the preceding year, or is in progress, including:

1) if the regulatory investment test for distribution is in progress, the current stage in the process;

2) a brief description of the identified need;

3) a list of the credible options assessed or being assessed (to the extent reasonably practicable);

4) if the regulatory investment test for distribution has been completed, a brief description of the conclusion, including:

    a. the net economic benefit of each credible option;

    b. the estimated capital cost of the preferred option; and

    c. the estimated construction timetable and commissioning date (where relevant) of the preferred option; and

5) any impacts on Network Users, including any potential material impacts on connection charges and distribution use of system charges that have been estimated.

5.1.1. Preceding year RIT-D projects

SA Power Networks has completed three RIT-D projects in 2023.

Northfield GIS

Northfield 66kV substation's gas insulated switchgear (GIS) was installed in the late 1980s and is in poor mechanical condition and subject to accelerated ageing due to significant external corrosion – specifically on the flanges and O-rings in the GIS – caused by 35 years of continuous service in an outdoor environment.

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

SA Power Networks has identified two credible network options to alleviate the network constraint that arises during contingent events, including:

- Option 1 – construct a new outdoor Northfield 66kV AIS immediately south of the existing Northfield Substation; and
- Option 2 – construct a new indoor Northfield 66kV GIS in a climate-controlled building in the North-East corner of the Northfield substation.

SA Power Networks has determined that there is unlikely to be a non-network option or SAPS option that could form a potential credible option on a standalone basis, or that could form a significant part of one of the potential credible options outlined in 4.7.

The summary of net market benefit of each credible option in NPV terms is in the following table.

Table 30. Summary of Net Market Benefits for Northfield GIS

Credible Options	Weighted PV of costs	Weighted PV of gross benefits	Weighted NPV	Ranking
Option 1: New Outdoor AIS	-25.7	1,246.0	1,220.3	1
Option 2: New Indoor GIS	-29.1	1,246.0	1,216.9	2

The regulatory investment test concludes that the preferred option is to construct a new Northfield 66kV outdoor AIS which satisfies the RIT-D. This option involves constructing a new 66kV outdoor AIS immediately south of the existing Northfield substation with three 66kV bus sections supplying all existing seven 66kV lines as well as supplying the two 66/11kV transformers at the existing Northfield substation. The total estimated capital cost of the preferred option is expected to be $45.5 million, including approximately $15 million in transmission (ElectraNet) capex.

Construction of the new AIS commenced in 2023 with commissioning to be completed in 2025. For more information, refer to the Ensuring Reliable Supply for Adelaide's Eastern Suburbs - Northfield GIS Final Project Assessment Report (FPAR).

Southern Outer Metro (SOM) 66kV Line Upgrades

The Southern Outer Metro (SOM) 66kV loop is the 66kV line source for the McLaren Flat, Willunga, Aldinga and Seaford substations within the Metro South region. From Willunga, it also supplies the Fleurieu radial 66kV network including the regions of Goolwa, Victor Harbor, Yankalilla and Kangaroo Island.

SA Power Networks has identified that components of the SOM loop are overloaded following an outage of the other (ie, under N-1 conditions) during 10 PoE conditions. SA Power Networks has identified four credible network options to alleviate the network constraint that arises during N-1 contingency events, including:

- Option 1 – replace all SOM loop underrated 66kV conductor sections with a higher capacity All Aluminium Alloy Composite (AAAC) conductor;
- Option 2 – replace all SOM loop underrated 66kV conductor sections with a higher capacity High Temperature Low Sag (HTLS) conductor;
- Option 3 – replace all Port Noarlunga to Seaford to Aldinga underrated 66kV conductor with a higher capacity All Aluminium Alloy Composite (AAAC) conductor. Install a second 66kV circuit between Port Noarlunga and Aldinga using the same AAAC conductor and augment the Port Noarlunga and Aldinga substations to accommodate second circuit; and
- Option 4 – replace all Port Noarlunga to Seaford to Aldinga underrated 66kV conductor with a higher capacity High Temperature Low Sag (HTLS) conductor. Install a second 66kV circuit between Port Noarlunga and Aldinga using the same HTLS conductor and augment the Port Noarlunga and Aldinga substations to accommodate second circuit.

The summary of net market benefit of each credible option in NPV terms is in the following table.

Table 31. Summary of Net Market Benefits for Southern Outer Metro (SOM) 66kV Line Upgrade

Credible Options	Weighted PV of costs	Weighted PV of gross benefits	Weighted NPV	Ranking
Option 1 – higher capacity AAAC conductor	-16.2	185.0	168.8	2
Option 2 – higher capacity HTLS conductor	-15.5	185.0	169.5	1
Option 3 – hybrid double circuit (AAAC conductor)	-16.9	185.0	168.2	4
Option 4 – hybrid double circuit (HTLS conductor)	-16.5	185.0	168.6	3

The regulatory investment test concluded that the preferred option was to replace all SOM loop underrated conductor sections with a higher capacity HTLS (High Temperature Low Sag) conductor which satisfies the RIT-D. The total estimated capital cost of the preferred option is expected to be $12.5 million.

Upon completion of detailed final design and field checks, it may be beneficial to combine Option 1 and Option 2 when developing the final construction solution. Furthermore, each Option has a very similar weighted NPV assessment outcome. The following factors are to be assessed and considered so that the project can be delivered in an overall efficient manner:

- Time of year site access – avoid wet weather months for steep terrain areas between Morphett Vale East and Willunga, avoid properties with grapevines within the 66kV line easement during vintage season.

- Limitations with Option 2 HTLS conductor – conductors left in stringing blocks for long period of time can result in damage, sharp angles within the existing 66kV line route and high pulling tensions can result in damage.
- Materials procurement – possible unusual very long lead times and shortages.

Construction of the conductor replacement is aimed to commence in 2024 with planned completion in 2025. For more information, refer to the SOM 66kV Loop Final Project Assessment Report (FPAR).

Voltage Management and Under Frequency Load Shedding Emergency Standards

The VM&UFLS Emergency Standards prescribe investment required by SA Power Networks to address power system issues associated with CER. The standards include implementing enhanced voltage management and installing or enhancing the capability of Under Frequency Load Shedding protection. SA Power Networks therefore considers the identified need for this investment to be a 'reliability corrective action' under the RIT-D because investment is required to comply with an applicable regulatory instrument.

Due to there being only one credible option to meet the identified need, SA Power Networks considers no categories of market benefit to be material to the outcome of this RIT-D because they will not change the ranking of the credible options. In addition, quantification of the market benefit is not required in the context of an identified need that is a reliability corrective action because such investments are permitted to have negative net economic benefits.[5]

The regulatory investment test concludes that preferred and only option is to implement the voltage management services and amendment or installation of prescriptive UFLS infrastructure which satisfies the RIT-D. The total estimated capital cost of this option is approximately $35 million comprising:

- $10.0 million for the first stage of enhanced voltage management works and emergency UFLS commissioning for works completed before 31 March 2021;
- $23.4 million for upgrade of UFLS systems to enable activation based on directional flow of power, taking place from 2022 to 2024; and
- $1.6 million for expansion of UFLS to areas of the network that do not currently have this capability.

5.1.2. Current RIT-D projects

At the time of publication, SA Power Networks does not have any RIT-D evaluations currently in progress.

[5] AER, Application guidelines - Regulatory investment test for distribution, December 2018, page 33.

5.1.3. Future RIT-D projects

Schedule 5.8(f) of the NER requires that we provide, for each identified system limitation which SA Power Networks has determined will require a RIT-D, an estimate of the month and year when the test is expected to commence.

SA Power Networks' forecast RIT-D projects for the forward planning period are shown in the following table.

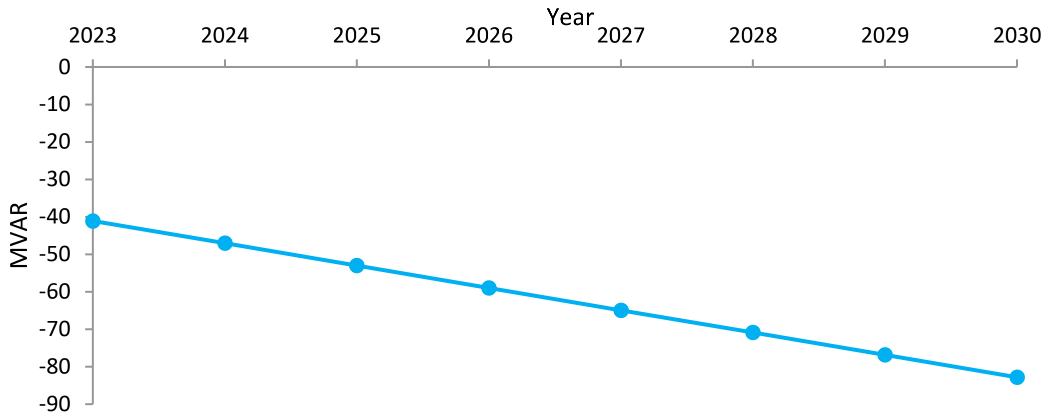
Table 32. Forecast RIT-D projects for the forward planning period

Project Name	Forecast RIT-D Commencement Date
Connection Point PF Correction Program	2024
Smithfield West Substation Upgrade	2024
Coonalypn – Meningie 33kV Line Replacement	2024
Tarlton – Ceduna 66kV line Replacement	2025
Mannum Connection Point Upgrade	2025
Northfield Substation Upgrade	2025
Virginia Substation Upgrade	2026
Clarence Gardens – Tee New 66kV line	2026
Athol Park – Woodville New 66kV line	2026
Hatherleigh – Robe No.2 33kV line 33kV line	2026
Hindley St 66kV Yard Replacement	2026
Tailem Bend 33kV Connection Point Upgrade	2027
Square Water Hole New Substation	2028

Connection Point PF Correction Program

ElectraNet has identified that the flow of capacitive reactive power from the distribution system into the transmission system is contributing to the occurrence of voltage control and system security issues on the SA transmission system, especially at times of low demand. In addition to system security issues on the transmission system, continuation of this trend could also cause widespread over-voltages on the distribution system that exceed compliant ranges, if a critical contingency event was to occur at such times. The requirements for reactive power flow at transmission connection points are defined in the Transmission Connection Agreement (TCA) between SA Power Networks and ElectraNet, which includes the requirement that no connection point shall have a leading power factor.

Figure 7. Example peak capacitive reactive export forecast



Preliminary investigation into this phenomenon across the distribution system indicates that there is a steady historic trend of increasing capacitive reactive flows at times of low demand, which is forecast to continue for the foreseeable future, as shown in Figure 7.

To bring transmission connection points within compliance of the TCA, SA Power Networks anticipates undertaking a program of 66kV and 11kV reactor installations throughout 2025-30, subject to the completion of the RIT-D.

5.2. Committed urgent and unforeseen investments

Schedule 5.8(g)(1) of the NER requires SA Power Networks to provide a summary of all committed investments to be carried out within the forward planning period with an estimated capital cost of $2 million or more (as varied by a cost threshold determination) that are to address an urgent and unforeseen network issue.

At the time of publication, SA Power Networks does not have any unforeseen network investment with an estimated capital cost of more than $2 million.

5.3. Interactions between frequency control, protection, and control systems

Schedule 5.8(o) of the NER requires SA Power Networks to provide an analysis of the known and potential interactions between:

1) any emergency frequency control schemes, or emergency controls in place under clause S5.1.8, on its network: and

2) protection systems or control systems of plant connected to its network (including consideration of whether the settings of those systems are fit for purpose for the future operation of its network),

3) undertaken under clause 5.13.1(d)(6), including a description of proposed actions to be undertaken to address any adverse interactions.

The Voltage Management and Under Frequency Load Shedding Emergency Standard RIT-D as discussed above in section 5.1.1 is seeking to address these requirements through implementing voltage management services and the amendment or installation of prescriptive UFLS infrastructure.

6. Demand Management and Non-Network Opportunities

Schedule 5.8(l) requires SA Power Networks to provide information on our demand management activities and activities relating to embedded generating units.

SA Power Networks trials and evaluates emerging demand management technologies. We identify economically viable opportunities to improve the levels of network security and reliability provided to customers and to reduce the costs of providing standard control services. The technologies investigated include the use of smart meter data and services, transformer monitoring, energy storage, dynamic voltage management and direct communication with customer devices such as air conditioners, electric vehicle chargers, smart hot water systems, solar and battery inverters and home energy management systems (HEMS).

6.1. Demand management non-network options

Schedule 5.8(l)(1)(i) requires SA Power Networks to provide information on non-network options that have been considered in the past year, including generation from embedded generating units.

For projects surpassing the RIT-D threshold, where SA Power Networks determines a non-network option (including SAPS solutions) as a potential resolution for a specific system limitation, an Options Screening Report (OSR) is published. This report invites comments and proposals for solutions to the identified system limitation from all market participants, interested parties and those parties registered on SA Power Networks' Industry Engagement Register.

Over the past year, SA Power Networks has not published any Options Screening Reports. However, in April 2023, an Expression of Interest (EOI) for Non-Network solutions was issued. As part of our ongoing commitment to the efficient management of the distribution network, SA Power Networks expanded the scope of RIT-D process of engaging non-network solution providers to also include network investments less than $6 m and address network constraints to defer network augmentation.

Following the release of the EOI, a customer information workshop was conducted in May 2023 to elaborate on how non-network solutions could be developed to limit or defer network augmentation and address system limitations in the Tailem Bend, South East, and Bordertown regions.

At the time of this publication, SA Power Networks is actively collaborating with the non-network service providers engaged through the EOI to refine and develop their service offers. In 2023, one Network Support Service Agreement (NSSA) was extended to defer the necessity for network augmentation in the Bordertown region. Another NSSA was established in the Tailem Bend region, with a customer located in Parilla, establishing a demand management solution thereby mitigating the risk of overload in the summer of 2023/24.

SA Power Networks continues to investigate additional demand management non-network options in both the Bordertown and Tailem Bend regions to address emerging constraints that cannot be resolved with the existing NSSAs.

SA Power Networks is also aware of a nation-wide funding round for community batteries currently being administered by the Australian Renewable Energy Agency (ARENA), which has potential to deliver non-network solutions to SAPN network constraints. SA Power Networks is actively monitoring opportunities to utilise the ARENA funding round to support non-network solutions – either through DNSP-allocated funding (stream A) or non-DNSP-allocated funding (stream B).

6.2. Key issues arising from applications to connect embedded generation

Schedule 5.8(l)(1)(ii) requires SA Power Networks to describe its key issues arising from applications to connect embedded generating units received in the past year.

South Australia is at the forefront of the energy transformation with world-leading levels of renewable generation relative to demand. The increasing penetration of rooftop solar PV has seen periods in the middle of the day of reach record levels of minimum demand. We are working with ElectraNet to analyse the challenges presented by a declining minimum demand.

Excessive voltage levels across the network at times of low demand and ‘reverse power flows’ through zone substations have been seen. Real time SCADA monitoring and controls are required for some exporting generating systems to prevent high voltage levels and exceeding equipment ratings during normal network conditions or after an outage of any single line, transformer, or temporary network reconfiguration.

SA Power Networks receives an extensive number of connection enquiries under the Chapter 5 and Chapter 5A process and an increasing number of informal enquiries to connect large exporting embedded generators.

In the past year, we have processed the following negotiated connections under Chapter 5A of the NER.

Table 33. Embedded generation connection enquiries and applications

2022/23 Embedded Generation	Quantity
Applications to connect received (30kW and under)	32,639
Connection enquiries received (applicable only for above 30kW, under 500kW)	247
New applications to connect received (above 500kW)	76
The average time take to complete applications to connect (above 500kW)	29 days

For further information on the impacts of CER refer to Section 8.2.6.

6.3. Actions taken to promote non-network proposals

Schedule 5.8(l)(1)(iii) requires SA Power Networks to describe its actions taken to promote non-network proposals (including SAPS solutions) in the preceding year, including generation from embedded generating units.

SA Power Networks revised and published its Industry Engagement Document (IED) in August 2022 following changes to the requirements and as part of the 3 yearly update cycle. This document provides a guide for third parties to explain how we will consider and assess the viability of non-network or SAPS solutions.

The RIT-D process requires augmentation investments in excess of $6 million to undergo a Screening Test in accordance with Section 5.17.4 of the NER. Further details of our non-network option engagement strategy can be found on our website here.

As outlined in section 6.1, SA Power Networks is actively engaging with proponents to encourage and advance non-network proposals through our EOI activities. In a continued effort to foster the implementation of non-network proposals in the Tailem Bend, South East, and Bordertown regions, letters of support for ARENA Community Battery funding were issued to respondents of the aforementioned EOI. The integration of Community Batteries in these areas holds the potential to mitigate the need for network upgrades and aligns with funding objectives.

SA Power Networks anticipates collaborating with applicants capable of offering successful alternative options to infrastructure upgrades. In cases where there are multiple requests for funding in the same region, SA Power Networks is open to collaborating with ARENA to determine an optimal solution for the network and best outcomes for consumers.

SA Power Networks takes this opportunity to emphasize the potential benefits of non-network proposals in enhancing network resilience in regions served by radial sub-transmission lines or feeders. As the establishment of electric vehicle (EV) charging infrastructure continues, the integration of non-network demand management solutions provides an opportunity to deliver cost-effective solutions for customers.

6.3.1. Demand Management Opportunities for Customer Connection Requests

SA Power Networks receives customer connection requests that sometimes result in a network constraint and hence the requirement for network augmentation. In areas where forecasted load growth is low, these customer connections can significantly accelerate the timing and level of the augmentation required for the network.

SA Power Networks will assess the duration and frequency of peak load conditions pertaining to any forecast constraint. Where considered prudent and efficient to do so, SA Power Networks offers customers an opportunity to enter demand management agreement to defer the required augmentation works.

6.4. Future plans for demand management and embedded generation

Schedule 5.8(l)(1)(iv) of the NER requires SA Power Networks to detail its plans for demand management and generation from embedded generating units over the forward planning period.

SA Power Networks recognises that alternatives to network solutions may exist which deliver either a lower cost solution or provide greater benefits to the electricity market (including electricity consumers) as a whole. The methods by which non-network solutions may achieve this include, but are not limited to:

- the use of embedded generation or storage to reduce demand on the network;
- shifting consumption to a period outside the peak period;
- increasing customers’ energy efficiency; and
- curtailing demand at peak periods, with the agreement of the relevant customer(s).

SA Power Networks evaluates all options, both network and non-network, using identical criteria that reflect both the regulatory requirements under the NER RIT-D process and our desire to implement the least cost solution to resolve the identified need.

This process is set out in more detail in clause 6.6 of the IED. A copy of the IED can be found on our website at: [Industry Engagement Document (sapowernetworks.com.au)]

A substantial surge in demand, propelled by macro factors such as electrification, especially in the business, transport, and residential sectors, the increased adoption of Electric Vehicles, renewable energy targets, and localized factors like in-fill housing, residential developments, and commercial and industrial loads, serves as the fundamental driver for the escalation of capacity-driven network augmentation. SA Power Networks is steadfast in its commitment to thoroughly explore and evaluate the potential of non-network solutions and flexible load connections to effectively manage this growing demand.

To capitalise on the collaborative efforts between SA Power Networks and non-network service providers engaged through our Expression of Interest (EOI), we have strategically staged our EOI process to align more closely with the ARENA Community Battery milestones. This strategic alignment provides a timely opportunity for providers to present cost-effective solutions to SA Power Networks.

While firm plans for the use of demand management and embedded generation to address identified constraints have been established only for system limitations requiring attention prior to the summer of 2023/24 (refer to section 6.1 for details), SA Power Networks has allocated dedicated resources to collaborate with service providers. The goal is to refine their service offerings, making them technically feasible, cost-efficient, and capable of addressing emerging system limitations. This collaborative effort will extend into 2024, providing service providers with more information and time to enhance and finalize their offers.

6.5. Consumer Energy Resources Enablement Program

In response to the emerging challenges of unmanaged CER systems as described in section 2.2.2, SA Power Networks has introduced a range of measures to increase network hosting capacity to support the continued growth of CER in South Australia, including but not limited to:

- Implementation of enhanced voltage management at 147 zone substations (described further in section 8.2.7);
- Introduction of a solar sponge tariff to encourage higher consumption during sunlight hours;
- Specifying that all new PV installations apply new volt-VAr and volt-watt response mode settings; and
- Introduction of OLTC tap block to increase power transformer ratings limited by the tap changer associated with reverse power flow.

Even with all these measures in place, constraints related to reverse power flow continue to emerge, including:

- Zone substation reverse N and N-1 constraints that cannot be cost effectively mitigated through network augmentation. These are detailed in section 4.4.2.
- Network QoS related issues as detailed in section 8.2.6.

The continued emergence of these constraints indicates that a static 5kW per phase export limit is unsustainable.

6.5.1. Changes to static export limits

To help address these challenges, SA Power Networks has introduced reduced fixed export limits in constrained areas of the network where hosting capacity limits are breached. Since 2022 this is currently being progressively introduced to other constrained parts of the network. Where a reduced fixed export limit applies, customers have the option to take up a flexible export connection instead, as described in section 6.5.2 below. Non-constrained network areas continue to have access to the existing 5kW/phase export limit.

Constrained network areas will include the zone substation reverse N and N-1 constraints (described in section 4.4.2) that cannot be resolved through the curtailment of existing SCADA connected generation, as well as areas constrained by emerging QoS issues (described in section 8.2.6). Constrained network areas will be identified when they arise through the new “connection checker” portal which will be part of the SEG application form for systems less than 30kW. This form will enable customers and installers to enter a specific NMI or address to identify if a customer is located in one of these constrained areas.

Connections for medium embedded generation systems will continue to be assessed on a case-by-case basis as part of the standard connection application process.

6.5.2. Flexible Export Limits

SA Power Networks is continuing to progressively roll out the Flexible Exports connection option to mitigate against these emerging challenges with high CERs. Unlike reduced fixed export limits that constrain customer exports all year round, flexible exports offer access to higher export limits at times when the network has adequate capacity by allowing SA Power Networks to reduce export limits only at the times and locations when the network is constrained. This capability is enabled in compatible internet connected smart inverters that download export limits from SA Power Networks which reflects the real-time capacity of the network where the inverter is located. The Flexible Export connection option will also be available for medium embedded generators with total export capacity less than 200kVA.

To find out more about Flexible Exports, visit Solar Flexible Exports | SA Power Networks.

6.5.3. Flexible Exports standard connection offering

The Government of South Australia as part of the Smarter Homes Program, has introduced Dynamic Export Requirements, requiring most new and upgrade exporting solar generation systems installed from 1 July 2023 to be capable of remotely updating their export limits.

In conjunction with this new Regulation, we are rolling out the Flexible Exports connection option to more areas to increase eligibility for new or upgrading customers across 2023 and 2024.

To find out more on the rollout, visit the Dynamic Export section on our website.

6.6. Demand management connection enquiries and applications to connect

Schedule 5.8(l)(2) requires SA Power Networks to provide a quantitative summary of:

(i) connection enquiries received under clause 5.3A.5 and of the total, the number for non-registered embedded generators

(ii) applications to connect received under clause 5.3A.9 and of the total, the number for non-registered embedded generators

(iii) the average time taken to complete applications to connect;

The below table provides a summary of embedded generation enquires and applications received since the publication of last year's DAPR.

Table 34. Embedded generation connection enquiries and applications under clause 5.3A

2022/23 Embedded Generation	Quantity
Connection enquiries received under clause 5.3A.5	12
Enquiries for non-registered embedded generators (included above)	1
Application to connect received under clause 5.3A.9	2
Applications for non-registered embedded generators (included above)	0
The average time taken to complete applications to connect.	7 months

6.7. Micro embedded generators and non-registered embedded generators connection enquiries and applications to connect

Schedule 5.8(l)(3) requires SA Power Networks to provide a quantitative summary of:

(i) enquiries received under clause 5A.D.2 in relation to the connection of micro embedded generators or non-registered embedded generators

(ii) applications for a connection service under clause 5A.D.3 in relation to the connection of micro embedded generators or non-registered embedded generators;

The below table provides a summary of embedded generation enquires and applications received since publication of last year's DAPR.

Table 35. Embedded generation connection enquiries and applications under clause 5A.D

2022/23 Embedded Generation	Quantity
Connection Enquiries received under clause 5A.D.2	25
Applications to connect received under clause 5A.D.3	287

6.8. Activities in relation to Regulated SAPS

Schedule 5.8(p) of the NER requires SA Power Networks, if a SAPS enabled network, to provide information on our activities in relation to DNSP-led SAPS projects including;

1) opportunities to develop DNSP-led SAPS projects that have been considered in the past year;

2) committed projects to implement a regulated SAPS of the forward planning period; and

3) a quantitative summary of:

   a. the total number of regulated SAPS in the network, and

   b. the total number of premises of retail customers supplied by means of those regulated SAPS

SA Power Networks do not have any SAPS in its network.

SA Power Networks will continue to evaluate SAPS opportunities. A few potential sites are being investigated to assess the financial viability of installing DNSP managed SAPS systems. The driver for considering SAPS systems at these sites is long lengths of overhead conductor (typically SWER) in poor condition.

7. Asset Management

7.1. Asset Management Approach

Schedule 5.8(k) of the NER requires SA Power Networks to provide information on its asset management approach.

Our Asset Management is informed by our recently developed Asset Management 2035 Vision aligned with our corporate Strategic Directions 2035.

We focus on what our customers and stakeholders value. The outcomes we seek to deliver through our assets reflect the needs of our customers and stakeholders. We combine this with evidence-based decision making to inform our response and develop optimal works planning and delivery.

We achieve this through an aligned organisation and by continually innovating and adapting how we do things by empowering our people, investing in our asset management system, and piloting and trialling new technologies and concepts.

SA Power Networks' asset management practices are set up to deliver sustainable network investments and performance that are cost efficient, consistent with prudent risk management approaches that maximise customer value.

A key feature of SA Power Networks' asset management practices is the asset management decision making process based on return on investment. The value framework considers not only the monetised risks addressed by an asset intervention, but also the other benefits generated by this. This enables SA Power Networks to select the optimum maintenance and replacement strategy for each asset sub-class that is technically feasible, economically viable, and delivers an acceptable residual risk against SA Power Networks' risk strategy measure while delivering customer value.

SA Power Networks' asset management approach ensures that the organisation maximises opportunities, while not exposing the business and its customers (community) to unacceptable levels of risk.

Different assets within the network have different characteristics. Therefore, SA Power Networks' asset management practices and strategies consider asset groups, asset classes and sub-classes. This enables SA Power Networks to balance its capital and operational expenditure appropriately and optimally on assets based on the performance and customer services provided. The features of SA Power Networks' asset management approach, include:

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

7.2. Asset management strategies

Schedule 5.8(k)(1) of the NER requires SA Power Networks to provide a summary of its asset management strategies.

SA Power Networks is continually improving its asset management practices and systems. A major part of that improvement has been the continuation of the transition from a replace-on-fail approach to a replace-based-on-value approach for assets. This approach requires good asset condition data and the use of improved analytical techniques that allow us to assess the risks of asset failure and facilitate prudent asset lifecycle decisions.

SA Power Networks has undertaken several initiatives to improve its understanding of asset risk, including:

- requiring all asset inspectors to be accredited to UET20612 Certificate II in Electricity Supply Industry (ESI) — Asset Inspection standard;
- taking targeted steps to improve our overhead line inspections by increasing the frequency of asset inspections, particularly, of those assets in high corrosion zones and high bushfire risk areas;
- implementing mobile data capture technology to enable inspectors to update asset information in the field and collect timely defect and asset condition information linked directly to the specific asset in the asset information system;
- determining the value of addressing defects from this information collected by inspectors and using it in operational asset management decisions;
- applying an increased level of diligence, prudence and foresight to the auditing of our asset inspection activities to achieve consistency of inspections; and
- implementing condition-based asset risk assessment software that uses actual asset data to quantify current and predict future asset risks.

SA Power Networks' inspection and condition monitoring practices include:

- Ground Component Inspections (GCI) – these visual inspections assess in detail the assets at ground level. In particular, condition of poles and footings including an assessment of mechanical integrity and the level of corrosion of channels on the pole.

- Overhead Component Inspections (OCI) – these visual inspections (using binoculars) assess in detail, components of assets above ground level that GCI does not cover. For example, all other components on the pole, including conductors (conductor, fittings, tie wires, joints, services etc) and overhead equipment (switchgear, transformers, regulators, bushings, fuses, public lighting etc).

- Aerial Inspections – SA Power Networks has contracts for outsourced aerial inspection and patrol services using helicopters. These are primarily utilised for annual pre-bushfire patrols but are also utilised for emergency patrols, typically for storm related events.

- Heli-drone Inspections (Unmanned Aeronautical Vehicles, UAV) – SA Power Networks engages aerial photography specialists to undertake remote controlled aerial surveillance and photography using state of the art micro UAVs. These are used in areas that cannot usually be accessed by full size helicopters where the top of the pole inspection is required and cannot be assessed visually from the ground (eg some suspension construction on 66kV lines).

- Aerial LIDAR Inspections – SA Power Networks is currently trialling the use of LIDAR technology to assess the benefits of assisting with vegetation scoping, vegetation auditing and asset inspection.

- Thermographic Inspections – use of thermographic cameras to provide thermal imagery, to identify those components that have deteriorated due to a combination of corrosion and/or high load current to the extent that failure is likely by detecting hot spots within the inspected assets. These inspections are conducted on overhead assets, in substations and selected switchgear.

- Substation Inspections – substations are inspected using a combination of visual inspection and thermographic inspection. Inspections include a check of the overall condition of assets (eg transformer, circuit breakers), the condition of all structural elements, the integrity of insulators and bushings, switchgear gas pressures, security of the site (eg fencing), oil levels in oil-insulated equipment, earthing connections, counter readings (for circuit breakers, reclosers).

- Substation Switchgear Condition Monitoring – specialist switchgear inspections are conducted to assess the condition and performance of switchgear components to identify hazards and component deterioration. A combination of radio frequency and ultrasonic detection, thermographic and visual inspections is used with non-intrusive electrical testing techniques to assess asset condition.

- Substation Transformer Condition Monitoring – routine oil physical/chemical tests are performed on transformer main and switch tanks. Specialist diagnostic and condition tests include thermographic inspection, Sweep Frequency Response Analysis (SFRA), Doble Insulation testing (power factor, capacitance).

- Underground Cable Testing - underground cables have historically not been routinely inspected due to difficulty (accessibility) and cost.

The frequency of inspections and monitoring practices differs between assets and locations, based upon various factors such as:

- the environment the asset operates within; ie how fast we expect the condition of an asset to deteriorate between inspections;
- the safety risk (ie likelihood and consequence), particularly with regard to the potential of starting bushfires or injuring the public or our personnel; and
- the performance of the asset in an area.

The asset assessment strategies, including inspection and maintenance cycles, are documented in SA Power Networks' Network Maintenance Manual (Manual 12), Line Inspection Manual (Manual 11) and Substation Inspection Manual (Manual 19). The replacement strategies are discussed in detail within SA Power Networks' Asset Management Plans.

7.3. Asset life-cycle strategies

Table 36 summarises our inspection and replacement strategies for various asset classes.

Table 36. Asset class and life-cycle strategies

Asset Class	Inspection Strategy	Replacement Strategy
Poles	Inspection cycle: routine cycle between 5 and 10 years, depending on location. Critical inspection: OCI and GCI.	A return on investment based replacement/refurbishment strategy is applied for poles, considering the value (risk reduction plus other benefits) of replacement/refurbishment.
Overhead Conductors (including insulators / connectors)	Inspection cycle: routine cycle between 5 years and 10 years, depending on location (inspected at the same time as poles). Critical inspection: Pre-bushfire patrols, OCI and thermographic.	A return on investment based replacement/refurbishment strategy is applied for conductors, considering the value (risk reduction plus other benefits) of replacement/refurbishment.
Underground Cables	Online cable testing is now being used to systematically determine the condition of underground cables, starting with poor performing areas and high-risk cables.	A return on investment based replacement/refurbishment strategy is applied for cables, considering the value (risk reduction plus other benefits) of replacement/refurbishment.
Low Voltage (LV) Services	Not routinely inspected.	Replace-on-fail

Asset Class	Inspection Strategy	Replacement Strategy
Distribution Transformers	Pole mounted Inspection cycle: routine cycle between 5 years and 10 years, depending on location (at the same time as poles). Critical inspections: OCI and thermographic. Ground mounted Inspection cycle: routine cycle between 1 year and 10 years, depending on location and type. Critical inspections: GCI and substation inspections.	A return on investment based replacement/refurbishment strategy is applied for distribution transformers, considering the value (risk reduction plus other benefits) of replacement/ refurbishment.
Substation Transformers	Inspection / testing cycle: routine cycle between 0.5 years and 6 years. Critical inspections: Dissolved gas oil analysis, substation inspection and thermographic, routine diagnostic testing.	Comprehensive analysis is undertaken to determine appropriate replacement/ refurbishment strategies for individual substation transformers. This includes an assessment of both the probability of the asset failing and the resulting consequences including safety, reliability and financial consequences.
Distribution Switchgear	Line switchgear Inspection cycle: routine cycle between 1 years to 5 years, depending on location and type. Critical inspections: OCI and thermographic. Ground/indoor switchgear Inspection cycle: routine cycle between 1 year to 10 years, depending on location and type. Critical inspections: OCI, substation inspections and switchgear inspections.	A return on investment based replacement/refurbishment strategy is applied for distribution switchgear, considering the value (risk reduction plus other benefits) of replacement/refurbishment.
Substation Switchgear	Inspection / testing cycle: routine cycle between 0.5 years and 6 years. Critical inspections: substation inspections, routine diagnostic testing, inspections and thermographic surveys.	Comprehensive analysis is undertaken to determine appropriate replacement/refurbishment strategies for substation switchgear. This includes an assessment of both the probability of the asset failing and the resulting consequences including safety, reliability and financial consequences.
Protection Relays	Inspection / testing cycle: routine cycle between 0.5 years and 6 years. Critical inspections: substation inspections and diagnostic routine testing.	Comprehensive analysis is undertaken to determine appropriate replacement/refurbishment strategies for protection relays. This includes an assessment of both the probability of the asset failing and the resulting consequences including safety, reliability and financial consequences.

Asset Class	Inspection Strategy	Replacement Strategy
SCADA, Network Control	Critical inspections: substation inspections and remote monitoring.	Replace-on-fail, and when no longer supported by vendor.
Telecommunications	Critical inspections: Aerial fibre cable and Radio Communications tower inspections and remote monitoring by Telecommunication management systems.	Replace-on-fail, and when no longer supported by vendor.

7.4. Planned Strategic Improvements

7.4.1. Asset class replacement programs

SA Power Networks has the oldest fleet of assets in the National Electricity Market and the lowest rate of replacement. As the network deteriorates, we risk an increasing number of electricity assets failing in-service resulting in power outages, safety incidents and bushfires. This risk will be made worse in coming decades by climate change.

To continue to deliver the level of service our customers and community expect will require increased investment in asset replacement as well as an increased sophistication in our approach to Asset Management.

The below table summarises the key asset replacement programs that are being undertaken.

Table 37. Key asset class replacement programs

Asset class	Program
Poles	Pole replacement and refurbishments volumes have risen in recent years due to the ageing asset population. It is anticipated pole replacement (and refurbishment) volumes will be stable during the next RCP. This is due to a greater understanding of the risk of poles enabling replacements to be deferred. It is anticipated that pole replacements (and refurbishments) will need to increase over the longer term as our network continues to age.
Overhead Conductors	It is forecast that conductor replacement levels will continue to increase to arrest further decline in the performance of this asset class.
Distribution Line Switchgear	The replacement of distribution line switchgear has increased recently as a result of finding a greater than anticipated number of defective switches and fuses. During the current RCP, we have focused on replacing switchgear and fuses on our older single phase high voltage circuits and some low voltage types. Focus has been given to upgrading some switch types to remotely controlled, electronic, switches to manage reliability, bushfire and safety risks.

Asset class	Program
Ground Level Switchgear	The volumes of ground level switchgear replacements have increased since 2008 as we moved from a replace-on-fail replacement strategy to a planned replace-before-fail strategy for certain types of switchgear. In particular, we have replaced a large number of switches that had restrictions on live switching due to their poor condition or safety risk. Our focus to date has been in CBD locations where we consider the risks and costs to be the highest. We still anticipate that planned replacement volumes will increase over the short term to address the remaining switches and arrest the ongoing ageing of the network.
Telecommunication	Communications asset replacements are being driven by areas such as a higher cyber security threat and changes in applications carried over the network requiring connectivity utilising IP (Internet Protocol) in contrast to older generation serial communications standards. Applications based around smarter devices in the network are driving a need for larger amounts of data being carried over the network therefore driving network capacity increases and technology changes to cater for these data increases.
Substation Switchgear	Substation circuit breaker replacement forecasts for the next RCP remain near constant. The focus is on oil filled CBs, both 11kV indoor and 66/33kV outdoor, which have high failure consequence. This allows the overall risk from the fleet to be maintained, even though the age and condition of the assets are deteriorating at a faster rate than replacement.
Substation Power Transformers	Substation transformer replacement volumes represent the continuation of unplanned asset replacements identified through ongoing condition monitoring programs.
Pipework Style Substation Switchyards	To address multiple, interrelated safety, environmental and security issues inherent to substations of pipework construction, a targeted replacement program commenced in 2015 and will continue through the forward planning period.
Substation Earthing	Since 2008, SA Power Networks has instituted a formal risk-based earth grid management strategy to substation earth grids, prioritising substation sites and remediation works by the safety risk posed by earth grid condition. The management of substation earth grids through the forward planning period represents a continuation of this established monitoring and remediation regime with each site planned for testing and inspection every 1 years.
Substation Security	In 2006 the Energy Networks Association (ENA) released the 'National Guidelines for Prevention of Unauthorised Access to Electricity Infrastructure'. SA Power Networks has subsequently adopted a risk-based approach conforming to ENA guidelines, and began implementation over the 2010-15 RCP. This strategy continues throughout the forward planning period to address security concerns of all high and medium risk substations.
Substation Environmental (Oil Containment)	All substations are subjected to ongoing audits and risk assessment as part of SA Power Networks' environmental management policies. This strategy continues throughout the forward planning period to complete high risk and medium risk sites.
Protection Systems	Substation protection systems are replaced based on condition, risk and performance (eg type of failure and defect history).

Asset class	Program
SCADA, Network Control	Substation SCADA systems are replaced on failure, or when vendor support is no longer available. SA Power Networks' strategy is to expand remote control and monitoring to those substations without SCADA to enable monitoring and regulatory reporting.

7.5. Distribution losses

Schedule 5.8(k)(1A) of the NER requires SA Power Networks to provide an explanation of how it takes into account the cost of electricity distribution losses when developing and implementing its asset management and investment strategy.

Losses incurred across the distribution network represent the difference between energy sourced from the transmission network and delivered to end customers. The cost of the energy lost in transporting power through the distribution network is paid by customers via their retailer, using an averaging formula.

As these losses represent a cost to all consumers of electricity, SA Power Networks seeks to minimise these costs wherever practical. In accordance with the NER and the AER's RIT-D guidelines, where deemed material to the outcome of the RIT-D evaluation, SA Power Networks considers the change in the cost of losses for each network and non-network solution considered to resolve the identified network constraint(s). Details of how SA Power Networks conducts and performs RIT-D evaluations can be found within our Industry Engagement Document on our website.

Minimisation of distribution losses is considered by SA Power Networks when managing and augmenting the network through the use of:

- low-loss zone substation transformers, which are encouraged by the use of a purchasing evaluation formula which penalises high loss designs (ie whole of life losses are considered);
- distribution transformers which meet the requirements of the minimum energy performance standards[6];
- power factor improvement solutions that maximise network utilisation by reducing line/feeder current for the same load, in turn reducing losses for the same load at peak load times; and
- capacity upgrade projects, where losses for loads are reduced by using higher voltages (ie reduced current), larger conductors or additional transformers, and shorter lines and feeders through the insertion of new connection point and zone substations.

SA Power Networks does not implement projects specifically designed for the purpose of reducing distribution losses.

[6] Distribution transformers are categorised based on factors such as location, insulation type, number of phases and voltage classes. Source: Distribution transformers | Energy Rating

7.6. Asset management issues that may impact system limitations

Schedule 5.8(k)(2) of the NER requires SA Power Networks to provide a summary of any issues that may impact on the system limitations identified in the DAPR that have been identified through carrying out its asset management practices.

SA Power Networks does not foresee any asset management related issues or practices that will impact on the system limitations identified in this DAPR.

7.7. Asset management further information

As required by Schedule 5.8(k)(3) of the NER, further information on SA Power Networks' asset management strategies and methodologies may be obtained by contacting the following Network Manager:

Head of Network Assets:	Caprice Davey
Contact number:	08 8404 5724
Email:	caprice.davey@sapowernetworks.com.au

8. Network Performance

8.1. Reliability performance

Schedule 5.8(j) of the NER requires SA Power Networks to provide information on the performance of its network. This Section sets out a summary of SA Power Networks' reliability measures and standards and our performance against these measures and standards. The detailed performance report Annual Public Performance Report for the 2022/23 period can be accessed via our website.

8.1.1. Reliability performance forecast

Reliability performance forecast targets differ slightly (on average by about 4%), to the jurisdictional reliability targets determined by the ESCoSA as defined in its EDC, refer to Section 8.1.2.

Reliability performance is affected by a combination of factors such as adverse weather conditions, targeted reliability improvement projects, asset condition and improved operational practices (eg emergency response procedures). Given it is not possible to accurately predict weather conditions, along with the interaction of the other factors mentioned above, forecasting future reliability performance is an inherently difficult undertaking.

For the purpose of complying with Schedule 5.8(b)(4) of the NER, SA Power Networks has developed the following reliability performance forecast shown in the below table.

Table 38. SA Power Networks' STPIS feeder category reliability performance forecast

Reliability Measures	2023/24	2024/25	2025/26	2026/27	2027/28
USAIDIn (minutes)7					
CBD	17	19	18	17	17
Urban	94	94	94	94	94
Rural Short	190	190	189	188	188
Rural Long	304	304	302	296	290
Overall	137	137	136	135	134
USAIFIn (interruptions)8					
CBD	0.14	0.14	0.14	0.14	0.14
Urban	0.87	0.86	0.86	0.87	0.87
Rural Short	1.28	1.28	1.28	1.29	1.30
Rural Long	1.49	1.49	1.49	1.48	1.47
Overall	1.00	1.00	1.00	1.00	1.01

The forecast set out in the table above is based on the following assumptions:

- Includes the additional funding proposed in our Regulatory Proposal for the 2025-30 regulatory control period.
- The forecast is based on the five-year average historical trends
- The forecast assumes similar average weather trends; and
- The forecast excludes the performance on MEDs as permitted under the STPIS regime.

8.1.2. Reliability measures and standards

Schedule 5.8(j)(1) of the NER requires SA Power Networks to provide a summary description of the reliability measures and standards that SA Power Networks must comply with. Under the Council of Australian Governments' (COAG) Australian Energy Market Agreement the South Australian Government has retained the responsibility for determining local (jurisdictional) distribution network reliability standards. The Government subsequently assigned that responsibility to ESCoSA.

ESCoSA establishes the service standard framework which includes the distribution network's reliability standards, in a public consultation process prior to the commencement of each regulatory control period (RCP). The reliability standards established as part of the consultation process are documented in the EDC published by ESCoSA. SA Power Networks' compliance with the EDC is a requirement of its

[7] USAIDIn is defined as 'Unplanned System Average Interruption Duration Index' normalised to exclude Major Event Days.

[8] USAIFIn is defined as 'Unplanned System Average Interruption Frequency Index' normalised to exclude Major Event Days.

distribution licence issued by ESCoSA. In addition to ESCoSA's reliability standards, Electricity distribution systems are extremely reliable, their overall reliability is typically measured in how many minutes on average they are not able to supply customers with electricity. If a distribution system was unable to supply electricity for 180 minutes in a year, then it was able to supply energy for 525,420 minutes of that year (ie its availability to supply electricity was 99.97%).

The reliability measures used by the ESCoSA and the AER to monitor a distributor's performance are:

- USAIDIn (unplanned system average interruption duration index) — a measure of how long on average each customer is without supply in minutes for the period (typically a year) and is normalised by excluding interruptions that start on Major Event Days (MEDs));
- USAIFIn (unplanned system average interruption frequency index) — a measure of how many times on average each customer is interrupted for the period (typically a year) and is normalised by excluding interruptions that start on MEDs; and
- In addition, ESCoSA uses two customer restoration of supply (CRoS) targets for each feeder category. These measure the percentage of the customers supplied by that feeder category who have an unplanned interruption exceeding a specified number of hours.

The measures are normalised because the variation in annual performance is significant with the inclusion of MEDs and masks underlying performance trends. For example, the USAIDI result for the distribution system in 2016-17 was 481 minutes with 9 MEDs, compared with 148 minutes in 2015-16 with one MED and 132 minutes in 2017-18 with nil MEDs. Most MEDs result from significant weather events that are beyond the distributor's control and are the major cause of the annual variation in reliability.

So that regulators can assess whether a distributor is maintaining the network to cope with normal weather events amongst other outage causes (eg animals), MEDs are excluded from the reliability measures they monitor. However, it is important to monitor the performance on MEDs to ascertain if distributors are still maintaining their ability to effectively respond to the effects of MEDs on their distribution system. Distributors need to have processes and practices in place to respond to MEDs so that customers impacted on those days have their supply restored in a reasonable time. As MEDs can have different characteristics and severity, it is not possible to establish standards for performance on MEDs. For example, the USAIDI contribution of a single MED, can vary from about 6 USAIDI minutes to about 160 USAIDI minutes.

The EDC requires the use of "best endeavours[9]" to achieve the reliability service standard targets for each year ending 30 June. The best endeavours requirement means that where a reliability standard's target is not achieved, SA Power Networks is still able to comply with that standard, provided it can demonstrate the use of best endeavours. The ability to still comply with the standard despite non-achievement of the target is cognisant of the fact that the target is based on average historic performance (established over a five-year period), which notionally means that the targets on average might only be achieved for half the years, all other things being equal.

The reliability standards which apply for the 2020-25 RCP (ie 1 July 2020 to 30 June 2025) are documented in the current version of the EDC (version EDC/13) clause 2.2.1. The EDC/13 targets are established for four HV feeder categories and exclude any interruption(s) that occur on a MED. The feeder categories are:

- Central Business District (CBD);
- Urban;[10]
- Short Rural;[11] and
- Long Rural.[12]

The following tables sets out ESCoSA's reliability standards for SA Power Networks over the 2020-25 RCP. The same standards will apply to the 2025-30 RCP.

Table 39. Feeder category reliability service standards

Reliability measures		**CBD**	**Urban**	**Short rural**	**Long rural**
USAIDIn (minutes)	Target	15	110	200	290
	Reporting threshold	20	125	220	330
USAIFIn (interruptions)	Target	0.15	1.15	1.65	1.75
	Reporting threshold	0.20	1.35	1.85	2.10

[9] In the EDC best endeavours, "means to act in good faith and use all reasonable efforts, skill and resources".

[10] Urban feeder is not a CBD feeder, where the maximum exceeds 0.3 MVA/km.

[11] Short rural is not a CBD or urban feeder with a total feeder length of less than 200kms.

[12] Long rural is a feeder that is not a CBD or urban feeder with a total feeder length of 200kms or more.

Table 40. Feeder category customer restoration of service standards

Target (%)	Single interruption duration	CBD	Urban	Short rural	Long rural
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

Table 41. Feeder category customer restoration of supply reporting thresholds

Reporting threshold	Interruption duration	CBD	Urban	Short rural	Long rural
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

SA Power Networks is required to report on how it has applied its best endeavours if its performance is worse than the reporting thresholds (RT) set out in Table 39 and Table 41.

8.1.3. Our reliability performance

Schedule 5.8(j)(3) of the NER requires SA Power Networks to provide a summary description of its reliability performance for its distribution network against the measures and standards described under Schedule 5.8(j)(1) for the preceding year.

Comprehensive reliability performance reporting is provided annually to ESCoSA. This section summarises the analysis and outcomes from the ESCoSA report on SA Power Networks' reliability performance for the year ending 30 June 2023.

SA Power Networks achieved ten of the sixteen normalised reliability targets, for the four feeder categories, specified in the South Australian EDC, for the year ending 30 June 2023[13]. The EDC now incorporates a reporting threshold[14] which acknowledges there will be expected variations in our annual performance against the reliability measures. For the six targets not achieved, five were within the reporting threshold (orange indicator) and one exceeded the reporting threshold (red indicator).

Table 42 and Table 43 below details each of the four feeder category targets and actual normalised performance for the year ending 30 June 2023.

Table 42. Feeder category normalised reliability performance

	USAIDI		**USAIFI**	
EDC Feeder Category	Target	2022/23	Target	2022/23
Central Business District (CBD)	15	13	0.15	0.18
Urban	110	102	1.15	0.87
Rural Short (RS)	200	180	1.65	1.23
Rural Long (RL)	290	299	1.75	1.43
Overall Distribution System15	150	143	1.30	1.00

Table 43. Restoration of supply performance (CRoSn)

EDC Feeder Category	**Length of Interruption (Hrs)**	**Target (%)**	**Actual (%)**
CBD	≥ 1	11	9.8
	> 2	4	1.8
Urban	> 2	27	25.4
	> 3	11	12.9
Rural Short (RS)	> 3	27	26.2
	> 5	8	10.9
Rural Long (RL)	> 4	30	31.5
	> 7	10	11.3

[13] The targets exclude the reliability contribution from interruptions starting on MED's.

[14] The threshold is set so that on average once every four years the performance will be worse than the reporting threshold and therefore will require detailed explanation.

[15] The ESCoSA reliability service standards do not include an overall distribution system target, so these figures are the implied equivalent targets using the individual feeder category targets and the number of customers supplied by each feeder category.

The EDC feeder category reliability targets were established using the average performance over the ten-year target setting period (TSP) 1 July 2009 to 30 June 2019. The averages were then rounded to the nearest five minutes for USAIDI and the nearest 0.05 interruptions for USAIFI (ie some targets were rounded down and others up). As the targets are based on averages, there cannot be an expectation that all targets will be achieved each year. ESCoSA was concerned that establishing service standards using feeder categories may result in some regional areas of the state experiencing a decline in reliability. Consequently, it required SA Power Networks to report on the reliability of ten regions, to enable it to detect if there was any longer-term decline in regional performance.

Non-achievement of the EDC reliability targets, when it occurs, is often due to one-off events or interruptions on a few non-MED days that result from localised significant weather events (SWE) that are verified by the Bureau of Meteorology (BoM).

In the year 2022/23 there were six MEDs.

Table 44. 2022/23 MEDs, contribution to reliability and MED category

Date(s)	USAIDI	Customers Affected	MED Category16	Comment
4 October 2022	8.1	26,897	Cat 1	Severe storms
12 November 2022	193.8	115,748	Cat 4	Severe storm
13 November 2022	14.7	10,828	Cat 4	Severe storm
19 November 2022	10.7	12,804	Cat 2	Severe storm
20 March 2023	26.8	49,566	Cat 3	Severe storm
7 June 2023	9.1	26,969	Cat 2	Severe storm
Total	263.2	242,812		

SA Power Networks monitors three key metrics (among others) to ensure that we are maintaining the distribution system to reliably transport electricity to customers under normal weather conditions. The three metrics are:

- The contribution to USAIDIn of equipment failure-caused interruptions. This monitors our performance in maintaining the distribution system under normal operating conditions;
- The contribution to USAIDIn of weather[17] related caused interruptions; and
- The percentage of USAIDI resulting from equipment failure-caused interruptions on MEDs. This monitors the ability of the distribution system to cope with SWE.

16 SA Power Networks categorises the severity of MEDs based on the USAIDI contribution from interruptions that commence on that day, with the severity graded from the least Cat1 to the most Cat4.

[17] Weather related includes unknown and vegetation, as the contribution from these causes is higher during SWE.

We monitor the resilience of the distribution system to cope with BoM SWEs by determining the average overall daily USAIDI on SWE days which do not result in the day being classified as a MED. Historically, on average there are around 37 days per annum where the BoM verifies the occurrence of a SWE with on average three of these days being classified as MEDs. Consequently, on average there are 34 days per annum where the BoM verifies a SWE which does not result in a MED. The BoM has advised SA Power Networks that it is likely that the number and intensity of SWEs will increase due to the effects of climate change.

In 2022/23, three of the four Rural Long feeder targets were exceeded (see Table 45 below). One-off breaches of the restoration target can occur, driven by the severity of conditions in that year. However, concerningly, there is a worsening trend in the percentage of customers exceeding the 4-hour target and a marginally worsening trend in the percentage of customers exceeding the 7-hour target for Rural Long feeders. The continuation of these trends suggests both the likelihood of exceeding the targets and that the extent by which they will be exceeded is very likely to increase (albeit more marginally with the 7-hour target). This suggests that, without action, we could exceed the targets, even when conditions (eg weather) during a year are relatively benign.

Table 45. Rural long reliability performance that exceeded the reporting threshold

Rural Long Feeders	USAIDIn	USAIFIn	% Restored 4 Hrs	% Restored 7 hrs
2022-23	299	1.43	31.5	11.3
Target	290	1.75	30.0	10.0
Reporting Threshold	330	2.10	32.5	12.5

8.1.4. Regional reliability performance

SA Power Networks is required to report the reliability of ten regions: nine distinct regions and another segmentation of feeders in a Major Regional Centres (MRC) as defined in ESCoSA's Guideline No.1.

The annual regional reliability performance varies from year to year, both positive (better) and negative (poorer) than the long-term historical average (ie 15-year period ending 30 June 2020). SA Power Networks monitors the regional reliability using the measures USAIDIn and USAIFIn, to determine if historic performance of any region has declined.

In 2022-23, 4 of the 20 reliability measures (two per region) were worse than the 15-year historic average. The USAIDIn and USAIFIn for the Riverland and Murrayland (RM) Region exceeded the equivalent RT. The poor reliability of the RM Region in 2022-23 resulted from the significant increase in weather related interruptions, which contributed more than 50 minutes to USAIDIn and more than 0.5 interruptions to USAIFIn, when compared to both 2020-21 and 2021-22. The RM Region exceeded the USAIDIn RT threshold in 2021-22 because of asset failure cause interruptions on two 33kV Sub-transmission lines. In 2021-22 resulted from asset failure related interruptions and the poor reliability in 2022-23 resulted from weather related interruptions.

8.1.5. Reliability corrective actions

SA Power Networks has several programs to manage reliability, including:

- A recurrent program to 'Maintain underlying reliability' on the network to maintain historic performance (ie this does not allow for additional upgrades to improve reliability).
- A 'Low reliability feeders improvement program' with remediations for specific low reliability feeders (mainly in rural and remote areas) that experience repeatedly poorer reliability, more than double their regional average. Customers on these feeders are our 'worst served customers'.
- A 'Regional reliability improvement program' to bring performance for worst served regions more in line with similar regions via remediations specific to the outage causes on feeders most impacting those regions – either to address current outage causes or reduce the customer numbers interrupted when outages occur.
- A 'Rural long feeders supply restoration improvement program' to make efficient and prudent progress to meeting SA Electricity Distribution Code (EDC) targets for rural long feeders. Targeting rural long feeders where it is efficient to improve supply restoration times.

8.1.6. Processes to ensure compliance with the reliability measures and standards

Schedule 5.8(j)(5) of the NER requires SA Power Networks to provide a summary description of the processes it has undertaken to ensure compliance with the reliability measures and standards described under subparagraph 5.8(j)(1).

SA Power Networks prepares a Reliability Management Plan annually, with the aim of maintaining reliability performance (ie achieving the EDC reliability targets). This Plan details the initiatives that SA Power Networks undertakes to maintain reliability performance when cost effective. Further it aims to minimise reliability Guaranteed Service Level (GSL) payments.

SA Power Networks has an Operational Reliability Group which:

- Prepares and issues the Reliability Management Plan;
- Reviews on a daily basis, previous interruptions to identify areas of poor performance or potential systemic causes of interruptions to initiate actions to remedy where warranted; and
- Annually prepares reliability improvement projects for the following calendar year.

The reliability improvement actions contribute to one basic outcome which is:

- Reducing the number of interruptions experienced by customers by:
  - Installing mid-line reclosers and sectionalisers to reduce the number of customers affected by a fault;
  - Installing spur fuses to reduce the number of customers affected by a fault;

  - Undertaking “no cause found” patrols for interruptions affecting more than 500 customers to reduce the likelihood of the same fault occurring (repeating) in the future; and
  - Undertaking “reclose” patrols for switchgear reclose events affecting more than 1,000 customers to reduce the likelihood of a sustained fault occurring in the future.

8.2. Quality of supply performance

This section outlines the QoS standards applicable to SA Power Networks and our performance against those standards.

8.2.1. Applicable quality of supply standards

In accordance with Schedule 5.8(j)(2) of the NER, SA Power Networks is required to provide a summary description of the QoS standards it must adhere to, including the relevant codes, standards and guidelines.

The Electricity Act 1996 and the Electricity (General) Regulations 2012, provides a framework for supplying electricity to customers on the South Australian electricity distribution network. SA Power Networks’ internal Power Quality Manual (Manual 24) sets out SA Power Networks’ standards for the QoS customers can expect.

There are a number of parameters that contribute to power QoS including (but not limited to):

- Supply voltage;
- Power factor;
- Harmonics; and
- Flicker.

SA Power Networks is not accountable for, nor can it influence, the Alternating Current Frequency of electricity supplied through its network. AEMO establishes the standards governing frequency control and regulates the frequency on the national grid. If SA Power Networks becomes aware of frequency excursions outside of AEMO’s standards, SA Power Networks notifies AEMO.

8.2.2. Range of supply voltage

Supply voltage is the voltage, measured either from phase to neutral or phase to phase, for electricity that is supplied at a customers’ service point. It is important to maintain a steady state supply voltage within acceptable upper and lower limits to ensure customers’ appliances and equipment are not damaged. In the event SA Power Networks’ steady state supply voltage is outside of the tolerance specified in the relevant codes, standards and guidelines, SA Power Networks undertakes remedial works to improve the quality of supply.

SA Power Networks’ low voltage network operates nominally at 230V single phase or 400V three phase. The high voltage distribution network typically operates at 7.6kV, 11kV and 19kV. Some major businesses are supplied at 3.3kV, 6.6kV, 11kV, 33kV or 66kV.

Low voltage network

The nominal voltage for the low voltage network is 230V, phase to neutral, and 400V phase to phase. Australian Standard, AS 61000.3.100 has specified a tolerance of +10%/-6% to allow for voltage regulation on the mains between distribution transformers and customers' service points. Therefore, under normal operating conditions the lowest limit of voltage that can be experienced on SA Power Networks' low voltage network at a customers' service point is 216V (230 - 6%) and the highest limit is 253V (230 + 10%).

High voltage network

SA Power Networks' high voltage distribution network operates at several voltage ranges as discussed above. Prospective high voltage customers should seek advice from SA Power Networks on the available supply voltage at their location before proceeding with any project expenditure or commitments.

SA Power Networks applies the following standards and guidelines when setting and assessing network voltage performance for its low voltage and high voltage networks:

- SA Power Networks' Power Quality Manual (Manual 24);
- SA Power Networks' Service and Installation Rules;
- Australian Standards: AS/NZS 60038 and AS 61000.3.100; and
- NER S5.1a.4 – Power Frequency Voltage.

8.2.3. Harmonic content of voltage and current waveforms

Harmonic current and voltage distortion results from the operation of appliances or equipment that draw non-sinusoidal currents from the network by presenting a variable impedance during the voltage cycle. Such distortion can cause the supply voltage to depart from a sine wave in a repetitive manner. The resultant distorted wave is made up of multiple 'pure' sine waves of varying magnitudes, having frequencies that are integer multiples of the fundamental frequency (50 Hz). Maintaining waveform distortion within acceptable limits is important because it can otherwise cause interference and damage to sensitive customer and network equipment. This form of distortion can also cause light flicker, incorrect operation of computers, audible noise in television, radio and audio equipment and vibration in induction motors.

SA Power Networks relies on the following standards and/or guidelines when limiting and assessing harmonic performance:

- Power Quality Manual 24 (September 2015);
- Australian Standards: IEC 61000.3.6:2012;
- Standards Australia Handbook for power quality HB264;
- NER S5.1a.6 – Voltage Waveform Distortion; and
- SA Power Networks Service and Installation Rules.

8.2.4. Voltage Fluctuations (Flicker)

Voltage fluctuations are short-term repetitive, regular or irregular changes in the voltage level. Voltage levels change in response to changes in the load on the network, so that as the current drawn from the network increases, the voltage level drops. Similarly, when load is switched off or embedded generation exports, the voltage level rises. Voltage fluctuations can cause lighting to flicker and in severe cases it can lead to malfunctions in sensitive electronic equipment.

SA Power Networks relies on the following standards and/or guidelines when limiting and assessing flicker (voltage fluctuations) performance:

- SA Power Networks Power Quality Manual (Manual 24);
- Australian Standards: IEC 61000.3.6:2012;
- NER S5.1a.5 – Voltage Fluctuations; and
- SA Power Networks Service and Installation Rules.

8.2.5. Load unbalance

Unbalanced voltages can result from unbalanced network impedance, unbalanced loads or unbalanced embedded generation. Balanced impedances under normal operating conditions are achievable by appropriate design and construction practices and consequently, the means of controlling unbalance is the balancing of three phase loads and the even distribution of single-phase loads. Control of unbalance in three phase networks is important to avoid damage to certain types of three phase motors. Voltage unbalance can also result in distribution network faults such as inadvertent operation of protection relays and voltage regulation equipment.

SA Power Networks relies on the following standards and/or guidelines when limiting and assessing Voltage Unbalance performance:

- Power Quality Manual (Manual 24);
- Australian Standards: IEC 61000.3.6:2012; and
- NER S5.1a.7 – Voltage Unbalance.

8.2.6. Quality of supply performance

Schedule 5.8(j)(3) of the NER requires SA Power Networks to provide a summary description of its QoS performance for its distribution network against the measures and standards described under Schedule 5.8(j)(2) for the preceding year.

SA Power Networks undertakes power quality (PQ) testing and monitoring using a number of methods including:

- short term PQ tests in response to customers' enquiries at supply transformers and at customer service points;
- customer load modelling and data from survey tests at transformers to determine their loading; and
- smart meter data where accessible;

In addition, since 2009, SA Power Networks has participated in the Quality of Supply Assurance Program conducted annually by the University of Wollongong – Power Quality Australia (PQA). SA Power Networks collected power quality voltage, harmonics and flicker data from monitored distribution transformers.

The sites were evaluated for compliance against the following standards:

- Range of Supply Voltage – AS 61000.3.100;
- Voltage Unbalance – IEC 61000.3.6:2012; and
- Harmonic Content of the Voltage Waveform IEC 61000.3.6:2012.

PQA made the following observations based on the data SA Power Networks provided for 2022-23:

- Overall LV Compliance performance is much better than the national average.
- Results indicate [supply] voltage is being very well managed.
- No Significant issues for other disturbances.
- Flicker is the disturbance of most concern ….[however]…. Performance is better than national average.
- National results indicate significant levels of non-compliance for… flicker at LV.
- National Results show an upward trend for flicker non-compliance for medium voltages.

SA Power Networks is also required to provide information on quality of supply complaints, to the AER in its annual Regulatory Information Notice (RIN). A complaint is defined as an expression of dissatisfaction made to an organisation related to its products or the complaints handling process itself, where a response or resolution is explicitly or implicitly expected. The following tables detail the percentage of QoS related complaints from customers, by category and cause.

Table 46. QoS number of complaints in 2022/23

Complaint- technical quality of supply	Number
Complaints - technical quality of supply	50

Table 47. QoS Percentage of Complaints by Category

Complaints by category	Percentage (%)
Low voltage supply	12
Voltage dips	12
Voltage swell	0
Voltage spike (impulsive transient)	0
Waveform distortion	0
TV or radio interference	2
Solar related	36
Noise from appliances	4
Other	34

Table 48. QoS Percentage of Complaints by Likely Cause

Complaints by Likely Cause	Percentage (%)
Network equipment faulty	28
Network interference by NSP equipment	0
Network interference by another customer	4
Network limitation	24
Customer internal problem	20
No problem identified	0
Environmental	16
Other	8

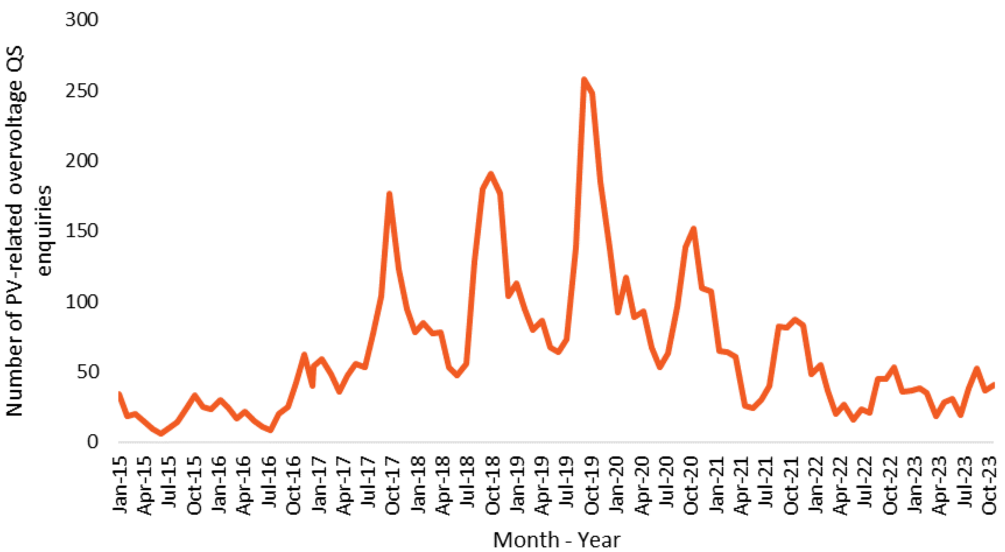
Since 2016/17, quality of supply related complaints had risen each year due to increasing levels of distributed energy resources significantly impacting the voltages on the LV network. Voltage excursions outside of mandated limits became more prevalent, significantly increasing the number of quality of supply enquiries and complaints. According to the table, solar related enquiries continue to be the largest contributor to complaints. However, in 2020/21 the number of complaints has reduced by more than half of the previous year (108 complaints in 2019/20). In 2021/22, a further 20% reduction in overall complaints was achieved and has remained at this level for 2022/23.

All customer enquiries and complaints are lodged with our Customer Care team who monitor the progress of these complaints and enquiries and report on them as part of the service standards referred to in the Distribution Code. An enquiry refers to a request for information (which requires further investigation) received from a customer or their representative via nominated enquiry channels. The below figure shows the volume of customer enquires received by SA Power Networks per month since January 2020.

Figure 8. QoS customer enquiries per month since January 2020

Further, the following figure shows that PV related over voltage enquiries have continued to trend downwards since June 2020 despite continued growth in CER uptake.

Figure 9. PV related over-voltage customer enquiries since January 2015 until November 2023



In 2020 SA Power Networks commenced a project to implement enhanced voltage management capabilities at substations to improve system security and increase the network hosting capacity for distributed energy resources. This has significantly improved customer supply voltages and reduced the number of PV-related over voltage enquiries since mid-2020, supporting increased hosting capacity for CER. Volumes of enquiries are returning to manageable levels; however, many substations are reaching the limit of their ability to adequately control network voltages.

After experiencing substantial increases in customer enquiries in 2016 and 2017, SA Power Networks began a program in 2017 to install power quality monitoring devices at distribution transformers in areas with high solar PV penetration. This program will continue through to 2024 to provide greater visibility of power quality issues on our network, enabling a more proactive remediation approach.

In 2022/23, SA Power Networks established and operationalised a Network Visibility and Modelling program to accurately and efficiently identify thermal load constraints across LV Networks and prioritise investment to reduce transformer failures and fuse operations. Furthermore, in 2023 data analytics packages of smart meter voltage data were operationalised to identify areas of the low voltage network that experience non-compliant voltages due to the existing levels of CER uptake.

Uptake of battery energy storage systems, growth of aggregated CER controlled Virtual Power Plants and future uptake of electric vehicles also pose new sources of power quality issues. Greater visibility of the LV network will play an essential role in managing the impacts of these new technologies and enable SA Power Networks to proactively address constraints or voltage compliance issues.

8.2.7. Quality of supply corrective actions

Where the measures and standards described under Schedule 5.8(j)(2) were not met in the preceding year, Schedule 5.8(j)(4) requires SA Power Networks to provide information on the QoS corrective actions that have been taken or are planned to be taken.

SA Power Networks allocates an annual capital budget to address QoS enquiries based on historic expenditure. These enquiries are investigated, and where required, corrective action is taken to resolve the QoS issue. SA Power Networks undertakes reactive actions to resolve these QoS related enquiries which include:

- Distribution transformer tap adjustments;
- Installation of an additional distribution transformer and dividing the local LV network between these transformers;
- Upgrading a distribution transformer with a higher capacity transformer;
- Upgrading LV and/or HV conductor with a higher capacity conductor;
- Phase balancing;
- Installation of low voltage regulation devices and Static Synchronous Compensator (STATCOM) devices.

In addition to our reactive approach addressing individual QoS issues, SA Power Networks has undertaken the following activities to lower excess voltages levels on selected zone substations with very high solar PV penetration and high customer enquiries, to deliver overall network functional compliance:

- Implemented enhanced voltage management capabilities at 147 zone substations, lowering 11kV bus set points and implementing Line Drop Compensation (LDC) where feasible. LDC provides dynamic voltage control in which the substation OLTC relay autonomously adjusts voltage according to a droop curve dependent on substation load.

However, some targeted metropolitan zone substation transformers have insufficient buck taps (voltage reduction) to effectively implement this level of control. This is common in many of our zone substation transformers, with older transformers being of particular concern which will require remedial action in the forward planning period;

- Change of distribution transformer tap settings to deliver the correct 99th percentile voltage (to AS61000.3.100:2011). Distribution transformer tap setting adjustments are performed in conjunction with customer enquiries where voltage testing for over or under voltages reveals voltages that are outside the prescribed limits;

- LV Monitoring has been deployed since the 2017-18 summer to selected distribution transformers across metropolitan Adelaide. By 2024, SA Power Networks will have a sufficient volume of monitored locations to establish a sufficiently sized sample of sites to be statistically representative of its overall low voltage network. PQ data is remotely retrieved from the monitors on a daily basis and will continue to assist in the development of electrical models of LV circuits to better predict overloads and power quality issues, and trends in behaviour over time;

- Smart meter data has been procured from meter data providers in order to proactively detect areas within LV networks that are experiencing voltages that breach AS61000.3.100:2011;

- Smart meter analytical tools are being developed to support detection of inverter system compliance to AS4777.2 power quality response modes in order to assist customers and electricians in correcting settings, avoiding excessive voltage rise and retaining inverter operation.

- Modelling performed under the SA Power Networks' LV Management Strategy shows that even with these measures in place, certain parts of the distribution network with high penetrations of solar PV will continue to experience QoS issues. In such areas, SA Power Networks has introduced reduced, fixed export limits for new residential systems and all CER less than 200kW have the choice of the new Flexible Exports connection option as an alternative. Reduced, fixed export limits will reduce the contribution of new residential CER systems to local voltage raise and thermal overloads, while flexible exports will enable SA Power Networks to reduce export limits of participating CER systems when and where QoS issues arise. Changes to export limit arrangements are further discussed in section 6.5.

- Even with flexible exports we cannot fully prevent issues such as voltage exceedances from occurring in the long term. This is because even when exports are curtailed, rooftop solar generation continues to erode underlying demand through self-consumption behind the meter. Thus, some level of ongoing export capacity augmentation is unavoidable as solar uptake grows.

8.2.8. Processes to ensure compliance with the QoS measures and standards

Schedule 5.8(j)(5) of the NER requires SA Power Networks to provide a summary description of the processes it has undertaken to ensure compliance with the QoS measures and standards described under subparagraph 5.8(j)(2).

Under the Standard Form Customer Connection Contract with SA Power Networks, low voltage network customers are required to comply with the requirements of the Service and Installation Rules and any other reasonable requirement of SA Power Networks. Consistent with those Rules and our rights under the Contract, SA Power Networks requires customers to ensure that:

- their electrical installation does not adversely affect SA Power Networks' network or other customers' installations; and
- that any audible or electronic noise generated by their electrical installation does not breach relevant laws or adversely affect others. If disturbances on the network are caused by more than one customer, SA Power Networks will establish overall limits for the interference by each customer, and customers who exceed their limits are required to rectify the situation.

SA Power Networks' network modelling process includes checks for voltage compliance on the high voltage network and our internal standards specify compliance requirements for the low voltage network. Customer QoS enquiries are reviewed, and corrective action is taken where required.

The process for managing power quality emission limits for major customer connections is generally dictated by the NER requirements for connection agreements. SA Power Networks is required to provide a 20-business day turnaround on responses to connection enquiries under the NER. Limits for automatic and minimum access standards for power quality are included in SA Power Networks' response to such connection enquiries.

There are different rules which apply to network customers and registered generators. However, generally the allocation of emission limits for customers and generators are defined in NER clauses S5.1.5-5.1.7. Power quality requirements for connections are based around the following access standards:

- Automatic Access Standards;
- Minimum Access Standards; and
- Negotiated Access Standards.

For generators, allocation limits are defined according to NER Clauses S5.2.5.2. For network customers, allocation limits are defined according to NER Clauses S5.3.7 and S5.3.8.

For both generators and customers, harmonic and flicker allocations are based on the AS/NZ 61000.3 series of documents. For voltage unbalance the proposed approach within SA Power Networks is to follow SA/NZ 61000.3.13:2012, which mirrors the Stages 1-3 approach of the harmonic and flicker Standards.

The process for achieving compliance with the prescribed power quality allocation limits is an iterative process, with consideration given to alternative connection points, or mitigation measures, should initial investigations indicate non-compliance. Where necessary this may involve a reassessment of limits, or the acceptance of a negotiated access.

Suitable clauses are included in SA Power Networks' connection agreements to ensure compliance with the power quality allocation limit via agreed levels of monitoring of the installation, and also for appropriate notification and approval of customers planned major equipment changes, such as new distorting loads or power factor correction. It should be noted that the NER provides scope for SA Power Networks to subsequently enforce automatic access standards where network conditions change.

8.3. Service Target Performance Incentive Scheme information

Schedule 5.8(j)(6) of the NER requires SA Power Networks to provide an outline of the information contained in its most recent submission to the AER under the STPIS regime.

SA Power Networks is incentivised by the AER's STPIS regime to meet annual targets based on its:

- STPIS feeder category reliability performance which measures the average number of interruptions per customer and the average total time a customer is without electricity supply annually because of unplanned interruptions; and
- Telephone call responsiveness expressed as the percentage of calls answered in 30 seconds.

Under the STPIS regime improved performance is rewarded and declining performance is penalised (noting that rewards and penalties are both capped). The STPIS regime and the targets are detailed in Chapter 10 of the AER's 'Final Decision SA Power Networks final determination 2020 to 2025 – Attachment 10, June 2020'.

The unplanned reliability performance measured under the STPIS excludes:

- MEDs; and
- events resulting from:
    - Transmission failures;
    - Police, Fire, Emergency Services isolations;
    - Generation failures;
    - Emergency disconnections; and
    - Single customer faults (where the fault is in the customer's electrical installation).

Accordingly, the reliability targets for SA Power Networks exclude "excluded event caused interruptions" and interruptions on MEDs. These exclusions each relate to extraordinary circumstances over which SA Power Networks has limited or no ability to mitigate the interruption to customer supply.

The following tables provide details of our STPIS feeder category performance for the regulatory year ending 30 June 2023.

Table 49. Unplanned minutes off supply (USAIDI)

Unplanned System Average Interruption Duration Index (USAIDI)	Feeder Category	Target	2022/23
Total sustained minutes off supply	CBD	22.5	14.59
	Urban	105.1	384.29
	Short rural	181.9	567.83
	Long rural	277.8	572.53
	Whole Network	-	437.43
Total minutes of excluded events	CBD		1.61
	Urban		282.14
	Short rural		387.59
	Long rural		273.41
	Whole Network	-	294.70
Total sustained minutes off supply after removing excluded events (ie normalised)	CBD	12.48	12.98
	Urban	121.50	102.15
	Short rural	231.06	180.24
	Long rural	311.70	299.12
	Whole Network	167.9	142.73

Table 50. Unplanned interruptions to supply (USAIFI)

Unplanned System Average Interruption Frequency Index (USAIFI)	Feeder Category	Target	2022/23
Total sustained interruption to supply	CBD	-	0.18
	Urban	-	1.22
	Short rural	-	1.52
	Long rural	-	1.93
	Whole Network	-	1.37
Total interruptions to supply of excluded events	CBD	-	0.00
	Urban	-	0.35
	Short rural	-	0.30
	Long rural	-	0.50
	Whole Network	-	0.36
Total sustained interruptions to supply after removing excluded events (ie normalised)	CBD	0.185	0.18
	Urban	1.057	0.87
	Short rural	1.427	1.23
	Long rural	1.526	1.43
	Whole Network		1.00

The below table details the submission to the AER on the STPIS telephone response performance (or Grade of Service (GOS)) for the regulatory year ending 30 June 2023.

Table 51. SA Power Networks telephone response performance

Faults and Emergency telephone calls	2022/23
Total number of calls (includes automated and Agent)	185,365
Number of calls after removing excluded events	72,092
Number of calls answered by Agent within 30 seconds	65,946
Percentage of calls answered within 30 seconds (GOS)	91.47%

9. Information and Communications Technology Systems Investments

Schedule 5.8(m) requires SA Power Networks to provide information on its investments in information technology and communications systems which occurred in the preceding year, and planned investments in information technology and communications systems related to management of network assets in the forward planning period.

Below is a list of key IT projects undertaken in the past year and within the forward planning period.

9.1. 2022/23 Investment focus

9.1.1. Flexible Exports

Enabling the Flexible Exports implementation as detailed in the sections above. The flexible exports offering has now been productionised, providing real time calculations of network constraints and consumer energy resources for customers on the flexible export service.

9.1.2. Applying for Batteries, EV chargers and Embedded Generation

Continued to improve the systems and processes for applications for consumer energy resources and recording the subsequent installation to allow a more complete record of CER resources.

9.1.3. Cyber Security

Recent incidents such as compromises of telecommunications utilities, universities, airports and insurance entities show that the threat of malicious cyber activity continues to be significant.

This heightened risk means SA Power Networks needs to continuingly increase preparedness and accelerate the uplift of cyber protections. In line with the legislated requirements for critical infrastructure SA Power Networks has begun implementing a cyber improvement program to achieve compliance with the legislation, aligning to the Australian Energy Sector Cyber Security Framework (AESCSF). We are currently on track to meet the compliance outcomes required during 2024.

9.1.4. Assets and Work Program

The Assets and Work Program aims to improve our understanding of the value our customers receive from the network and realign our asset management practices maximising customer value. This includes understanding the basis of risk and performance, making better investment decisions about the assets we replace and better targeting the efforts of our people. This requires an uplift in the capability of our skills, systems, data and processes across the business. This Program spans multiple regulatory control periods.

The key investments in 2022/23 related to the Program include:

Forecast Risk Cost (and Investment) Model

Building and refining a risk and investment forecasting tool for network assets that is suitable for both long term investment decisions and short-term forecasting. We refined the forecasting model and trialled the operational risk cost model and added the ability to value projects.

Asset Information Capture

We redefined and implemented a materials catalogue, allowing more efficient and reliable asset data collection.

Asset Inspection Interface

We implemented new software to collect and interpret asset data in the field and to provide a desktop inspection interface. The interface is not just to convert data to make it useful for an inspector, it also shares asset information with downstream processes e.g. works preparation/make ready. We then extended that to support substation maintenance activities.

9.1.5. Data Governance & Analytics Uplift Program

The quality and timeliness of both network operational data and asset related data has become more critical to our service operations and underpins the quality of the network and assets decisions being made. The energy transition for example is driving towards more data-focused time-critical decision-making. SA Power Networks implemented a program to significantly uplift our data management and governance capabilities and toolsets. This will enable us to ensure we are only collecting the data we need to collect, at the most efficient point for it to be collected and maximise our usage of that data across the organisation and for customer.

In 2022/23 the foundation frameworks, toolsets and organisational structures and responsibilities were established. We have commenced rolling this out to business units, and they are starting to use the data governance. We are expanding the data sets available via the centralised analytics platform to improve decision-making across the organisation.

9.1.6. Geographic Information System (GIS) Consolidation

Understanding the location of the network assets and customers connected to them allows us to understand the impacts on our customers from activities on those assets. GIS underpins the delivery of customer, network and outage management services as well as supporting the management of the real time capacity of the network.

Over the past decade, the need for GIS capabilities has grown dramatically. We need to consolidate our two existing GIS software platforms onto a single platform to extend the work being undertaken in the Assets and Work Program as well as to reduce the risk to our outage management responses and minimise the costs associated with double handling the data and inconsistency error risks.

2022/23 saw significant progress in implementing a single system and the continued the migration of data into that system.

9.2. 2023/24 to 2027/28 Investment Focus

9.2.1. CER Operational Uplift

The CER management capability has been implemented and proved over the last few years based on proofs of concept and trails eg. Flexible Exports. Going forward we will make these capabilities more scalable, available and secure. We will provision a dedicated and secured technology environment to manage CER integrations, systems and data.

9.2.2. Smarter Homes Automation

Currently responding to load management events is a manual process requiring phone calls to turn off inverters. This is not a practical nor scalable solution as the number of systems that are to be managed increases. The next phase of this process involves improved automation of the load management process using system to system calls. We will also connect the execution of load management signals from the core operational systems to enable minimum demand and localised network constraints to be managed.

9.2.3. More Targeted Generation Shedding in Emergency Situations

We will continue to add more network monitoring data sources for the constraints management engine to provide more granular and accurate pictures of constraints and minimise the number of customers impacted by potential curtailment of shedding events.

9.2.4. Uplifting Capability & Compliance Testing for Flexible Export Devices

As the management of the operational network becomes more reliant on the quality and security of customer devices there is need to ensure those devices have the correct capabilities and comply with network requirements. We will be uplifting our technical capabilities to support ongoing testing of new device types.

9.2.5. Network protection settings system replacement

The Network Protection Settings System (PSS) is the core database system for managing our network protection devices and settings. PSS is essential to maintaining the quality, reliability, security and safety of electricity distribution services. PSS was developed in-house in 1997 and has had a number of upgrades since that time. However, many of the underlying technologies are no longer supported. Investment is needed to replace the system and reduce the risk of failure of the current system. This work is planned for 2023/24, by which time the current system will be over 25 years old.

9.2.6. Assets and Work Program (Continued)

Key focus areas for the continuing Assets and Work Program include:

Redefining the Asset Management Vision, Roadmap and System

The current Asset Management framework and approaches (how we make asset management decisions) have been in place for a decade. We will complete a refresh of this during 2023/24 which will be used to drive the next iteration of improvements in our asset management capabilities and finding new value for our customers.

Next Generation Data Collection

Creating, testing and implementing new technologies to reduce cost of asset data collection while trying to add new data types (lidar, thermography, HD Video). Inspect more often and target inspection. We are developing a proof of concept with a digital twin solution to understand the value for SAPN.

Data Governance & Analytics Uplift Program (continued)

Building on the foundation activity, completing the rollout of the data governance, data quality tools, data modelling and data catalogues across the rest of the organisation to deliver the required uplifts in data management and data driven decision making. Bringing more data sets under governance. Adding more data sets to the centralised analytics tools. Rolling out of data quality system and processes. Formalising our data science capability.

GIS Consolidation (continued)

Completion of the consolidation activity. We will also implement a "utilities data model" – which will allow improved analysis and tracing of electrical connectivity through the network and provide better capability to run scenarios for planning purposes.

9.2.7. Customer Technology Program

In our Regulatory submission we have proposed a large program of replacements and improvements to our customer systems to enable easy to use, secure and cost-effective customer services during the energy transition. This program will run out past 2030. We will commence with some improvements on our customer portals during 2024.

9.2.8. Satellite Communications

We plan on improving our satellite communications for both day to day operations and improved safety during disasters and incidents.

10. Planning

10.1. Joint planning undertaken with ElectraNet

Schedule 5.8(h) requires SA Power Networks to provide the results of any joint planning undertaken with a Transmission Network Service Provider in the preceding year, including:

1) a summary of the process and methodology used by the Distribution Network Service Provider and relevant Transmission Network Service Providers to undertake joint planning;

2) a brief description of any investments that have been planned through this process, including the estimated capital costs of the investment and an estimate of the timing (month and year) of the investment; and

3) where additional information on the investments may be obtained.

SA Power Networks and ElectraNet undertake regular joint planning meetings (JPM) on a bi-monthly basis to review system limitations and future projects that affect both the distribution and transmission networks. These joint planning sessions address the following issues:

- Load Forecasts for connection points;
- Asset replacement projects;
- Capacity driven augmentation projects;
- Voltage management issues;
- Major customer (including generator) connections that may impact both the transmission and distribution networks; and
- Non-network solutions.

Subsequent to these regular planning sessions, SA Power Networks and ElectraNet jointly manage a Connection Point Management Plan (CPMP) which outlines expected projects that affect transmission connection point substations within the forward planning period.

In addition, we have enhanced collaboration through an executive working group with ElectraNet to facilitate alignment across the businesses' respective strategies.

In general, works undertaken by ElectraNet at transmission connection point substations, whether augmentation or asset replacement, will affect SA Power Networks' assets and require expenditure by SA Power Networks. Such works are coordinated between the parties through a common notification process.

Investments that have been planned through this process and are expected to impact on SA Power Networks' expenditure within the forward planning period are summarised in the table below.

Table 52. Major joint investments in forward planning period

Project	Timing	Anticipated Cost (SA Power Networks only)
Mannum 132/33kV TF1 Transformer Replacement	2026	$8.2 million. SA Power Networks' works associated with project by ElectraNet to replace end of life 132/33kV TF1 transformer at Mannum Connection Point, refer to Transmission Annual Planning Report.
Northfield GIS	2023-24	$45.5 million. SA Power Networks proposes to replace the existing 66kV gas insulated switchgear (GIS) to an outdoor air insulated switchgear. Refer to 4.1.1 Preceding year RIT-D projects for more information.

Further details of ElectraNet's planned projects during the forward planning period can be found in their Transmission Annual Planning Report (TAPR).

Several years ago, it was evident that voltage management was going to become a significant issue due to the emergence and rapid uptake of CER within South Australia. Since 2016, in addition to the joint planning meetings, SA Power Networks and ElectraNet have also convened a Voltage Control Working Group (VCWG) looking specifically at managing voltage levels on both networks. This working group typically meets bi-monthly in alternate months to those in which JPMs occur.

We are actively engaged in collaboration with ElectraNet through joint planning activities associated with their Transmission Network Voltage Control Project, which aims to address reactive power and voltage control needs. Complementing this work are joint planning activities specifically focused on understanding and addressing SA Power Networks' obligation to meet Connection Point power factor requirements outlined in the Transmission Connection Agreement (TCA). This collaborative effort and shared priorities ensure that the identified needs are accurately defined, with comprehensive consideration given to a range of transmission and distribution solutions, encompassing both network and non-network options.

Our enduring relationship and continuous Joint Planning activities establish an effective mechanism to collaboratively address voltage control and system security issues in response to the evolving energy needs of our customers.

10.2. Joint planning undertaken with other Distribution Network Service Providers

Schedule 5.8(i) of the NER requires SA Power Networks to provide the results of any joint planning undertaken with other Distribution Network Service Providers in the preceding year.

Given SA Power Networks is the only DNSP in South Australia, it has no requirement to undertake joint planning activities with other DNSPs. Nor has any Victorian DNSP (eg Powercor) to which SA Power Networks provides supply (e.g. at Murtho and Nelson), initiated any regular joint planning discussions with SA Power Networks over the preceding 12 months.

Our commitment is to consistently make every effort to collaborate with Powercor in addressing issues that may arise, including changes in demand, power quality, or harmonic concerns, ensuring a timely and efficient resolution.

10.3. Regional development plans

Schedule 5.8(n) of the NER requires SA Power Networks to provide a regional development plan consisting of a map of our network as a whole, or maps by regions, in accordance with our planning methodology or as required under any regulatory obligation or requirement, identifying:

1) sub-transmission lines, zone substations and transmission-distribution connection points; and

2) any system limitations that have been forecast to occur in the forward planning period, including, where they have been identified, overloaded primary distribution feeders.

In previous DAPRs, this section has been used to both provide a description, along with a network map identifying the location of network limitations where applicable, for each regional and metropolitan segment of our network. In this publication, the description and network maps for each segment have been maintained however the network limitations have been removed.

The system limitations are now available on our network visualisation portal (Annual network plans - SA Power Networks).

The vast majority of our customers are supplied via primary high voltage distribution feeders (typically at 11kV), which are connected to zone substations. These feeders are extended and upgraded as required to meet customer demand, customer connection requests and to maintain quality of supply. Large customer projects may require a zone substation upgrade as well as feeder or sub-transmission line modifications. Therefore, SA Power Networks should be notified as early as possible during the planning stages of a project so that customer connection requirements can be met.

SA Power Networks regional development plans are found in Appendix D – Regional Overviews.

Glossary

Abbreviation	Definition or description
ACR	Adelaide Central Region as defined in the ETC
ADMS	Advanced Distribution Management System
AEMA	Australian Energy Market Agreement
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AIS	Air Insulated Switchgear
BOM	Bureau of Meteorology
CAIDI	Customer Average Interruption Duration Index. The average time in minutes to restore supply to customers who experience an interruption in a given year
CBD	Central Business District
CBD feeder	A feeder supplying predominantly commercial, high-rise buildings, supplied by a predominantly underground distribution network containing significant interconnection and redundancy when compared to urban areas.
CER	Consumer Energy Resources, (e.g., solar PV systems, batteries).
Complaint (SA Power Networks)	Any expression of dissatisfaction with an action, a proposed action, or failure to act, or in respect of a product or service offered or provided by, an electricity entity.
Contingency Condition (N-1)	The term used to describe the state of the distribution network when any one major item of plant (N-1) is out of service, with the rest of the network remaining intact
CPMP	Connection Point Management Plan – a document jointly maintained by SA Power Networks and ElectraNet, which outlines the predicted timing and scope of future connection upgrades
CRoS	Customer restoration of supply – percentage of total customers who have an interruption exceeding a specific number of hours
Customer Zone Substation	A zone substation dedicated to supplying a single customer's load. Information on customer zone substations is not included in this report for privacy reasons
DAPR	Distribution Annual Planning Report
Distribution Network	Has the meaning defined within Chapter 10 of the NER
Distribution System	Has the meaning defined within Chapter 10 of the NER
DNSP	Distribution Network Service Provider as defined in Chapter 10 of the NER
DPAR	Draft Project Assessment Report. A report we prepare and publish in accordance with clauses 5.17.4 (i) – (n) of the NER
EDC	Electricity Distribution Code as published by ESCoSA
EGU	Embedded Generating Unit
ElectraNet	The company which owns and operates the transmission system in South Australia and is registered with AEMO as the transmission network service provider for the South Australian transmission system
Embedded Generation	The generation of electricity by a generating unit connected within a distribution network and not having direct connection to the transmission network
Enquiry	A request for information (which requires further investigation) received from a customer or their representative via nominated enquiry channels.

ESCoSA	The Essential Services Commission of South Australia. The jurisdictional service standards regulator of electricity distribution in South Australia
ESS	Any form of Energy Storage System (i.e., not limited to inverter based systems)
ETC	Electricity Transmission Code as published by ESCoSA
Firm Delivery Capacity	The maximum allowable output or load of a network or facility under single contingency conditions, including any short-term overload capacity having regard to external factors, such as ambient temperature, that may affect the capacity of the network or facility
FPAR	Final Project Assessment Report. A report we prepare and publish in accordance with NER clause 5.17.4(o) – (s)
GIS	Gas Insulated Switchgear
HBFRA	High Bushfire Risk Area
HV	High Voltage. A voltage greater than 1000V
IED	Industry Engagement Document
IES	Inverter Energy System
kV	kilovolt (= 1000 Volts)
LDC	Line Drop Compensation.
LV	Low Voltage. A voltage less than 1000V
MED	Major Event Day. A day on which the cumulative SAIDI exceeds a designated threshold, for which the reliability impact occurring on that day is excluded from the STPIS results
MBFRA	Medium Bushfire Risk Area
Meshed Sub-Transmission	A sub-transmission line that has a source of supply available from both ends
N	See Total Capacity (power system capacity under normal operating conditions – all major items of plant in service).
N-1	See Contingency Condition (power system capacity with one major item of plant out of service).
Native Demand	Native Demand in a region is demand that is met by local scheduled, semi-scheduled, non-scheduled and non-registered generation and by generation imports to the region, excluding the demand of local scheduled loads
NBFRA	Non-Bushfire Risk Area
NECF	National Energy Customer Framework
NEM	National Electricity Market
NER	National Electricity Rules
NERL	National Energy Retail Law
NERR	National Energy Retail Rules
NSSA	Network Support Service Agreement
OLTC	On-Load Tap Changer on power transformers
OSR	Options Screening Report. This is the term used in the NER to describe a report that outlines broad range of options such as embedded generation, voluntary load curtailment, alternative sources of energy and direct load control that may be used to delay or resolve an identified need. These solutions may be delivered by groups other than SA Power Networks
OTR	Office of the Technical Regulator
PoE	Probability of Exceedance

PF	Power Factor - The ratio of real power (in kW or MW) to apparent power (in kVA or MVA) in an alternating current circuit
Primary Distribution Feeder	Means a distribution line connecting a sub-transmission asset to either other distribution lines that are not sub-transmission lines, or to distribution assets that are not sub-transmission assets. The term “feeder” shall be construed accordingly.
PV	Photo Voltaic
QoS	Quality of Supply
Radial Sub-transmission	Sub-transmission line that has a single source of supply
RDP	Regional Development Plan
Regulator Station	An item of plant used to maintain system voltage within pre-determined voltage limits. Regulator stations are limited by their load (normal) capacity and voltage boosting capability
RIT-D	Regulatory Investment Test – Distribution
RIT-T	Regulatory Investment Test – Transmission
RSS	Reliability Service Standard
SAIDI	System Average Interruption Duration Index. This is a measure of the average number of minutes each customer is without supply in a given year
SAIFI	System Average Interruption Frequency Index. This is a measure of the average number of interruptions each customer experiences in a given year
SAPS	Stand-Alone Power System
SCADA	Supervisory Control and Data Acquisition. A technology enabling remote control and real-time monitoring of devices connected to the distribution network
SCAP	State Commission Assessment Panel
SRMTMP	Safety, Reliability, Maintenance and Technical Management Plan
SSF	The Service Standard Framework established by ESCoSA
STATCOM	Static Synchronous Compensator. A regulating device used to either source or sink reactive power in the network.
STPIS	Service Target Performance Incentive Scheme.
Sub-transmission Line	For SA Power Networks’ purposes, an overhead conductor or underground cable energised at 33kV or 66kV that supplies a zone substation. The term “line” shall be construed accordingly.
SWE	Severe Weather Event as defined and verified by the BOM
SWER	Single Wire Earth Return. A powerline consisting of a single wire to convey electricity to customers utilising the earth to act as the return current path. SA Power Networks’ SWER systems operate at 19kV and 6.35kV
System Limitation	A limitation identified by a DNSP under clause 5.13.1(d)(2) of the NER
TNSP	Transmission Network Service Provider
Total Capacity (N)	The capacity of a sub-transmission line, primary distribution feeder or zone substation with all plant and equipment in service. The design life of the sub-transmission line, zone substation and distribution feeder assets (typically 30 years) will be reduced if the peak cyclic load exceeds this value
Total Nameplate Capacity	The summed substation transformer capacity as written on each nameplate of the substation transformers. Where different size transformers are used, the capacity of the smallest transformer may be used to calculate the total nameplate capacity
Transmission Connection Point	A substation shared with ElectraNet, at which electrical power is injected from the ElectraNet transmission network into SA Power Networks’ distribution network

Transmission Network	Has the meaning defined within Chapter 10 of the NER
UCAIDI	Unplanned Customer Average Interruption Duration Index
UFLS	Under-Frequency Load Shedding
USAIDI	Unplanned System Average Interruption Duration Index
USAIFI	Unplanned System Average Interruption Frequency Index
Voltage Capacity	The amount of load capable of being carried by a line or feeder before causing the voltage at the extremities of the line or feeder to drop below the minimum acceptable levels mandated by the Electricity Act 1996, Electricity (General) Regulations 2012, the South Australian EDC and the NER
VPP	Virtual Power Plant
Zone Substation	A substation for the purpose of connecting a high voltage distribution network to a sub-transmission network

Appendix A – SA Power Networks Contacts

For any queries relating to the information presented in this DAPR please contact the following Network Managers.

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Appendix B – Compliance Statement

NER schedule 5.8	Document reference
(a) information regarding the *Distribution Network Service Provider* and its *network*, including:	
(1) a description of its *network*;	Section 1
(2) a description of its operating environment;	Section 1 and 2
(3) the number and types of its distribution assets;	Section 1
(4) methodologies used in preparing the *Distribution Annual Planning Report*, including methodologies used to identify system limitations and any assumptions applied; and	Section 4 and Appendix C
(5) analysis and explanation of any aspects of forecasts and information provided in the *Distribution Annual Planning Report* that have changed significantly from previous forecasts and information provided in the preceding year;	Section 4
(b) forecasts for the forward planning period, including at least: a description of the forecasting methodology used, sources of input information, and the assumptions provided	Appendix C
(2) *load* forecasts: (i) at the transmission-distribution connection points; (ii) for sub-transmission lines; and (iii) for zone substations, including, where applicable, for each item specified above: (iv) total capacity; (v) firm delivery capacity for summer periods and winter periods; (vi) *peak load* (summer or winter and an estimate of the number of hours per year that 95% *of peak load* is expected to be reached); (vii) *power factor* at time of *peak load*; (viii) load transfer capacities; and (ix) generation capacity of known *embedded generating units*;	Section 4.1.1 Attachments A1 to A4 Network Visualisation Portal
(2A) forecast use of *distribution services* by *embedded generating units*: (i) at the *transmission-distribution connection points*; (ii) for *sub-transmission lines*; and (iii) for *zone substations*, including, where applicable, for each item specified above:	Section 4 Attachments A1 to A4

NER schedule 5.8	Document reference
(iv) *total capacity* to accept *supply* from *embedded generating units*; (v) *firm delivery capacity* for each period during the year; (vi) peak *supply* into the *distribution network* from *embedded generating units* (at any time during the year) and an estimate of the number of hours per year that 95% of the peak is expected to be reached; and (vii) *power factor* at time of peak *supply* into the *distribution network*;	Network Visualisation Portal
(3) forecasts of future transmission-distribution connection points (and any associated *connection assets*), sub-transmission lines and zone substations, including for each future transmission-distribution connection point and zone substation: (i) location; (ii) future *loading level*; and (iii) proposed commissioning time (estimate of month and year);	Section 4.1.2 Attachments A1 to A4 Network Visualisation Portal
(4) forecasts for the *Distribution Network Service Provider's* performance against any reliability targets in a *service target performance incentive scheme*; and	Section 4.1.3
(5) a description of any factors that may have a material impact on its *network*, including factors affecting; (i) fault levels; (ii) *voltage* levels; (iii) other *power system security requirements*; (iv) the quality of *supply* to other *Network Users* (where relevant); and (v) ageing and potentially unreliable assets;	Section 2.1
(b1) for all *network* asset retirements, and for all *network* asset de-ratings that would result in a system limitation, that are planned over the forward planning period, the following information in sufficient detail relative to the size or significance of the asset: (1) a description of the *network* asset, including location; (2) the reasons, including methodologies and assumptions used by the *Distribution Network Service Provider*, for deciding that it is necessary or prudent for the *network* asset to be retired or de-rated, taking into account factors such as the condition of the *network* asset; (3) the date from which the *Distribution Network Service Provider* proposes that the *network* asset will be retired or de-rated; and (4) if the date to retire or de-rate the *network* asset has changed since the previous *Distribution Annual Planning Report*, an explanation of why this has occurred;	Section 4.2, 4.3 Attachments B1 to B5
(b2) for the purposes of subparagraph (b1), where two or more *network* assets are: (1) of the same type; (2) to be retired or de-rated across more than one location; (3) to be retired or de-rated in the same calendar year; and (4) each expected to have a replacement cost less than $200,000 (as varied by a cost threshold determination), those assets can be reported together by setting out in the *Distribution Annual Planning Report*: (5) a description of the *network* assets, including a summarised	Section 4.2, 4.3

NER schedule 5.8	Document reference
description of their locations; (6) the reasons, including methodologies and assumptions used by the *Distribution Network Service Provider*, for deciding that it is necessary or prudent for the *network* assets to be retired or de-rated, taking into account factors such as the condition of the *network* assets; (7) the date from which the *Distribution Network Service Provider* proposes that the *network* assets will be retired or de-rated; and (8) if the calendar year to retire or de-rate the *network* assets has changed since the previous *Distribution Annual Planning Report*, an explanation of why this has occurred.	
(c) information on system limitations for sub-transmission lines and zone substations, including at least: (1) estimates of the location and timing (month(s) and year) of the system limitation; (2) analysis of any potential for load transfer capacity between *supply* points that may decrease the impact of the system limitation or defer the requirement for investment; (3) impact of the system limitation, if any, on the capacity at transmission-distribution connection points; (4) a brief discussion of the types of potential solutions that may address the system limitation in the forward planning period, if a solution is required; and (5) where an estimated change in forecast *load* or forecast *generation* from *embedded generating units* would defer a forecast *system limitation* for a period of at least 12 months, include: (i) an estimate of the month and year in which a *system limitation* is forecast to occur as required under subparagraph (1); (ii) the relevant *connection points* at which the estimated change in forecast *load* or forecast *generation* may occur; and (iii) the estimated change in forecast *load* or forecast *generation* in MW or improvements in *power factor* needed to defer the forecast *system limitation*;	Section 4.4 Attachments B1 to B5 Network Visualisation Portal
(d) for any primary distribution feeders for which a *Distribution Network Service Provider* has prepared forecasts of *maximum demands* under clause 5.13.1(d)(1)(iii) and which are currently experiencing an overload, or are forecast to experience an overload in the next two years *the Distribution Network Service Provider* must set out: (1) the location of the primary distribution feeder; (2) the extent to which load exceeds, or is forecasted to exceed, 100% (or lower utilisation factor, as appropriate) of the normal cyclic rating under normal conditions (in summer periods or winter periods); (3) the types of potential solutions that may address the overload or forecast overload; and (4) where an estimated reduction in forecast *load* would defer a forecast overload for a period of 12 months, include: (i) estimate of the month and year in which the overload is forecast to occur;	Section 4.5

NER schedule 5.8	Document reference
(ii) a summary of the location of relevant *connection points* at which the estimated reduction in forecast *load* would defer the overload; (iii) the estimated reduction in forecast load in MW needed to defer the forecast system limitation;	
(d1) for any *primary distribution feeders* for which a *Distribution Network Service Provider* has prepared forecasts of demand for *distribution services* by *embedded generating units* under clause 5.13.1(d1)(3) and which are currently experiencing a *system limitation*, or are forecast to experience a *system limitation* in the next two years, the *Distribution Network Service Provider* must set out: (1) the location of the *primary distribution feeder*; (2) the extent to which demand for *distribution services* by *embedded generating units* exceeds, or is forecast to exceed, 100% (or lower utilisation factor, as appropriate) of the normal capacity to provide those *distribution services* under normal conditions; (3) the types of potential solutions that may address the *system limitation* or forecast *system limitation*; (4) where an estimated reduction in demand for *distribution services* by *embedded generating units* would defer a forecast *system limitation* for a period of 12 months, include: (i) an estimate of the month and year in which the *system limitation* is forecast to occur; (ii) a summary of the location of relevant *connection points* at which the estimated reduction in demand for distribution services by *embedded generating units* would defer the *system limitation*; and (iii) the estimated reduction in demand for *distribution services* by *embedded generating units* in MW needed to defer the forecast *system limitation*;	Section 4.6
(d2) for a *SAPS enabled network*, information on *system limitations* in the *forward planning period* for which a potential solution is a *regulated SAPS*, including at least: (1) estimates of the location and timing (month(s) and year) of the *system limitation*; and (2) a brief discussion of the types of potential *stand-alone power systems* that may address the *system limitation*;	Section 4.7
(e) a high level summary of each RIT-D project for which the *regulatory investment test for distribution* has been completed in the preceding year or is in progress; including: (1) if the *regulatory investment test for distribution* is in progress, the current stage in the process; (2) a brief description of the *identified need*; (3) a list of the credible options assessed or being assessed (to the extent reasonably practicable); (4) if the *regulatory investment test for distribution* has been completed a brief description of the conclusion, including: (i) the net economic benefit of each credible option; (ii) the estimated capital cost of the preferred option; and (iii) the estimated construction timetable and commissioning date (where relevant) of the preferred option; and	Section 5.1.1 and 5.1.2

NER schedule 5.8	Document reference
(5) any impacts on *Network Users*, including any potential material impacts on *connection* charges and *distribution use of system charges* that have been estimated;	
(f) for each identified system limitation which a *Distribution Network Service Provider* has determined will require a *regulatory investment test for distribution*, provide an estimate of the month and year when the test is expected to commence;	Section 5.1.3
(g) a summary of all committed investments to be carried out within the forward planning period with an estimated capital cost of $2 million or more (as varied by the cost threshold determination) that are to address an urgent and unforeseen network issue in clause 5.17.3.(a)(1),including: (1) a brief description of the investment, including its purpose, its location, the estimated capital cost of the investment and an estimate of the date (month and year) the investment is expected to become operational; (2) a brief description of the alternative options considered by the *Distribution Network Service Provider* in deciding on the preferred investment, including an explanation of the ranking of these options to the committed project. Alternative options could include, but are not limited to, *generation* options, demand side options, and options involving other *distribution or transmission networks*.	Section 5.2
(h) the results of any joint planning undertaken with a *Transmission Network Service Provider* in the preceding year, including: (1) a summary of the process and methodology used by the *Distribution Network Service Provider* and relevant *Transmission Network Service Providers* to undertake joint planning; (2) a brief description of any investments that have been planned through this process, including the estimated capital costs of the investment and an estimate of the timing (month and year) of the investment; and (3) where additional information on the investments may be obtained;	Section 10.1
(i) the results of any joint planning undertaken with other *Distribution Network Service Providers* in the preceding year, including: (1) a summary of the process and methodology used by the *Distribution Network Service Providers* to undertake joint planning; (2) a brief description of any investments that have been planned through this process, including the estimated capital costs of the investment and an estimate of the timing (month and year) of the investment; and (3) where additional information on the investments may be obtained;	Section 10.2
(j) information on the performance of the *Distribution Network Service Provider's Network*, including: (1) a summary description of reliability measures and standards in *applicable regulatory instruments*; (2) a summary description of the quality of *supply* standards that apply, including the relevant codes, standards and guidelines; (3) a summary description of the performance of the *distribution network* against the measures and standards described under subparagraphs (1) and (2) for the preceding year;	Section 8

NER schedule 5.8	Document reference
(4) where the measures and standards described under subparagraphs (1) and (2) were not met in the preceding year, information on the corrective action taken or planned; (5) a summary description of the *Distribution Network Service Provider's* processes to ensure compliance with the measures and standards described under subparagraphs (1) and (2); and (6) an outline of the information contained in the *Distribution Network Service Provider's* most recent submission to the AER under the service target performance incentive scheme;	
(k) information on the *Distribution Network Service Provider's* asset management approach, including: (1) a summary of any asset management strategy employed by the *Distribution Network Service Provider*; (1A) an explanation of how the *Distribution Network Service Provider* takes into account the cost of *distribution losses* when developing and implementing its asset management and investment strategy; (2) a summary of any issues that may impact on the system limitations identified in the *Distribution Annual Planning Report* that has been identified through carrying out asset management; and (3) information about where further information on the asset management strategy and methodology adopted by the *Distribution Network Service Provider* may be obtained;	Section 7
(l) information on the *Distribution Network Service Provider's* demand management activities and activities relating to *embedded generating units*, including: (1) a qualitative summary of: (i) *non-network options* that have been considered in the past year, including *generation* from *embedded generating* units; (ii) key issues arising from *applications to connect embedded generating units* received in the past year; (iii) actions taken to promote non-*network* proposals or (for a *SAPS enabled network*) SAPS proposals in the preceding year, including *generation* from *embedded generating units*; and (iv) the *Distribution Network Service Provider's* plans for demand management and generation from *embedded generating* units over the forward planning period; (2) a quantitative summary of: (i) *connection* enquiries received under clause 5.3A.5 and of the total, the number for *non-registered embedded generators*; (ii) *applications to connect* received under clause 5.3A.9 and of the total, the number for *non-registered embedded generators*; and (iii) the average time taken to complete *applications to connect*; (3) a quantitative summary of: (i) *enquiries* under clause 5A.D.2 in relation to the *connection* of *micro embedded generators* or *non-registered embedded generators*; and (ii) applications for a *connection service* under clause 5A.D.3 in relation to the *connection* of *micro embedded generators* or *non-registered embedded generators*;	Section 6

NER schedule 5.8	Document reference
(m) information on the *Distribution Network Service Provider's* investments in information technology and communication systems which occurred in the preceding year, and planned investments in information technology and communication systems related to management of *network assets* in the forward planning period; and	Section 9
(n) a regional development plan consisting of a map of the *Distribution Network Service Provider’s* network as a whole, or maps by regions, in accordance with the *Distribution Network Service Provider’s* planning methodology or as required under any *regulatory obligation or requirement*, identifying: (1) sub-transmission lines, zone substations and transmission-distribution connections points; and (2) any system limitations that have been forecast to occur in the forward planning period, including, where they have been identified, overloaded primary distribution feeders.	Appendix D – Regional Overviews and Network Visualisation Portal
(o) the analysis of the known and potential interactions between: (1) any *emergency frequency control schemes*, or emergency controls in place under clause S5.1.8, on its *network*; and (2) *protection systems* or *control systems* of *plant connected* to its *network* (including consideration of whether the settings of those systems are fit for purpose for the future operation of its *network*), undertaken under clause 5.13.1(d)(6), including a description of proposed actions to be undertaken to address any adverse interactions; and	Section 5.3
(p) for a *SAPS enabled network,* information on the *Distribution Network Service Provider's* activities in relation to *DNSP-led SAPS projects* including: (1) opportunities to develop *DNSP-led SAPS projects* that have been considered in the past year; (2) committed projects to implement a *regulated SAPS* over the *forward planning period*; and (3) a quantitative summary of: (i) the total number of *regulated SAPS* in the *network*; and (ii) the total number of premises of *retail customers* supplied by means of those *regulated SAPS*.	Section 6.8

Appendix C – Forecasting Methodology

Forecasting methodology

Schedule 5.8(b)(1) of the NER requires SA Power Networks to provide a description of the forecasting methodology it has used, sources of input information, and the assumptions applied in delivering the demand forecasts published within this document.

Load forecasting methodology

Maximum Demand Forecasts

SA Power Networks reviews its load forecast annually after each summer. These annual reviews consider the impact of the latest load recordings, recent system modifications and any new committed spot load or generation developments, in accordance with SA Power Networks' load forecasting procedure. SA Power Networks does not produce a winter load forecast as the network presently only peaks in summer.

In 2018, SA Power Networks purchased a license from AEMO to use its existing connection point forecasting system. The load forecasting tool enables the production of connection point and zone substation forecasts at 10 PoE and 50 PoE levels. The tool performs regression analysis of the temperature sensitive component of the measured demand, to weather correct recorded load readings with respect to historic temperatures over the preceding 30 years. Prior to performing the regression analysis, the actual load readings are adjusted to account for the impact of load transfers, spot loads, major customers, PV and embedded generation. This ensures the values regressed represent those underlying or native loads which are temperature sensitive. Upon completion of the regression analysis, post regression adjustments are made to add back previously removed spot loads or major customer load forecasts whilst forecast levels of negative loads such as PV are added to arrive at the final forecast value. The forecasts produced assume that other forms of embedded generation are not operating.

In order to account for econometric factors, the temperature corrected PoE spatial forecasts are reconciled to the next level of the network (ie zone substations are reconciled to transmission connection points, transmission connection points are reconciled to the aggregated state / SA Power Networks total level). The forecasting tool also considers the impact of past and future embedded generation (including PV), spot loads, transfers and the behaviour of major customers, when arriving at its final forecast values for the nominated PoE level. The tool also considers the time shift of demand due to PV in arriving at the underlying or native demands which are regressed.

With respect to spot loads, increases are only considered for inclusion within the relevant asset's forecast (eg zone substation or connection point) where the spot load is committed and represents more than 5% of the substation's installed transformer capacity. It is therefore possible that a new load considered as a spot load for the purposes of a zone substation's forecast will not be considered for the upstream connection point, because the spot load is likely to be less than 5% of the installed transformer capacity at the connection point. Only those loads for committed customer projects or State Government projects with a high likelihood of proceeding are considered for inclusion as spot loads within the moderate forecast. Even then, the customers' forecast load is reduced to 50% of the submitted demand to allow for over-estimation by the customer, and load diversity. Similarly, only actual or committed load reductions (eg due to measured changes or announced closures) are considered as spot load reductions.

The 2022 connection point forecast was reconciled against the future 20-year trend of the categories "Residential Business" + "Electrification" + "Electric Vehicle" forecast under AEMO's SA system "central" demand scenario contained within its 2022 ESOO. Connection Points dominated by non-temperature sensitive major customer load (eg: Snuggery Industrial and Whyalla LMF) were subject to manually set growth rates.

The reconciliation process modifies the transmission connection point forecast, thereby considering the global impact of energy efficiency measures, PV, electric vehicle uptake, fuel substitutions (aka electrification) and any other economic factors as forecast by AEMO, for South Australia (eg the reconciliation process uses AEMO's ESOO underlying forecast, reduced by the forecast PV and storage growth at each connection point) to produce a reconciled coincident and non-coincident forecast for each connection point substation. The major customers are separately forecast based on their measured demand and their advice of their future plans and historical usage. A number of these customers have modified or are about to modify their demand requirements. Each zone substation forecast trend is then reconciled to the upstream transmission connection point substation's reconciled non-coincident forecast, similarly, modifying the zone substation forecast to include consideration of global factors considered by AEMO within their ESOO forecasts. The result is the creation of a reconciled coincident and non-coincident forecast for each zone substation.

Minimum Demand Forecasts

With the increasing penetration of CER in South Australia, SA Power Networks has recognised the importance of producing minimum demand forecasts to enable early identification of any constraints or operating issues resulting from diminishing minimum demand and ultimately increasing reverse / export flows through its network.

As a result, since 2019, SA Power Networks has produced minimum demand forecasts for its transmission connection point and zone substations. In addition, SA Power Networks commenced publication of sub-transmission line forecasts from 2022.

SA Power Networks' methodology for forecasting minimum demands relies on the identification of historic minimum demands for each zone and connection point substation excluding spurious minimum readings due to faults or offloads. These minima typically occur on mild, fine weekend days or public holidays. SA Power Networks reviews measured minimum demands observed during the preceding financial year in deriving its minimum demand forecasts.

The methodology employed sees the underlying demand determined through the addition of a calculated, theoretical CER output and any other form of embedded generation to the measured values. The methodology assumes an ideal CER output response and that there is no load growth in this underlying demand.

Forecasts of future year's minimum values then rely on the application of CER forecasts. The growth of small residential and commercial systems (ie capacity 100kW and below) reconciles to the AEMO ESOO forecasts. In 2022, SA Power Networks collaborated with an external provider to implement an improved CER forecasting methodology. The outcomes were to expand the historic growth derivation to the earliest installations, circa early 2000s. Additional demographic parameters are now also considered, including home and vehicle ownership, dwelling arrangements, income, age, education level and the type and proportion of energy usage (ie electricity, gas). Improving the forecasting approach for these smaller systems was the priority as they are the collective majority of CER on the distribution network. The total CER forecast however also includes the larger CER systems – which are forecast differently.

Larger CER systems (ie greater than 100kW) are only increased according to committed connection enquiries. No growth is applied to established systems. Reconciliation to the AEMO ESOO published capacities for these systems would not be useful as the forecast figures (up to 30 MW) also represents TNSP connected systems.

The forecast minimum demand for each connection point and substation are produced by subtracting the forecast CER output for each future year from the existing underlying demand. These forecasts are intended to represent the minimum demand expected to occur as at 1 July in the year stated (eg the 2023 minimum forecast is the forecast as at 1 July 2023). SA Power Networks is continuing to review its minimum demand forecasting methodology to ensure its ongoing suitability for integrating ESS and EV loads in addition to PV.

Constraint identification

All identified peak demand constraints and their timings described in this report are based on the forecasts produced by the forecast tool under 10 PoE and 50 PoE levels (as applicable). All forecasts consider the historical measured loads, adjusted for any transfers, spot loads, PV, embedded generation or major customers. The historic period selected can vary (eg where the asset has existed for less than five years, the forecast will only consider historic demands over this period). Potential changes in customer demand due to the effects of PV installations and demand management programs have also been considered within the forecasts.

Any identified minimum demand constraints and their timings are based on comparison of the minimum demand forecasts with the equipment ratings of the relevant substations in the reverse or exporting direction. Potential voltage driven constraints under minimum demand conditions across the network have not been assessed or identified but may be in the future.

The timing of the various network augmentations proposed within this DAPR are based on the comparison of the relevant forecast with the relevant asset ratings in accordance with SA Power Networks' planning criteria.

In the case of SA Power Networks' sub-transmission lines, these forecasts have been developed through modelling of the zone substation 10 PoE coincident forecasts using system load flow modelling software. The line flows indicated by these models are then used to determine the timing of any constraint. The intent of the modelling is to recreate the scenario which will result in the highest forecast load in the relevant line.

Whilst many of SA Power Networks' country zone substations are radially connected, a large proportion are "daisy chained" from a single transmission connection point with the sub-transmission lines entering the zone substation and subsequently continuing to supply other zone substations in series. For those sub-transmission lines which only supply a single zone substation, the sub-transmission line forecast is based on the zone substation's non-coincident forecast.

The timing of augmentation projects detailed within this DAPR are based on SA Power Networks' load forecasts which have been reconciled against the normal AEMO load forecast as detailed in their 2022 ESOO.

Individual forecasts for zone substations consider long term usage, measured growth, local customer 10 PoE behaviour and the impact of embedded generation including PV (both existing and forecast).

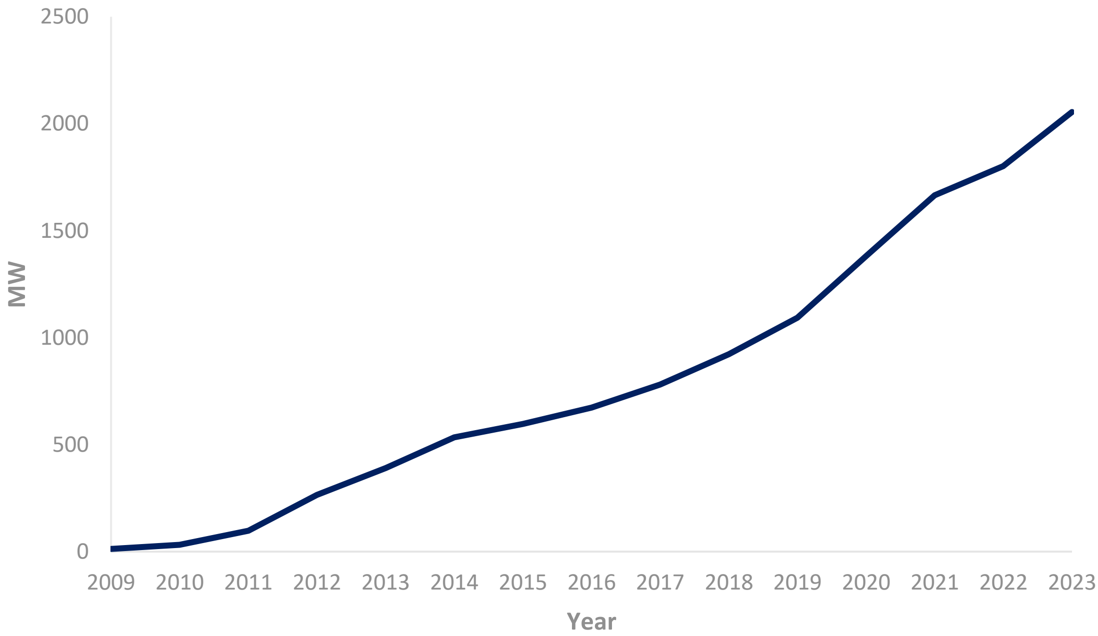
The total connection point forecast is a non-coincident summation of demands across the distribution network. The coincident demand for the total distribution network is less than the summation of the non-coincident values due to diversity between connection points (eg time of day and customer type), the impact of embedded generation and large customers. The total State forecast is lower again due to the diversity between transmission and distribution customers, distribution losses and transmission system connected generation.

PV Generation Effects

Since 2009, SA Power Networks has experienced a significant increase in the level of installed solar PV systems, from negligible penetration levels of less than 20 MW in 2009/10 to today's installed capacity of 2,195 MW as at 1 June 2023. This represents more than half of SA Power Networks' peak system demand and has resulted in SA Power Networks having one of the highest PV penetration levels as a proportion of system demand in the nation. As a proportion of SA Power Networks' 919,000 customers, approximately 37% have a PV system installed.

This increase has been driven by several factors including initial significant State Government "feed in tariffs" and the subsequent large reductions in the cost of installing such systems. Figure 10 indicates the level of installed PV inverter capacity within the distribution network as at 1 July for each respective year.

Figure 10. Total installed PV inverter capacity per annum

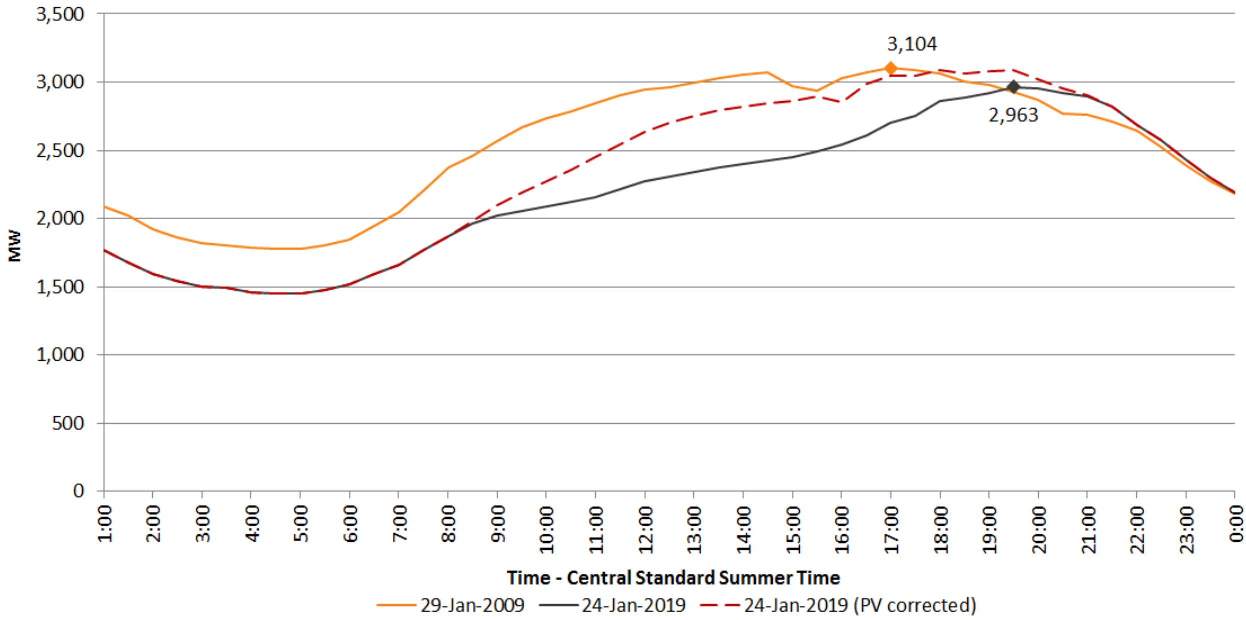


As a result, the implementation of PV systems has altered the supply - demand balance in all regions over this period to the extent that the impact of PV needs to be accounted for within the spatial demand forecasts.

Since 2009 the increasing level of PV systems have altered the daily demand profile and shifted the peak demand period at a zone substation level from the traditional 17:00 – 18:00 hour period to 19:00 – 20:00 hour. With respect to transmission connection points and state demand, the effect of these PV systems has had a similar impact, with the time of peak demand shifting from 17:00 to 19:00 Central Standard Summer Time.

This time shift in demand has been considered within SA Power Networks' load forecasts.

Figure 11. Example load profile comparison



The energy output of PV systems is inherently variable and is affected by factors such as:

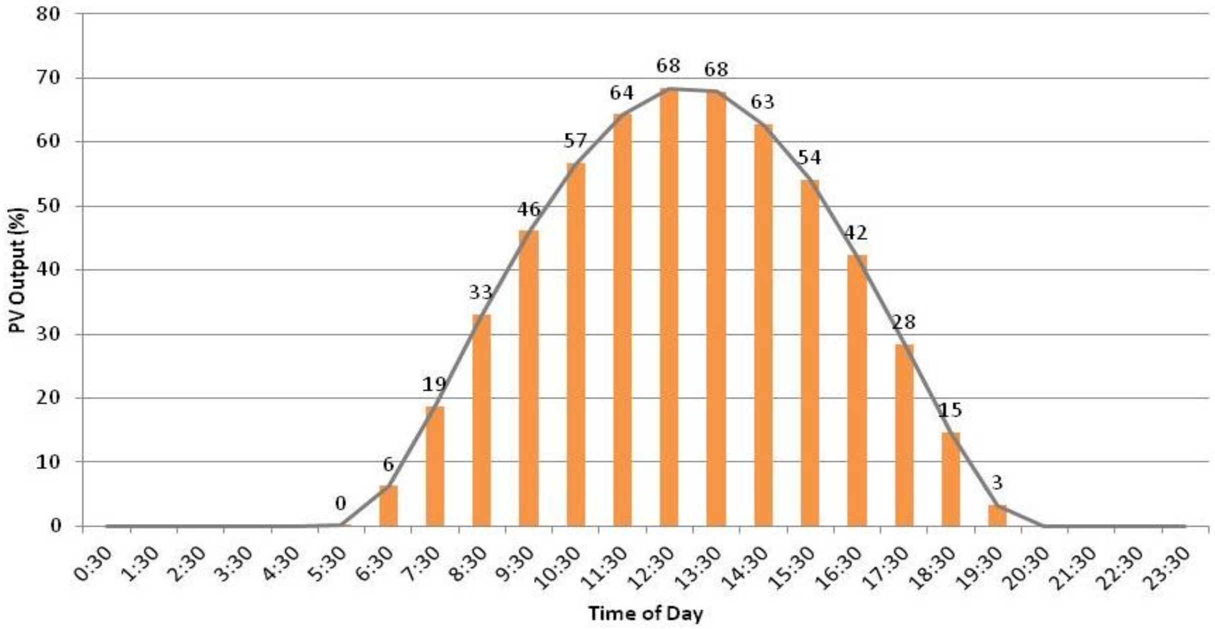
- Shading from trees and nearby structures;
- Panel orientation with respect to the sun (ie time of day);
- Ambient temperature (ie PV panels exhibit reduced efficiency at higher temperatures);
- Panel to inverter capacity; and
- General cleanliness / efficiency of the system.

As is the case with more traditional forms of embedded generation, in order to account for the impact of PV generation on the network and subsequently its zone substation and connection point forecasts, the forecasting tool used by SA Power Networks attempts to forecast the level of PV generation at each daily half hour interval for each month of the summer in order to correct the measured daily demand to its underlying demand value prior to performing any temperature correction analysis.

The methodology employed by the forecasting tool to estimate the amount of PV output is based on:

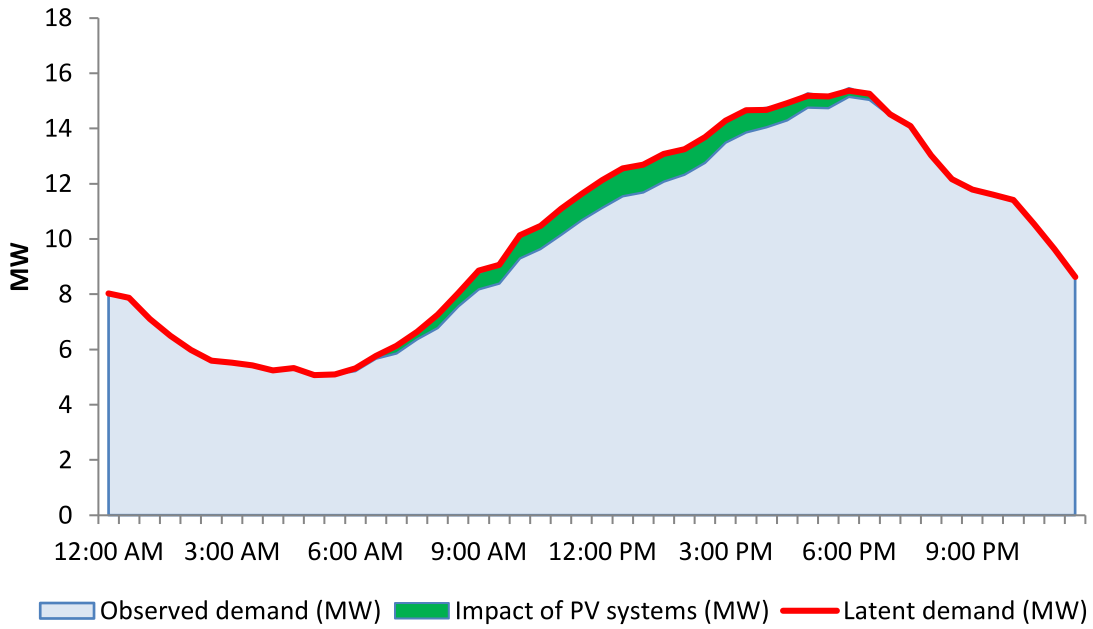
- the installed capacity of PV systems at both zone substation and connection point level (as at the first day of each month);
- apportionment of the total annual output of these systems to each half hour and month based on solar insolation data from Renewables SA (refer to Figure 12 for an example of a single month's curve).

Figure 12. PV Output versus Time of Day in January



The forecasting tool uses the data provided to determine, for each half hour, the estimated/latent impact of PV on the measured demand and the resultant underlying demand. This value is then added back to the measured daily demand prior to performance of any temperature correction regression. Upon completion of the temperature correction, the effect of these PV systems is deducted from the forecast value at the nominated PoE level to arrive at the final, unreconciled forecast. provides an example of the impact of PV on measured versus native demand.

Figure 13. Example of measured demand compared with underlying (native/latent) demand



AEMO's ESOO forecast growth in PV and storage is used to augment the forecast of underlying demand at each transmission connection point taking into account the time of the critical peak demand and the effectiveness of PV at this time.

Embedded Generation

SA Power Networks' forecasting tool treats non-PV embedded generation as a negative load. Given embedded generation may or may not be operating at any given time, its operation may result in misleadingly low / high demands if considered or not considered within the forecasting process.

The level of embedded generation output for each embedded generator for every half hour over the summer is recorded and added back to the relevant zone and/or connection point substation's measured transformer output to arrive at the underlying/native demand value used within the forecast tool's regression.

Upon completion of the regression analysis and arriving at a temperature corrected demand at the nominated PoE level by the forecast tool, those embedded generators whose operation is consistent (eg small biogas generators which operate irrespective of temperature or network demand levels) can then be deducted (outside the tool) from the temperature corrected demand to arrive at the final forecast demand level. Those embedded generators that have historically operated intermittently are assumed to not be operating and are not deducted from the model's forecast.

Spot Loads

SA Power Networks has only included spot load increases arising from committed customer projects and State Government funded or sponsored projects. Similarly, spot load decreases are only considered where they are due to committed load reductions.

Load Transfers

Known historic and forecast temporary and permanent load transfers are accounted for within the connection point and zone substation forecasts. Temporary transfers are applied as corrections to the raw SCADA data, whilst planned, long term transfers are catered for as post-regression adjustments to the weather corrected data.

Major Customers

Major customer loads are excluded / removed from the raw data prior to temperature correction and a forecast of these customer's demand is added to the forecasts as a post regression model adjustment. This is to prevent what are typically temperature insensitive loads from adversely affecting the temperature-sensitive portion of the measured load's regression.

Holiday Peaking Locations

The load forecasting tool considers loads recorded in the summer period between 1 November and 31 March excluding the Christmas holiday period from the Monday immediately prior to Christmas to the first Friday after New Years Day and excluding weekends and public holidays, to minimise the chance of distortion due to abnormal conditions. Although this provides a sound basis for reconciliation with the AEMO ESOO for South Australia as the State demand peaks during this period, it does not provide accurate results for locations that peak during the holiday period (eg Christmas/New Year's Eve). For such locations, the forecasting tool allows us to include these periods within the data stream available to be considered for regression.

Appendix D – Regional Overviews

Eastern Suburbs Regional Overview

The SA Power Networks Eastern Suburbs region includes the area from Golden Grove in the north to Linden Park in the south and extends westwards to Prospect and North Adelaide and eastwards to the Adelaide Hills. There are two main transmission connection points in the Eastern Suburbs, being Northfield and Magill, with connections to the embedded ACR system (East Terrace and City West connection points) and Dry Creek Power Station. The forecast loads for the Eastern Suburbs system includes the Adelaide Central Region (ACR) which covers the Adelaide CBD. The CBD system is an integral part of the Eastern Suburbs system.

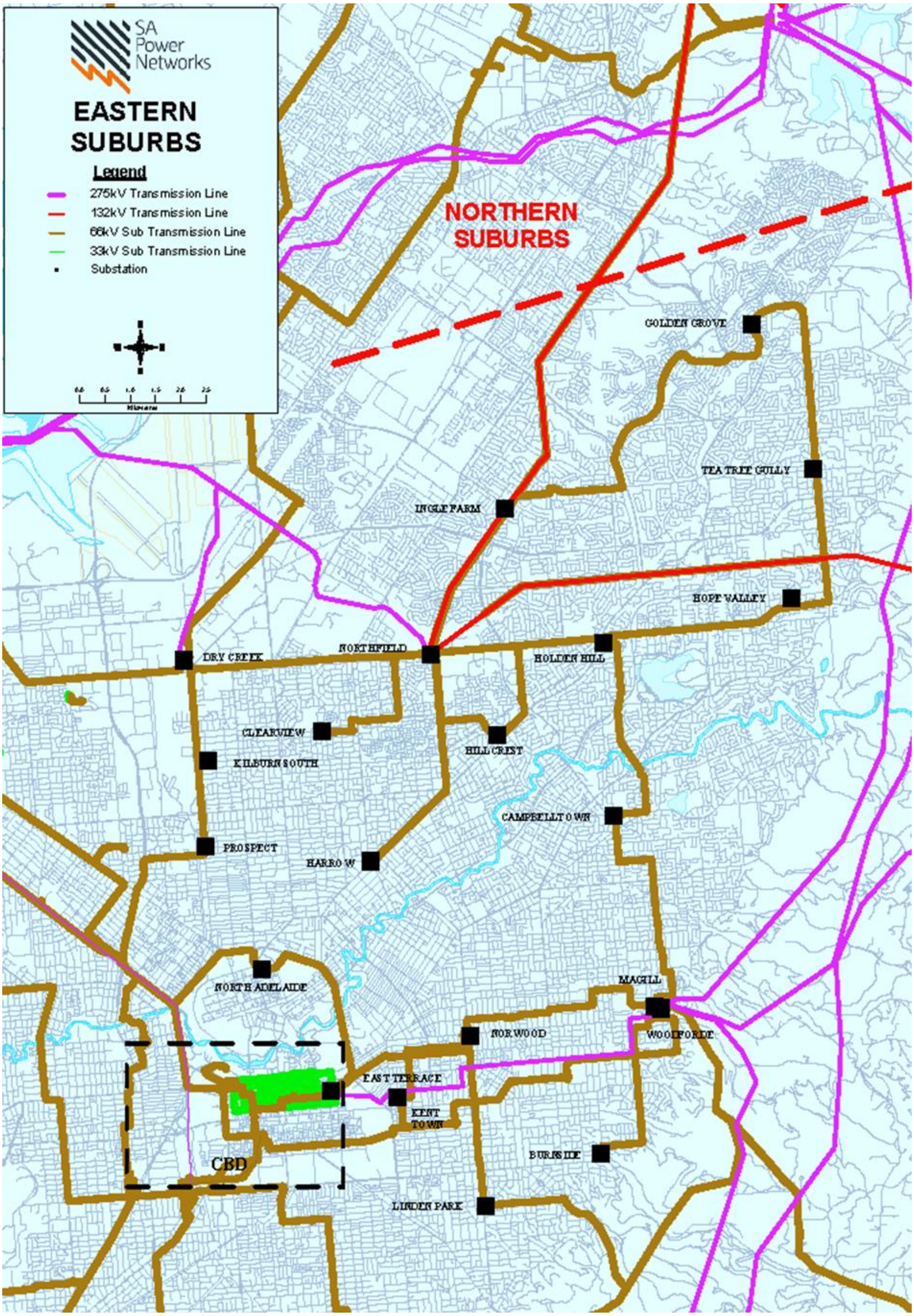
Electricity is supplied throughout the Eastern Suburbs from zone substations supplied directly from the 66kV sub-transmission network. These substations are operated at 66,000 Volts stepped down to 11,000 Volts and upgraded when load exceeds capacity.

Table 53 lists SA Power Networks' Eastern Suburbs zone substations with SCADA, and Figure 14 shows the extent of the Eastern Suburbs region.

Table 53. Eastern Suburbs SCADA Substations

Source Connection Point	Associated SCADA Substations
Eastern Suburbs Meshed 66kV Network: City West – ACR Dry Creek – Central and East East Terrace - ACR Magill – Transformers 2 and 3 Northfield	Burnside Campbelltown Clearview Golden Grove Harrow Hillcrest Holden Hill Hope Valley Ingle Farm Kent Town Kilburn South Linden Park North Adelaide Northfield Norwood Prospect Tea Tree Gully Woodforde Coromandel Place (ACR) East Terrace (ACR) Whitmore Square (ACR) Hindley Street (ACR)

Figure 14. Eastern Suburbs Regional Map



Western Suburbs Regional Overview

SA Power Networks' Western Suburbs region includes the region from the Adelaide metropolitan coast, south to West Beach, extending south-east to Richmond, north-east to Cavan, and north-west to the LeFevre Peninsula. There are four main transmission connection points in the region, being Torrens Island Power Station, LeFevre, New Osborne and Kilburn. The region contains a significant amount of generation sources which greatly influence the operation of the 66kV sub-transmission network, although these are not embedded generators as they are connected to ElectraNet's transmission network.

Electricity is supplied throughout the Western Suburbs via zone substations. These zone substations are operated 66,000 Volts stepped down to either 11,000 Volts or 33,000 Volts.

Table 54 lists SA Power Networks' Western Suburbs zone substations with SCADA and Figure 15 shows the extent of the Western Suburbs region.

Table 54. Western Suburbs SCADA Substations

Source Connection Point	Associated SCADA Substations	
Western Suburbs Meshed 66kV Network: Dry Creek – West Kilburn LeFevre New Osborne Torrens Island	Athol Park Blackpool Cavan Cheltenham 33kV Cheltenham 11kV Croydon Croydon Park Findon Flinders Park Fulham Gardens Glanville Henley South	Kilburn Kilkenny Largs North LeFevre New Osborne New Richmond Port Adelaide Port Adelaide North Queenstown Thebarton Woodville 11kV Woodville 33kV

Figure 15. Western Suburbs Regional Map

Northern Suburbs Regional Overview

SA Power Networks' Northern Suburbs region includes Elizabeth and extends north to Gawler and south to Parafield Gardens. There are three transmission connection points in the Northern Suburbs, being Para and Parafield Gardens West and Munno Para.

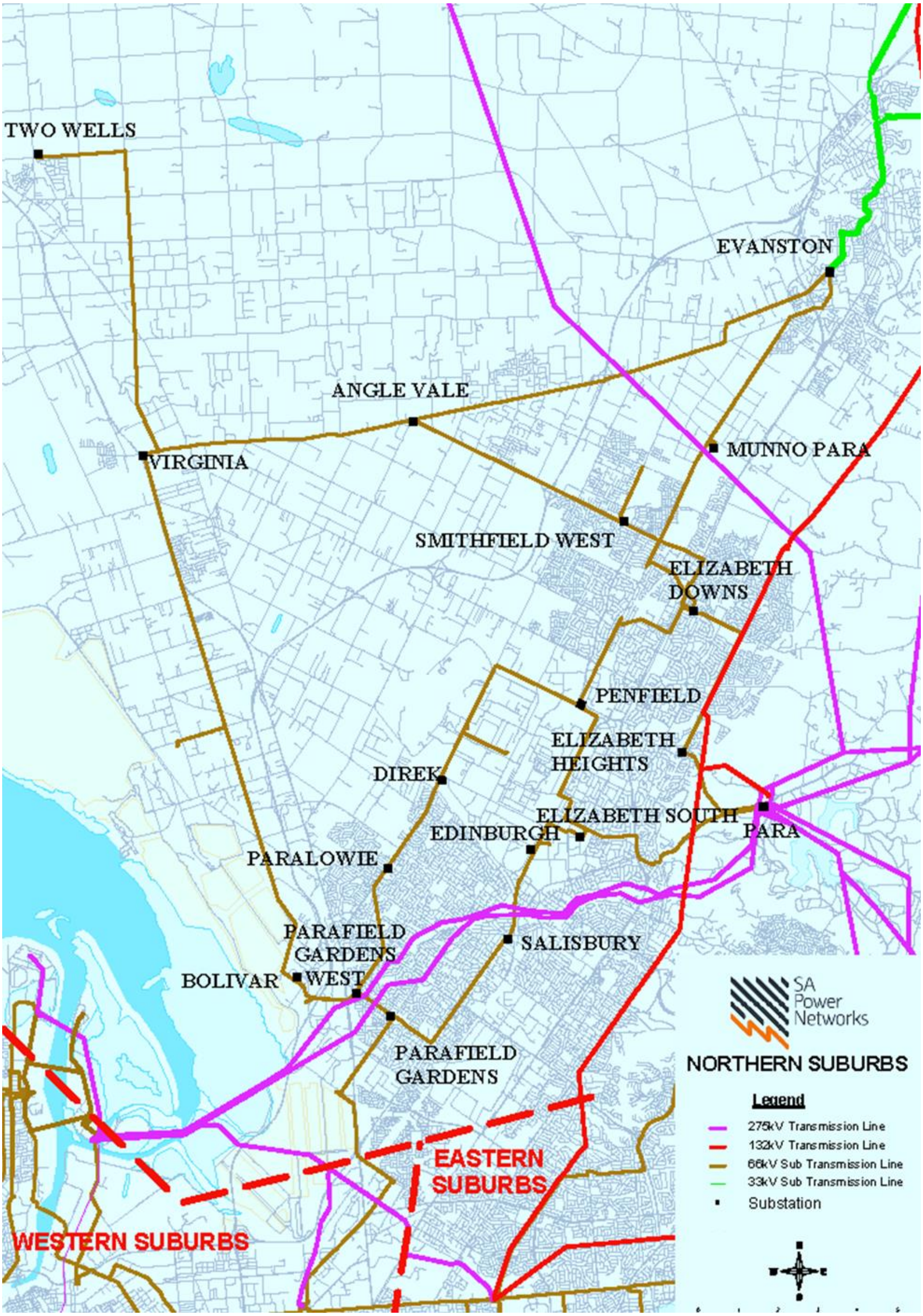
Electricity is supplied throughout the region via zone substations. These substations are operated at 66,000 Volts stepped down to 11,000 Volts.

Table 55 lists SA Power Networks' Northern Suburbs zone substations with SCADA, and Figure 16 shows the extent of the Northern Suburbs region.

Table 55. Northern Suburbs SCADA Substations

Source Connection Point	Associated SCADA Substations
Northern Suburbs Meshed 66kV Network: Para Parafield Gardens West Munno Para	Angle Vale Direk Edinburgh Elizabeth Downs Elizabeth Heights Elizabeth South Evanston Parafield Gardens Paralowie Penfield Salisbury Smithfield West Virginia Two Wells

Figure 16. Northern Suburbs Regional Map



Southern Suburbs Regional Overview

The SA Power Networks Southern Suburbs region includes the region from Glenelg North to the west extending north-east to North Unley, south-west to Aldinga, and south to Willunga, from where it supplies the Fleurieu region. There are four main transmission connection points in the Southern Suburbs: City West, Magill, Morphett Vale East and Happy Valley.

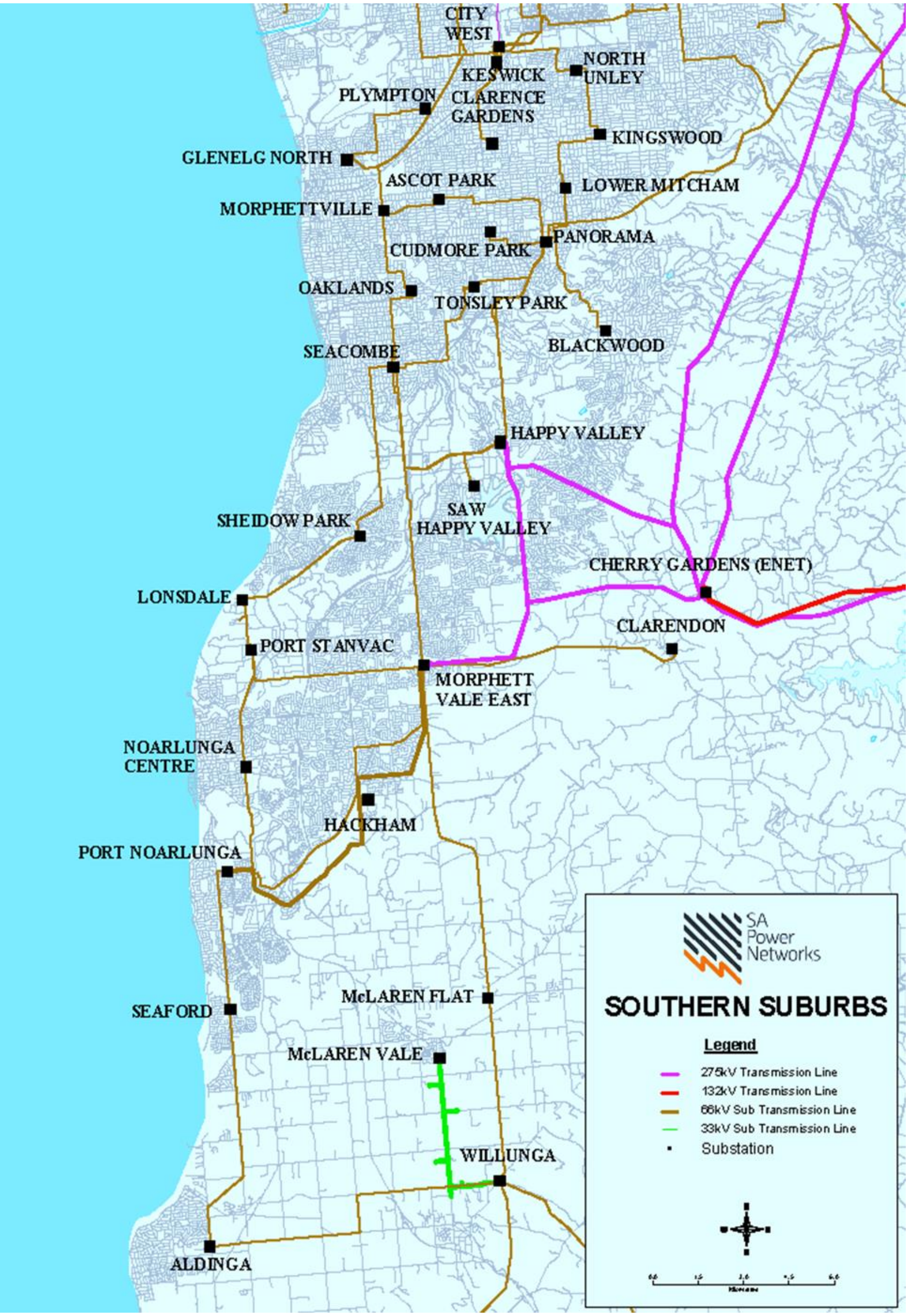
Electricity is supplied throughout the Southern Suburbs via zone substations. These zone substations are predominately operated at 66,000 Volts stepped down to 11,000 Volts. McLaren Vale is supplied at 33kV from Willunga Zone Substation.

Table 56 lists SA Power Networks' Southern Suburbs zone substations with SCADA, and Figure 17 shows the extent of the Southern Suburbs region.

Table 56. Southern Suburbs SCADA Substations

Source Connection Point	Associated SCADA Substations	
Southern Suburbs Meshed 66kV Network: City West – South Happy Valley Magill – Transformer 1 Morphett Vale East	Aldinga Ascot Park Blackwood Clarence Gardens Clarendon Cudmore Park Glenelg North Hackham Happy Valley Keswick Kingswood Lower Mitcham McLaren Flat TF1 McLaren Flat TF2 McLaren Vale	Morphett Vale East Morphettville Noarlunga Centre North Unley Oaklands Panorama Plympton Port Noarlunga Port Stanvac Seacombe Seaford Sheidow Park Tonsley Park Willunga 33kV Willunga 11kV

Figure 17. Southern Suburbs Regional Map



Adelaide Central Region (Central Business District) Overview

SA Power Networks’ Adelaide Central Region (ACR) includes the area east of West Terrace, north of South Terrace, west of East Terrace, and south of the River Torrens and contains the Adelaide CBD.

The ACR is meshed within the Eastern Suburbs sub-transmission network system, supplied via East Terrace and City West transmission connection points, with other sub-transmission lines supplying the ACR from the Magill and Northfield transmission connection points.

Electricity is supplied throughout the ACR via zone substations. These zone substations are operated at 66,000 Volts stepped down to either 11,000 Volts or 33,000 Volts.

Customers are supplied from SA Power Networks’ distribution system via 33kV and 11kV feeders. The ACR feeder system is characterised by cables installed within an extensive duct and manhole system. These feeders are extended and upgraded as required to meet customer demand and customer connection requests. Large customer projects may require a zone substation upgrade as well as feeder modifications, therefore SA Power Networks should be notified as early as possible during the planning stages of a project so that customer connection requirements can be met.

Table 57 lists SA Power Networks’ ACR zone substations with SCADA, and Figure 18 shows the extent of the ACR region.

Table 57. ACR SCADA Substations

Source Connection Point	Associated SCADA Substations
ACR Meshed 66kV Network: City West – ACR East Terrace	Coromandel Place East Terrace 11kV East Terrace 33kV Hindley Street 11kV Hindley Street 33kV Whitmore Square

Figure 18. ACR Regional Map

Barossa Regional Overview

SA Power Networks' Barossa region includes the Barossa Valley extending north to Stockwell, south to Williamstown and west to Dorrien and Lyndoch. There is one transmission connection point in the Barossa: Dorrien 132/33kV Substation.

Electricity is supplied to the various towns and localities throughout the Barossa Region via zone substations. These zone substations are operated at 33,000 Volts stepped down to 11,000 or 7,600 Volts.

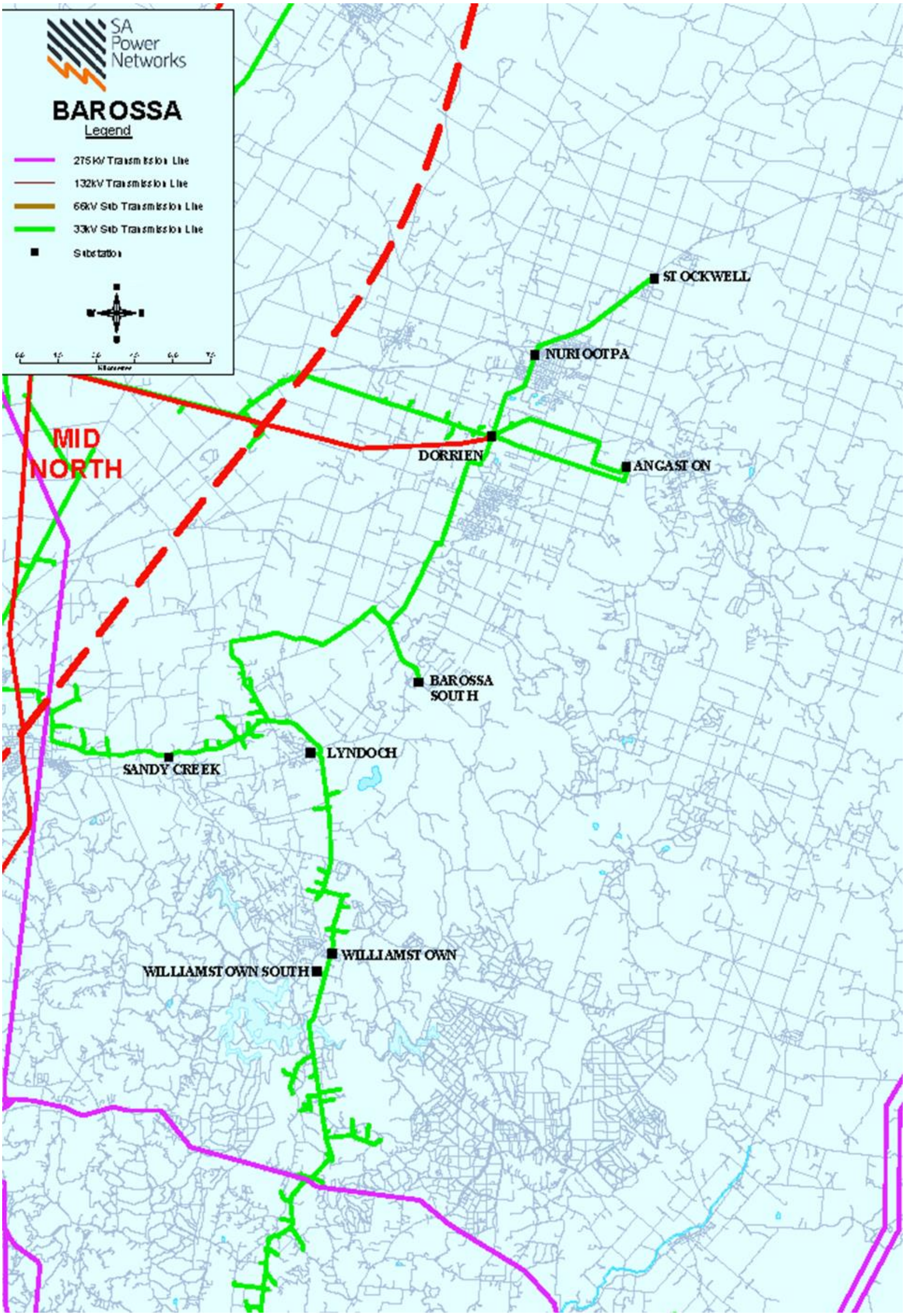
Customers are supplied from SA Power Networks' distribution system via 7.6kV and 11kV primary distribution feeders, which are connected to zone substations. These feeders are extended and upgraded as required to meet customer demand and customer connection requests. In addition, some customers are supplied from 19kV SWER systems. Large customer projects may require a zone substation upgrade as well as feeder modifications, therefore SA Power Networks should be notified as early as possible during the planning stages of a project so that customer connection requirements can be met.

Table 58 lists SA Power Networks' Barossa zone substations with SCADA, and Figure 19 shows the extent of the Barossa region.

Table 58. Barossa SCADA Substations

Source Connection Point	Associated SCADA Substations
Dorrien	Angaston Barossa South TF1 Barossa South TF2 Dorrien TF4 Dorrien TF5 Gomersal North Lyndoch Lyndoch South Nuriootpa Sandy Creek Stockwell TF1 Stockwell TF2 Williamstown Williamstown South

Figure 19. Barossa Regional Map



Eastern Hills Regional Overview

SA Power Networks' Eastern Hills region includes the region from Milang extending north to Williamstown, west to Crafers, and east to Nairne. There are three main transmission connection points in the Eastern Hills, being the meshed Mount Barker / Mount Barker South, Angas Creek, and a minor transmission connection point at Kanmantoo Copper Mine.

Electricity is supplied to the various towns and localities throughout the Eastern Hills via zone substations. These zone substations are operated at either 66,000 Volts stepped down to 11,000 Volts or 33,000 Volts stepped down to 11,000 Volts or 7,600 Volts.

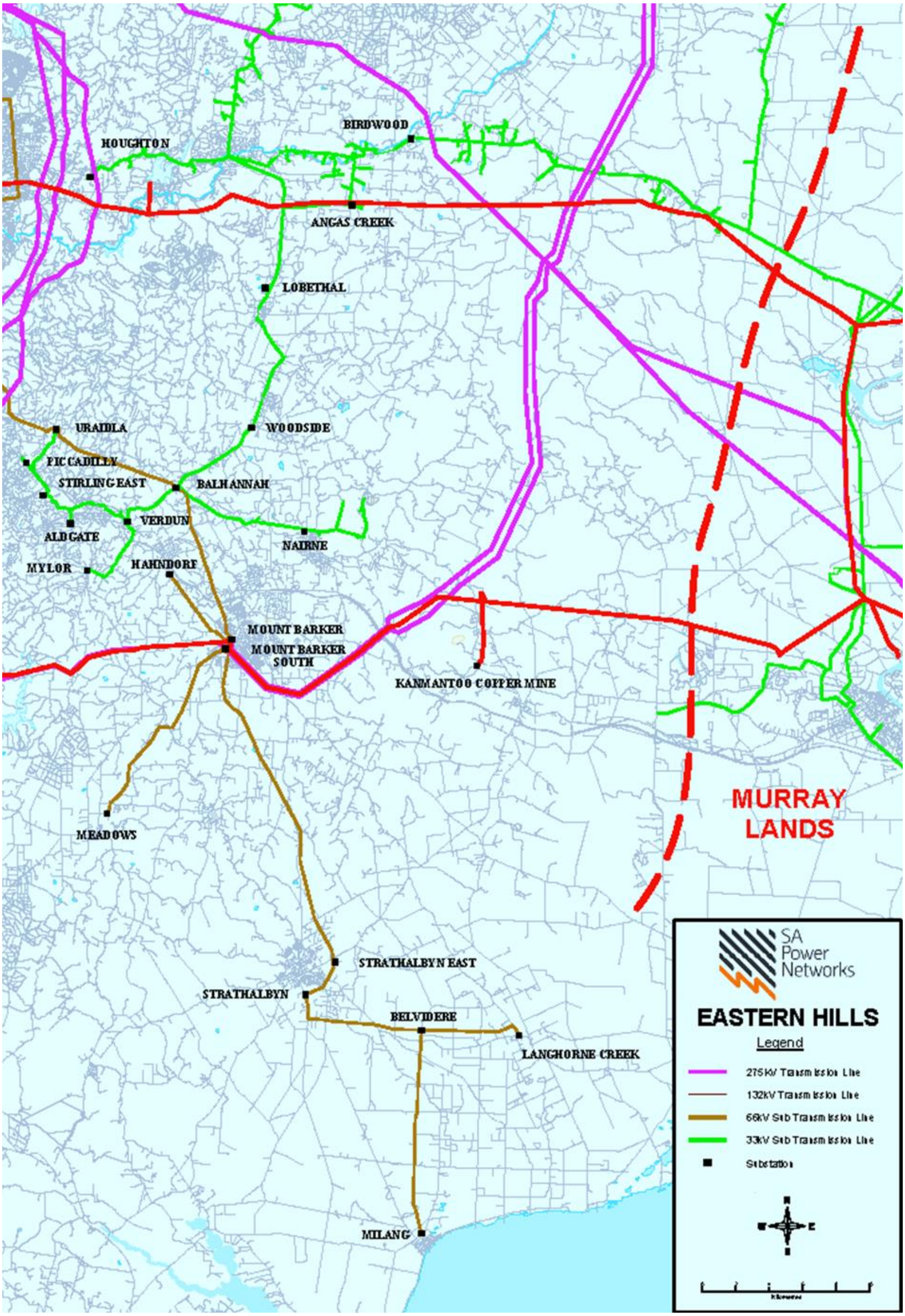
Customers are supplied from SA Power Networks' distribution system via 7.6kV and 11kV primary distribution feeders which are connected to zone substations. These feeders are extended and upgraded as required to meet customer demand and customer connection requests. In addition, some customers are supplied from 19kV SWER systems. Large customer projects may require a zone substation upgrade as well as feeder modifications, therefore SA Power Networks should be notified as early as possible during the planning stages of a project so that customer connection requirements can be met.

Table 59 lists SA Power Networks' Eastern Hills zone substations with SCADA, and Figure 20 shows the extent of the Eastern Hills region.

Table 59. Eastern Hills SCADA Substations

Source Connection Point	Associated SCADA Substations	
Angas Creek	Birdwood Chain of Ponds Forreston Hermitage Houghton Kersbrook Lobethal Mount Pleasant	
Mount Barker / Mount Barker South	Aldgate Balhannah 33kV Brukunga Hahndorf Langhorne Creek Meadows Milang Mt Barker 11kV Mylor	Nairne Piccadilly Stirling East Strathalbyn Uraidla 11kV Uraidla 33kV Verdun Woodside
Kanmantoo Copper Mine		

Figure 20. Eastern Hills Regional Map



Eyre Peninsula Regional Overview

SA Power Networks' Eyre Peninsula region includes the region south of Whyalla, and west to Ceduna. Transmission connection points are located at Port Lincoln, Whyalla, Wudinna, and Yadnarie.

Electricity is supplied to the various towns and localities throughout the Eyre Peninsula region via zone substations. These zone substations are operated at either 66,000 Volts stepped down to 11,000 Volts or 33,000 Volts stepped down to 11,000 Volts.

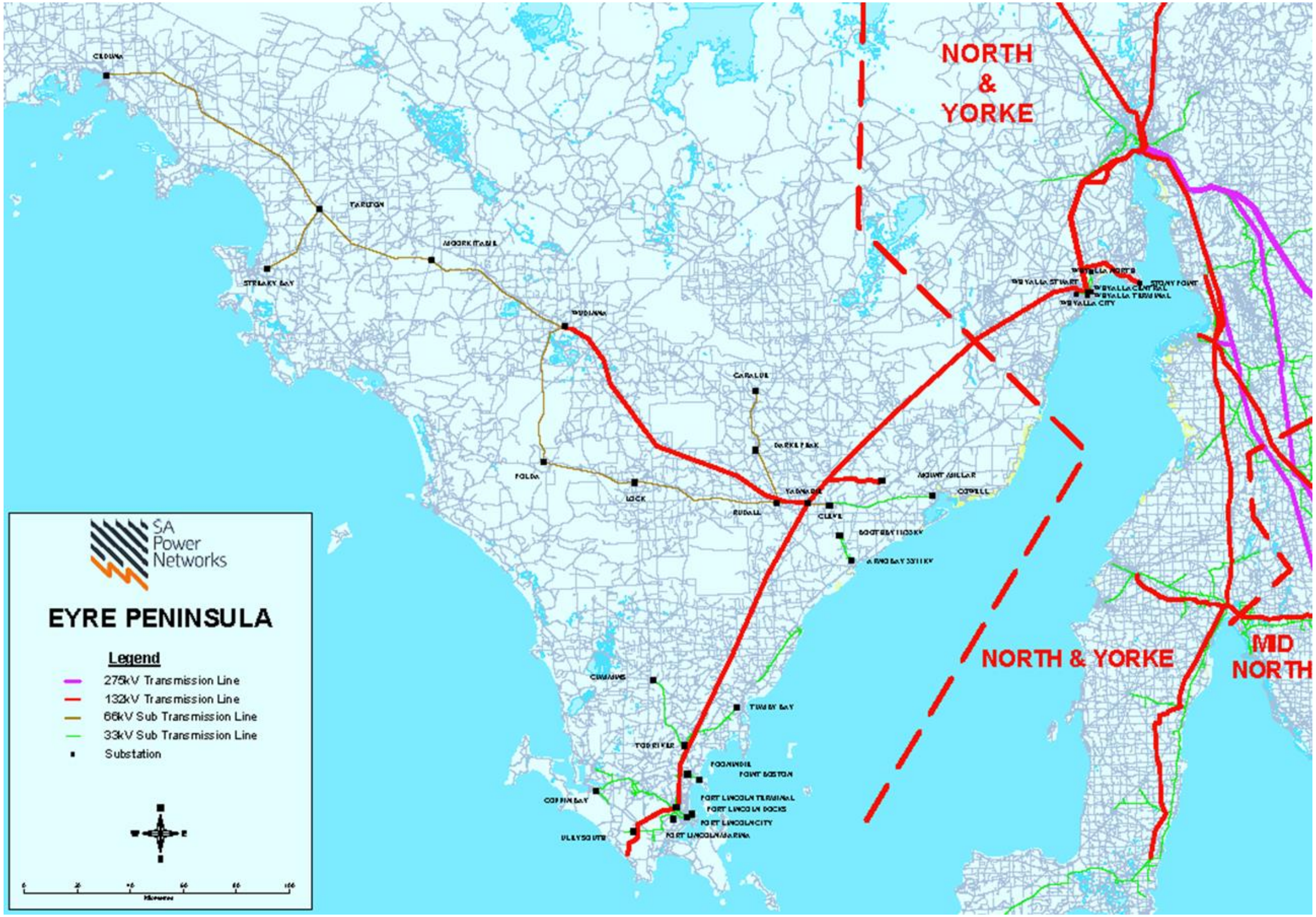
Customers are supplied from SA Power Networks' distribution system via 11kV primary distribution feeders, which are connected to zone substations. These feeders are extended and upgraded as required to meet customer demand and customer connection requests. In addition, some customers are supplied from 19kV SWER systems. Large customer projects may require a zone substation upgrade as well as feeder modifications, therefore SA Power Networks should be notified as early as possible during the planning stages of a project so that customer connection requirements can be met.

Table 60 lists SA Power Networks' Eyre Peninsula zone substations with SCADA, and Figure 21 shows the extent of the Eyre Peninsula region.

Table 60. Eyre Peninsula SCADA Substations

Source Connection Point	Associated SCADA Substation	
Port Lincoln Terminal	Coffin Bay Cummins Little Swamp Point Boston Poonindie	Port Lincoln City Port Lincoln Docks Port Lincoln Marina Tumby Bay Uley Uley South
Whyalla Central	Whyalla City Whyalla North Whyalla Stuart	
Wudinna	Ceduna Moorkitabie Polda Streaky Bay Tarlton Wudinna	
Yadnarie	Arno Bay Boothby Caralue Cleve 11kV Cleve 33kV Cowell Darke Peak Lock	

Figure 21. Eyre Peninsula Regional Map



Fleurieu Peninsula Regional Overview

SA Power Networks' Fleurieu Peninsula region includes the region south of Willunga extending south-east to Goolwa, south-west to Cape Jervis, and further south-west to Kangaroo Island. The Fleurieu Peninsula is supplied via the Southern Suburbs meshed transmission connection points.

Electricity is supplied to the various towns and localities throughout the Fleurieu Peninsula via zone substations. These zone substations are operated at either 66,000 Volts stepped down to 11,000 Volts or 33,000 Volts stepped down to 11,000 Volts.

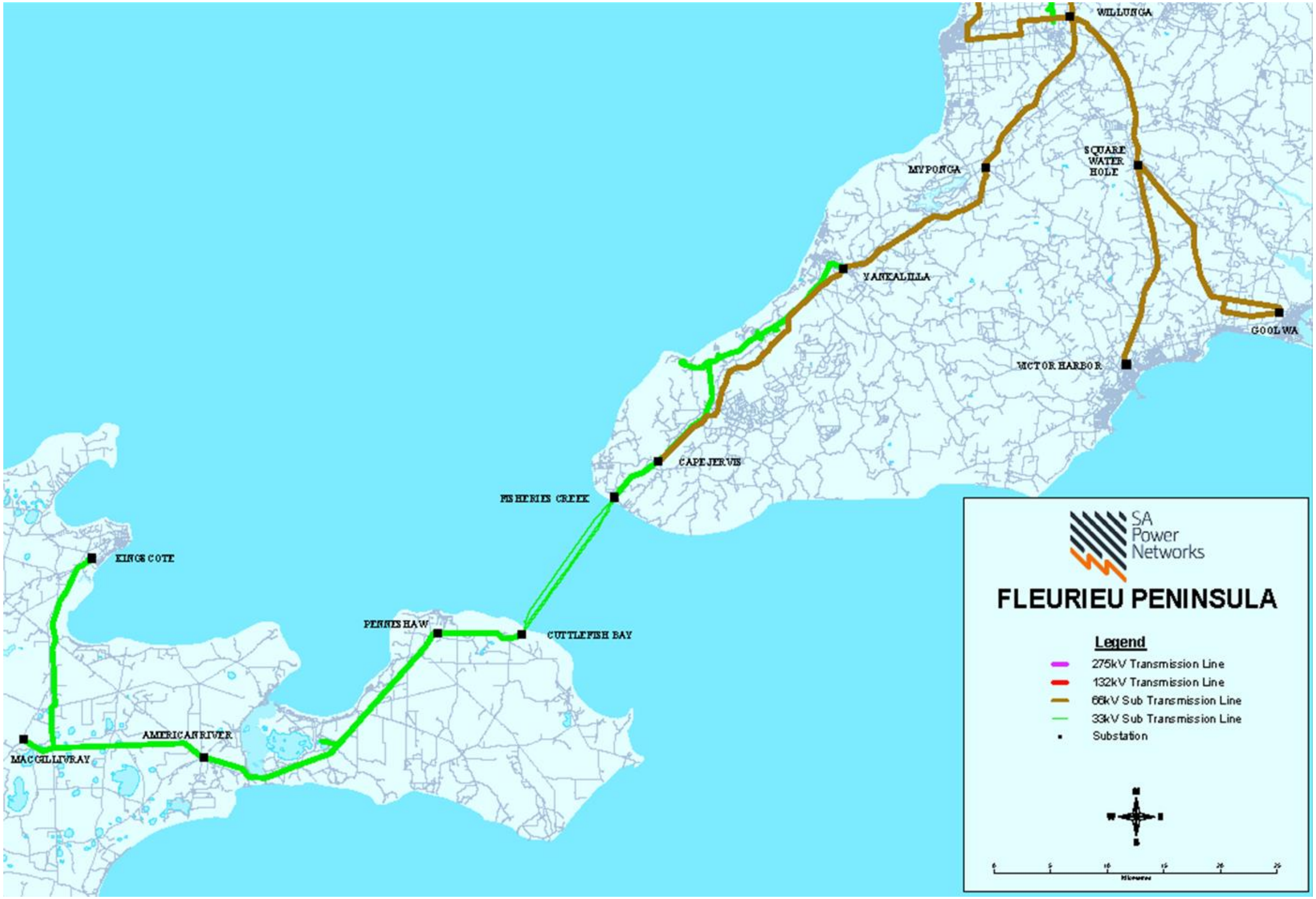
Customers are supplied from SA Power Networks' distribution system via 11kV primary distribution feeders, which are connected to zone substations. These feeders are extended and upgraded as required to meet customer demand and customer connection requests. In addition, some customers are supplied from 19kV SWER systems. Large customer projects may require a zone substation upgrade as well as feeder modifications, therefore SA Power Networks should be notified as early as possible during the planning stages of a project so that customer connection requirements can be met.

Table 61 lists SA Power Networks' Fleurieu Peninsula zone substations with SCADA, and Figure 22 shows the extent of the Fleurieu Peninsula region.

Table 61. Fleurieu Peninsula SCADA Substations

Source Connection Point	Associated SCADA Substations
Southern Suburbs Meshed 66kV Network	American River Cape Jervis 33kV Cape Jervis 11kV Goolwa Kingscote MacGillivray Myponga Penneshaw Rapid Bay Second Valley Square Water Hole Victor Harbor Yankalilla 33kV Yankalilla 11kV

Figure 22. Fleurieu Peninsula Regional Map



Mid North and Yorke Peninsula Regional Overview

SA Power Networks' Mid North and Yorke Peninsula region includes the region from Clare extending north to Wilmington, south to Mallala and the Yorke Peninsula. There are several main transmission connection points in the Mid North and Yorke Peninsula, being Dalrymple, Ardrossan West, Clare North, Hummocks, Kadina East, Brinkworth, Waterloo and Templers. A map of this region can be found in Figure 26.

Electricity is supplied to the various towns and localities throughout the Mid North and Yorke Peninsula via zone substations. These zone substations are operated at 33,000 Volts stepped down to 11,000 or 7,600 Volts.

Customers are supplied from SA Power Networks' distribution system via 7.6kV and 11kV primary distribution feeders, which emanate from the zone substations. These feeders are extended and upgraded as required to meet customer demand and customer connection requests. In addition, some customers are supplied from 19kV SWER systems. Large customer projects may require a zone substation upgrade as well as feeder modifications, therefore SA Power Networks should be notified as early as possible during the planning stages of a project so that customer connection requirements can be met.

Table 62 lists SA Power Networks' Mid North and Yorke Peninsula zone substations with SCADA, while Figure 23 shows the extent of the Mid North and Figure 24 shows the extent of the Yorke Peninsula region.

Table 62. Mid North and Yorke Peninsula SCADA Substations

Source Connection Point	Associated SCADA Substations	
Ardrossan West	Ardrossan Maitland Minlaton	Port Julia Port Vincent
Brinkworth	Brinkworth Town Collinsfield Georgetown	Hoyleton Kybunga Spalding
Clare North	Burra TF2	Clare
Dalrymple	Edithburgh Marion Bay Port Giles	Stansbury Warooka Yorketown
Hummocks	Balaklava Paskeville	Port Clinton
Kadina East	Kadina Moonta	Wallaroo
Templers	Freeling Freeling North Gawler Belt TF1 Gawler Belt TF2 Hamley Bridge	Kapunda TF1 Kapunda TF2 Mallala Wasleys
Waterloo	Auburn Eudunda Marrabel	Riverton Robertstown Waterloo Town

Figure 23. Mid North Regional Map

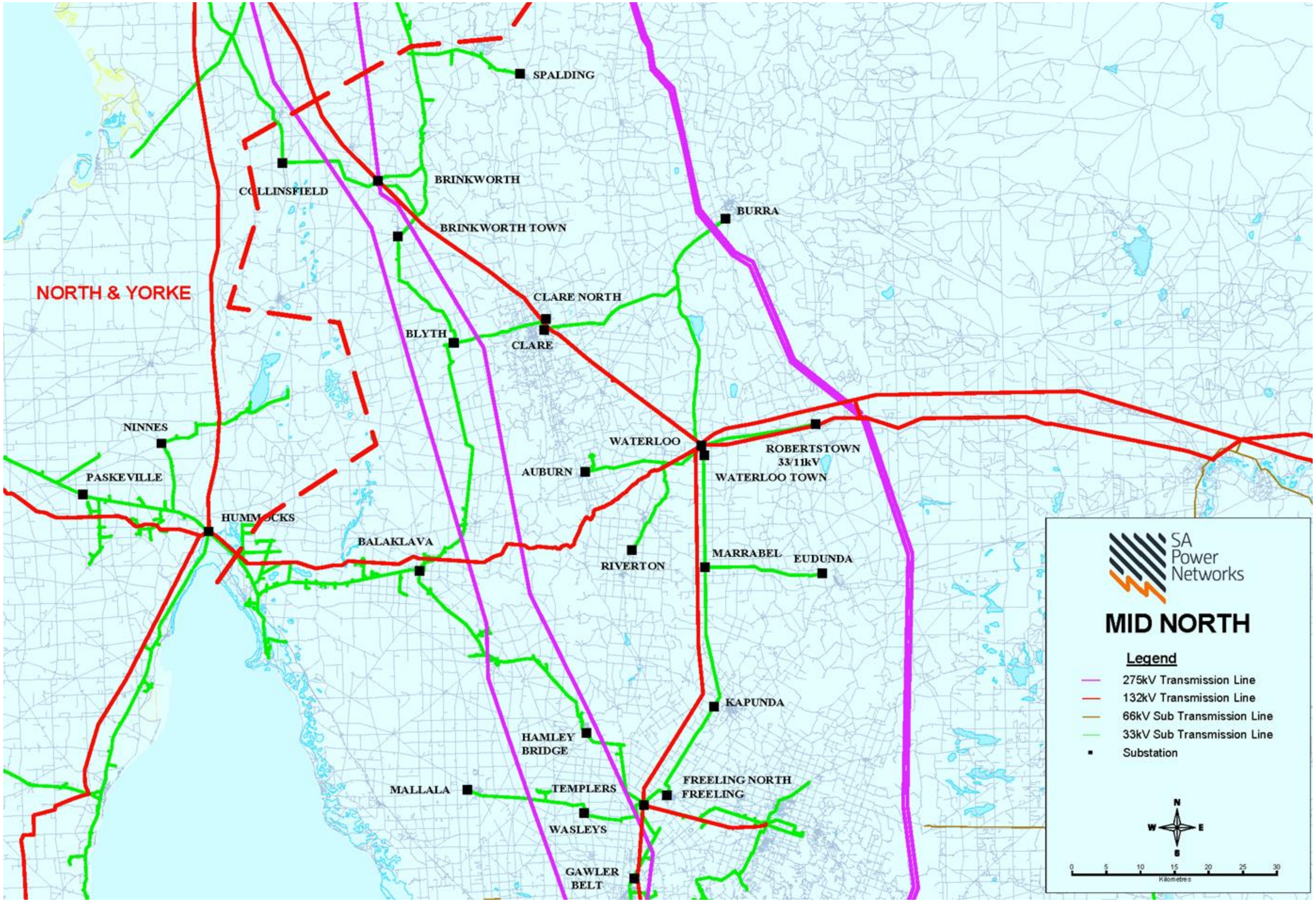
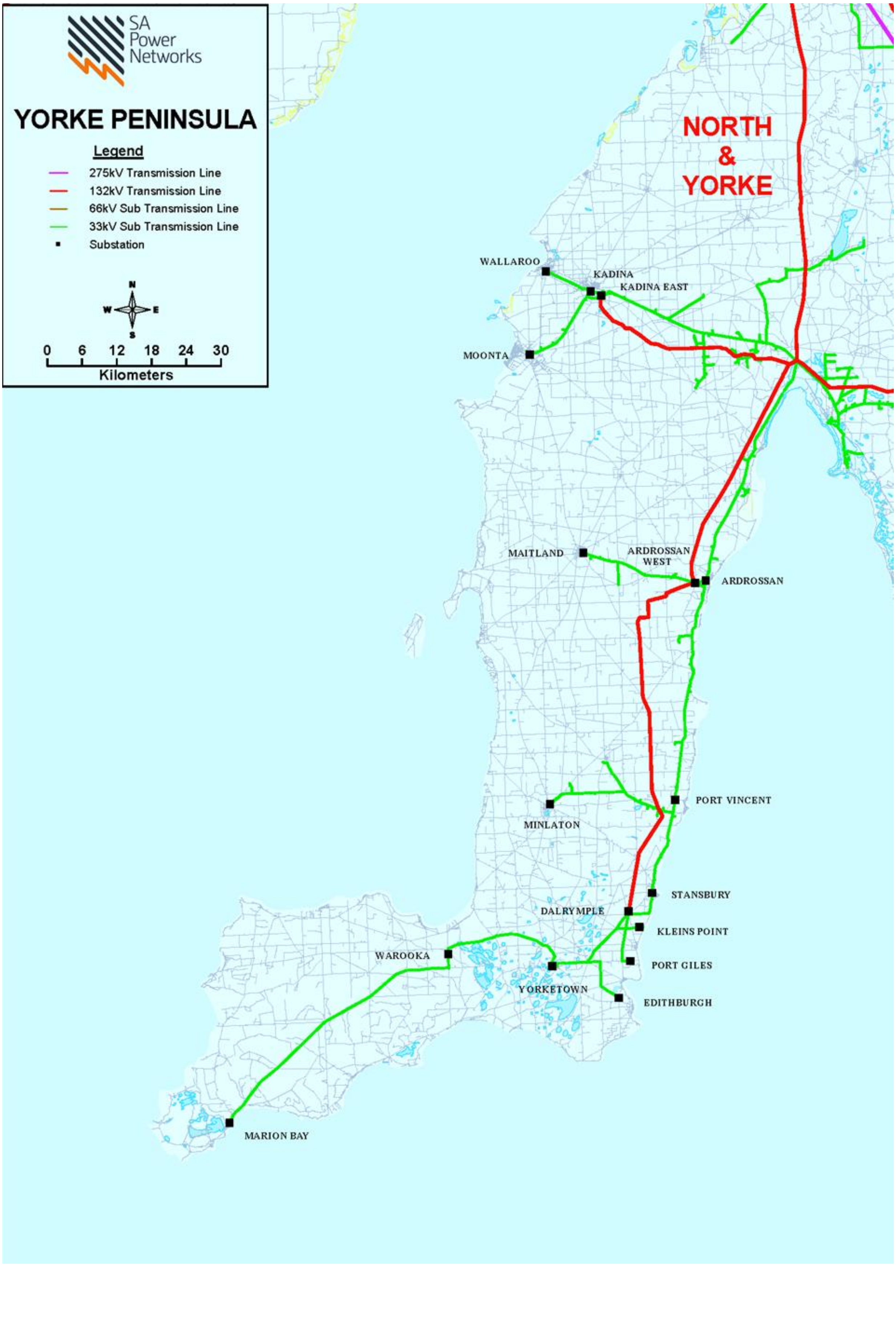


Figure 24. Yorke Peninsula Regional Map



Murraylands Regional Overview

SA Power Networks' Murraylands region includes the region from Punyelroo in the north to Coonalpyn in the south and extends eastwards to Pinnaroo and west to Narrung. There are three main transmission connection points in the Murraylands region, being Mannum, Mobilong and Tailem Bend.

Electricity is supplied to the various towns and localities throughout the Murraylands region directly from the 33kV sub-transmission network or via zone substations. These zone substations are operated at 33,000 Volts stepped down to 11,000 Volts or 7,600 Volts and are upgraded when load exceeds capacity.

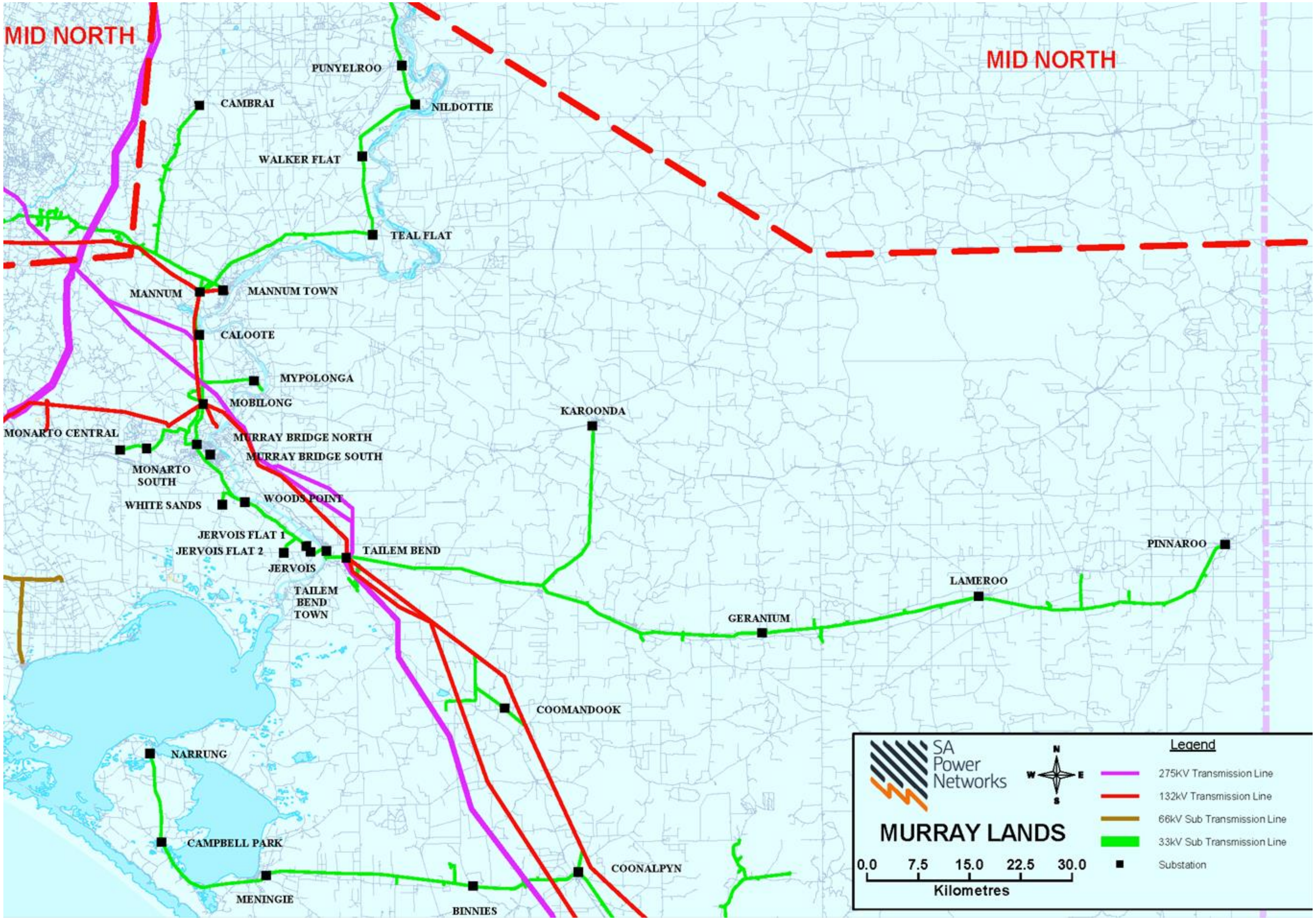
Customers are supplied from SA Power Networks' distribution system via 33kV sub-transmission lines and 7.6kV and 11kV primary distribution feeders, which emanate from zone substations. These lines and feeders are extended and upgraded as required to meet customer demand, customer connection requests and to maintain QoS. In addition, some customers are supplied from 19kV SWER systems. Large customer projects may require a zone substation upgrade as well as feeder or 33kV line modifications. Therefore, SA Power Networks should be notified as early as possible during the planning stages of a project so that customer connection requirements can be met.

Table 63 lists SA Power Networks' Murraylands zone substations with SCADA, and Figure 25 shows the extent of the Murraylands region.

Table 63. Murraylands SCADA Substations

Source Connection Point	Associated SCADA Substations	
Mannum	Belvedere Road Caloote Cambrai Mannum Town	Nildottie Punyelroo Teal Flat Walker Flat
Mobilong	Monarto Central Monarto South Murray Bridge North	Murray Bridge South Mypolonga
Tailem Bend	Binnies Campbell Park Coomandook Coonalpyn Geranium Jervois Lameroo Meningie	Narrung Parilla Pinaroo Pinaroo South Tailem Bend Town White Sands Woods Point

Figure 25. Murraylands Regional Map



Riverland Regional Overview

SA Power Networks' Riverland region includes the region from Berri extending north-west to Morgan, south-west to Swan Reach, and north-east to Renmark and Paringa. There are two main transmission connection points in the Riverland, being Berri/Monash and North West Bend.

Electricity is supplied to the various towns and localities throughout the Riverland region via zone substations. These zone substations are operated at either 66,000 Volts stepped down to 11,000 or 33,000 Volts, or 33,000 Volts stepped down to 11,000 Volts.

Customers are supplied from SA Power Networks' distribution system via 33kV and 11kV primary distribution feeders, which are connected to zone substations. These feeders are extended and upgraded as required to meet customer demand and customer connection requests. Large customer projects may require a zone substation upgrade as well as feeder modifications, therefore SA Power Networks should be notified as early as possible during the planning stages of a project so that customer connection requirements can be met.

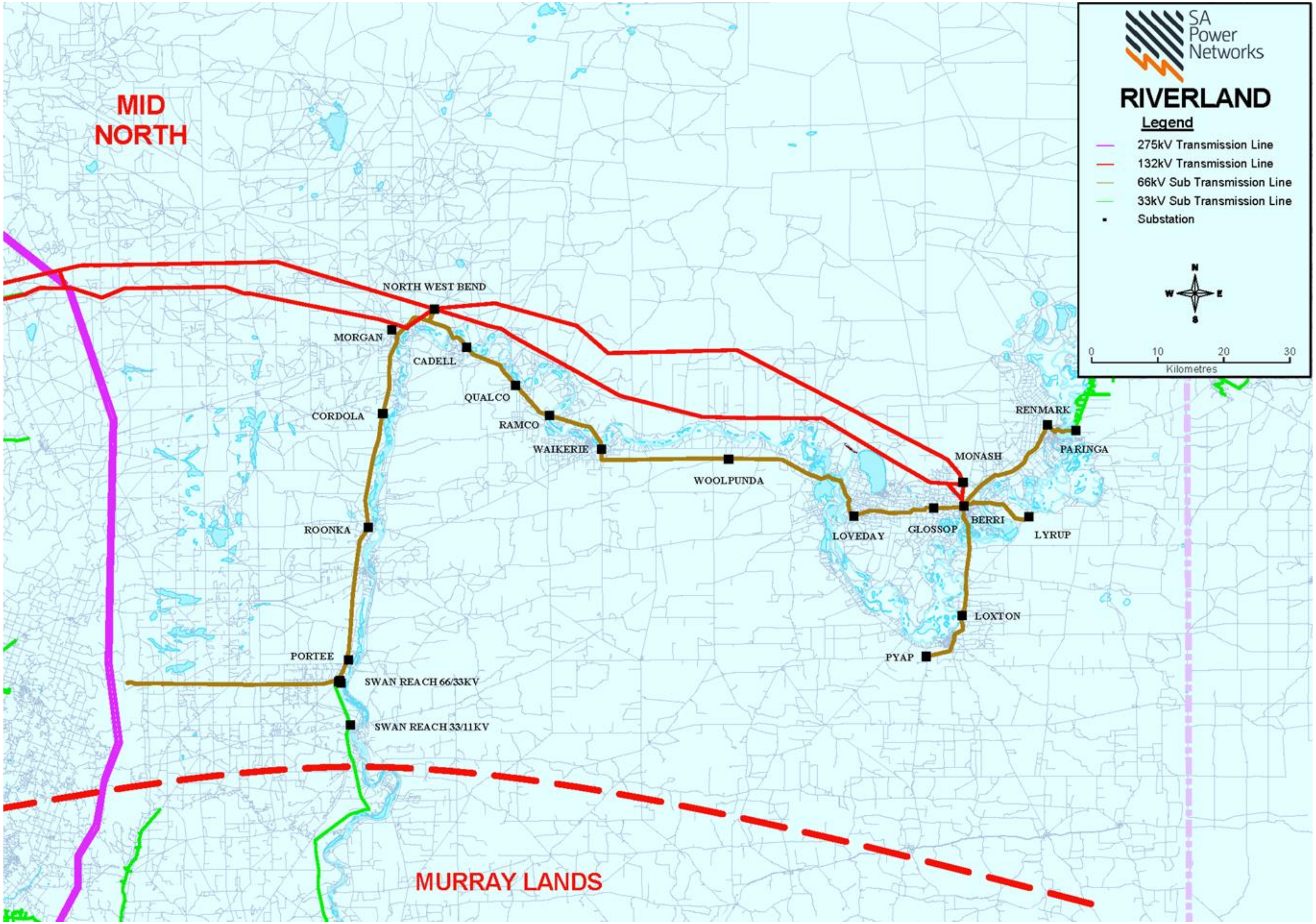
There is one system limitations forecast for substations under minimum demand conditions in the Riverland region during the next five years, refer to 6.2.1.

Table 64 lists SA Power Networks' Riverland zone substations with SCADA, and Figure 26 shows the extent of the Riverland region.

Table 64. Riverland SCADA Substations

Source Connection Point	Associated SCADA Substations
Berri / Monash	Berri Glossop Loveday Loxton Lyrup Paringa 11kV Paringa 33kV Pyap Remark Woolpunda
North West Bend	Cadell Cordola Morgan Portee Qualco Ramco Roonka Swan Reach 11kV Swan Reach 33kV Waikerie

Figure 26. Riverland Regional Map



South East Regional Overview

SA Power Networks' South East region includes the region from Tintinara in the north to Port MacDonnell in the south and extends westwards to the coast and eastwards to the Victorian border. There are six main transmission connection points in the South East, being Keith, Kincraig, Snuggery, Mount Gambier, Blanche and Penola West. A map of this region can be found at the end of this section.

Electricity is supplied to the various towns and localities throughout the South East region directly from the 33kV sub-transmission network or via zone substations. These zone substations are operated at 33,000 Volts stepped down to 11,000 Volts (7,600 Volts at Robe) and are upgraded when load exceeds capacity.

Customers are supplied from SA Power Networks' distribution system via 33kV lines and 11kV primary distribution feeders and 19kV SWER systems. These lines and feeders are extended and upgraded as required to meet customer demand, customer connection requests and to maintain QoS. Large customer projects may require a zone substation upgrade as well as 11kV feeder or 33kV line modifications.

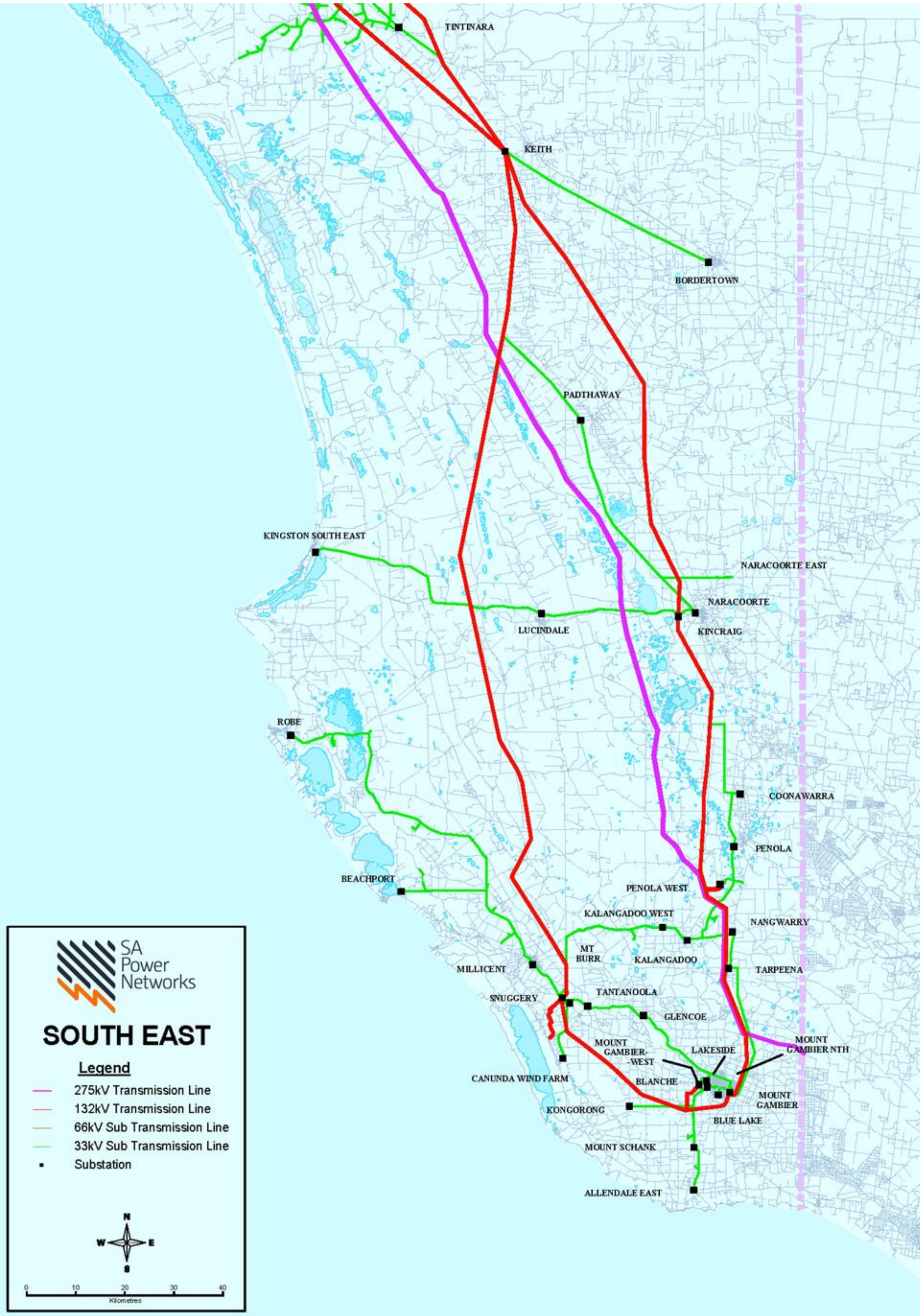
Therefore, SA Power Networks should be notified as early as possible during the planning stages of a project so that customer connection requirements can be met.

Table 65 lists SA Power Networks' South East zone substations with SCADA, and Figure 27 shows the extent of the South East region.

Table 65. South East SCADA Substations

Source Connection Point	Associated SCADA Substations	
Blanche	Allendale East Glencoe Kongorong Mount Gambier North	Mount Gambier West Mount Schank Tantanoola
Keith	Bordertown Keith 11kV	Kumorna Padthaway
Kincraig	Inverness Kingston SE Lucindale	Naracoorte Naracoorte East
Mount Gambier	Mount Gambier Tarpeena South	
Penola West	Coonawarra Nangwarry Penola	
Snuggery	Beachport Kalangadoo West Millicent	Robe South End

Figure 27. South East Regional Map



Upper North Regional Overview

SA Power Networks' Upper North region includes the Upper North areas incorporating the major towns of Port Augusta and Port Pirie. Transmission connection points are located at Baroota, Davenport West, Leigh Creek South, Mount Gunson, Neuroodla, and the meshed connection points at Bungama and Port Pirie.

Electricity is supplied to the various towns and localities throughout the Upper North Region via zone substations. These zone substations are operated at 33,000 Volts stepped down to 11,000 Volts.

Customers are supplied from SA Power Networks' distribution system via 11kV primary distribution feeders, connected to zone substations or 19kV SWER systems. These feeders are extended and upgraded as required to meet customer demand and customer connection requests. Large customer projects may require a zone substation upgrade as well as feeder modifications, therefore SA Power Networks should be notified as early as possible during the planning stages of a project so that customer connection requirements can be met.

Table 66 lists SA Power Networks' Upper North zone substations with SCADA, and Figure 28 shows the extent of the Upper North region.

Table 66. Upper North SCADA Substations

Source Connection Point	Associated SCADA Substations	
Baroota	Baroota Town Booleroo Centre Bungama-Napperby Melrose Orroroo	Port Germein Telowie Wilmington Wirrabara Forest
Davenport West	Port Augusta Port Augusta West TF1 Port Augusta West TF2	Quorn Stirling North TF1 Stirling North TF2
Leigh Creek South		
Mount Gunson		
Neuroodla	Hawker	
Port Pirie / Bungama	Caltowie Crystal Brook Gladstone Jamestown	Peterborough Port Broughton Port Pirie South Yongala

Figure 28. Upper North Regional Map