SA Power Networks

Distribution Annual Planning Report 2019/20 to 2023/24

Version control

Version	Date	Description	Approved by
0.1	Dec 2019	Final draft for review	Richard Sibly – Head of Regulation Matthew Napolitano – Manager Network Planning
1.0	Dec 2019	Final	Doug Schmidt – General Manager Regulation Mark Vincent – General Manager Network
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Executive Summary

SA Power Networks is the licenced Distribution Network Service Provider (**DNSP**) for South Australia. We value our 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 for more than 70 years, initially as part of the Electricity Trust of South Australia, and then as a stand-alone distribution business established in the late 1990s when the electricity supply industry was transformed by a new regulatory framework.

SA Power Networks is 51 percent owned by Cheung Kong Infrastructure Holdings Limited and Power Assets Holdings Limited, which form part of the Cheung Kong group of companies based in Hong Kong. The remaining 49 percent of the partnership is owned by the Spark Infrastructure group, a publicly listed infrastructure fund trading on the Australian Stock Exchange.

As the only South Australian DNSP, 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.

The electricity distribution network in South Australia covers more than 178,000km^2. We supply electricity to around 900,000 customers ranging from isolated farms in rural areas to regional and metropolitan residential homes, businesses, industry precincts and city centres.

SA Power Networks operates within the National Electricity Market (**NEM**) and is regulated by the Australian Energy Regulator (**AER**), the Essential Services Commission of South Australia (**ESCoSA**) and the South Australian Government’s Office of the Technical Regulator (**OTR**).

SA Power Networks is pleased to present its 2019/20 to 2023/24 Distribution Annual Planning Report (**DAPR**). The DAPR has been prepared by SA Power Networks to inform NEM regulators, participants and stakeholders about existing and forecast system limitations on our distribution network, and where and when they are expected to arise within the forward planning period from 2019/20 to 2023/24 and whether the AER’s Regulatory Investment Test for Distribution (**RIT-D**) process applies.

The DAPR complies with the National Electricity Rules (**NER**) clause 5.13.2. This report is published annually in accordance with clause 5.13.2(a)(2) and provides the information specified in the NER Schedule 5.8.

This DAPR includes a system limitation template for augmentation works and asset replacements where the unit cost of the asset exceeds $200,000. The system limitation template is in Excel format and has been included as Attachment B to this report.

This DAPR also provides information on our demand management initiatives, reliability and quality of supply (**QoS**) performance.

Table 1, **Table** 2 and **Table** 3 provide a summary of SA Power Networks’ forecast sub-transmission system, zone substation and distribution feeder limitations over the five-year forward planning period. Based on feedback received by SA Power Networks and for ease of use by interested parties, the load forecasts and asset ratings have been provided in Excel format and can be found in Attachment A to this report.

Table 1: Summary of sub-transmission system limitations for the forward planning period

Constrained asset	Region	Limitation	Preferred option	Status	Previous Timing	Indicative timing	Reason for Change	Document reference
DF41874 to Mallala 33kV Line	Mid North	Capacity	Uprate the 33kV line by increasing conductor clearances.	Design	-	Dec 2020	-	Page 66
Templers to Hamley Bridge 33kV Line	Mid North	Capacity	Uprate the 33kV line by increasing conductor clearances.	Investigating	-	Dec 2021	-	Page 67
Dorrien to Barossa South 33kV Line	Barossa	Reliability	Duplicate 33kV cable to Barossa South.	Investigating	-	Dec 2021	-	Page 67
Dorrien to Stockwell 33kV Line	Barossa	Reliability	Duplicate 33kV cable to Stockwell.	Investigating	-	Dec 2021	-	Page 67
Elizabeth Downs to Smithfield West 66kV Line	Metro North	Reliability	Monitor Loads over 2019/20 Summer period.	Investigating	-	-	-	Page 63
Morphett Vale East to McLaren Flat 66kV Line	Metro South	Reliability	Monitor Loads over 2019/20 Summer period.	Investigating	-	-	-	Page 64
New Osborne to Glanville 66kV Line	Metro West	Reliability	Monitor Loads over 2019/20 Summer period.	Investigating	-	-	-	Page 65
Norwood to East Terrace 66kV Line	Metro East	Reliability	Monitor Loads over 2019/20 Summer period.	Investigating	-	-	-	Page 63
Port Noarlunga to Seaford 66kV Line	Metro South	Reliability	Monitor Loads over 2019/20 Summer period.	Investigating	-	-	-	Page 63
Queenstown to Glanville 66kV Line	Metro West	Reliability	Monitor Loads over 2019/20 Summer period.	Investigating	-	-	-	Page 65

Table 2: Summary of zone substation limitations for the forward planning period

Constrained asset	Region	Limitation	Preferred option	Status	Previous Timing	Indicative timing	Reason for Change	Document reference
Clearview Substation	Metro East	N Overload	Monitor loads. Transfer load as needed.	Investigating	-	Dec 2020	-	Page 68
Meadows Substation	Eastern Hills	N Overload & Reverse N-1 Overload	Monitor loads. Transfer load as needed. Upgrade substation with x2 new 3MVA 33/11kV TF.	Investigating	-	Dec 2020 (transfers) Dec 2021 (upgrade)	-	Page 68
Verdun Substation	Eastern Hills	N Overload	Monitor loads. Transfer load as needed.	Investigating	-	Dec 2020	-	Page 68
Deloraine Substation	Eastern Hills	N Overload	Monitor loads. Transfer load as needed. Upgrade substation with a new 1MVA 33/11kV TF.	Investigating	-	Dec 2020 (transfers) Dec 2021 (upgrade)	-	Page 68
Gumeracha Substation	Eastern Hills	N Overload	Upgrade substation with a new 0.5MVA 33/11kV TF.	Investigating	Dec 2018	Dec 2021	Forecast based on 3 yearly data logging (peak). Upgrade timing to be determined with more accurate data post Summer 2019/20 peak demand data capture.	Page 68
Mount Pleasant Substation	Eastern Hills	N Overload	Monitor loads. Transfer load as needed. Upgrade substation with a new 3MVA 33/11kV TF.	Investigating	-	Dec 2020 (transfers) Dec 2021 (upgrade)	-	Page 68
Moonta Substation	Yorke Peninsula	N-1 Overload	Monitor loads. Add TF fans to increase rating.	Investigating	-	Dec 2020	-	Page 69

Mount Gambier North	South East	N-1 Overload	Monitor loads. Manage constraint with large mobile sub.	Investigating	-	Dec 2023	-	Page 70
Nuriootpa	Barossa Valley	N-1 Overload	Upgrade existing feeder tie on Nuriootpa East 11kV feeder.	Design	-	Dec 2020	-	Page 70
Ceduna Substation	Eyre Peninsula	Reverse N-1 Overload	Monitor loads. Implement changes to export limits on controllable embedded generation.	Investigating	-	2019/20	-	Page 68
Glossop Substation	Riverland	Reverse N-1 Overload	Monitor loads. Implement changes to export limits on controllable embedded generation.	Investigating	-	2019/20	-	Page 68
Loveday Substation	Riverload	Reverse N-1 Overload	Monitor loads. Implement changes to export limits on controllable embedded generation.	Investigating	-	2019/20	-	Page 68
Lyrup Substation	Riverland	Reverse N-1 Overload	Monitor loads. Implement changes to export limits on controllable embedded generation.	Investigating	-	2019/20	-	Page 68
Roonka Substation*	Riverland	Reverse N-1 Overload	Monitor loads. Implement changes to export limits on controllable embedded generation.	Investigating	-	2019/20	-	Page 68
Streaky Bay Substation	Eyre Peninsula	Reverse N & Reverse N-1 Overload	Monitor loads. Implement changes to export limits on controllable embedded generation.	Investigating	-	2019/20	-	Page 68
Sheidow Park Substation	Metro South	Reverse N-1 Overload	Monitor loads. Implement changes to export limits on controllable embedded generation.	Investigating	-	2020/21	-	Page 68
Naracoorte Substation	South East	Reverse N-1 Overload	Monitor loads. Implement changes to export limits on controllable embedded generation.	Investigating	-	2019/20	-	Page 68

N = The capacity of the power system in normal configuration with all items of plant in service.

N-1 = The total capacity of the power system with one major item of plant out of service (a "single contingent event").

Table 3: Summary of distribution feeder limitations for the next two years

Constrained asset	Region	Limitation	Preferred option	Status	Previous timing	Indicative timing	Reason for change	Document reference
Rostrevor 11kV Feeder	Metro East	N Overload	New feeder exit and transfer loads.	Design	Dec 2019	Dec 2020	-	Page 71
Sellicks Beach 11kV	Metro South	N-1 Overload	Construct new 11kV feeder tie	Investigating	-	Dec 2020	-	Page 72
Uley Road 11kV	Metro North	N Overload	Monitor loads. Transfer load as needed.	Investigating	-	-	-	Page 71
North 11kV	Eyre Peninsula	N Overload	Monitor loads. Transfer load as needed.	Investigating	-	-	-	Page 71
Risdon Park 11kV	Upper North	N Overload	Monitor loads. Transfer load as needed.	Investigating	-	-	-	Page 71
Loxton West 11kV	Riverlands	N Overload	Monitor loads. Transfer load as needed.	Investigating	-	-	-	Page 71

Shortened forms

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
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
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 point upgrades
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
DAC	The South Australian Government's Development Assessment Commission
DAPR	Distribution Annual Planning Report
DER	Distributed Energy Resources, (eg solar PV systems, batteries).
Distribution Network	Has the meaning defined within Chapter 10 of the NER
DNSP	Distribution Network Service Provider as defined in Chapter 10 of the NER
Distribution System	Has the meaning defined within 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

Abbreviation	Definition or description
DSED	Demand Side Engagement Document
EDC	Electricity Distribution Code as published by ESCoSA
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
ETC	Electricity Transmission Code as published by ESCoSA
Firm Delivery Capacity	The maximum allowable capacity of a zone substation or distribution line under single contingency conditions, including any short term overload capacity
FPAR	Final Project Assessment Report. A report we prepare and publish in accordance with NER clause 5.17.4(o) – (s)
HBFRA	High Bushfire Risk Area
HV	High Voltage. A voltage greater than 1000V
kV	kilo-Volt (= 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).

Abbreviation	Definition or description
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. Copies of the NER can be obtained from the AEMC website.
NERL	National Energy Retail Law
NERR	National Energy Retail Rules
Non-Network Options Report (NNOR)	This is the term used in the NER to describe a 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
OLTC	On-Load Tap Changer on power transformers
OTR	The South Australian Government's 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
RSS	Reliability Service Standard
RIT-D	Regulatory Investment Test – Distribution

Abbreviation	Definition or description
RIT-T	Regulatory Investment Test – Transmission
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
SCADA	Supervisory Control and Data Acquisition. A technology enabling remote control and real-time monitoring of devices connected to the distribution network
SRMTMP	Safety, Reliability, Maintenance and Technical Management Plan
SSF	The Service Standard Framework established by ESCoSA
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 system 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

Abbreviation	Definition or description
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

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- A-1 10% PoE substation load forecast
- A-2 50% PoE substation load forecast
- A-3 33kV sub-transmission line forecast
- A-4 66kV metro sub-transmission line forecast
- A-5 66kV rural sub-transmission line forecast
- A-6 Substation Minimum Load Forecast

Attachment B – System limitation templates
- B-1 2019 system limitation templates
- B-2 2021 system limitation templates
- B-3 2022 system limitation templates
- B-4 2023 system limitation templates

Attachment C – Projects with changed dates

1. Introduction

SA Power Networks is the licensed DNSP in South Australia. We recognise that electricity is an essential service for our community and we understand the responsibility we hold in the delivery of our services to all South Australians.

SA Power Networks has a proud history of providing cost-efficient, safe and reliable electricity supply to around 900,000 customers. Recent benchmarking data gathered across the industry by the AER shows that, in addition to our network being one of the most reliable, we continue to be the most efficient distributor in the NEM on a state-wide basis.

The economic regulation of SA Power Networks is undertaken by the AER. In undertaking this role, the AER is required to do so in a manner that will or is likely to contribute to the achievement of the National Electricity Objective (**NEO**) as stated in Section 7 of the National Electricity Law (**NEL**).

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

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

This DAPR explains how SA Power Networks has developed prudent investment plans in order to maintain our required reliability and QoS performance targets whilst ensuring the safety of the public and our employees by managing the demands on, and risks associated with, an ageing electricity network.

When developing our plans we are cognisant that the electricity industry is in transition, and South Australia is at the forefront of change. Rooftop solar penetration in South Australia, already the highest in the world at more than 30% of customer and business premises, continues to increase, and the battery storage market is beginning to accelerate as prices to adopt this technology fall faster than expected. Government, the Australian Energy Market Operator (**AEMO**) and the wider energy industry are grappling with the challenge of integrating these emerging technologies within existing networks whilst maintaining stability and security of supply as traditional baseload generation sources are displaced by intermittent renewable energy sources. New energy products and services are emerging to service customers seeking empowerment in the face of rising prices. The global transition to electric vehicles (**EV**) is well underway, with Australia's EV market poised to develop in the next five years.

The take up of Distributed Energy Resources (**DER**) at the levels forecast by the Commonwealth Scientific and Industrial Research Organisation (**CSIRO**) will have material impacts on distribution networks which were not built for two-way flows of energy. In South Australia, these issues are anticipated to arise in advance of the rest of the country, with AEMO forecasting that from as early as 2024 (previously 2026), the State's total demand could be met entirely by rooftop photo voltaic (**PV**) systems during low demand periods. Reverse flows are already being experienced at some of SA Power Networks' zone substations. This will continue to emerge and become more widespread across South Australia by 2020.

This DAPR sets out the results of SA Power Networks' planning activities as required by the NER. It includes load forecasts and emerging network limitations (both demand related or as a result of an asset retirement), for the purposes of market consultations. This DAPR also includes, for the first time, information on our replacement projects and programs for the forthcoming planning period.

Where system limitations are identified in the forward planning period, details of these limitations are summarised, including the extent and timing of the limitation, as well as potential solutions to address the identified system limitations. A system limitation template developed by the AER is included as an Attachment to this DAPR. The template is in Excel format for ease of data management.

For projects exceeding $6 million, SA Power Networks is required by the NER to undertake the RIT-D process which has now been extended to include asset replacement projects. The RIT-D process invites proponents with potential alternative non-network solutions to provide submissions. In the five-year forward planning period we foresee two projects that will require a RIT-D consultation:

- Myponga to Square Waterhole 66kV sub-transmission line; and
- Northfield 66kV Gas Insulated Switchgear replacement.

Further details of how SA Power Networks' will engage with third parties who may propose to connect a generator to our network or provide Network System Support Services can be found in our Demand Side Engagement Document (**DSED**) via the following link:

http://www.sapowernetworks.com.au/centric/industry/our_network/annual_network_plans/demand_side_engagement_document.jsp

Future (non-committed) augmentations due to large customer load or generator connections are not included in this report. Network augmentation and any associated RIT-D required for such projects will be managed in accordance with the NER and assessed on a case-by-case basis.

1.1 Purpose of this 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 SA Power Networks' website in accordance with clause 5.13.2(a)(2) and provides the information specified in NER Schedule 5.8.

The DAPR has been prepared by SA Power Networks to inform NEM regulators, participants and stakeholders about existing and forecast system limitations on our distribution network, and where and when they are expected to arise within the forward planning period from 2019/20 to 2023/24 and whether the AER's Regulatory Investment Test for Distribution (**RIT-D**) process applies.

The DAPR complies with the National Electricity Rules (**NER**) clause 5.13.2. This report is published annually in accordance with clause 5.13.2(a)(2) and provides the information specified in the NER Schedule 5.8.

This report also provides information on our annual replacement programs and projects in accordance with NER S5.8(b1) and (b2).

1.2 Structure of this report

This DAPR has been structured to enable compliance with the specific requirements of the NER Schedule 5.8. The substantive sections of this DAPR are set out in Table 4 below.

Table 4: Structure of SA Power Networks' 2019 DAPR

Section		Purpose
Executive summary		Provides an introduction and a summary table of the DAPR outcomes
Shortened forms		Provides a description of shortened forms used within the DAPR
1	Introduction	Introduces the DAPR and explains the purpose and structure of the report
2	SA Power Networks overview	Provides a corporate overview of SA Power Networks, our regulatory framework, a summary of our distribution network and the environment in which we operate. This section also explains how we have prepared this DAPR and summarises the material changes from our 2019/20 – 2023/24 DAPR
3	Forecasts for the forward planning period	Sets out our load forecast methodologies for each transmission – distribution connection point, sub-transmission lines and zone substations. It also details our reliability performance and other factors that impact on our network. Load forecast data is now located in Attachment A
4	Network asset retirements that result in a system limitation	Provides details of our asset replacement (retirement) protects and programs
5	System limitations resulting from asset de-ratings	Sets out system limitations resulting from asset de-ratings
6	System limitations for sub-transmission lines and zone substations	Sets out SA Power Networks' forecast system limitations for our sub-transmission lines and zone substations
7	Overloaded primary distribution feeders	Summarises our overloaded primary distribution feeders (location and PoE), and the potential solutions to address the overload
8	RIT-D for distribution projects	Provides details of our preceding year, current and future RIT-Ds
9	Committed investments	Provides information on committed investments (exceeding $2 million) in the forward planning period to address an urgent and unforeseen network issue
10	Joint planning undertaken with ElectraNet	Provides details of ElectraNet's and SA Power Networks' joint planning outcomes
11	Joint planning undertaken with other DNSPs	Provides details of SA Power Networks' joint planning outcomes with other DNSPs
12	Performance of our network	Summarises our reliability, QoS and STPIS performance with respect to the measures and standards applicable to SA Power Networks, and any corrective actions that may be required
13	Asset management approach	Outlines our asset management approach and strategies, how we manage distribution losses and any other asset management issues that may impact system limitations

Section		Purpose
14	Demand management activities	Provides details of demand management options that have been considered, future demand management options, key issues arising from applications to connect embedded generators and a quantitative summary of demand management connection enquiries
15	IT systems and communications investment	Provides a high level summary of IT systems and communications investments that were undertaken in the preceding year and planned investments for the forward planning period
16	Regional development plans	Provides a summary of our 14 regional development plans and where relevant, the details of system constraints and the corresponding network map
Appendix 1 - Contacts		Provides contact details for further information
Appendix 2 – Compliance statement		A detailed compliance matrix that sets out the relevant Rules and where we have specifically addressed these Rules in the DAPR
Attachment A – Load forecast (excel format)		Load forecast data for connection points, sub-transmission and zone substations
Attachment B – System limitation templates (excel format)		System limitation templates for augmentation and asset replacement projects
Attachment C – Projects with changed dates (excel format)		List of projects that have changed implementation dates

2. SA Power Networks overview

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. It has proudly served South Australians for more than 70 years, initially as part of the Electricity Trust of South Australia, and then as a stand-alone distribution business established in the late 1990s 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.

In general, the distribution system connects to 275kV and 132kV transmission connection points supplied by ElectraNet. SA Power Networks' assets include 66kV and 33kV sub-transmission lines, zone substations, primary distribution feeders, distribution substations (street transformers), low voltage (430V/230V) circuits and services to customers.

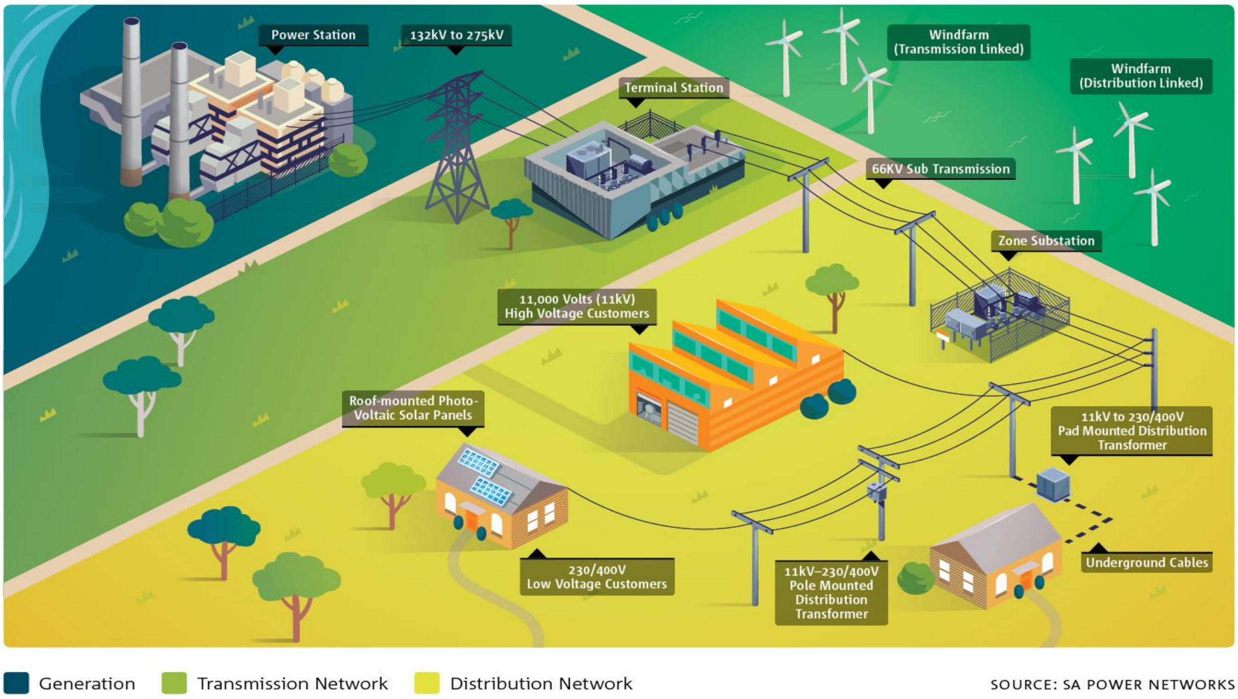


Figure 1: The South Australian electricity supply chain

2.1 Corporate overview

SA Power Networks is a limited liability partnership which is 51 percent owned by Cheung Kong Infrastructure Holdings Limited and Power Assets Holdings Limited, which form part of the Cheung Kong group of companies based in Hong Kong. The remaining 49 percent of the partnership is owned by the Spark Infrastructure group, a publicly listed infrastructure fund trading on the Australian Stock Exchange.

2.2 Our statutory and regulatory framework

SA Power Networks is a DNSP which operates within the NEM. We are governed by a number of agencies at the National and State levels as shown in Figure 2 below.

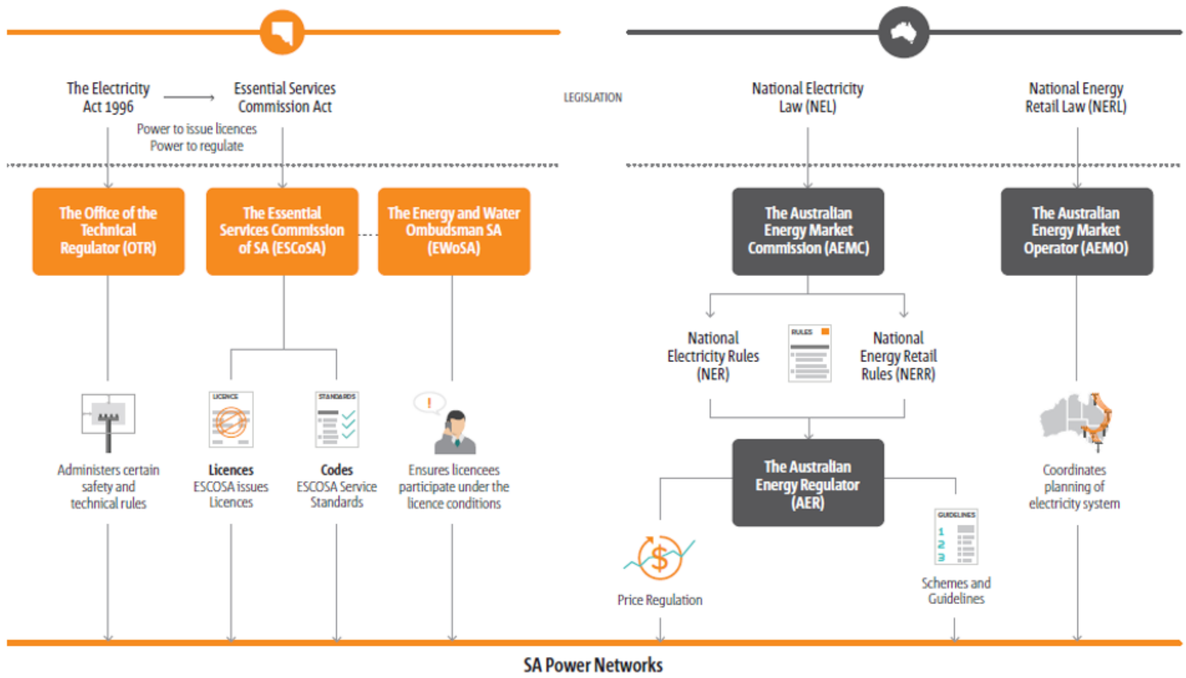


Figure 2: SA Power Networks' regulatory framework

The economic regulation of SA Power Networks is undertaken by the AER. In undertaking this role, the AER is required to do so in a manner that will or is likely to contribute to the achievement of the NEO as stated in Section 7 of the NEL.

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

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

The State-based regulator, ESCoSA, retains responsibility for setting service levels, whilst the OTR is responsible for setting and overseeing the safety and technical regulation of the energy industry in South Australia.

We operate within a comprehensive regulatory framework which includes:

- the National Electricity (South Australia) Act 1996, encompassing the NEL which sets out the key regulatory institutions of the NEM and establishes the NEO;
- the NER which govern the operation of the NEM, and provide the regulatory framework for power system security, network connections and access, and pricing for network services. The NER has the force of law, and is made under the NEL;
- the Electricity Act 1996 which regulates the electricity supply industry in South Australia, requires ESCoSA to license distribution network operators in South Australia, and stipulates safety and technical standards for electricity infrastructure and electrical installations

including the preparation of and compliance with a Safety, Reliability, Maintenance and Technical Management Plan (**SRMTMP**);

- the Electricity (General) Regulations 2012, which supports the Electricity Act, and prescribe a range of safety and technical requirements in relation to electricity infrastructure and electrical installations;
- the Electricity (Principles of Vegetation Clearance) Regulations, which supports the Electricity Act, and prescribe requirements upon SA Power Networks to inspect and clear vegetation from around power lines;
- the Australian Energy Market Agreement (**AEMA**) which provides for State and Territory Governments to retain responsibility for developing jurisdictional reliability standards to ensure network security and reliability. In South Australia, ESCoSA sets jurisdictional reliability standards and customer service standards;
- our Distribution Licence (**Licence**) which requires us to comply with all applicable regulatory instruments, including any technical or safety requirements under the Electricity Act, and to prepare and comply with a SRMTMP, which lays out the safety and technical compliance management framework agreed between the OTR and SA Power Networks, and which must be approved by the OTR;
- the Electricity Distribution Code (the **EDC**) which prescribes the jurisdictional reliability and service standards, and the connection of embedded generators;
- the Electricity Transmission Code (**ETC**) which establishes the standards of security which ElectraNet must meet in providing transmission services in South Australia. Changes to the ETC's standards at a connection point may result in flow-on requirements upon the downstream distribution system; and
- the National Energy Retail Law (South Australia) Act 2011, encompassing the National Energy Retail Law (**NERL**) and National Energy Retail Rules (**NERR**) which establishes a National Energy Customer Framework (**NECF**) for the regulation of the retail supply of energy to customers, and makes provision for the relationship between the distributors and consumers of energy.

2.3 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. The network extends across difficult and remote terrain and operates in demanding conditions and stretches for over 82,000km, and includes over 400 zone substations, 77,800 street transformers, more than 640,000 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.

We supply electricity to around 900,000 customers ranging from isolated farms in rural areas to industry precincts, regional and metropolitan residential homes, businesses and city centres.

With the exception of much of the coastal area, South Australia is very sparsely settled. Approximately 70% of SA Power Networks' customers reside in major metropolitan areas, including the great majority of business and commercial customers. However, the extensive area serviced by our distribution system results in 70% of the network infrastructure (in terms of circuit length) delivering energy to the remaining 30% of customers. Compared with other states, South Australia has relatively few regional centres, and they are generally small and sparsely located. As a result, the average customer density per kilometre of distribution line in South Australia is the lowest among the NEM DNSPs.

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.

2.4 Our network operating environment

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

Environmental factors

Figure 3**Error! Reference source not found.** the e xtent of our overhead network in South Australia. The network is centred on Adelaide and supplies electricity to the south-east coastal region of South Australia and north towards inland South Australia.

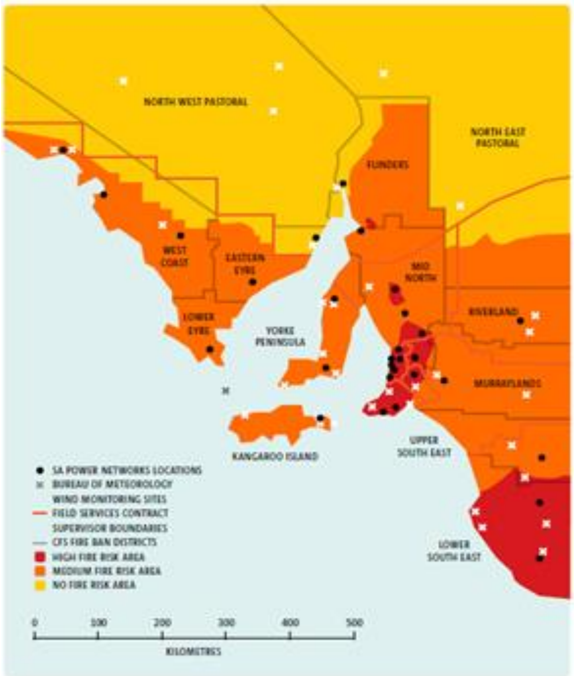
As can be seen in Figure 3, SA Power Networks' overhead power line network is predominantly situated along the coast, resulting in high exposure to a saline environment. As a consequence, corrosion of network assets is a major cause for concern to SA Power Networks. We have acknowledged the impact of corrosion on the assets in the overhead power line network, including poles and conductors, by identifying different corrosion zones within South Australia. Figure 4 details the levels and location of the atmospheric corrosion zones in South Australia.

Figure 3: SA Power Networks' service area

There are three levels of corrosion zones: low; severe; and very severe. The severe corrosion zones extend further inland due to the transfer of airborne salts by the atmosphere. Comparison of Figure 3**Error! Reference source not found.** with Figure 4 identifies that a large proportion of the distribution network is located in the severe and very severe corrosion zones.

SOURCE: SA POWER NETWORKS

Figure 4: Atmospheric corrosion zone map of South Australia



SOURCE: SA POWER NETWORKS

Figure 5: Bushfire risk areas in South Australia

South Australia has several protected natural reserves, conservation parks and forestry plantations, which our distribution network intersects. Operating the distribution network in forested areas poses the risk of bushfire. We have recognised the importance of minimising any risk associated with operating the distribution network in the protected natural environment by identifying the levels and location of bushfire prone areas. Figure 5 illustrates the three bushfire risk areas designated by SA Power Networks within South Australia.

The areas identified are high bushfire risk areas (**HBFRAs**), medium bushfire risk areas (**MBFRAs**) and non-bushfire risk areas (**NBFRAs**). HBFRAs include most of the protected natural reserves, conservation parks and forestry plantations. MBFRAs reflect the risk to developments on the fringe of dense bushland. Areas whilst NBFRAs consists of metropolitan, suburban, and country districts.

In order to effectively manage our asset portfolio, SA Power Networks specifies and considers the corrosion zone level and the bushfire risk area category for each asset in our Asset Management Database.

In managing our assets and planning our network, a number of other factors that impact on the electricity needs of South Australian business and residential customers are taken into account including:

- Changes in spatial demand and consumption diversity;
- Impacts of DER;
- Hot and dry climate;
- Severe weather events;
- Quality of supply; and
- Rapid changes in emerging technology.

These factors are explained in more detail below.

Changes in spatial demand and consumption diversity

Following a period of ever-increasing demand for electricity, most recently driven by residential air-conditioning use, maximum demand on our network peaked in 2009. Since then, demand has declined and remained relatively steady due to lower economic growth, customers adopting more energy efficient appliances and lighting and uptake of solar PV systems. Although actual global demand has been relatively stable, local spatial demand varies with reductions in some locations and increases in others as a result of localised economic and demographic changes (eg localised development).

The impact of Distributed Energy Resources

Should DER take-up at the levels forecast by the CSIRO (refer to **Figure** 6) eventuate, this will have material impacts on networks that were not designed for complex two-way flows of energy. In South Australia, these issues are anticipated to arise in advance of the rest of the country, with AEMO forecasting that from as early as 2024, the State demand could be met entirely by rooftop PV during low demand periods (ie during daytime). Increasing zone substation reverse flows will emerge across South Australia by 2020, and by 2050, distributed solar PV load flows on high voltage feeders could potentially exceed asset ratings at times of minimum demand. It should be noted that some zone substations already experience periods of export to the upstream sub-transmission network.

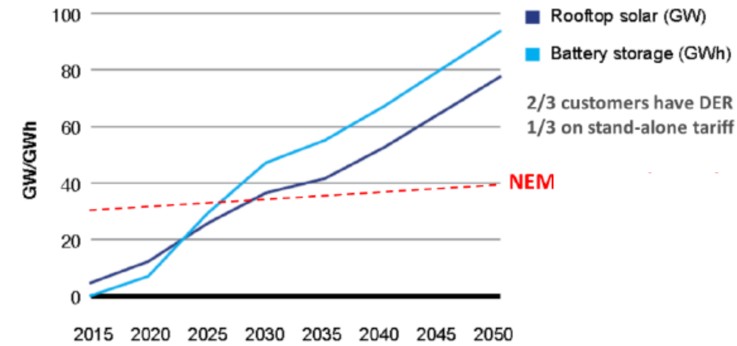


Figure 6: Forecast DER uptake in the NEM

Network impacts will arise first in the low voltage network, where the effect of increasing penetration of solar PV and other DER is to increase the dynamic range of power flows between peak demand and peak export, and the rate with which the system can swing from one end of this range to the other. This happens naturally because of the intermittent nature of solar PV, but will be exacerbated by the aggregation of customer DER into Virtual Power Plants that enable customer resources to be dispatched in a coordinated manner in response to market signals, ie orchestration. These effects are already visible in data from our Salisbury battery trial, as can be seen in **Figure** 7.

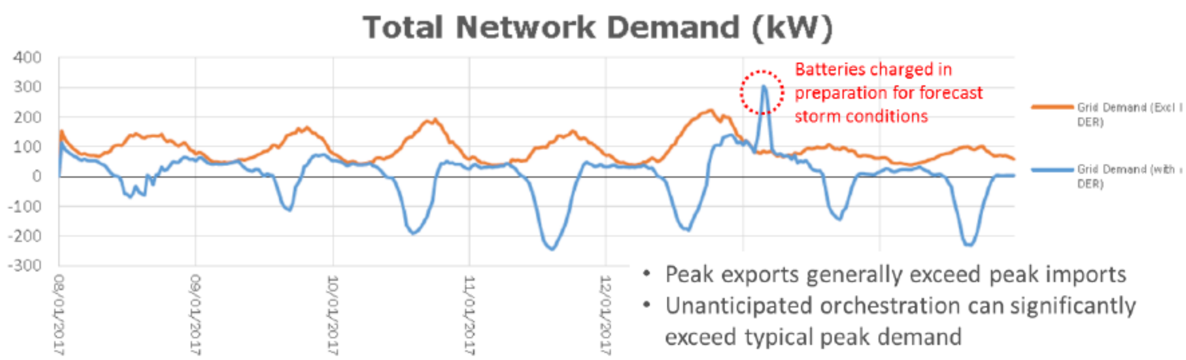


Figure 7: SA Power Networks' Salisbury battery trial – aggregate customer load profile

In the absence of new approaches to the investment in, and the operating and management of the network, these changes could:

- Overload existing assets, particularly at times of peak export or unconstrained orchestration of DER, resulting in outages to nearby customers;
- Exceed quality of supply (voltage) tolerances, risking damage to customer equipment, causing customers' inverters to disconnect and increasing transient variations and flicker; and
- Reduce the resilience of the network to faults, whereby relatively small network disturbances could place the stability of large portions of the network at risk.

A reduction in energy transported through the network as customers become more self-sufficient may increase the unit cost of grid energy. Customers may abandon the grid in favour of standalone systems, even though this may not be efficient for the community as a whole.

Equally, with increasing DER combined with a modified approach in the operation of the distribution network, presents opportunities for:

- Improved network efficiency, through leveraging distributed resources for network support;
- Supporting new markets, by providing a robust platform to enable customers to share and trade energy using their distributed energy resources and enabling electric vehicles; and
- To optimise the whole of system security and reliability outcomes.

Hot and dry climate

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.

As a result, South Australia has one of the peakiest electricity demands in the world driven by the extraordinary demand for cooling during our hot summers. More than 90% of South Australian households have air conditioning and the size of those air conditioners continues to grow as they are replaced, contributing to localised demand growth on the network. On the few extremely hot days of a South Australian summer, typically around six to nine days each year, air conditioning loads cause South Australia's electricity demand to double relative to average demand levels. Air conditioning plays an important role in maintaining reasonable levels of comfort for customers and is critical for the health of many customers. Customers expect SA Power Networks to ensure sufficient capacity exists in our network infrastructure or with the support of non-network solutions, to meet these peak demands that occur for less than 2% of the year.

Severe weather events

Based on our observation of the long term patterns of historical weather-driven reliability outcomes, the severity of severe weather events (**SWE**) is increasing. SWEs are the major cause of prolonged interruptions to power supply in South Australia.

Lightning and high winds are the most damaging effects of SWEs. Lightning strikes directly damage network equipment, while high winds can blow limbs or whole trees onto power lines. As a result, power interruptions 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**). These days are typically when storms with lightning and high winds occur.

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 27-28 December 2016 represented the most significant South Australian distribution reliability event 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 and no MEDs in 2017/18.

Quality of supply

QoS relates to the characteristics of the power customers receive, primarily in terms of voltage levels. Historically, in the low voltage (**LV**) network, QoS issues have been due to the operation of numerous large air conditioners during heatwave conditions.

Rapid growth in solar PV installations has accelerated the number of QoS issues reported causing significant local effects in terms of voltage fluctuation, often affecting surrounding customers. South Australia (with Queensland) has the highest penetration of domestic rooftop solar PV panels in the NEM, with around 30% of residential customers having solar PV installed. The strong growth in solar PV installations is expected to continue, and beyond that, other new customer equipment such as battery storage and EVs are likely to increase QoS issues over time. SA Power Networks has a significant and growing challenge to monitor and manage both the 11kV and LV networks within regulated standards.

The continued high growth in customer embedded generation (solar PV) coupled with the very high level of renewable energy generation connected to the transmission network (wind) has led to an increasingly volatile net customer demand, with periods of very low or localised negative demand (around noon) versus periods of high demand (in the late afternoon and evening).

During periods of high renewable generation, such as noon or on weekends and public holidays, the transmission and distribution regulation devices are reaching the limit of their ability to adequately control network voltages. Solutions being implemented to resolve this issue include modification of the connection standard to require new generation to utilise the capability of their inverters to assist negating the impact of their solar generator on the local voltage, the use of LV regulators, voltage regulating distribution transformers, extending the tap range of targeted zone substation transformers and/or installation of reactive plant in zone substations on 11kV lines and increased monitoring and control of the distribution network down to LV.

We are also 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 DER connections.

Rapid changes in network technology

Technological developments not only provide options for customers, but also create opportunities for improvements to our network operations through new ways to monitor, control, maintain and augment assets that were previously cost prohibitive.

Remote monitoring and control technology is evolving rapidly and quickly expanding the range of cost effective solutions available. Installation of more intelligent devices such as distribution transformer monitors, supervisory control and data acquisition (**SCADA**) enabled remote-controlled switching devices and advanced meters will help us to manage risk and network performance. These technologies also facilitate flexibility in our network operations that will enable the 'two-way' network of the future.

These changes also require new ways to manage these predominantly electronic devices, which require an increased focus on configuration management, their daily operation, maintenance and eventual replacement programs.

2.5 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.

2.5.1 Sub-transmission network

The SA Power Networks sub-transmission network includes transmission connection point substations, sub-transmission lines 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 four 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. A fifth region, the Adelaide Central Region (**ACR**) was created by ESCoSA within the ETC to define the area containing the larger Adelaide CBD. However, from a sub-transmission perspective, this region is not independently planned as it is meshed within the larger Metro East region.

The supply capacity of the 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 (**PoE**) conditions. The ETC refers to these connection points as 'category 4', 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 they 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 or where performance of a RIT-D indicates a positive net market benefit.

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

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 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.

2.5.2 Distribution network

SA Power Networks' distribution network is supplied by 355[1] zone substations. The distribution network typically operates at 19kV in rural and remote locations and at 11kV in higher customer density rural and urban locations. The standard LV customer supply 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 530,530 poles[2]. These poles are constructed of steel and concrete and are known as Stobie poles.

Zone substations

Zone substations are supplied by sub-transmission lines. While there are some exceptions in rural areas, 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.

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.

1 Excludes connection point substations.

2 Excludes Stobie poles supporting conductor operating above 11kV.

Alternatively, 11kV voltage regulators are 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.

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 high voltage (**HV**) to LV and may be connected to SA Power Networks' network at 33kV, 19kV, 11k 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 single customers 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)[3] systems used to supply multiple customers from a single distribution substation.

Asset summary

Table 5 below details our asset types by voltage as reported in our 2018/19 response to the AER's Category Analysis Regulatory Information Notice, for SA Power Networks.

3 There are some instances where single phase customers are supplied across two phases which results in a 460V supply.

Table 5: SA Power Networks' asset summary

Asset type	Description	Quantity
OVERHEAD CONDUCTORS BY: HIGHEST OPERATING VOLTAGE; NUMBER OF PHASES (AT HV)	< = 1 kV	75,210
	> 1 kV & < = 11 kV	53,725
	> 11 kV & < = 22 kV ; SWER	29,186
	> 22 kV & < = 66 kV	16,348
UNDERGROUND CABLES BY:HIGHEST OPERATING VOLTAGE	< = 1 kV	13,703
	> 1 kV & < = 11 kV	4,171
	> 11 kV & < = 22 kV	92
	> 22 kV & < = 33 kV	169
	> 33 kV & < = 66 kV	92
SERVICE LINES BY: CONNECTION VOLTAGE; CUSTOMER TYPE; CONNECTION COMPLEXITY	< = 11 kV ; Residential ; Simple Type	717,186
	< = 11 kV ; Commercial & Industrial ; Complex Type	88,441
TRANSFORMERS BY: MOUNTING TYPE; HIGHEST OPERATING VOLTAGE ; AMPERE RATING; NUMBER OF PHASES (AT LV)	Pole Mounted ; < = 22kV ; < = 60 kVA ; Single Phase	33,895
	Pole Mounted ; < = 22kV ; > 60 kVA and < = 600 kVA ; Single Phase	486
	Pole Mounted ; < = 22kV ; < = 60 kVA ; Multiple Phase	9,482
	Pole Mounted ; < = 22kV ; > 60 kVA and < = 600 kVA ; Multiple Phase	16,629
	Pole Mounted ; < = 22kV ; > 600 kVA ; Multiple Phase	52
	Kiosk Mounted ; < = 22kV ; < = 60 kVA ; Single Phase	400
	Kiosk Mounted ; < = 22kV ; > 60 kVA and < = 600 kVA ; Single Phase	162
	Kiosk Mounted ; < = 22kV ; < = 60 kVA ; Multiple Phase	93
	Kiosk Mounted ; < = 22kV ; > 60 kVA and < = 600 kVA ; Multiple Phase	11,465
	Kiosk Mounted ; < = 22kV ; > 600 kVA ; Multiple Phase	1,776

Asset type	Description	Quantity
	Ground Outdoor / Indoor Chamber Mounted; < 22 kV ; > 60 kVA and < = 600 kVA ; Single Phase	38
	Ground Outdoor / Indoor Chamber Mounted; < 22 kV ; > 60 kVA and < = 600 kVA ; Multiple Phase	66
	Ground Outdoor / Indoor Chamber Mounted; < 22 kV ; > 600 kVA ; Multiple Phase	123
	Ground Outdoor / Indoor Chamber Mounted; > = 22 kV & < = 33 kV ; < = 15 MVA	336
	Ground Outdoor / Indoor Chamber Mounted; > = 22 kV & < = 33 kV ; > 15 MVA and < = 40 MVA	31
	Ground Outdoor / Indoor Chamber Mounted; > 33 kV & < = 66 kV ; < = 15 MVA	209
	Ground Outdoor / Indoor Chamber Mounted; > 33 kV & < = 66 kV ; > 15 MVA and < = 40 MVA	152
SWITCHGEAR BY: HIGHEST OPERATING VOLTAGE ; SWITCH FUNCTION		
	< = 11 kV ; Switch	1,504
	< = 11 kV ; Circuit Breaker	1,281
	> 11 kV & < = 22 kV ; Switch	70
	> 22 kV & < = 33 kV ; Switch	1,097
	> 22 kV & < = 33 kV ; Circuit Breaker	289
	> 33 kV & < = 66 kV ; Switch	1,478
	> 33 kV & < = 66 kV ; Circuit Breaker	499
SCADA, NETWORK CONTROL AND PROTECTION SYSTEMS BY: FUNCTION	Field Devices	6,397
	Communications Network Assets	3,320
	Master Station Assets	393
	Communications Site Infrastructure	98
	Communications Linear Assets	2,806
OTHER BY: DNSP DEFINED		
	< = 1 kV; stobie pole	233,287
	> 1 kV & < = 11 kV; stobie pole	230,514
	> 11 kV & < = 22 kV; stobie pole	113,768
	> 22 kV & < = 66 kV; stobie pole	35,118
	Pole REFURBISHED; STOBIE Pole	34,177

Asset type	Description	Quantity
	Pole Mounted ;> = 22 kV & < = 33 kV ; < = 60kVA	1,316
	Pole Mounted ;> = 22 kV & < = 33 kV ; > 60 KVA AND < = 600 KVA	659
	Pole Mounted ; > = 22 kV & < = 33 kV ; > 600 kVA	48
	Kiosk Mounted; > = 22 kV & < = 33 kV ;	77
	Recloser ;SWITCHGEAR	1,550
	Sectionaliser ;SWITCHGEAR	729
	>= 11 kV & < ≈ 22 kV ; LOAD BREAK SWITCH; GROUND LEVEL (Switching Cubicle);SWITCHGEAR	7,573
	Pipework Switchyard Substations	103

Source: AER CA RIN 2019 – 5.2 Asset age profile, SA Power Networks

2.6 How we have prepared this Distribution Annual Planning Report

In accordance with Schedule 5.8(a)(4) of the NER, this section details the methodologies SA Power Networks has used in preparing this DAPR, including methodologies used to identify system limitations and any assumptions we have applied.

SA Power Networks' sub-transmission and distribution network augmentation is generated either from requirements to upgrade our infrastructure resulting from changes to the ETC, EDC, or as an output of our planning process to ensure compliance with the NER 6.5.7(a) objectives:

1. meet/manage expected demand; and
2. comply with all applicable regulatory obligations.

The network planning process considers when network and/or specific customer load growth will breach our Network Planning Criteria. This identifies a network constraint that must be addressed by either a network or non-network solution. The process followed in planning and augmenting our distribution network is shown in Figure 8.

Each transmission connection point forecast is reconciled to AEMO's Electricity Statement of Opportunities (**ESOO**) for South Australia, our zone substations are then reconciled to the relevant ElectraNet Transmission Connection Point forecast.

Network augmentation for the forward planning period is based on the 2019 spatial demand forecast produced by SA Power Networks at 10% and 50% PoE level.

In addition to these forecasts, SA Power Networks has commenced production of minimum demand forecasts in an attempt to enable identification of potential constraints due to the export of electricity by embedded generators and distributed energy resources (DER) such as PV.

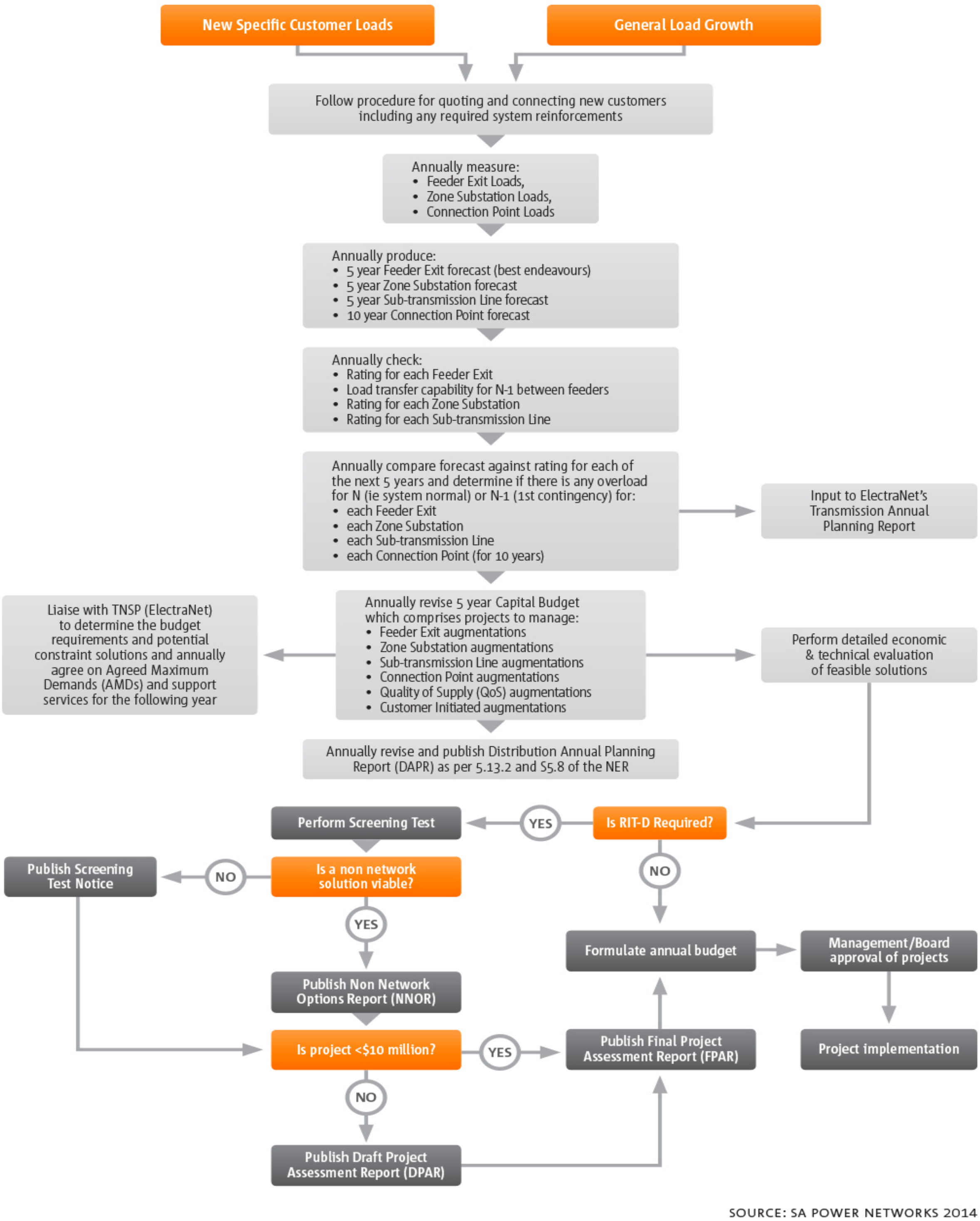


Figure 8: Overview of the distribution planning process

2.6.1 Network Planning Criteria

SA Power Networks' Network Planning Criteria seeks to incorporate the objectives of maintaining compliance with all applicable Statutes, National and International Standards, Codes of Practice, the Electricity Act and NEM obligations. In particular, the criteria embody those obligations imposed by legislation including the requirement to adhere to standards and practices generally accepted as appropriate internationally or throughout Australia by the electricity supply industry and to ensure the security of electricity supply to customers.

The forecast load for future years contained within the load forecast is compared against the capacity of the relevant network element to identify overloads or system limitations. This comparison is undertaken for both system normal (N) and single contingency (N-1) conditions. For the transmission connection points and the meshed sub-transmission system, the 10% PoE forecast is used. For zone substations, the 10% PoE forecast is compared against the substation's normal capacity ('N', ie all plant in service) and the 50% PoE forecast is compared against the substation's contingent capacity ('N-1', ie one item of plant out of service) load that can be transferred to other zone substations and a risk margin. In other words, augmentation under contingent conditions is only required where the load at risk compared to the contingency capacity exceeds the zone substations risk margin. Each substation is allocated a risk margin from 0 – 3MVA depending on the ability to utilise mobile plant to mitigate the load at risk.

Following the same principles used for forecast load growth, the forecast change in minimum load is compared against the capacity of the relevant network element to identify system limitations for reverse flows. This comparison is undertaken for both N and N-1 conditions. To date, minimum load forecasts have been produced for zone substations and are still under development for other network elements.

SA Power Networks implements solutions for those assets that are forecast to be overloaded under normal conditions, prior to the overload occurring. However, the timing to implement solutions for assets overloaded for N-1 contingency events considers both the likelihood and consequence of such an event and the amount and type of customer load at risk.

Optimum repair times for major equipment categories are:

- Zone Substation Transformer 7 Days
- 66kV Underground Cable (Oil Filled) 8 Weeks
- 66kV Underground Cable (Other) 2 Weeks
- 66kV Circuit Breaker 7 Days
- 66kV Overhead Line 12 – 24 Hours

Note: The actual repair time can often be much longer due to site specific factors or asset type.

When the forecast load breaches the planning criteria, a system limitation is established and a suitable solution is sought. Solutions required to avoid breaching the asset ratings established within the planning criteria are considered where:

- the overload cannot be eliminated by load transfers;
- the conditions at a transmission connection point will not comply with the ETC;
- the 10% PoE forecast exceeds an asset's normal capacity;
- the 10% PoE forecast exceeds an asset's emergency capacity during contingency conditions in the CBD or Metropolitan 66kV Sub-transmission network;
- the 50% PoE forecast exceeds an asset's emergency capacity during contingency conditions at all other locations;
- the overload cannot be technically or economically eliminated by power factor correction;
- the short circuit rating of the network may be exceeded during network faults; or
- voltage cannot be maintained within codified limits.

The Network Planning Criteria for each asset type are summarised in **Table** 6 to **Table** 9.

The likelihood and consequence of an asset failure affecting the impacted customers have been considered in establishing the planning criteria limits and a risk margin is generally applied to achieve a balance between minimising customer supply risk and capital expenditure and to maintain reliability levels.

Table 6: Planning criteria for sub-transmission systems

Category	System	Planning Criteria	Forecast Basis
Interconnected 66kV & 33kV sub-transmission lines in the ACR	N	10% PoE	No supplies interrupted for a single line outage at 10% PoE demand – no impact on SAIDI, CAIDI or SAIFI. No sub-transmission line loaded above emergency rating, and no transmission connection point transformer above normal rating, as a consequence.
	N-1 (Continuous)		
	N	Minimum Demand	N & N-1 export ratings = N & N-1 import ratings.
	N-1 (Continuous)		
Meshed sub-transmission lines (ie Metropolitan Area, Mt Barker / Mt Barker South) and Pirie / Bungama 33kV	N	10% PoE	No supplies interrupted for a single line outage at 10% PoE demand (excludes substations teed off a line and substations without line circuit breakers) – no impact on SAIDI, CAIDI or SAIFI. No sub-transmission line loaded above emergency rating, and no transmission connection point transformer above normal rating, as a consequence of a line fault.
	N-1 (Continuous)		
	N	Minimum Demand	N & N-1 export ratings = N & N-1 import ratings.
	N-1 (Continuous)		

Category	System	Planning Criteria	Forecast Basis
Radial / Interconnected sub-transmission line	N	10% PoE	Supplies may be interrupted for a single line outage, but all should be restorable, at 10% PoE demand, within 12 hours. May be achieved by repair, or transfer of load to adjoining substations, without causing any other line or transformer to be loaded above emergency rating (contingency plans to be prepared if line contains cable, with preparatory work if required). Consideration will be given to the construction of a second line when the load exceeds 30 MVA according to the 10% PoE forecast or where the performance of a RIT-D indicates a positive net market benefit of the de-radialisation. Definite impact on SAIFI, CAIDI and SAIDI due to a typical outage of up to 12 hours for customers.
	N	Minimum Demand	N export rating = 90% of N import rating.

Table 7: Planning criteria for substations

System	Planning Criteria	Forecast Basis	Impact of transformer outage
All 66/33kV and 66/11kV substations within the ACR	N	10% PoE	No supplies interrupted for a single transformer outage at 10% PoE demand – no impact on SAIDI, SAIFI or CAIDI. No other transformer loaded above emergency rating as a consequence.
	N-1 (Continuous)		
	N	Minimum Demand	Typically, N export rating = 90% of N import rating*. N-1 export rating = N-1 import rating*. *Subject to site specific export rating constraints.
	N-1 (Continuous)		
Specific major zone substations, namely LeFevre	N	10% PoE	No supplies interrupted for a single transformer outage at 50% PoE demand – no impact on SAIDI, SAIFI or CAIDI. No other transformer loaded above emergency rating as a consequence.
	N-1 (Continuous)	50% PoE	
	N	Minimum Demand	Typically, N export rating = 90% of N import rating*. N-1 export rating = N-1 import rating*. *Subject to site specific export rating constraints.
	N-1 (Continuous)		

System	Planning Criteria	Forecast Basis	Impact of transformer outage
Substations supplying major industrial customers or critical commercial load regions, or where supply cannot be restored within 12 hours, namely: • Woodville 11kV • North Adelaide • Kilkenny • Kent Town • Norwood • Direk Substations where mobile substation can't be used (eg 66/7.6kV substations)	N	10% PoE	Supplies may be interrupted for a single transformer outage, but all should be restorable following transfer of load to adjoining substations, at 50% PoE demand, without causing any equipment to be loaded above emergency rating. Possible impact on SAIFI if momentary outage achieved, but small impact on SAIDI and CAIDI due to short duration of customer outage.
	N-1 (+ feeder transfers) (ie contingency capacity)	50% PoE	
	N	Minimum Demand	Typically, N export rating = 90% of N import rating*. N-1 export rating = N-1 import rating*. *Subject to site specific export rating constraints.
	N-1 (Continuous)		
All other zone substations	N	10% PoE	Supplies may be interrupted for a single transformer outage, but all should be restorable following transfer of load to adjoining substations and installation of a mobile substation, at 50% PoE, without causing any equipment to be loaded above emergency rating. Full supply to be restored within 24 hours. Definite impact on SAIFI and potentially significant impact on SAIDI and CAIDI due to up to 24 hour outage for some customers.
	N-1 (+feeder transfers + 3 MVA Load at Risk Margin) (ie constraint capacity)	50% PoE	
	N	Minimum Demand	Typically, N export rating = 90% of N import rating*. N-1 export rating = N-1 import rating*. *Subject to site specific export rating constraints.
	N-1 (Continuous)		

Table 8: Planning criteria for primary distribution feeders

System	Planning Criteria	Forecast Basis	Impact of transformer outage
All feeders within the ACR	N	10% PoE	No supplies interrupted for a single transformer outage at 10% PoE demand – no impact on SAIDI, SAIFI or CAIDI.
	N-1		Supplies may be interrupted for a single feeder outage, but all should be restorable following transfer of load to adjoining substations, at 10% PoE demand, without causing any equipment to be loaded above emergency rating.
	N	Minimum Demand	N export rating = 90% of N import rating. N-1 export rating = N-1 import rating.
	N-1 (Continuous)		
Urban feeders	N	10% PoE	Supplies may be interrupted for a single feeder outage, but all should be restorable following transfer of load to adjoining substations, at 50% PoE demand, without causing any equipment to be loaded above emergency rating. Possible impact on SAIFI if momentary outage achieved, but small impact on SAIDI and CAIDI due to short duration of customer outage.
	N-1 (+ feeder transfers) (ie contingency capacity)	50% PoE	
	N	Minimum Demand	N export rating = 90% of N import rating. N-1 export rating = N-1 import rating.
	N-1 (Continuous)		
Rural feeders	N	10% PoE	
	N	Minimum Demand	N export rating = 90% of N import rating.

Table 9: Planning criteria for transmission connection points

Category	System	Planning Criteria	Forecast Basis
Single TF / Single Transmission Line	N TX Line	Peak	Import Rating(s) as specified by EN
	N TF		

	N TF	Minimum Demand	Export Rating(s) as specified by EN
Multiple TFs / Single Transmission Line	N TX Line	Peak	Import Rating(s) as specified by EN
	N-1 (continuous) TF		
	N-1 (continuous) TF	Minimum Demand	Export Rating(s) as specified by EN
Multiple TFs / Single Transmission Line	N TX Line	10 PoE / Peak	Import Rating(s) as specified by EN. AMD = 10 PoE Forecast (unless otherwise agreed) Standby Maximum Demand = Peak – 10 PoE. Higher restoration requirement than CP2.
	N-1 (continuous) TF		
	N-1 (continuous) TF	Minimum Demand	Export Rating(s) as specified by EN
Multiple TFs / Multiple Transmission Lines	N-1 (continuous) Line	10 PoE / Peak	Import Rating(s) as specified by EN. AMD = 10 PoE Forecast (unless otherwise agreed) Standby Maximum Demand = Peak – 10 PoE
	N-1 (continuous) TF		
	N-1 (continuous) TF	Minimum Demand	Export Rating(s) as specified by EN
Multiple TFs / Multiple Transmission Lines	N-1 (continuous) Line	10 PoE / Peak	Import Rating(s) as specified by EN. AMD = 10 PoE Forecast (unless otherwise agreed) Standby Maximum Demand = Peak – 10 PoE Higher restoration requirement than CP4.
	N-1 (continuous) TF		
	N-1 (continuous) TF	Minimum Demand	Export Rating(s) as specified by EN

Note that connection points designated as Category 1 may not have adequate backup capacity under contingency conditions (via Electranet or SA Power Networks' Network Management) to supply the load until Electranet repairs are complete. Refer to the Electricity Transmission Code and the SA Power Networks / ElectraNet Connection Agreement for further details regarding the reliability criteria applicable to connection points.

2.7 Material changes since the 2018/19 to 2022/23 Distribution Annual Planning Report

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.

In 2018, SA Power Networks purchased a licence from AEMO to use its existing connection point forecasting system. This system has been used to produce the forecasts in Attachment A. Refer to section 3.1 for further details.

The 2019/20 to 2023/24 Distribution Annual Planning Report is the first year that SA Power Networks has published substation minimum demand forecast. This forecast can be found in Attachment A. Refer to section 3.1.1 for further details.

3. Forecasts for the forward planning period

3.1 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.

3.1.1 Load forecasting methodology

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 large 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 a variety of 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 model adjustments are made to add back previously removed spot loads or major customer load forecasts. Negative loads such as PV are excluded from the final regressed 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 2019/20 to 2023/24 connection point forecast was reconciled against AEMO's SA system "normal" demand forecast trend contained within its 2019 Electricity Statement of Opportunities (ESOO), for the same period. For the non-major customer load, (ie residential and commercial customers) the 2019 ESOO shows slight overall growth similarly to that of the demand forecast in the 2018 ESOO.

Major customer load was removed by separately considering those connection points dominated by single customers such as those at Port Pirie, Whyalla Central and Snuggery Industrial.

The reconciliation process modifies the transmission connection point forecast, thereby considering the global impact of energy efficiency measures, PV and economic factors as forecast by AEMO, for South Australia (eg the reconciliation process uses AEMO's 2019 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 forecast by AEMO within their ESOO. The result is the creation of a reconciled coincident and non-coincident forecast for each zone substation.

SA Power Networks' methodology for forecasting minimum demands relies on the identification of historic minimum demands for each zone and transmission connection point substation excluding spurious minimum readings due to faults or offloads.

The methodology employed sees the underlying demand determined through the addition of DER output and any other form of embedded generation to the measured values. It is assumed that there is no load growth in this underlying demand. Forecasts of future year's minimum values then rely on the application of DER forecasts which are generated based on the DER growth rates specified in AEMO's ESOO for the small residential sized systems. Larger DER systems (ie greater than 30kW) are only increased according to committed generation connection enquiries. This forecast DER output is then subtracted from the existing underlying demand to produce forecast minimum values for each connection point and zone substation.

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 as the basis for determining the growth rate. The historic period selected can alter (eg where the asset has existed for less than five years, the growth rate will likely only be determined 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.

The timing of the various network augmentations proposed within this 2019 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 loadflow modelling software. The line flows indicated by these models are then used to determine the timing of any constraint.

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 forecast which is then reconciled with the normal AEMO load forecast as detailed in their 2019 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 growth rates across the distribution network. The coincident growth rate for the total distribution network is less than the non-coincident value 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.

3.1.2 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 1,220 MW as at 1 December 2019. This represents more than a third of SA Power Networks' peak system demand and has resulted in SA Power Networks having the equal highest PV penetration levels as a proportion of system demand in the nation. As a proportion of SA Power Networks' 875,000 customers, approximately 27% 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** 9 indicates the level of installed PV inverter capacity[4] within the distribution network as at 1 July for each respective year.

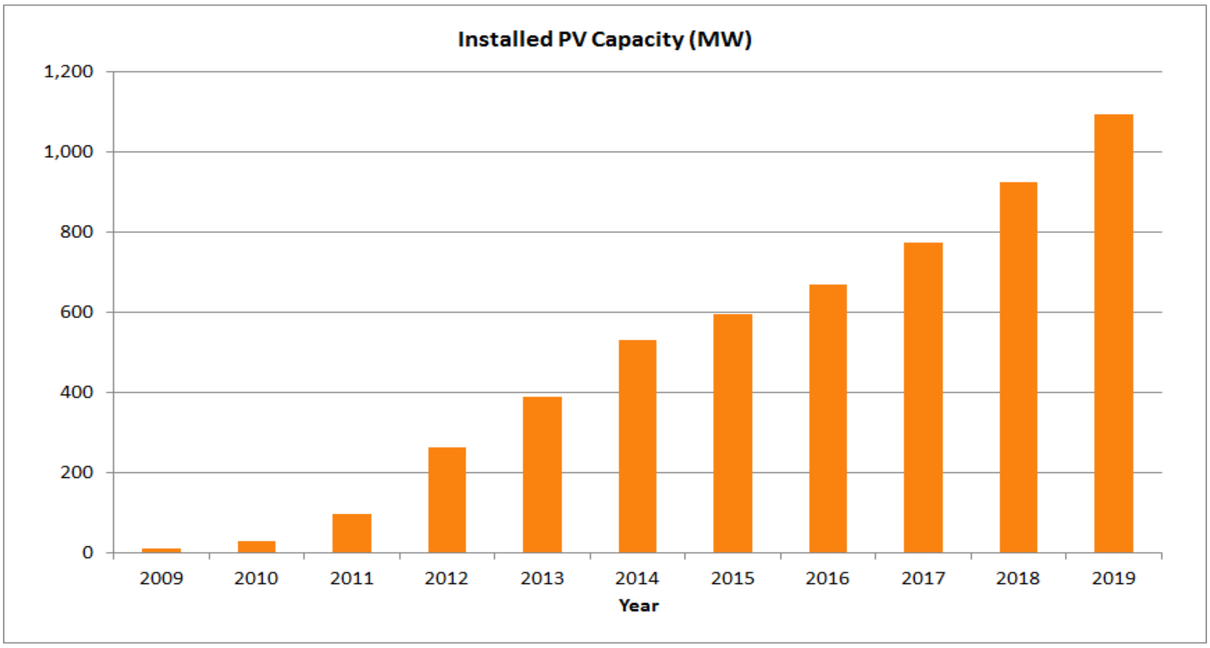


Figure 9: Total installed PV inverter capacity per annum

4 Some solar PV installations have an inverter that is rated higher than the capacity of the solar panel installation.

Note: Data is based on installed Network Market Identifiers (**NMIs**) at the average PV approval size.

As a result, the implementation of these State Government schemes has altered the supply - demand balance in most, if not all, regions over this period to the extent that the impact of PV needs to be accounted for within the spatial demand forecasts. The effect these PV systems have had on both the daily demand profile since 2009 as well as on shifting the peak demand period at a zone substation level from the traditional 17:00 – 18:00 hrs period to 19:00 – 20:00 hrs.

With respect to transmission connection points and state demand, the effect of these PV systems has had a far greater 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.

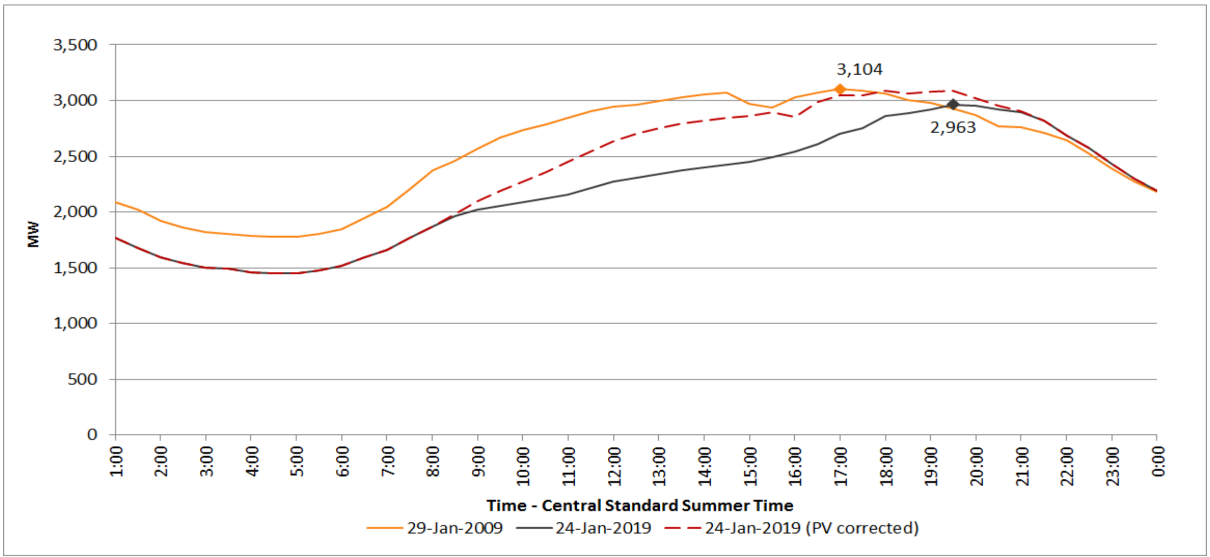


Figure 10: Load profile comparison

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 **Figure** 11 for an example of a single month's curve).

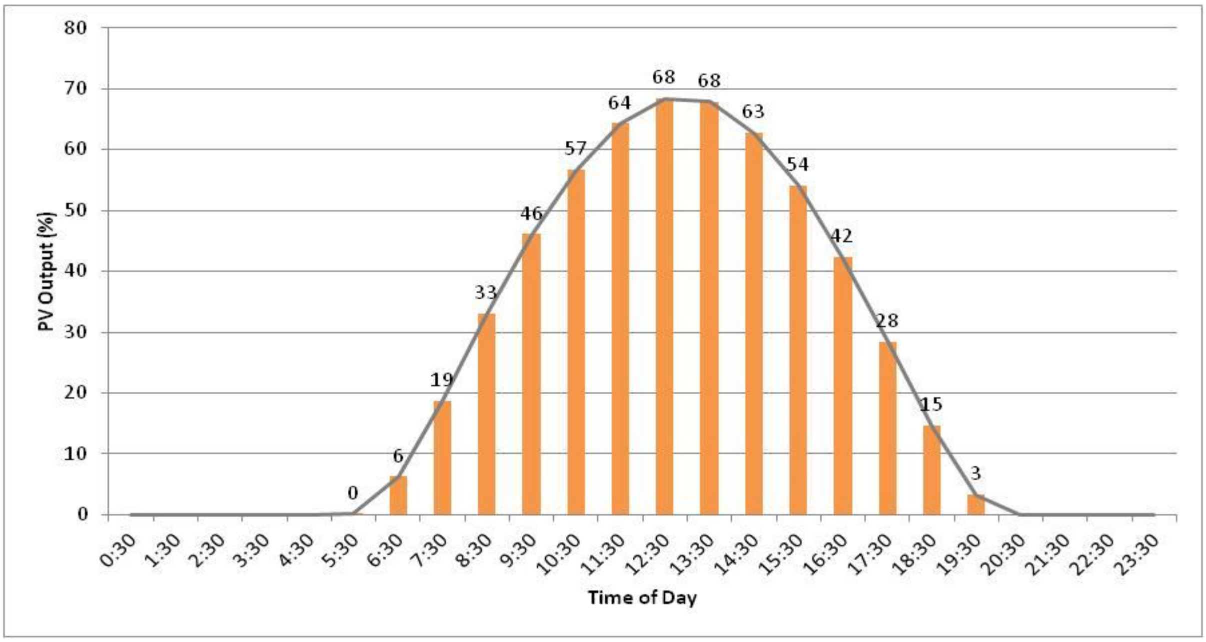


Figure 11: PV Output versus Time of Day in January

The forecasting tool uses the data provided to determine, for each half hour, the 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. Figure 12 provides an example of the impact of PV on measured versus native demand.

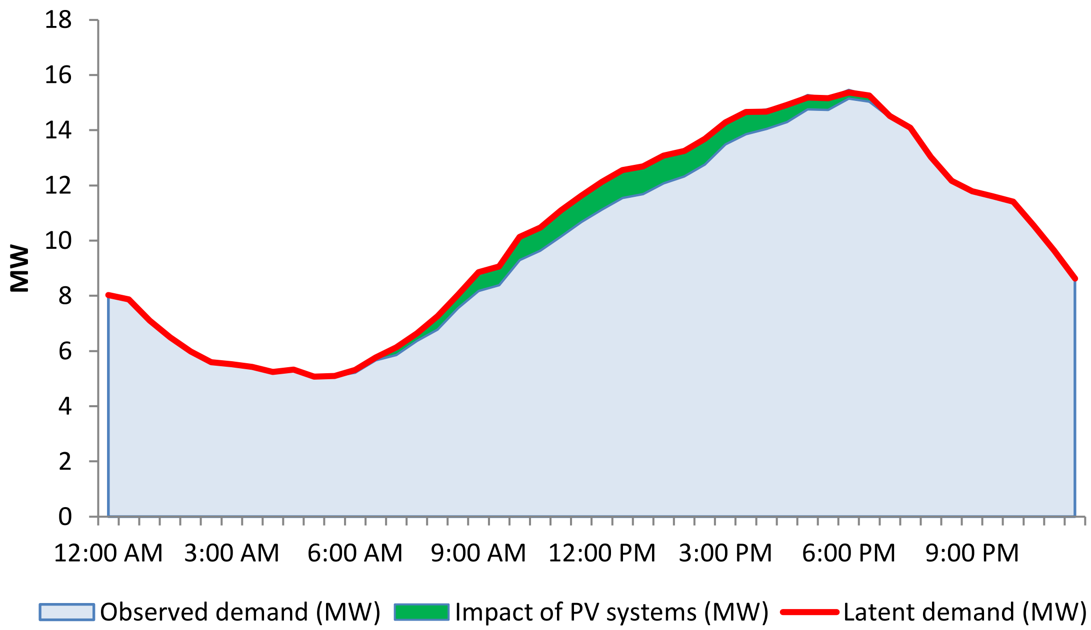


Figure 12: Example of measured demand compared with underlying (native) demand

AEMO's 2019 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.

3.1.3 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 at the time of each zone substation's and transmission connection point's measured peak reading is recorded and added back to the measured substation transformer output to arrive at the underlying/native demand value used within the regression.

Upon completion of the regression analysis and arriving at a temperature corrected demand at the nominated PoE level, those embedded generators whose operation is intermittent are then deducted (along with other post-model adjustments) from the temperature corrected demand to arrive at the final forecast demand level. Those embedded generators that have historically operated consistently irrespective of temperature or network demand levels (eg small biogas generators) are deducted from the model's forecast.

3.1.4 Spot Loads

In the 2019 load forecast, 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 due to committed load reductions (eg Holden post 2017).

3.1.5 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.

3.1.6 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.

3.1.7 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.

3.2 Load forecasts

Schedule 5.8(b)(2)(ii) of the NER requires SA Power Networks to provide load forecasts for its transmission connection points, sub-transmission lines and zone substations including where applicable:

(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;

The 10% PoE load forecasts for our sub-transmission lines by region substations have been provided in Excel format in Attachment A. Note, for our sub-transmission lines, SA Power Networks only prepares the total capacity and power factor at the time of the peak load forecast. Similarly, given such forecasts are only produced for summer conditions, no winter forecasts are provided.

The 10% PoE and 50% PoE load forecasts for our zone substations have been provided in Excel format in Attachment A. The connection point substation forecasts are included at the beginning of each regional forecast table and are highlighted green. Note we only report 10% PoE forecasts for transmission connection point substations and the ACR zone substations in accordance with our planning criteria.

3.3 Future transmission – distribution connection point forecast

Schedule 5.8(b)(3) of the NER requires SA Power Networks to provide forecasts of future transmission-distribution connection points (and any associated connection assets), sub-transmission lines and zone substations.

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.

3.4 Reliability performance forecast

Schedule 5.8(b)(4) of the NER requires SA Power Networks to forecast its performance against the Australian Energy Regulator's (AER's) reliability targets [5] established under the Service Target Performance Incentive Scheme (STPIS) for SA Power Networks. These 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 12.1.1.

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.

5 Defined in the AER Final Decision for SA Power Networks distribution determination – Attachment 11 – STPIS – October 2015, Page 7.

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 **Table** 10

Table 10: SA Power Networks' STPIS feeder category reliability performance forecast

Reliability measures	2019/20	2020/21	2021/22	2022/23	2023/24
USAIDIn (minutes)					
CBD	15	15	15	15	15
Urban	105	105	105	105	105
Rural Short	190	190	190	190	190
Rural Long	265	265	265	265	265
Overall	145	145	145	145	145
USAIFIn (interruptions)					
CBD	0.15	0.15	0.15	0.15	0.15
Urban	1.15	1.15	1.15	1.15	1.15
Rural Short	1.55	1.55	1.55	1.55	1.55
Rural Long	1.60	1.60	1.60	1.60	1.60
Overall	1.25	1.25	1.25	1.25	1.25

Note:

1. USAIDIn is defined as 'Unplanned System Average Interruption Duration Index' normalised to exclude Major Event Days.
2. USAIFIn is defined as 'Unplanned System Average Interruption Frequency Index' normalised to exclude Major Event Days.

The forecast set out in **Table** 10 is based on the following assumptions:

- SA Power Networks maintaining existing reliability performance except where it is cost effective to improve reliability performance (ie reward from STPIS is greater than the cost of the improvement);
- The forecast is based on the average historic performance over the last seven years excluding outlier years in performance (we are currently investigating whether the 2017/18 year to date CBD reliability performance is an outlier or representative of an emerging issue with an ageing underground cable infrastructure);
- The average performance has been rounded up to the nearest 5 minutes or 0.05 interruptions;
- The forecast assumes similar average weather that has occurred over the preceding seven-year period 2011/12 to 20017/18; and
- The forecast excludes the performance on MEDs as permitted under the STPIS regime.

3.5 Factors that impact 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;

(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.

3.5.1 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 equipment may be damaged 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

The installation of new embedded generation on the distribution network has the potential to increase fault levels. Generally, the fault levels in the majority of the distribution network are well within limits, however in the Adelaide CBD the fault level is 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 proponent. In 2017 we commenced a program to install neutral earthing resistors (NERs) at multiple 66/33kV zone substations, similar to those installed in 2015 in the CBD 66/11kV zone substations. This program was completed in May 2019. Installation of these NERs is intended to lower the phase to ground fault level in the CBD 33kV network mitigating the risk of high energy faults in the cable duct systems which are typically located in footpaths and minimising the potential damage to the 33kV network's ageing cables. However, the overall three phase and phase to phase fault levels in the CBD will remain at their existing high levels and therefore limiting synchronous generator connections to the CBD's 11kV network.

3.5.2 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 embedded generation;
- Switching of network equipment such as reactive plant; and
- Disturbances upstream of SA Power Networks' system (eg 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 approximately 2000 to 3000 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.

Since 2017, SA Power Networks has observed a continual increase in customer complaints arising from voltages exceeding prescribed limits. In October 2019, we experienced the largest number of customer enquiries ever recorded, twice the historical 10-year average.

In 2017, we commenced a program to install permanent metering in our small rural substations to aid in the management of solar PV related issues. Given the step increase in PV related complaints, we also commenced a program installing LV metering at strategically located distribution transformers (on the LV side), to further quantify and assist with the management of demand / supply in high solar PV penetration locations. This is discussed further in Section 12.

3.5.3 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 install equipment to interrupt certain load in order to manage system frequency.

SA Power Networks, on advice from AEMO and following approval from the OTR, has modified several under-frequency load shedding relays settings in recent years to ensure sufficient load can be interrupted to meet the obligations of the NER under most operating conditions.

Due to the high DER penetrations within SA Power Networks' network, a significant number of feeders and lines included within the UFLS scheme are net exporters of energy. The shedding of these feeders and lines by the UFLS system will exacerbate rather than arrest the under-frequency event the scheme is designed to arrest.

An ongoing review by AEMO into the adequacy of the UFLS scheme, is likely to require SA Power Networks to implement changes to our existing system, in order to maintain security of supply with increasing levels of DER. At the time of writing, the initial study results from AEMO indicate that significant augmentation may be required by SA Power Networks to enable the UFLS scheme to be prevented from operating at specific locations during the middle of the day.

3.5.4 Ageing and unreliable 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 complete the alignment of our asset management practices with the latest asset management industry standard, ISO 55001. We also propose to continue our plans to maintain our overall risk profile to historical levels.

We have the oldest distribution network in the NEM. A large proportion of our network was installed between the 1950s and 1970s, and so is now over 50 years old. We are however only in the early stages of replacing many of these assets. Consequently, replacement levels have been increasing recently to arrest the condition effects of this ageing, and to manage the overall risk of our network.

In our 2010-15 regulatory determination, the AER allowed additional operating expenditure to increase our asset inspections and we implemented a more detailed and frequent asset inspection regime, completing our first full cycle of inspections across the State in 2018.

The increased inspection rate and adoption of an improved, standardised approach to inspections has resulted in a significant increase in the number of identified defects on our network, in particular on our overhead assets. The volume of these defects continues to grow as we complete more inspections, and has been significantly greater than anticipated by SA Power Networks, resulting in higher than expected network risk levels overall.

We have addressed the most critical risks, focussing on HBFRAs. However, we anticipate that replacement levels will continue to increase in this forward planning period and over the longer term, to arrest the rising trend in risk associated with the ongoing ageing of our network.

Currently significant work is being undertaken to further refine our understanding of the risk posed by asset defects through adopting Condition Based Risk Management (CBRM) principles. This work coupled with bringing our asset inspections into cycle in 2018 will place us in good stead to develop forecasts of the necessary rectification work required to efficiently maintain the risk profile of our network to acceptable levels.

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. The primary reason for maintaining our risk profile to current levels is our heightened concern that the structural failure of an asset could result in damage to people, property, the environment or our network. That is, limiting the potential for public safety risk through direct impact or electric shock following structural failure (which is more likely in densely populated urban areas) and for bushfire risk (asset failure causing fires particularly in BFRAs).

For our power line assets, we forecast a significant increase in asset replacement to enable us to manage the current forecast level of network asset defects whilst meeting our regulatory obligations and progressively moving network risks back to levels acceptable to SA Power Networks and the OTR. We consider this approach is prudent, delivers an efficient outcome over the longer term, and is required to discharge our duty to take reasonable steps to ensure that our distribution system is safe and safely operated in accordance with section 60(1) of the Electricity Act 1996 (SA).

4. 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 Attachment B.

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 two 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 underground cable which was previously being considered for replacement in the forward planning period. We have recently applied an innovative cable oil leak detection technology that has significantly reduced maintenance costs compared with our traditional applied methods. Given the significant reduction in the time and cost associated with locating and repairing leaks that we have achieved, we have deferred the renewal of this asset beyond the forward planning period. The 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. The majority 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. Note, pole replacement is both planned and unplanned and therefore the volumes shown in **Error! Reference source not found.** are indicative.

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) are replaced 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 11kV 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 fault 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 11kV 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 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 SAPN's distribution 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.

Table 11 lists the planned circuit breaker replacements in the forward planning period.

Table 11: Substation circuit breaker replacement program

Volume	Voltage	Date
SQUARE WATER HOLE CB5011	66kV Circuit Breaker	1/01/2020
BALHANNAH CB5297	66kV Circuit Breaker	1/01/2020
BALHANNAH CB5298	66kV Circuit Breaker	1/01/2020
WHYALLA CITY CB4297	33kV Circuit Breaker	1/01/2021
WHYALLA CITY CB4296	33kV Circuit Breaker	1/01/2021
ELIZ DWNS CB5180	66kV Circuit Breaker	1/01/2021
BLANCHE CB4480	33kV Circuit Breaker	1/01/2021
BLANCHE CB4479	33kV Circuit Breaker	1/01/2021
PT LINCOLN TERMINAL CB4346	33kV Circuit Breaker	1/01/2022
PT LINCOLN TERMINAL CB4344	33kV Circuit Breaker	1/01/2022
PT LINCOLN CITY CB4352	33kV Circuit Breaker	1/01/2022
PT LINCOLN CITY CB4353	33kV Circuit Breaker	1/01/2022
ANGAS CREEK CB4059	33kV Circuit Breaker	1/01/2022
ANGAS CREEK CB4058	33kV Circuit Breaker	1/01/2022
MOBILONG CB4223	33kV Circuit Breaker	1/01/2023
BORDERTOWN CB4502	33kV Circuit Breaker	1/01/2023
HINDLEY ST CB4300	33kV Circuit Breaker	1/01/2023

HINDLEY ST CB4301	33kV Circuit Breaker	1/01/2023
HINDLEY ST CB4302	33kV Circuit Breaker	1/01/2023
HINDLEY ST CB4303	33kV Circuit Breaker	1/01/2023
HINDLEY ST CB4304	33kV Circuit Breaker	1/01/2023
HINDLEY ST CB4305	33kV Circuit Breaker	1/01/2023
HINDLEY ST CB4306	33kV Circuit Breaker	1/01/2023
HINDLEY ST CB4307	33kV Circuit Breaker	1/01/2023
HINDLEY ST CB4308	33kV Circuit Breaker	1/01/2023
HINDLEY ST CB4326	33kV Circuit Breaker	1/01/2023
HINDLEY ST CB4327	33kV Circuit Breaker	1/01/2023
PT VINCENT CB4217	33kV Circuit Breaker	1/01/2024
RUDALL CB5353	66kV Circuit Breaker	1/01/2024
KILBURN CB527	66kV Circuit Breaker	1/01/2024
GLADSTONE CB4433	33kV Circuit Breaker	1/01/2024
PADTHAWAY CB4333	33kV Circuit Breaker	1/01/2024
WHYALLA TERMINAL CB4394	33kV Circuit Breaker	1/01/2024
WHYALLA STUART CB4438	33kV Circuit Breaker	1/01/2024

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.

Hawker Siddeley Switchgear (HSS) Horizon substation 33kV circuit breaker replacement program

The HSS Horizon circuit breaker is a specific make and type of 33kV Vacuum/SF_6 insulated dead tank circuit breaker. SA Power Networks has approximately 110 of these units installed across our network since 2003, typically installed at transmission connection points and major country substations.

The HSS Horizon circuit breakers have been diagnosed as having a major design/construction flaw which leads to early life failure. Attempts have been made to rectify this via a program of asset removal and refurbishment by the manufacturer. This was performed on approximately 80 units over a three year period at a direct cost to SA Power Networks of over $3 million.

In mid 2018, we became aware that the manufacturer's solution had not completely resolved these issues and that other options needed to be investigated. Due to the significant risk that many of these circuit breakers present, we propose to commence a program to replace selected HSS Horizon circuit breakers in our network until confident of a long term solution that addresses equipment performance issues.

The replacements are determined based on unit criticality (failure consequence) within the network. We are allowing for replacement of three circuit breakers per year in the forward planning period.

Substation single phase voltage regulator replacement program

A voltage regulator is a type of power transformer. Its purpose is to regulate the output voltage up or down as required within a limited voltage range, typically +/- 5 to 10% of the nominal system voltage. A single-phase regulator is a relatively low-cost item and is used in sets of two or three to provide three phase voltage regulation on 11kV or 33kV lines, and are increasingly critical to manage service level impacts caused by high levels of distributed PV generation throughout the distribution network.

Replacement of single phase regulators is required as they approach the end of their economic life and present unacceptable risks to safety and network security. Planned single phase regulators replacements are determined using a risk based approach that considers age, condition, performance and failure consequences for individual assets. We are proposing to replace nine sets of single phase regulators across our network in 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 20 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 three sites per year in the forward planning period.

Substation disconnector (air break switch) 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 copper or aluminium primary conductors supported by insulators on a metal support frame. The majority of devices on the network are presently issue free but a number of models manufactured by AK Power Solutions show increasing likelihood of being seized and unswitchable when required. The majority of installed devices require manual operation and so this failure is resulting in safety, reliability and operational issues that cannot be reasonably managed without significant remediation works.

Disconnector replacement activities include planned and unplanned replacement projects and refurbishment of problematic AK Power types undertaken at various locations across South Australia. We propose to replace approximately five units per year and refurbish 45 units per year in the forward planning period.

Ground Level Air Insulated Switchgear replacement program

Air insulated switched disconnectors are power switching and high voltage isolation devices that are installed in a number of small indoor substations within Adelaide's CBD. This switchgear provides controlled switching and isolation of high voltage distribution transformers and review of a number of sites have identified ten devices that are at the end of technical life and present an unacceptable risk to safe and reliable network operation.

Replacement of this switchgear is required as they are no longer fit for application and replacement works to address all sites, prioritised by asset condition, performance and failure consequences are planned 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 & 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 by undertaking a review of the relay type, protection scheme, past failure rate, test results and the consequence of maloperation.

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 like-for-like replacement of existing mechanical reclosers with recalibrated settings, in addition to installation of new electronic reclosers to address the protection inadequacy in rural 19kV network. Without adequate backup protection, it is expected a fault on the network will remain energised and then burn down the conductors and/or SWER supply transformers.

The methodology for determining whether a protection upgrade is required is by undertaking cost – benefits analysis considering:

1. A review of the protection backup clearing time for all credible faults;
2. Whether the asset located in a bushfire risk area; and
3. The number of customers in the local area.

Protection backup protection compliance activities are undertaken at various substations and locations across the South Australian network throughout the forward planning period.

5. 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.

6. System limitations for sub-transmission 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.

6.1 System limitations for sub-transmission lines

The NER Schedule 5.8(c)(1) to (5) requires SA Power Networks to provide the following system limitation information for its sub-transmission lines:

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

(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 reduction in forecast load 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 reduction in forecast load may occur; and

  (iii) the estimated reduction in forecast load in MW or improvements in power factor needed to defer the forecast system limitation.

SA Power Networks' sub-transmission line system limitations forecast for the forward planning period is outlined below and set out in Attachment B.

6.1.1 Load transfers and Monitoring Program

There are several sub-transmission lines that are forecast to marginally cause an overload constraint. SA Power Networks considers it prudent and efficient to monitor and perform minor load transfers during the summer period to defer the need for major upgrades. The unit costs for such works is less than $2 million. Details of these programs are set out below.

Table 12: Load transfers and monitoring program sub-transmission constraints list

Constrained Asset	Region	Limitation	Overload (MVA)	Year of Exceedance
Elizabeth Downs to Smithfield West 66kV Line	North	N-1 Overload	0.5	2019/20
Norwood to East Terrace 66kV Line	East	N-1 Overload	1.6	2019/20

6.1.2 Port Noarlunga to Seaford 66kV sub-transmission line

The Port Noarlunga to Seaford 66kV sub-transmission line is part of the meshed 66kV sub-transmission network that supplies the southern suburbs and Fleurieu Peninsula. This sub-transmission line is designed for a temperature of 100°C (T100) and is forecast to be overloaded following a N-1 event under 10 PoE conditions.

This constraint was previously deemed to be an emerging constraint. Previous forecasts for the region suggested the line was approaching overload but had not yet breached SA Power Networks' planning criteria. With the region's forecast decreasing, it was forecast that this emerging constraint would not come to fruition and therefore would not necessitate augmentation works.

With the inclusion of the most recent summer's load data (ie 2018/19) and due to variations in AEMO's ESOO forecasts (to which SA Power Networks' forecasts are reconciled), the most recent forecast now suggests that this line is already quite significantly in breach of the planning criteria with a slow rate of decline. Given the volatility of the forecasts, SA Power Networks proposes that loads are further monitored during the 2019/20 summer period to provide a higher degree of confidence in the forecast before committing to any augmentation. In this interim period, SA Power Networks will consider the use of other post contingent measures to mitigate the overload such as the use of SA Power Networks' 8MW power station on Kangaroo Island to reduce load seen by this line under contingent conditions. SA Power Networks proposes to spend nothing on remediation of this constraint at this time pending the outcome of this continued monitoring.

Should subsequent forecasts and measured actual loads confirm the need for remedial action, SA Power Networks will determine possible network and non-network solutions to address the identified constraint and initiate the performance of a RIT-D evaluation.

The location of the Port Noarlunga to Seaford 66kV sub-transmission line constraint is shown in Section 16.4. As the proposed extent of augmentation has not yet been finalised, the remediation costs have not yet been confirmed, however they are expected to require the performance of a RIT-D evaluation.

The forecast overload is outlined in Table 13.

Table 13: Limitation for the Port Noarlunga to Seaford 66kV sub-transmission line

66kV sub-transmission line	N-1 Rating (MVA)	2019/20 N-1 Overload (MVA)	2020/21 N-1 Overload (MVA)	2021/22 N-1 Overload (MVA)	2022/23 N-1 Overload (MVA)	2023/24 N-1 Overload (MVA)
Port Noarlunga to Seaford	93	10	9	9	9	8

6.1.3 Morphett Vale East to McLaren Flat 66kV sub-transmission line

The Morphett Vale East to McLaren Flat 66kV sub-transmission line is part of the meshed 66kV sub-transmission network that supplies the southern suburbs and Fleurieu Peninsula. This sub-transmission line is designed for a temperature of 100°C (T100) and based on the most recent forecast is proposed to be overloaded following a N-1 event under 10 PoE conditions.

This line constraint is directly related to the Port Noarlunga to Seaford line constraint (see Section 6.1.2) 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.

This constraint was previously deemed to be an emerging constraint. Previous forecasts for the region suggested the line was approaching overload but had not yet breached SA Power Networks' planning criteria. With the region's forecast decreasing, it was forecast that this emerging constraint would not come to fruition and therefore would not necessitate augmentation works.

With the inclusion of the most recent summer's load data (ie 2018/19) and due to variations in AEMO's ESOO forecasts (to which SA Power Networks' forecasts are reconciled), the most recent forecast now suggests that this line is already quite significantly in breach of the planning criteria with a slow rate of decline. Given the volatility of the forecasts, SA Power Networks proposes that loads are further monitored during the 2019/20 summer period to provide a higher degree of confidence in the forecast before committing to any augmentation. In this interim period, SA Power Networks will consider the use of other post contingent measures to mitigate the overload such as the use of SA Power Networks' 8MW power station on Kangaroo Island to reduce load seen by this line under contingent conditions. SA Power Networks proposes to spend nothing on remediation of this constraint at this time pending the outcome of this continued monitoring.

Should subsequent forecasts and measured actual loads confirm the need for remedial action, SA Power Networks will determine possible network and non-network solutions to address the identified constraint and initiate the performance of a RIT-D evaluation. Given the synergies between this constraint and the Port Noarlunga to Seaford constraint, it is likely that any solution chosen will remedy both constraints.

The location of the Morphett Vale East to McLaren Flat 66kV sub-transmission line constraint is shown in Section 16.4. As the proposed extent of augmentation has not yet been finalised, the remediation costs have not yet been confirmed, however they are expected to require the performance of a RIT-D evaluation.

The forecast overload is outlined in Table 14.

Table 14: Limitation for the Morphett Vale East to McLaren Flat 66kV sub-transmission line

66kV sub-transmission line	N-1 Rating (MVA)	2019/20 N-1 Overload (MVA)	2020/21 N-1 Overload (MVA)	2021/22 N-1 Overload (MVA)	2022/23 N-1 Overload (MVA)	2023/24 N-1 Overload (MVA)
Morphett Vale East to McLaren Flat	92	8	8	8	7	7

6.1.4 New Osborne to Glanville & Glanville to Queenstown 66kV sub-transmission lines

The New Osborne to Glanville and Glanville to Queenstown 66kV sub-transmission lines form part of the meshed 66kV sub-transmission network that supplies the western suburbs. Both sub-transmission lines consist of a combination of 54/7/3.5 ACSR/GZ designed for a temperature of 100°C (T100) and double circuit 0.25 in^2 Copper designed for operation at a temperature of 80°C (T80). Based on the most recent forecast both lines are proposed to be overloaded following a N-1 event under 10 PoE conditions.

These constraints were previously identified and a network solution to resolve these constraints was included within SA Power Networks' reset submission to the AER for remediation within the 2020-25 regulatory control period. In making its draft determination, the AER rejected SA Power Networks' proposal.

Given the meshed nature of the network, the level of load reduction required to mitigate the constraint is not simply equivalent to the level of overload in MVA. Therefore, although the 10 PoE load exceeds the rating of the New Osborne to Glanville line by only 4.2MVA, closer to 15MVA of load would actually need to be shed to bring the load in this line to within its rating. The level of overload is also highly contingent on the output of three 66kV connected power stations in the region, 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.

Based on the latest available forecast, the level of overload in these lines is forecast to slowly diminish over time due to an overall decline in the western suburbs demand. SA Power Networks proposes that loads within the region continue to be monitored during the 2019/20 summer period and beyond to provide a higher degree of confidence in the decreasing forecast. Should this additional data suggest a continuing constraint, SA Power Networks will look to resolve this constraint sometime in the future. SA Power Networks proposes to spend nothing on remediation of this constraint at this time pending the outcome of this continued monitoring.

Given any network solution is expected to exceed $15 million, before committing to any augmentation, SA Power Networks will undertake a formal RIT-D process. The timing of the performance of this RIT-D is subject to the outcome of this continued monitoring and future forecasts and will be advised in future DAPR publications.

The forecast overload is outlined in Table 15.

Table 15: Limitation for the New Osborne to Glanville & Glanville to Queenstown 66kV sub-transmission lines

66kV sub-transmission line	N-1 Rating (MVA)	2019/20 N-1 Overload (MVA)	2020/21 N-1 Overload (MVA)	2021/22 N-1 Overload (MVA)	2022/23 N-1 Overload (MVA)	2023/24 N-1 Overload (MVA)
New Osborne to Glanville	144	4.2	3.8	3.3	2.9	2.4
Glanville to Queenstown	137	1.1	0.7	0.3	0	0

6.1.5 Wasleys to Mallala 33kV sub-transmission line

Mallala Zone Substation is supplied from a 33kV sub-transmission line from Templers Connection Point via Wasleys. Part of this sub-transmission line is designed for a temperature of 50°C (T50) and is now overloaded during present day summer conditions.

No load transfers are available to alleviate the overload. Potential solutions include increasing the clearance of the sub-transmission line to achieve a higher temperature rating.

The location of Wasleys to Mallala 33kV sub-transmission line constraint is shown in Section 16.10. 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.

The forecast overload (and load reduction required to defer the limitation) is outlined in Attachment B and Table 16.

Table 16: Limitation for the Wasleys to Mallala 33kV sub-transmission line

33kV sub-transmission line	N Rating (MVA)	2019/20 N Overload (MVA)	2020/21 N Overload (MVA)	2021/22 N Overload (MVA)	2022/23 N Overload (MVA)	2023/24 N Overload (MVA)
Wasleys (DF41874) to Mallala	5.1	0.73	0.67	0.61	0.55	0.49

6.1.6 Templers to Hamley Bridge 33kV sub-transmission line

Hamley Bridge Zone Substation is supplied from a 33kV sub-transmission line from Templers Connection Point. This sub-transmission line is designed for a temperature of 50°C (T50) and it is forecast to be overloaded under 10 PoE conditions in 2021/22.

There are no available tie points that would offer a suitable alternate option to supply Hamley Bridge Zone Substation.

The location of Templers to Hamley Bridge 33kV sub-transmission line constraint is shown in Section 16.10. 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.

The forecast overload (and load reduction required to defer the limitation) is outlined in Attachment B and Table 17.

Table 17: Limitation for the Templers to Hamley Bridge 33kV sub-transmission line

33kV sub-transmission line	N Rating (MVA)	2019/20 N Overload (MVA)	2020/21 N Overload (MVA)	2021/22 N Overload (MVA)	2022/23 N Overload (MVA)	2023/24 N Overload (MVA)
Templers to Hamley Bridge	5.1	0.0	0.0	0.05	0.18	0.31

6.1.7 Dorrien to Barossa South 33kV sub-transmission line

Barossa South Zone Substation is supplied from a single 33kV sub-transmission line from Dorrien Connection Point via Dorrien Distribution Zone Substation. This line has a section of radial underground cable which passes under a road.

The section of cable raises reliability concerns due to its significant repair lead times. There is no N-1 solution if the cable were to fault which would leave Barossa South Zone Substation unsupplied for the entirety of a potentially lengthy repair process.

The location of Dorrien to Barossa South 33kV sub-transmission line is shown in Section 16.6. 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.

The forecast reliability constraint (and load reduction required to defer the limitation) is outlined in Attachment B.

6.1.8 Dorrien to Stockwell 33kV sub-transmission line

Stockwell Zone Substation is supplied from a radial 33kV sub-transmission line from Dorrien Connection Point via Dorrien Distribution Zone Substation. This line has a section of underground cable which is approximately 350m long.

The section of cable raises reliability concerns. There is no N-1 solution if the cable were to fault which would leave Stockwell Zone Substation unsupplied for the entirety of a potentially lengthy repair process.

The location of Dorrien to Barossa South 33kV sub-transmission line is shown in Section 16.6. 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.

The forecast reliability constraint (and load reduction required to defer the limitation) is outlined in Attachment B.

6.2 System limitations for zone substations

The NER Schedule 5.8(c)(1) to (5) requires SA Power Networks to provide the following system limitation information for its zone substations:

(1) estimates of the location and timing (month(s) and year) of system limitations;
(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 reduction in forecast load 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 reduction in forecast load may occur; and
  (iii) the estimated reduction in forecast load in MW or improvements in power factor needed to defer the forecast system limitation.

SA Power Networks' zone substation system limitations forecast for the forward planning period are outlined below.

6.2.1 Load transfers and Monitoring Program

There are several Substations that are forecast to marginally cause an overload constraint. SA Power Networks considers it prudent and efficient to monitor and perform minor load transfers during the summer period to defer the need for major upgrades. For Reverse constraints, SA Power Networks will mitigate all overloads by utilising export limits on any existing embedded generation that has SCADA control. The unit costs for such works is less than $200,000. Details of these programs are set out in Table 18.

Table 18: Load transfers and monitoring program substation constraints list

Constrained Asset	Region	Limitation	Overload (MVA)	Year of Overload
Clearview Substation	Metro East	N Overload	0.1	2020/21

Meadows Substation	Eastern Hills	N Overload & Reverse N-1 Overload	0.2	2019/20
Verdun Substation	Eastern Hills	N Overload	0.1	2019/20
Deloraine Substation	Eastern Hills	N Overload	0.1	2019/20
Gumeracha Substation	Eastern Hills	N Overload	0.2	2019/20
Mount Pleasant Substation	Eastern Hills	N Overload	0.5	2019/20
Ceduna Substation	Eyre Peninsula	Reverse N-1 Overload	0.03	2019/20
Glossop Substation	Riverland	Reverse N-1 Overload	0.9	2019/20
Loveday Substation	Riverload	Reverse N-1 Overload	0.03	2019/20
Lyrup Substation	Riverland	Reverse N-1 Overload	0.3	2019/20
Roonka Substation*	Riverland	Reverse N-1 Overload	-	2019/20
Streaky Bay Substation	Eyre Peninsula	Reverse N & Reverse N-1 Overload	0.2 (N) 1.7 (N-1)	2019/20
Sheidow Park Substation	Metro South	Reverse N-1 Overload	0.4	2020/21
Naracoorte Substation	South East	Reverse N-1 Overload	0.1	2019/20

*Within planning criteria risk margin (assuming generation operating at full capacity).

6.2.2 Moonta Substation

Moonta Zone Substation supplies the town of Moonta on South Australia's Yorke Peninsula. It consists of two 5MVA 33/11kV transformers which are supplied from the Kadina East Distribution Zone Substation.

Moonta Zone Substation does not have any available feeder transfers, and in the event of the loss of a transformer a portion of the load will be unable to be supplied.

The preferred network solution is to monitor loads and produce a revised forecast for December 2020 to reassess the overload. Potential solutions include installing transformer fans to increase the rating of the transformers or a demand management solution to reduce customer load by at least 0.2MVA.

The forecast overload (and load reduction required to defer the limitation) is outlined in Attachment B and Table 19 below.

Table 19: Limitation for the Moonta Substation

Zone substation	N-1 Rating (MVA)	2019/20 N-1	2020/21 N-1	2021/22 N-1	2022/23 N-1	2023/24 N-1

		Overload (MVA)	Overload (MVA)	Overload (MVA)	Overload (MVA)	Overload (MVA)
Moonta	10.1	0.0	0.1	0.2	0.2	0.2

Note: N-1 rating = Firm Delivery Capacity + Available Transfers + 3MVA load at risk.

6.2.3 Mount Gambier North

Mount Gambier North Zone Substation supplies part of Mount Gambier in the state's South East. It consists a single 12.5MVA 33/11kV transformer which is supplied from the Mount Gambier 33kV Zone Substation.

In the event of the loss of the transformer, there are insufficient feeder ties to enable full restoration of the load to other substations.

The preferred network solution is to monitor the loads for the 2019/20 summer and manage the constraint with a large mobile substation. Upon producing a revised forecast for 2020/21 summer, the constraint will be reassessed.

Table 20: Limitation for the Mount Gambier North Substation

Zone substation	N-1 Rating (MVA)	2019/20 N-1 Overload (MVA)	2020/21 N-1 Overload (MVA)	2021/22 N-1 Overload (MVA)	2022/23 N-1 Overload (MVA)	2023/24 N-1 Overload (MVA)
Mount Gambier North	10.3	0.0	0.0	0.0	0.1	0.1

Note: N-1 rating = Firm Delivery Capacity + Available Transfers + 3MVA load at risk.

6.2.4 Nuriootpa Substation

Nuriootpa Zone Substation supplies the surrounding Nuriootpa areas in the Barossa Valley. It consists of a single 12.5MVA 33/11kV transformer which is supplied from the Dorrien 33kV Zone Substation.

In the event of the loss of the transformer, there are insufficient feeder ties to enable full restoration of the load to other substations.

The preferred network solution is to rebuild a 300m feeder tie on the Nuriootpa East 11kV feeder in 2020 and include a SCADA operated load switch to enable remote controlled load transfers.

The forecast overload (and load reduction required to defer the limitation) is outlined in Attachment B and Table 21 below.

Table 21: Limitation for the Nuriootpa Substation

Zone substation	N-1 Rating (MVA)	2019/20 N-1 Overload (MVA)	2020/21 N-1 Overload (MVA)	2021/22 N-1 Overload (MVA)	2022/23 N-1 Overload (MVA)	2023/24 N-1 Overload (MVA)
Nuriootpa	8.6	0.3	0.4	0.5	0.6	0.6

Note: N-1 rating = Firm Delivery Capacity + Available Transfers + 3MVA load at risk.

7. 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 two primary distribution feeders that are forecast to be overloaded and proposed to be addressed in the forward planning period. There are several feeders that are forecast to marginally cause an overload constraint in the next two years. SA Power Networks considers it prudent and efficient to monitor and perform minor load transfers during the summer period to defer the need for major upgrades. Details of these programs are set out in Table 22.

7.1.1 Load transfers and Monitoring Program

Table 22: Load transfers and monitoring program primary distribution feeders constraints list

Constrained Asset	Region	Limitation	Overload (MVA)	Year of Overload
Uley Road 11kV (Elizabeth Downs Substation)	Metro North	N Overload	0.04	2019/20
Greenwith 11kV (Golden Grove Substation)	Metro East	N Overload	0.22	2019/20
Salisbury Plains 11kV (Salisbury Substation)	Metro North	N Overload	0.16	2019/20
Brukunga 11kV (Brukunga Substation)	Eastern Hills	N Overload	0.02	2019/20
North 11kV (Port Lincoln City Substation)	Eyre Peninsula	N Overload	0.08	2019/20
Risdon Park 11kV (Port Pirie South Substation)	Upper North	N Overload	0.5	2019/20
Loxton West 11kV (Pyap Substation)	Riverlands	N Overload	0.06	2019/20

7.1.2 Rostrevor (HH409D) 11kV

Rostrevor 11kV feeder is located to the east of Adelaide City and is supplied from the Woodforde Zone Substation, which is growing at approximately 1% per annum. The feeder is forecast to be overloaded under normal conditions in the 2019-2020 summer according to the 10% PoE forecast – see Attachment B for details.

Due to heavy loads on neighbouring 11kV feeders there is no further capacity for permanent transfers to other less loaded feeders. The preferred network solution is to construct an additional feeder exit in 2020 and transfer a proportion of load onto the new feeder. Any demand management solution to reduce peak demand would need to have a minimum response of 1.9MVA.

7.1.3 Sellicks Beach (MV62) 11kV

Sellicks Beach 11kV feeder is located to the south of Adelaide City and is supplied from the Aldinga Zone Substation, which is growing at approximately 1% per annum. The feeder is forecast to be overloaded under N-1 conditions in the 2020-21 summer according to the 50% PoE forecast – see Attachment B for details.

In the event of a loss of the feeder exit supply, there is insufficient capacity for the feeder to be fully transferred using the existing feeder ties. The preferred network solution is to construct a new feeder tie to a neighbouring 11kV feeder in 2020.

8. 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.

8.1 Preceding year RIT-D projects

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

SA Power Networks has not completed any RIT-D projects in 2019.

8.2 Current RIT-D projects

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

SA Power Networks commenced analysis for the Myponga to Square Waterhole 66kV sub-transmission line in 2018/19. In the AER's Draft Decision for SA Power Networks' 2020-25 Regulatory Control Period, the AER raised a number of concerns regarding this project. Subject to additional analysis and the AER's Final Decision, and the outcome of the RIT-D process, SA Power Networks proposes to proceed with the Myponga to Square Waterhole 66kV sub-transmission line in 2023/24. The RIT-D process will commence in 2022/23.

SA Power Networks intenally commenced analysis for the Athol Park to Woodville RIT-D project in 2018/19. In the AER's Draft Decision for SA Power Networks' 2020-25 Regulatory Control Period, the AER raised a number of concerns regarding this project. The proposed Athol Park to Woodville 66kV sub-transmission line is, in our view, the least cost, technically feasible solution that resolves both the peak summer N-1 constraint and the N-1-1 constraints when performing planned outages in the Metro West Region.

The Original Proposal submission for the Athol Park to Woodville 66kV sub-transmission line was based on the most up to date network model and forecast available. At the time, the total area load was forecast to grow steadily across a 20-year period, meaning that these constraints were forecast to become more severe over time. However, since that time the forecast has been updated and it indicates a slight decline in the total area load. This results in the identified constraints becoming less severe over time and therefore the project can be deferred beyond the forward planning period.

8.3 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 Table 23 below.

Table 23: Forecast RIT-D projects for the forward planning period

Project name	Forecast RIT-D commencement date
Myponga to Square Waterhole 66kV sub-transmission line	2022
Northfield 66kV Gas Insulated Switchgear partial replacement	2021
Port Noarlunga to Seaford & Morphett Vale East to McLaren Flat 66kV sub-transmission lines	TBA
New Osborne to Glanville & Glanville to Queenstown 66kV sub-transmission lines	TBA
Athol Park to Woodville 66kV sub-transmission line	TBA

9. 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.

SA Power Networks is currently investigating the year to date 2019/20 reliability performance in the Adelaide CBD where we have experienced an unprecedented level of 11kV cable faults which have resulted in our annual reliability performance being significantly exceeded part way through the year.

The investigation will seek to determine whether the CBD network performance is an outlier or whether we are experiencing an emerging issue with our older lead sheathed paper insulated cables.

10. 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.

Network Planning personnel from SA Power Networks and ElectraNet undertake regular joint planning sessions bi-monthly 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.

In addition 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 points within the forward planning period.

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 co-ordinated between the parties through a common notification process.

Investments that have been planned through this process and are expected to have significant impact on SA Power Networks' expenditure within the forward planning period as summarised in Table 24 below.

Table 24: Major joint investments in forward planning period

Project	Timing	Anticipated Cost (SA Power Networks only)
Leigh Creek South 132/11kV Transformer Replacement	2020 - 2022	$1.0 million. SA Power Network works associated with project by ElectraNet to replace end of life 132/33kV transformers at Leigh Creek South Connection Point with a 132/11kV transformer, refer to page 84 of Transmission Annual Planning Report.
Mount Gambier 132/33kV Transformer Replacement	2021	$4.2 million. SA Power Network works associated with project by ElectraNet to replace end of life 132/33kV transformer at Mount Gambier Connection Point, refer to page 82 of Transmission Annual Planning Report.
Mannum 132/33kV Transformer Replacement	2022 - 2023	$4.0 million. SA Power Networks works associated with project by ElectraNet to replace end of life 132/33kV transformers at Mannum Connection Point, refer to page 84 of Transmission Annual Planning Report.

Yadnarie 66kV segregation	2021	$4.3 million. SA Power Networks works associated with project by ElectraNet to refurbish Transmission Network in Cultana-Yadnarie region, refer to page 76 of Transmission Annual Planning Report.

Further details of ElectraNet's planned projects in the forward planning period can be found in their Transmission Annual Planning Report at:

https://www.electranet.com.au/wp-content/uploads/2019/06/2019-ElectraNet-TAPR_WEB.pdf

11. 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 (eg at Murtho and Nelson), initiated any discussions with SA Power Networks over the preceding 12 months.

12. Performance of our network

Schedule 5.8(j) of the NER requires SA Power Networks to provide information on the performance of its network.

12.1 Reliability performance

This Section sets out SA Power Networks' reliability measures and standards and our performance against these measures and standards.

12.1.1 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 distribution licence issued by ESCoSA.

The EDC measures the reliability performance of the distribution network using the following two measures:

- Unplanned system average interruption duration index (**$USAIDI_n$**), a measure of the normalised (to exclude MEDs) average time in minutes that a customer is without supply per annum due to an unplanned interruption; and
- Unplanned system average interruption frequency index (**$USAIFI_n$**), a measure of the normalised (to exclude MEDs) average number of times a customer experiences an unplanned interruption per annum.

The EDC requires the use of "best endeavours[6]" 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 2015-20 RCP (ie 1 July 2015 to 30 June 2020) are documented in the current version of the EDC (version EDC/12) clause 2.2.1. The EDC/12 targets are

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

established for four HV feeder categories and exclude any interruption(s) that occur on a MED[7]. The feeder categories are:

- Central Business District (CBD);
- Urban[8];
- Short Rural[9]; and
- Long Rural[10].

Note for the 2020-25 regulatory control period ESCoSA will continue to establish reliability standards using the above four feeder categories.

Table 25 sets out ESCoSA's reliability standards for SA Power Networks over the 2015-20 RCP.

Table 25: ESCoSA's reliability standard targets for each year ending 30 June for the 2015-20 RCP

Reliability measures	CBD	Urban	Short rural	Long rural
USAIDIn (minutes)	15	120	220	300
USAIFIn (interruptions)	0.15	1.30	1.85	1.95

12.1.2 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 2019.

SA Power Networks achieved 88% of the reliability service standards

SA Power Networks achieved seven of the eight normalised reliability targets, for the four feeder categories, specified in the South Australian EDC for the year ending 30 June 2019[11]. Table 26 below details each of the four feeder category targets and actual normalised performance for the year ending 30 June 2019.

7 A MED is any day where the daily USAIDI from the interruptions that commence on that day exceed a predetermined threshold.

8 Urban feeder is not a CBD feeder, where the maximum exceeds 0.3 MVA/km

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

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

11 The targets exclude the reliability contribution from interruptions starting on MED's.

Table 26: Feeder Category Normalised Reliability Performance for 2018/19

EDC Feeder Category	USAIDI			USAIFI		
	TARGET	2018/19		TARGET	2018/19	
Central Business District (CBD)	15	13	●	0.15	0.10	●
Urban	120	99	●	1.30	0.95	●
Rural Short (RS)	220	181	●	1.85	1.46	●
Rural Long (RL)	300	333	●	1.95	1.68	●
Overall Distribution System[12]	165	146	●	1.50	1.13	●

It should be noted that not all of the EDC's reliability targets will be achieved each and every year, as the targets are based on average performance over a 5-year period (ie 1 July 2009 to 30 June 2014, referred to as the target setting period (**TSP**)). Non-achievement of the EDC reliability targets, when it occurs, is normally 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 2018/19 there were four MEDs.

Table 27: 2018/19 MEDs, contribution to reliability and MED category

Date(s)	USAIDI	Customers Affected	MED Category[13]
15 October 2018	8.5	43,759	Cat1
2 November 2018	8.9	29,452	Cat2
21 November 2018	24.8	59,911	Cat2
22 November 2018	7.2	21,429	Cat2
Total	49.4	154,551	

SA Power Networks is maintaining the distribution system to deliver electricity to customers reliably

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

12 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.

13 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.

- The average daily contribution to USAIDI from all distribution system unplanned interruption causes on BoM verified SWEs (non-MEDs)[14]. This monitors the distribution system's resilience to reliably cope with typical SWEs; and
- The contribution to USAIDI of equipment failure-caused interruptions. This monitors our performance in maintaining distribution system equipment prior to failure.

SA Power Networks monitors 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. In 2018/19 the average contribution to overall USAIDI from these BoM verified SWE (non-MEDs) was 1.03 minutes which is less than the historical average of 1.32 minutes. Figure 13 below also shows that there is no increasing trend (ie no decline in the resilience of the distribution system to cope with typical SWEs) in this measure.

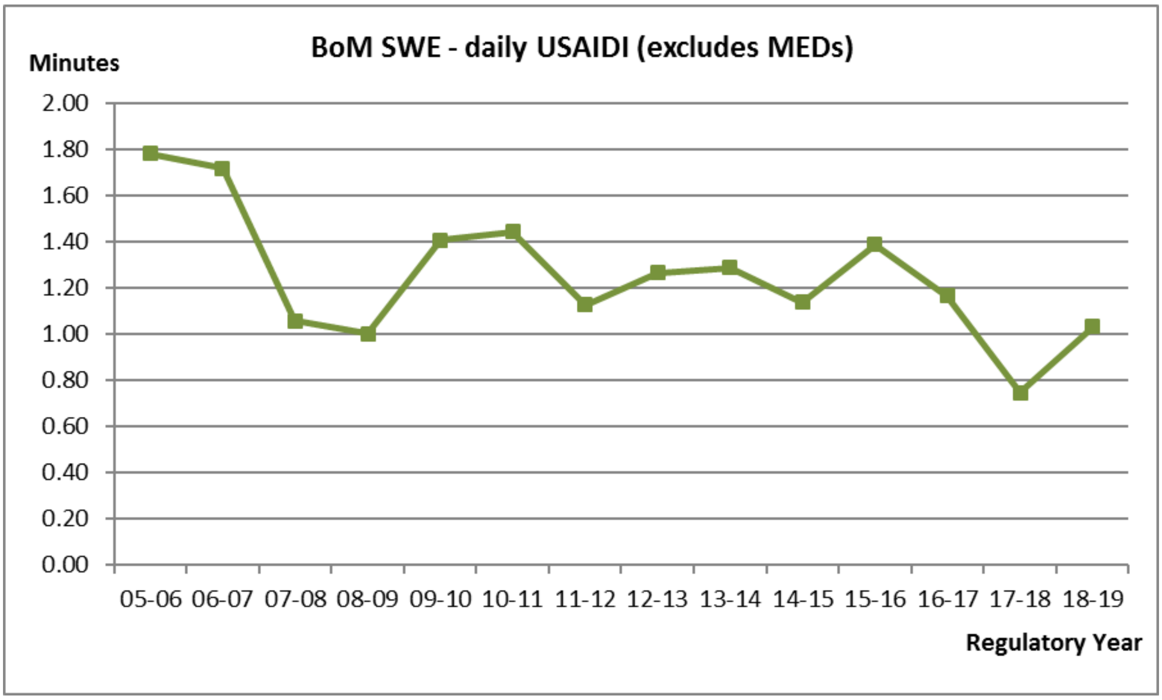


Figure 13: Ave. daily overall USAIDI on BoM verified SWE (excludes MEDs)

14 There are on average more than 30 non-MED BoM verified SWEs annually.

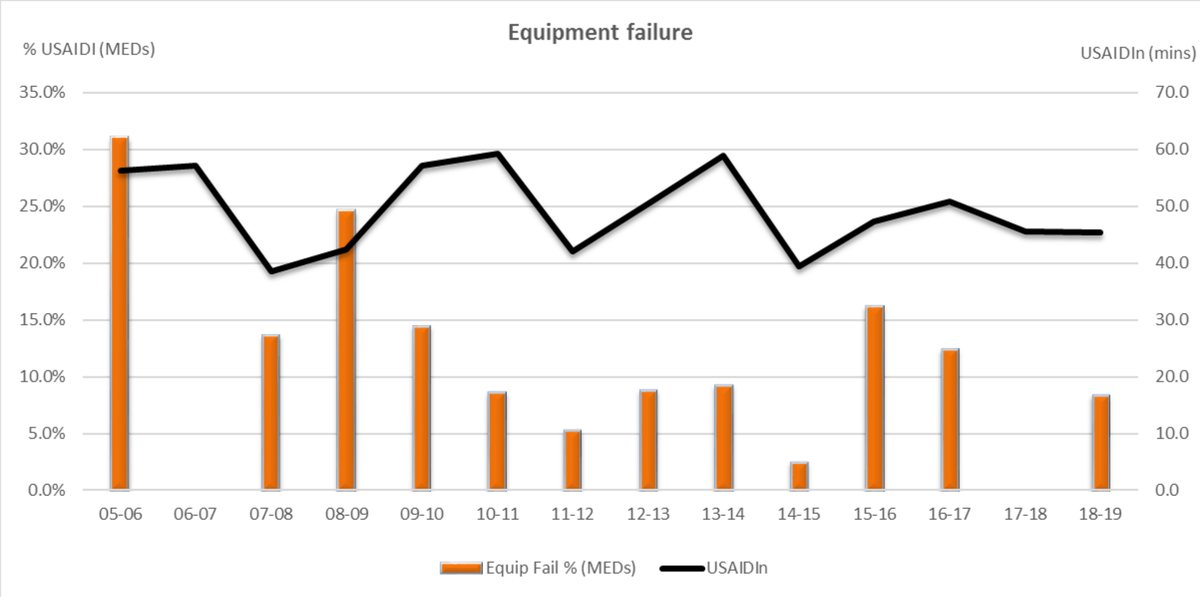


Figure 14: USAIDI from equipment failure-caused interruptions

Figure 14 indicates that SA Power Networks has been appropriately maintaining the distribution system as there is no increasing trend in the $USAIDI_n$ from equipment failure contribution annually nor is there a long term increasing trend (ie no decline in distribution system's resilience) in the percentage contribution to USAIDI due to equipment failure on MEDs.

Performance on Rural Long Feeders was worse than target

The Rural Long USAIDI performance was 333 minutes compared to a target of 300 minutes. ESCoSA in its Final Decision on SA Power Networks' reliability standards review – January 2019, introduced the concept of a reporting threshold. The reporting threshold applicable for Rural Long feeders USAIDI is 340 minutes, based on the reported reliability over the TSP. The USAIDI result for 2018/19 was less than the reporting threshold.

The poor USAIDI result in 2018/19 was the result of two SWEs, neither classified as a MED, one on 1 December 2018[15] and the other on 18 and 19 May 2019[16]. These two SWE contributed 53 minutes to USAIDI, if these two SWEs were excluded, then the USAIDI Rural Long target would have been achieved. Also, SA Power Networks will incur a penalty under the AER's STPIS for exceeding the Rural Long USAIDI target.

There are no declining trends in regional reliability performance

SA Power Networks is required to report the reliability of distribution network in seven geographic regions. Prior to the 2015-20 RCP we were required to use best endeavours to meet annually a total of 13 regional targets (ie two per region except for Kangaroo Island). These targets did not exclude MEDs and were based on average annual performance. The regional reliability targets applied for two 5-year RCPs and over those periods we achieved on average 8 targets annually, ranging between a minimum of 4 and a maximum of 12.

15 Bureau of Meteorology (BoM) reported SWE.

16 Not a BoM reported SWE, but BoM SWE issued a severe weather event warning which was subsequently cancelled. The SWE (mainly lightning), impacted the regional areas of Upper North & Eyre Peninsula, Kangaroo Island and the Major Metropolitan Region, and contributed over 9 minutes to distribution system USAIDIn and affected about 20,000 customers.

SA Power Networks achieved 10 of the 13 regional reliability targets (including MEDs) as the SAIDI targets for Upper North and Eyre Peninsula (**UNE**), Kangaroo Island (**KI**) and the South East (**SE**) in 2018-19.

Our analysis has shown that there has been no declining trend in the reliability performance of any region's normalised reliability performance (ie excluding MEDs) over the long-term. See Section 12.1.2 for more details of this analysis.

SA Power Networks used 'best endeavours' to meet all reliability targets in 2018/19

The EDC requires SA Power Networks to use best endeavours to achieve the EDC feeder category reliability targets for each year ending 30 June. The best endeavours benchmark means that SA Power Networks can still comply with these obligations despite not achieving some feeder category reliability targets. The following supports that SA Power Networks has used best endeavours to meet all targets despite not achieving two targets.

As outlined above, SA Power Networks achieved seven of the eight feeder category normalised reliability targets, compared to achievement of an average of 4.6 out of eight targets for the TSP. Further, there is no declining trend in normalised reliability performance for any feeder category, just typical annual variations in performance (see Section **Error! Reference source not found.** for more d etails).

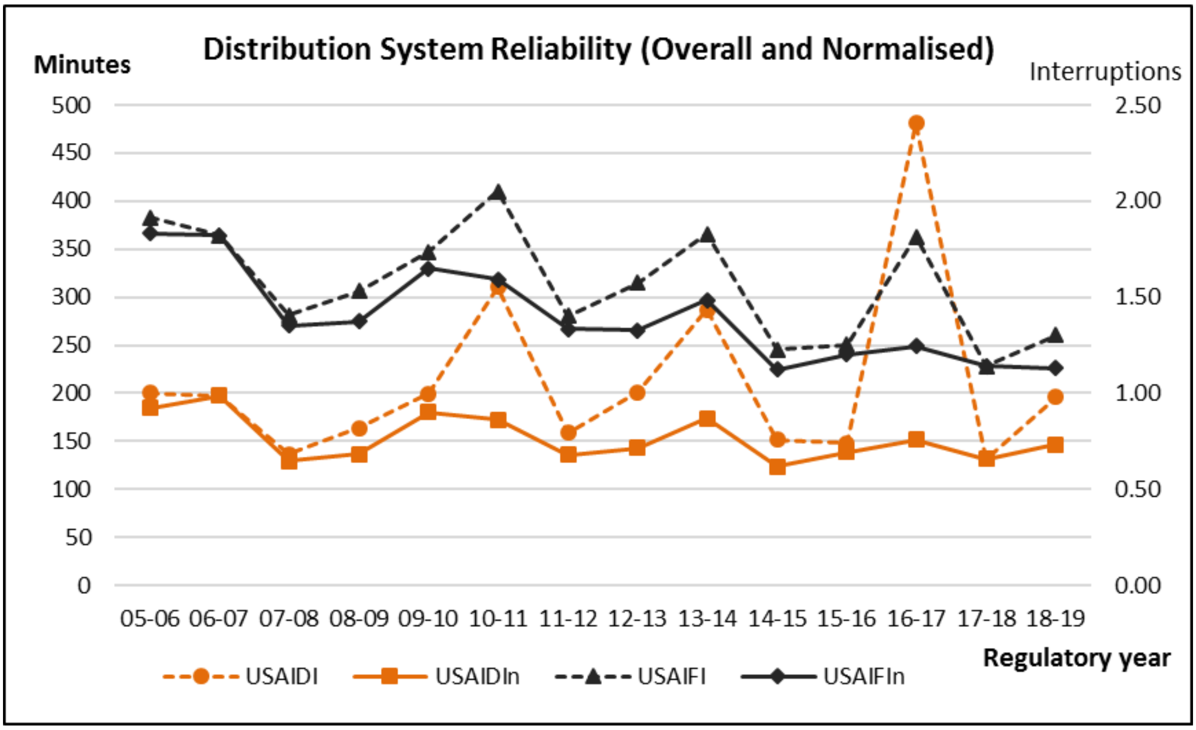


Figure 15: Overall distribution system unplanned reliability performance

Our analysis shows that reliability performance at the aggregate level of the distribution system has been maintained in 2018/19 and reflects that SA Power Networks used 'best endeavours' to meet the EDC reliability targets. This assessment is based on the following observations:

- Trends of normalised USAIDI and USAIFI performance show that reliability performance has been maintained in 2018/19 and over recent years. As shown in Figure 15 above, normalised reliability is consistent with the long term average since 2007/08;

- Seven of the eight EDC feeder category normalised reliability targets were achieved in 2018/19 favourably comparing to a historic average of 4.6 over the TSP;
- Analysis of distribution system maintenance practices and outcomes indicates that:
  - The contribution to normalised USAIDI performance due to the cause 'equipment failure' is stable and has no declining trend;
  - The contribution to USAIDI performance during MEDs due to the cause 'equipment failure' is stable; and
  - The average daily contribution to USAIDI that results from all distribution system unplanned interruption causes on non-MED BoM verified SWEs is stable; and

- The poor performance of Rural Long feeders in 2018/19 is due to two SWEs, there is no declining trend in USAIDI performance.

12.1.3 Reliability corrective actions

Where the measures and standards described under 5.8(j)(1) were not met in the preceding year, Schedule 5.8(j)(4) requires SA Power Networks to provide information on the corrective action that has been taken or is planned.

Rural long

The non-achievement of the Rural long USAIDIn target in 2018/19 is not systemic. The main reason for the failure to achieve the target in 2018/19 was the result of three localised SWE which contributed 65 minutes to USAIDIn and without this contribution the USAIDIn target would have been achieved. Figure 16 below highlights that there is no declining trend in USAIDIn performance which demonstrates that there are no long term systemic causes for the USAIDIn performance in 2018/19.

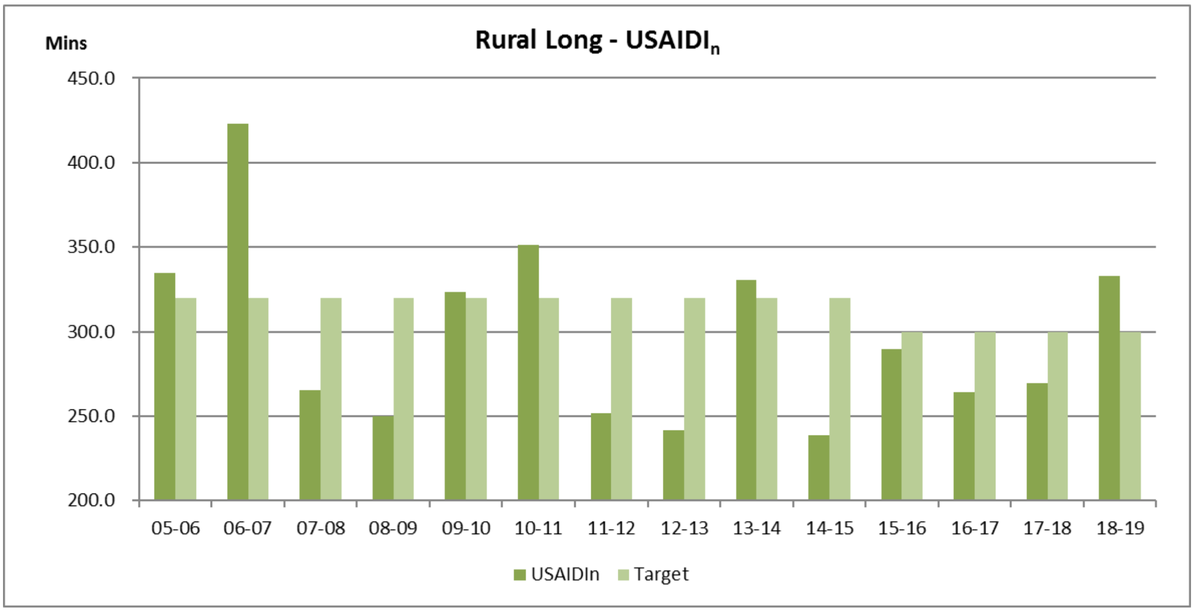


Figure 16: Rural long USAIDIn performance since 2005/06

As there are no long term systemic issues with the USAIDIn result for 2018/19, we intend to take no corrective actions. We expect that the USAIDIn performance for 2019/20 will achieve the target.

12.1.4 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 where 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.

12.2 Quality of supply performance

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

12.2.1 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 frequency of electricity supplied through its electricity network. The Australian Energy Market Operator (**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.

12.2.2 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, 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%[17] 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.

12.2.3 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

17 The 99th percentile (V99%) of the 10-minute average voltage readings for a 1-week survey should be less than 253V and the 1st percentile (V1%) should be greater than 216V.

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.

12.2.4 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:

- 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.

12.2.5 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 of 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.

12.2.6 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; and survey tests at transformers to determine their loading.

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:

- there appeared to be no major concerns relating to the overall power quality performance of SA Power Networks; and
- In terms of network compliance based on the performance of 95% of sites, all measured disturbance values were compliant.
- SA Power Networks did not participate in the Quality of Supply Assurance Program in 2016/17 but has since resumed participation in the 2018/19 program. The latest power quality data has been supplied to PQA for further analysis.

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[18]. Table 28 details the percentage of QoS related complaints from customers, by category and cause.

Table 28: QoS related complaints by category and cause for 2018/19

Complaints - technical quality of supply	2018/19
Complaints - technical quality of supply - number	97
Complaints by category	%
Low voltage supply	7
Voltage dips	6
Voltage swell	11
Voltage spike (impulsive transient)	1
Waveform distortion	0
TV or radio interference	1

[18] As per AS/NZS 10002:2014.

Solar related	64
Noise from appliances	0
Other	9
Complaints by Likely Cause	%
Network equipment faulty	6
Network interference by NSP equipment	0
Network interference by another customer	0
Network limitation	33
Customer internal problem	51
No problem identified	0
Environmental	1
Other	9

Source: SA Power Networks 2018/19 Annual RIN, 3.6 Quality of services

According to Table 28, quality of supply related complaints has since doubled due to increasing levels of distributed energy resources significantly impacting the voltages on the LV network. Voltage excursions outside of mandated limits are becoming more prevalent, significantly increasing the number of quality of supply enquiries and complaints. This step-change in customer enquiries is consuming more resources in both the increased number of investigations required and the number of network upgrades mandated.

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. Enquiry refer to a request for information (which requires further investigation) received from a customer or their representative via nominated enquiry channels. In October 2019, we experienced the largest number of customer enquiries ever recorded, as can be seen in Figure 17.

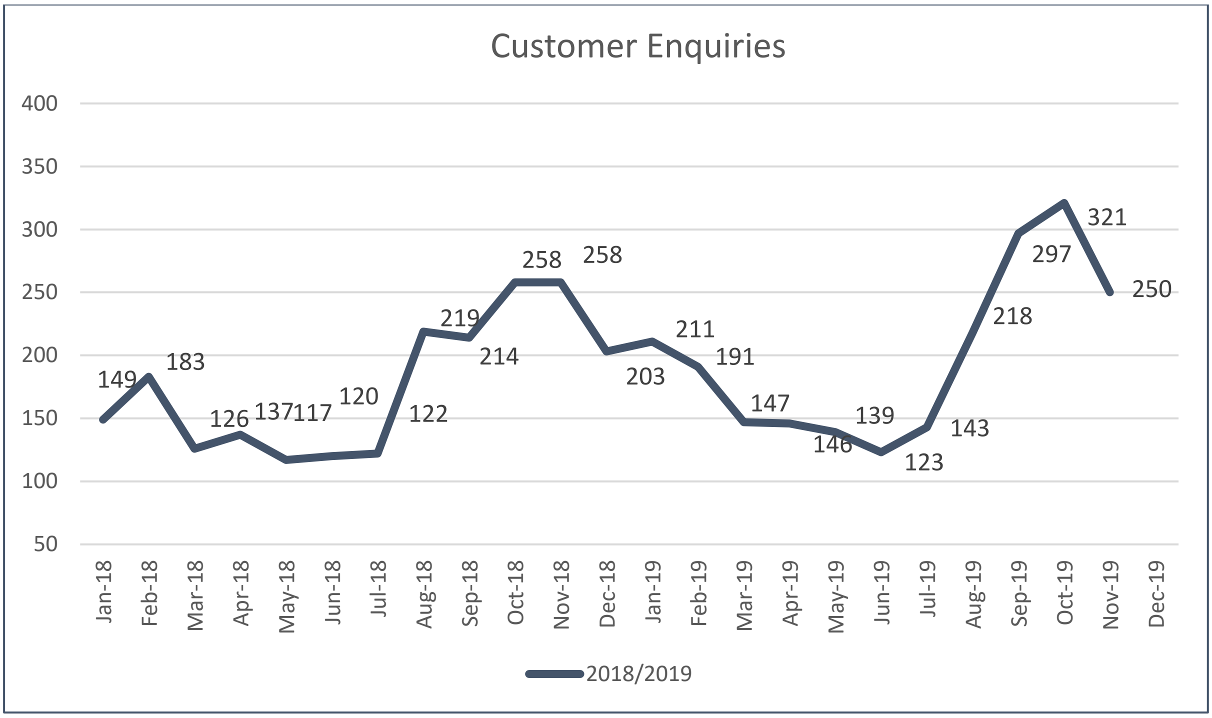


Figure 17: QoS customer enquiries in 2018/19

Figure 18 shows that PV related over voltage enquiries have experienced a significant step increase over recent years due to DER uptake. The sharp increasing trend seen in 2017 and 2018 has continued in 2019, with a new record number of enquiries in September 2019, up 33% on the previous year.

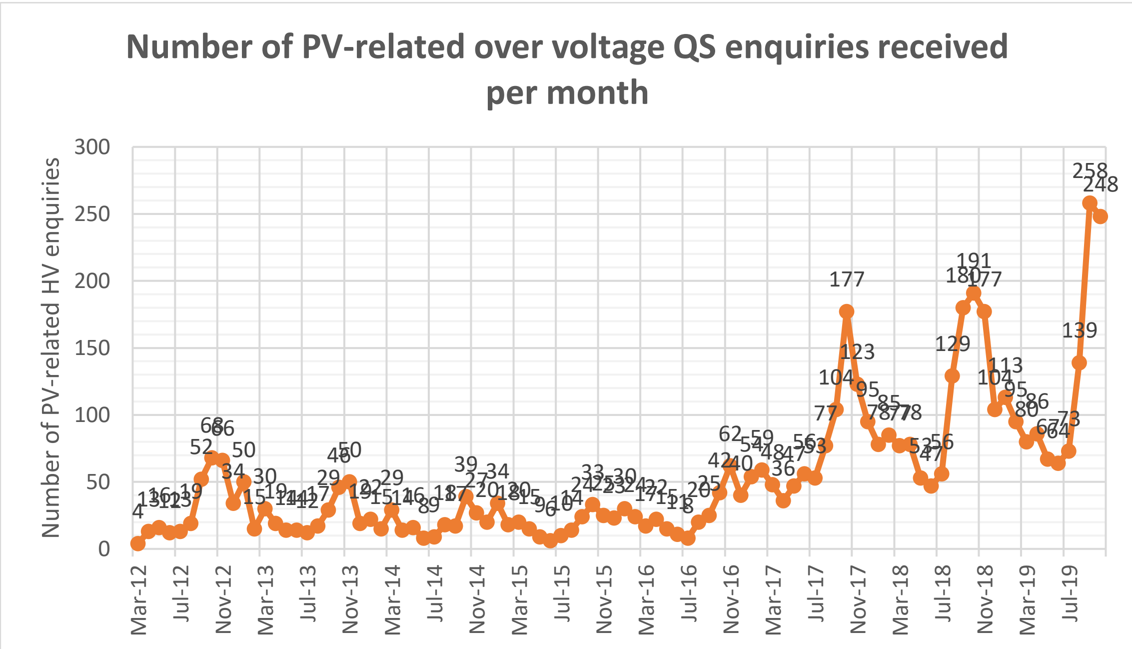


Figure 18: PV related over-voltage customer enquiries in 2018/19

With the significant rise in customer enquiries, SA Power Networks is no longer able to manage QoS issues reactively. In 2017 we commenced a program to install permanent HV metering in our rural substations. SA Power Networks has also commenced a program in 2017 installing metering in the LV compartments of pad transformers in areas with high solar PV penetration, this program continued in 2018. The metering provides greater visibility of power quality issues on our network, enabling a more proactive remediation approach.

12.2.7 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. As highlighted in section 12.2.6, in most cases these enquiries are due to customers receiving voltages above the limits prescribed by the Electricity (General) Regulations. SA Power Networks has concerns that complaints arising from voltages above the prescribed limits will increase as solar PV penetration increases across the network. Given we have limited visibility of our LV network, 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; and
- Phase balancing.

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:

- Lowering of 11kV bus set points at Fulham Gardens, Henley South, Holden Hill, Seacombe (including LDC), Kingswood (including LDC), Plympton, Woodforde, Flinders Park, Port Stanvac and Willunga (including LDC) in 2019. Line Drop Compensation (LDC) provides dynamic voltage control in which the substation OLTC relay autonomously adjusts voltage according to a droop curve dependent on substation load. However, it was found that some targeted metropolitan zone substation transformers have insufficient buck taps (voltage reduction) to effectively implement this level of control. This is common to 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 2017-18 summer to selected distribution transformers across metropolitan Adelaide. 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
- SA Power Networks has specified that all new PV installations from 1 December 2017 must apply a ‘volt response’ mode to their inverter (via a setting adjustment) and is recommending the same to customers with compatible equipment. This functionality allows the customer’s

own inverter for their PV system to assist in the management of localised over-voltage, particularly when there is significant voltage rise beyond the Service Point.

- A comprehensive Low Voltage Management Strategy has been developed. This will enhance the capability of SA Power Networks to understand the DER hosting capacity of its LV network and enable dynamic management of the output of customers' DER to maintain exports at levels that do not exceed these thresholds. This approach is described in detail within SA Power Networks' 2020 – 2025 Regulatory Proposal.

12.2.8 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 complaints 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.

12.3 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 11 of the AER's 'Final Decision SA Power Networks final determination 2015-16 to 2019-20 – Attachment 11, October 2015'.

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.

Table 29 and Table 30 provide details of our STPIS feeder category performance for the regulatory year ending 30 June 2019.

Table 29: Unplanned minutes off supply (USAIDI)

Unplanned System Average Interruption Duration Index (USAIDI)	Feeder Category	Target	2018/19
Total sustained minutes off supply	CBD		59.0
	Urban		152.6
	Short rural		222.9
	Long rural		400.9
	Whole Network		**200.3**
Total minutes of excluded events	CBD		45.6
	Urban		53.5
	Short rural		41.9
	Long rural		68.0
	Whole Network		**53.9**
Total sustained minutes off supply after removing excluded events (ie normalised)	CBD	12.48	13.3
	Urban	121.50	99.1
	Short rural	231.06	181.1
	Long rural	311.70	333.0
	Whole Network	**167.9**	**146.4**

Table 30: Unplanned interruptions to supply (USAIFI)

Unplanned System Average Interruption Frequency Index (USAIFI)	Feeder Category	Target	2018/19
Total sustained minutes off supply	CBD		0.1
	Urban		1.2
	Short rural		1.8
	Long rural		2.0
	Whole Network		**1.4**
Total minutes of excluded events	CBD		0.0
	Urban		0.3
	Short rural		0.3

Unplanned System Average Interruption Frequency Index (USAIFI)	Feeder Category	Target	2018/19
	Long rural		0.4
	Whole Network		**0.3**
Total sustained minutes off supply after removing excluded events (ie normalised)	CBD	0.132	0.1
	Urban	1.353	0.9
	Short rural	1.930	1.5
	Long rural	2.027	1.7
	Whole Network	**1.539**	**1.1**

Table 31 details the submission to the AER on the STPIS telephone response performance (or Grade of Service (**GOS**)) for the regulatory year ending 30 June 2018 (ie 2018/19).

Table 31: SA Power Networks telephone response performance

Faults and Emergency telephone calls	2018/19
Total number of calls (includes automated and Agent)	231,392
Number of calls after removing excluded events	209,780
Number of calls received by Agent	113,589
Number of calls answered by Agent within 30 seconds	92,354
Percentage of calls answered within 30 seconds (GOS)	81%

Figure 19 below details the total number of telephone calls to our Faults and Emergency telephone line (including on MEDs) (blue line), the number of calls where the customers elects to speak to an agent (excluding MEDs) (red line) and of those calls then answered by an agent within 30 seconds GOS after excluding MEDs (green line). The figure shows that our GOS has gradually improved since 2005/06.

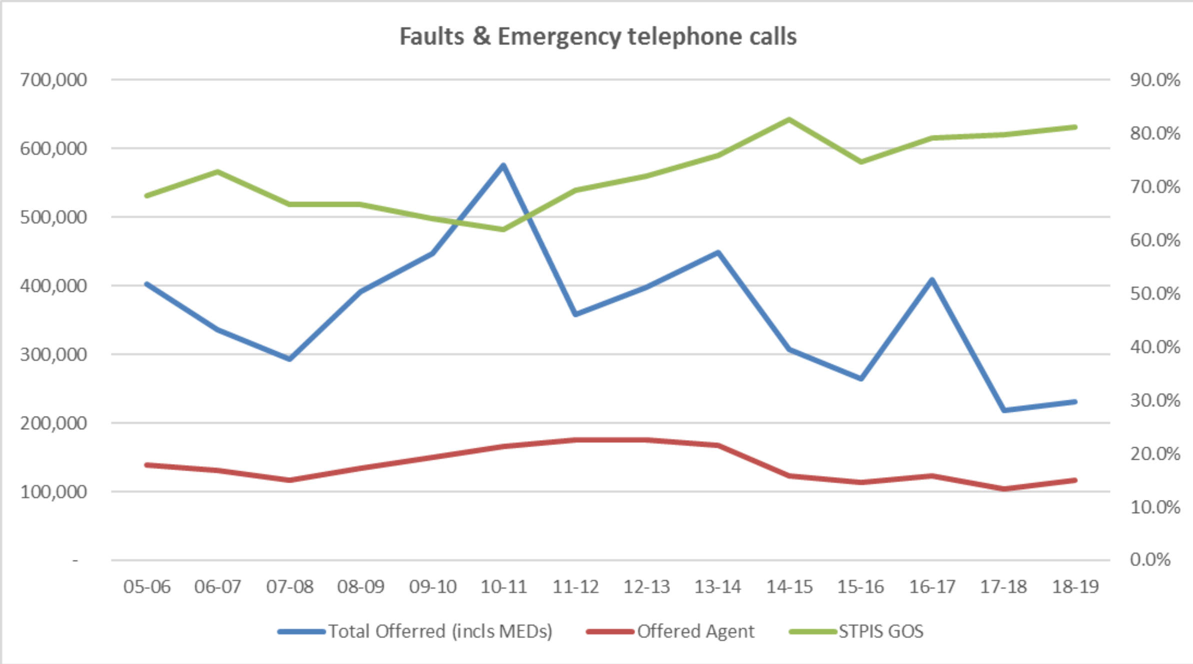


Figure 19: Number of calls to SA Power Networks Faults and Emergency telephone line

13. Asset management approach

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

SA Power Networks asset management approach is guided by its strategic intent of being "A Leader in Delivering Energy Services that Customers Value."

To achieve this, SA Power Networks has a high focus organisationally on asset management and employs good industry asset management practices, guided by its Asset Management Policy, objectives, strategies and plans.

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 and delivers 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 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 appropriately and optimally balance its capital and operational expenditure on assets based on the performance and customer services they provide.
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.

13.1Asset 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.
- Helidrone 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.

13.1.1 Asset life-cycle strategies

Table 32 summarises our inspection and replacement strategies for various asset classes.

Table 32: 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
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.

Asset Class	Inspection Strategy	Replacement Strategy
Substation Transformers	Inspection / testing cycle: routine cycle between 0.5 years and 6 years. Critical inspections: DGA 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	<u>Line switchgear</u> Inspection cycle: routine cycle between 1 years to 5 years, depending on location and type. Critical inspections: OCI and thermographic. <u>Ground/indoor switchgear</u> 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.
SCADA, Network Control	Critical inspections: substation inspections and remote monitoring.	Replace-on-fail, and when no longer supported by vendor.

Asset Class	Inspection Strategy	Replacement Strategy
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.

13.2 Planned strategic Improvements

13.2.1 Increased Inspection Cycles

We have one of the oldest distribution networks in the NEM. A large proportion of our network was installed between the 1950s and 1970s, and so is now in many instances, well over 50 years old. We are however in the early stages of replacing many of these assets. Consequently, replacement levels have been increasing recently to arrest the condition effects of this ageing and in an effort to manage the overall risk of our network.

In our 2010-15 regulatory determination, the AER allowed additional operating expenditure to increase our asset inspections. In response, we have implemented a more detailed and frequent asset inspection regime and are in-cycle across the network.

The increased inspection rate and adoption of an improved, standardised approach to inspections has resulted in a significant increase in the number of identified defects on our network, in particular on our overhead assets..

We have addressed the most critical risks, for instance those in HBFRAs. However, we anticipate that replacement levels will continue to increase in this forward planning period and over the longer term to arrest the rising trend in risk associated with the ongoing ageing of our network.

Table 33 summarises the key asset replacement programs that are being undertaken.

Table 33: Key asset class replacement programs

Asset Class	Replacement Program
Poles	Pole replacement and refurbishments volumes have risen sharply in recent years due to the ageing asset population. It is anticipated pole replacement (and refurbishment) volumes will increase over the longer term as our network continues to age.
Overhead Conductors	Similar to poles, 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.
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 during the 2015-20 RCP 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 2015-20 RCP reflect a change of investment focus driven by the completion of targeted programs in the 66kV and 33kV networks to address known defects and a need for greater ongoing investment to manage the current fleet of poor condition indoor small bulk oil 11kV switchgear, which is technically obsolete and has limited serviceable spare parts available without specialist manufacturing. A program of mid-life mechanical refurbishment over the 2015-20 RCP is also being undertaken to extend the reliable service life of these assets and defer the need for capital replacement works.
Substation Power Transformers	Substation transformer replacement forecasts for the 2015-20 RCP largely align with average annual replacement numbers from the 2010-15 RCP. 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 over the 2015-20 and 2020-25 RCPs.

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 2015-20 RCP represents a continuation of this established monitoring and remediation regime with each site planned for testing and inspection every 10 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 will continue throughout the 2015-20 RCP to address security concerns of all high risk substations, with the progression to medium risk substation sites anticipated during the 2020-25 RCP period.
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 will continue throughout the 2015-20 RCP to complete high risk sites in this period. Medium risk sites are planned for completion towards the end of the 2020-25 RCP.
Protection Systems	Substation protection systems are replaced based on condition, risk and performance (eg type of failure and defect history).
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.

13.3 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 possible. 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 Demand Side Engagement Document on our website at http://www.sapowernetworks.com.au/centric/industry/our_network/annual_network_plans/demand_side_engagement_document.jsp.

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

1. 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);
2. distribution transformers which meet the requirements of the minimum energy performance scheme (**MEPS**);
3. 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
4. capacity upgrade projects, which generally reduce losses for the same load by the use of 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. Investigations by the Department of Resources, Energy and Tourism (**DRET**) in 2012 and 2013 exploring the viability of expanding the Energy Efficiency Opportunities program to include electricity and gas networks[19] concluded that investment in specific network augmentations solely to reduce network losses was uneconomic and therefore not viable.

13.4 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.

13.5 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:

Network Asset Management Manager:	Steve Wachtel
Contact number:	08 8404 5877
Email:	steven.wachtel@sapowernetworks.com.au

[19] http://eeo.govspace.gov.au/files/2013/07/EEO-electricity-trials-report.pdf

14. Demand management activities

Schedule 5.8(l) requires SA Power Networks to provide information on our demand management activities.

SA Power Networks' Network Strategy group trials and evaluates emerging demand management technologies. The group is charged with identifying 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 range from metering, transformer monitoring, energy storage and direct load control of customer appliances such as air conditioners to customer-based technology such as in-home-displays.

Aside from consideration of specific demand management opportunities, SA Power Networks' Demand Side Participation Strategy seeks to provide knowledge, incentives and tools to enable customers to optimise their own energy costs and those of the community.

14.1Demand 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.

Where SA Power Networks determines a non-network option may be a viable solution to resolve a specific system limitation, a Non-Network Options Report (**NNOR**) 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' Demand Side Engagement Register.

In the past year, SA Power Networks has not published any NNOR's.

14.2 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 energy transformation with world-leading levels of renewable generation relative to demand, and the increasing penetration of rooftop solar PV has seen periods in the middle of the day of record low demand. We are working with ElectraNet to analyse the challenges presented by a declining minimum demand.

Excessive voltage levels across the network are 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.

Whilst there were no completed applications to connect embedded generation under Chapter 5 of the NER in the past year (refer Table 34), 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 34: Embedded generation connection enquiries and applications

2018/19 Embedded Generation	Quantity
Applications to connect received (30kW and under)	34,821
Connection enquiries received (applicable only for above 30kW, under 200kW)	393
New applications to connect received (above 200kW)	96
The average time taken to complete applications to connect (above 200kW)	6 months

For further information on the impacts of DER refer to Section 12.2.6.

14.3 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 in the preceding year, including generation from embedded generating units.

SA Power Networks revised and published its Demand Side Engagement Document (**DSED**) in August 2019. This document provides a guide for third parties to explain how we will consider and assess the viability of non-network 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 at:

https://www.sapowernetworks.com.au/industry/annual-network-plans/demandside-engagement-register/

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.

Virtual Power Plant (VPP) Integration Platform

In 2018, SA Power Networks began trials for implementation of a VPP integration platform. The platform is proposed to enable flexible connections to the network and provide an increase in export capacity of distributed energy resources based on network capacity. It is envisaged that future stages of this platform will enable the ability for network constraints to be made dynamically visible to providers of non-network solutions and the broader energy market to promote a competitive market.

14.4 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 DSED. A copy of the DSED can be found on our website at:

https://www.sapowernetworks.com.au/data/3033/demand-side-engagement-document/

No applications have been made under clause 5.3A of the NER in the 2019 period.

14.5 Demand management connection enquiries and applications to connect

Schedule 5.8(l)(2) requires SA Power Networks to provide a quantitative summary of those connection enquiries, applications to connect and the average time taken to complete applications to connect received according to clause 5.3A of the NER.

Table 35 provides a summary of embedded generation enquires received since publication of the 2018 DAPR.

Table 35: Embedded generation connection enquiries and applications under clause 5.3A

2019 Embedded Generation	Quantity
Connection enquiries received under clause 5.3A.5	11
Applications to connect received under clause 5.3A.9	2
The average time taken to complete applications to connect	N/A

15. Information Technology and Communications investment

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 IT projects being undertaken in the past year and within the forward planning period.

2018/19 to 2019/20 Investment focus

Outage Management System (OMS) Replacement

SA Power Networks' Outage Management System (OMS) is a critical operational system that should enable efficient management of customers off supply and subsequent restoration and reporting of events to meet SAPN's regulatory compliance requirements. Given the critical nature of these activities it is essential that the OMS is efficient and resilient to ensure the highest quality of service delivery to customers and the effective running of the business. The current OMS is no longer fit for purpose for SAPN's operational and regulatory requirements. It was unable to cope during the major storm and system events in 2016/17 due to the volume of jobs created. This had a major negative impact on customer service resulting in an urgent need to address these issues by replacing the existing OMS. The Schneider Electric OMS will replace the existing system, leveraging the existing investment in the Advanced Distribution Management System and providing a true fit for purpose OMS for an electricity distribution network and alleviating many current workarounds to ensure greater customer service and the ability to cope with storm events. It also enables SAPN to reduce the complexity of the current system environment to manage and support. The OMS replacement is expected to be completed in 2020.

Assets and Work Program

The Assets & Work (A&W) Program (The Program) aims to improve our asset management capabilities to focus on what the customers value (doing the right work) while managing the risks on an aging network infrastructure. This Program spans multiple regulatory periods and comprises five integrated focus areas which provide capabilities across the asset management framework defined in the Strategic Asset Management Plan 2018.

- Collect the data – optimising our asset data collection;
- Manage the work – how we invest in and monitor our work and resources;
- Select the work –identifying the right work;
- Plan the work – standardising our work preparation processes;
- Do the work – optimising our service delivery.

The key investments across 2017/18 to 2019/20 related to the Program include:

Value and Visibility (V & V) Tool

This project has spanned 2017/18 and 2018/19 and will provide a single methodology and initial tools to value work, assisting with the selection of efficient work packages for execution in the field. The visibility scope of this project will enable planners and schedulers to visualise on a map the risk that exists in the distribution network, which then enables the selection of efficient and prudent work packages (the Right Work).

Risk Quantification Tool

The replacement of our standalone risk quantification tool was completed in 2017/18. This enabled the integration of systems and data used in network planning and expanded the analysis of risks associated with different asset types.

Material Integration and Asset Foundation

We have commenced foundation data work to integrate key asset management systems (SAP and GIS) and then bring the data under governance to improve data quality for improved decision making and allows more accurate reporting information notice (RIN) reporting.

Scheduling and Mobility

Our work scheduling and dispatch system (Click Software) and related field mobility solution is currently undergoing a major upgrade with the existing vendor which involves transitioning the current 'on-premise' software to 'Software-as-a-Service'. This is expected to be completed in 2020.
The Program initiatives planned for the 2020-25 RCP leverage the foundational and pilot capabilities enabled by the above initiatives, enabling us to greatly improve our asset management capability to manage the distribution network assets and risks. We will improve our ability to select the right work and reduce network maintenance costs therefore benefiting our customers.

Environment, Safety and Operational Risk Management System Replacement:

In 2017/18 and 2018/19 we have invested in the replacement of our legacy Environment, Safety and Operational Risk Management system, Cura. The replacement system, Enablon, will improve environment, safety and operational risk management and decision making with higher quality and timely risk, accident, incident or near miss data captured in day to day work.

2020/21 to 2022/23 Investment focus

Cyber security

Cyber security is a fundamental necessity in the delivery of safe and reliable distribution services. In recent years there has seen a significant escalation in threats to critical infrastructure, with State sponsored threat actors specifically targeting the energy sector. The cyber security threats faced by the energy sector have increased and evolved in ways that could not have been perceived just a few years ago. These threats will continue to change very quickly and increase in prevalence and sophistication. Accordingly, an ongoing annual and prudent investment in cyber security is required to ensure the IT and OT systems that provide services to our customers are reliable, available and trustworthy, and meet these regulatory obligations and requirements.

Network protection settings system replacement

The Network Protection Settings System (**PSS**) is the core 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 2022/23 coinciding with a ramp down in activity on other major IT programs, by which time the current system will be 25 years old.

Geographic Information System (GIS) Consolidation

Understanding the location of the network assets allows us to understand the impact on the customer service of that asset. GIS underpins the delivery of customer, network and outage management services as well as 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 instance in order to enable the continued extension of the work being undertaken in the A&W 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. We expect the bulk of the system consolidation effort to be completed by 2022/23.

Worker safety: Fatigue risk management

Worker fatigue is now a well-documented safety risk which requires improved management. Worker fatigue arises from a number of factors including climate change impacting on working conditions; increased volume of unplanned work; changes in electrical infrastructure and technology; and changes in the nature and intensity of the asset maintenance work. New safety measures and an integrated fatigue risk management system are required to maintain worker and community safety. Investment in Fatigue risk management is planned for 2021/22 and 2022/23.

Assets & Work Program (Continued)

Key focus areas for the continuing A & W Program between 2020/21 and 2022/23 include:

Asset Data Foundations

We will increase the number of asset classes under active asset management and data Governance to continue our improvement in asset management and identification of risk to ensure we select the right assets to be maintained.

Technology Asset Condition & Capture

We will broaden the channels for collection (from customers, all field personnel, and technology eg. Drones and LIDAR), store and management of different types (LIDAR, Thermal, video etc) of condition and fault information about our assets. This will enable improved analysis and decision making.

Value and Visibility Extension

We will extend the pilot V & V methodology and tools into an integrated and automate part of our systems and processes, embedding our improved asset management capability and selection of the right work.

Predictive Fault Identification

Use the increased amount of data and our new approaches to predict and model potential network faults, enabling improved response times to network outages.

Compatible Unit Standardisation

We will increase the use of our ‘compatible units’ to standardise asset planning, improve or design and estimation capability to ensure we can respond to customers faster and more accurately through integrated systems and processes.

Scheduling Resource Management

We will extend out new scheduling system to take advantage of smart optimisation capabilities, maximising the work value using real-time work bundling.

Avalanche Management

Enable Field staff to pull work through the schedule more effectively based on their current location.

16. 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.

This section provides descriptions and network maps identifying the location of network limitations where applicable, for each regional and metropolitan segment of our network.

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 QoS. 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 has regional development plans for the following locations:

16.1 Eastern Suburbs

16.2 Western Suburbs

16.3 Northern Suburbs

16.4 Southern Suburbs

16.5 Adelaide Central Region (CBD);

16.6 Barossa Region

16.7 Eastern Hills

16.8 Eyre Peninsula

16.9 Fleurieu Peninsula

16.10 Mid North and Yorke Peninsula

16.11 Murraylands

16.12 Riverland

16.13 South East

16.14 Upper North

16.1Eastern Suburbs Regional Development Plan

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 Tce 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.

There are system limitations forecast for a sub-transmission line under N-1 conditions, a zone substation and a distribution feeder under normal conditions in the Eastern Suburbs in the forward planning period. Refer to section 6 and 717.1.2 for more details.

Table 36 lists SA Power Networks' Eastern Suburbs zone substations with SCADA, and Figure 20 shows the extent of the Eastern Suburbs region.

Table 36: Eastern Suburbs SCADA Substations

Source Connection Point	Associated SCADA Substations
Eastern Suburbs Meshed 66kV Network: • City West – ACR • Dry Creek – Central and East • East Tce - 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)

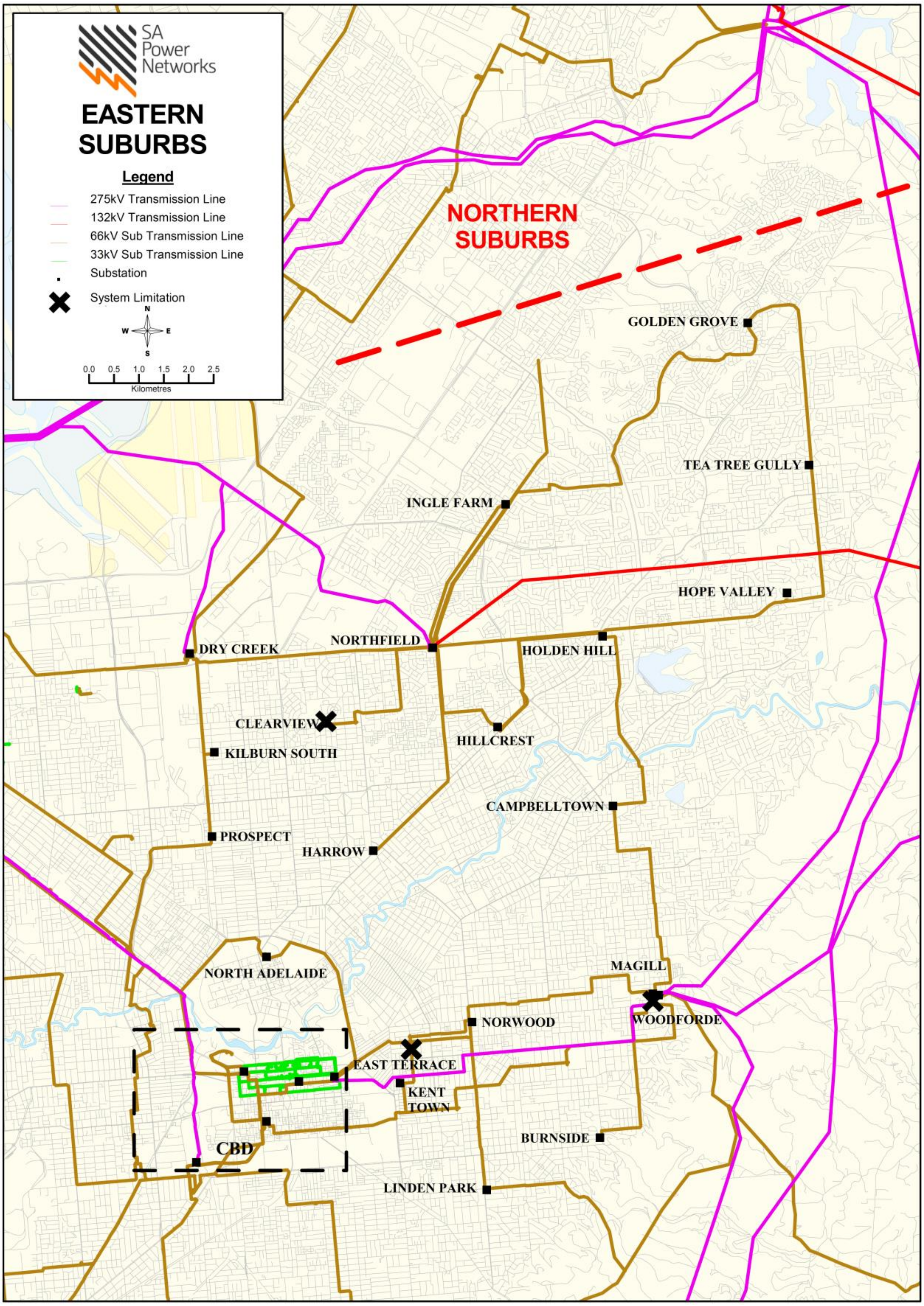


Figure 20: Eastern Suburbs Regional Map

16.2 Western Suburbs Regional Development Plan

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 7,600 Volts, 11,000 Volts or 33,000 Volts.

There are two system limitations forecast for some sub-transmission lines under N-1 conditions in the Western Suburbs in the next two years. Refer to Section 6.1.1 for more details.

Table 37 lists SA Power Networks' Western Suburbs zone substations with SCADA and Figure 21 shows the extent of the Western Suburbs region.

Table 37: 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

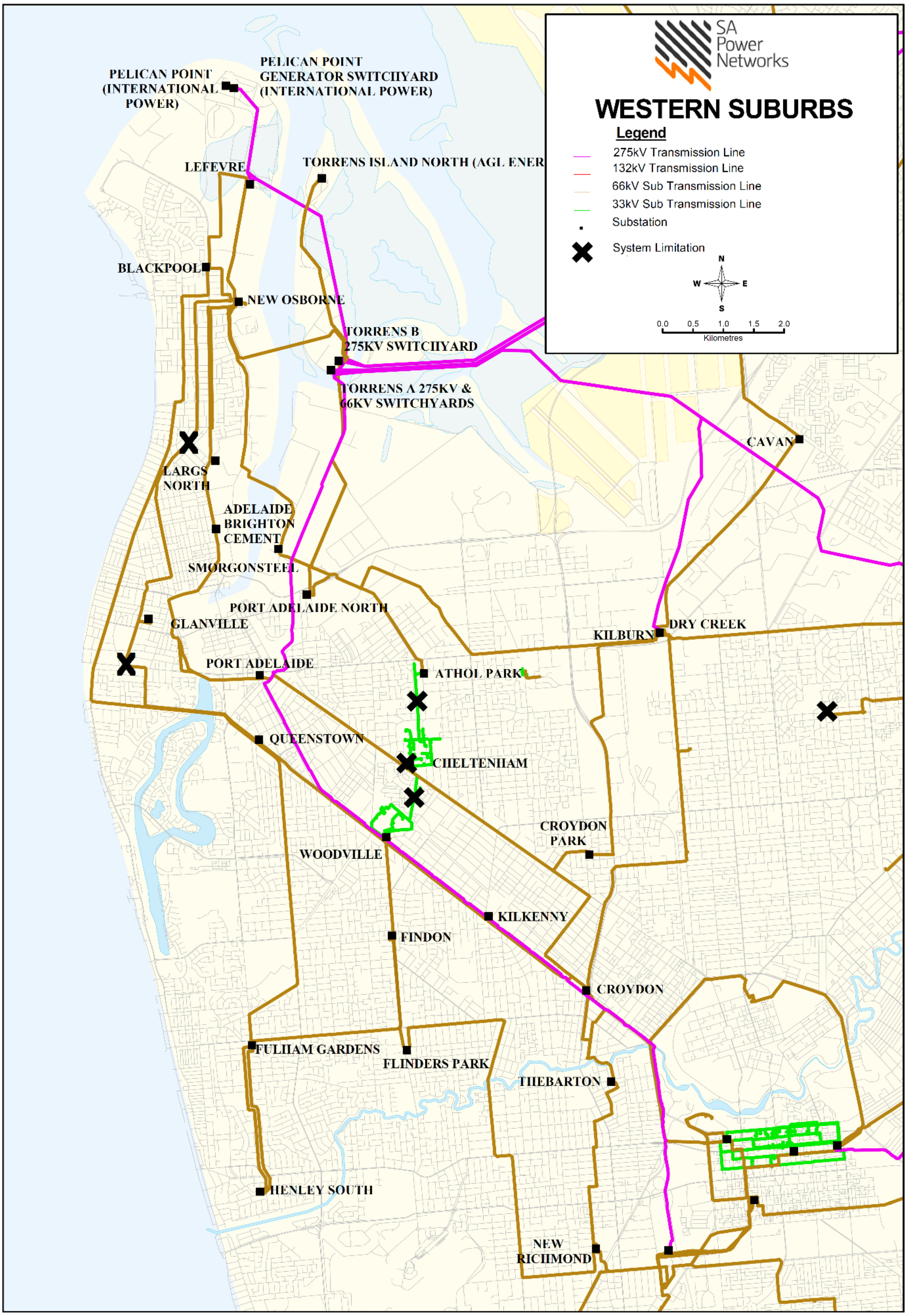


Figure 21: **Western Suburbs Regional Map**

16.3 Northern Suburbs Regional Development Plan

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.

There is one system limitation forecast for a sub-transmission line under N-1 conditions and a system limitation for a distribution feeder under normal conditions in the Northern Suburbs in the next two years. Refer to Section 6.1.1 for more details.

Table 38 lists SA Power Networks' Northern Suburbs zone substations with SCADA, and Figure 22 shows the extent of the Northern Suburbs region.

Table 38: 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

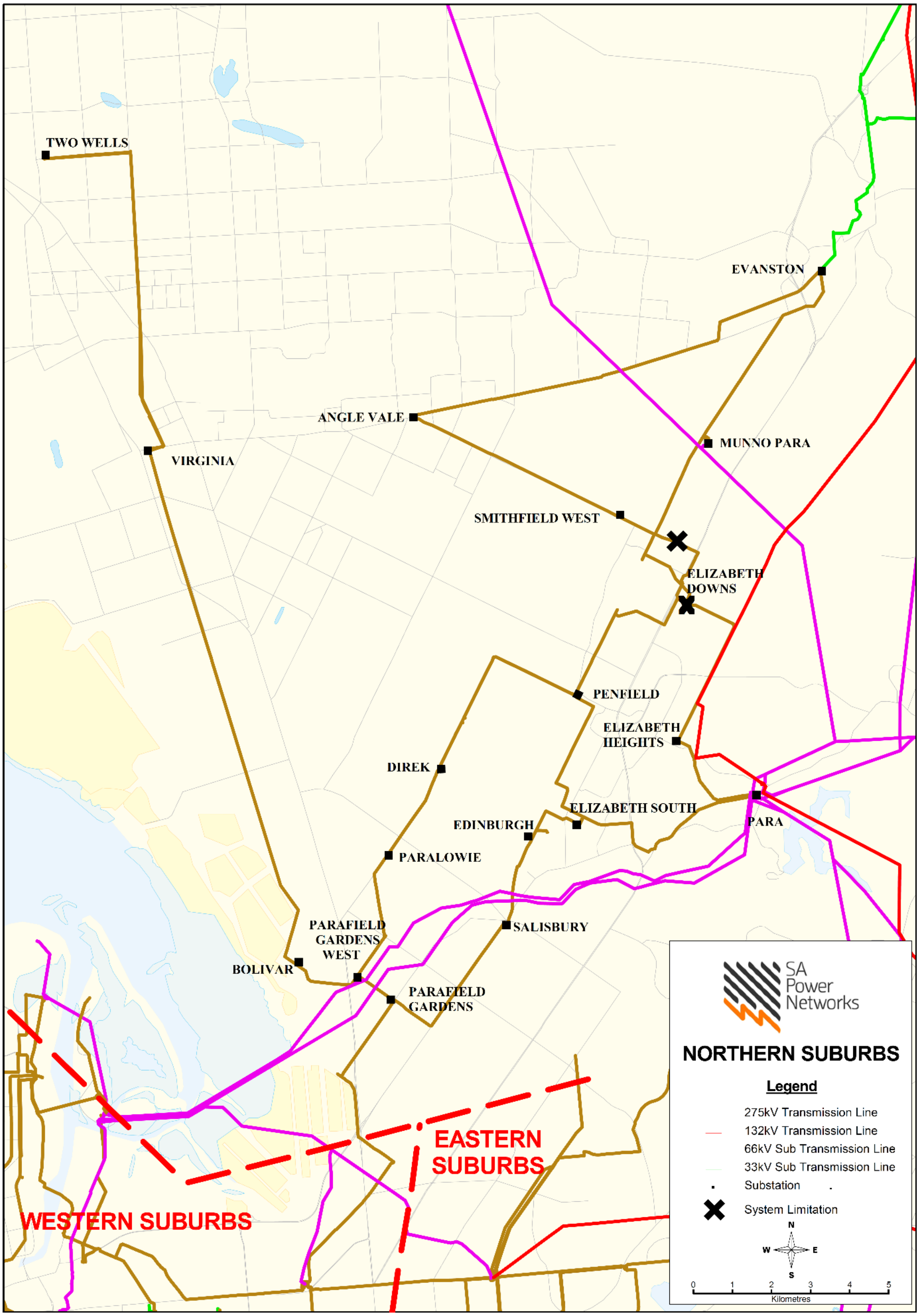


Figure 22: **Northern Suburbs Regional Map**

16.4 Southern Suburbs Regional Development Plan

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.

There are three system limitations forecast for some sub-transmission lines and a substation under N-1 conditions and one system limitation forecast for a distribution feeder under normal conditions in the Southern Suburbs in the next two years. Refer to Section 6.1.1 and 6.2.1 for more details.

Table 39 lists SA Power Networks' Southern Suburbs zone substations with SCADA, and Figure 23 shows the extent of the Southern Suburbs region.

Table 39: 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 • 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

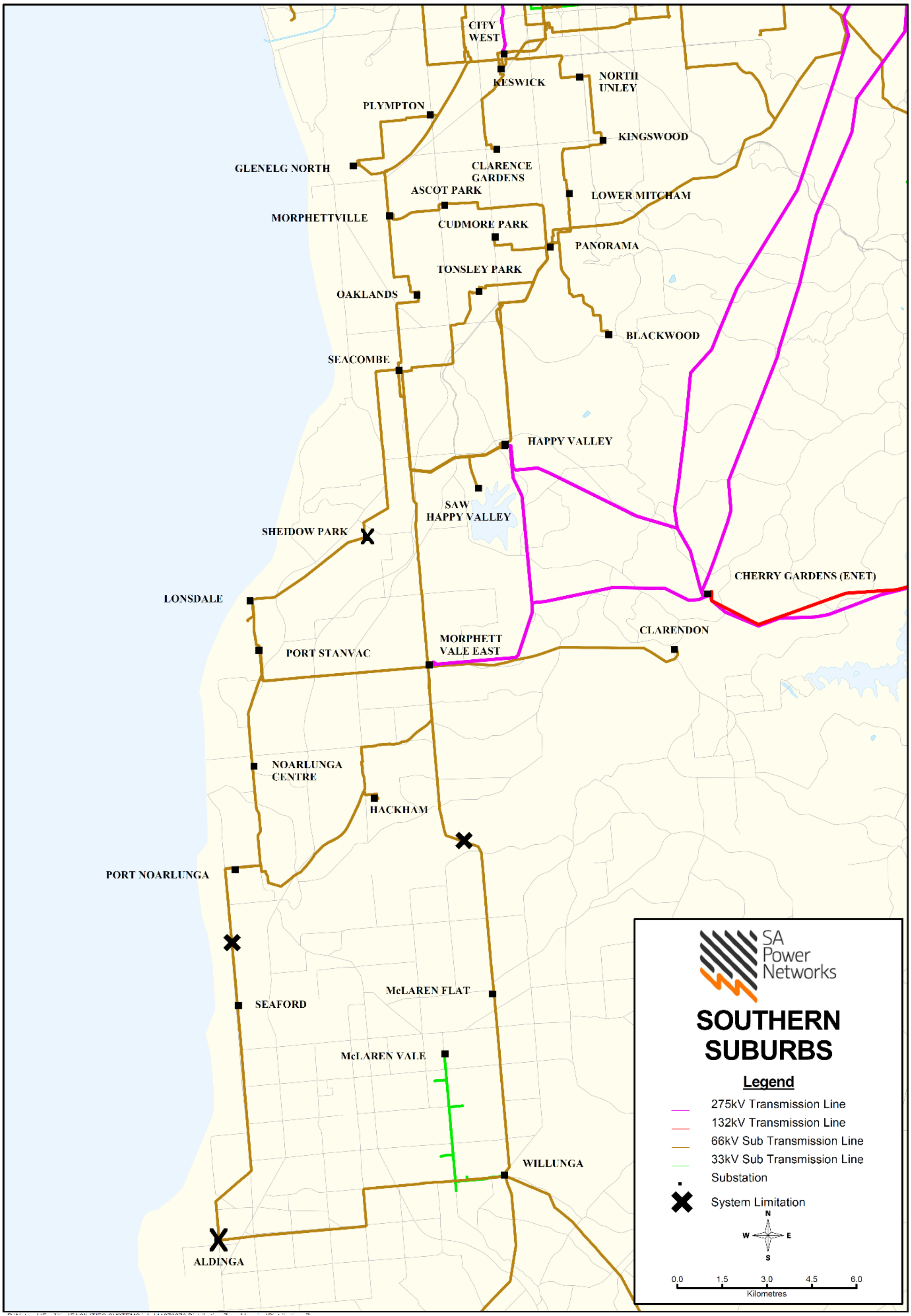


Figure 23: **Southern Suburbs Regional Map**

16.5 Adelaide Central Region (Central Business District) Regional Development Plan

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.

There are no system limitations forecast for the primary distribution feeders under normal conditions in the Adelaide Central Region in the next two years.

Table 40 lists SA Power Networks' ACR zone substations with SCADA, and Figure 24 shows the extent of the ACR region.

Table 40: ACR SCADA Substations

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

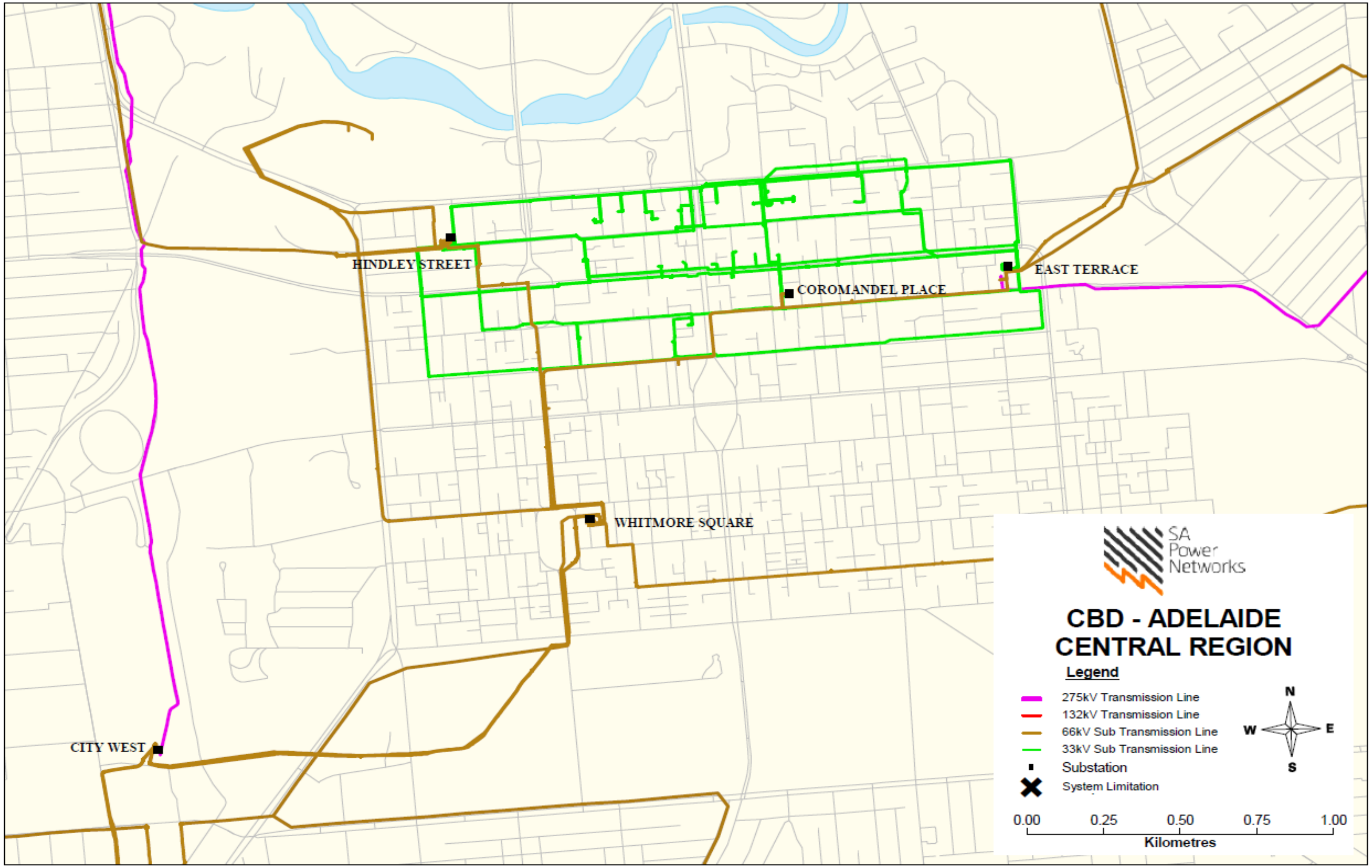


Figure 24: ACR Regional Map

16.6 Barossa Regional Development Plan

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.

There are three system limitations forecast for a substation and some sub-transmission lines under N-1 conditions in the Barossa region in the next two years. Refer to Sections 6.1.7, 6.1.8 and **Error! Reference source not found.** for more details.

Table 41 lists SA Power Networks' Barossa zone substations with SCADA, and Figure 25 shows the extent of the Barossa region.

Table 41: Barossa SCADA Substations

Source Connection Point	Associated SCADA Substations
Dorrien	• Angaston • Barossa South • Dorrien • Gomersal North • Lyndoch • Lyndoch South • Nuriootpa • Sandy Creek • Stockwell • Williamstown • Williamstown South

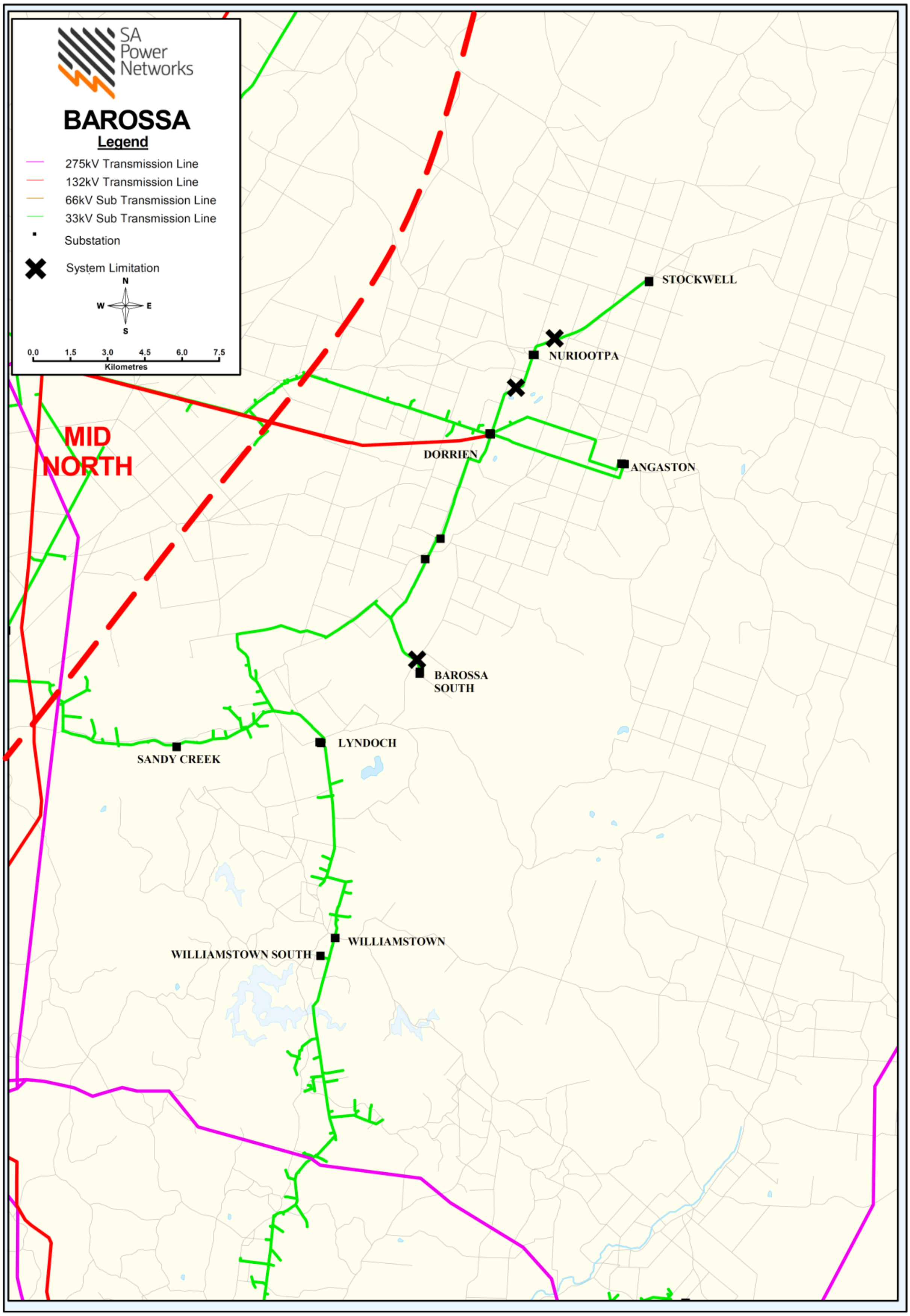


Figure 25: Barossa Regional Map

16.7 Eastern Hills Regional Development Plan

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 Mount Barker, Mount Barker South and Angas Creek, and a minor transmission connection point at Kanmantoo 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.

There are five system limitations forecast for substations under normal conditions in the Eastern Hills region in the next two years. Refer to Section 6.1.16.2.1 for more details.

Table 42 lists SA Power Networks' Eastern Hills zone substations with SCADA, and Figure 26 shows the extent of the Eastern Hills region.

Table 42: 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 • Hahndorf • Langhorne Creek • Meadows • Milang • Mt Barker 11kV • Mylor	• Nairne • Piccadilly • Stirling East • Strathalbyn • Uraidla 11kV • Uraidla 33kV • Woodside

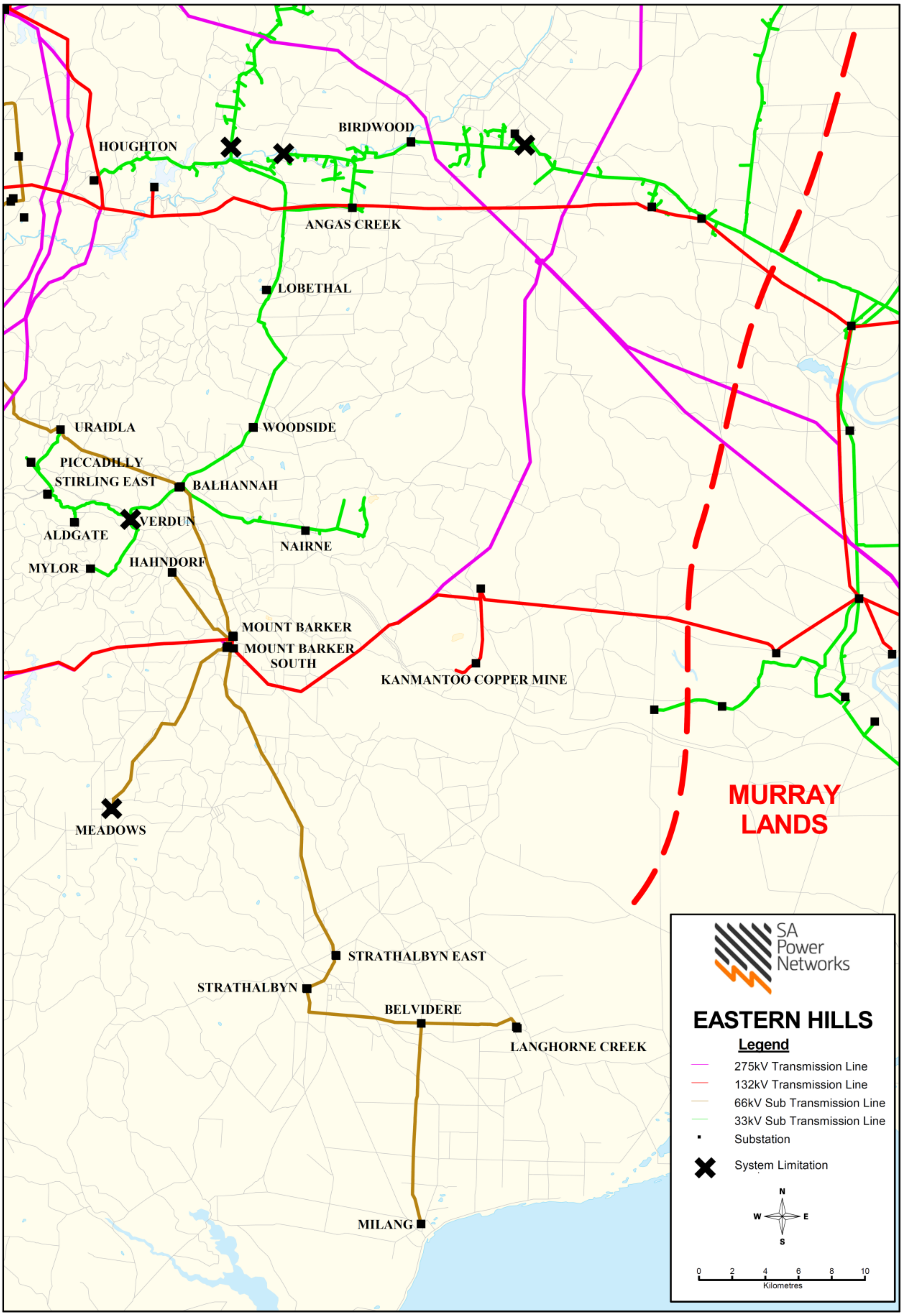


Figure 26: Eastern Hills Regional Map

16.8 Eyre Peninsula Regional Development Plan

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.

There are two system limitations forecast for some substations under N-1 conditions and two system limitations for a substation and a primary distribution feeder under normal conditions in the Eyre Peninsula region in the next two years.

Table 43 lists SA Power Networks' Eyre Peninsula zone substations with SCADA, and Figure 27 shows the extent of the Eyre Peninsula region.

Table 43: Eyre Peninsula SCADA Substations

Source Connection Point	Associated SCADA Substation	
Port Lincoln Terminal	• Coffin Bay • Cummins • Point Boston • Poonindie • Port Lincoln City	• Port Lincoln Docks • Port Lincoln Marina • Tumby Bay • Little Swamp • 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	

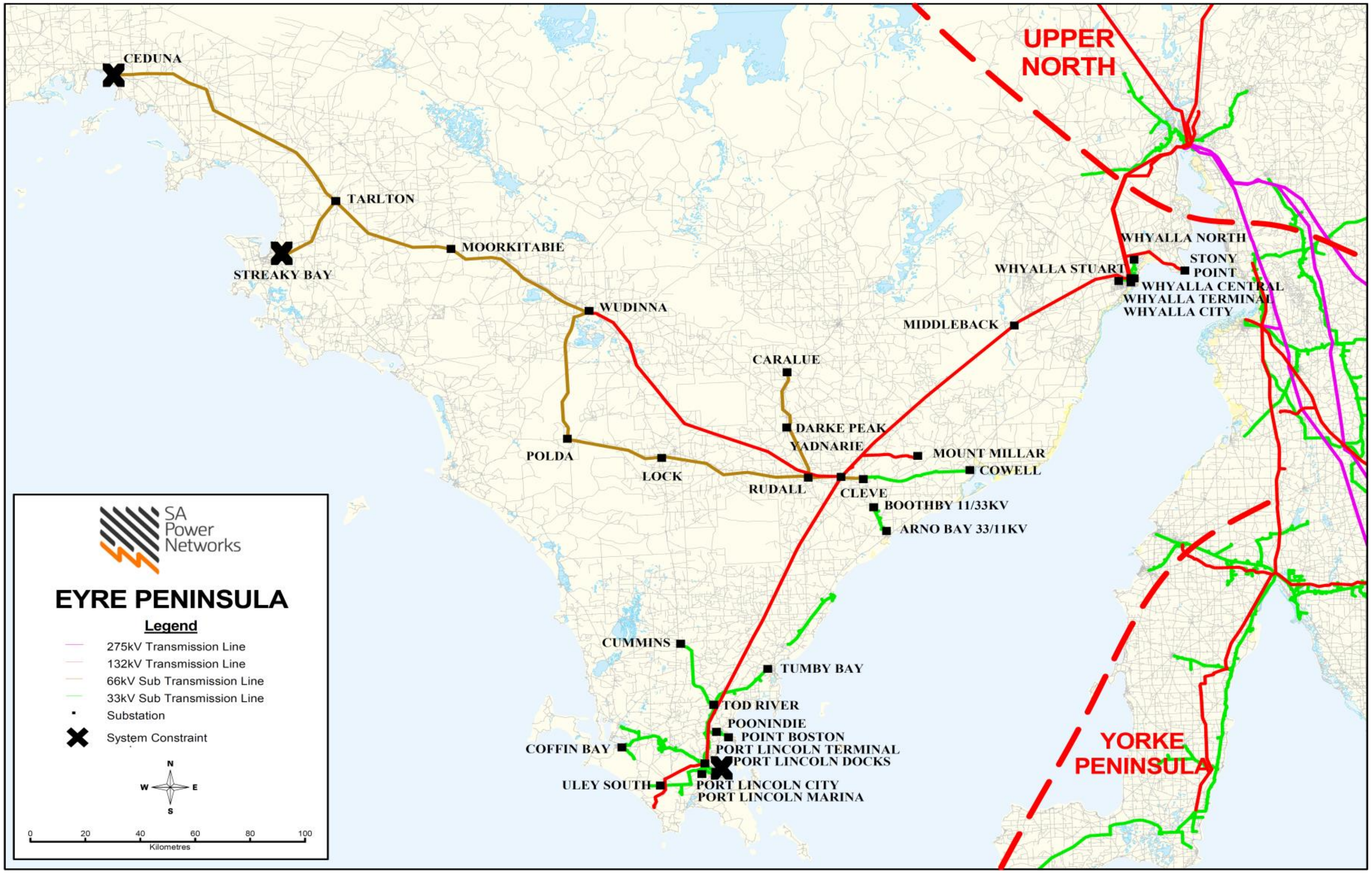


Figure 27: Eyre Peninsula Regional Map

16.9 Fleurieu Peninsula Regional Development Plan

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.

There are no system limitations forecast for the primary distribution feeders under normal conditions in the Fleurieu Peninsula in the next two years.

Table 44 lists SA Power Networks' Fleurieu Peninsula zone substations with SCADA, and Figure 28 shows the extent of the Fleurieu Peninsula region.

Table 44: Fleurieu Peninsula SCADA Substations

Source Connection Point	Associated SCADA Substations
Southern Suburbs Meshed 66kV Network (Refer to 15.4 Southern Suburbs Regional Development Plan)	• American River • Cape Jervis 33kV • Cape Jervis 11kV • Goolwa • Kingscote • MacGillivray • Myponga • Penneshaw • Square Water Hole • Victor Harbor • Yankalilla 33kV • Yankalilla 11kV

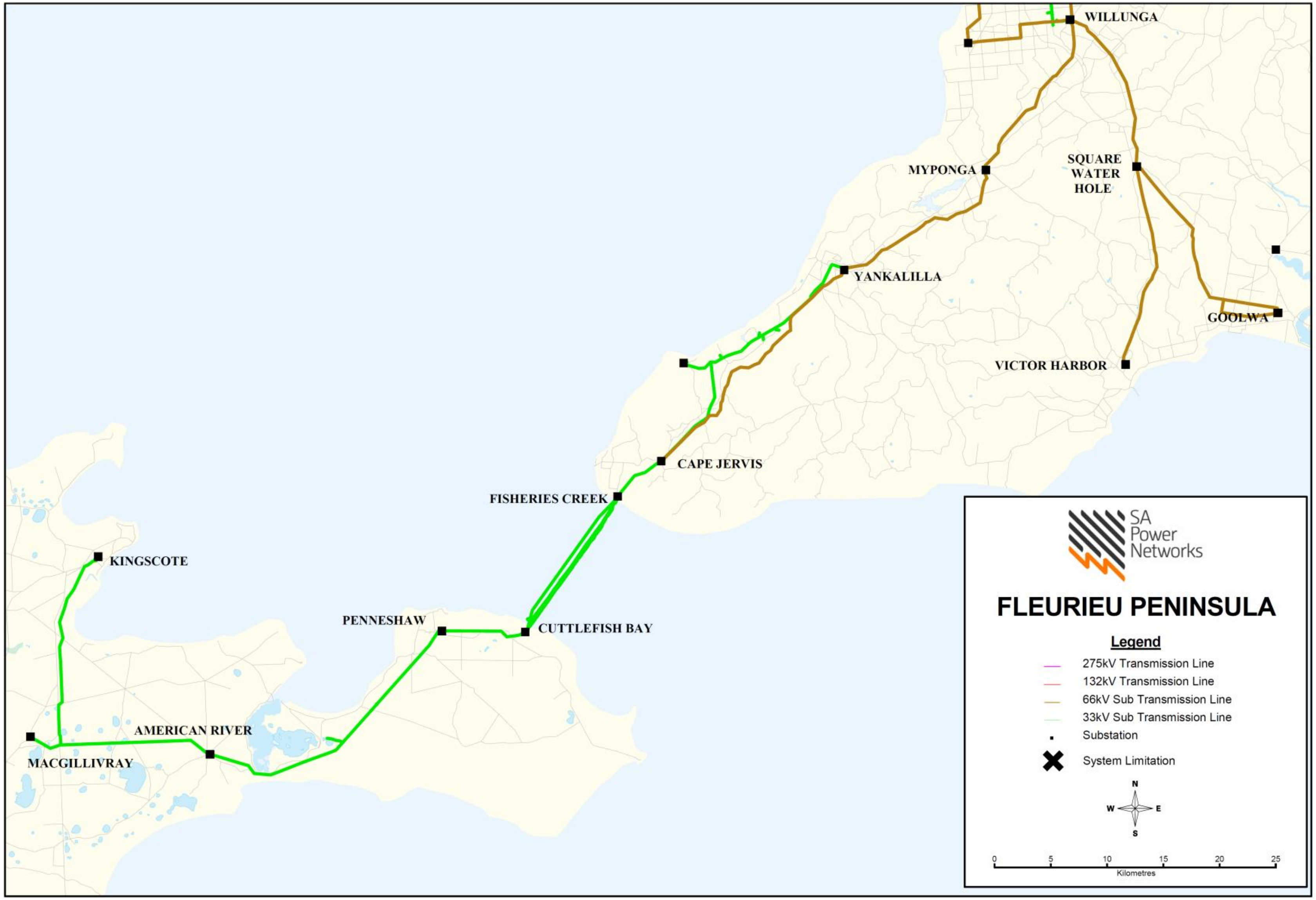


Figure 28: Fleurieu Peninsula Regional Map

16.10 Mid North and Yorke Peninsula Regional Development Plan

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.

There are three system limitations forecast for a substation and some sub-transmission lines under N-1 conditions in the Mid North and Yorke Peninsula region in the next two years. Refer to sections **Error! Reference source not found.**, 6.1.6 and 6.2.2 for details.

Table 45lists SA Power Networks' Mid North and Yorke Peninsula zone substations with SCADA, and Figure 29 shows the extent of the Mid North and Figure 30 shows the extent of the Yorke Peninsula region.

Table 45: Mid North and Yorke Peninsula SCADA Substations

Source Connection Point	Associated SCADA Substations	
Ardrossan West	Ardrossan Maitland	Minlaton Port Vincent
Brinkworth	Brinkworth Town Georgetown Hoyleton	Collinsford Kybunga Spalding
Clare North	Burra TF2	Clare
Dalrymple	Edithburgh Marion Bay Port Giles	Marion Bay Warooka Yorketown
Hummocks	Balaklava	Port Clinton
Kadina East	Kadina Moonta	Wallaroo
Templers	Freeling North Gawler Belt 1/2 Hamley Bridge	Kapunda 1/2 Mallala
Waterloo	Riverton Marrabel	Waterloo Town Eudunda

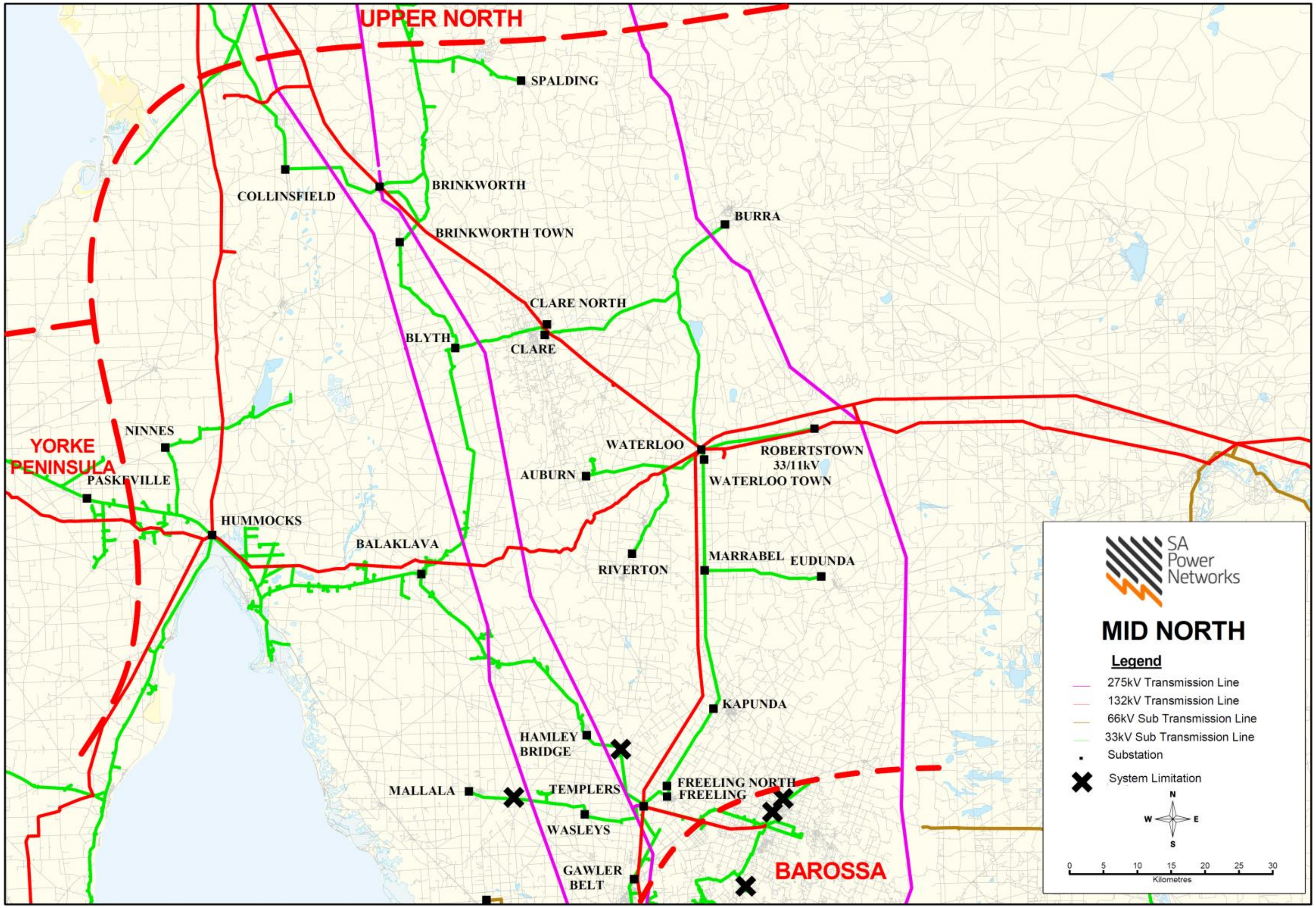


Figure 29: Mid North and Yorke Peninsula Regional Map

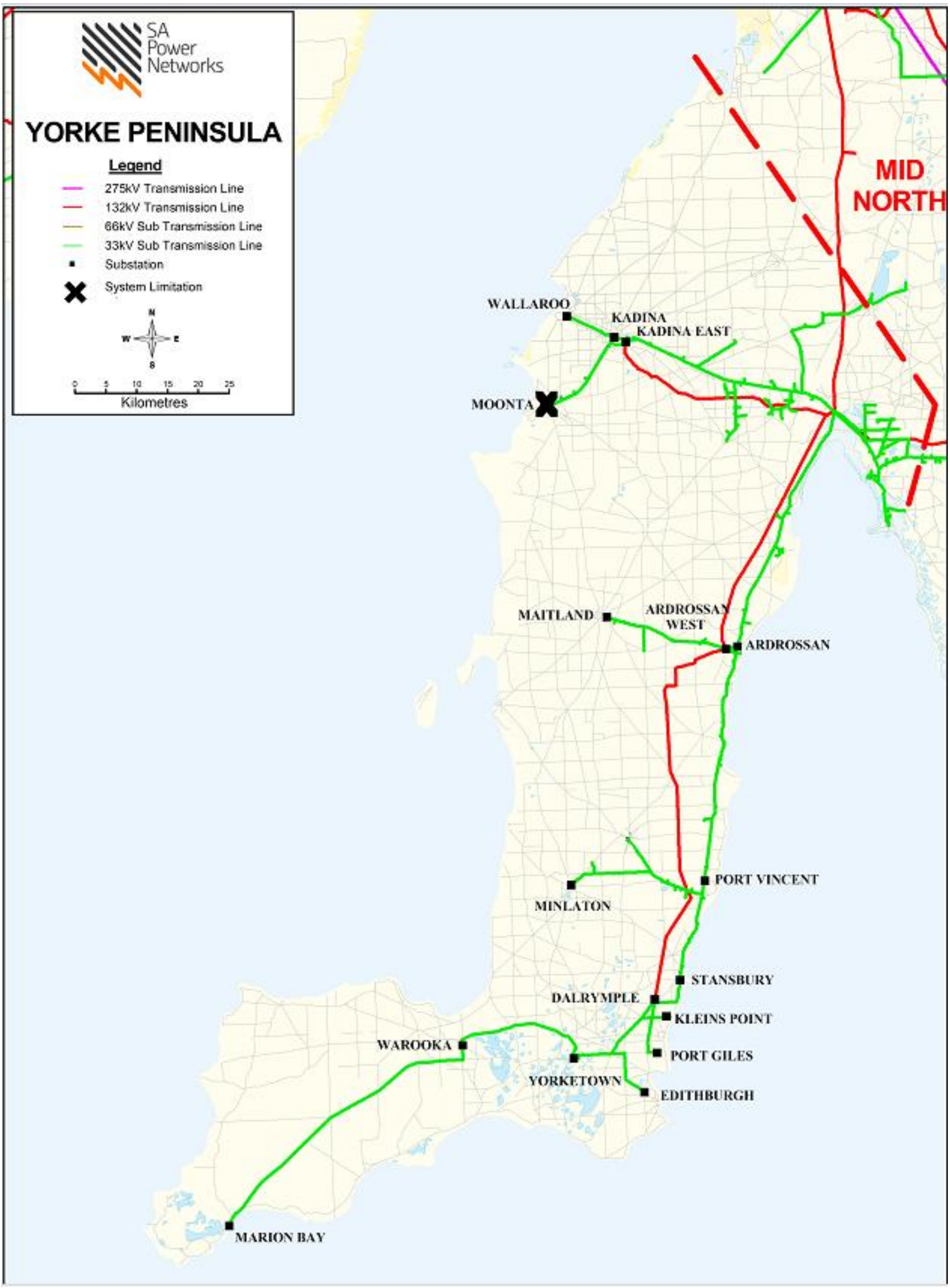


Figure 30: Yorke Peninsula Regional Map

16.11 Murraylands Regional Development Plan

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.

There are no system limitations forecast for the primary distribution feeders in the Murraylands Region in the next two years.

Table 46 lists SA Power Networks' Murraylands zone substations with SCADA, and Figure 31 shows the extent of the Murraylands region.

Table 46: Murraylands SCADA Substations

Source Connection Point	Associated SCADA Substations	
Mannum	Caloote Nildottie Mannum Town	Punyelroo Walker Flat
Mobilong	Monarto South Monarto Central Murray Bridge North	Murray Bridge South Mypolonga
Tailem Bend	Binnies Coonalpyn Coomandook Geranium Jervois Meningie	Narrung Parilla Pinaroo Tailem Bend Town White Sands Woods Point

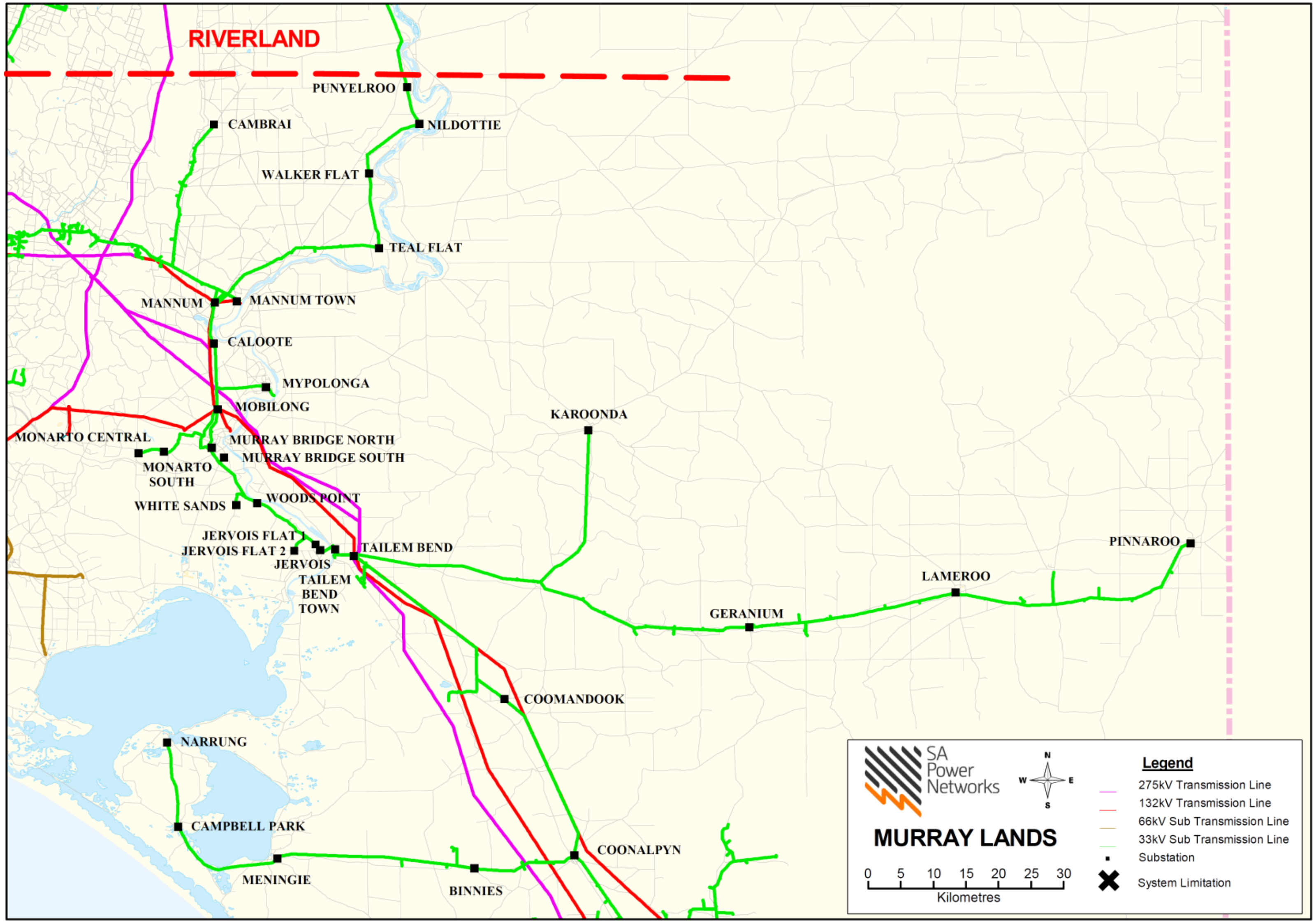


Figure 31: Murraylands Regional Map

16.12 Riverland Regional Development Plan

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 are four system limitations forecast for the substations under N-1 conditions in the Riverland region in the next two years.

Table 47 lists SA Power Networks' Riverland zone substations with SCADA, and Figure 32 shows the extent of the Riverland region.

Table 47: 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 • Portee • Qualco • Ramco • Roonka • Swan Reach 11kV • Swan Reach 33kV • Waikerie

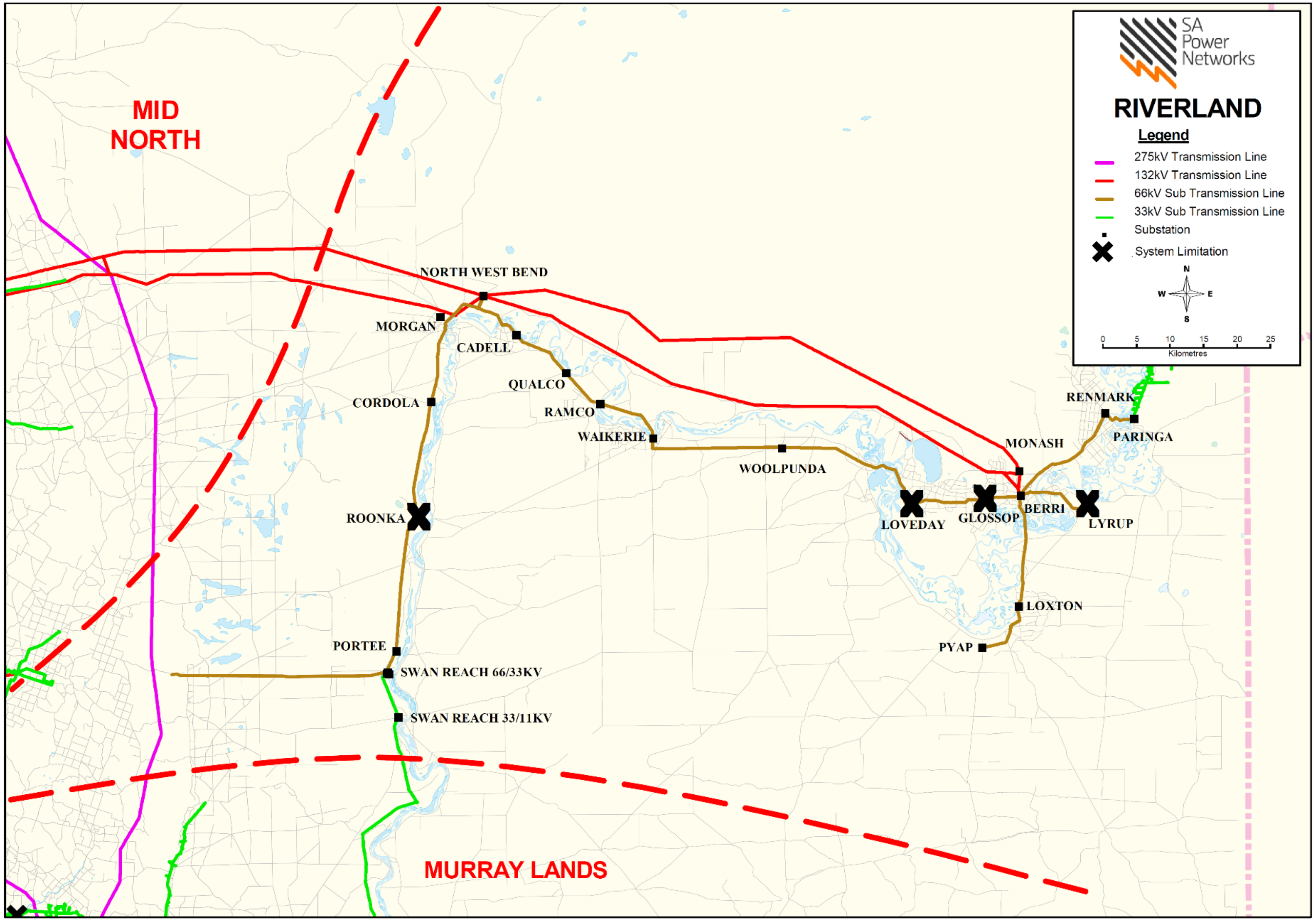


Figure 32: Riverland Regional Map

16.13 South East Regional Development Plan

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.

There are two system limitations forecast for a substation under N-1 conditions in the South East Region in the next two years. Refer to Sections 6.2.1 and 6.2.3 for more details.

Table 48 lists SA Power Networks' South East zone substations with SCADA, and Figure 33 shows the extent of the South East region.

Table 48: South East SCADA Substations

Source Connection Point	Associated SCADA Substations	
Blanche	Allendale East Lakeside Mount Gambier North Mount Gambier West	Glencoe Kongorong Mount Schank Tantanoola
Keith	Bordertown Padthaway	Keith 11kV
Kincraig	Lucindale Naracoorte Naracoorte East	Inverness Kingston SE
Mount Gambier	Mount Gambier Tarpeena South	
Penola West	Coonawarra Nangwarry Penola	
Snuggery	Beachport Kalangadoo West Millicent	Robe South End

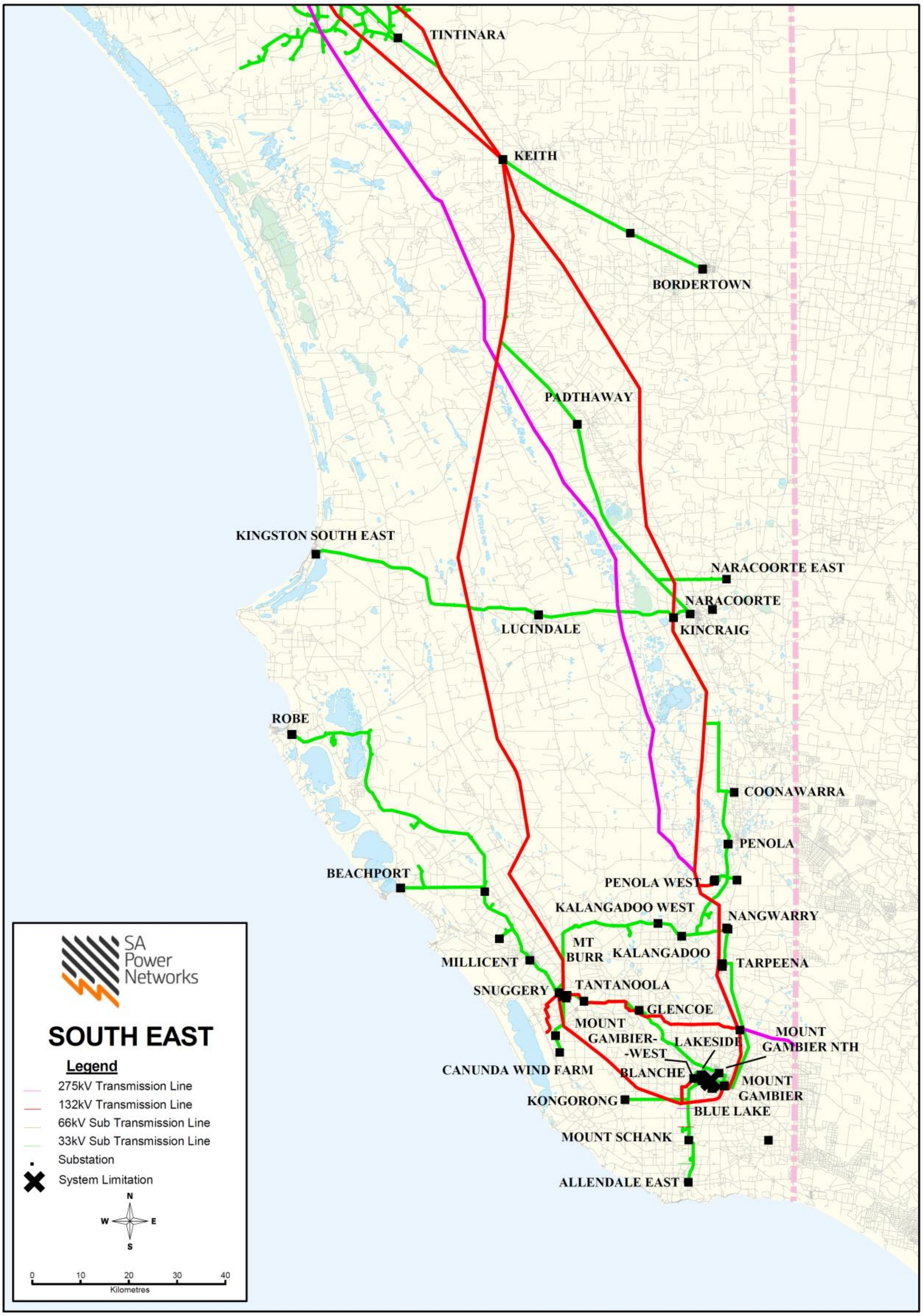


Figure 33: South East Regional Map

16.14 Upper North Regional Development Plan

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.

There is one system limitations forecast for the primary distribution feeders under normal conditions in the Upper North region in the next two years.

Table 49 lists SA Power Networks' Upper North zone substations with SCADA, and Figure 34 shows the extent of the Upper North region.

Table 49: Upper North SCADA Substations

Source Connection Point	Associated SCADA Substations	
Baroota	Bungama Booleroo Centre Port Germein	Melrose Telowie Wirrabara Forest Wilmington
Davenport West	Port Augusta Pt Augusta West TF1 Pt Augusta West TF2	Quorn Stirling North TF1 Stirling North TF2
Port Pirie / Bungama	Caltowie Crystal Brook Peterborough	Jamestown Port Broughton Port Pirie South
Neuroodla	Hawker	
Leigh Creek South	Copley-Nepabunna	

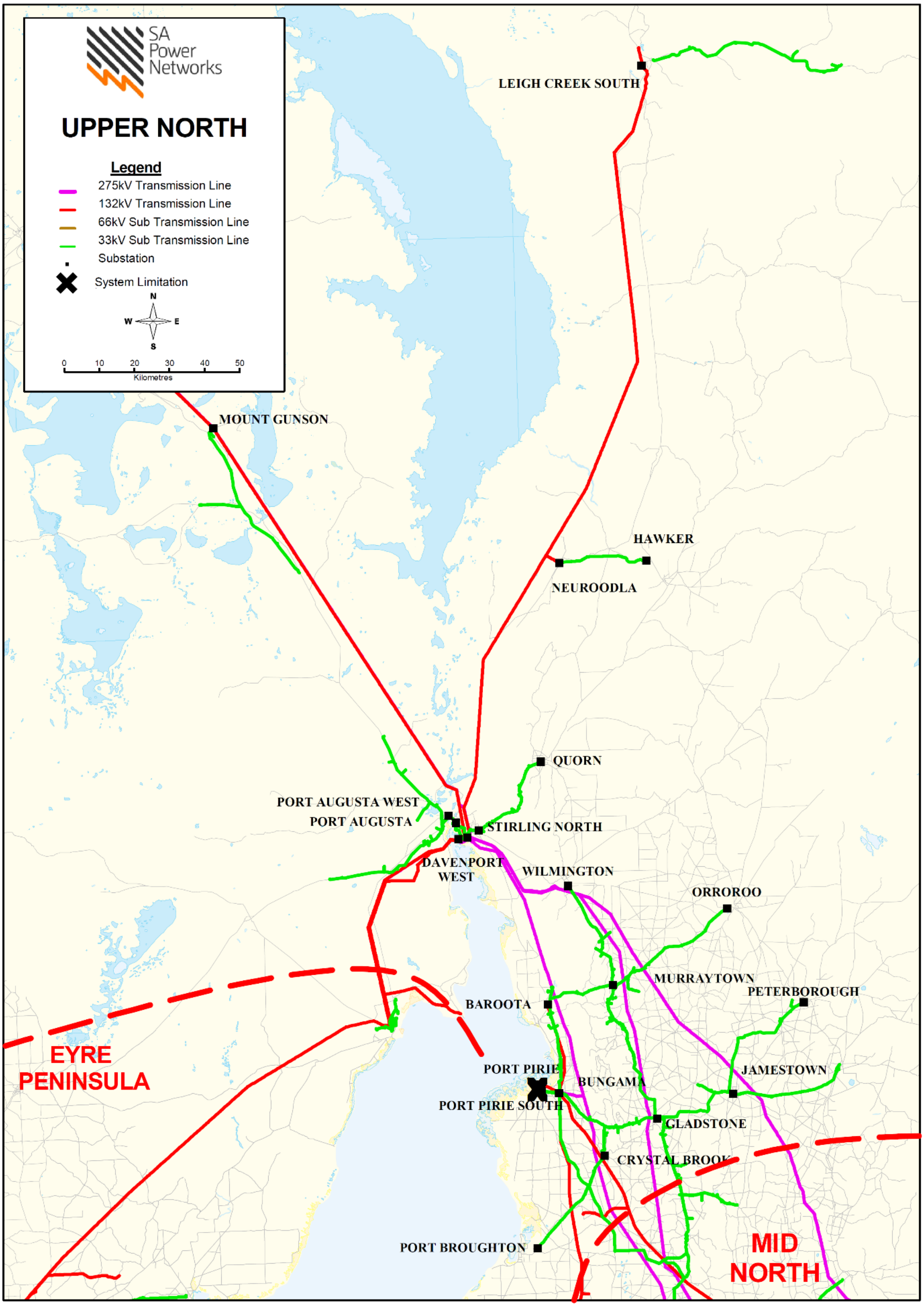


Figure 34: Upper North Regional Map

Appendix 1 – SA Power Networks contacts

In accordance with NER clause 5.13.2 (e), this DAPR has been published on SA Power Networks' website at:

http://www.sapowernetworks.com.au/centric/industry/our_network/annual_network_plans.jsp

The purpose of this document is to provide information about actual and forecast constraints on our distribution network along with details of these constraints, where and when they are expected to arise within the forward planning period.

This document is not intended to be used for other purposes, such as making decisions to invest in generation, transmission or distribution capacity.

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

Network Manager South (and Embedded Generation)	Darren Milligan or	0400 661 805
	Tim Adams	0400 582 146
Network Manager North	Tim Adams	0400 582 146

We welcome your feedback on the information provided in our DAPR. Please direct any feedback on the contents of this document to Dannielle Kurbatfinski at:

dannielle.kurbatfinski@sapowernetworks.com.au

Appendix 2 - Compliance Statement

NER clause 5.13.2(c) requires SA Power Networks to include the information specified in Schedule 5.8 in its DAPR. The Table 51 identifies the requirements of schedule 5.8 together with a cross reference to the relevant sections within this document where this information can be located.

Table 51: NER Schedule 5.8 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 2.3
(2) a description of its operating environment;	Section 2.4
(3) the number and types of its distribution assets;	Section 2.5
(4) methodologies used in preparing the *Distribution Annual Planning Report*, including methodologies used to identify system limitations and any assumptions applied; and	Section 2.6
(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 2.7
(b) forecasts for the forward planning period, including at least:	
(1) a description of the forecasting methodology used, sources of input information, and the assumptions provided	Section 3.1
(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*;	Section 3.2 Attachments A1 to A4

NER schedule 5.8	Document reference
(viii) load transfer capacities; and (ix) generation capacity of known *embedded generating units*;	
(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 3.3 Attachments A1 to A4
(4) forecasts for the *Distribution Network Service Provider's* performance against any reliability targets in a *service target performance incentive scheme*; and	Section 3.4
(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 3.5
(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 Attachments B1 to B5

NER schedule 5.8	Document reference
(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 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.	Section 4
(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 reduction in forecast *load* 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);	Section 6 Attachments B1 to B5

NER schedule 5.8	Document reference
(ii) the relevant *connection points* at which the estimated reduction in forecast load may occur; and (iii) the estimated reduction in forecast *load* in MW or improvements in *power factor* needed to defer the forecast system limitation;	
(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; (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;	Section 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 8.1 Section 8.2

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 8.3
(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 9
(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
(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 11

NER schedule 5.8	Document reference
(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; (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;	Section 12
(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 13
(l) information on the *Distribution Network Service Provider's* demand management activities, 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;	Section 14

NER schedule 5.8	Document reference
(iii) actions taken to promote non-network 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; (ii) *applications to connect* received under clause 5.3A.9; and (iii) the average time taken to complete *applications to connect*;	
(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 15
(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.	Section 16