



Supporting
document 5.10

Distribution System Planning Report

2020-2025
Regulatory Proposal
January 2019





ASSET PLAN 1.1.01 DISTRIBUTION SYSTEM PLANNING REPORT

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SA Power Networks

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DOCUMENT VERSION

Version No	Date	Description
0.1	31/03/2018	First Draft
0.2	19/06/2018	Second Draft
0.3	18/12/2018	Third Draft
0.4	20/12/2018	Fourth Draft – included updated section 2.3.1 PV Generation Effect.
0.5	16/1/2019	Fifth Draft - updated Section 11
0.6	29/1/2019	Sixth Draft
0.7	30/1/2019	Final review and approval for publication

Disclaimer

The purpose of this document is to provide information about SA Power Networks' assessment of its distribution system's capacity to meet growth in demand over the next eleven years, and possible plans for augmentation of the distribution network.

Persons proposing to use the information in this document should independently check and verify the accuracy, completeness, reliability and suitability of the information in this document and the reports and other information relied upon by SA Power Networks in preparing it.

This document also contains certain predictions, estimates and statements that reflect various assumptions concerning, amongst other things, economic growth scenarios and load growth forecasts. These assumptions may or may not prove to be correct.

This document also contains statements about SA Power Networks' plans. These plans may change from time to time without notice and should therefore be confirmed with SA Power Networks before any action is taken based on this document.

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OWNERSHIP OF STANDARD

Name of Standard / Manual: **Asset Plan 1.1.01 Distribution System Planning Report**

Standard/Manual Owner - Title: **Manager Network Planning**

Name: **M Napolitano**

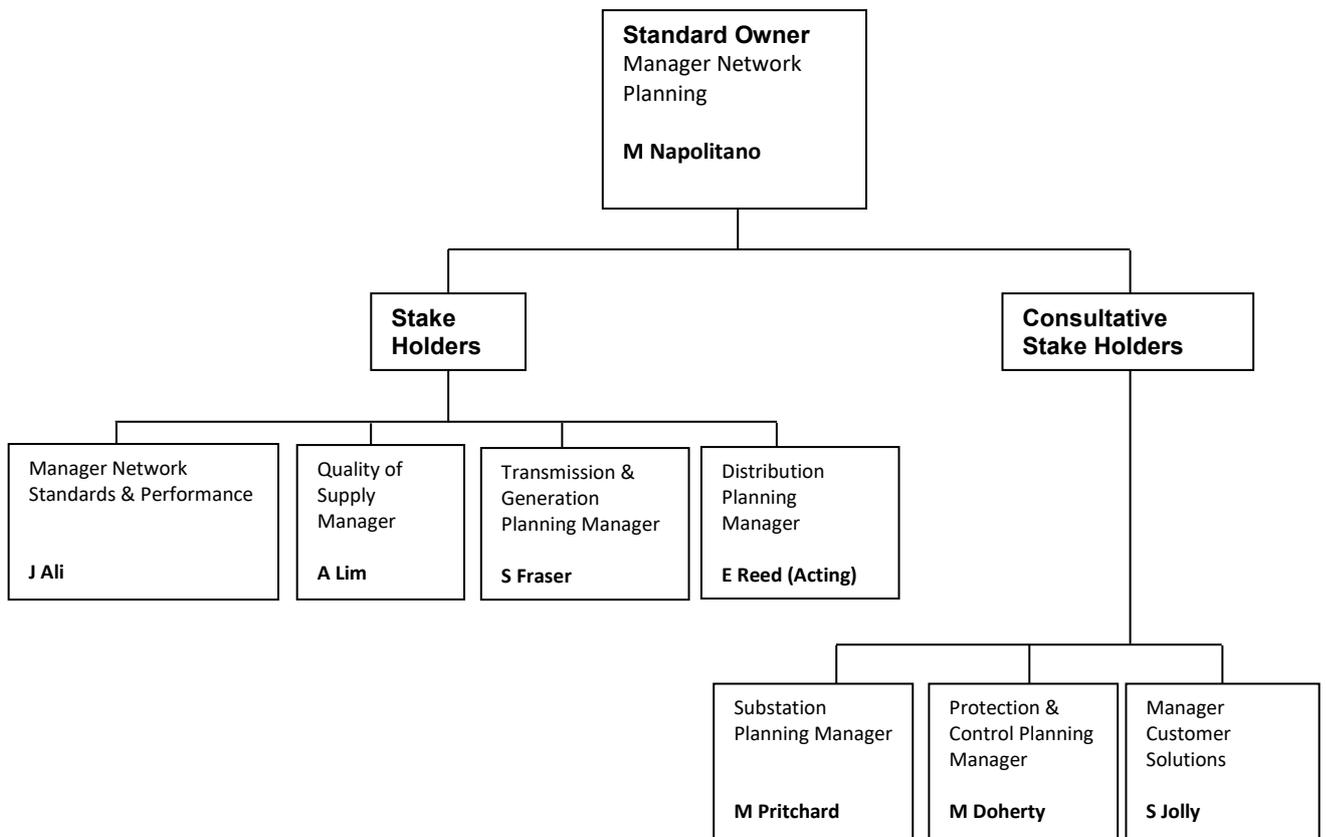
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STANDARD/MANUAL OWNERSHIP STRUCTURE



OTHER RELATED MANUALS

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COMMENTS

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EXECUTIVE SUMMARY

SA Power Networks is the sole licensed distribution network service provider (DNSP) in South Australia. This report is SA Power Networks' assessment of its distribution system's capacity to meet forecasted demand over the five years from 2020/21 to 2025/2026 and possible plans for augmentation of the distribution network. It is based on the information and estimates available at the time of publication. Proposed project timings have been based on the official 2018 peak, 10% and 50% PoE load forecasts (as applicable).

This report includes an overview of SA Power Networks' system planning methodology and development plans covering SA Power Networks' capacity related expenditure. Where relevant, details of system constraints and the proposed corresponding projects are included within these development plans. Only those projects that have the most significant customer impact have been specified in detail. This generally includes those connection points, zone substations and sub-transmission line projects with an estimated value in excess of \$5 million, whilst for all other expenditure categories (eg voltage support, power factor correction, feeders etc), these have been specified in detail where the estimated value is in excess of \$0.5 million.

The planning criteria used to develop this capacity plan are designed to meet the quality of supply (QoS) requirements of the Electricity Act reflected through the Electricity Distribution Code to maintain historic levels of network performance, security and reliability.

Network augmentations planned for completion in 2019/20 that have financial commitment at the time of publication of this plan are considered "completed" for the purposes of this plan. There is a possibility that some proposed sub-transmission line routes may change after the publication date of this report owing to the impact of the Development Assessment Commission process and that some of the planned sub-transmission line works may not be completed in 2019/20 if delayed by external approvals such as the Development Assessment Commission or the Office of the Technical Regulator. Future (non-committed) large customer connections, where the customer's maximum demand increase exceeds the forecasted annual load growth of the relevant network asset, are not included within this plan. Network augmentations required for such projects will be managed in accordance with the Electricity Distribution Code and SA Power Networks' customer connection processes in accordance with the National Energy Customer Framework (NECF) and SA Power Networks' customer connection charging manual on a case by case basis.

Definitions

AC	Alternating Current
ACR	Adelaide Central Region as defined by the ETC.
ADMD	After Diversity Maximum Demand
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AP	Asset Plan
BAU	Business as Usual
CAIDI	Customer Average Interruption Duration Index
Capex	Capital Expenditure
CB	Circuit Breaker
CBD	Central Business District
Connection Point	<p>is as defined within Section 5.10.2 of the <i>NER</i> for a transmission-distribution <i>connection point</i> which states,</p> <p>(a) subject to paragraph (b), the agreed point of supply established between a <i>transmission network</i> and a <i>distribution network</i>;</p> <p>(b) in relation to the declared transmission system of an adoptive jurisdiction, the agreed point of supply between the transmission assets of the declared transmission system operator and a distribution network.</p> <p>For the purposes of this AP, this shall constitute a site, at which electrical power is injected from ElectraNet's Transmission Network into <i>SA Power Networks' Distribution network</i>.</p>
Constraint Capacity	<p>With respect to a zone substation, will be taken to mean the lesser of the <i>normal capacity</i> (N), the <i>contingency capacity</i> or the <i>contingency capacity</i> plus an allowance of up to 3 MVA that may be made available by the connection of a <i>mobile substation</i>. The typical time to install the <i>mobile substation</i> is generally within 12 hours in metropolitan areas and generally within 12 to 24 hours outside the Adelaide metropolitan area.</p> <p>For <i>sub-transmission lines</i> and <i>feeders</i>, this will be taken to be the <i>normal rating</i> when all <i>lines</i> are in service and the <i>emergency rating</i> of the <i>line</i> or <i>feeder</i> under <i>contingency conditions</i>.</p>
Contingency Capacity	<p>With respect to a <i>zone substation</i>, will be taken to mean the <i>N-1</i> or <i>firm delivery capacity</i> of the <i>zone substation</i> plus any load which can be transferred to adjacent <i>zone substations</i> via <i>feeder</i> transfers (excluding those <i>zone substations</i> where <i>feeder</i> transfers are not to be considered according to <i>SA Power Networks' planning criteria</i> – eg <i>ACR</i>). The typical time to implement <i>feeder</i> transfers is four hours.</p>

	With respect to <i>sub-transmission lines</i> , this will be taken to be the capacity of the <i>network</i> when the first <i>line</i> becomes overloaded within a region during a <i>contingency condition</i> .
Contingency Condition	The term used to describe the state of the <i>distribution network</i> when any one piece of plant or equipment (<i>N-1</i>) is out of service, with the rest of the <i>network</i> remaining intact. It should be noted, that the loss of one item of equipment may result in the instantaneous loss of multiple items of equipment (eg a <i>sub-transmission line</i> fault may result in the loss of a <i>zone substation</i> transformer where no <i>line circuit breakers</i> exist).
Contingency Load	The maximum forecast load expected to be carried by the <i>line, feeder</i> or <i>zone substation</i> in a specified year under peak, 10 or 50% <i>PoE</i> conditions (as applicable), with any one piece of plant or equipment (<i>N-1</i>) out of service and with the rest of the <i>network</i> remaining intact.
CPMP	<i>Connection Point Management Plan</i> – a document jointly maintained by <i>SA Power Networks</i> and <i>ElectraNet</i> , which outlines the predicted required timing and high level scope of future <i>connection point</i> upgrades.
CT	Current Transformer
Customer Substation	A <i>zone substation</i> dedicated to supplying a single customer’s load. Information on <i>customer substations</i> is not included within this report for confidentiality reasons.
DAPR	Distribution Annual Planning Report. An annual report produced by <i>SA Power Networks</i> in accordance with section 5.13.2 of the <i>NER</i> .
DC	Direct Current
DER	Distributed Energy Resource
Distribution Network	Shall have the meaning as defined within Chapter 10 of the <i>NER</i> and pertaining to the regulated <i>network</i> owned and operated by <i>SA Power Networks</i> . The terms “ <i>network</i> ” and “ <i>distribution System</i> ” shall be construed accordingly.
Distribution Substation	A substation connected to a <i>SA Power Networks’ feeder</i> which transforms the voltage from <i>HV</i> to <i>LV</i> or in the case of its <i>SWER</i> systems, a <i>SWER</i> isolating transformer.
DM	Demand Management
DNSP	Distribution Network Service Provider
DPTI	Department of Planning, Transport and Infrastructure
DSED	Demand Side Engagement Document. A document produced by <i>SA Power Networks</i> in accordance with section 5.13.1(e) – (j) of the <i>NER</i> .
DSER	Demand Side Engagement Register
DSP	Demand-Side Participation

Embedded Generation	The generation of electricity by a generating unit connected to a <i>distribution network</i> and not having direct access to the <i>transmission network</i> .
Emergency Rating	The long-term emergency rating of the <i>line, feeder or zone substation</i> with all plant in service. If the peak load exceeds this rating the <i>line, feeder or zone substation</i> assets may be permanently damaged, or fail.
EDC	Electricity Distribution Code as published by <i>ESCOSA</i> .
ElectraNet	The company who owns and operates the <i>transmission network</i> in South Australia and is registered with <i>AEMO</i> as the <i>TNSP</i> for the South Australian <i>transmission network</i> .
EPA	Environmental Protection Authority
ETC	Electricity Transmission Code as published by <i>ESCOSA</i> .
ESCOSA	Essential Services Commission of South Australia
Fast Connection	With respect to the connection of a <i>mobile substation</i> , is a <i>zone substation</i> located within two hours travelling time from Angle Park.
Fault Rating	The maximum short circuit current carrying capacity of a given piece of equipment for a specified fault duration.
Firm Delivery Capacity	is as defined within Section 5.10.2 of the <i>NER</i> which states, “means the maximum allowable output or load of a <i>network</i> or facility under single <i>contingency conditions</i> , including any short term overload capacity having regard to external factors, such as ambient temperature, that may affect the capacity of the <i>network</i> or facility.
FR3	A propriety name given to a particular soy based insulating oil used within power transformers. This insulating medium is sometimes also referred to as EnviroTemp® or BioTrans®.
GSL	Guaranteed Service Level
High Voltage	Means any voltage greater than 1000 Volts and “ <i>HV</i> ” shall be construed accordingly.
Interested Party	Any person or organisation that has an interest in <i>SA Power Networks’</i> long term planning, <i>demand management</i> , addressing a particular constraint or more generally in addressing <i>demand management</i> issues.
kV	kilo Volt
LGA	Local Government Area
Low Voltage	Means any voltage less than or equal to 1000 Volts and “ <i>LV</i> ” shall be construed accordingly
Meshed Sub-Transmission Line	A <i>sub-transmission line</i> that has a source of supply available from both ends.
Mobile Substation	A trailer mounted, 3.8 or 10 MVA <i>zone substation</i> , with a primary voltage of 66kV and/or 33kV, and either a dual secondary voltage of 7.6kV / 11kV in the case of the 3.8 MVA unit or 11kV in the case of the 10 MVA unit, for use within 66/11kV, 33/11kV and 33/7.6kV

	<i>zone substations</i> in the event of a single transformer failure at a <i>zone substation</i> .
MVA	Mega Volt Ampere
MVAr	Mega Volt Ampere Reactive
MW	Mega Watt
Nameplate Capacity	The summated <i>zone substation</i> transformer capacity as written on the nameplate of each <i>zone substation</i> transformer. Where different size transformers are used, the capacity of the smallest transformer may be used to calculate the total <i>nameplate capacity</i> of the <i>zone substation</i> to account for uneven sharing of the <i>zone substation's</i> transformers.
NCA	Network Connection Agreement
NECF	National Energy Customer Framework
NEM	National Electricity Market
NER	National Electricity Rules and " <i>Rules</i> " shall be construed accordingly.
NERs	Neutral Earthing Resistors
NEXs	Neutral Earthing Reactors
NGM	National Grid Metering
NNOR	Non-Network Options Report
NOC	<i>SA Power Networks'</i> Network Operations Centre
Nominal Voltage	A nominal value assigned to a circuit, system or item of equipment for the purpose of conveniently designating its operating voltage class. The actual voltage at which a circuit operates can vary from the nominal within a range specified within the <i>EDC</i> that permits satisfactory operation of equipment.
Normal (N) Capacity / Rating	The cyclic rating of the <i>line, feeder, connection point</i> or <i>zone substation</i> with all plant and equipment in service. The design life of the <i>line, connection point</i> and <i>zone substation</i> assets (typically 30 years) will be reduced if the peak cyclic load exceeds this value.
NPV	Net Present Value
NSSA	Network System Support Agreement.
N-1 Rating	see <i>Firm Delivery Capacity</i> .
OLTC	On-Load Tap Changer
OPEX	Operational Expenditure
OTR	Office of the Technical Regulator
Overhead Conductor Ratings	The Overhead Conductor Ratings for <i>lines</i> and <i>feeders</i> are determined in accordance with ESAA Document D(b)5 (Current Rating of Bare Overhead Line Conductors) using a 30°C ambient temperature for the emergency rating and a 40°C ambient temperature for the normal rating, both with 1ms ⁻¹ wind speed, and with wind direction at 90° to the conductor. Note: the rating is

	dependent on the difference between the <i>line's</i> or <i>feeder's</i> design operating temperature and the ambient temperature.
PCB	Poly-Chlorinated Biphenyl. A synthetic organic chemical compound of Chlorine attached to biphenyl, which is a molecule composed of two Benzene rings. This compound is suspected of being carcinogenic and banned from importation into Australia since 1975. This substance exists under a variety of product names including Askarel®.
PoE	Probability of Exceedence. The probability that a forecast will be exceeded in any given year (ie a 10% <i>PoE</i> forecast is one which is likely to be exceeded one year in ten, whilst a 50% <i>PoE</i> forecast is likely to be exceeded once every two years)
Power Factor	The ratio of real power (in kW or <i>MW</i>) to apparent power (in kVA or <i>MVA</i>) in an AC circuit
Primary Distribution Feeder	is as defined within Section 5.10.2 of the <i>NER</i> which states, “means a <i>distribution line</i> connecting a <i>sub-transmission</i> asset to either other <i>distribution lines</i> that are not <i>sub-transmission lines</i> , or to distribution assets that are not <i>sub-transmission</i> assets”. For the purposes of this AP, this shall be taken to represent an overhead conductor or underground cable energised at 19kV, 11kV, 7.6kV, 6.6kV or 3.3kV supplied from either a <i>SWER</i> isolating transformer or <i>zone substation</i> . The terms “ <i>distribution feeder</i> ” and “ <i>feeder</i> ” shall be construed accordingly
PSS/E	Power System Simulator for Engineering
PV	Photo Voltaic. This term is used to refer to solar, inverter based <i>embedded generation</i> schemes.
QMS	Network Management’s Quality Management System certified to ISO 9001.
QoS / QS	Quality of Supply
QSI	Quality of Supply Investigation
Radial Sub-transmission Line	A <i>sub-transmission line</i> that has a source of supply from only one end.
RDP	Regional Development Plan
Registered Participant	A person who is registered with <i>AEMO</i> as a Network Service Provider, a System Operator, a Network Operator, a Special Participant, a Generator, a Customer or a Market Participant.
Regulator Station	An installation used to maintain system voltages within pre-determined voltage limits from the relevant system’s <i>nominal voltage</i> . Regulator stations are limited by their <i>normal capacity</i> and voltage boosting/ bucking tap range capability.
RIT-D	The Regulatory Investment Test – Distribution as per Section 5.17 of the <i>NER</i> and promulgated by the <i>AER</i> with which all proposed <i>network</i> investment with an estimated expenditure greater than or equal to \$6 million must be assessed to determine the solution with the least cost or greatest market benefit to all <i>network</i> users.

RIT-T	Regulatory Investment Test – Transmission
SAIDI	System Average Interruption Duration Index. A measure of the average outage duration for each customer served over the preceding year.
SAIFI	System Average Interruption Frequency Index. A measure of the average number of interruptions that customers experienced over the preceding year.
SA Power Networks	<i>SA Power Networks</i> is South Australia’s principal Distribution Network Service Provider (<i>DNSP</i>), and is responsible for the distribution of electricity to all distribution grid connected customers within the State under a regulatory framework. <i>SA Power Networks</i> is a partnership of Spark Infrastructure SA (No. 1, 2 &3), CKI Utilities Development Limited and HEI Utilities Development Limited.
SCADA	Supervisory Control and Data Acquisition
SCAP	State Commission Assessment Panel
SF ₆	Sulphur HexaFluoride. A synthetic, highly inert, colourless, odourless gaseous insulating compound typically used within switchgear as an arc quenching medium. This gas is an ozone depleting gas presently subject to the Federal carbon tax.
STPIS	Service Target Performance Incentive Scheme as developed and published by the <i>AER</i> in accordance with clause 6.6.2 of the <i>NER</i> .
Sub-transmission	is as defined within Section 5.10.2 of the <i>NER</i> which states,“ means any part of the power system which operates to deliver electricity from the <i>transmission system</i> to the <i>distribution network</i> and which may form part of the <i>distribution network</i> , including <i>zone substations</i> .”
Sub-transmission Line	is as defined within Section 5.10.2 of the <i>NER</i> which states,“means a power <i>line</i> connecting a <i>sub-transmission</i> asset to either the <i>transmission system</i> or another <i>sub-transmission</i> asset.” For the purposes of this AP, this shall be taken to represent an overhead conductor or underground cable energised at 33kV or 66kV that emanates from a <i>connection point</i> or a <i>zone substation</i> and supplies a <i>zone substation</i> . The term “ <i>line</i> ” shall be construed accordingly.
SWER	Single Wire Earth Return. A system consisting of a single wire to convey electricity to consumers utilising the ground / earth to act as the return current path. <i>SA Power Networks’ SWER</i> systems operate at 19kV and 6.35kV.
Transmission Network	Shall have the meaning as defined within Chapter 10 of the <i>NER</i> .
TNSP	Transmission Network Service Provider
Underground Cable Ratings	Underground cables can have several ratings dependent on a large number of parameters (eg the installation depth, number of cables, proximity to other cables, load levels, sheath bonding arrangement, cable spacing and cable construction). The continuous, cyclic and

	emergency rating for underground cables used to form all or part of <i>sub-transmission lines</i> and <i>distribution feeders</i> are determined in accordance with Network Management's' QMS Procedure 638.
URD	Underground Residential Development
VCR	Value of Customer Reliability
Voltage Capacity	Shall mean the amount of load capable of being carried by a <i>line</i> or <i>feeder</i> before causing the voltage at the extremities of the <i>line</i> or <i>feeder</i> to drop below the minimum acceptable levels mandated by the <i>EDC</i> .
VPP	Virtual Power Plant
VT	Voltage Transformer
WACC	Weighted Average Cost of Capital
Zone Substation	is as defined within Section 5.10.2 of the <i>NER</i> which states," means a <i>substation</i> for the purpose of connecting a <i>distribution network</i> to a <i>sub-transmission network</i> ". A <i>SA Power Networks' substation</i> at which the <i>sub-transmission</i> voltage (66kV or 33kV) is transformed down to a distribution voltage (33kV, 11kV, 7.6kV, 6.6kV or 3.3kV). " <i>Substation</i> " shall be construed accordingly.

1. INTRODUCTION

1.1 Purpose of this report

This report details how SA Power Networks plans to meet the predicted demand for electricity supplied through its sub-transmission lines, zone substations, distribution feeders, distribution substations and connection points with ElectraNet which constitute the distribution network.

The purpose of this document is to provide information regarding SA Power Networks' assessment of the distribution system's capacity to meet demand over the period from 2020 to 2025 and possible plans for augmentation of the distribution network.

1.2 Description of the network

SA Power Networks is responsible for planning the ongoing development and augmentation of the distribution system within South Australia. The distribution network in general, commences from the 66kV and 33kV connection points at sites shared with ElectraNet down to the customer's point of supply. The assets forming the network include 66kV and 33kV buses, switchgear (and associated relays), sub-transmission lines, zone substations, distribution feeders, distribution substations, low voltage mains and services to customers.

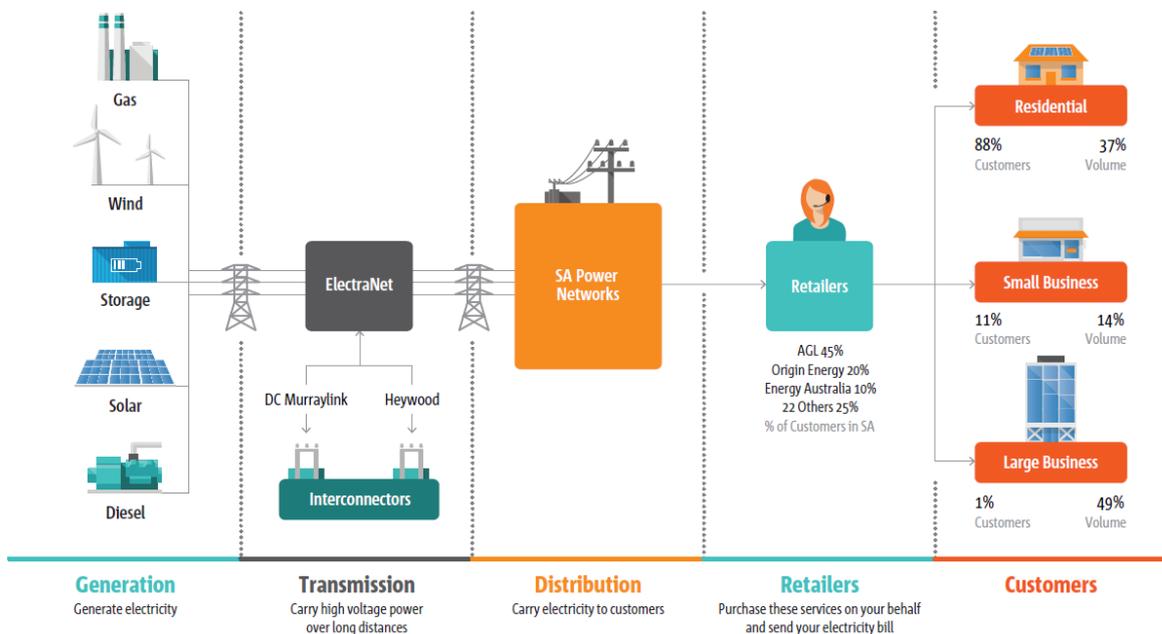


Figure 1: Electricity Supply System

1.3 The planning process

The flow chart below provides a summary of the process followed in planning and augmenting the distribution network.

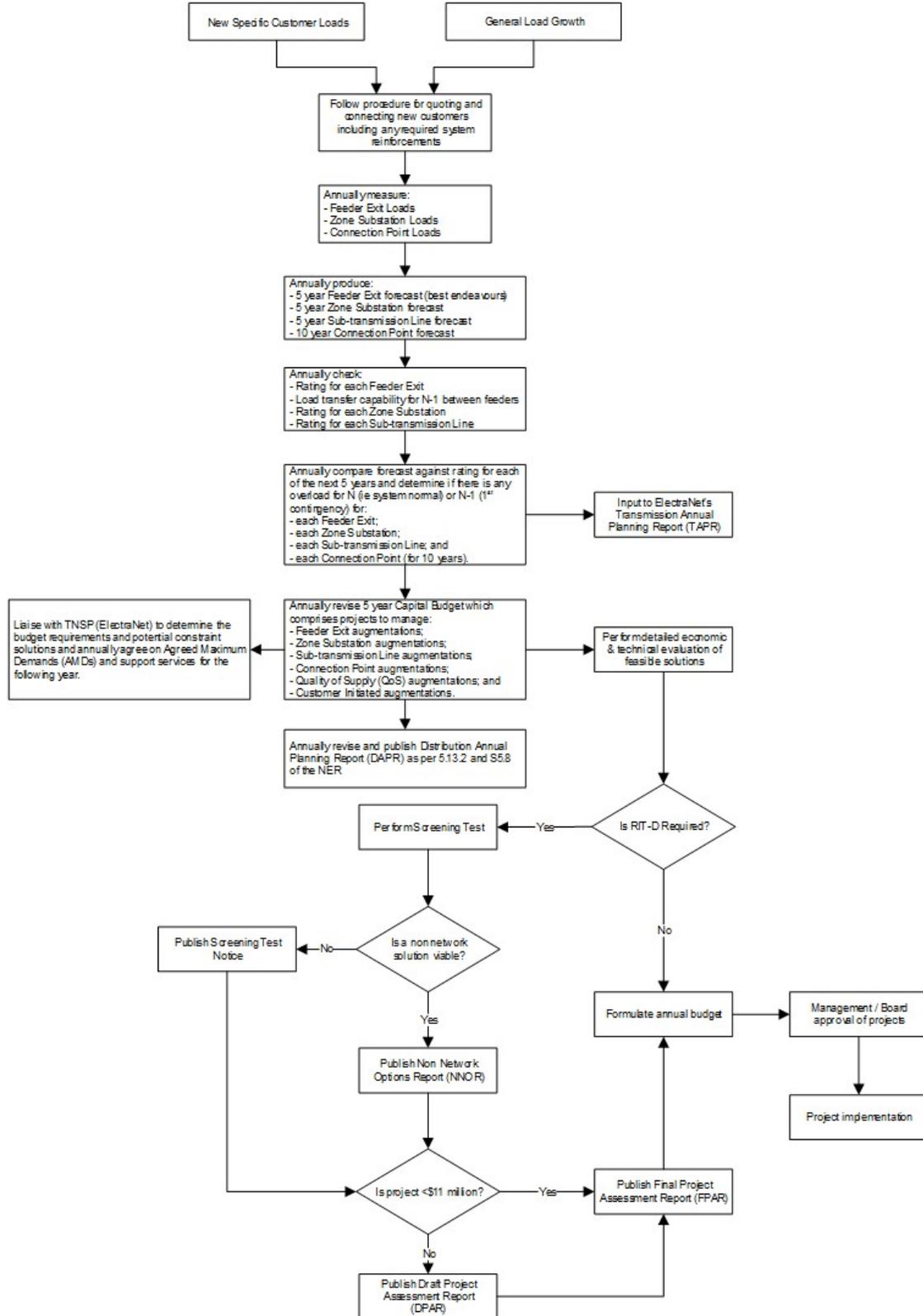


Figure 2: Overview of Distribution System Planning Process

2. PLANNING STANDARDS & PROCEDURES

2.1 Sub-transmission Capacity Terminology

Sub-transmission lines are usually allocated two types of rating:

1. Normal Rating; and
2. Emergency Rating.

Normal ratings are applied when all network components are in service while emergency ratings are applied when one or more network components are out of service. The normal ratings applied to sub-transmission lines take into consideration and utilise the lowest of the following ratings:

1. Switchgear nameplate rating;
2. For 66kV lines containing cable, the cable's continuous rating;
3. For 33kV lines containing cable, the cable's normal cyclic rating; or
4. The overhead conductor's normal rating at the line's design temperature.

The emergency ratings applied to sub-transmission lines take into consideration and utilise the lowest of the following ratings:

1. Switchgear nameplate rating;
2. For 66kV lines containing cable, the cable's cyclic rating;
3. For 33kV lines containing cable, the cable's emergency cyclic rating;
4. The overhead conductor's emergency rating at the line's design temperature; or
5. Up to a maximum of 1600A for lines containing overhead conductor.

2.2 Connection Point and Zone Substation Capacity Terminology

Within this report, various measures of a zone substation's capacity are used. While these terms are defined within the "Definitions" section of this document, further explanation of the capacity terms used within this report is provided here for further clarity.

The various forms of capacity terminology used within this document are best explained by way of an example.

Let us say we have a zone substation containing two 66/11kV transformers, each having the following ratings:

Transformer No	Nameplate Rating (MVA)	Normal Rating (MVA)	Emergency Rating (MVA)
1	21	25	26.4
2	25	30.4	32.1
Total	46	51.1	26.4

Table 1: Zone Substation Transformer Ratings

NB Both the *normal* and *emergency ratings* are based on cyclic loading of the transformer relevant for that location.

Based on these ratings, the graph below shows the various types of rating which may be used within this report to identify the existence and timing of a constraint. Each of these various capacity ratings and their method of determination is provided below.

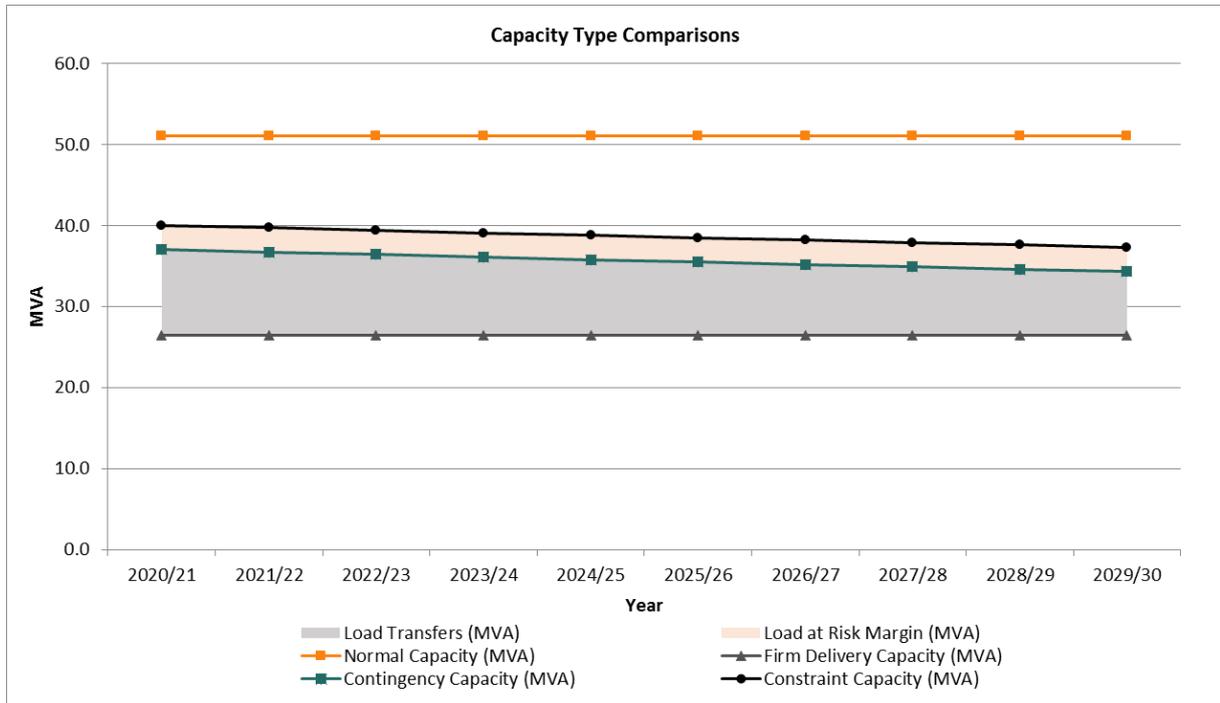


Figure 3: Zone Substation Capacity Type Comparisons

2.2.1 Normal Capacity (N)

SA Power Networks, apply the normal rating of each transformer to determine the zone substation’s overall normal rating, taking into consideration the ability of different sized transformers to share based on their impedance. In this example, the substation’s normal rating is 51.1 MVA as opposed to 55.4 MVA based on this unequal sharing between the different sized transformers.

Whilst the normal capacity of a zone substation will usually be limited by the size of its transformers, this capacity may be dictated by the capacity of switchgear, cables, protection systems or other equipment which restricts the zone substation’s maximum output.

2.2.2 N-1 Capacity / Firm Delivery Capacity (N-1)

For zone substations, this capacity assumes the transformer with the largest emergency rating is out of service. The remaining in service transformer(s) emergency rating(s) are then summated to determine the N-1 capacity. Since in this example the transformers are not equally rated, the firm delivery capacity (ie N-1) will be equivalent to the emergency rating of the smallest remaining transformer (ie 26.4 MVA).

Again, this rating may be dictated by the capacity of switchgear, cables, protection systems or other equipment which restricts the zone substation’s maximum output following the loss of a transformer.

2.2.3 Contingency Capacity

This capacity value takes into consideration the ability of SA Power Networks to transfer load from the affected zone substation to adjacent zone substations via feeder transfers. This capacity may vary over time depending on the available capacity of the adjacent substation’s transformers and/or feeders to accommodate the additional load transferred. This variance in the contingency capacity may result in either a reduction, an increase or it may remain constant depending on whether the adjacent substation’s transformers and/or feeders are forecast to experience positive, negative or no load growth respectively. Note, the available

feeder transfer capacity may be limited by either the capacity of the adjacent feeders or the adjacent substation(s) transformer capacity.

The contingency capacity in Figure 3 above assumes that in year 1, SA Power Networks is able to transfer up to 10.6 MVA of load to adjacent substations through feeder transfers. Assuming this transfer capability reduces by 0.3 MVA per annum due to positive load growth on these adjacent feeders, the amount of free substation transformer and /or feeder capacity available to accept load transfers from the affected substation will also reduce by this amount. Therefore, we see that the substation's contingency capacity also reduces over time.

It should be noted that (whilst rare) it is possible for a substation's contingency capacity to be greater than its normal capacity (N) should the amount of feeder transfer capacity in the adjacent feeders be greater than the capacity of the transformer which is out of service.

2.2.4 Constraint Capacity

This value takes into consideration the level of load SA Power Networks is prepared to allow to remain unsupplied following the performance of all available feeder transfers (i.e. Load at Risk) and the ability of SA Power Networks to connect one of its mobile substations in the event of a transformer outage.

Provided all customer load can be restored at all times by use of SA Power Networks' mobile substations or generation within 24 hours of the outage. The maximum allowable load at risk varies with the criticality of the site, but is typically a maximum of 3 MVA. The choice of 3 MVA ensures that at all times (ie peak, 10% PoE and 50% PoE), all customer load can be restored and deliver similar reliability of supply performance to that provided at the time of sale in 2000 (a requirement of the Electricity Act reflected through the EDC). This strategy generally allows verification of a measured demand (temperature adjusted) exceeding contingency capacity prior to project commitment.

SA Power Networks' planning criteria allows for consideration of the use of these mobile substations at those substations where:

1. *The primary and secondary voltages are compatible with those of the mobile substations and can be dispatched and connected within 24 hours of the contingency event occurring; or*
2. *The planning criteria does not require SA Power Networks to deliver continuous N-1 capacity (ie firm delivery capacity) without a resulting loss of supply.*
3. *The constraint capacity is therefore determined as the lower of either the normal capacity or the result of adding the capacity of the relevant "Load at Risk" allowance to the contingency capacity (ie constraint capacity = the lower of normal capacity or contingency capacity + Load at Risk Margin).*

Where SA Power Networks are unable to consider the use of a mobile substation for planning purposes, (eg 66/7.6kV zone substations), the constraint capacity will equal either the normal or contingency capacity of the substation (ie no Load at Risk Margin allowed).

Similarly, for those areas where the planning criteria does not allow consideration of the use of feeder transfers (eg CBD), the constraint capacity will equal the firm delivery capacity of the substation.

A zone substation constraint is therefore deemed to exist where the forecast demand exceeds the zone substation's constraint capacity.

2.3 Load Forecast Procedure

The SA Power Networks load forecast is reviewed after each summer. These reviews consider the impact of the latest load recordings, generator connections (including PV and battery), system modifications and any new committed large load developments, in accordance with SA Power Networks' Network planning and load forecasting procedures.

In 2013, SA Power Networks engaged Acil Allen to develop a new load forecasting tool to enable the production of connection point and zone substation forecasts at a variety of PoE levels.

A detailed description of the methodology employed by this model is described within the Acil Allen user guide document¹. A summary of the use of this tool to develop SA Power Networks 2018 forecast is outlined below.

This forecasting tool performs regression analysis for each substation per summer. The tool then performs a simulation using historic temperatures dating back to 1978 to generate a range of PoE levels. Post model adjustments (spot loads, transfers, generation including PV and battery) are then made to calculate substation growth rates and final PoE forecast values.

To account for econometric factors, the temperature corrected PoE spatial forecasts are reconciled to the next level of the network (ie zone substations reconciled to connection point, connection points reconciled to system level).

With respect to spot loads, any new spot load increase is only considered for inclusion within the relevant asset's forecast as a new spot load (eg zone substation or connection point) where the load represents more than 5% of the asset'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 as such for the supplying 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, with the load concerned being reduced to 50% of the submitted demand to allow for over-estimation by the customer and diversity prior to their inclusion as a spot load. Similarly, only committed load reductions (eg due to measured changes or announced closures) are considered as spot load reductions.

With respect to load transfers between zone substations, only those transfers that make a material difference are included in the load forecast.

The 2017/18 to 2025/26 connection point forecast was then reconciled with AEMO's SA generation forecast trend contained within the Electricity Forecasting Insights data, published in August 2018. For the non-major customer load, this shows in essence a flat characteristic (ie for residential and commercial customers). Connection Points dominated by major customer load were removed from the reconciliation and separately considered (such as at Port Pirie, Whyalla and Snuggery).

The last load forecast produced prior to publication of this document was produced in 2018. All identified constraints and their timings described in this report are based on the forecasts produced by this tool at 10% and 50% PoE level. Potential changes in customer demand due to the effect of PV installations and demand management programs are considered within the forecasts.

The timing of the various network augmentations proposed within this AP are based on the comparison of the relevant forecast with the relevant asset 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 loads coincident with the time of the relevant connection point peak using PSS/E. The line flows indicated by these models have then been used to determine the timing of any constraint.

¹ Maximum Demand Forecast Tool – A Users Guide to the SA Power Networks Maximum Demand Forecasting Tool, February 2014.

Whilst many of SA Power Networks’ country zone substations are radial in nature, a large proportion are “daisy chained” from a single connection point with the sub-transmission lines entering the zone substation and subsequently continue on to supply other zone substations in series. Those sub-transmission lines which only supply a single zone substation rely on the zone substation’s forecast as the basis for the relevant sub-transmission line forecast.

The timing of those augmentation projects detailed within this AP are based on the moderate AEMO load forecast.

2.3.1 PV Generation Effects

Since 2009, SA Power Networks has experienced a massive 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 989 MW as at December 1, 2018. This represents more than a quarter of SA Power Networks’ peak system demand and has resulted in SA Power Networks’ having the highest PV penetration levels as a proportion of system demand in the nation. As a proportion of SA Power Networks’, 875,000 customers, more than 24%, have a PV system installed.

AEMO’s minimum demand forecast for South Australia, illustrated in Figure 4, predicts on minimum demand days rooftop PV is forecast to provide all demand by as early as 2025.

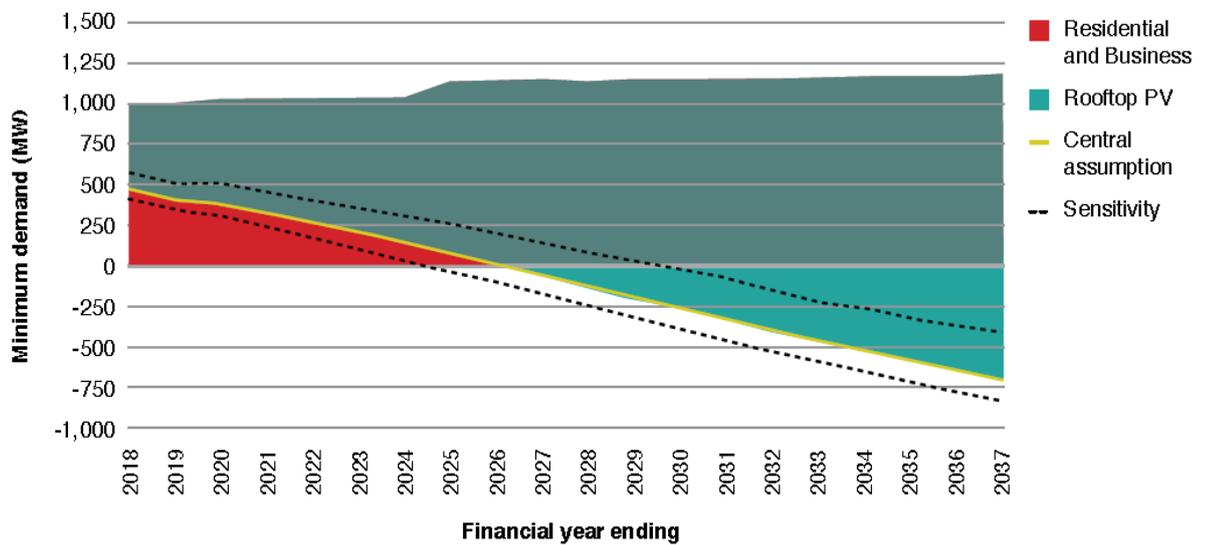


Figure 4: AEMO Minimum Demand Forecast for South Australia

[Source: https://www.energynetworks.com.au/sites/default/files/open_energy_networks_consultation_paper.pdf]

This increase in popularity has been driven by several factors including significant State Government "feed in tariffs" and the subsequent large reductions in the cost of installing such systems. Figure 5 indicates the level of installed inverter capacity (as at the end of each summer ie 1 April), split according to metropolitan Adelaide and country regions per annum as at April 1, for each respective year.

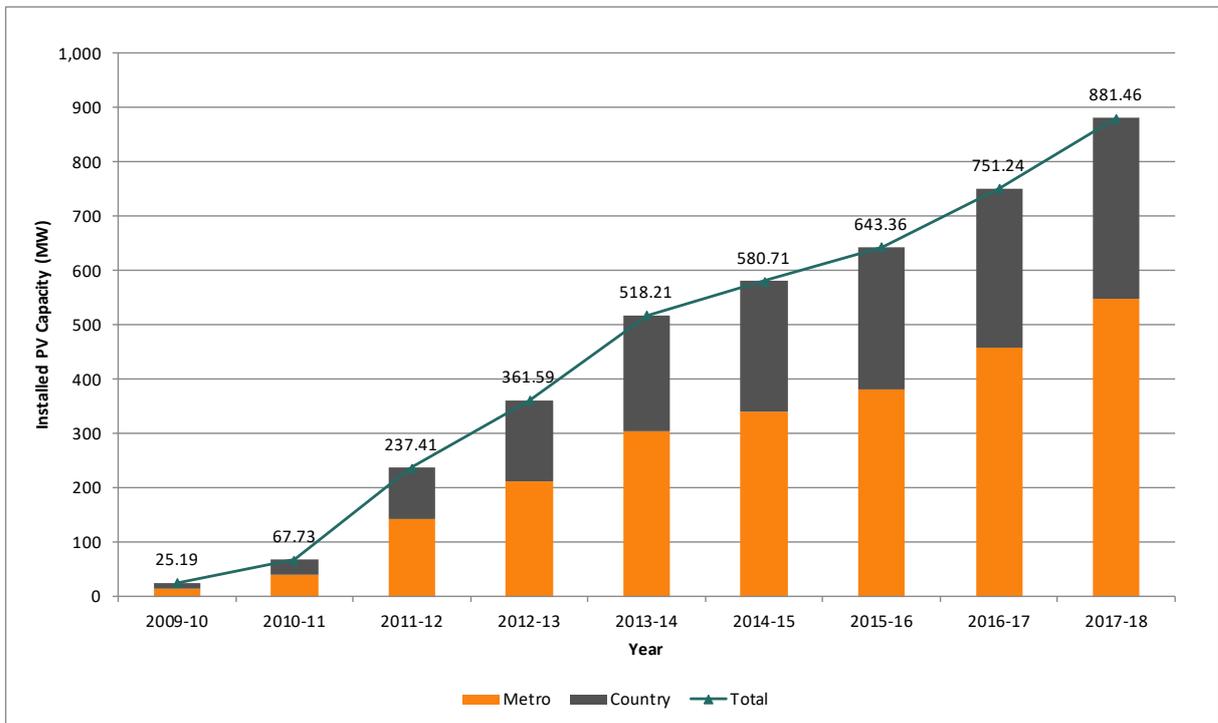


Figure 5: Installed PV Capacity per annum

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. Figure 6 provides an indication of the effect these PV systems have had on both the daily demand profile since 2009 as well as shifting the peak demand period at a zone substation level from the traditional 17:00 – 18:00 period to 19:00 – 20:00. With respect to transmission connection point 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 19:30 Central Standard Summer Time. This time shift in demand has been considered within SA Power Networks’ load forecasts.

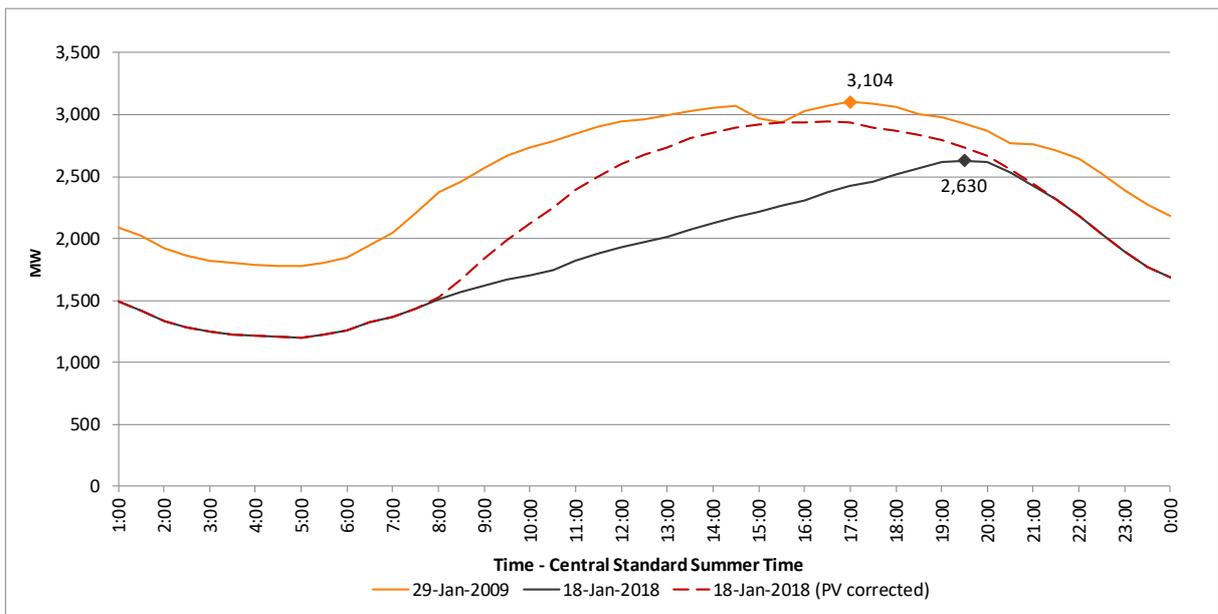


Figure 6: Load Profile Comparison

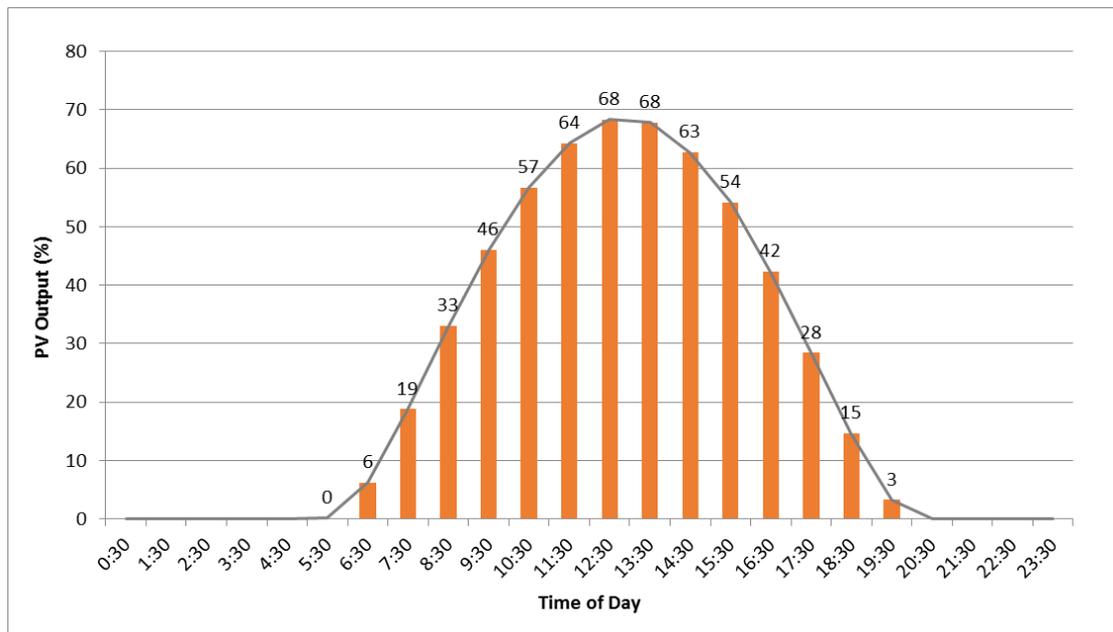
The energy output of PV systems is inherently variable and is affected by factors such as:

4. *Shading from trees and nearby structures;*
5. *Panel orientation with respect to the sun (ie time of day);*
6. *Ambient temperature (ie PV panels exhibit reduced efficiency at higher temperatures);*
7. *Panel to inverter capacity; and*
8. *General cleanliness / efficiency of the system.*
- 9.

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 developed by Acil Allen on behalf of SA Power Networks attempts to forecast the level of PV generation at each daily half hour interval for each month of the year in order to correct the measured daily demand to its latent 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:

10. *The installed capacity of PV systems at both zone substation and connection point level (at a given point in time);*
11. *The estimate of total annual energy output of these systems on a MWh per kW installed basis obtained from the Clean Energy Regulator; and*
12. *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 7).*

**Figure 7: PV Output versus Time of Day in January**

This methodology has been previously used by Acil Allen to advise regulators in both South Australia and Victoria on the efficient level at which to set feed in tariffs.

The forecasting tool uses the data produced 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 8 provides an example of the impact of PV on measured versus native demand.

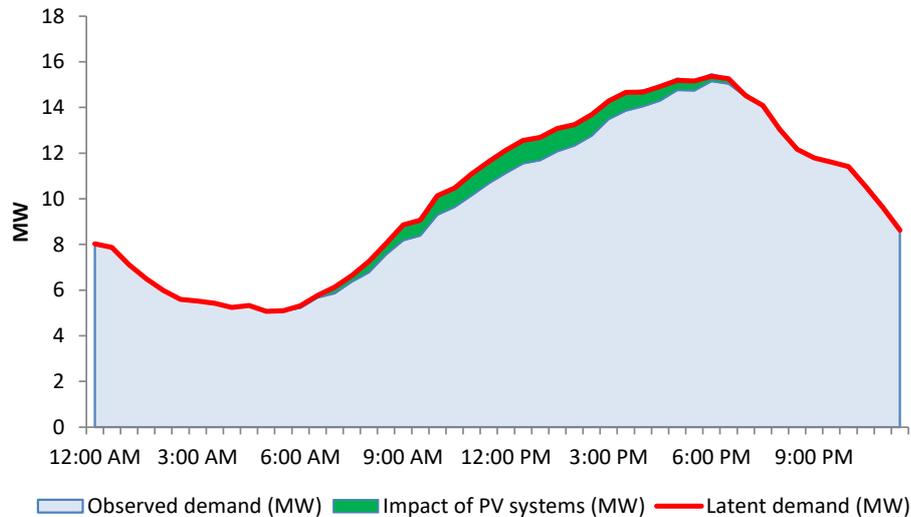


Figure 8: Measured Demand Compared with Underlying (Native) Demand²

AEMO's 2018 ESOO forecast growth in PV and storage is used to reduce 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.

2.3.2 Embedded Generation

The 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 demands if not considered within the forecasting process.

The level of embedded generation output at the time of each zone substation's and connection point's measured peak reading is recorded and added back to the measured substation transformer output to arrive at the 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 who have historically operated consistently irrespective of temperature or network demand levels (eg small biogas generators etc) are retained within the model's forecast.

2.3.3 Spot Loads

Known spot load increases and decreases are considered within the connection point and zone substation forecasts. Only those spot loads in excess of 5% of the connection point's or zone substation's installed capacity are considered as spot loads in generating the relevant forecast. Future spot loads are added at 50% of their expected maximum demand to allow for over-estimation and diversity with the time of peak demand.

² Maximum Demand Forecast Tool – Methodology and Users Guide for SA Power Networks Maximum Demand Forecasting Tool – Acil Allen Consulting, August 2014.

Within the 10 year plan, the only spot load increases included within the forecasts are State Government funded or sponsored projects while decreases are due to committed load reductions.

2.3.4 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.

2.3.5 Major Customers

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

2.4 Network planning criteria

2.4.1 Application of the criteria

SA Power Networks' planning criteria incorporates the objectives of establishing and maintaining compliance with all applicable Statutes, National and International Standards, Codes of Practice, the Electricity Act, and satisfying the obligations specified within the Electricity Distribution Code and the National Electricity Rules. In particular, the criteria embody obligations imposed by legislation including the requirement to adhere to standards and practices generally accepted as appropriate either internationally or throughout Australia by the electricity supply industry and to ensure the security and reliability of electricity supply to customers.

The forecast load for future years contained within the 10% and 50% PoE load forecasts is compared with the capacity of the relevant network segments to produce a list of overloaded or constrained assets. This is done for both system normal (N) and contingency conditions (N-1). Solutions to resolve asset overloads at times of forecast load are considered for inclusion within SA Power Networks' annual capital budget submission where the planning criteria for the relevant asset are violated.

SA Power Networks plans to implement solutions for those assets forecast to be overloaded under normal conditions, prior to the overload occurring. However, the solution for contingency events considers both the likelihood and consequence of such an event as well as the amount and type of customer load at risk. The load at risk level chosen usually allows verification of exceedence of the contingency capacity prior to project commitment.

SA Power Networks' typical repair / supply restoration times (in the event of a failure) for major equipment categories based on actual best case response times achieved over the last five years (often response times may be much longer):

Small Substation transformer (N ≤ 3MVA)	48 hours
Large Substation transformer (N > 3MVA)	7 days (installation of system spare)
11kV underground cable	24 hours
33kV underground cable	24 hours
33kV overhead line	12 hours
66kV underground cable	10 days
66kV circuit breaker	7 days
66kV overhead line	12 - 24 hours

2.4.2 Summary of the planning criteria

As a DNSP within the National Electricity Market, SA Power Networks must comply with the technical standards specified within the National Electricity Rules. In particular, requirements relating to reliability and system security contained in Schedule 5.1 of the Rules are relevant to planning for future electricity needs. In addition, as a licensed electricity entity in South Australia, SA Power Networks is required to comply with the service obligations imposed by the South Australian Electricity Distribution Code (EDC) and licence conditions imposed at the time of sale in 2000. SA Power Networks is required to operate its power system within plant ratings and with acceptable quality of supply under reasonably expected operating conditions in order to comply with its requirements under the NER and the EDC.

SA Power Networks has developed its planning criteria to meet and maintain the reliability and security of supply requirements of the NER and EDC. Where the forecast load breaches the planning criteria, a constraint is established and a suitable solution is sought whether this involves implementation of a major network augmentation, a deferral solution or a suitable contingency plan taking all risks and their associated consequences into consideration.

Projects required to avoid breaching the planning criteria are included within the 10-year capital plan generally where:

- A connection point does not comply with the security requirements of the allocated category for the connection point as detailed within the Electricity Transmission Code (ETC);
- The overload cannot be eliminated by load transfers for zone substations and distribution feeders or by distribution support services for connection points (requires ElectraNet agreement to latter);
- The 10% PoE load is greater than a zone substations' normal capacity;
- The 10% PoE load is greater than a sub-transmission line's normal rating³ or emergency rating⁴;
- The 50% PoE load under contingency conditions is greater than a zone substation's or feeder's constraint capacity⁵;
- The normal load exceeds the distribution feeder exit's normal rating; or
- The voltage at the 11kV bus terminals of an OLTC controlled zone substation is below 98%, when the OLTC is at maximum tap (however, a lower or higher voltage may be acceptable provided it can be shown that the voltage at each customer's supply point complies with the requirements of the Electricity Distribution Code).

The network planning criteria for connection points, lines, substations and feeders are summarised in Table 2, Table 3, Table 4 and Table 5 respectively.

Note that transmission connection points designated as Category 1 may not have adequate backup capacity under contingency conditions (via ElectraNet's transmission network or SA Power Networks distribution network) to supply the load until ElectraNet's repairs are complete.

ETC Connection Point Category	Connection Point Line Capacity	Connection Point Transformer Capacity
1	N	N
2	N	N-1
3	N-1	N-1
4	N-1	N-1
5	N-1	N-1

Table 2: Planning Criteria for Transmission Connection Points

³The normal rating allocated to sub-transmission lines is dependent on the rating of the switchgear, cable and conductors associated with the line in accordance with Procedure 630 – Network Planning Criteria & Process.

⁴The emergency rating allocated to sub-transmission lines is dependent on the rating of the switchgear, cable and conductors associated with the line in accordance with Procedure 630 – Network Planning Criteria & Process.

⁵The constraint capacity may be greater than or equal to the zone substation's N-1 or contingency capacity, depending on the criterion applicable to the zone substation in accordance with Procedure 630 – Network Planning Criteria & Process.

Category	System	Planning Criteria	Forecast Basis	Line outage
L1	Interconnected ACR 66kV & 33kV sub-transmission lines	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)		
L1	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)		
L2	Radial 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.

Table 3: Planning Criteria for Sub-transmission Systems

Category	System	Planning Criteria	Forecast Basis	Impact of transformer outage
S1	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)		
S2	Specific major zone substations, namely: <ul style="list-style-type: none"> 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	
S3	Substations supplying major industrial customers or critical commercial load regions, or where supply cannot be restored within 12 hours, namely: <ul style="list-style-type: none"> Woodville North Adelaide Kilkenny Kent Town Norwood Direk Substations where mobile substation can't be used (eg 66/33kV and 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	
S4	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	

Table 4: Planning Criteria for Zone Substations

Category	System	Planning Criteria	Forecast Basis	Impact of transformer outage
F1	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. 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-1		
F2	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	
F3	Rural feeders	N	10% PoE	

Table 5: Planning Criteria for Feeders

2.5 Impact of customer connection projects

Customers contribute to the costs of advancing augmentation works in accordance with the EDC and the NECF. Future augmentation works that are advanced by the connection of major customers within the 10-year plan's window will cause the plan to be revised. This revision is completed at each annual review. This AP's forecast expenditure does not consider demand increases due to new customer connection activity unless the connection is committed.

2.6 Method of calculating forecast expenditure

There are two methods that have been employed to calculate the required future expenditure for each category of work.

Future expenditure for some work categories is calculated based on historic expenditure over the last five years, as the rate of expenditure has historically proven to be steady and not influenced greatly by the rate of system load growth. Examples of this include Quality of Supply and SWER augmentation works.

Alternatively, future expenditure for other work categories may be calculated based on the load forecasts. The rate of augmentation expenditure for these categories of work has historically proven to be significantly influenced by the rate of system load growth and estimates for these projects are based on SA Power Networks' unit costs.

Table 6 indicates the basis upon which the forecast expenditure for each work category has been derived.

Work Category	Calculation Method
Zone substation capacity	Forecast
Sub-transmission line capacity (ie 33kV and 66kV)	Forecast
ElectraNet connection point capacity	Forecast
Voltage support	Forecast
VAr support	Forecast
Distribution feeders (eg 11kV and 7.6kV)	Forecast
19kV SWER systems	Historic
Distribution substation capacity	Historic & Forecast
Quality of Supply minor works	Historic & Forecast
Low Voltage mains capacity	Historic & Forecast

Table 6: Expenditure Determination Methods

3. SA POWER NETWORKS' COSTING METHODOLOGY

In developing its capacity driven capital plan, SA Power Networks has assigned each project to a works category relating to the component of the Network requiring augmentation, reinforcement or construction (eg Sub-transmission Network – Metro, Sub-transmission Network - Country etc).

For the purposes of this document, these work categories have been consolidated into five generic areas of work. Table 8 indicates the consolidated annual expenditure associated with these areas of work in the years from 2019/20 to 2024/25.

The costs assigned to each project are determined using a set of standard components or "unit" costs expressed in a nominal year's dollars. For the purposes of this plan, all values are expressed in 2018 nominal dollars.

Each project's total cost is derived using these standard construction components in order to ensure each project's costs are directly comparable to one another. These "unit" costs are revised annually and have been determined based on estimates for each "unit" using SA Power Networks' "RealEst" estimating tool. The costs developed within RealEst have been compared to the historic costs of actual projects (escalated to 2018 dollars) within the present regulatory period (2015 – 2020) based on the scope for each "unit cost" element to ensure their credibility.

It is the intent of these unit costs that they represent all possible costs likely to be incurred by the business in undertaking a specific project since it is this plan which is used to formulate the annual budget submission. The unit costs values are intended to be all inclusive and therefore include all business overheads at rates applicable for the nominal year's dollars as well as consideration of expenditure on non-field based activities such as design, third party approvals etc.

Further details of the methodology employed to determine and validate the veracity of these “unit” costs are further detailed within SA Power Networks’ “Unit Cost Methodology version 2”.

4. CAPACITY RELATED EXPENDITURE 2015-20

Within the present regulatory period, SA Power Networks has spent (on average) \$51 million per financial year (in 2018 dollars) on capacity related augmentations of the network. Based on forecasts of expenditure over the 2018/19 financial year, by the end of the regulatory period, this average expenditure is forecast to be \$43 million per annum (in 2018 dollars).

Since 2010, several factors have combined to reduce the customer forecasted demand growth at peak times. This includes the connection of over 960 MW of embedded PV generation at distribution level, closure of large commercial and industrial businesses, self generation of some larger commercial businesses and the general economic slowdown. As a consequence, the capacity program has followed a downward trend to reflect these changes. These changes in customer demand have been factored into the 2015-20 demand forecasts including the increase in embedded PV generation. While the growth in maximum demand has been reduced, the significant embedded generation does pose challenges to our network with the increasing reverse flow and difficulty in managing network voltage.

Within its 2015-20 submission, SA Power Networks included 34 projects with forecast expenditure in excess of \$2 million.

Of these 34 major projects, eight have been deferred to post 2025 and one deferred to the 2020-25 period, with the remaining being complete or in progress at the time of writing. The seven deferrals are due to a reduction in demand forecast which has resulted in changes to the timing of the constraint the project was proposed to resolve.

Table 7 below provides a summary of the major projects submitted within the 2015-20 regulatory submission and an indication of those completed, in progress or deferred while Figure 9 shows a comparison of SA Power Networks’ capacity related expenditure over the 2010-20 period with the forecast expenditure in this area over the next 5 years.

Project Name	Region	Project Category	Planned Year	Estimated Cost (\$ million ⁶)	Status	Reason for deferral / Comment
Barossa South Sub Upgrade (Mod 2)	Barossa	Substation Capacity - Existing	2016	3.5	Completed	-
Dorrien 33/11kV substation upgrade	Barossa	Substation Capacity - Existing	2015	2.8	Completed	-
Lyndoch East Substation (2 x Mod 6)	Barossa	Substation Capacity - New	2018	4.0	Not commenced	Slower customer load growth – deferred post 2025
Stockwell Sub Upgrade (No2 Mod 2 Substation)	Barossa	Substation Capacity - Existing	2018	3.9	Completed	-
Eliza Street Cable Duct works	CBD	Substation Capacity - New	2019	3.7	In progress	-
Meadows Substation Upgrade	Eastern Hills	Substation Capacity - Existing	2019	2.3	Not commenced	Slower customer load growth – deferred post 2025.
Mount Barker East Substation – New	Eastern Hills	Substation Capacity - New	2019	5	Not commenced	Slower customer load growth – deferred post 2025.

⁶ Values escalated from 2018 nominal dollars to those of construction year.

Project Name	Region	Project Category	Planned Year	Estimated Cost (\$ million ⁶)	Status	Reason for deferral / Comment
Mount Barker Substation - New Summit 11kV Feeder and MTB-10 and MTB-12 backbone restrung	Eastern Hills	Distribution Feeders - Country	2017	2.7	Completed	-
Port Neill SWER Conversion	Eyre Peninsula	Distribution Feeders - Country	2019	4.5	Not commenced	Customer demand not yet recorded
Kingscote 4th Generator	Fleurieu Peninsula	Substation Capacity - Existing	2015	2.1	Completed	-
Myponga to Square Water Hole 66kV line	Fleurieu Peninsula	Supply Security	2019	21.8	Not commenced	Deferred due to Fleurieu 66kV re-insulation projects
Kangaroo Island Submarine Cable	Fleurieu Peninsula	Supply Security	2018	30.5	Completed	-
Glynde Substation - New Substation & 66kV line	Metro East	Substation Capacity - New	2017	18.8	Completed (Alternate Solution).	Addressed by Campbelltown Substation Upgrade
Elizabeth South Sub - Salisbury Park new 11kV feeder	Metro North	Distribution Feeders - Metro	2019	3.2	Completed (Alternate Solution).	Demand Management solution.
Gawler East New Substation	Metro North	Substation Capacity - New	2018	15.8	Not commenced	Slower residential development – deferred post 2025.
Two Wells New Mod 1 Substation and Virginia 66kV line	Metro North	Substation Capacity - New	2015	9.9	Completed	-
Aldinga to Willunga Pole Upgrade	Metro South	Sub-transmission Capacity - Metro	2017	3.0	Completed	-
Ascot Park Sub 66kV Line CBs	Metro South	Supply Security	2019	2.5	Completed	-
McLaren Flat Sub Upgrade (Second Mod 1)	Metro South	Substation Capacity - Existing	2015	5.2	Completed	-
Morphett Vale East to Clarendon 66kV Line Uprate	Metro South	Sub-transmission Capacity - Metro	2016	3.8	Completed	-
Oaklands Sub 66kV Line CBs	Metro South	Supply Security	2018	2.5	Completed	-
Port Noarlunga to Aldinga Number 2 66kV Line	Metro South	Sub-transmission Capacity - Metro	2017	15.1	Not commenced	Slower customer load growth – deferred post 2025
Cheltenham 7.6kV Feeder Conversion to 11kV	Metro West	Distribution Feeders - Metro	2017	4.4	Completed	-
Clare 33/11kV substation upgrade	Mid North	Substation Capacity - Existing	2018	6.2	Not commenced	Slower customer load growth – deferred post 2025
Gawler Belt 33/11kV Substation Upgrade (second Mod 1)	Mid North	Substation Capacity - Existing	2015	5.1	Completed	-
Kapunda Sub Upgrade (second Mod 1)	Mid North	Substation Capacity - Existing	2016	3.9	Completed	-
Mallala sub upgrade	Mid North	Substation Capacity - Existing	2016	2.9	Completed	-
Mypolonga Substation Upgrade	Murraylands	Substation Capacity - Existing	2018	2.1	Completed	-

Project Name	Region	Project Category	Planned Year	Estimated Cost (\$ million ⁶)	Status	Reason for deferral / Comment
Swan Reach 66/33kV Sub Upgrade	Riverland	Substation Capacity - Existing	2019	2.5	Completed	-
Cape Jaffa Substation	South East	Substation Capacity - New	2017	2.4	Not commenced	Slower customer load growth – deferred post 2025.
Glencoe Substation Upgrade	South East	Substation Capacity - New	2016	2.0	Completed	-
Snuggery to Robe 33kV Voltage Support	South East	Voltage Regulation	2018	9.9	Completed	Demand Management Solution
Baroota Connection Point Upgrade	Upper North	Connection Point Capacity – Existing	2017	5.1	Completed	-
Dalrymple Connection Point Upgrade	Yorke Peninsula	Connection Point Capacity - Existing	2017	4.6	Completed	-

Table 7: 2015-20 Project Summary

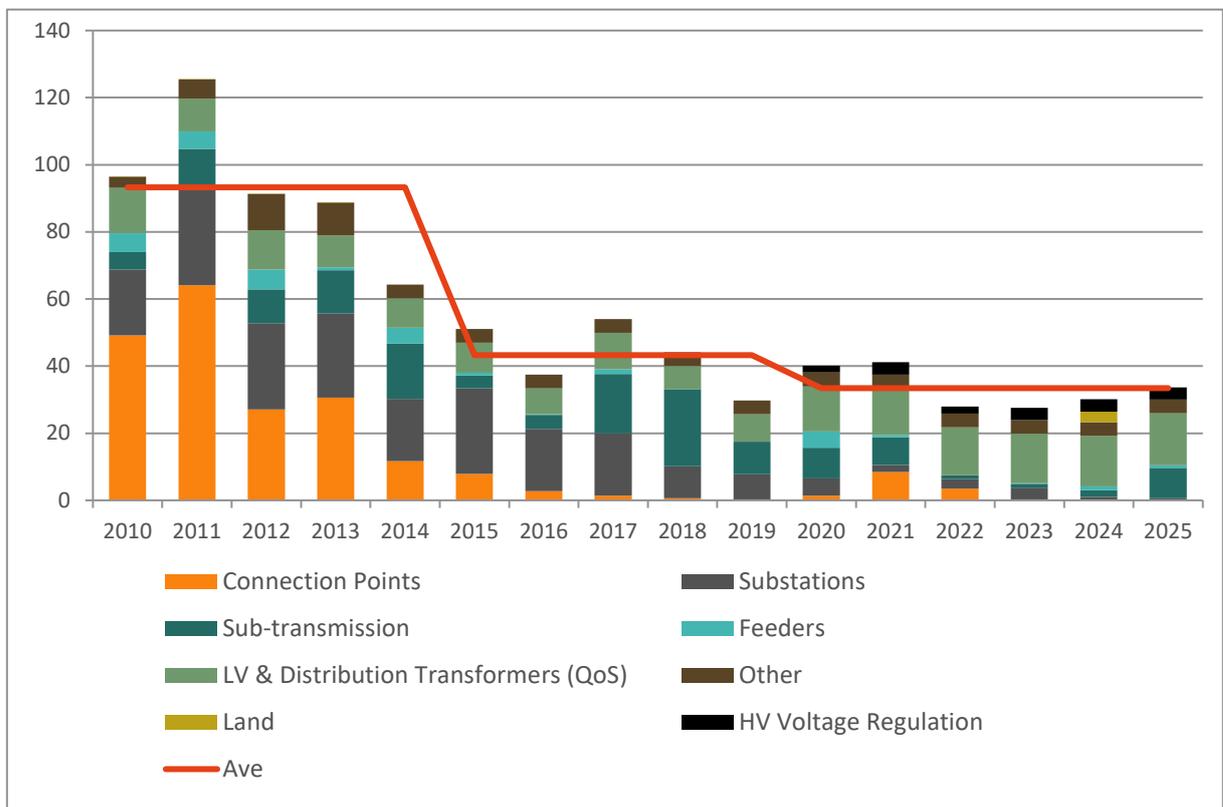


Figure 9: Historic and Forecast Expenditure by Area of Work (in 2018 dollars)

As can be seen from Figure 9, average expenditure within the 2020/21 to 2024/25 regulatory period is forecast to reduce from its present levels of \$43 million per annum to \$33 million per annum. A large one-off expenditure on the Kangaroo Island 33kV submarine cable in 2017/2018 puts the expenditure in these years above the otherwise \$35-40 million per annum average.

5. CONSTRAINT RESOLUTION METHODS CONSIDERED

5.1 Introduction

There are many factors that may affect the final solution chosen as the “preferred solution” to resolve an identified network constraint proposed to be implemented by this report. The factors influencing the selection of the “preferred” solution identified within this report include:

1. Major project cost variations;
2. Major new or increased customer connections;
3. Possible Demand-Side Participation (DSP) options;
4. New third party embedded generation;
5. Performance of preliminary RIT-Ds to determine the market benefits associated with both network and non-network solutions;
6. As a result of formal public consultations such as Regulatory Investment Tests (both RIT-D and RIT-T) or third-party approvals (eg SCAP) which may affect the solution’s costs (eg overhead conductors versus underground cables); or
7. Changes in forecast demand.

Each of these items is discussed in the sections that follow.

5.2 Network Augmentation Solutions

The following are general examples of network augmentation solutions considered (for the HV network), which may be necessary to meet increasing demand on SA Power Networks' network and alleviate network inadequacies and constraints, assuming all other deferral options utilising the existing network (eg load transfers) have been exhausted:

1. Establish new, upgrade or up-rate⁷ existing sub-transmission lines;
2. Establish new or upgrade existing high voltage distribution feeders;
3. Upgrade existing zone substations (eg add or upgrade existing transformers);
4. Establish new zone substations;
5. Improve power factor through capacitor installation, either to reduce substation demand, improve system voltages or improve power factor at the connection point level to comply with the NER requirements;
6. Install in-line voltage regulators to improve system voltages;
7. Upgrade existing or establish new connection points in consultation with ElectraNet;
8. Establish new generation stations to provide network support; or
9. Implement non-network solutions such as load curtailment or third party generation proposals.

5.3 Approval of 66kV Aerial Lines

Construction of new 66kV aerial lines within South Australia requires approval from the State Commission Assessment Panel (SCAP), which involves a consultation process with stakeholders such as local councils, the Department of Planning, Transport and Infrastructure (DPTI) and other government agencies.

Comments and/or opposition may be received by SCAP from these third parties, to the construction of any new overhead 66kV lines. This may reduce the feasibility of many of SA Power Networks’

⁷The term “up-rate” relates to the alteration of the overhead conductor’s design temperature in order to increase the rating of the *line* or *feeder*.

favoured options, involving the construction of new or the upgrading of existing overhead 66kV lines where these works require the installation of additional 66kV poles.

If community or government opposition prohibits the use of overhead lines, in particular cases, it may be necessary to use underground cables if an alternative route suitable to all parties can not be found. In these instances, this will likely make all such options significantly more expensive and may alter the effectiveness or financial evaluation of some options. The preferred (ie most cost-effective) option for reinforcement of each sub-transmission line constraint may therefore change.

The costs included within the capital plan and quoted in the body of this report are predominantly based on the use of overhead 66kV line construction where this is possible in SA Power Networks' best judgement. In those cases, where in SA Power Networks' opinion, it is unlikely that approval for the use of an overhead solution will be granted, the cost of an underground solution has been employed. It should be noted that whilst most council jurisdictions would prefer the implementation of underground 66kV lines, their actual use is relatively rare and only chosen as a last resort or where the use of an overhead solution is impractical such as in the CBD. The cost of implementing an underground solution at 66kV is often cost prohibitive or may require re-evaluation of the available solution in accordance with the NER's RIT-D requirements.

It has been assumed that any upgrades required to increase the clearance to ground of any existing overhead lines can remain as overhead solutions, by either raising the existing conductors or through the insertion of additional poles along an existing Line's route. Whilst for 66kV lines, the addition of any new poles will require approval from SCAP, the granting of such approval has been assumed to be forthcoming.

5.4 Market participant consultation

As a Distribution Network Service Provider (DNSP) operating in the National Electricity Market, SA Power Networks is required to consult with Registered Participants and Interested Parties under the National Electricity Rules (NER) prior to undertaking any capacity related augmentation of its distribution system where the expected cost of the network solution is in excess of \$6 million.

The objectives of the consultation process are to:

1. Determine and advise of network and non-network options available and identify potential DSP options to address specific system constraints as they arise and assess more broadly where focussed DSP options may offer strategic or longer-term load reductions as appropriate;
2. Identify the estimated costs and market benefits of overcoming forecast constraints;
3. Inform and consult with customers and Interested Parties; and
4. Ensure that potential non-network solutions are given due consideration and comparable weighting to that afforded to network augmentation options.

The consultation processes followed by SA Power Networks have been developed to meet the requirements of Chapter 5 of the NER. This involves the annual issuance of a Distribution Annual Planning Report (DAPR), publication of a Demand Side Engagement Document and the performance of Regulatory Investment Test – Distribution (RIT-D) where the estimated value of the proposed network augmentation project is in excess of \$6 million.

All complying submissions that are received as a result of the issuing of a non-network options report (NNOR) are evaluated against the available network solution(s) under consideration in accordance with section 5.15 and 5.17 of the NER and the AER's RIT-D Guidelines. The results of the RIT-D are used to determine the solution that is ultimately implemented and the cost borne by Registered Participants and electricity consumers.

Historically, non-network solutions (the result of the RIT-D process) do not permanently eliminate the need for a required network augmentation project, but may defer some major augmentation projects by several years, if viable alternative solutions are provided.

In accordance with sections 5.13.2, 5.13.1 (e) – (j) and 5.17 of the NER, all relevant documents (ie the DAPR, DSED and the various RIT-D documents respectively) are published on SA Power Networks' website. Upon publication, AEMO and the AER as well as all parties contained within SA Power Networks' Demand Side Engagement Register (DSER) are notified by e-mail of the publication of each document. It should be noted that it is the responsibility of each party registered on the DSER to advise SA Power Networks of changes to their contact details.

5.5 Variations to Existing Risk Profile

This AP seeks to maintain SA Power Networks' historic level of network security and reliability, as defined by SA Power Networks' network planning criteria (Procedure 630). For example, SA Power Networks has two 66/11kV mobile substations mounted on trailers. The long term contingency capacity for metropolitan 66/11kV substations is composed of the emergency rating of any remaining substation transformer(s), plus all possible load transfers to adjacent substations via feeders interconnecting the substations and an additional 3MVA at risk for no more than 24 hours when compared to the 50% PoE forecast. The use of mobile substations is a key element of ensuring this otherwise unsupplied load is not without supply for longer than 24 hours. The consequential response time to secure load following a transformer outage to allow for the dispatch and installation of the mobile substation.

Any regulatory changes that require an improvement in network security levels or response times compared to the historic levels of network security or reliability will result in an increase in the capital works required within the regulatory reset period. SA Power Networks will seek a pass-through for any and all additional expenditure required as a result of any such changes.

5.6 Regulation and Code Changes

SA Power Networks will seek a pass-through for any expenditure increase that is required due to any regulatory or code changes which impact on the timing of constraints or the solutions to resolve said constraints. Examples of such possible changes include:

- More stringent regulatory reliability targets;
- More onerous regulatory quality of supply requirements;
- Decreased customer contributions due to any changes to the prescribed augmentation charging methodology;
- More stringent environmental standards and/or technical requirements;
- Electricity Transmission Code changes (such as a requirement to provide backup supply to Category 1 connection points, or to provide firm N-2 capacity to the ACR);
- Changes in council / SCAP approval criteria;
- Increased regulatory reporting, NER rule changes which require significant resource and/or information technology (IT) changes; and
- Government (local / state / federal) legislative changes which impose additional obligations or restrictions on SA Power Networks' operations.

This capital plan assumes no change to the existing Electricity Distribution Code's incentives or penalties related to reliability performance or other obligations imposed under the NER. Consequently, for any regulatory changes requiring capital expenditure, SA Power Networks will seek a pass-through where the materiality threshold established by the AER is breached. This breach may take into consideration the cost alterations of multiple projects as opposed to the need for a breach on a project by project basis.

5.7 Demand Management

The viability of Demand Management (DM) or Demand Side Participation (DSP) solutions, depends on the ability of electricity consumers and/or DNSPs to reduce or curtail consumer's electricity demand at will. This has the potential to reduce the peak electricity demand, for example, through the use of direct load control via firm load reduction or load shedding contracts with customers. Such arrangements could delay the need for some reinforcement projects, if a guaranteed amount of load can be shed on request from SA Power Networks' NOC.

As a matter of course, SA Power Networks considers various non-network solutions when attempting to determine its preferred solution to address an identified constraint on its network. Examples of DM solutions considered by SA Power Networks include,

1. Power factor correction;
2. Peak lopping embedded generation;
3. Load transfers / balancing; and
4. Amendment or creation of, Network System Support Agreements (NSSA) with customers to generate or curtail load on demand.

In addition, all projects estimated to cost in excess of \$6 million are subject to the RIT-D in accordance with section 5.17 of the NER. Where it is determined as a result of the Screening Test that publication of a Non-Network Options Report (NNOR) is warranted, a NNOR is created and issued for public consultation seeking alternative solutions to remedy the identified network constraint.

Direct load control and other demand management solutions have and are being actively investigated and trialled by SA Power Networks in the previous and current regulatory period (ie 2010 - 2015 and 2015 - 2020).

During the present regulatory period (2015 – 20), SA Power Networks has instituted one non-network solution to resolve an identified network constraint at Salisbury using Residential Energy Storage. The Residential Energy Storage project involved the targeted offering and deployment of up to 100 energy storage systems on customer premises across three 11kV distribution feeders in the Salisbury region. The residential energy storage trial had three primary aims:

- To defer an infrastructure augmentation with a capital cost of \$2.9 million;
- To validate the assumptions about the performance of these energy storage systems; and
- To prove the projected customer and network benefits.

In November 2018, we released a call for Expressions of Interest (EOI) to test the market for non-network solutions to a number of smaller constraints that fall below the RIT-D threshold of \$6 million, and we continue to engage actively with industry to explore these opportunities. We are also pursuing a number of innovation initiatives in this area as part of our Future Network Strategy that are outside the scope of this document.

As demand side initiatives become more widespread, economically viable and dispatchable (eg load curtailment), this should enable DNSPs to reduce peak demand at call, which may result in some deferral of capital augmentation projects. Demand management solutions are likely to be adopted only where they can be shown to be economically and technically viable and able to be implemented in a timely enough fashion to resolve the identified network constraint. Any expenditure thus saved by the deferral of traditional network solutions to network constraints will be partially offset by the cost of implementing the demand management solution which will typically consist of both an initial capital expenditure together with an ongoing operational cost.

Those demand management options that result in a "flattening" of the load cycle will also reduce the cyclic asset ratings for such assets as transformers and cables. This will reduce the benefit in the reduction in peak demand. It will also affect the asset utilisation levels reported by SA Power Networks to the AER (thereby potentially suggesting inefficiencies in SA Power Networks' operations).

In summary, it is believed that demand management initiatives have a limited potential to impact on this plan, especially given SA Power Networks' performance of preliminary RIT-Ds for those projects in excess of \$6 million, only one or two of which have historically suggested the adoption of a non-network solution as being economically viable. A number of demand management solutions for smaller projects are included as deferral solutions where preliminary analysis has shown they may be economically viable. Any successful demand management initiative is not expected to permanently eliminate the need for network reinforcement projects but rather defer them for some period of time (typically 1 – 10 years).

5.8 Losses

Projects designed solely for the purpose of reducing distribution losses have not been included in this capital plan. The cost of the energy lost in transporting power through the distribution network (distribution losses) is paid by the customer via their retailer, using an averaging formula. This averaging formula is based on the difference between the energy measured at the transmission connection points and the customers' supply points at the customer's supply voltage.

Minimisation of distribution losses is considered by SA Power Networks when 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 (whole of life losses are considered);
2. 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
3. Capacity upgrade projects, which generally reduce losses for the same load by the use of higher voltages (reduced current), larger conductors or transformers (lower impedance), and shorter lines and feeders through the insertion of new connection point and zone substations (zone substation insertion between two existing zone substations reduces feeder load and length and hence losses).

Generally, almost all of the proposed augmentation projects contained within SA Power Networks' 10-year capacity plan reduce distribution losses when supplying the same load. However, the proposed rate of expenditure is not likely to materially reduce average losses over time as any reductions are generally offset by increases in losses due to load growth. SA Power Networks has not included any augmentation projects to specifically address the issue of losses within its capacity augmentation plans. It is worth noting the findings of previous 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 the electricity and gas networks. This investigation explored the economic benefits of reducing losses in distribution networks through targeted network augmentations. The conclusion of this investigation⁸ was that investment in specific network augmentations solely to reduce network losses was uneconomic and therefore not viable.

5.9 Embedded Generation

The National Electricity Rules require Network Service Providers (NSP) to explore all options, including the installation of embedded generation to address any projected network limitations.

In theory, it would appear that the installation of embedded generation offers a practical solution to defer large capital expenditure required to augment the network in addressing the projected constraint, and the Bordertown generator is an example of this solution being used effectively in our network. However, the installation and connection of embedded generation poses specific issues for the distribution network that must be taken into consideration in assessing such solutions.

⁸ <http://eeo.govspace.gov.au/files/2013/07/EEO-electricity-trials-report.pdf>

Largely, the existing distribution network was not designed for the connection of embedded generating units. The following issues must be addressed as part of any serious embedded generation connection feasibility study:

1. Availability of a suitable site in relatively close proximity to the network / constrained area;
2. Availability and access to a suitable fuel source;
3. Environmental issues (eg noise, emissions);
4. External approvals (eg council, Environmental Protection Agency, SCAP etc);
5. The ability of the embedded generator to adapt and successfully operate according to the changing generation / demand mix at all times of the day; and
6. Capital, operational, maintenance and ongoing compliance monitoring costs.

To provide security utilising an embedded generation option, plant redundancy needs to be catered for. Depending on the type and configuration of the generation plant proposed, the extent of redundancy required for security may add significant costs to the generation option, irrespective of whether this was a DNSP or third party owned operation.

For example, embedded generation capacity in excess of 5 MW made up of multiple 1 to 2 MW units (eg reciprocating engines), may require an additional one or two units to provide the redundancy required to meet normal load at all times in order to enable the performance of maintenance or in the event of a generator fault. In contrast, the installation of gas turbine generating units, which generally are sized to suit the total demand, would require an equally sized second unit to provide this redundancy. This security consideration can therefore add significant costs to the embedded generation option selected and increases the uncertainty faced by DNSPs in considering these options.

Similarly, any embedded generation solution needs to be capable of operating successfully in conjunction with other non controlled forms of embedded generation (eg PV) that may exist in the relevant part of the network. Proponents suggesting the use of embedded generation as a viable non-network solution should therefore consider such issues as cold load pick up and the minimum operating load of the proposed generation solution. In order to operate successfully, such proponents may need to provide "load banks" to cater for period when uncontrolled asynchronous generation output is high and load on the relevant network area may therefore be low or negative (ie a net exporter).

In addition, the use of embedded generation brings with it significant ongoing operating costs both in terms of fuel, maintenance and environmental compliance.

5.9.1 Technical Issues

There are many technical issues that must be considered when connection of embedded generation is considered, such as:

1. System fault levels;
2. Thermal ratings of equipment;
3. System stability;
4. Reverse power flow capability of the OLTCs;
5. Line drop compensation;
6. Steady state voltage rise;
7. Losses;
8. Power quality; and
9. Protection.

Generally, throughout the metropolitan area's network, the installation of embedded generation may be restricted due to the existing relatively high fault levels. This can be overcome with connection at the 66kV sub-transmission level, however this adds other

significant costs including, but not limited to, the requirement for a step-up transformer(s). This however also reduces the number of suitable sites available for connection of such generation plant.

5.9.2 Site Availability

Locating a suitable site to accommodate any proposed generation plant within the metropolitan area in close proximity to the area of the network constraint is difficult with the possible exception of industrial areas (although this may still prove problematic). These difficulties are further complicated by the requirements imposed on these sites to comply with the statutory environmental and land zoning obligations, particularly with regard to the need for bulk fuel storage, air and noise emissions, which often make the acquisition of suitable land within the metropolitan area extremely difficult and expensive to achieve.

5.9.3 Fuel Availability

The major operational cost for any generation option is fuel. Back-up generation plant generally consists of diesel fired engines or gas turbines fuelled by diesel, as diesel is the most readily available fuel and the generating units themselves tend to be cheaper than gas turbines. Reliable gas supplies for generation purposes are often difficult or expensive to source, but may be an option for smaller plant within the metropolitan area, subject to agreement for the connection from the relevant gas authority which will be dependent on the quantity and operating pressure of the gas supply required with respect to the existing gas network's capability. However, the cost of gas fired engines will add significantly to the capital cost of plant installation, as gas engines are typically about twice as expensive as conventional diesel engines.

5.9.4 Environmental Issues

The metropolitan area has additional requirements in relation to the Environmental Protection Authority (EPA) Act. The most significant requirements relate to noise and air quality with higher restrictions generally applying within the envelope of the metropolitan area. Both the issues of noise and air quality can generally be overcome but at significantly higher capital cost.

SA Power Networks' recent experience indicates that to meet current EPA requirements for a standby 6.0MW power station within the metropolitan area, an estimated \$1 million would be required to meet air quality and noise emissions standards. The additional costs relate to the provision of catalytic converter systems installed to control Nitrogen Oxide (NOx) and Sulphur Oxide (SOx) emissions for air quality and the installation of additional acoustic treatment to the exhaust system(s).

For larger plant, further acoustic treatment would be required to the engine house and potentially the installation of variable speed drives for the cooling system to reduce both engine and air noise to within prescribed levels, thus further increasing the required capital expenditure.

In addition, it will be highly difficult (if not impossible) to obtain planning permission from councils to construct any embedded generator station of any significant size within the metropolitan area other than within those areas zoned as industrial.

5.9.5 Capital & Operational costs

When considering the cost of installing embedded generation, the following items need to be considered within any evaluation and comparison with alternative solutions:

1. Plant acquisition costs (including unit(s) for redundancy);
2. Site acquisition;
3. Connection costs, or connection interfaces;
4. Protection requirements;

5. Environmental compliance;
6. Provision of a medium voltage transformer installation to step the generator voltage up to network nominal voltages (eg 11kV, 33kV, 66kV);
7. Maintenance & servicing costs; and
8. Fuel costs.

Similarly, where SA Power Networks considers the use of third party owned embedded generation to resolve an identified network constraint, we must consider the following items in addition to those listed above:

9. Potential availability charges (these will vary on the generation capacity installed);
10. Likely run time hours per annum and the associated operational charges to SA Power Networks;
11. Capital cost to SA Power Networks to facilitate connection of the generator to the network;
12. Cost of procuring the installation should the third party become insolvent; and
13. Operational costs to ensure ongoing compliance by the third party with the requirements of the NSSA and NCA.

Inclusion within the capital plan

SA Power Networks and third party embedded generation solutions have not been included within the capital plan. However, these types of solutions may be considered for inclusion, particularly where performance of a preliminary RIT-D analysis shows them to be economically and technically viable.

6. CAPITAL PROJECT CATEGORIES

6.1 Introduction

This section describes the different categories of augmentation projects that are included in SA Power Networks' 2020 to 2025 capital plan. It also provides a general description of the projects that are typically required for augmentation of each asset category. The capital plan includes projects specifically aimed at deferring larger augmentation works through the use of demand management measures where a preliminary RIT-D investigation has suggested it is economical to do so. Augmentation projects are only considered where permanent load transfers are not capable of resolving the identified constraint.

6.2 Transmission Connection Points

Transmission connection points are categorised according to the different levels of reliability and security of supply, as specified by ESCOSA within the Electricity Transmission Code.

ElectraNet augments its connection point capacity based on joint planning with SA Power Networks and the connection point forecast annually produced by SA Power Networks in conjunction with ElectraNet. ElectraNet and SA Power Networks jointly maintain a Connection Point Management Plan (CPMP) which outlines the predicted timing and high level scope of new connection points, connection point upgrades and deferral solutions to connection point constraints via SA Power Networks' distribution network.

This 2020 to 2025 capital plan only contains costs and scopes for SA Power Networks' component of these connection point upgrades, which may include components such as 33kV or 66kV bus works, new circuit breakers and 66kV or 33kV line exits. Some of these upgrade works are mandated through the alteration of existing connection point's categorisation within the ETC or due to the timing of asset replacement works by ElectraNet approved by the AER as part ElectraNet's most recent price reset determination in 2018.

6.3 Metropolitan 66kV Sub-transmission Lines

SA Power Networks' metropolitan 66kV sub-transmission network consists of four islanded 66kV meshed systems that distribute the customer demand from ElectraNet's connection points to 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 Adelaide CBD. From a sub-transmission perspective, this region is not independently planned as it is contained 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% PoE conditions. The Electricity Transmission Code refers to these connection points as category 4, and requires 100% N-1 transmission line and connection point transformer capacity to be continuously available.

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).

Upgrade projects are planned when the 10% PoE forecasted load exceeds the emergency rating of an overhead line or the normal rating of an underground line during a single contingency event. Projects to resolve any contingent overloads are generally completed within three years of this rating being exceeded. The potential (up to) three year deferral period was historically based on the maximum deferral period previously afforded to ElectraNet within the ETC. This enabled SA Power Networks where applicable, to align the timing of its sub-transmission works with the works of ElectraNet. Whilst this three year deferral provision has now been removed by ESCOSA from the ETC, it has been retained by SA Power Networks to enable it to maintain its existing planning criteria in this area.

The Electricity Distribution Code (EDC), published by ESCOSA does not provide specific guidelines for the design and operation of SA Power Networks' metropolitan meshed sub-transmission lines. However, the EDC does provide incentives for SA Power Networks to maintain the present levels of supply reliability. These levels of reliability are achieved through maintaining the contingency capacity of the metropolitan meshed sub-transmission network of 66kV lines. However, a condition of sale in 2000, also required maintenance of the historic reliability performance.

Reinforcement of the metropolitan meshed sub-transmission networks is needed to prevent overload of 66kV lines under 10% PoE conditions during particular single contingency events. This avoids the need for load shedding and the possibility of cascade tripping of the meshed 66kV network concerned which could otherwise occur during contingency events.

The 2015 - 2025 AMP has considered line overloads that are the result of circuit breaker, line conductor, or underground cable rating limits. ElectraNet transformer overloads have been based on the ratings of each transformer published by ElectraNet.

When circuit breakers are required to operate outside their design capabilities (ie both current and fault ratings) there is a risk of catastrophic failure. Failure of a particular circuit breaker would require an upstream circuit breaker to operate, resulting in loss of supply to a larger part of the network. Depending on the extent of the damage to the circuit breaker, restoration would generally be expected to take up to a week.

Overhead line conductors deteriorate gradually depending on the temperature at which they are operated. Generally, SA Power Networks' 66kV lines are designed and operated for an ultimate line conductor temperature of 100° Celsius (however not all lines are designed for operation at this temperature). The typical restoration time following a metropolitan 66kV line outage due to an overhead line fault is twelve hours.

Approximately eight percent of SA Power Networks' metropolitan meshed lines are underground. Underground cable faults can occur in two ways:

1. Failure at specific locations due to site conditions such as termites or third party activities (ie struck during digging); or
2. Failure due to general deterioration caused by prolonged overload.

In the first instance, the best case duration of such a cable outage is ten days to allow for fault location and repair. In the second case, the cable could be expected to remain out of service for between six to nine months (depending on cable delivery time) while awaiting replacement.

Overhead 66kV line construction is preferred for the augmentation of these networks where technically feasible, due to the much higher cost of 66kV underground cable installations and the longer repair / restoration times in the event of a failure. Typical examples of augmentation are to:

1. Upgrade an existing lines conductor or raise the existing conductor's design temperature to provide a higher rating;
2. Build a new 66kV line to relieve overloads on one or more existing lines; or
3. Establish a new ElectraNet connection point to relieve overloads on one or more existing lines.

Metropolitan 66kV radial sub-transmission lines (where permanent supply is available from one end only) are considered for de-radialisation where the load in the existing line exceeds 30MVA or where a RIT-D shows a positive net market benefit.

6.4 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 not designed to provide N-1 backup as most lines are radial in nature and consist of overhead construction, with a repair time generally of up to 12 to 24 hours.

Examples of typical augmentation projects for these systems include:

1. Uprating lines by increasing line to ground clearances;
2. Upgrading lines by replacing the existing conductor;
3. Building new 33kV or 66kV lines; or
4. Establishing new ElectraNet connection points.

Country radial sub-transmission lines (where supply is available from one end only) are considered for de-radialisation where the load exceeds 30 MVA or where performance of a RIT-D indicates a positive net market benefit.

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

6.5 Zone Substations

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

Typically, augmentation of zone substations is achieved through:

The performance of minor works to maximise the substation's existing capacity, eg upgrading transformer cables or switchgear, adding transformer fans or installing capacitors to improve the effective power factor of the customer load seen by the substation's transformers;

1. Adding an additional transformer;
2. Replacing existing transformer(s) with larger capacity units;
3. Establishing a new substation; or

4. Establishing additional feeder ties to nearby substations with spare transformer capacity to increase the available feeder transfers.

Some upgrades require the replacement or addition of 11kV switchgear to achieve higher fault level or load ratings. Sometimes it is necessary to replace fixed-tap transformers with OLTC enabled transformers or install 11kV regulators in substations to maintain adequate customer volts on the downstream feeder network.

6.5.1 Land and Easements

In some cases, SA Power Networks already owns land earmarked for future substations. Much of this land was acquired by the former Electricity Trust of South Australia (ETSA) prior to privatisation. Any new land acquired since this time has been acquired on an “as needs” basis for the establishment of a new substation, regulator station site or sub-transmission line easement. Where new substations are required in other locations, suitable land needs to be purchased as part of the project. An allowance for this is included within the plan and has been separately identified from the overall project costs.

The costs associated with the procurement of these sites normally precede the planned project commencement date by between two and ten years depending on location and the time taken to negotiate the land sale with the relevant land holders. Whilst SA Power Networks has compulsory land acquisition powers under the Act, these are rarely invoked as time usually prohibits their use and are difficult to enact (ie it must be demonstrated that all other options have been exhausted and requires ministerial approval).

Where new lines are built along the verge of public roads, easements are generally not required (other than overhang easements). However, in cases where lines are to be built using alternative routes through private property, new line easements are required. An allowance for this is again separately itemised within the “Land” section of this capacity plan.

6.5.2 Telecommunications for Capacity Projects

All new substation projects are required to be established with SCADA telecommunications back to SA Power Networks’ NOC and for protection signalling purposes. This may require new communication networks to be installed or existing networks to be upgraded. An allowance for these works have been included within each project’s cost estimate as required.

6.6 Sub-transmission Voltage Levels

SA Power Networks is required by the EDC to provide customers with voltage levels that comply with Australian Standard AS60038 – 2012, Standard Voltages.

SA Power Networks usually receives a voltage level from ElectraNet 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, where the voltage level is often boosted back to around 100% of the nominal voltage by the zone substation’s transformer OLTC tap changers or 11kV regulators.

As the load increases on long 66kV and 33kV sub-transmission lines, the voltage drop along these lines can become large enough that the existing system is no longer capable of boosting the voltage to within adequate levels. One or more of the following potential solutions may be required to maintain adequate customer voltage levels on the downstream system:

1. Install capacitor bank(s), to reduce the effective reactive load on the system;
2. Upgrade 66kV or 33kV lines with larger, higher capacity / lower loss conductors;
3. Install 66kV, 33kV, or 11kV voltage regulators to provide additional voltage regulation;
4. Establish new connection points to reduce the length and/or load on particular sub-transmission lines.

6.7 11kV and 7.6kV Feeders

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

One or more of the following potential solutions may be required to increase the 11kV or 7.6kV feeder's capacity as loads increase:

1. Upgrade the existing feeder exit cable;
2. Construct a new 11kV or 7.6kV feeder to reduce the load on the existing feeder;
3. Convert a 7.6kV feeder to 11kV operation; and/or
4. Upgrade the feeder exit switchgear (ie circuit breaker or recloser).

6.8 19kV & 6.35kV SWER Systems

SA Power Networks' SWER systems consist of a single 19kV or 6.35kV phase conductor that supplies single-phase to ground distribution substations. These systems have traditionally been used to supply small amounts of load distributed over long distances, such as in remote areas where there has traditionally been low load density. The largest SWER isolating transformer used by SA Power Networks is a 200kVA unit. These systems (ie 19kV) are typically supplied directly from the rural 33kV sub-transmission network, however a handful of 6.35kV systems exist, supplied by metro 11kV feeders.

Possible solutions for resolving overloads on SWER systems are to:

1. Upgrade the SWER isolating transformer, regulator and recloser;
2. Establish a new SWER system to reduce the load on the existing system by splitting it;
3. Rebuild part of the SWER system as a three-phase 33kV or 11kV feeder and relocate the isolating transformer downstream of its existing location; or
4. Convert the entire SWER system to three phase 33kV or 11kV.

NB: SA Power Networks has a minimal number of 6.35kV SWER systems. These SWER systems are no longer constructed or extended and will be phased out over time as and when the SWER system is upgraded.

6.9 Distribution Substations

Distribution substations convert the voltage from HV to LV and may be connected to SA Power Networks' network at 33kV, 19kV, 11kV, 7.6kV or 6.35kV. The secondary voltage of the distribution substation may be either 400V (three-phase), 460V (single phase) or 230V (single-phase) and can supply either single customers or a low-voltage mains system from which multiple customers may be connected.

Possible solutions for resolving overloads on distribution substations are:

1. To replace the existing transformer with a larger capacity unit; or
2. Install a new "infill" transformer nearby, enabling the transfer of some of the low-voltage mains supplied by the existing transformer to be supplied by the new transformer.

6.10 Low-voltage Mains

Low-voltage mains systems operated by SA Power Networks are either radial three-phase 400V (three-phase) or 460V / 230V (single-phase) systems used to supply multiple customers from a single distribution substation. Possible solutions to resolve overloaded low-voltage mains systems are:

1. Upgrade the LV main's conductor or cable;
2. Install an "infill" distribution substation nearby to split the load on the existing low-voltage mains system; or
3. Install LV regulators.

6.11 National Electricity Rules, Power Factor and Metering Compliance

The National Electricity Rules (NER) requires a minimum power factor where requested by the TNSP (ie ElectraNet) of 0.95 lagging at 66kV connection points and 0.90 lagging at 33kV connection points. In addition, the Electricity Transmission Code (ETC) allows ElectraNet to request a higher power factor at connection points where this is required to achieve the necessary level of system power transfers.

Typically, the required power factor is achieved by the installation of capacitors at 66kV, 33kV or 11kV to improve the effective power factor of the system load seen by ElectraNet's connection point transformers and by requesting customers to comply with NER power factor requirements for all new installations. This often has the added benefit of reducing effective load in lines and feeders, improving voltage levels, and reducing network losses. The introduction of kVA and excess kVA_r tariffs in 2001 and 2006 respectively by SA Power Networks' also incentivised many existing customers to improve their power factor by installing their own power factor correction measures. This has seen a marked improvement in localised power factors at some zone substations and connection points.

Chapter 7 of the NER prescribes the various classes of metering to be employed by NSPs on their network. The NER prescribes the levels of redundancy and accuracy required for each metering class. Where the existing metering installation does not meet the relevant NER criteria, SA Power Networks plans upgrades of the NGM installations in conjunction with any major augmentations at the site.

6.12 ACR/CBD Assets – Feeders, Distribution Transformers, Ducts and Manholes

The CBD distribution system is comprised mostly of an underground cables, duct and manhole system along CBD streets.

Load increases within the ACR region are usually associated with large building developments, hence feeder augmentation is generally included within customer connection projects costs, with property developers contributing towards these projects as prescribed by the Electricity Distribution Code. There is therefore no specific allowance for CBD feeder upgrades included in this plan.

Some distribution substations in the ACR area supply low voltage mains which are not attributable to any single customer. No allowance has been made in this plan for the upgrade of such installations.

New ducts and associated manholes are required along CBD streets where there is little or no remaining duct capacity. Provision for these assets is not included within the scope of this document.

7. CAPITAL PROJECT DRIVER CATEGORIES FOR THE 2020-25 PERIOD

Whilst the majority of projects contained within this AP are driven by capacity constraints, many are driven by constraints unrelated to future load growth for the asset(s) concerned.

The drivers of the projects contained within this capacity AP can be classified as either independent or dependent of the future load growth.

Those projects which may be categorised as being independent of future demand growth include:

- (i) ETC or ElectraNet augmentations;
 - (ii) Regulatory compliance (eg NER or EDC driven – includes QoS and management of the two way network);
 - (iii) Existing committed augmentations or those constraints where the planning criteria has already been breached;
 - (iv) Security driven augmentations; and
 - (v) Strategic projects (eg land and easements).
- Those projects which may be categorised as future demand growth dependent include:
- (vi) New Greenfield developments (where little or no infrastructure exists today);
 - (vii) Continued development of new housing areas or infill areas;
 - (viii) Agricultural or mining developments; and
 - (ix) General demand growth.

An explanation of each category and the rationale for their inclusion within each category is discussed below. Of the project expenditure contained within the 2015-20 period, on average, 91% can be categorised as being independent of the load forecast. Projects beyond 2020 are also likely to be independent of future demand growth.

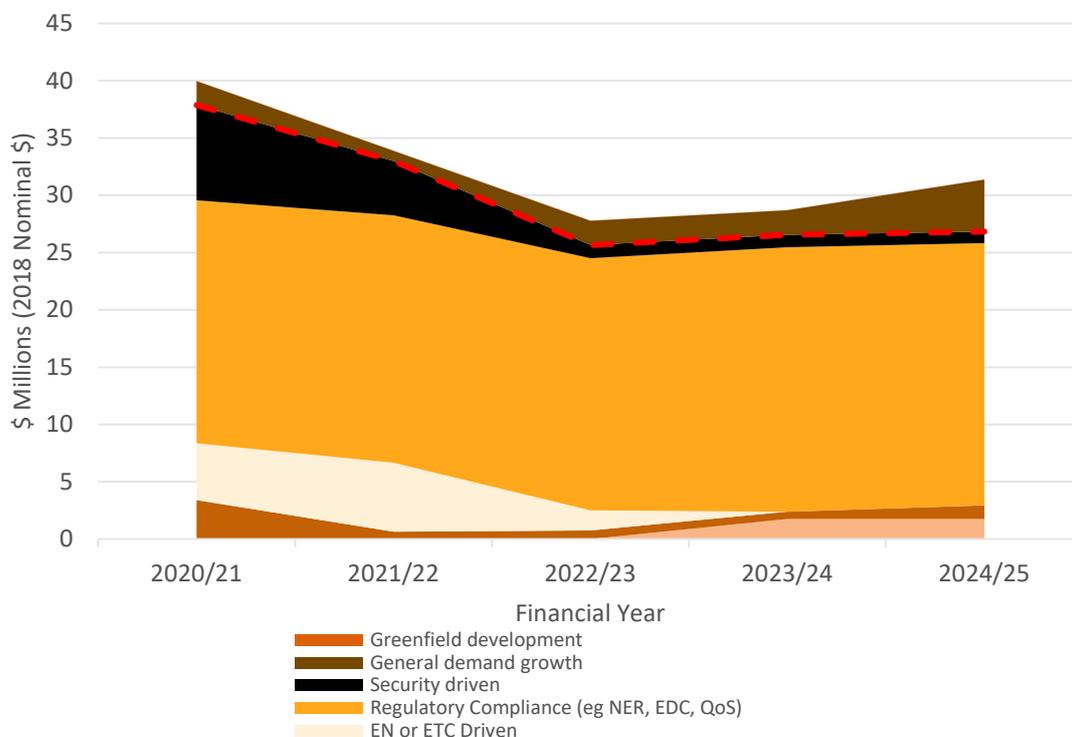


Figure 10: AP Expenditure Breakdown by Forecast Dependent and Forecast Independent Project Categories (20-25)

7.1 Growth independent project categories

7.1.1 ETC or ElectraNet augmentations

These projects are performed by SA Power Networks in-conjunction with ElectraNet either to comply with changes to the reliability category assigned to a given connection point mandated by ESCOSA within the ETC or to enable the continued correct operation of SA Power Networks' network following asset replacement works planned to be performed by ElectraNet as previously approved by the AER as part of the TNSP's regulatory submission. As such, these works are required irrespective of the forecast demand at these sites and are subject to the Regulatory Investment Test – Transmission (RIT-T) by ElectraNet.

This category constitutes approximately 8% of the proposed capital expenditure within the forthcoming regulatory period.

7.1.2 Regulatory Compliance

As a licensed DNSP operating within the NEM, SA Power Networks is obliged to comply with the requirements of the NER regarding the planning, security and quality of supply delivered by its distribution network within nominated standards. In addition, SA Power Networks is also obliged as a condition of its licence (issued by ESCOSA) to comply with the requirements of the EDC. Whilst the EDC does not explicitly specify reliability standards for the operation of the distribution network, it does prescribe minimum requirements with respect to quality of supply. As a result, all expenditure required to ensure regulatory compliance is classed as being independent of load growth.

This category also includes those planned strategic projects related to LV monitoring and voltage control to enable the ever expanding two-way network. South Australia has over 960 MW (as at 1st December 2018) of distributed solar generation connected to its network (predominantly at LV level), with a forecast growth of between 60 and 80 MW per annum. As such, the issues of managing the two way and LV networks are significant and growing, independently of customer demand growth.

This category constitutes approximately 68% of the proposed capital expenditure within the forthcoming regulatory period.

7.1.3 Committed Augmentations or existing planning criteria breaches

Projects within this category are those which are either already in progress, committed or for which the latest load readings indicate that the planning criteria was breached during the summer of 2017/18. These projects include those projects due for completion in progress or due for completion in 2020/21. As such, the performance of or need for these projects is independent of future customer demand growth.

This category constitutes approximately 4% of the proposed capital expenditure within the forthcoming regulatory period.

7.1.4 Security related augmentations

Projects within this category are not growth driven, but rather by maintaining existing levels of reliability or improving the security of the network where a positive market benefit according to the RIT-D can be demonstrated. A preliminary RIT-D assessment has been performed on present load levels rather than forecast levels and demonstrates a positive market benefit.

These network augmentations are intended to either minimise the duration of network outages or prevent cascade outages within the network (eg installation of line exit or section CBs at a sub-transmission level). Prior to their inclusion within the AP, they are subjected to a

preliminary RIT-D analysis to justify their inclusion. Only those indicating a positive net market benefit are considered for inclusion within the AP.

This category constitutes approximately 10% of the proposed capital expenditure within the forthcoming regulatory period.

7.1.5 Strategic Projects

In order for a DNSP to adequately plan for the future, it needs to make certain strategic acquisitions such as land and easements prior to their actual need. This requirement is to ensure that both suitably located and sized areas exist for future network augmentation requirements and to ensure new regions can be planned by the responsible jurisdiction (eg SA Government and/or local council) in a logical and efficient manner. This is particularly the case within new underground residential development (URD) areas. Whilst these augmentations are ultimately demand and therefore forecast driven, the acquisition of these sites is required prior to this time. Given the size requirements of substations and statutory easement widths required for new sub-transmission lines, it is considered prudent planning for DNSPs to procure such sites when land division developments are approved. In addition, it is also prudent to procure land in advance of forecast requirements to ensure delays to the required network augmentation do not arise in trying to procure such land holdings from the relevant land holders on a "just in time" basis.

Typically, SA Power Networks looks to acquire land or easement holdings more than two to ten years prior to the need to establish an asset on the relevant parcel of land. The longer periods are required in new development areas such as underground residential developments (URDs) to ensure optimum regional planning with the relevant responsible bodies.

This category constitutes approximately 3% of the proposed capital expenditure within the forthcoming regulatory period.

7.2 Growth dependent project categories

Combined, these categories constitute approximately 7% of the proposed capital expenditure within the forthcoming regulatory period.

7.2.1 New Greenfield developments

These areas by their very nature influence demand forecasts given they are based on new customer developments that are forecast to occur in a region with little or no distribution network assets today and will require major network expansion to supply. This only applies to regions where a strong indication of customer development will occur in the 2020-25 regulatory period and includes multiple customers and large scale residential subdivisions. This portion of the submission does not include the HV feeders, distribution transformers and LV connection assets as these are covered by the customer connection submission.

7.2.2 Continued development of new housing areas

Again, by their nature, these areas are forecast dependant. These forecasts are largely based on those forecasts provided by the property developer relating to the continued development of the housing development.

7.2.3 Infill developments

Augmentation expenditure driven by infill developments such as sub-division of existing properties or conversion of former commercial or industrial sites to residential areas is clearly growth dependent. The nature of these developments is such that they may be catered for

within the general demand growth category if they have been occurring for several years or may drive the need for development specific augmentations.

7.2.4 Agricultural or mining developments

Augmentations supporting proposed developments within existing agricultural areas or possible mining ventures are clearly forecast related. Such proposals are not considered within the moderate load forecast unless committed, however their timing is potentially volatile, particularly for mining ventures where the overall project's viability is subject to commodity prices.

7.2.5 General demand growth

Augmentation based on forecasted demand growth rates is essential to maintaining both existing reliability and quality of supply standards. Obviously, by its very terminology, augmentation as a result of this category is forecast driven.

8. RISK RANKING

The Network Planning Department has developed its own risk ranking system to prioritise those projects covered by this AP. Whilst SA Power Networks has a corporate risk ranking process, the risk allocation process and scoring system is focussed on risk at a corporate level and is considered to coarse for application at an individual project level. Network Power Asset Management Plan details the corporate risk ranking methodology.

As such, the risk allocation method used by Network Planning has sought to quantify the financial consequence of each project and allocate risk scores based on the corporate risk system's financial consequence values. In this way, those risk allocations applied by Network Planning's risk ranking methodology should remain directly comparable with other SA Power Networks departments but are also directly comparable on a project by project basis.

Each project's risk score is based on an allocation of both a likelihood and consequence score. These two scores are added (in line with the corporate risk scoring system) to arrive at the final risk score. Each of these components (ie likelihood and consequence) is assigned a value between one and five resulting in a final risk value ranging between two and ten.

Each project's risk is assessed both pre and post augmentation to arrive at a risk score based on a "do nothing" scenario as well as assessing the residual risk on completion of the project. This also provides a method for measuring the overall level of risk reduction due to the proposed augmentation.

In order to remove as much subjectiveness as possible from the risk allocation process, likelihood and consequence scores are automatically assigned based on responses to a series of questions posed to Network Planning personnel. This also ensures consistency across different assessors. Automated risk scores can only be overridden by administrators of the system used to perform risk rankings. All risk ranked projects are independently reviewed prior to budget submission to ensure the integrity of the risk scores derived.

Typically, only those projects registering a final risk score greater than seven out of ten will be "automatically" considered for inclusion within the annual budget submission (see Figure 11 below). Where suitable funds exist within a given year's budget, projects with a score of six may also be considered for inclusion, however, as detailed within Power Asset Management Plan, these are micro ranked according to their decimal value (ie non integer consequence scores may be used – refer to section 8.2 below).

Likelihood	Consequence				
	Minimal (1)	Minor (2)	Moderate (3)	Major (4)	Catastrophic (5)
Almost Certain (5)	6 (Medium)	7 (High)	8 (High)	9 (Extreme)	10 (Extreme)
Likely (4)	5 (Low)	6 (Medium)	7 (High)	8 (High)	9 (Extreme)
Possible (3)	4 (Low)	5 (Low)	6 (Medium)	7 (High)	8 (High)
Unlikely (2)	3 (Negligible)	4 (Low)	5 (Low)	6 (Medium)	7 (High)
Rare (1)	2 (Negligible)	3 (Negligible)	4 (Low)	5 (Low)	6 (Medium)

Figure 11: Risk Scoring Matrix

8.1 Likelihood

The likelihood is a measure of the probability that the risk will occur. For all capacity related projects, Network Planning uses a default rating of five when the “N” capacity planning criteria has been breached and a default rating of four where the “N-1” capacity planning criteria has been breached (ie forecast load, generally at 50% PoE exceeds the relevant asset’s planning criteria taking into consideration the maximum allowable load at risk).

Rating	Descriptor	Description	Probability	Indicative Frequency
5	Almost Certain	Is expected to occur	96 – 100%	At least one event per year
4	Likely	It will probably occur	81 – 95%	One event per year on average
3	Possible	May occur	21 – 80%	One event per 2 – 10 years
2	Unlikely	Not likely to occur	6 – 20%	One event per 11 – 50 years
1	Rare	Most unlikely to occur	0 – 5%	One event per 51 – 100 years

Figure 12: Likelihood Scoring Matrix

8.2 Consequence

The consequence is a measure of the implication of a possible event occurring. As such, the consequence score assigned by the risk ranking system assumes that the contingent event has occurred (eg for a project with load at risk under a N-1 scenario only, the consequence score is based on the contingent event having occurred).

In order to assign a consequence value, the risk ranking system assigns a financial value to the selected safety, environmental or reliability risks based on the responses provided within the system. This financial value then allocated a score according to the bands within the corporate risk matrix (see Figure 13). Given the broadness of these financial consequence bands, in order to more effectively differentiate one project from another, Network Planning’s risk scoring system assigns non integer values to the consequence value according to financial “sub-bands”, thereby enabling those projects with an overall risk score less than seven to be “micro-ranked”.

Weightings based on the operating voltage of the assets are applied to attempt to account for the differences between the sub-transmission and distribution portions of the network. Without these weightings, it is very easy to justify expensive augmentations of the sub-transmission network at the expense of the distribution network on a risk only basis due to the large difference in both the load at risk and customer numbers at risk. Whilst this may appear reasonable at face value, the fact is, that in general, the majority of reliability issues experienced by SA Power Networks are at distribution level as opposed to sub-transmission level. This is largely due to the greater area covered the distribution network as well as the additional hardening afforded to the sub-transmission network (eg overhead earth wires, higher installation height, greater phase conductor separation etc).

For instance, where a reliability constraint exists under a N-1 scenario on the sub-transmission network, the financial consequence of this outage will typically be based on the energy at risk and AEMO's average Value of Customer Reliability (VCR) value to arrive at a financial value for the load at risk. Conversely, for the distribution network, this financial consequence may be based on either the load at risk or the number of customers affected (whichever is the greater). The derived financial consequence values are then weighted according to the operating voltage.

Rating	1 Minimal	2 Minor	3 Moderate	4 Major	5 Catastrophic
Financial	Less than \$100,000	\$100,000 or more, but less than \$1million	\$1 million or more, but less than \$10 million	\$10 million or more, but less than \$100 million	\$100 million or more
OH&S	Incident but no injury	Medical treatment only	Lost time injury	Death or Permanent Disability	Multiple Fatalities
Environment	Negligible damage that is contained on-site	Minimal damage to the environment and small clean-up. Immediately contained on-site	Moderate damage to the environment and significant clean up cost	Significant environmental damage with wide spread impacts. Damage may be permanent	Long term environmental harm. Permanent irreparable damage
Reputation / Customer Service	Localised customer complaints	Widespread customer complaints or complaints to Ombudsman or Regulator	Intervention by the Ombudsman or Regulator	Repeated intervention by the Ombudsman or Regulator	Loss of Distribution Licence
	Adverse regional coverage	Adverse State media coverage	Adverse media campaigns by customers, media, industry groups	Severe negative impact on both regulator and un-regulated businesses	Loss of Distribution Licence
Legislation and Regulatory	Minor breaches by employees resulting in customer complaints or publicity	Act or Code infringements resulting in minor fines	Severe Company or Officer fines for Act or Code Breaches	Prison sentences for Directors or Officers	Loss of Distribution Licence
	ACCC require apology and / or corrective advertising	ACCC require special offer be made to all customers / suppliers	ACCC minimum level penalties	ACCC moderate level penalties	ACCC maximum level penalties
	Directors / Officers given minimum fines	Directors / Officers given moderate fines	Directors / Officers given severe fines	Directors / Officers given prison sentences	Loss of Distribution Licence
Organisational	Absorbed without additional management activity	Absorbed with minimal management activity	Significant event which requires specific management	Critical event which can be endured with targeted input	Disaster which can cause collapse of the business

Figure 13: Consequence Scoring Matrix

8.3 Risk Categories

The risk ranking methodology employed considers risks (ie likelihood and consequence) attributable across three categories, namely:

1. Safety;
2. Environment; and
3. Reliability / Regulatory compliance.

Users must submit risk assessments for all three categories, with the final risk scores (ie pre and post augmentation) being the highest value of all three categories unless the user indicates that a particular category should be ignored. Where this is the case, the user is required to provide justification for this (eg addition of SF₆ gas switches increases environmental risk if unit fails - risk outweighed by increased operational flexibility under contingent condition conditions. Risk of failure should be negligible given equipment is new).

8.3.1 Safety

The safety portion of the risk assessment considers risks to both SA Power Networks personnel as well as the general public. These risks may be both operational and/or non operational in nature (ie only posed when operating equipment or always present as a result of the equipment being in service). This risk category assigns risk based on:

1. Operating voltage;
2. Exposure to live components;
3. Consequence of equipment failure (from a safety perspective only – other consequences may be considered within the other categories);
4. Accessibility by external parties (eg unauthorised access); and
5. Anticipated frequency of operation / exposure.

8.3.2 Environment

The environment section of the risk assessment considers the potential impact of our assets on both the flora and fauna in the vicinity of our assets. This portion of the assessment is more subjective than other risk categories; however it requests users to consider:

1. The proximity of equipment to water courses;
2. The nature and effect of any fluid insulating mediums' release on the environment (eg SF₆, PCBs, mineral oil or FR3); and
3. The existence (or otherwise) of bunds or other environmental control measures (eg oil pressure alarms) etc.

8.3.3 Reliability (Financial)

For Network Planning's purposes, this aspect of the risk assessment is generally the most crucial. Users are required to indicate the following:

1. Nature of constraint (ie N, N-1 etc);
2. Operating voltage;
3. Equipment failure type considered (transformer, conductor, cable, CB) - typically the worst credible contingent event only will be considered;
4. Load at risk at time of peak (ie MW);
5. Hours per annum at risk;
6. Instantaneous customer numbers at risk;
7. Customer numbers without supply following restoration of healthy transformers;
8. Customer numbers without supply following the performance of feeder transfers;
9. Customer numbers without supply following connection of mobile substation;
10. Total duration of outage (hours);
11. Availability of spares; and

12. Indication of whether the project is being driven by a regulatory compliance requirement.

Where a project is driven by regulatory compliance (eg to either the ETC or EDC), the risk score assigned will default to a value of eight out of ten to ensure its inclusion within the annual budget, irrespective of any other entries made.

9. CAPACITY EXPENDITURE SUMMARY

Table 8 provides a summary of the historic capacity related expenditure as well as the proposed total capital expenditure over the 5-year period covered by this AP. Further information on the projects which constitute this expenditure are detailed within the following Sections.

	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
Connection Points	5.30	2.05	1.04	0.34	0.71	4.95	6.01	1.77	-	-
Substations	22.03	18.60	14.02	8.64	6.46	3.58	2.44	3.32	2.41	0.80
Sub-transmission	3.98	10.88	20.26	16.29	9.41	8.72	4.73	1.14	1.60	5.57
Feeders	0.54	0.85	0.75	0.02	2.42	2.75	0.33	0.09	0.63	0.91
LV & Distribution Transformers (QoS)	8.35	9.28	8.89	7.54	10.84	13.70	14.10	14.50	14.90	15.30
HV Voltage Regulation	-	-	-	-	1.03	2.86	2.86	2.86	3.66	3.66
Other	4.10	4.10	4.10	4.10	4.10	4.10	4.10	4.10	4.10	4.10
Land & Easements	-	-	-	-	-	-	-	-	1.55	1.55
Totals	44.30	45.77	49.07	36.93	34.95	40.65	34.56	27.77	28.84	31.89

Table 8: Forecast Capacity Related Expenditure⁹

⁹All values are expressed in millions and 2018 nominal dollars.

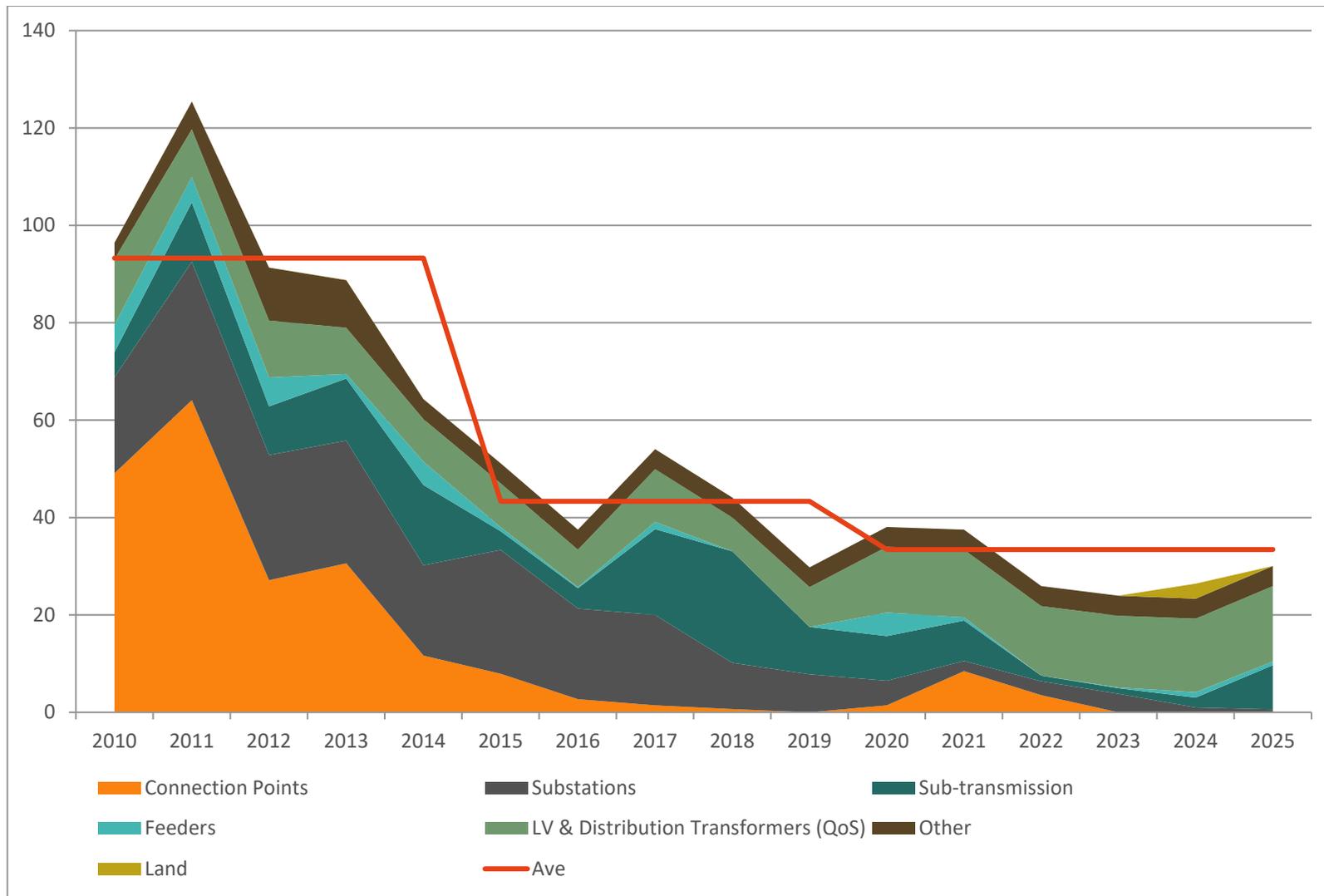


Figure 14: Forecast Expenditure by Area of Work per annum (in 2018 dollars)

10. Major Projects (RIT-D Required)

10.1 Major Project –Myponga to Square Water Hole 66kV line.

10.1.1 Background

Supply to the Fleurieu Peninsula consists of three components:

1. A 66kV line loop (the Southern Loop) from Port Noarlunga Zone Substation to Seaford, Aldinga, Willunga and McLaren Flat Zone Substations, terminating at Morphett Vale East Connection Point. Morphett Vale East is a 275kV / 66kV Connection Point and Port Noarlunga is meshed into the Metro South 66kV network via two additional 66kV lines.
2. A 66kV radial line from Willunga Substation to Square Water Hole Substation and then onto Victor Harbor and Goolwa Zone Substations;
3. A radial line from Willunga Zone Substation to Myponga, Yankalilla and Cape Jarvis and then via undersea cable to Kangaroo Island.

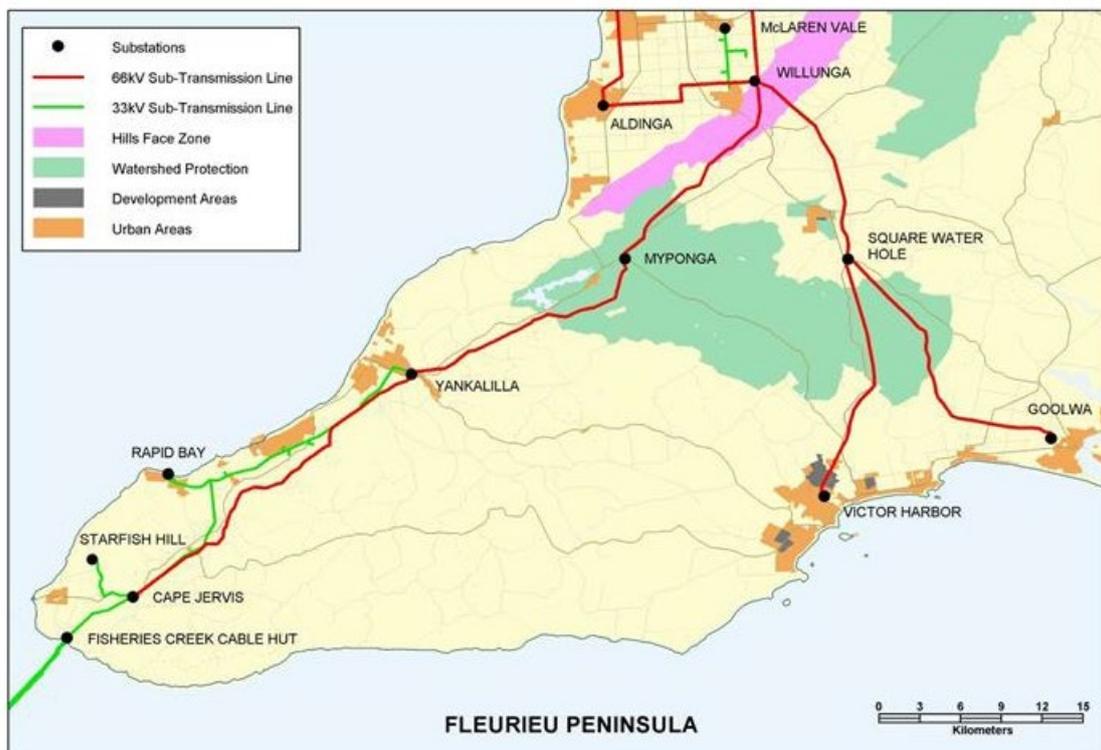


Figure 15: Fleurieu Peninsula Sub-transmission System

Southern 66kV Loop

The 66kV line loop connecting Port Noarlunga, Seaford, Aldinga, Willunga, McLaren Flat and Morphett Vale East Zone Substations forms part of the Metro South region's meshed 66kV sub-transmission system. In the event of:

- In 2018/19, an outage of the section of line between Morphett Vale East and Willunga, the 66kV line between Seaford and Port Noarlunga Zone Substations is loaded to 99% (92MVA) of its emergency summer rating (93MVA).
- In 2018/19, an outage of the line between Port Noarlunga and Aldinga results in the 66kV line section between Morphett Vale East and McLaren Flat being loaded to 98% (90MVA) of its emergency summer rating (92MVA).

All values are based on measured load as at April 2018. No capacity constraints of the line are forecast in the short to medium term horizon.

Radial 66kV Line Willunga – Square Water Hole

A single 66kV sub-transmission line from Willunga supplies Square Water Hole Zone Substation and subsequently those loads further south at Victor Harbor and Goolwa Zone Substations. This line is approximately 15km long, passes through paddocks and lies within a High Bush Fire Risk Area (HBFRA). Under SA Power Networks' planning criteria, a second source of supply is to be considered once peak loads on a radial line exceed 30MVA. This first occurred in 2006 during the summer peak and occurs regularly during both the summer and winter peaks, demonstrated in Figure 16.

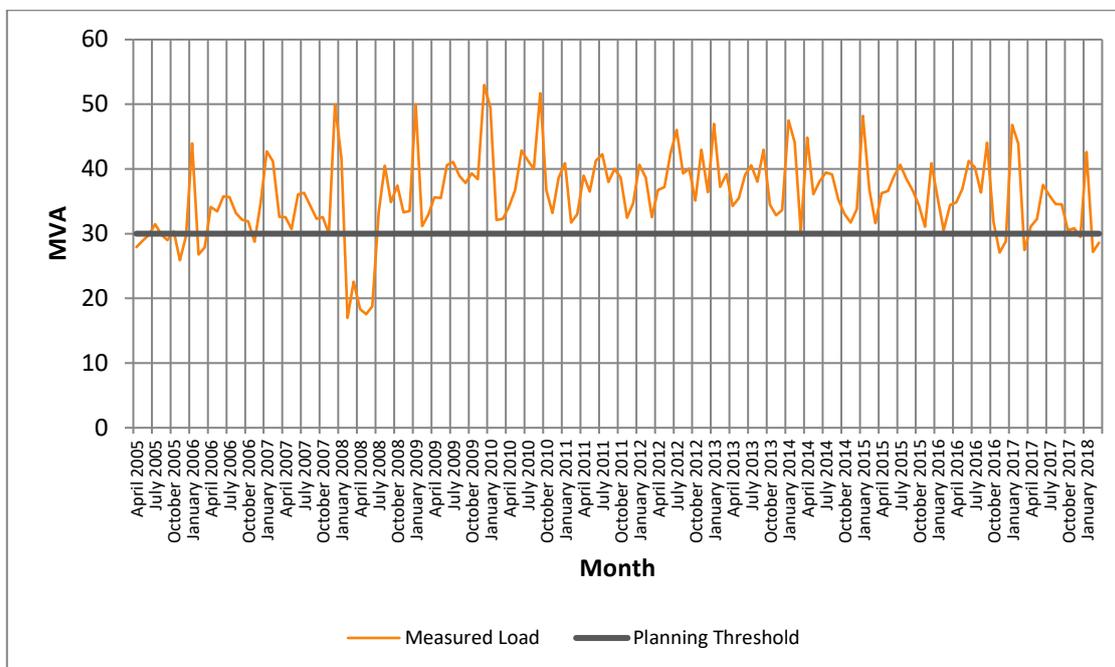


Figure 16: Willunga to Square Water Hole Monthly Maximum Demands

Radial 66kV Line - Willunga – Myponga

A single 66kV sub-transmission line from Willunga supplies Yankalilla and Cape Jervis Zone Substations via Myponga Zone Substation. Loads south of Cape Jervis (including Kangaroo Island) are supplied at 33kV from Cape Jervis. This section of 66kV line between Willunga and Myponga is approximately 33km long, passes through paddocks and a High Bush Fire Risk Area (HBFRA). Customer loads peak at approximately 29MW and wind farm production (connected at Cape Jervis) at approximately 32MW. No capacity constraints of the line are forecast in the short to medium term horizon.

10.1.2 Consequences for Customers

Radial 66kV Line - Willunga – Square Water Hole

An outage of the Willunga – Square Water Hole 66kV line will impact over 20,000 customers, leaving them without supply until the line is restored to service. Due to the distances and the topography there are no practical means of transferring load to other zone substations.

The line traverses a High Bush Fire Risk Area and areas of farm land that is difficult to access during winter. Consequently, there is a significant risk of lengthy delays in restoring the line following a fault that requires heavy vehicle access to remedy.

Radial 66kV Line - Willunga – Myponga

An outage of the Willunga – Myponga 66kV line will impact over 9,000 customers, leaving them without supply until the line is restored to service. Due to the distances and the topography there are no practical means of transferring load to other zone substations. The generator station at Kingscote on Kangaroo Island would be operated thereby restoring supply to Kangaroo Island.

The line traverses a High Bush Fire Risk Area and also an area of farmland that is difficult to access during winter. Consequently, there is a significant risk of lengthy delays in restoring the line following a fault that requires heavy vehicle access to remedy.

10.1.3 Load Profile

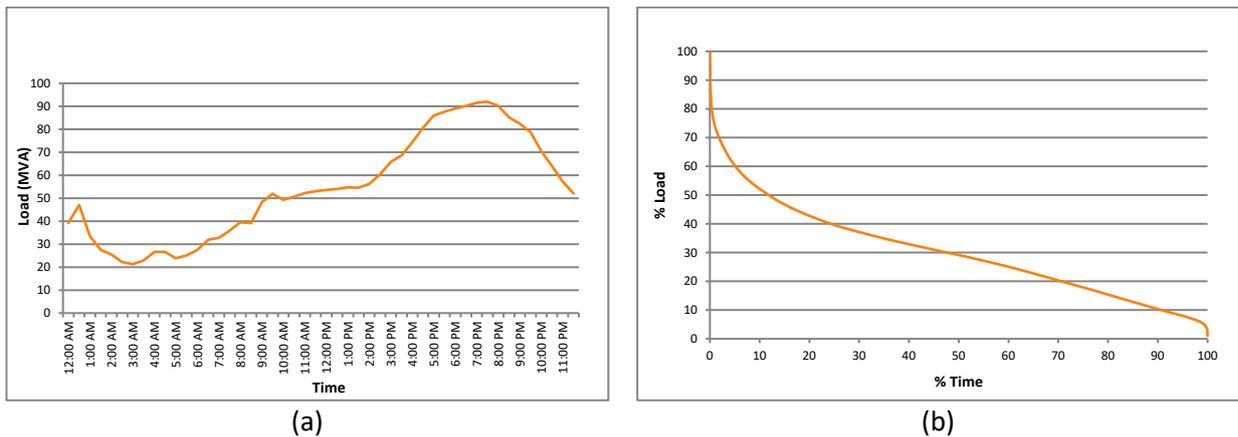


Figure 17: (a) Southern Loop Load Profile, (b) Load Duration Curve

10.1.4 Regulatory Investment Test - Distribution

The current situation does not result in a capacity constraint on the network, and complies with the reliability standards accepted as appropriate by ESCOSA in South Australia. However, under the NER, reliability improvements above the standard can be justified and included in the regulated budget as it can be shown that there is a net benefit to the market. With respect to the radial load at risk posed by both the Willunga to Square Water Hole and Willunga to Myponga 66kV lines, the need has been identified to improve the reliability of the radial 66kV networks from Willunga Substation to the extent justified under the market benefits test of the RIT-D.

Further, several non-network proposals were received in response to a Request for Proposals, RFP 001-10, published in March 2010, however, only one appeared to have the potential to be financially viable. Since this time, the load forecast for the Fleurieu Peninsula has been revised downward from that originally contained within the RFP, due in part to the significant amounts of PV generation installed within the region.

10.1.5 Deferral Options Considered

The following deferral options were considered:

Power Factor Correction:

- Due to the extent of the load at risk, power factor correction would not address the system constraint.

Replacement of the 66kV insulators:

- Replacement of the line insulators is underway in 2018 to improve the security of supply of the Willunga – Square Water Hole 66kV line. This solution does not improve security of supply to the western half of the Fleurieu Peninsula.

10.1.6 Non-Network Options considered (RFP 001-10)

We have received a proposal from a third party for a non-network solution. This proposal consisted of the construction of a 60MW diesel powered peaking power station south of Square Water Hole Zone Substation to provide network support following loss of the Willunga – Square Water Hole 66kV line.

This solution would support the eastern half of the Fleurieu Peninsula by operating in island mode to maintain supply to Victor Harbor, Goolwa and Square Water Hole Zone Substations.

This non-network solution does not improve security of supply to the western half of the Fleurieu Peninsula. There is also a technical issue to be resolved in the future due to continuing growth in installed PV at Victor Harbor and Goolwa.

10.1.7 Network Options considered

With respect to the radial load at risk posed by both the Willunga to Square Water Hole and Willunga to Myponga 66kV lines, the following options have been considered:

1. Build a new 66kV line between Myponga and Square Water Hole Zone Substations to form an open mesh (ie Willunga – Square Water Hole – Myponga – Willunga) with an open point at Myponga.
2. Build a second single circuit line between Willunga and Square Water Hole and another between Willunga and Myponga in parallel with the existing lines; and
3. Build new double circuit lines to replace the existing single circuit lines.

10.1.8 Preferred Solution

SA Power Networks has performed a preliminary market benefits test according to the RIT-D of the above options and has concluded that the preferred network solution.

- Construction of a new 66kV line connecting Square Water Hole to Myponga in 2020 at a cost of approximately \$21.6 million.

In addition, we have also evaluated the non-network option of a 60MW diesel peaking power station installed south of Square Water Hole Zone Substation. This option has two components: a capital requirement of \$19.3 million to facilitate connection of the power station to the sub-transmission network and an ongoing operational expenditure for 15 years for the power station to be available for network support and to cover the expected generation run time costs.

When comparing the preferred network and non-network solutions, the difference in net market benefits between these two options is marginal when compared against the overall capital investment required. This analysis suggests the network solution has a higher market benefit than the non-network proposal, however the overall capital cost is higher.

10.1.9 Preliminary RIT-D Analysis

A detailed preliminary RIT-D analysis is to be undertaken in 2019 for each of the three options, namely:

1. The minimalist network solution;
2. The nominated preferred network solution; and
3. The non-network solution.

This analysis shall be conducted over a range of growth rate scenarios and it is expected that the minimalist network solution will be the least cost. The preferred network solution is expected to have a greater market benefit regarding improvement in reliability than the minimal network solution, however, this is likely to be marginal when compared with the non-network solution.

10.1.10 Commitment Status

The relevant regulatory process (Regulatory Test) is expected to commence in 2019. The preliminary analysis undertaken to date suggests the solution with the highest net market benefit is the network solution and has been included within SA Power Networks' funding plans. Final commitment to either solution will be subject to finalisation of the RIT-D process and further discussion with the non-network proponent.

10.1.11 Regulatory Period Expenditure

Approximately \$21.6 million is forecast to be required during the 2020-25 regulatory control period to remove the radial risk exposure at Square Water Hole and Myponga.

10.2 Athol Park-Woodville new 66kV line

10.2.1 Background

The Metro West 66kV network is a meshed system that is forecast to supply a peak load of 437MW in 2018/19, rising to 458MW in 2036/37. This network is supplied by four ElectraNet connection points:

- Torrens Island Power Station (TIPS);
- LeFevre Substation;
- Kilburn Substation; and
- New Osborne Substation.

From these connection points there are four main lines that supply the majority of the load to the southern region: two lines from New Osborne, one line from Blackpool, and another from Kilburn.

Total load growth in the Metro West 66kV network has been slow over recent years, however there has been a shift in the timing of the peak as a result of declining industry and increased residential load. In previous years, the summer peak in the Metro West was the result of combined industrial and residential load in the late afternoon (approx. 4pm). At present, the peak occurs in the evening (approx. 6.30pm) and is largely residential. As a result, the load during peak times has shifted geographically from the northern region (more industrial) to the southern region (more residential).

Whilst this network has been very close to maximum capacity for several years, this geographic shift in the peak load has now resulted in N-1 constraints at summer peak. As

shown in Table 1, the current and forecast N-1 constraints exist due to a reliance on certain critical lines to supply the southern region of the Metro West. In particular, an outage of the Blackpool - Fulham Gardens 66kV line will result in an overload of the New Osborne – Glanville and Glanville – Queenstown 66kV lines.

Line	Contingency	Line Rating (MVA)	Load / Line Emerg. Rating (%)	
			2018	2025
New Osborne-Glanville	Blackpool-Fulham Gardens	144	103.5	104.4
Glanville-Queenstown	Blackpool-Fulham Gardens	137	102.8	103.7
New Osborne-Glanville	Croydon-Cheltenham-Croydon Park	144	97.7	98.7
Glanville-Queenstown	Croydon-Cheltenham-Croydon Park	137	96.6	97.4

Table 9: Metro West 66kV N-1 Constraints

Additionally, as part of the Torrens to Torrens (T2T) project in 2015, the former Kilburn – Croydon 66kV line was converted into the Kilburn – Croydon Park 66kV line. This has altered network flows within the Metro West network enough that it has resulted in restriction on the timing of planned outages. As such, these restrictions have reached or are reaching a stage where planned outages of many 66kV lines within the Metro West region are unachievable during normal working hours for much of the year, therefore imposing severe operating restrictions on the performance of planned maintenance activities throughout the region.

10.2.2 Consequences for Customers

Blackpool – Fulham Gardens 66kV Line Contingency

An outage of the Blackpool – Fulham Gardens 66kV line will result in a 3.5% overload of the New Osborne – Glanville 66kV line, and a 2.8% overload of the Glanville – Queenstown 66kV line. Under this contingency, there is no acceptable way of transferring load out of the Metro West 66kV network. Therefore, a total of 15MW of load would need to be shed from the southern part of the Metro West system under a Blackpool – Fulham Gardens 66kV line contingency event. There is also risk of cascading overloads of 66kV lines, resulting in a loss of supply to the majority of substations in the Metro West region.

The Blackpool – Fulham Gardens 66kV line has a length of 16.4km, traversing residential suburbs. Given the substantial length of this line, fault-finding and restoration is likely to take a number of hours.

Athol Park Substation Radial

Athol Park Substation supplies a peak load of 19MW, and is radially supplied from the three ended TIPS-Port Adelaide North-Athol Park 66kV line. Under the current network configuration, a fault on this 7km overhead line will result in the loss of supply to 5,473 urban customers. Restoration of this line is likely to take a number of hours.

10.2.3 Metro West 66kV Load Profile

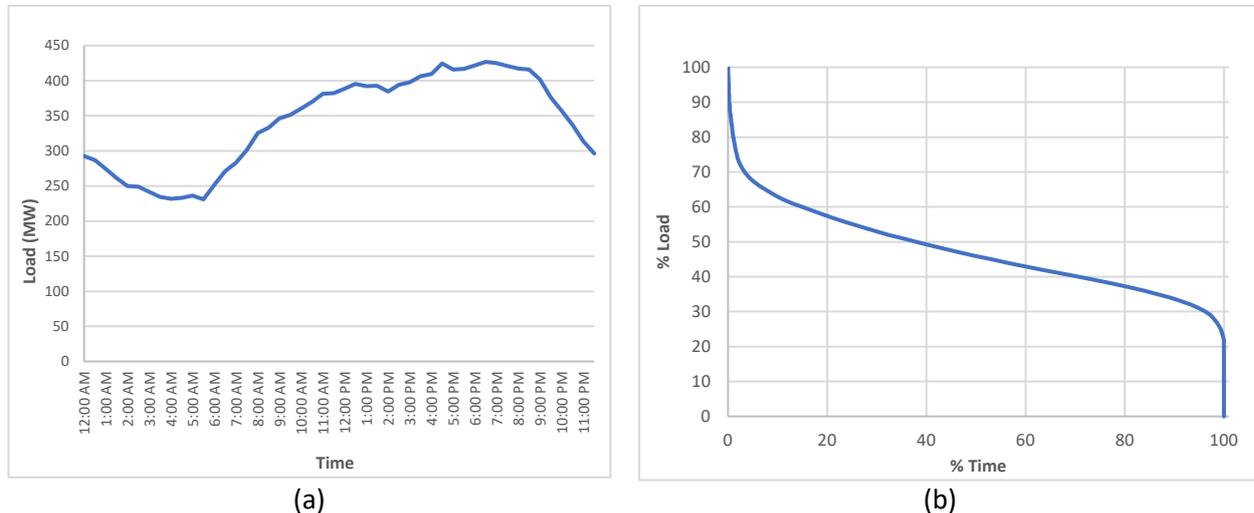


Figure 18: (a) Metro West 66kV Load Profile on 9th February 2017, (b) Load Duration Curve

10.2.4 Deferral Options Considered

The following deferral options were considered:

Power Factor Correction:

- The power factor within the Metro West region is close to unity, and as such power factor correction would not address the system constraint.

10.2.5 Non-Network Options considered

A generating system located within the southern region of the Metro West 66kV network could support enough load during peak times to defer the need for a network option. The system would need to support a minimum of 15MW of load immediately, increasing to 27MW by 2037. The exact amount of load the proposed system would need to support will depend on where the system is located within the Metro West region. Any proposed generating system would be required to connect to an appropriate substation in the Metro West 66kV network at either 11kV or 66kV. The feasibility of non-network proposals is to be assessed on a case by case basis. It should be noted that the relevant areas where generation connection would be required are already densely populated by residential premises. A cursory examination by SA Power Networks suggests it is unlikely that a generation proponent would find a suitable site from a development planning or environmental approval perspective within close proximity to the identified constraint.

10.2.6 Network Options considered

With respect to the aforementioned N-1 constraint in the Metro West 66kV network, the following options have been considered:

1. Construct a new 66kV line between Athol Park and Woodville Substations, and split the existing TIPS – Port Adelaide North – Athol Park three-ended line into two distinct 66kV circuits.
1. Construct a new 66kV line between New Osborne and Woodville Substations.

2. Install a new 275/66kV transformer at City West Substation, connecting into the Metro West region through a new 66kV line to New Richmond Substation.

Other options were investigated, but did not satisfactorily resolve all of the constraints in the system.

10.2.7 Preferred Solution

SA Power Networks has undertaken preliminary analysis according to the Regulatory Investment Test of the above options and has concluded that the preferred solution is:

- Construct a new 66kV line between Athol Park and Woodville Substations, and split the existing TIPS – Port Adelaide North – Athol Park three-ended line into two distinct 66kV circuits in 2021 and 2022 at a cost of approximately \$16 million.

When comparing the preferred network and non-network solutions, the preliminary analysis undertaken suggests the network solution has a higher market benefit than a embedded generation non-network proposal, however the overall capital cost is higher.

10.2.8 Preliminary RIT-D Analysis

A preliminary RIT-D analysis is to be conducted for all the options, namely:

1. The nominated preferred network solution;
2. All other network solutions; and
3. The non-network solution.

This analysis will be conducted over a range of growth rate scenarios. Preliminary analysis shows the preferred network solution has a greater market benefit regarding improvement in reliability than all other solutions, including the non-network solution.

10.2.9 Commitment Status

A preliminary RIT-D is to be conducted. A screening test notice and corresponding draft project assessment report (DPAR) are planned to be issued by SA Power Networks. Proponents wishing to offer alternate non-network proposals during the DPAR consultation period will be encouraged to do so for assessment by SA Power Networks prior to publication of the Final Project Assessment Report (FPAR).

Commitment is also contingent upon the outcome of the AER's reset determination and the approval of the SA Power Networks board.

10.2.10 Regulatory Period Expenditure

Approximately \$16 million is forecast to be required during the 2020-25 regulatory control period, with \$1 million in 2024, \$5 million in 2025, the remainder to be spent in the following regulatory period, to remove the N-1 constraint in the Metro West 66kV network.

11. Market Benefit Programs

11.1 Backup of radial substations using remote feeder transfers

11.1.1 Background

Many substations in our metropolitan network are at risk following the failure of a single item of equipment resulting in the automatic shedding of customer load. This equipment may be:

- A radial 66kV sub transmission line; or
- A single 66 / 11kV transformer.

At present customers are restored by crews manually switching feeders to an alternative substation, a process which can take many hours and therefore incur substantial costs to the community from loss of supply.

This situation does not result in a capacity constraint on our network if the total load at the substation does not exceed the amount of load that can be temporarily transferred to other substations plus three MVA. This corresponds to the reliability standards accepted as appropriate by ESCOSA in South Australia.

However, under the NER, if it can be shown that there is a net benefit to the market, security improvements above our published standards can be justified and be included in our regulated budget.

The Service Target Performance Incentive Scheme (STPIS) will not provide sufficient revenue reward to justify incurring the investment and therefore has not been considered for this program. That is, the appropriate return on and of the capital investment over the regulatory period would be below the revenue provided by the STPIS. The risks being addressed are low frequency, high impact events and statistically will have minimal impact over a five year period as the probability of occurrence is quite low. For instance, if an individual substation transformer is assumed to fail once in a 50 year period (2% chance of failure per year), compared to an individual feeder which may fail several times a year. Any reduction in STPIS, as a result of this work, is likely to be immaterial given the low frequency of events.

Traditional solutions such as additional transformers, circuit breakers or sub-transmission lines generally cost too much to be a net benefit for smaller substations.

With recent advances in technology and prices, SCADA controlled 11kV load switches are a potentially cost-effective method of reducing these restoration times.

11.1.2 Identified need

This proposal seeks to improve the security of the Adelaide metropolitan network to the extent justified under the market benefits test of the RIT-D.

For a project to be approved under this category the market benefits, in this case improved security of the network, the market benefits must be greater than the costs incurred in making the change (ie have a positive net market benefit). The network currently meets or exceeds the minimum security standards expected of the metropolitan network, therefore any improvement in security can only be justified in terms of market benefit. Each substation area forms its own project and therefore spending on a substation can only be justified by the market benefits that accrue to that substation and not to the network as a whole. That is, a strongly beneficial project for one substation cannot subsidise the costs associated with changes at an unrelated substation that would otherwise not pass the RIT-D test.

11.1.3 Proposed Solution

The preferred solution to the identified need is to, where appropriate, install SCADA controlled 11kV load switches at 11kV feeder tie points to allow the rapid transfer of load between substations following a radial sub-transmission line or single transformer substation fault.

The scope of works includes:

- The installation of 11kV load switches on feeder tie points; and
- Creation of pre-written contingency switching sheets and alarms in the ADMS (Advanced Distribution Management System) to facilitate the use of the load switches.

It is expected that this will reduce the typical time taken to restore supply from 4 to 8 hours to 15 minutes.

11.1.4 Non-network options

No non-network options have been identified as being viable as benefits per substation are low when compared to the relatively significant load that a non network option must support. It is only the relatively low cost of the 11kV load switches and the availability of low cost SCADA controlled switching that makes the proposed program of works viable. Cost per MW of consumer load backed up for substations that have passed the RIT-D range from approximately \$20 per MW to \$70 per MW (10% POE load).

11.1.5 Preliminary Reliability Investment Test – Distribution (RIT-D) Analysis

A preliminary RIT-D analysis has been completed for each substation in the Adelaide metropolitan network that is radial in nature; eg a single fault will interrupt supply to the whole substation. This analysis used the following parameters:

- Sub-transmission line (66kV) reliability of 0.02 faults per km per annum.
- Each substation transformer (66/11kV) has a failure rate of one failure per 50 years of operation and that this rate is uniform across the age of the fleet and across all weather conditions.
- Load recovery through manual switching of feeders can be completed in an average of 4 hours per substation. This is a conservative figure as at some times of the year, restoration can take up to 8 hours.
- SCADA enabled switching time (via ADMS) of 15 minutes.
- Standard values for VCR as determined by AEMO and standard discount rates (6.36% mid range, 4.36% min and 8.4% max).
- Changes in network losses are not material to the outcome of the test.

This analysis identified that 14 out of 28 radial substations in the Adelaide metropolitan network have a positive market benefit and are therefore eligible to be included in the planned program of works. Please refer to the table below for a full list of the preliminary results of the test¹⁰.

It is expected that the augmentation activities will be scheduled over a number of years with substations placed in groups where the augmentations are mutually supporting. For instance,

¹⁰ All values are expressed in thousands and 2018 nominal dollars

work to transfer load from Smithfield West Substation to Virginia also helps transfer load from Virginia Substation to Smithfield West.

Substation	Combined Market Benefit (NPV)	NPV Cost	NPV Market Benefit	Project Cost (nominal)
Seaford	\$1,166	\$133	\$1,299	\$140
Hope Valley	\$1,132	\$418	\$1,550	\$660
Athol Park	\$1,028	\$418	\$1,446	\$440
Smithfield West	\$985	\$1,084	\$2,069	\$1,140
McLaren Flat	\$949	\$480	\$1,429	\$505
Hackham	\$703	\$1,179	\$1,882	\$1,240
Two Wells	\$671	\$304	\$975	\$320
Harrow	\$666	\$376	\$1,041	\$395
Kilburn South	\$595	\$133	\$728	\$140
Virginia	\$502	\$561	\$1,062	\$590
Burnside	\$470	\$231	\$700	\$243
Clearview	\$270	\$628	\$897	\$440
Angle Vale	\$243	\$38	\$281	\$40
McLaren Vale	\$109	\$76	\$185	\$80
Clarendon	-\$23	\$162	\$139	\$0
Cheltenham	-\$46	\$181	\$134	\$0
Ascot Park	-\$50	\$228	\$178	\$0
Woodville	-\$67	\$181	\$114	\$0
North Unley	-\$67	\$228	\$161	\$0
Largs North	-\$81	\$228	\$147	\$0
Willunga	-\$139	\$181	\$42	\$0
Glanville	-\$146	\$228	\$83	\$0

Substation	Combined Market Benefit (NPV)	NPV Cost	NPV Market Benefit	Project Cost (nominal)
Flinders Park	-\$206	\$418	\$213	\$0
Noarlunga Centre	-\$298	\$466	\$168	\$0
Plympton	-\$323	\$466	\$143	\$0
Croydon Park	-\$394	\$551	\$158	\$0
Elizabeth Heights	-\$443	\$628	\$185	\$0
Northfield	-\$2,002	\$2,192	\$189	\$0

Table 10: Market Benefit Substation backup¹¹

¹¹ All values are expressed in thousands and 2018 nominal dollars

12. Zone Substation Voltage Control

12.1 Background

SA Power Networks is regulatorily obliged to maintain supply voltages at customers' service points in accordance with Australian Standard AS60038. The network penetration of solar PV has already significantly increased the number of excursions outside of the mandated limits and the forecast growth in PV will only exacerbate this problem. In the 2020-25 regulatory period there are multiple substations where SA Power Networks will be unable to sufficiently reduce the 11kV voltage to conform to these regulatory requirements.

At present, SA Power Networks can holistically manage customer voltages with transformer voltage control at zone substations. This utilises OLTC functionality to dynamically adjust the winding ratio of the substation transformer(s) to regulate the voltage in response to the observed load. The available range is determined by the transformer design. Many substation transformers now approaching the end of their economic life were never designed to respond to the high system voltages caused by solar PV. They have a maximum total voltage reduction of 2.5% with only two taps available to increase the winding ratio. In comparison, new SA Power Networks transformers have four times this range, with eight taps corresponding to a maximum total voltage reduction of 10%. Importantly, these ageing transformers also constrain the capability of newer specification transformers at substations where they operate in parallel configuration. Table 11 summarises the substations in the 2020-25 regulatory period where the existing 2.5% voltage reduction will no longer provide sufficient voltage control.

12.2 Proposal

There are 51 substation transformers at 31 zone substations with limited voltage response. These range in age from 47 to 58 years old in 2018. The current average economic life of a substation transformer before a replacement for a medium size substation transformer is 65 years. An analysis projecting the expected neutral PV growth forecast by AEMO, identified five substations, corresponding to eight transformers, in the 2020-25 regulatory period where SA Power Networks will lose the ability to control voltage in accordance with AS60038. These are summarised in Table 11. The recommendation is to advance the planned replacement of these transformers as the most economic solution for widely addressing the voltage control constraint. It was considered against two alternative remediation options.

Project Timing	Substation	No. TFs Replaced	Age (Years)	Advancement (Years)	Cost (\$M)
2020	Lower Mitcham	1	57	8	2.1
2021	Athol Park	2	60	5	3.7
2022	New Richmond	1	55	10	2.1
2023	Noarlunga Centre	2	60	5	3.7
2024	Northfield	2	64	1	3.7

Table 11: Voltage Control Transformer Replacement Advancement

12.3 Alternative Options

Both alternative options deliver a more focussed remediation rather than the overarching substation transformer advancement solution. Consequently, scaling these solutions to achieve a similar network voltage control capability resulted in significantly higher implementation costs in each respective case.

The first alternative option considered reinforcing the downstream LV networks of the identified substations. This would encompass increasing the funding of the Quality of Supply team to deploy solutions in accordance with their existing operational processes. Even without considering the site-specific works, extrapolation of an average remediation cost for the number of required cases exceeded the preferred solution.

The other alternative examined the installation of distribution level reactive power (ie VAR) control plant. At present, SA Power Networks does not have any equipment currently approved to achieve this functionality. The viability of this option is therefore theoretical. Factoring in research and development costs with the need for bespoke assessments and solutions for each feeder of the identified substations, as well as an expected functional life considerably less than the proposed solution resulted in a smaller NPV for this approach.

13. Connection Point Projects

This 2020 to 2025 capital plan contains costs and scopes for SA Power Networks' component of connection point upgrades driven by ElectraNet's asset management. These projects typically include components such as 33kV or 66kV bus works, new circuit breakers and 66kV or 33kV line exits. The timing of these projects is in line with the asset replacement works by ElectraNet approved by the AER as part ElectraNet's most recent price reset determination in 2018.

Project Timing	Project Name	Proposed Solution	2015-20 Cost (\$ million)	2020-25 Cost (\$ million)	Total Cost (\$ million)
2020	Leigh Creek Connection Point Upgrade	Upgrade Leigh Creek connection point including new 33kV circuit breakers, 33kV protection and segregation of site	-	0.99	0.99
2021	Mount Gambier Connection Point Upgrade	Upgrade of Mount Gambier connection point including new 33kV circuit breakers, 33kV protection	-	4.27	4.27
2022	Mannum Connection Point Upgrade	Upgrade Mannum connection point including new 33kV circuit breakers, 33kV bus and line protection and associated SCADA/telecommunications	-	3.92	3.92
2022	Yadnarie Connection Point Upgrade	Upgrade Yadnarie connection point including new 66kV circuit breakers, 66kV line protection and segregation of site	-	4.24	4.24

Table 12: Connection Point Upgrades

14. Minor Substation Projects

This 2020-2025 capital plan contains minor substation upgrades at sites where the 10% PoE forecast is expected to exceed the capacity of the substation. While overall demand growth in South Australia is relatively flat, there are some small substations where demand is expected to exceed capacity. Several of these substation overloads have not been previously identified due to a lack of monitoring.

Project Timing	Project Name	Proposed Solution	2015-20 Cost (\$ million)	2020-25 Cost (\$ million)	Total Cost (\$ million)
2020	Cape Jervis 33/11kV Upgrade	Upgrade Cape Jervis 33/11kV substation with 12MVA 33/11kV transformer, 33kV recloser and associated infrastructure	-	1.97	1.97
2020	Tintinara 33/11kV Upgrade	Upgrade Tintinara 33/11kV substation with 3MVA pad-mount 33/11kV transformer, 33kV and 11kV reclosers and associated infrastructure	-	2.10	2.10
2021	Gumeracha 33/11kV Upgrade	Upgrade Gumeracha 33/11kV pole-top substation with 500kVA pole-top 33/11kV transformer, 11kV recloser and 33kV fuses	-	0.71	0.71
2022	Curramulka 33/7.6kV Upgrade	Upgrade Curramulka 33/7.6kV pole-top substation with 500kVA pole-top 33/11kV transformer and replace 7.6/0.4kV distribution transformers	-	0.89	0.89
2022	Mount Burr	Upgrade Mount Burr 33/11kV pole-top substation with pole-top substation with 500kVA pole-top 33/11kV transformer	-	0.61	0.61
2023	Portee 66/11kV Upgrade	Upgrade Portee 66/11kV substation with 2.5MVA 66/11kV transformer, 66kV circuit breaker and associated protection/infrastructure	-	1.81	1.81
2023	Deloraine 33/11kV Upgrade	Upgrade Deloraine 33/11kV pole-top substation with 500kVA pole-top 33/11kV transformer, 11kV recloser and 33kV fuses	-	0.93	0.93

Table 13: Minor Substation Upgrades

15. Minor Sub-transmission Projects

Minor upgrades of sub-transmission lines are outlined below.

Project Timing	Project Name	Proposed Solution	2015-20 Cost (\$ million)	2020-25 Cost (\$ million)	Total Cost (\$ million)
2020	Naracoorte to Naracoorte East 33kV Up-rate	Up-rate 10 km of 33kV line between Naracoorte and Naracoorte East.	-	0.34	0.34
2020	Penola Tee to Penola 33kV Uprate	Up-rate 3 km of 33kV line between Penola Tee and Penola.	-	0.11	0.11
2020	Mount Schank to Allendale East 33kV Up-rate	Up-rate 13 km of 33kV line between Mount Schank to Allendale East.	-	0.45	0.45

Table 14: Minor Sub-Transmission Upgrades

16. Minor Distribution Feeders Projects

The following distribution feeder upgrades and new feeder ties are proposed in the 2020-2025 period. The majority of these projects are due to forecast overloads previously not identified due to a lack of available conductor data.

Project Timing	Project Name	Proposed Solution	2015-20 Cost (\$ million)	2020-25 Cost (\$ million)	Total Cost (\$ million)
2020	Nuriootpa East 11kV feeder tie	Construct 300m 11kV feeder tie between Nuriootpa East (NU21) and adjacent 11kV feeder including 11kV switch	-	0.49	0.49
2020	Cheltenham and Woodville 33kV conversion	Convert 33kV lines to 11kV at Woodville and Cheltenham substations, replace open-bushing 33/0.4kV with 11/0.4kV and retire 66/33kV substation transformers	-	4.16	4.16
2020	Airport 11kV feeder tie	Construct 600m 11kV feeder tie between Airport (ME347H) and adjacent 11kV feeder including 11kV switch	-	0.82	0.82
2021	Burnside 11kV feeder restring	Restring 600m of 11kV overhead feeder backbone of Burnside (HH148D) feeder	-	0.19	0.19
2021	Mutton Cove 11kV feeder tie	Construct 100m 11kV feeder tie between Mutton Cove (AP510L) and adjacent feeder to provide backup	-	0.29	0.29
2022	Keith 11kV feeder tie	Construct 100m 11kV feeder tie between Keith (BT6) and Keith South (BT26) to provide backup	-	0.18	0.18
2023	Renmark 11kV feeder restring	Restring 600m of 11kV overhead feeder backbone of Renmark (BM51) feeder	-	0.17	0.17
2023	Maslin Beach 11kV feeder tie	Construct new 500m 11kV underground feeder tie between Maslin Beach (MV64) and Willunga West (MV63) to provide backup	-	0.82	0.82

Project Timing	Project Name	Proposed Solution	2015-20 Cost (\$ million)	2020-25 Cost (\$ million)	Total Cost (\$ million)
2024	Winkie 11kV feeder tie	Construct 800m 11kV overhead feeder tie between Winkie (BM34) and adjacent 11kV feeder including 11kV switch	-	0.33	0.33
2024	Ferryden Park 11kV feeder restrung	Restrung 800m of 11kV overhead feeder backbone of Ferryden Park (AP146B) 11kV feeder	-	0.27	0.27
2024	Chandlers Hill 11kV upgrade	Upgrade multiple sections of underground 11kV cable in feeder backbone of Chandlers Hill (NL210D) feeder	-	0.48	0.48
2025	Lowbank 11kV feeder tie	Construct 1.8km 11kV feeder tie between Lowbank (WK43) and adjacent 11kV feeder including 11kV switch	-	0.34	0.34
2025	Cowandilla 11kV feeder restrung	Restrung 1200m of 11kV overhead feeder backbone of Cowandilla (ME347C) 11kV feeder	-	0.39	0.39

Table 15: Distribution Feeder Upgrades

17. Land Acquisition

While overall system demand is not forecast to increase over the 2020-2025 period, a number of locations in the state are still experiencing demand growth due to greenfield developments. Where greenfield development is occurring at the fringes of the metropolitan network, new substation sites may be required as existing substations are unable to cater to the new load. As shown in Table 16, Mount Barker East site has been identified.

Project Timing	Project Name	Proposed Solution	2015-20 Cost (\$ million)	2020-25 Cost (\$ million)	Total Cost (\$ million)
2024	Mount Barker East new Substation site	Purchase land in Mount Barker East region for a new 66/11kV substation to cater for future demand growth east of Mount Barker Substation.	-	3.10	3.10

Table 16: Land Acquisitions

18. Low Voltage & Quality of Supply Remediation

18.1 Abstract

This submission recommends the continuation of funding for the Business as Usual functions for maintaining Quality of Supply, at a total cost of \$48 million over the 2020-25 regulatory period.

The main functions of Quality of Supply (QS) are to investigate QS enquiries received from customers, implement corrective action including network augmentation where required, and to manage the low voltage network in compliance with regulatory obligations.

The proposed funding increase of \$400 thousand per annum above the current annual capital expenditure of \$8.0 million will commence from 2019 and continue throughout the 2020-25 period. The increase is required to fund the additional network augmentation demanded by the increase in customer enquiries related to Distributed Energy Resources (DER) in the low voltage (LV) network; in particular, residential solar photovoltaic (PV) and energy storage. Greater funding would be required should it not be for the non-network solutions being actioned; in particular, mandated PV inverter settings which reduce the impact on the LV network.

The proposed expenditure is \$8.8 million for 2020, increasing by \$400 thousand per year for the remaining four years of the 2020-2025 reset period, for a total of \$48 million.

18.2 Introduction

SA Power Networks has a regulated obligation to maintain supply voltage at customers' service points between 216V and 253V, the range specified in Australian Standard AS60038.

Quality of Supply is responsible for:

- Responding to customer enquiries regarding quality of supply;
- Performing investigation and remedial works to resolve customer enquiries or alleviate LV network constraints eg upgrading overloaded transformers;
- Analysing and determining the feasibility of inverter-based embedded generation connections less than 200kW; and
- LV, distribution transformer and Single Wire Earth Return (SWER) network planning. Note, SWER capital expenditure (CAPEX) is captured under a separate line; see SWER Management.

With increasing levels of DER significantly impacting the voltages on the LV network, voltage excursions outside of mandated limits are becoming more prevalent, significantly increasing the number of QS enquiries. 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.

18.3 Quality of Supply Business as Usual and LV Management Plan

Current CAPEX expenditure to maintain quality of supply and manage the *LV network* as *BAU* is \$8.0 million (in 2018). This is demonstrated by the CAPEX over the past four years, as provided in Table 17. Forecast *BAU* CAPEX for the two years preceding the 2020-25 reset period is also provided (shaded in grey).

Calendar Year	Business as Usual Capital Expenditure 2014-2019 (\$M)
2014	7.6
2015	8.5
2016	7.9
2017	8.3
2018	8.0
2019	8.4

Table 17: Historical (2014-17) and forecast (2018-19) QS BAU capital expenditure

The total QS BAU expenditure required for 2020-25 is shown in Table 18. Commencing in 2019 and continuing during the 2020-25 regulatory period, an increase of approximately 4% on the current CAPEX, or \$400k per annum, is required.

Calendar Year	Business as Usual Capital Expenditure 2014-2019 (\$M)
2020	8.8
2021	9.2
2022	9.6
2023	10.0
2024	10.4
Total	48.0

Table 18: QS BAU 2020-2025 CAPEX Totals

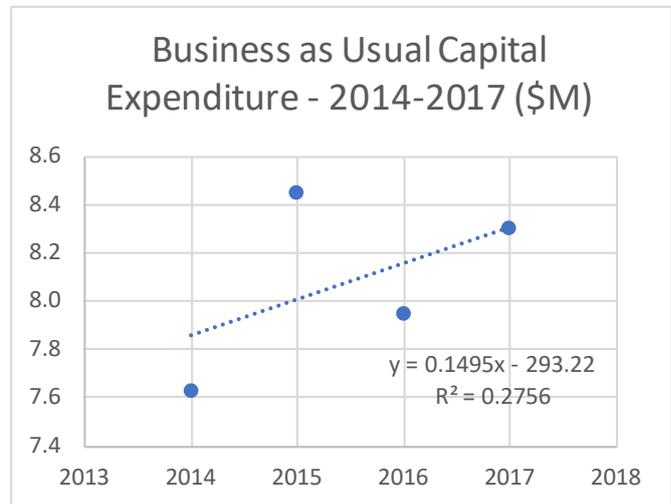


Figure 19: Historical BAU Capital Expenditure

Figure 19 shows an increased trend line in business as usual capital expenditure from 2014 due to the increased customer QS enquiries that have been directly attributed to the impact of distributed energy resources on the low voltage network. This trend (up to 4%) based on historic expenditure is expected to continue in the next reset period and has been factored in our forecast as shown in

Table 19. This general increase is further supported and explained in the Emerging Trends section.

In 2017, the QS BAU CAPEX was predominantly used for:

1. Upgrading the LV distribution network with new transformers, conductor, regulators and other equipment to address QS enquiries raised by customers (remediation work) and to increase LV capacity where required;
2. Quality of Supply team management; and
3. Low voltage loggers.

For the 2020-25 period, the QS BAU CAPEX is expected to be allocated similarly to the expenditure in 2017. However, as the volume of QS customer enquiries is going to continue to increase (refer to Emerging Trends), so too will the volume of remediation required.

Using unit costing (as actuals differ between projects), the 2017 CAPEX was allocated as provided in Table 19. Note that unit costings were derived from the 2017 actual project costs; effectively an average by category.

Submission Components	Unit Cost (\$ 2017)	Number of each solution installed in 2017	Total Cost (\$k 2017)
QS Team Management	1,500,000	1	1,500
LV Regulator	15,457	15	232
Replace TF (same pole, increased capacity, with taps)	29,382	98	2,879
Restraining Conductor	49,664	9	447
Infill TF (no HV extension)	51,887	57	2,958
Infill TF (with HV extension)	77,747	3	233
LV Data Loggers (model CHK PQ35)	10,750	40	430
Total	-	-	8,679

Table 19: QS BAU 2017 CAPEX breakdown

Using the same 2017 unit-costs, the breakdown of the forecast QS BAU CAPEX for the 2020-25 reset period is presented in Table 20.

Submission Components	Unit Cost (\$ 2017)	Cost 2020 (\$k)	Cost 2021 (\$k)	Cost 2022 (\$k)	Cost 2023 (\$k)	Cost 2024 (\$k)
QS Team Management	1,500,000	1,500	1,500	1,500	1,500	1,500

Submission Components	Unit Cost (\$ 2017)	Cost 2020 (\$k)	Cost 2021 (\$k)	Cost 2022 (\$k)	Cost 2023 (\$k)	Cost 2024 (\$k)
LV Regulator	15,457	243	257	261	274	288
Replace TF (same pole, increased capacity, with taps)	29,382	3,023	3,193	3,236	3,407	3,577
Restrung Conductor	49,664	469	496	502	529	555
Infill TF (no HV extension)	51,887	3,105	3,280	3,324	3,499	3,674
Infill TF (with HV extension)	77,747	245	259	262	276	290
LV Data Loggers (model CHK PQ35)	10,750	215	215	215	215	215
Total	-	8,800	9,200	9,600	10,000	10,400

Table 20: QS BAU forecast expenditure (figures in \$ 2017)

18.4 Emerging Trends

A significant increase in the number of customer QS enquiries was observed in 2017 and 2018, which can be directly attributed to high voltage caused by residential PV generation. (Refer to Figure 20 through to Figure 22). That increase is expected to continue and has driven the need for more QS investigations and testing. With an increase in QS testing there is a proportional increase in network augmentation to correct the QS issues, requiring additional CAPEX above historic BAU expenditure.

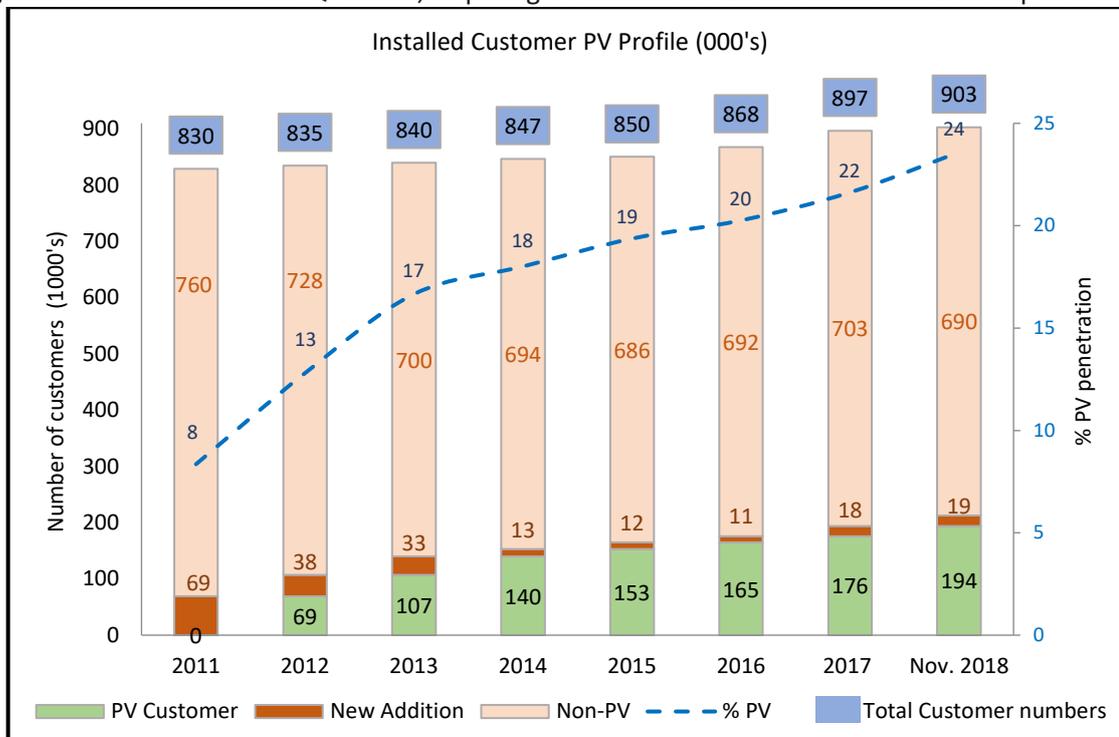


Figure 20: Uptake of residential solar PV generation since 2011

Note: The level of PV penetration indicated for 2018 includes *only the first eleven months of the year*.

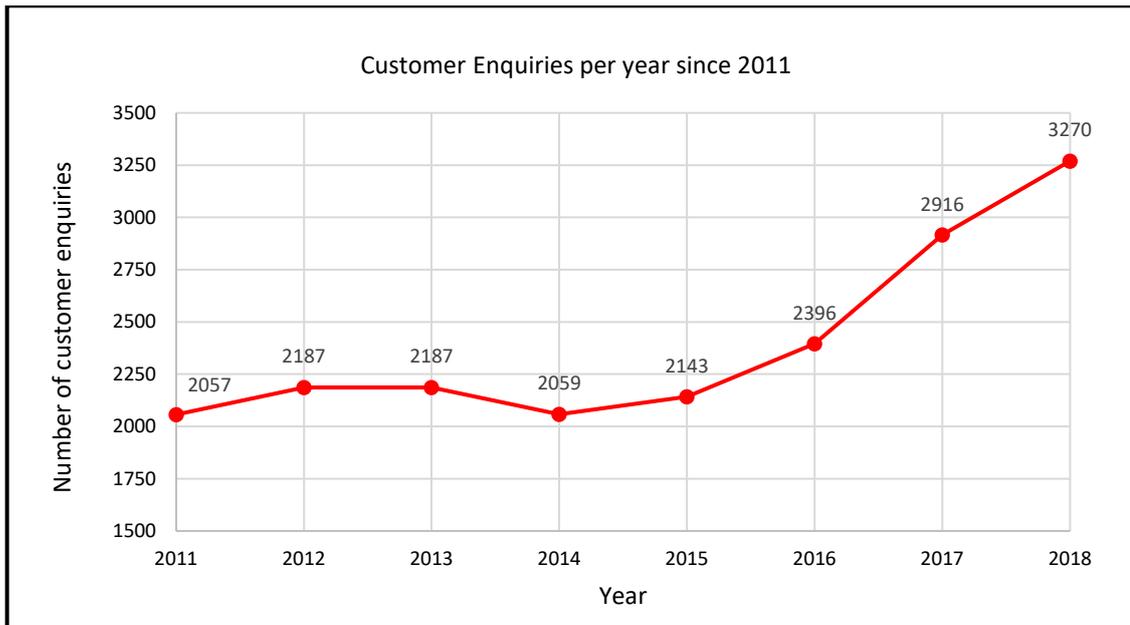


Figure 21: Residential customer QS enquiries per year since 2011

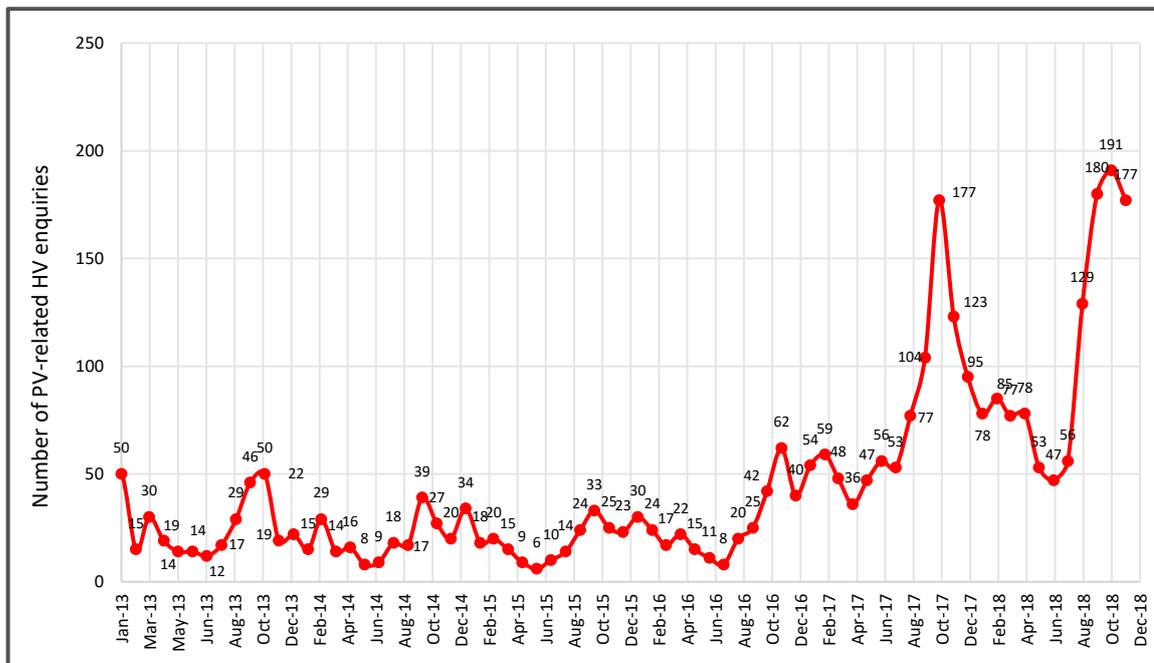


Figure 22: Number of PV-related high voltage QS enquiries received per month since January 2013

- Notes:
- 1) PV related enquires experienced a step increase in the second half of 2017 (triple the monthly average and twice the number received for the same time in 2016).
 - 2) Enquiries received in the Spring of 2017 peaked at approximately two and a half times those of the previous year and continued to rise in 2018 to a record peak in October 2018.
 - 3) The number of PV-related HV customer enquiries peaks during Spring (September to November), when the days are relatively cloudless, ambient daytime temperatures are cool to warm, and solar irradiance¹² is high.

¹² Irradiance is a measurement of solar power and is defined as the rate at which solar energy falls onto a surface. The unit of power is the Watt (abbreviated W). In the case of solar irradiance, we usually measure the power per unit area, so irradiance is typically quoted as W/m² - that is, Watts per square meter.

18.5 Emerging challenges and opportunities

There are many network impacts not observed to-date, but which are expected to emerge in the near future and have the potential to require significant additional CAPEX to address unless new strategies are employed. They include the following:

- A high uptake of other forms of DER, other than PV, leading to a further increase in QS enquiries. These include technologies such as electric vehicles, battery storage, fuel cells and virtual power plants (VPP). VPPs, in particular, have the potential to cause a significant increase in QS issues if large volumes of DER are coordinated by a VPP operator in response to macro conditions, such as a high pool price for the state, without consideration for technical constraints at the micro level; for example, voltage issues on the LV circuit or overloading the LV transformer; and
- Saturation of DER consuming all the available hosting capacity on a wide scale. The existing electricity distribution network has a finite hosting capacity for DER. The exact capacity varies across the state between LV circuits, and is generally determined by the size and length of conductors and distribution transformers supplying the area. SA Power Networks approves all small-scale PV systems (< 30kW) provided that they meet the requirements published in SA Power Networks' Technical Standard TS129. This assumes that there is available hosting capacity, and when there's not, it generally leads to a QS enquiry as the customer's PV system is unable to function correctly. At current forecast PV uptake rates, QS enquiries are expected to continue to increase as hosting capacity limits are reached across more areas of the network.

Strategies for managing these emerging issues in the longer terms are considered in detail in the *LV management business case*.

18.6 QS BAU CAPEX Detail

Of all the QS customer enquiries received by SA Power Networks, approximately one third require follow-up investigation. A field test is conducted by the Quality of Supply Investigation team (QSI) for each of those enquiries, followed by analysis of the field test results by the QS team. A large portion of the enquiries (over two thirds) required remediation. QS remediation can take the form of either minor or major remediation, as discussed below, with minor remediation always being considered first as a low-cost alternative to a customer QS enquiry.

QS expenditure is also driven by the summer 'heatfix' process. Every summer, the QS team closely monitor the LV fuse operations across the state. As a fuse operation can be due to either a fault or an overload, an assessment is made to determine which of the two was most likely the cause. Suspected overloads are further investigated and can lead to minor remediation to balance the LV network or, more commonly, major remediation to upgrade the LV network capacity in that area. A proactive process is also used to predict LV overloads for the Adelaide metropolitan area, using historical records of the number of LV fuse operations during past heatwaves, combined with the corresponding maximum and minimum daily temperatures during those heatwaves. This too can lead to both minor, but more typically major, remediation.

18.6.1 Minor Remediation

Minor remediation includes, but is not limited to, such works as listed in Table 21:

Type of minor remediation	Reason
Changing distribution transformer taps	To change (generally to lower) the voltage level on a LV feeder as a means of addressing PV related high voltages.

Type of minor remediation	Reason
Balancing load across the three phases of a LV feeder	To re-distribute loads / PV generation more evenly across the three phases to avoid cumulative voltage rise on only one or two of the phases.
LV switching	Changing open points to transfer load / PV generation from one distribution transformer to another.
Road crossing upgrades	To reduce impedance in customer connections to improve voltage levels at the customer's connection point

Table 21: Examples of minor remediations and general reasons for using them

The numbers of minor remediations completed per annum that were issued by Quality of Supply team since 2013 are presented in Table 22. They are based on the average number of minor works completed between 2013 and 2017 and do not include remediations that are fixed on initial site visit by field personnel. The average number of escalated minor remediations completed per annum for that period was 420.

Forecast	2013	2014	2015	2016	2017	Average
Minor remediation numbers per calendar year	440	324	35	433	546	420

Table 22: Historic numbers of minor remediations per calendar year

18.6.2 Major Remediation

When minor remediation is not possible, the network must be upgraded to address a customer enquiry or to upgrade the capacity of the LV network. The historical QS BAU CAPEX budget has broadly been allocated as shown in Table 23.

Major remediation includes, but is not restricted to, the types of projects listed below:

- LV regulator installation
- LV transformer replacement on the same pole with one of greater capacity and with taps
- Conductor restring
- Infill transformer installation (requiring no HV extension); and
Infill transformer installation (requiring an HV extension).

Historic QS project numbers and expenditure	2013	2014	2015	2016	2017	Average
Transformer infills	77	67	50	48	73	63
Transformer upgrades	146	107	97	130	107	118
Total number of transformers installed	223	174	147	178	180	181
Total QS project costs (\$M2017)	9.51	7.64	8.46	7.7	8.3	8.69

Table 23: Examples of types of major transformer remediation implemented, including historic actual costs.

18.6.3 Major Remediation - Low Voltage Regulation

Low voltage regulation is often a cost-effective means of major remediation to resolve high or low voltage in areas of very low-density dwellings. In such cases, the single-phase transformer may supply 1 to 10 customers. If the regulator can be located relatively close to the impacted customer, it will correct the voltage without negatively impacting other nearby customers and less cost than the other major remediation options. In 2014, SA Power Networks installed the first three-phase LV regulator, although there tend to be far fewer cases for which this is a cost-effective solution.

18.6.4 Customer-side solutions

When investigating customer enquiries, every effort is made to first determine whether the issue lies with the customer's equipment or is on the customer's side of the service point. If this can be established, the customer is advised to contact their electrician requesting they correct the issue on the customer's behalf. This avoids the OPEX in investigation and CAPEX in network augmentation.

A significant portion of customer enquiries relate to customer PV inverters disconnecting from the distribution network due to high voltage levels. Commencing in 2017, many such enquiries are found to be caused by incorrect PV inverter settings. In such instances, customers are advised to contact their electrician to ensure that their inverter settings are set in accordance with:

- Section 5.1 of SA Power Networks' Technical Standard TS 129: Small Inverter Energy Systems (IES) – Capacity not exceeding 30kW, published November 2017;
- Australian Standard AS4777.1: Grid connection of energy systems via inverters, Part 1: Installation requirements; and
- Australian Standard AS4777.2: Grid connection of energy systems via inverters, Part 2: Inverter requirements.

The same standards are also required to be implemented for all new PV connections. New single-phase connections are limited to 10kW of PV with a 5kW maximum export. Furthermore, inverters must implement Volt-Var and (where available) Volt-Watt Response modes, which manages the inverter's output and power factor when the voltage approaches the regulated limits. These measures mean that new connections will consume less of the

remaining available hosting capacity and therefore delay the need for network augmentation in the area.

Another example of a customer-side issue is high impedance consumer mains between the service point and the solar PV inverter. If the QS investigation reveals that this is the cause, the customer is advised to contact their electrician to review and upgrade their consumer mains.

18.7 Recommendation

This submission recommends the continuation of funding for the business as usual functions of Quality of Supply, at a total cost of \$48 million over the 2020-25 regulatory period.

The proposed expenditure is \$8.8 million for 2020, increasing by \$400 thousand per year for the remaining four years of the 2020-2025 reset period, for a total of \$48 million. The increase is required to fund the additional network augmentation demanded by the proliferating increase in customer enquiries related to Distributed Energy Resources in the low voltage network to ensure voltage at customer service point stays within safe and statutory voltage limits.

Our longer-term strategy for managing high levels of DER includes the use of more active and dynamic management of export limits. This requires the development of new capabilities which are the subject of a separate document, the *LV management business case*.

19. Low Voltage Monitoring Strategy

19.1 Abstract

This business case proposes the installation and commissioning of 2,250 remotely-readable low voltage power quality monitors in the greater Adelaide metropolitan area during the five years of the 2020-25 Reset Period, at a total cost of \$20 million. This is an extension of the existing LV monitoring program that began in 2017 and will see 600 monitors installed by the end of 2020.

The continuing uptake of residential distributed energy resources, particularly residential solar photovoltaic (PV) generation, is resulting in increasing voltage issues on the low voltage (LV) distribution network during periods of high residential solar generation and low customer loads. Conversely, during periods of high residential customer loads and no contribution from residential PV, customers are increasingly experiencing outages due to LV fuse operations, for which public tolerance is declining.

Customers' increasing expectations are that their solar inverters can export at full power throughout the day and that no loss of supply occurs during times of high residential load. This, in turn, is resulting in an increasing number of customer enquiries being received by SA Power Networks' Quality of Supply branch, with each enquiry requiring investigation and many remediation.

With limited visibility on the low voltage network, it is proposed that 2,250 additional power quality monitors be installed on a representative range of metropolitan residential low voltage transformers to better-manage residential solar PV issues and daily business operations via modelling and analysis of the low voltage network. Installation of the 2,250 additional power quality monitors by the end of the 2020-25 regulatory period will result in visibility of 26.4% of the residential major metropolitan network (or 4% visibility of total transformers in the network). Installation of the additional LV monitors will be a continuation of the power quality monitoring program which commenced in 2017, and is designed to provide a statistically sound basis for modelling the LV network and analysing customer enquiries without the need to physically conduct tests at the customer's connection point. This new visibility will improve low voltage network knowledge and decision making capability and will also provide opportunities to explore non-network solutions which can't be implemented effectively in the current reactive process.

Permanent End of Line monitoring is not planned in this strategy. Rather, the option to utilise customer metering data to support the distributed energy transition is considered in the *LV Management Strategy*.

The funding required to implement this proposal is \$4 million per year for each of the five years of the 2020-25 Reset Period. Cost-benefit analysis has shown that the benefits of proactive monitoring and utilising the proactive network modelling (which uses extrapolation from measured data for the unmetered transformers) will exceed the increasing cost of the "do-nothing" option incurred by having to investigate increasing customer complaints. Proactive network modelling will also provide a significant improvement in customer satisfaction due to a large reduction in PV-related customer outages and response times by SA Power Networks.

19.2 Introduction

SA Power Networks has a regulated requirement to maintain supply voltage at customers' service points between 216V and 253V, the range specified in Australian Standard AS60038. In the past, this has generally been achieved with minimal active monitoring of voltages in the LV distribution network. However, with increasing levels of distributed energy resources (DER) significantly impacting the voltages on the LV network, voltage excursions outside of the mandated limits are becoming more prevalent, significantly increasing the number of Quality of Supply (QS) enquiries. This step-change in customer enquiries has meant that the traditional reactive approach of investigating via testing after receiving an enquiry is consuming more resources and consequently taking longer to deliver conclusive results and appropriate remediation for the customer.

Thermal overload of LV plant; specifically, LV distribution transformers; is also an issue. While metropolitan residential load growth is low, localised growth in peak demand due to housing infill and customer behaviour is still occurring. Furthermore, large quantities of DER can also cause thermal overload of distribution transformers during times of high residential PV export. The traditional reactive approach of investigating LV fuse operations is both resource-intensive and disruptive to customers who may experience multiple outages under peak load conditions while a solution is sought. Unbalance between the phases on a three phase LV network further exacerbates the issues of both voltage management and thermal overload, in that limits are reached more quickly. All reactive QS investigation techniques to-date have involved field testing since there is no visibility of the LV network. More specifically, temporary local monitoring of the LV network is installed at the service point and the distribution transformer. For calculating peak loads, adjustment is made by comparing LV measurements against measurements taken at the zone substation during peak load events. Until the mass take-up of residential PV, this reactive approach has served SA Power Networks well, but now is not adequate.

This changing environment in which SA Power Networks must continue to fulfil its obligations as South Australia's sole Distribution Network Service Provider (DNSP) is providing new challenges, and the need for new tools and methods to enable SA Power Networks to better-understand the impacts of the changing environment and role of the residential LV network. These changes are recognised by the Australian Energy Regulator (AER), as demonstrated in the following extract from its 'AER Readiness' publication:

*"The NEM is currently in a transitional phase. There has been an emergence of new technologies and some traditional generation plant has been retired. At the same time, the Electricity Rules are being adapted with urgency to ensure that they keep pace with new and changing requirements around the security and reliability of the power system. It is important for the industry as a whole to be cognisant of this transition and to act to ensure that any associated risks are managed. We consider it is crucial for all participants and institutions to assist where they can to achieve a successful transition."*¹³

¹³ Extract from the AER publication 'Quarterly Compliance Report: National Electricity and Gas Laws 1-July-30 September 2017': 'Electricity, NEM Summer Readiness'

19.3 Emerging Trends on the LV Network

Since 2010 there has been a fundamental and increasing change in the role of the LV network. As of March 2018, 198,000 residential and commercial customers have installed rooftop solar PV generation systems (170,000 in the Adelaide metropolitan area), and are continuing to do so at a rate of more than 12,000 installations per year. This is equivalent to approximately 135MW of additional DER from January to December 2017 (refer Figure 23 on following page). By November 2018, approximately 180MW of additional DER has been installed in 2018. The level of residential solar PV generation in South Australia, and its continuing uptake, is recognised in a November 2018 South Australian Electricity Report from AEMO¹⁴ which states, in part, that “consumers continue to increase their adoption of behind-the-meter rooftop PV and storage, with capacity reaching 930MW of rooftop PV and 15MW of battery systems after 2017-18, and rooftop PV contributing 1,162 gigawatt hours (GWh) in the 2017-18 year. More than 24% of South Australian dwellings now have rooftop PV systems installed, the second highest level of penetration in Australia. Over the next 10 years, South Australia is projected to have the highest ratio of rooftop PV generation to operational consumption of all NEM regions”.

As a consequence of this continuing uptake, at periods of low load (generally weekdays, when residents are at their places of employment, or otherwise away from their homes) and there are cloudless, low ambient temperature days, solar PV export is often at a maximum, causing the LV network to effectively reverse its role and become a net exporter of power from PV installations back into the wider electricity supply network.

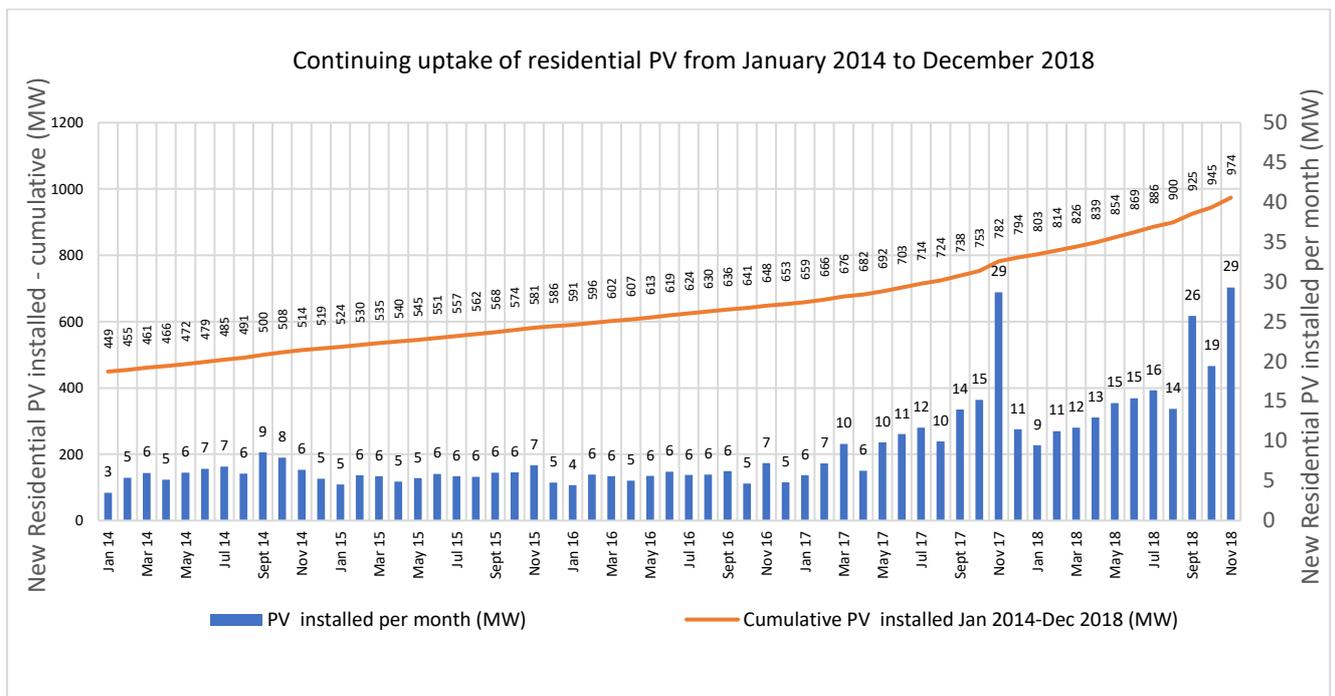


Figure 23: Continuing uptake of residential PV generation from January 2014 to November 2018

Note: Installed residential PV generation prior to and including December 2013 totalled 446MW¹⁵

¹⁴ Refer AEMO publication ‘South Australian Electricity Report’ (published November 2018)

¹⁵ Refer AEMO publication ‘South Australian Renewable Energy Report’ (published December 2016)

In some extreme cases, installed PV already exceeds the nameplate of the transformer, for some of our small transformers. The continues installation of rooftop solar PV systems is expected to continue at roughly 18,000 per annum.

Due to the continuing uptake of customer PV generation, there is now unprecedented two-way power flow in the residential metropolitan LV network, where power flow fluctuates in both direction and magnitude throughout the entire LV network as well as throughout the course of a 24-hour day. The LV network was not originally designed to operate in a bi-directional mode, but rather, was designed only to provide supply *to* customers. Because of this, LV feeders were tapered by designing them with a larger capacity conductor nearest the supplying LV transformer, a reduced capacity conductor as the distance from the LV transformer increased, and a still-smaller conductor for road-crossings and customer services. The inherent impedance of that design means that as residential PV generation nearer the ends of LV feeders increases, those customers' inverters had to contend with a higher impedance conductor, causing PV inverters to raise voltage levels to enable successful export into the network, with adverse consequences for neighbouring PV generation inverters. As a consequence, the historically-designed LV network is now limiting, or restricting, some customer PV connections, and the DER hosting capacity is diminishing.

This change in role for the LV network is presenting a new set of challenges for SA Power Networks, South Australia's DNSP, which must now also maintain a sound LV network during times of high residential PV generation and low residential loads, when residential customers become net exporters of electrical power into the LV network. That is, SA Power Networks has an obligation to maintain a secure and reliable electrical supply to its customers regardless of whether customers are being supplied from the LV network, or under this relatively new operating regime during times of high PV generation and low residential load levels, when customers become net exporters of electrical power to the LV network and into the high voltage network.

The complexity and consequences of this evolving situation for SAPN and customers alike are significantly increased by the lack of real-time monitoring of the LV network. Consequently, SAPN operates in a reactive mode, waiting for customers to call in to report quality of supply issues such as high voltage from solar PV generation. An investigation is then undertaken before remedial action can be issued. Furthermore, without a way of monitoring power quality at the customer's premises, there are no means of measuring the effectiveness of any remedial action taken to confirm that it has been successful. Figure 24 indicates that PV-related customer enquiries experienced a step change in 2017 in addition to the normal seasonal variations and increased further in 2018.

A key element that is missing today is visibility of actual power quality across the LV network which, if available, would enable the identification of solutions to quality of supply issues, as well as facilitate consideration of the impact of implementing those solutions on power flows in the wider network as a result. Increased visibility would also provide the opportunity for future, or impending, limitations to be identified, and proactive corrective action taken to avoid the consequences of those limitations, rather than reactively responding to issues as is presently the case. This ability would significantly decrease the number of PV-related customer outages, and therefore increase the level and standard of service provided to customers.

19.4 Actions Taken to Mitigate Impact of DER

After an extensive consultation period on 2017 mandatory connection conditions were introduced from 1 December 2017 to mitigate impact of additional DER and maximise ability of network to absorb DER without augmentation.

These connection conditions include:

- Maximum out of balance export to network of 5kW;
- PV limit voltage raised to 258V at PV; and
- Power quality Volt-var and Volt-watt response mode characteristics applied to limit voltage rise due to PV when voltage exceeds threshold.

Even with all these changes the rate of customer enquiries continues to rise.

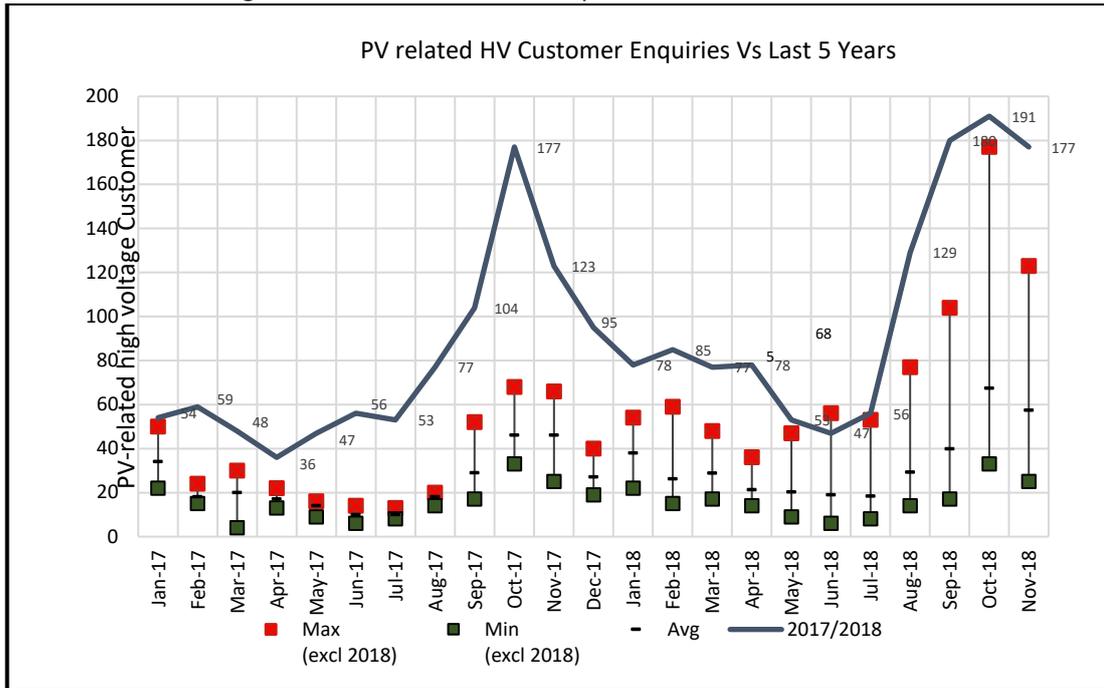


Figure 24: PV-related high voltage enquiries received to date for the 2017 calendar year and until November 2018, compared with the maximum, minimum and average enquiries for the past five years

- Notes:
- 1) PV related enquires have experienced a step increase in the past six months (triple the monthly average and twice the number received for the same time in 2016.)
 - 2) Enquires for 2017 are 142% higher than for the previous year, and the number of enquiries received in the Spring of 2017 are approximately three times those of the previous year. YTD enquiries in 2018 continue to increase to a high maximum record in October 2018.
 - 3) It can be noted from the graph that the number of PV-related high voltage customer enquiries peak during the Spring season (September to November), when the days are relatively cloudless, ambient daytime temperatures are cool to warm, and solar irradiance¹⁶ is high.

¹⁶ Irradiance is a measurement of solar power and is defined as the rate at which solar energy falls onto a surface. The unit of power is the Watt (abbreviated W). In the case of solar irradiance, we usually measure the power per unit area, so irradiance is typically quoted as W/m² - that is Watts per square meter.

19.5 Other Emerging Trends on the LV Network

Another emerging trend on the LV network is the elevated customer expectation of continuity of supply, particularly during heatwave events at times of peak demand. This is evident in the metropolitan residential LV network with adverse customer reactions to the number of LV fuse operations during heatwave conditions. Residential electricity demand is known to be highly dependent on the duration and severity of a heatwave, which then reflects the number of LV fuse operations that are experienced. In one example in January of 2018, a single LV fuse operation due to overload in a popular Adelaide restaurant precinct gained the attention of the local media, council and State Regulator. While every endeavour is made to plan, manage and upgrade the electrical distribution network, with the data currently available this is very challenging at the micro level which directly impacts the LV network.

As the number of high temperature days, accompanied by high temperature nights, increases, so too does the demand on the residential electricity network. The longer residential customers endure high temperature days followed by only minimal relief from those high temperatures during the night, the more likely they are to resort to using air-conditioners. This leads to increasing demand on the residential LV network as heatwave conditions persist, and with the growing demand at a micro level, the increasing likelihood of LV fuse operations as a result. In this instance too, the ability to measure the voltage and current at the LV transformer LV terminals during heatwave conditions would provide a means of identifying specific parts of the LV network which are most likely to have a high incidence of LV fuse operations during such conditions, and consequently the opportunity to take appropriate remedial action such as load balancing or transformer upgrades.

Figure 25 below indicates that most LV fuse operations due to overload occur in clusters of five or more in a day, and often more than twenty fuse operations when heatwave conditions are at their peak and customer tolerance for outages is at its lowest.

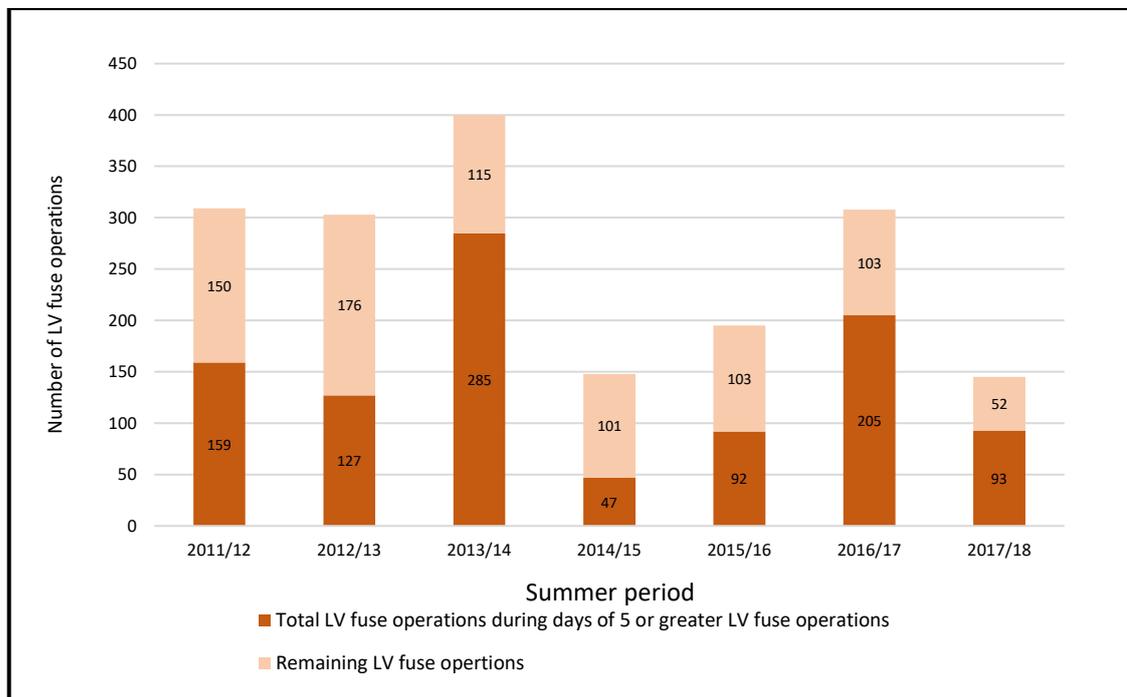


Figure 25: Total LV fuse operations per summer, including the portion of those fuse operations that were on days of five or greater LV fuse operations

19.6 Benefits

Installation of LV power quality monitors, as recommended in this Business Case, will provide a variety of benefits for SA Power Networks and its customers by providing greater visibility of the LV network. By proactively monitoring these transformers, it will also provide opportunities to explore non-network solutions due to the added network visibility and lead time to procure such services.

It should also be noted that while this business case justifies the deployment of transformer monitoring in support of improved BAU quality of supply process efficiency, it also provides a foundational capability to support the introduction of dynamic constraint management as outlined in the *LV Management Strategy*¹⁷.

19.6.1 Thermal load forecasting – ADMD, k-factor

Information gained from the outputs of the proposed LV power quality transformer monitors will allow a more accurate After Diversity Maximum Demand (ADMD) to be calculated. SAPN uses ADMD to approximate the average electricity usage per customer for each suburb. The improved accuracy of the ADMDs will enhance SAPN's ability to identify overloaded distribution transformers and initiate action before customer's experience an outage from an LV fuse operation.

The same information will also improve the accuracy of the calculated 'k-factors', adjustment factors used to approximate peak loads from temporary monitoring. A significant limitation of temporary monitoring as is used today is that the absolute peak and minimum loads are rarely observed in the short window that the temporary transformer monitoring is deployed. Consequently, an estimate of the peak and minimum loads is made by comparing the values recorded to a known measurement on the high voltage network. The permanent LV monitoring proposed here will provide a far more accurate method of estimating the peak and minimum loads for a distribution transformer. Not only does it assist in determining whether a transformer is overloaded without measuring the peak, it also assists with other remediation actions. For example, adjusting the distribution transformer tap is often noted as a cheap and quick fix, and is indeed an option for QS enquiries. However, lowering the tap for a high voltage enquiry can create a low voltage issue, and vice versa for a low voltage enquiry. If the peak and minimum loads can accurately be determined, tap changes can be made which may have otherwise been discounted, while avoiding a low voltage issue for a high voltage enquiry, and vice versa.

¹⁷ The *LV Management Strategy* proposes to extend LV visibility further by augmenting the transformer monitor data with a broader dataset of mid-line and end-of-line monitoring points, leveraging data procured from third parties such as smart meter providers.

19.6.2 Voltage profile and DER hosting capacity forecasting

While more complex than load forecasting, ultimately the data from the LV PQ monitors will be used with power flow models of the LV network to forecast the voltage profile along the LV circuit (maximum and minimums) and the DER hosting capacity. That is, how much PV generation, battery storage, and other DER can be added to the LV network before augmentation is required. If accurate forecasting can be achieved, corrective action can be taken before a customer raises a QS enquiry and ultimately at the time when new DER and load is approved for the network. Consequently, this would reduce customer QS enquiries particularly related to voltage and improve the overall quality of supply and customer experience. Furthermore, when customers do raise a QS enquiry with SA Power Networks, it may be possible to avoid field testing if the forecast of load and voltage for their service point is sufficiently accurate. At the least, temporary transformer monitoring could be avoided if a similar nearby transformer has permanent LV PQ monitoring.

19.6.3 Other benefits

Other benefits include:

- *Decreased low voltage fuse operation through modelling and analysis of the low voltage network;*
- *Decreased customer enquiries for voltage issues – ability to predict limitations before customer connect;*
- *Capability to model customers' requests to connect, possibly avoiding field testing;*
- *Enhanced visibility of power quality of the low voltage network;*
- *Optimisation of DER management on the low voltage network;*
- *Reduced risk of adverse media coverage and customer enquiries;*
- *Reduced exposure to significant financial risk and SPS penalties;*
- *Improved customer service – faster turn-around times through modelling; and*
- *Improved customer enquiry response times.*

Customer enquiry response times are critical. At present, the number of dissatisfied customers due to the rapidly increasing backlog of still-to-be-addressed customer enquiries is increasing, owing to the rapid escalation of the number of PV related enquiries.

19.6.4 Cost-Benefit Analysis

Installation of the LV power quality monitors will provide multiple strategic benefits for SA Power Networks and its customers however sufficient justification is provided by the primary operational benefit of avoided QoS investigation costs.

Costs:

- \$4.0 million per year for the five years of the 2020-25 Regulatory Reset period, totalling \$20 million.

Benefit 1: Control increase in site investigation- avoided site visits and data logging.

- Number of increased site investigations required that can be mitigated by use of permanent LV monitors – refer Table 24 for survey work (to monitor load demand) and Table 26 for QoS customer investigations.

	2020-21	2021-22	2022-23	2023-24	2024-25
Costs (\$M)	\$4.0	\$4.0	\$4.0	\$4.0	\$4.0
LV network <i>Visibility</i> in residential areas due to LV monitor installations	9.5%	13.6%	17.8%	22.0%	26.1%
Average number of metropolitan LV surveys related to demand per year	675	675	675	675	675
Avoided surveys due to visibility	64	92	120	149	176
Cost per QSI logger test	\$2,614	\$2,614	\$2,614	\$2,614	\$2,614
Benefits: Savings due to avoided logger survey test related to demand	\$167,296	\$240,488	\$313,680	\$389,486	\$460,064

Table 24: Value of benefits of avoided surveys due to visibility, which is provided by the installation of the LV monitors

‘Other benefits’ derived from installing LV monitors will include, among other benefits, the ability to determine from analysis of the data received from the monitors that in some instances there will be no need to perform detailed investigation. Some HV enquiries will be able to be dealt with by issuing to field personnel the solution before any visits are required; for instance, raising or lowering taps on an LV transformer.

As can be seen in Table 25, the *purchase* cost of the LV monitor is only 50% (approximately) of the total cost of purchasing and installing an LV monitor.

Cost of single LV monitor	\$4,300
Cost of installation	\$3,600
Average network cost	\$1,000
Total cost per unit	\$8,900

Table 25: Total cost of one LV monitor (installed)

The additional costs are attributed to installation and network costs (communications, analysis software).

The avoided costs in QoS customer investigations (excluding surveys) under this proposal equate to \$1.94 million per year. This is based on an assumed investment life of 20 years and a cost of \$4,774 per investigation – refer Table 26.

One logger install, remove, report	=	3	hours to install x	2	persons @ \$95/hour	\$95	/hour =	\$570	
(Estimated Cost)	+	3	hours to remove x	2	persons @ \$95/hour	\$95	/hour =	\$570	
	+	6	hours truck use x	1	truck @ \$200/hour	\$200	/hour =	\$1,200	
	+	1	one hour to download and report	1	analyst @ \$150/hour	\$150	/hour =	\$150	
1% cost of capital value of equipment (Class A logger) at							\$12,400	/ unit =	\$124
Total cost of logger test and report =								\$2,614	

	Time (hrs)	Unit costs	Totals
<u>Cost of single customer enquiry investigation:</u>			
Cost of QSI test and report			\$2,614
Cost of administration (2) and QS analysis (5)	7.0	\$150	\$1,050
Customer Relations cost	1.0	\$150	\$150
First (initial) call-out (visual inspection etc)		\$900	\$900
EWOSA (Energy & Water Ombudsman) fee (assuming escalation of investigations of 10% of customer enquiries received)		\$60	\$60
Total cost of single customer enquiry investigation			\$4,774
Total average increase in customer PV-related HV enquiries in 2017 compared with average number received for previous five years	406		
<u>Avoided cost per year of increased customer HV enquiry investigations due to continuing uptake of residential solar PV generation (2017 number less average of previous 5 years):</u>			\$1,938,244

Table 26: Avoided cost of individual PV-related high voltage investigations achieved by proposed installation of 450 LV monitors per year for the five years of the 2020-25 Regulatory Period

Note: EWOSA fee per investigation provided by EWOSA to SA Power Networks via email 8/3/2018 – copy available

Benefit 2: High Profitability Index

Profitability Index is an indication of the costs and benefits of investing by showing the value created per unit of investments. Based on Present Value of costs over a twenty-year financial analysis (assuming cost of capital to be 2.89% pa) of \$18.91 million versus the Present Value of benefits (survey work and customer investigations) over a twenty-year financial analysis (assuming cost of capital of 2.89% pa) of \$32.54 million, the profitability index is calculated to be 1.72.

Cost of capital (cost to borrow)	2.89%
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	2020/21	2021/22	2021/22	2022/23	2023/24	2024/5	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34	2034/35	2035/36	2036/37	2037/38	2038/39	2039/40
Progressive years	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Cost (\$M)	\$4.00	\$4.00	\$4.00	\$4.00	\$4.00																
Present worth factor	1.00	0.97	0.94	0.92	0.89	0.87	0.84	0.82	0.80	0.77	0.75	0.73	0.71	0.69	0.67	0.65	0.63	0.62	0.60	0.58	0.57
Time-weighted Costs (\$M)	\$4.00	\$3.89	\$3.78	\$3.67	\$3.57																
Benefit (\$)	\$2,105,540	\$2,178,732	\$2,251,924	\$2,327,730	\$2,398,308	\$1,938,244	\$1,938,244	\$1,938,244	\$1,938,244	\$1,938,244	\$1,938,244	\$1,938,244	\$1,938,244	\$1,938,244	\$1,938,244	\$1,938,244	\$1,938,244	\$1,938,244	\$1,938,244	\$1,938,244	\$1,938,244
Present worth factor	1.00	0.97	0.94	0.92	0.89	0.87	0.84	0.82	0.80	0.77	0.75	0.73	0.71	0.69	0.67	0.65	0.63	0.62	0.60	0.58	0.57
Time-weighted Benefits	\$2,105,540	\$2,117,535	\$2,127,195	\$2,137,042	\$2,139,993	\$1,680,903	\$1,633,689	\$1,587,802	\$1,543,203	\$1,499,857	\$1,457,729	\$1,416,784	\$1,376,989	\$1,338,312	\$1,300,721	\$1,264,186	\$1,228,677	\$1,194,166	\$1,160,624	\$1,128,024	\$1,096,340

Net Present Worth Costs (\$M)	\$18.91
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Net Present Worth Benefits (\$M)	\$32.54
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Profitability Index	1.72
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Table 27: Net Present Worth analysis over the 20-year asset life and 2.89% pa cost of capital

To move from a reactive approach to a proactive one for the management of the LV network quality of supply, visibility¹⁸ of the of LV network is required. However, due to the size of the LV network (over 76,000¹⁹ distribution transformers and approaching 905,000 customers), full visibility will not be economically viable for many years to come, if at all. Consequently, the strategy SA Power Networks is proposing is to enable visibility of a representative sample of the populations of LV transformers such that for any customer enquiry received, either that transformer or a similar nearby transformer is monitored.

Proposed locations for LV monitoring devices in the proposed 2020-25 deployment will be based on the following criteria:

- LV monitors at the LV terminals of distribution transformers, but *not* at the customer service point. For end of line monitoring, SA Power Networks will pursue other diverse data options that are covered as part of the strategy to enable the distributed energy transition, such as *smart meter*²⁰ data acquisition under negotiated arrangements with the relevant retailer²¹;
- Installing LV monitors only on residential LV transformers with a rating of 100kVA or greater, and medium to high customer loading; and
- Targeting LV transformers which supply *only* residential customers.

This strategy is favoured as 'large' residential transformer loads will have collective issues of DER and load levels, but with the appropriate characteristic mapping will be indicative of the power flow seen on similar nearby transformers. Commercial and industrial customers generally have different load profiles and power flow, and are often supplied by dedicated or localised transformers without the collective issues of many customers.

The LV transformer monitoring project commenced in 2017 with the installation of 200 power quality monitors in the Adelaide metropolitan area.

The strategy for the installation of the initial 200 power quality monitors and a further 450 LV transformer monitors in the years leading up to the 2020-25 Reset period is as follows:

2017: 200 LV transformer monitors to be installed in the Adelaide metropolitan residential areas, with the intention of locating at least one LV monitor in each suburb (completed);

2018: A further 200 LV transformer monitors to be installed in the Adelaide metropolitan residential areas, with the intention of locating at least one LV monitor in each suburb ; and

2019: An additional 200 LV transformer monitors to be installed, focusing on those areas of the Adelaide metropolitan area warranting greater visibility including other remaining suburbs or major regional town centres, as advised by QS Analysts.

It is intended that the installation schedule outlined above be used as a period of familiarisation with the capability, usability and outputs of the monitors, with the aim of ultimately providing a comprehensive evaluation of the monitoring units and proof-of-concept, in preparation for the 2020-25 installation programme.

¹⁸ Visibility of the network in this instance is defined as the number of installed LV transformer monitors in the metropolitan area divided by the total number of LV transformers ($\geq 100\text{kVA}$, >1 customers) servicing the metropolitan area.

¹⁹ This number of LV transformers is a state-wide number, and not restricted to the Adelaide metropolitan area.

²⁰ The installation of smart meters is not presently widespread in the South Australian LV network, unlike in Victoria, but is increasing.

²¹ Details can be found in the *LV Management Strategy*

19.7 Implementation Plan

The planned rate of installation of LV power quality units is 200 per year for the three years 2017/18, 2018/19 and 2019/20, and then 450 per year during the five years of the 2020-25 Reset period.

The cost of the LV monitors, including installation and communications costs, is \$8,800 per unit, based on the cost of identical LV monitors installed in 2017.

The proposed LV monitor installation schedule will bring the total number of units installed in the Adelaide metropolitan area to 2,800 by the end of June 2025 (200 units per year for the three years 2017/18, 2018/19 and 2019/2022, and 450 units per year for the five years of the 2020-25 Regulatory period). The total number of residential LV transformers $\geq 100\text{kVA}$ within the Adelaide metropolitan area is 10,785 (as at the date of the writing of this Business Case), meaning that the visibility of the metropolitan LV network will increase from 0% (pre-2017) to $200/10,785 = 1.9\%$ in 2017/18, and then to $2,800/10,785 = 26.4\%$ by June 2025. The step-increase in the number of units to be installed from 200 in 2019/20 to 450 per year for the five years of the 2020-25 Reset period is required to manage the continuing uptake of metropolitan residential customer PV generation (refer Table 28).

Adelaide Metropolitan area	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25
Number of LV monitors to be installed on metropolitan LV transformer LV terminals	200	200	200	450	450	450	450	450
Cumulative number of LV monitors installed in Adelaide metropolitan network	200	400	600	1050	1500	1950	2400	2850
Total number of residential metropolitan LV transformers ²³ $\geq 100\text{kVA}$ (as at 2017/18)	10785	-	-	-	-	-	-	-
'Visibility' of the metropolitan LV network (%)	1.9%	3.7%	5.6%	9.7%	13.9%	18.1%	22.3%	26.4%

Table 28: Proposed schedule of LV monitor installations (20/21-24/25 represents the approaching Reset Period – shaded light green)

It is also proposed that LV transformer monitoring be installed in South Australia's major regional towns, many of which now have relatively high residential PV penetration. Monitoring will target only a few 'typical' LV transformers within each of those towns to give an indication of the extent of PV-related voltage excursion outside of the limits stipulated in AS60038 and other DER-related issues. Table 29 provides an indication of when those installations are proposed to occur.

²² Funding for the pre-July-2020 monitors will be sourced from the existing business-as-usual budgets of the 2017/18, 2018/19 and 2019/20 financial years, and will serve as an initial familiarisation and learning period for the QS analysts, with funding of the remaining 5x450 monitors sourced from the positive-outcome of this Reset submission.

²³ Does not include country towns.

Major regional South Australian towns	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25
Number of LV monitors to be installed on regional LV transformer LV terminals	-	50	-	-	-	-	-	-

Table 29: Proposed schedule of LV monitor installations in major regional towns

Note: Installation of the 50 LV transformer monitors in major regional towns in 2018/19 will occur outside of the 2020-25 Reset period and the cost of their purchase and installation will be funded from the existing business-as-usual budget of 2018/19.

This visibility will provide a vital new tool/source of data to assist in the understanding, insight, effectiveness and efficiency of the various solutions identified, and will potentially enable impending shortcomings/limitations to be proactively avoided.

Figure 26 to Figure 29 and Table 30, provided on the following pages, present the distribution of the initial 2017 batch of 200 metropolitan LV transformer monitors compared with the numbers of residential metropolitan LV transformers within the various categories of the LV transformer population. Installation of the additional 200 LV transformer monitors for each of the years 2017/18 and 2019/20, 200 monitors in 2018/19, and the proposed 450 monitors per year during the 2020-2025 Regulatory period, will follow a similar profile, targeting high PV penetration transformer areas, as well as in a range of locations which will provide a comprehensive sample of the various categories of LV network found in the metropolitan area.

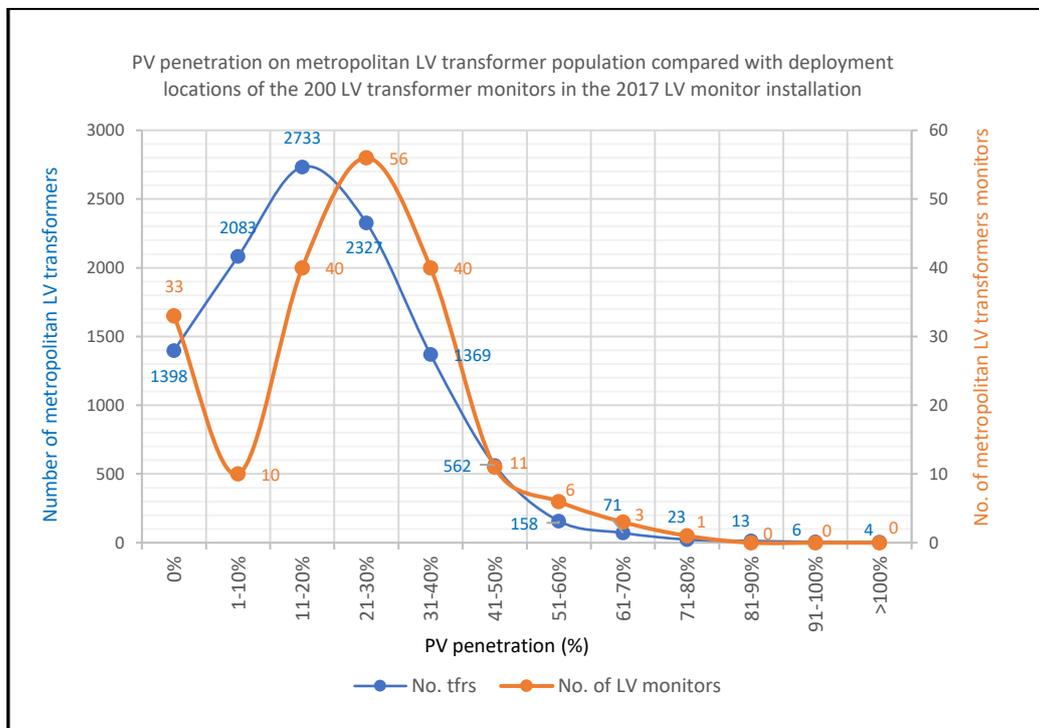


Figure 26: PV penetration on the metropolitan LV transformer population compared with the deployment locations of the 200 LV transformer monitors in the 2017 LV monitor installation²⁴

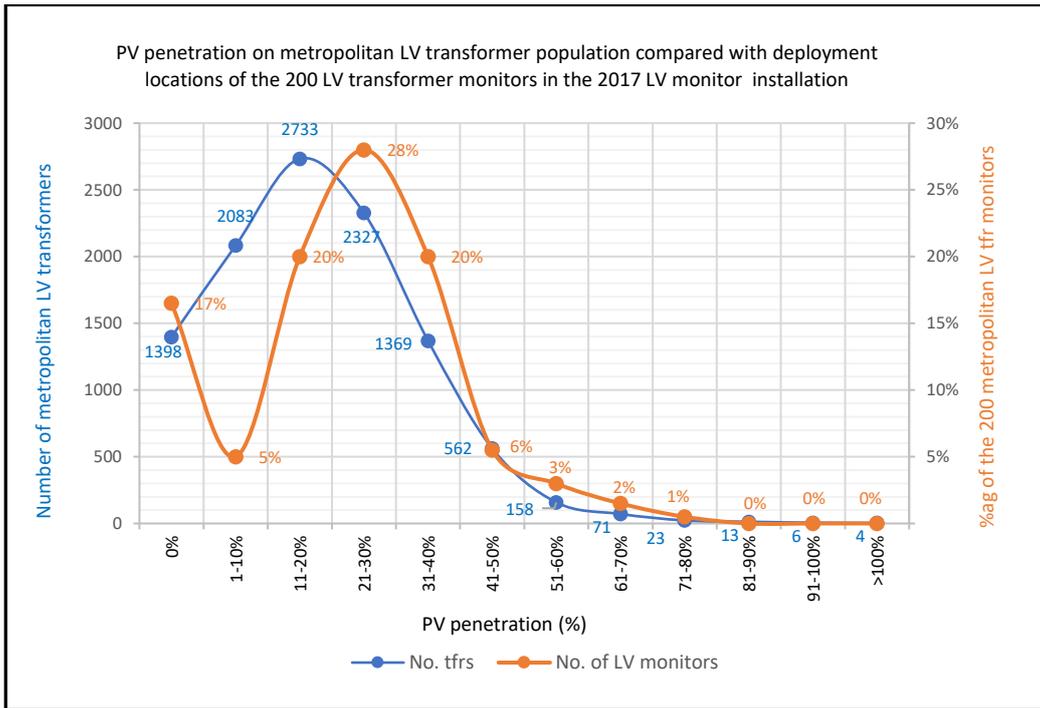
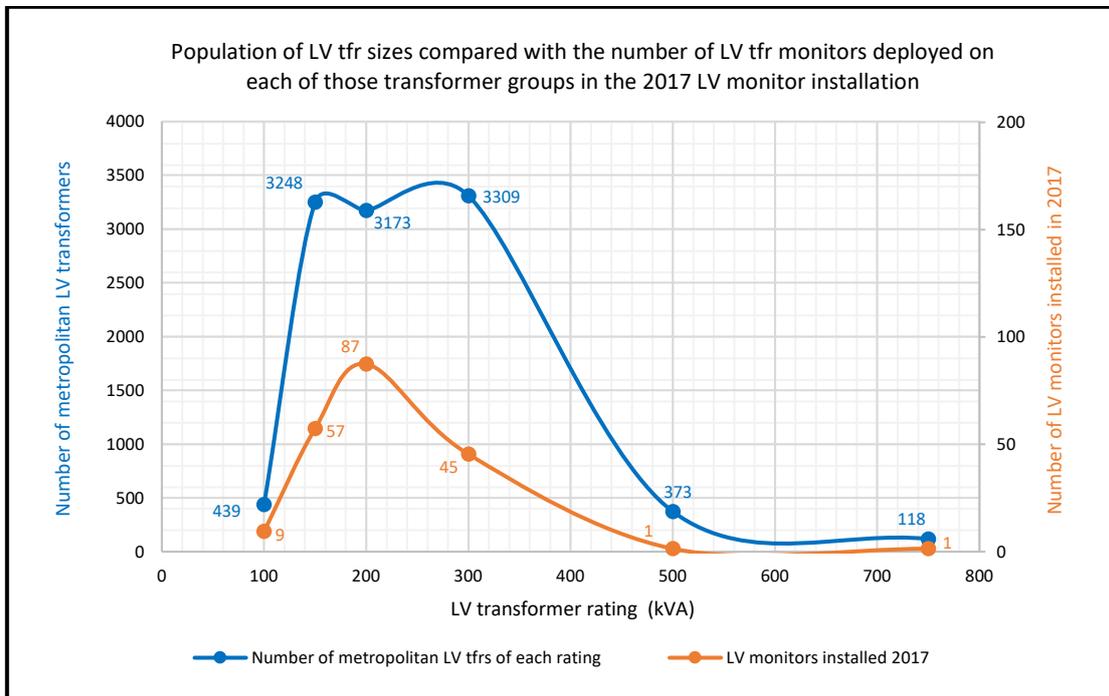


Figure 27: PV penetration on the metropolitan LV transformer population compared with the deployment locations of the 200 LV transformer monitors (as a %age of the number of monitors) in the 2017 LV monitor installation



²⁴ 38 metropolitan LV transformers have no record of PV penetration in this category

Figure 28: Metropolitan LV transformer ratings populations compared with the deployment locations of the 200 LV transformer monitors in the 2017 LV monitor installation^{25,26}

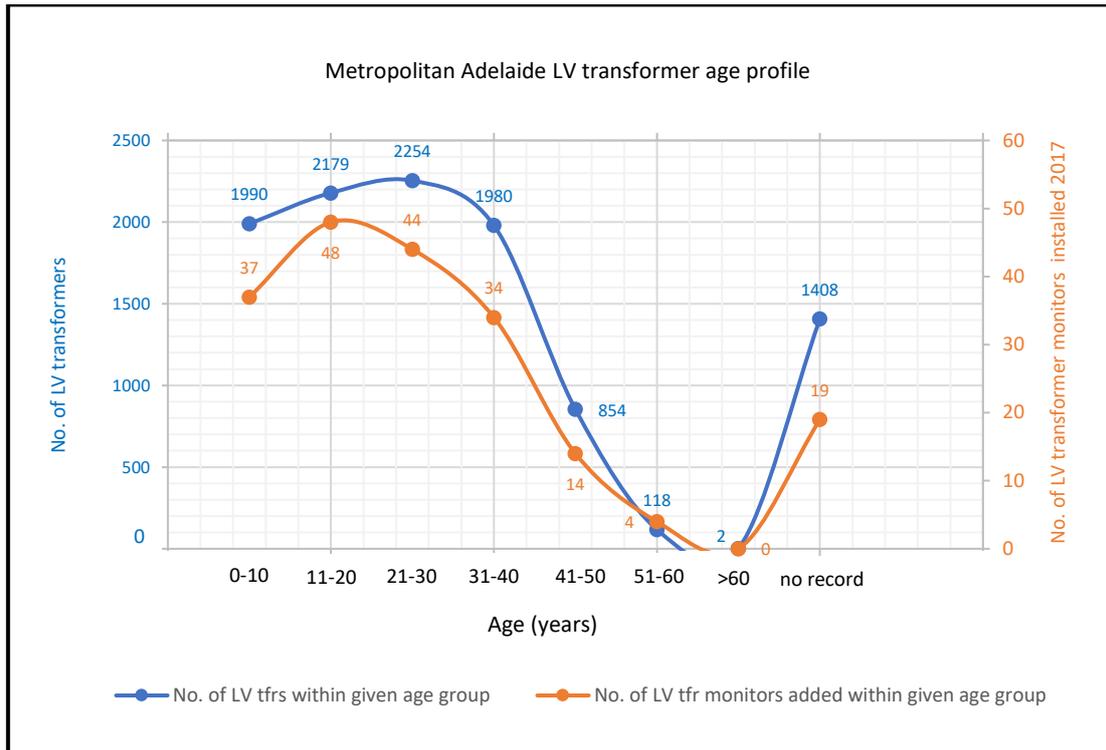


Figure 29: Metropolitan LV transformer age populations compared with deployment locations of the 200 LV transformer monitors in the 2017 LV monitor installation

	Number of LV transformers serving the Adelaide metropolitan area	Number of LV transformer monitors installed on metropolitan LV transformers (for 2017 installation of 200 LV monitors)	
pole mounted LV transformers	4789	162	3.38%
pad mounted LV transformers	5996	38	0.63%
Total metropolitan LV transformers	10785		

Table 30: Apportioning of the 200 LV transformer monitors between metropolitan LV pad-mounted and pole-mounted transformers for the 2017 installation

²⁵ 125 metropolitan LV transformers have no record of transformer rating in this category

²⁶ Metropolitan LV transformers rated at 315kVA have been grouped with metropolitan LV transformers rated at 300kVA for the purposes of this exercise

19.8 Recommendation

This business case recommends the installation and commissioning of 2,250 remotely-readable low voltage power quality monitors in the greater Adelaide metropolitan area during the five years of the 2020-25 Reset Period at a total cost of \$20 million, thereby providing visibility of 26.4% of transformers in the residential metropolitan LV network by the end of June 2025.

20. SWER Investment Strategy

20.1 Abstract

This submission recommends the continuation of funding of the Quality of Supply team (QS) for the ongoing management and planning of South Australia's extensive 'single wire earth return' (SWER) network, at a total cost of \$3.5 million over the course of the 2020-25 regulatory period. The proposed expenditure for each of the five years of the 2020-25 reset period is the same as that which was spent on the SWER network for each of the five years of the previous reset period.

Quality of Supply is part of Network Planning Branch. Its principle role is to ensure that customer and network supply quality complies with relevant statutory and regulatory requirements, Australian Standards, and industry practice.

One of the roles of QS is to undertake 'single wire earth return' (SWER) network planning. The SWER network is a cost-effective means of providing electricity supply to rural and remote customers. SWER planning is principally focussed on ensuring that the SWER network, presently consisting of 456 radial SWERs, has adequate capacity and that power quality complies with supply standards.

Compliance with Quality of Supply Standards includes resolving issues with isolating transformer capacity, steady-state voltage levels, voltage fluctuations and flicker, voltage dips, and harmonics.

20.2 Introduction

SA Power Networks has 456 SWER feeders supplying the rural areas of South Australia. Widespread 19kV SWER networks were first established in the 1950's as a cost-effective means of providing electricity supply to rural and remote customers. SWER feeders are energised at 19kV and are supplied from either 33kV or 11kV networks via isolating transformers. The high voltage and long spans of a SWER feeder enable the supply of electricity to remotely-located customers in a cost-effective manner.

20.3 2020-25 Management Plan

The SWER network is in a unique category of its own, both providing supply directly to remote customers via 19,000/230V SWER LV distribution transformers and operating as a sub-transmission line by transporting electrical power over vast distances. The SWER network supplies a relatively small number of customers but, requires a large amount of infrastructure to do so.

The SWER expenditure forecast, presented in this, and in previous reset submissions, apportions the forecast expenditure equally over the five years of the relevant regulatory period, whereas, in reality, expenditure in a particular year may be withheld for the purpose of accumulating yearly budget allocation to fund major SWER augmentation. An example of this is the splitting of a SWER feeder, including the extension of the 3-phase network supplying it, and adding a dedicated isolating transformer and SCADA-enabled recloser to supply the newly-created SWER.

Every effort is made by QS to spend money on the SWER network prudently. Analysis of SWER limitations and customer enquiries first establishes with certainty whether the underlying cause is on the SWER network, or whether it is beyond the customer connection point and therefore the responsibility of the customer to resolve. If multiple voltage issues are experienced on a single SWER feeder, it may be far more effective to install a single high voltage regulator rather than installing individual low voltage regulators at customer connection points along the length of the SWER. Should a SWER isolating transformer be overloaded, the transformer will be replaced with one having a higher rating rather than more expensive remediation (to a maximum rating of 200kVA).

There are two main limitations impacting SWER feeders; voltage excursions outside of prescribed limits, and isolating-transformer overload. The cause of voltage issues, which have been increasing in

recent times, is generally determined by performing multiple voltage and load tests along the length of the SWER, including the low voltage terminals of the isolating transformer, the end of the SWER line, and at the connection point of the premises of the customer lodging the enquiry. The information gained from the results will enable QS analysts to determine whether the cause of the voltage issue is on the SWER feeder, or localised to a single LV transformer, whether a SWER voltage regulator would remedy the situation, and if so, where best to locate the regulator.

The second possible limitation is an overloaded isolating transformer. SWER isolating transformers are capable of being loaded to a maximum of 130% of their nameplate ratings (due to the cooling effect of circulating air), after which the transformer must be upgraded to a larger unit, or other remediation implemented. For 100kVA and 150kVA SWER isolating transformers which are loaded to 130% of their nameplate rating, the transformer will be upgraded to a 200kVA unit. For a 200kVA SWER isolating transformer which is loaded to 130% of nameplate rating, the SWER feeder that it is supplying will generally be split into two SWERs to offload the transformer, and an additional isolating transformer and SCADA-enabled recloser installed to supply the newly-created SWER feeder. Protection settings must be adjusted accordingly to accommodate the new configuration. Splitting a SWER feeder is generally a very costly solution, and is always a solution of last resort. There are presently four SWER feeders which are heavily loaded, and with no other solution available, are candidates for splitting. The four SWER feeders are presented in Table 31. This business case proposes splitting two of those feeders. The SWER feeders 'Skilly' and 'Weetulta' are planned to be reconfigured by splitting during the 2020-25 regulatory period.

Supplying substation	Supplying feeder	SWER identification	SWER name	Recloser number	Installed customer transformer capacity (kVA)	Isolating transformer capacity (kVA)	Isolating transformer current rating (A)	Summer normal load test (A)	Isolating transformer loading (%)	Recloser trip coil size (A)	Recloser trip value (A)
AUBURN	AUBURN CL-25	CL22	SKILLY 19kV SWER	R5376	700	200	10.5	14.2	135%	10	17.0
MACGILLIVRAY	PARNDANA KI-42	KI57	EMU BAY 19kV SWER	R5176	905	200	10.5	12.6	120%	10	18.0
MAITLAND	ARTHURTON MT-3	MT02	WEETULTA 19kV SWER	R4206	880	200	10.5	14.0	133%	10	17.0
MALLALA	WINDSOR GA-28	GA24	DUBLIN TOWNSHIP 19kV SWER	R5048	355	200	10.5	14.0	133%	10	17.5

Table 31: Candidates requiring splitting to off-load their isolating transformers

When a 200kVA SWER isolating transformer is installed, QS allows the transformer to be loaded to 130% of its rating (cyclic peak load of 13.65A at 19kV, or 260kVA). The SCADA-enabled recloser that is installed as a means of protection for the SWER feeder is specified to have a 15A recloser coil sensitivity, with a 30A pick up current. The high pickup current means that the length of the SWER is limited (because of the inability to distinguish between load current and fault current nearing the end of a long SWER), as is the allowable pole footing resistance, unless an additional mid line reclosers is also installed (only practicable if the load is distributed along the length of the SWER, and not accumulated at one end).

The decision concerning which augmentation should be implemented involves consideration of the following guidelines, as a minimum:

- The solution should be adequate and effective for at least 10 years;
- The solution should be that which has the lowest net present value (NPV); and
- The solution should meet any relevant guidelines; for example, adequate protection using SCADA-enabled reclosers (adjacent the LV terminals of the isolating transformer, and where warranted, midline), quality of supply standards such as voltage limits, in accordance with Australian Standard AS60038 (in some instances, requiring voltage regulation, particularly to maintain end-of-line voltage levels), and fault levels.

The capacity of a SWER Network is dependent on the rating of the SWER isolating transformer. Major upgrades of the SWER network can involve converting a SWER feeder to a 3-phase feeder, upgrading the existing isolating transformer to a 200kVA capacity isolating transformer and the installation of a SCADA enabled line recloser, installing voltage regulation and improved protection systems where

necessary, or splitting the existing SWER network and creating an additional SWER feeder with an additional isolating transformer and SCADA-enabled recloser.

20.4 Capital Expenditure Detail

The 2020-2025 SWER Remediation Program is based on consideration of the increasing number of projects that will be undertaken each year, and the average unit-costs of those various projects (provided in Table 32). Suspected transformer overloads will be confirmed by load monitoring, and customer voltage enquiries will be investigated by individual measurement (installation of a logger at the customer connection point, generally for three to five days) and subsequent analysis of the results by QS analysts. Average unit-costs are derived from recent SWER projects undertaken.

	Average unit-cost (\$2017) (including overheads)
Upgrade SWER isolating transformer	\$45,000
Install SCADA-enabled SWER recloser	\$70,000
Install HVR (SWER regulator)	\$70,000
Split SWER	Project-specific
Extend 11kV and split SWER	Project-specific

Table 32: Unit-costs of standard SWER remediation techniques

Adequately funded management of the SWER network is essential to ensure that customers can connect both loads, such as air-conditioners and refrigeration, as well as embedded generation; specifically, residential solar PV generation. The SWER network must also be developed with consideration of possible future connection of energy storage installations and electric vehicle charging.

Table 33 presents the historic (and that proposed in 2018/19 and 2019/20) expenditure on the SWER network over the 5 years of the 2015-20 regulatory period, totalling \$1.85 million (\$2017). The budgeted estimate of SWER network expenditure for the 2015-20 regulatory period was \$0.70 million per year, but as can be seen in Table 33, lesser amounts were recorded for the years 2015/16, 2016/17 and 2017/18 due to issues with cost allocation and lack of visibility due to a shortfall in the testing program (routine test program deferred due to need to resolve customer PV voltage complaints).

Historic Expenditure	2015/16	2016/17	2017/18	2018/19	2019/20
SWER Network historic expenditure (\$M)	\$0.05	\$0.18	\$0.22	\$0.70	\$0.70

Table 33: Historical expenditure (and proposed expenditure 2018, 2019) on the SWER network during the 2015-20 regulatory period.

Note: Costs include all overheads (\$2017).

Table 34 provides a summary of the forecast expenditure on the SWER network during the 2020-25 regulatory period, totalling \$3.5 million over the 5 years. A broad breakdown of fund allocation is also provided.

Proposed expenditure (\$k 2017)	2020/21	2021/22	2022/23	2023/24	2024/25
High voltage SWER regulators (5 per annum at \$70k per regulator)	350	350	350	350	350
SWER isolating transformer upgrades (2 per annum at \$45k per isolating TF)	90	90	90	90	90
SWER splits (one or two during the regulatory period, depending on cost – costs spread evenly over the five years)	260	260	260	260	260
SWER network proposed expenditure	700	700	700	700	700

Table 34: Proposed expenditure on the SWER network during the 2020-25 regulatory period.

20.5 Emerging Trends

As presented in the Quality of Supply BAU business case, a significant increase in the number of customer QS enquiries was observed in 2017, which can be mainly attributed to high voltage levels caused by residential PV generation. This is also the case for the SWER network, but the voltage issues being experienced by customers supplied by SWER feeders and who also have PV generation installed are exacerbated because of the high impedance of the standard SWER conductor historically used in SWER construction.

The increase in customer enquiries has driven the need for more QS investigations and augmentation work.

There is also an emerging requirement to install increasing numbers of SWER HV regulators due to the large voltage envelope now being encountered on SWER feeders. This is the result of the high impedance of SWER conductor (generally steel construction) and its impact on the magnitude of voltage drop (evening residential peak loads and no contribution from solar PV) and increased magnitude of voltage rise (minimal residential load and high levels of residential PV generation).

20.6 Recommendation

This submission recommends the approval of funding for the management of the SWER network supplying remote and rural customers in South Australia, at a total cost of \$3.5 million over the five years of the 2020-25 regulatory period.

The proposed expenditure of \$700 thousand per year will be allocated to the installation of SCADA-enabled SWER reclosers and regulators and upgrades to select SWER feeder capacity as detailed.

The proposed expenditure is the same as that budgeted for the 2015-20 regulatory period.