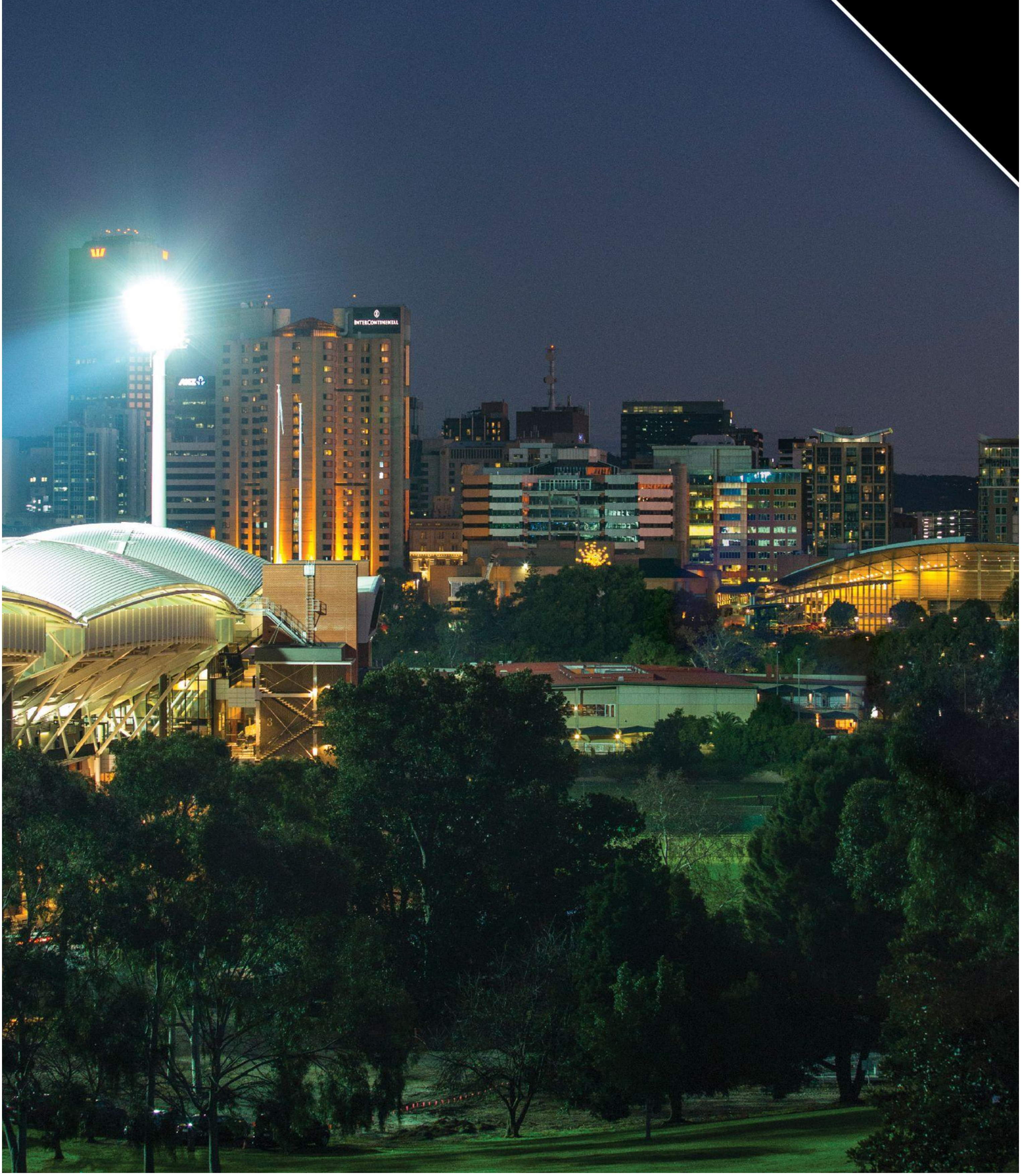
Attachment 7.4

SA Power Networks:
Distribution System Planning
(AMP 1.1.01)



ASSET MANAGEMENT PLAN 1.1.01
DISTRIBUTION SYSTEM PLANNING REPORT

2015 – 2025

Published: October 2014

SA Power Networks

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OWNERSHIP OF STANDARD

Procedure 916 Annex B
Issue 2/13

OWNERSHIP OF STANDARD

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

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

Name: ***D Pritchard***

Standard Last Reviewed: October 2014

Standard Last Issued: October 2014

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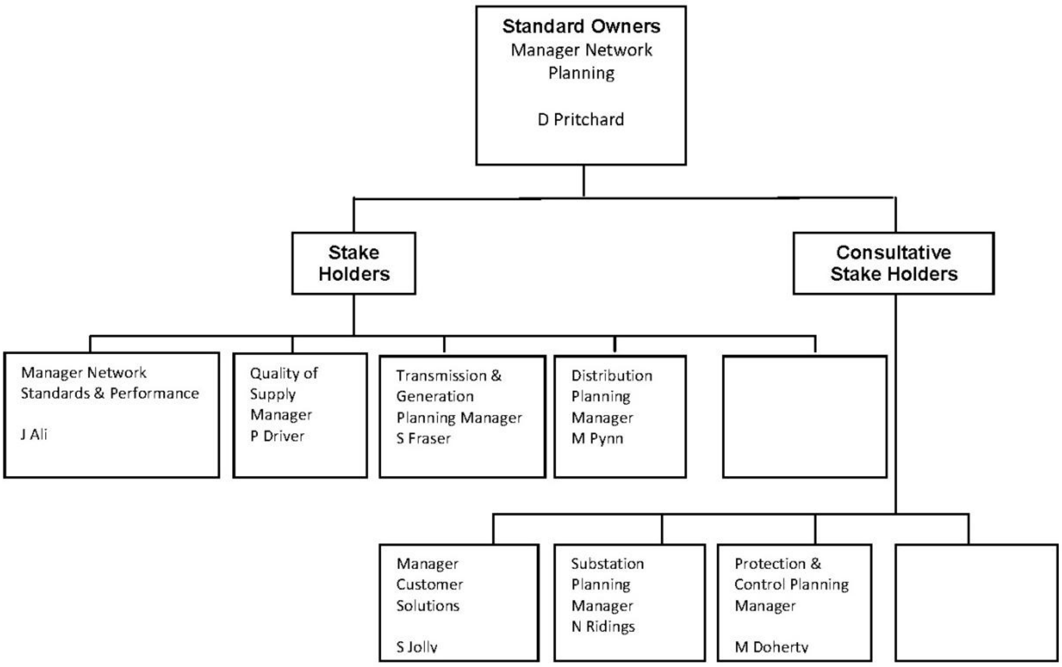
Next Review Due: October 2018 *(ie. When the next review process is due to commence)*

STANDARD/MANUAL OWNERSHIP STRUCTURE



OTHER RELATED MANUALS

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COMMENTS

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(Asset Management Plan 1.1.01 Distribution System Planning Report)

DOCUMENT VERSION

Version No	Date	Description
0.1	1/5/2012	First Draft
0.2	14/1/2014	Second Draft
0.3	13/2/2014	Third Draft
0.4	20/9/2014	Fourth Draft
0.5	20/10/14	Fifth Draft
1.0	15/10/2014	Final Draft
1.1	27/10/2014	Final

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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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 ten years from 2015/16 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 2014 peak, 10% and 50% *PoE* load forecasts (as applicable).

This report includes an overview of *SA Power Network*s' system planning methodology, 15 *regional development plans* covering *SA Power Networks' connection points*, *sub-transmission lines*, *zone substations*, *distribution feeder* exits and the *low voltage network*. 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 2014/15 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 2014/15 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.

Contents

List of Figures

List of Tables

Definitions

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

Contingency Condition	The term used to describe the state of the *distribution network* when any one piece of plant or equipment (*N-1*) is out of service, with the rest of the *network* 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 *sub-transmission line* fault may result in the loss of a *zone substation* transformer where no *line circuit breakers* exist).
Contingency Load	The maximum forecast load expected to be carried by the *line*, *feeder* or *zone substation* in a specified year under peak, 10 or 50% *PoE* conditions (as applicable), with any one piece of plant or equipment (*N-1*) out of service and with the rest of the *network* remaining intact.
CPMP	*Connection Point* Management Plan – a document jointly maintained by *SA Power Networks* and ElectraNet, which outlines the predicted required timing and high level scope of future *connection point* upgrades.
CT	Current Transformer
Customer Substation	A *zone substation* dedicated to supplying a single customer's load. Information on *customer substation*s is not included within this report for confidentiality reasons.
DAC	Development Assessment Commission
DAPR	Distribution Annual Planning Report. An annual report produced by *SA Power Networks* in accordance with section 5.13.2 of the *NER*.
DC	Direct Current
Distribution Network	Shall have the meaning as defined within Chapter 10 of the *NER* and pertaining to the regulated *network* owned and operated by *SA Power Networks*. The terms "*network*" and "*distribution System*" shall be construed accordingly.
Distribution Substation	A substation connected to a *SA Power Networks' feeder* which transforms the voltage from *HV* to *LV* or in the case of its *SWER* systems, a *SWER* 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 *SA Power Networks* in accordance with section 5.13.1(e) – (j) of the *NER*.
Embedded Generation	The generation of electricity by a generating unit connected to a *distribution network* and not having direct access to the *transmission network*.
Emergency Rating	The short-term emergency rating of the *line*, *feeder* or *zone substation* with all plant in service. If the peak load exceeds this rating the *line*, *feeder* or *zone substation* assets may be permanently damaged, or fail.

EDC	Electricity Distribution Code as published by *ESCOSA*.
ElectraNet	The company who owns and operates the *transmission network* in South Australia and is registered with *AEMO* as the *TNSP* for the South Australian *transmission network*.
ETC	Electricity Transmission Code as published by *ESCOSA*.
ESCOSA	Essential Services Commission of South Australia
Fast Connection	With respect to the connection of a *mobile substation*, is a *zone substation* 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 *NER* which states, “means the maximum allowable output or load of a *network* or facility under single *contingency condition*s, including any short term overload capacity having regard to external factors, such as ambient temperature, that may affect the capacity of the *network* or facility.
FR3	A proprietry 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 “*HV*” shall be construed accordingly.
Interested Party	Any person or organisation that has an interest in *SA Power Networks*’ long term planning, *demand management*, addressing a particular constraint or more generally in addressing *demand management* issues.
kV	kilo Volt
LGA	Local Government Area
Low Voltage	Means any voltage less than or equal to 1000 Volts and “*LV*” shall be construed accordingly
Meshed Sub-Transmission Line	A *sub-transmission line* that has a source of supply available from both ends.
Mobile Substation	A trailer mounted, 3.8 or 10 MVA *zone substation*, with a primary voltage of 66*kV* and/or 33*kV*, and either a dual secondary voltage of 7.6*kV* / 11*kV* in the case of the 3.8 *MVA* unit or 11*kV* in the case of the 10 *MVA* unit, for use within 66/11*kV*, 33/11*kV* and 33/7.6*kV* *zone substations* in the event of a single transformer failure at a *zone substation*.
MVA	Mega Volt Ampere
MVAr	Mega Volt Ampere Reactive
MW	Mega Watt

Nameplate Capacity	The summated *zone substation* transformer capacity as written on the nameplate of each *zone substation* transformer. Where different size transformers are used, the capacity of the smallest transformer may be used to calculate the total *nameplate capacity* of the *zone substation* to account for uneven sharing of the *zone substation's* transformers.
NCA	Network Connection Agreement
NECF	National Energy Customer Framework
NEM	National Electricity Market
NER	National Electricity Rules and "*Rules*" shall be construed accordingly.
NERs	Neutral Earthing Resistors
NEXs	Neutral Earthing Reactors
NGM	National Grid Metering
NOC	*SA Power Networks'* 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 *EDC* that permits satisfactory operation of equipment.
Normal (N) Capacity / Rating	The cyclic rating of the *line*, *feeder*, *connection point* or *zone substation* with all plant and equipment in service. The design life of the *line*, *connection point* and *zone substation* 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 *Firm Delivery Capacity*.
OLTC	On-Load Tap Changer
OPEX	Operational Expenditure
OTR	Office of the Technical Regulator
Overhead Conductor Ratings	The Overhead Conductor Ratings for *lines* and *feeders* 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 *line's* or *feeder's* 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% *PoE* forecast is one which is likely to be exceeded one year in ten, whilst a 50% *PoE* forecast is likely to be exceeded once every two years)
Power Factor	The ratio of real power (in kW or *MW*) to apparent power (in kVA or *MVA*) in an AC circuit
Primary Distribution Feeder	is as defined within Section 5.10.2 of the *NER* which states, "means a *distribution line* connecting a *sub-transmission* asset to either other *distribution lines* that are not *sub-transmission lines*, or to distribution assets that are not *sub-transmission* assets". For the purposes of this *AMP*, 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 *SWER* isolating transformer or *zone substation*. The terms "*distribution feeder*" and "*feeder*" shall be construed accordingly
PSS/E	Power System Simulator for Engineering
PV	Photo Voltaic. This term is used to refer to solar, inverter based *embedded generation* schemes.
QMS	Network Management's Quality Management System certified to ISO 9001.
QoS	Quality of Supply
Radial Sub-transmission Line	A *sub-transmission line* that has a source of supply from only one end.
RDP	Regional Development Plan
Registered Participant	A person who is registered with *AEMO* 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 *nominal voltage*. Regulator stations are limited by their *normal capacity* and voltage boosting/ bucking tap range capability.
RIT-D	The Regulatory Investment Test – Distribution as per Section 5.17 of the *NER* and promulgated by the *AER* with which all proposed *network* investment with an estimated expenditure greater than or equal to $5 million must be assessed to determine the solution with the least cost or greatest market benefit to all *network* users.
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	*SA Power Networks* is South Australia's principal Distribution Network Service Provider (*DNSP*), and is responsible for the distribution of electricity to all distribution grid connected customers within the State under a regulatory framework. *SA Power Networks* 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
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 *AER* in accordance with clause 6.6.2 of the *NER*.
Sub-transmission	is as defined within Section 5.10.2 of the *NER* which states," means any part of the power system which operates to deliver electricity from the *transmission system* to the *distribution network* and which may form part of the *distribution network*, including *zone substations*."
Sub-transmission Line	is as defined within Section 5.10.2 of the NER which states,"means a power *line* connecting a *sub-transmission* asset to either the *transmission system* or another *sub-transmission* asset." For the purposes of this *AMP*, this shall be taken to represent an overhead conductor or underground cable energised at 33kV or 66kV that emanates from a *connection point* or a *zone substation* and supplies a *zone substation*. The term "*line*" 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. *SA Power Networks' SWER* systems operate at 19kV and 6.35kV.
Transmission Network	Shall have the meaning as defined within Chapter 10 of the *NER*.
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 *sub-transmission lines* and *distribution feeders* are determined in accordance with Network Management's' QMS Procedure 638.
VCR	Value of Customer Reliability
Voltage Capacity	Shall mean the amount of load capable of being carried by a *line* or *feeder* before causing the voltage at the extremities of the *line* or *feeder* to drop below the minimum acceptable levels mandated by the *EDC*.

VT	Voltage Transformer
WACC	Weighted Average Cost of Capital
Zone Substation	is as defined within Section 5.10.2 of the *NER* which states," means a *substation* for the purpose of connecting a *distribution network* to a *sub-transmission network"*. A *SA Power Networks' substation* at which the *sub-transmission* voltage (66kV or 33*kV*) is transformed down to a distribution voltage (33*kV*, 11*kV*, 7.6*kV*, 6.6*kV* or 3.3*kV*). "*Substation*" 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 2015 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.

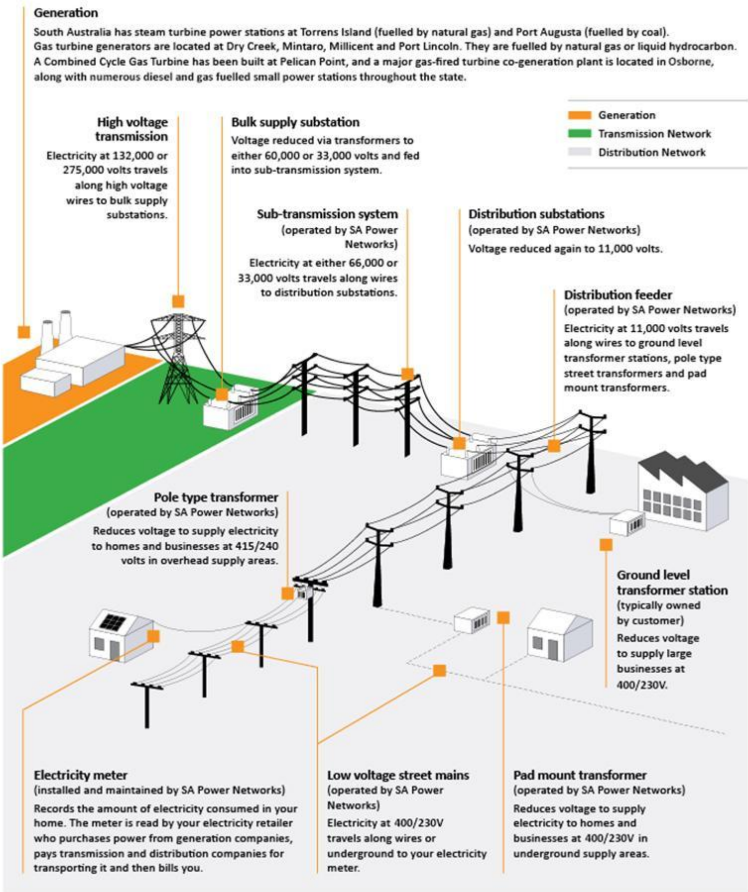


Figure 1: Electricity Supply System

1.3 The planning process

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

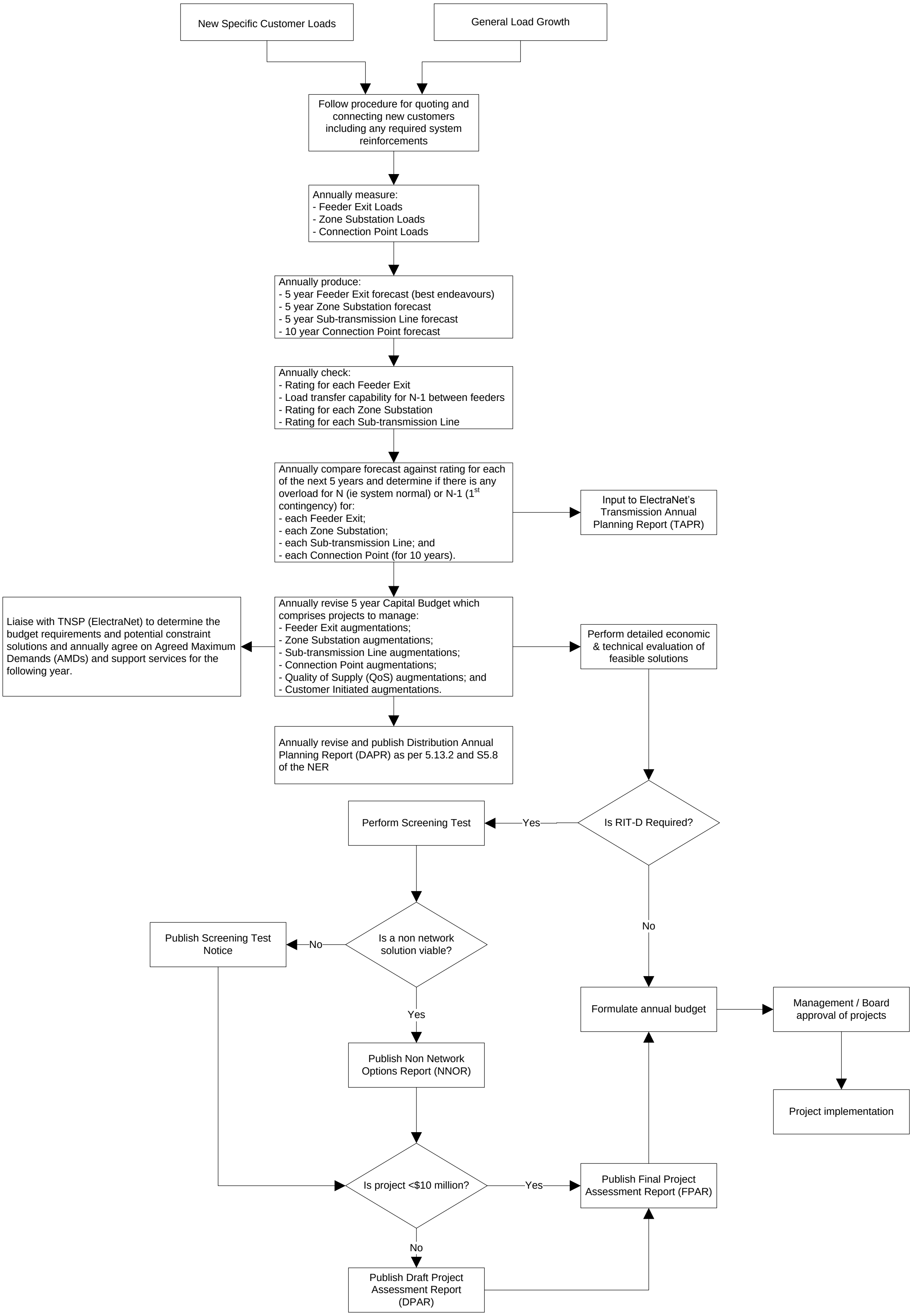


Figure 2: Overview of Distribution System Planning Process

2. PLANNING STANDARDS & PROCEDURES

2.1 Sub-transmission Capacity Terminology

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

1. *Normal Rating*
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
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
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 66/11*kV* 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**

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.

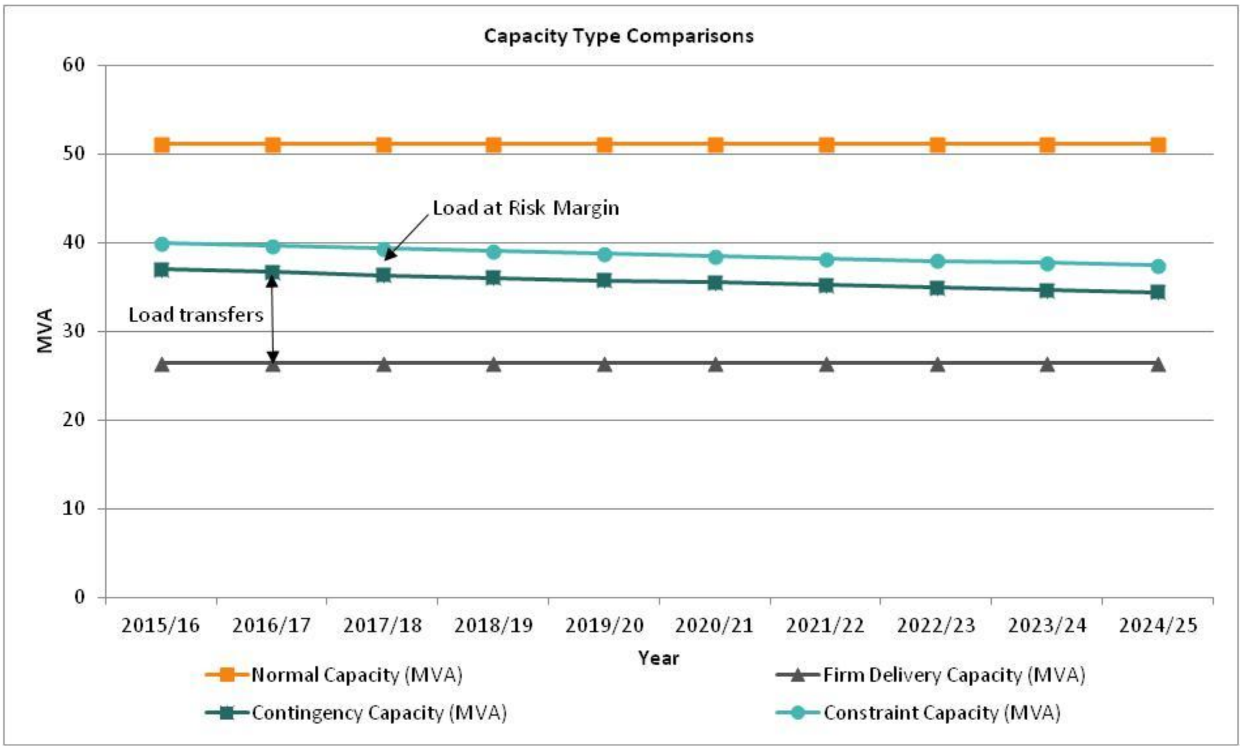


Figure 3: Zone Substation Capacity Type Comparisons

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 (ie 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* ocurring; 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.

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 66/7.6*kV 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, 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 document[1].

This forecasting tool performs regression analysis to weather correct recorded load readings with respect to historic temperatures dating back to 1978. Prior to performing the regression, the actual load readings are adjusted to take into account the effects of load transfers, spot loads, major customers, *PV* and *embedded generation* such that the values regressed represent those native loads which are temperature sensitive. Upon completion of the regression analysis, post model adjustments are then made to add back in any previously removed spot loads or major customer loads whilst negative loads such as *embedded generation* and PV are removed from the final regressed value.

In order to account for econometric factors, the temperature corrected *PoE* spatial forecasts are able to be reconciled to the next level of the *network* (ie *zone substations* reconciled to *connection point*, *connection points* reconciled to system level). The model considers the impact of past and future *embedded generation* (including *PV*), spot loads, transfers and the behaviour of major customers in arriving at its final forecast values for the nominated *PoE* 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.

The measured 2013/14 demand values were compared with the 10% *PoE* forecast (where relevant) as most locations experienced 10% *PoE* conditions, enabling checking of *PV*, energy efficiency and underlying customer growth.

The 2013/14 to 2019/20 *connection point* forecast was then reconciled with *AEMO's* SA generation forecast trend contained within the National Energy Forecast Report (NEFR), published in July 2014 for the same period. For the non major customer load, this shows in essence a flat characteristic (ie for residential and commercial customers). The major customer load was removed by separately considering those *connection points* dominated by a single customer such as at Port Pirie, Whyalla and Snuggery.

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

The reconciliation process then modifies the *transmission connection point* forecast, thereby considering the global impact of energy efficiency measures, *PV* and economic factors as forecast by *AEMO* for South Australia. The major customers are separately forecast based on the 2014 measured values and their advice of future plans. Several of these customers have or are about to modify their demand requirements. Each *connection point* forecast trend is then reconciled with the forecast of the *zone substations* that are supplied by the *connection point(s)*, similarly modifying the *zone substation* forecast to include consideration of global factors forecast by *AEMO*.

The last load forecast produced prior to publication of this document was produced in 2014. All identified constraints and their timings described in this report are based on the forecasts produced by this tool at peak, 10% and 50% *PoE* level (as applicable). All forecasts consider the historical measured loads, adjusted for any transfers, spot loads, *PV*, *embedded generation* or major customers as the basis for determining the growth rate. The historic period considered is selected relevant to the location (eg where the asset has only existed for four years, the growth rate will likely only be taken over this period). Potential changes in customer demand due to the effects of *PV* installations and *demand management* programs have also been considered within the forecasts.

The timing of the various *network* augmentations proposed within this *AMP* 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.

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 continuing 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 *AMP* are based on the moderate *AEMO* load forecast.

The moderate forecast growth rates applied to the *SA Power Networks' connection points* with *ElectraNet* (excluding large customer step load changes) are shown in Table 1.

Region	**Growth Rate (excl major customers) 2014/15 to 2019/20**
Total *connection points*	0%
Metro *connection points*	-0.01%
Country *connection points*	0.03%

Table 1: Forecast Growth Rates (excluding step loads) used in this plan

Zone substation forecasts are reconciled against their upstream *connection point's* forecasts with these *connection point's* forecasts also being reconciled to state forecasts to cater for macro-economic factors.

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

The total *connection point* forecast is a non-coincident summation of growth rates. The coincident growth rate for the toal *SA Power Networks distribution network* is less than the non-coincident value due to diversity between *connection points* (eg time of day and customer type), the impact of *embedded generation* and large customers. The total state generation forecast is lower again due to the diversity between transmission and distribution customers, losses and transmission system connected generation.

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 which is in excess of 585 *MW*. This represents approximately a sixth 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',* 830,000 customers, approximately 169,000 (20%), have a *PV* system installed.

This increase in popularity has been driven by several factors including generous state government "feed in tariffs" prior to their cessation in September 2013 and large reductions in the cost of installing such systems. Figure 4 indicates the level of installed inverter capacity, split according to metropolitan Adelaide and country regions per annum.

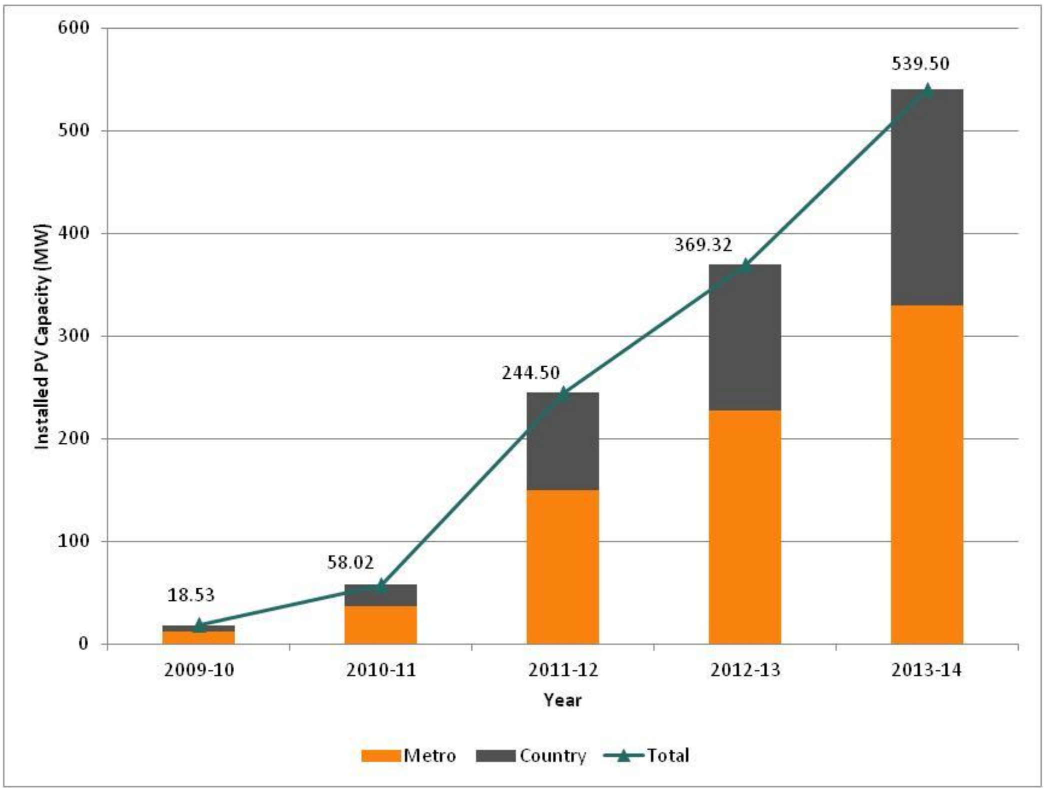


Figure 4: Installed PV Capacity per annum

As a result, the implementation of these 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 5 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 *connection point* and state demand, the effect of these *PV* systems has had a far greater impact, with the time of peak demand shifing from 17:00 to 19:00 Central Standard Summer Time. This time shift in demand has been considered within *SA Power Networks'* load forecasts.

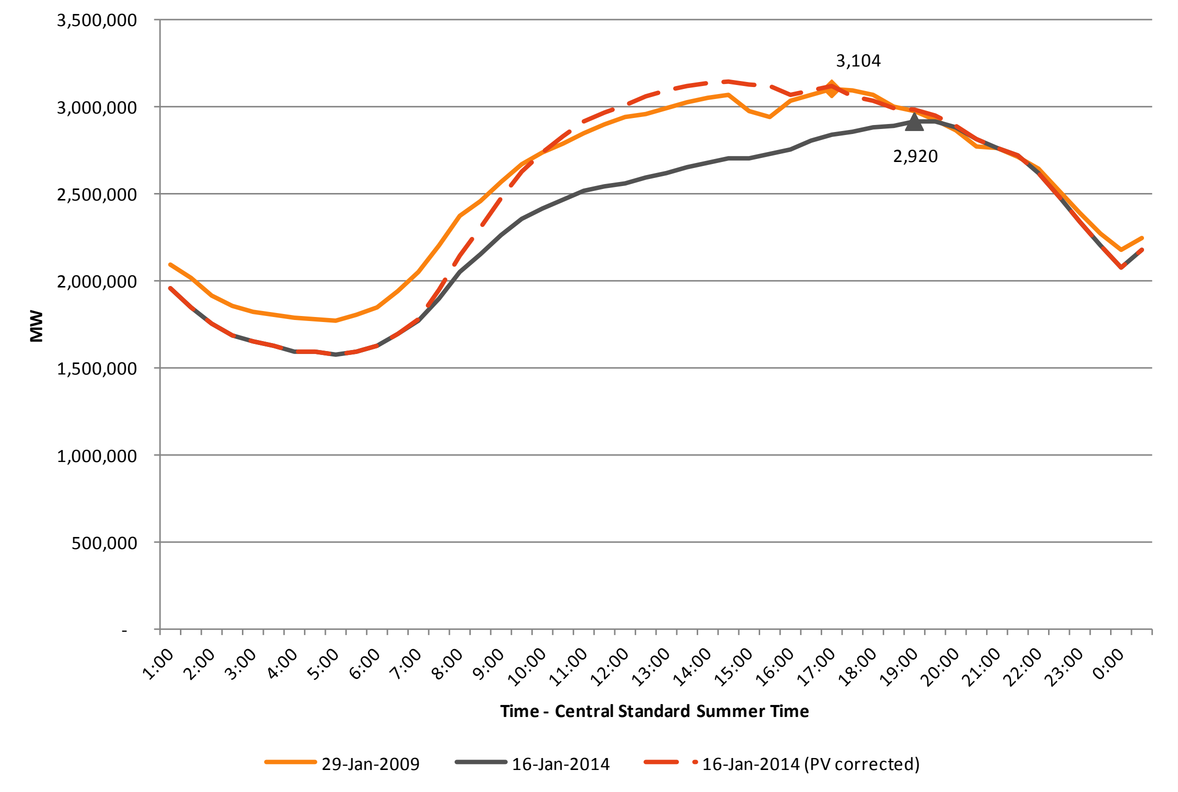


Figure 5: Load Profile Comparison

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

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

As is the case with more traditional forms of *embedded generation*, in order to account for the impact of *PV* generation on the *network* and subsequently its *zone substation* and *connection point* forecasts, the forecasting tool 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 "native 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:

8. The installed capacity of *PV* systems at both *zone substation* and *connection point* level (at a given point in time);

9. The estimate of total annual energy output of these systems on a MWh per kW installed basis obtained from the Clean Energy Regulator; and
10. 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 6).

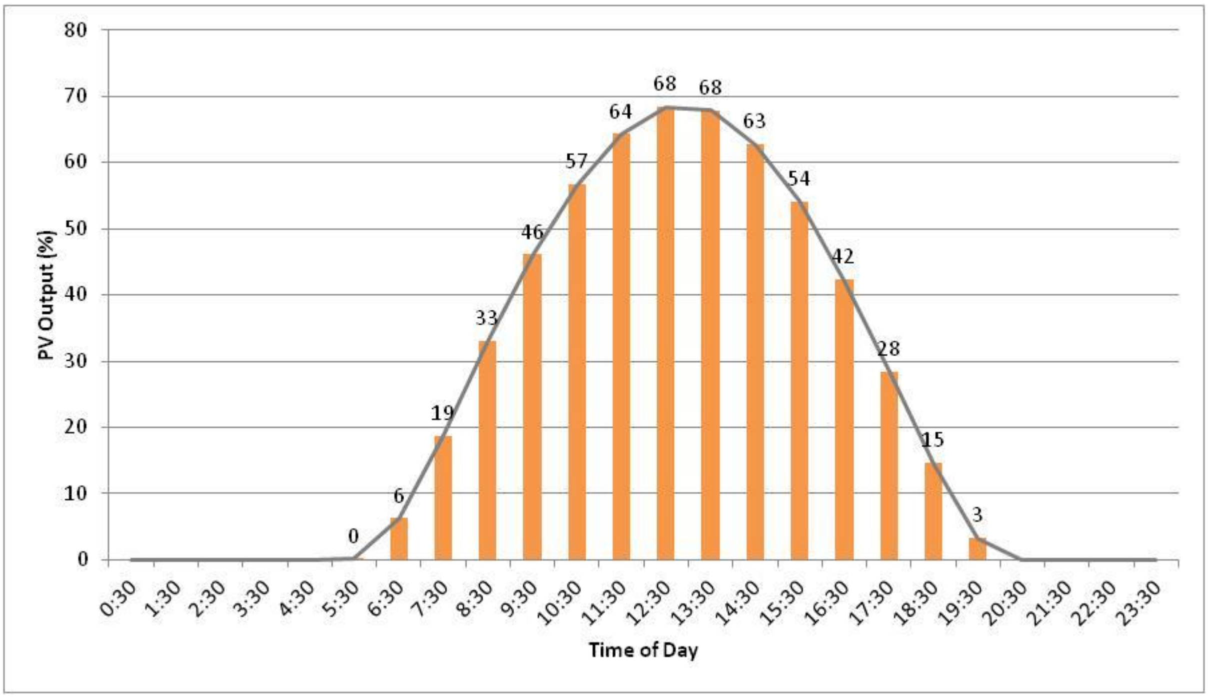


Figure 6: PV Output versus Time of Day in January

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 "native 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 are deducted from the forecast value at the nominated *PoE* level to arrive at the final, unreconciled forecast. Figure 7 provides an example of the impact of *PV* on measured versus native demand.

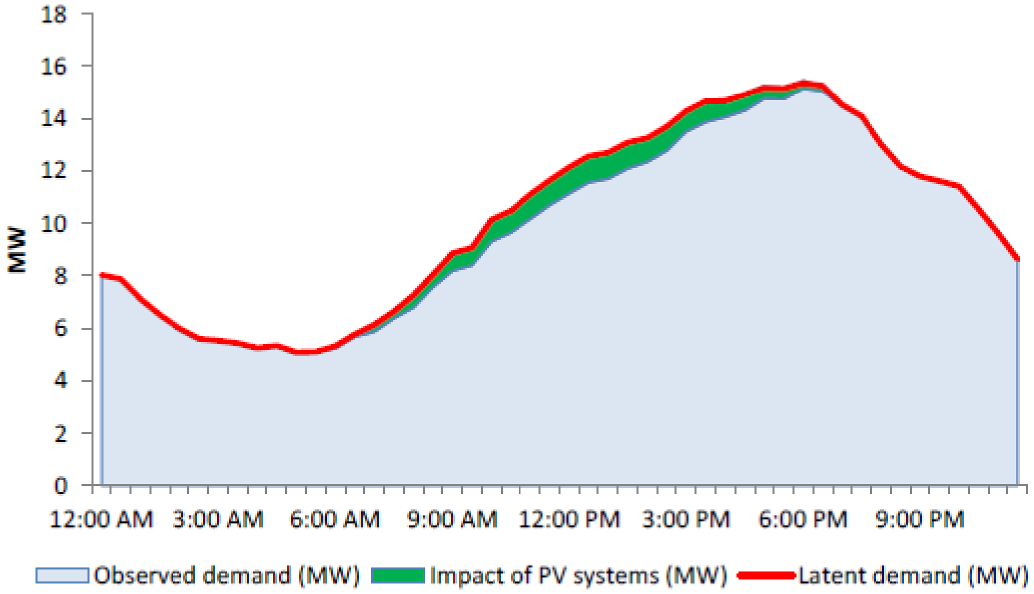


Figure 7: Measured Demand Compared with Native Demand[2]

The forecasted increase in *PV* installed capacity used by *SA Power Networks* is reconciled to that forecast by *AEMO* and is apportioned based on the measured *PV* growth rate at each *zone substation* and *connection point* over the last six months. Irrespective of the *PV* forecast value used, it is largely immaterial given that the final forecast used for planning purposes is reconciled to *AEMO's* state level forecast which takes into consideration the effects of *PV* and energy efficiency measures.

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

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.

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 (eg Holden post 2017).

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 condition*s (*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 ≤ 3*MVA*)	48 hours
Large *Substation* transformer (N > 3*MVA*)	7 days (installation of system spare)
11*kV* underground cable	24 hours
33*kV* underground cable	24 hours
33*kV* overhead *line*	12 hours
66*kV* underground cable	10 days
66*kV circuit breaker*	7 days
66*kV* 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 point*s (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 rating*[3] or *emergency rating*[4];
- the 50% *PoE* load under contingency conditions is greater than a zone substation's or *feeder's constraint capacity*[5]

[3] The *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.
[4] The *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.
[5] The *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.

- the normal load exceeds the *distribution feeder* exit's *normal rating*; or
- the voltage at the 11*kV* 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 and Table 4 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

<table>
<tr><th>Category</th><th>System</th><th>Planning Criteria</th><th>Forecast Basis</th><th>Line outage</th></tr>
<tr><td rowspan="2">L1</td><td rowspan="2">Interconnected ACR 66kV & 33kV sub-transmission lines</td><td>N</td><td rowspan="2">10% PoE</td><td rowspan="2">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.</td></tr>
<tr><td>N-1 (Continuous)</td></tr>
<tr><td rowspan="2">L1</td><td rowspan="2">Meshed sub-transmission lines (ie Metropolitan Area, Mt Barker / Mt Barker South) and Pirie / Bungama 33kV</td><td>N</td><td rowspan="2">10% PoE</td><td rowspan="2">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.</td></tr>
<tr><td>N-1 (Continuous)</td></tr>
<tr><td>L2</td><td>Radial sub-transmission line</td><td>N</td><td>10% PoE</td><td>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.</td></tr>
</table>

Table 3: Planning Criteria for Sub-transmission Systems

<table>
<tr><th>Category</th><th>System</th><th>Planning Criteria</th><th>Forecast Basis</th><th>Impact of transformer outage</th></tr>
<tr><td rowspan="2">S1</td><td rowspan="2">All 66/33kV and 66/11kV substations within the ACR</td><td>N</td><td rowspan="2">10% PoE</td><td rowspan="2">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.</td></tr>
<tr><td>N-1 (Continuous)</td></tr>
<tr><td rowspan="2">S2</td><td rowspan="2">Specific major zone substations, namely:
• Edinburgh
• LeFevre</td><td>N</td><td>10% PoE</td><td rowspan="2">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.</td></tr>
<tr><td>N-1 (Continuous)</td><td>50% PoE</td></tr>
<tr><td rowspan="2">S3</td><td rowspan="2">Substations supplying major industrial customers or critical commercial load regions, or where supply cannot be restored within 12 hours, namely:
• Elizabeth South
• Woodville
• North Adelaide
• Kilkenny
• Kent Town
• Norwood
• Direk
Substations where mobile substation can't be used (eg 66/33kV and 66/7.6kV substations)</td><td>N</td><td>10% PoE</td><td rowspan="2">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.</td></tr>
<tr><td>N-1 (+ feeder transfers) (ie contingency capacity)</td><td>50% PoE</td></tr>
<tr><td rowspan="2">S4</td><td rowspan="2">All other zone substations</td><td>N</td><td>10% PoE</td><td rowspan="2">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.</td></tr>
<tr><td>N-1 (+feeder transfers + 3 MVA Load at Risk Margin) (ie constraint capacity)</td><td>50% PoE</td></tr>
</table>

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.
		N-1		Supplies may be interrupted for a single feeder outage, but all should be restorable following transfer of load to adjoining substations, at 10% PoE demand, without causing any equipment to be loaded above emergency rating.
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 *AMP'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 33*kV* and 66*kV*)	Forecast
ElectraNet connection point capacity	Forecast
Voltage support	Forecast
VAr support	Forecast
Distribution *feeders* (eg 11*kV* and 7.6*kV*)	Forecast
19kV *SWER* systems	Historic
Distribution substation capacity	Historic
Quality of Supply minor works	Historic
Low Voltage mains capacity	Historic

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 2015/16 to 2024/25.

The costs assigned to each project are determined using a set of standard component or "unit" costs expressed in a nominal year's dollars. For the purposes of this plan, all values are expressed in 2013 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 2013 dollars) within the present regulatory period (2010 – 2015) 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 is further detailed within *SA Power Networks'* "Unit Cost Methodology version 2".

4. CAPACITY RELATED EXPENDITURE 2010-15

Within the present regulatory period, *SA Power Networks* has spent (on average) $ 97 million per financial year (in 2013 dollars) on capacity related augmentations of the network. Based on forecasts of expenditure over the 2014/15 financial year, by the end of the regulatory period, this average expenditure is forecast to be $91 million per annum (in 2013 dollars).

Since 2009, several factors have combined to reduce the customer forecasted demand growth at peak times. This includes the connection of over 580 *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 over this period was curtailed from 2012 to reflect these changes. These changes in customer demand have been factored into the 2015-20 demand forecast including the increase in *embedded PV generation*.

Within its 2009 submission, *SA Power Networks* submitted 33 projects with forecast expenditure in excess of $5 million.

Of these 33 major projects, *SA Power Networks* expects to complete 20 by the end of the 2010-15 period, with a further three in progress at the time of writing. The remaining ten projects have been deferred due to a reduction in load growth which has resulted in changes to the timing of the constraint the project was proposed to resolve or alternative customer initiated augmentations have enabled deferral of the proposed solution.

Table 7 below provides a summary of the major projects submitted within the 2009 regulatory submission and an indication of those completed, in progress or deferred while Figure 8 shows a comparison of *SA Power Networks'* capacity related expenditure over the 2010-15 period with the forecast expenditure in this area over the next 10 years.

Project Name	Region	Project Category	Planned Year	Estimated Cost ($ million[6])	Actual Cost ($ million)	Status	Reason for deferral / Comment
Cavan 66*kV* Alternative Supply	Metro North	Metro 66kV *Sub-transmission Lines*	2012	15.9	10.6	Completed	-
City West 275/66*kV Connection Point*	*Adelaide Central Region*	*Connection Points*	2011	105.6	76.4	Completed	-
Clare North *Connection Point*	Mid North	*Connection Points*	2010	6.9	6.8	Completed	-
Findon to Flinders Park 66*kV Line*	Metro West	Metro 66*kV Sub-transmission Lines*	2011	6.5	9.9	Completed	-
Flinders Park 66/11*kV Substation* Upgrade	Metro West	*Substations*	2013	7.5	-	Not commenced	Slower customer load growth – deferred post 2020.

[6] Values escalated from 2008 nominal dollars to those of construction year.

Project Name	Region	Project Category	Planned Year	Estimated Cost ($ million[6])	Actual Cost ($ million)	Status	Reason for deferral / Comment
Glenelg North 66*kV* Alternate Supply	Metro South	Metro 66*kV* *Sub-transmission Lines*	2015	7.0	2.4[7]	In Progress (to be completed in 2014/15)	-
Glynde 66/11*kV* *Substation*	Metro East	*Substations*	2012	13.0	1.0	In Progress	Slower customer load growth – deferred to 2016/17
Hackham 66/11*kV* *Substation*	Metro South	*Substations*	2010	10.5	9.2	Completed	-
Hahndorf 66/33*kV* *Substation* Upgrade	Eastern Hills	*Substations*	2013	6.7	2.0[8]	In Progress (to be completed in 2014/15)	Alternative solution implemented at Uraidla
Harrow 66/11*kV* *Substation* Upgrade	Metro East	*Substations*	2011	7.0	-	Not commenced	Slower customer load growth and deferred by *feeder* solution from North Adelaide post 2020.
Hope Valley 66/11*kV* *Substation* Upgrade	Metro East	*Substations*	2015	6.5	-	Not commenced	Slower customer load growth – deferred post 2020
Kadina East 132/33*kV* *Connection Point* Upgrade	Yorke Peninsula	*Connection Points*	2011	6.0	6.2	Completed	-
Keith to Wirrega Second 33*kV Line*	South East	Country *Sub-transmission Lines*	2015	10.1	6.0	Completed	Alternative non-network solution implemented at Bordertown.
Lucindale West 132/33*kV* *Connection Point*	South East	*Connection Points*	2014	6.0	-	Not commenced	Slower customer load growth – deferred post 2020
Morphett Vale East to Willunga Second 66*kV Line*	Metro South	Metro 66*kV* *Sub-transmission Lines*	2012	16.5	0.6[9]	In progress	Slower customer load growth - Possible non-*network* solution under investigation – deferred to 2016.
Morphettville 66/11*kV* *Substation* Upgrade	Metro South	*Substations*	2011	11.2	8.0	Completed	Alternate solution to defer Kingswood *sub* overload performed - deferral post 2020.
Mount Barker 66/11*kV* *Substation* Upgrade	Eastern Hills	*Substations*	2013	9.5	12.0	Completed	-

[7] Expenditure to date
[8] Expenditure to date
[9] Expenditure to date

Project Name	Region	Project Category	Planned Year	Estimated Cost ($ million[6])	Actual Cost ($ million)	Status	Reason for deferral / Comment
Mount Barker South 275/66*kV Connection Point*	Eastern Hills	*Connection Points*	2011	11.6	10.3	Completed	-
Munno Para 275/66*kV Connection Point*	Metro North	*Connection Points*	2014	7.4	2.9[10]	In Progress (to be completed in 2014/15)	-
North Adelaide 66/11*kV Substation* Upgrade	Metro East	*Substations*	2013	7.6	15.6	Completed	-
Northfield 66/11*kV Substation* Upgrade	Metro East	*Substations*	2015	6.5	-	Not commenced	Slower customer load growth – deferred post 2020
Northfield to Ingle Farm Second 66*kV Line*	Metro East	Metro 66*kV Sub-transmission Lines*	2015	7.3	7.0	Completed	-
Parafield Gardens West to Parafield Gardens Second 66*kV Line*	Metro North	Metro 66*kV Sub-transmission Lines*	2010	9.0	4.2	Completed	Alternate solution implemented - upgrade of *line* exits at Para *connection point*
Pinnaroo Power Station	Murraylands	Voltage Regulation	2014	11.0	-	Not commenced	Slower customer load growth – deferred post 2020
Post Office Place 66/11*kV Substation*	Adelaide Central Region	*Substations*	2014	22.0	-	Not commenced	Slower customer load growth – deferred post 2020
Queenstown 7.6*kV* to 11*kV* Conversion	Metro West	*Substations*	2012	11.5	-	Not commenced	Slower customer load growth – deferred post 2020
Salisbury South 66/11*kV Substation*	Metro North	*Substations*	2012	7.8	8.9	Completed	Alternate solution implemented – Parafield Gardens *Sub* Upgrade
Seaton 66/11kV Substation	Metro West	*Substations*	2014	12.0	-	Not commenced	Slower customer load growth – deferred post 2020
Two Wells 66/11*kV Substation*	Metro North	*Substations*	2014	7.6	0.8[11]	In progress	Expected completion in 2015.
Waterloo 132/33*kV Connection Point* Upgrade	Mid North	*Connection Points*	2013	7.3	7.6	Completed	-
Whyalla Terminal 132/33*kV Connection Point* Upgrade	Eyre Peninsula	*Connection Points*	2013	10.3	14.7	Completed	-

[10] Expenditure to date

[11] Expenditure to date

Project Name	Region	Project Category	Planned Year	Estimated Cost ($ million[6])	Actual Cost ($ million)	Status	Reason for deferral / Comment
Wingfield 66/11*kV* *Substation*	Metro West	*Substations*	2015	6.5	-	Not commenced	Slower customer load growth – deferred post 2020
Wudinna 132/66*kV* *Connection Point* Upgrade	Eyre Peninsula	*Connection Points*	2012	7.6	5.5	Completed	-

Table 7: 2009 Reset Submission Major Project List

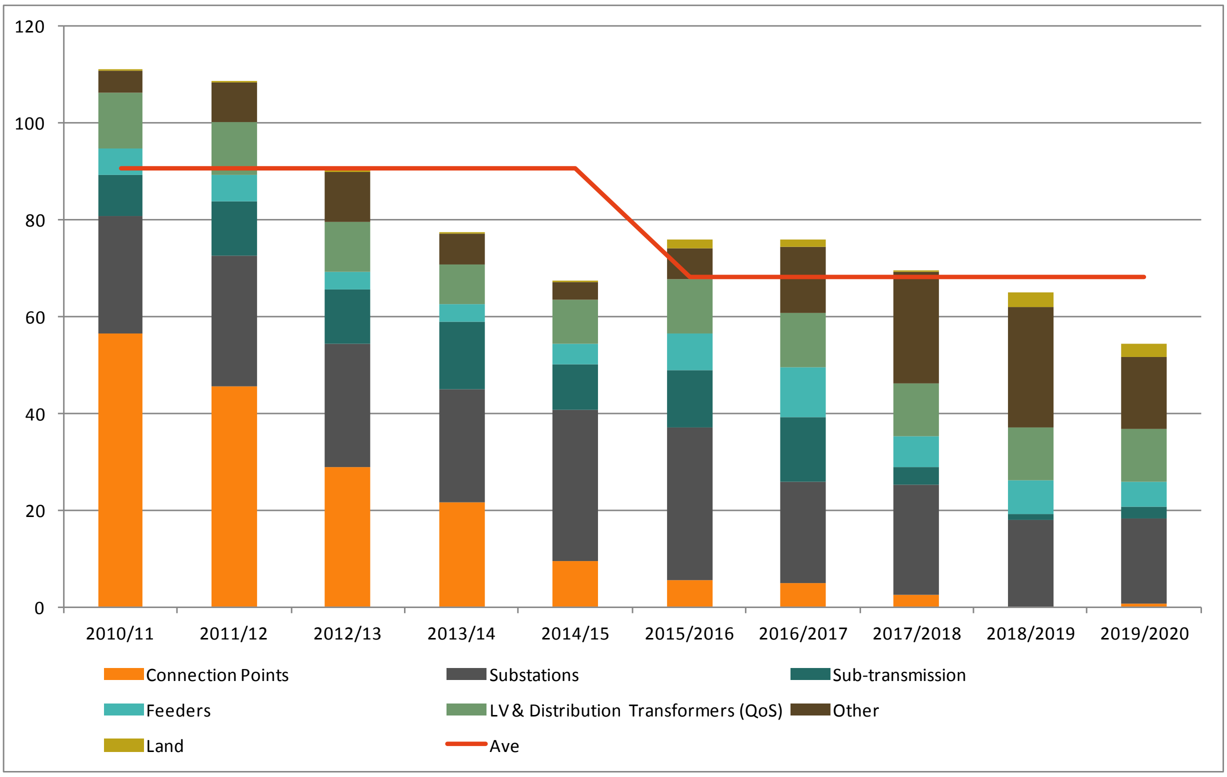


Figure 8: Historic and Forecast Expenditure by Area of Work (in 2013 dollars)

As can be seen from Figure 8, average expenditure within the 2015/16 to 2019/20 regulatory period is forecast to reduce from its persent levels of $91 million per annum to $68 million per annum. Forecast expenditure in the 2014/15 financial year of $67 million is also inline with this average expenditure over the forthcoming regulatory period. Slightly above average expenditure in the 2015/16 and 2016/17 periods is largely due to *connection point* works mandated by the *ETC*.

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-D*s 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 *DAC*) 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-rate[12] 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 point*s 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 66*kV* aerial *lines* within South Australia requires approval from the *Development Assessment Commission* (*DAC*), 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 *DAC* from these third parties, to the construction of any new overhead 66*kV lines*. This may reduce the feasibility of many of *SA Power Networks'* favoured options, involving the construction of new or the upgrading of existing overhead 66*kV lines* where these works require the installation of additional 66*kV* 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.

[12] The 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*.

The costs included within the capital plan and quoted in the body of this report are predominantly based on the use of overhead 66*kV 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 66*kV 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 66*kV* 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 66*kV lines*, the addition of any new poles will require approval from *DAC*, 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 $5 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 $5 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 *AMP* 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 66/11*kV mobile substations* mounted on trailers. The long term *contingency capacity* for metropolitan 66/11*kV 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 3*MVA* 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 point*s, or to provide firm N-2 capacity to the *ACR*);
- Changes in council / *DAC* 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 *DNSP*s 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 $5 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 2005 - 2010 and 2010 - 2015). These trials however, are yet to consistently show any clear medium to long term ability to defer capital works, either from a load or economic perspective where funding for such initiatives is limited to the deferral of the available *network* augmentation solutions.

During the present regulatory period (2010 – 15), *SA Power Networks* has instituted one non-network solution to resolve an identified *network* constraint. This example is located at Bordertown in the far east of the state near the Victorian border where constraints were identified for both the radial 33kV *line* supplying Bordertown *zone substation* and the transformer capacity at Bordertown *zone substation* itself. The non-network solution implemented has seen the construction of a third party owned, 4*MW* power station connected to Bordertown *zone substation* via an express 11kV *feeder* exit. The *NSSA* is valid for nine years.

As demand side initiatives become more widespread, economically viable and dispatchable (eg load curtailment), this should enable *DNSP*s to reduce peak demand at call, which may result in some deferment 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 $5 million, only one or two of which has 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* re-enforcement 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 point*s 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 recent 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 network*s through targeted *network* augmentations. The conclusion of this investigation[13] 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.

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

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. However the installation and connection of *embedded generation* poses a new set of issues for the *distribution network*.

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, *DAC* etc); and
5. 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 *DNSP*s in considering these options.

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:

11. system fault levels;
12. thermal ratings of equipment;
13. system stability;
14. reverse power flow capability of the *OLTCs*;
15. *line* drop compensation;
16. steady state voltage rise;
17. losses;
18. power quality; and
19. 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 66*kV 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 6.0*MW* 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:

20.plant acquisition costs (including unit(s) for redundancy);

21. site acquisition;
22. connection costs, or connection interfaces;
23. protection requirements;
24. environmental compliance;
25. provision of a medium voltage transformer installation to step the generator voltage up to *network nominal voltages* (eg 11*kV*, 33*kV*, 66*kV*);
26. maintenance & servicing costs; and
27. 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:

28. potential availability charges (these will vary on the generation capacity installed).
29. likely run time hours per annum and the associated operational charges to *SA Power Networks*.
30. capital cost to *SA Power Networks* to facilitate connection of the generator to the *network*.
31. cost of procuring the installation should the third party become insolvent.
32. 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 been included within the capital plan where performance of a preliminary *RIT-D* analysis has shown 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'* 2015 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 point*s 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 2015 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 33*kV* or 66*kV* bus works, new *circuit breakers* and 66*kV* or 33*kV 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 2013.

6.3 Metropolitan 66kV Sub-transmission Lines

SA Power Networks' metropolitan 66*kV* sub-transmission *network* consists of four islanded 66*kV* meshed systems that distribute the customer demand from *ElectraNet's connection point*s 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 66*kV 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 66*kV line* outage or a single *ElectraNet* transformer outage (*N-1* condition) under 10% *PoE* conditions. The *Electricity Transmission Code* refers to these *connection point*s 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 66*kV 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 66*kV 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 66*kV 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'* 66*kV lines* are designed and operated for an ultimate *line* conductor temperature of 100^{o} Celsius (however not all *lines* are designed for operation at this temperature). The typical restoration time following a metropolitan 66*kV 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 66*kV line* construction is preferred for the augmentation of these *networks* where technically feasible, due to the much higher cost of 66*kV* 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 66*kV 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 66*kV 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 30*MVA* or where a *RIT-D* shows a positive net market benefit.

6.4 Country 66kV and 33kV Sub-transmission Lines

SA Power Networks' country 66*kV* and 33*kV 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 33*kV* or 66*kV 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 33*kV sub-transmission lines* which do exist within country regions, are planned to a *N-1* standard as per the metropolitan 66*kV 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 11*kV* switchgear to achieve higher fault level or load ratings. Sometimes it is necessary to replace fixed-tap transformers with *OLTC* enabled transformers or install 11*kV* 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'* 66*kV* and 33*kV 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 11*kV* regulators.

As the load increases on long 66*kV* and 33*kV 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 66*kV* or 33*kV lines* with larger, higher capacity / lower loss conductors;
3. Install 66*kV*, 33*kV*, or 11*kV* voltage regulators to provide additional voltage regulation; or
4. Establish new *connection point*s to reduce the length and/or load on particular *sub-transmission lines*.

6.7 11kV and 7.6kV Feeders

SA Power Networks' 11*kV* and 7.6*kV 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* 11*kV* or 7.6*kV 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 11*kV* or 7.6*kV feeder's* capacity as loads increase:

1. Upgrade the existing *feeder* exit cable;
2. Construct a new 11*kV* or 7.6*kV feeder* to reduce the load on the existing *feeder*;
3. Convert a 7.6*kV feeder* to 11*kV* 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 19*kV* or 6.35*kV* 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 19*kV*) are typically supplied directly from the rural 33*kV sub-transmission network*, however a handful of 6.35*kV* systems exist, supplied by metro 11*kV 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 33*kV* or 11*kV feeder* and relocate the isolating transformer downstream of its existing location; or
4. convert the entire *SWER* system to three phase 33*kV* or 11*kV*.

NB: *SA Power Networks* has a minimal number of 6.35*kV 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 substation*s convert the voltage from *HV* to *LV* and may be connected to *SA Power Networks' network* at 33*kV*, 19*kV*, 11*kV*, 7.6*kV* or 6.35*kV*. 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 66*kV connection point*s and 0.90 lagging at 33*kV connection point*s. In addition, the *Electricity Transmission Code* (*ETC*) allows *ElectraNet* to request a higher *power factor* at *connection point*s 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 66*kV*, 33*kV* or 11*kV* 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 kVAr 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 point*s.

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 inconjunction 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 substation*s 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. For further information regarding the management of the *CBD*'s duct and manhole systems, refer to the *CBD Asset Management Plan*.

7. CAPITAL PROJECT DRIVER CATEGORIES FOR THE 2015-20 PERIOD

Whilst the majority of projects contained within this *AMP* 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 *AMP* 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:

(i) New Greenfield developments (where little or no infrastructure exists today);

(ii) Continued development of new housing areas or infill areas;

(iii) Agricultural or mining developments; and

(iv) General demand growth.

(v) 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, 63% can be categorised as being independent of the load forecast. Projects beyond 2020 are more likely to be dependant on future demand growth. A consolidated list of all projects in the 2015-20 period and their driver is contained in section 0.

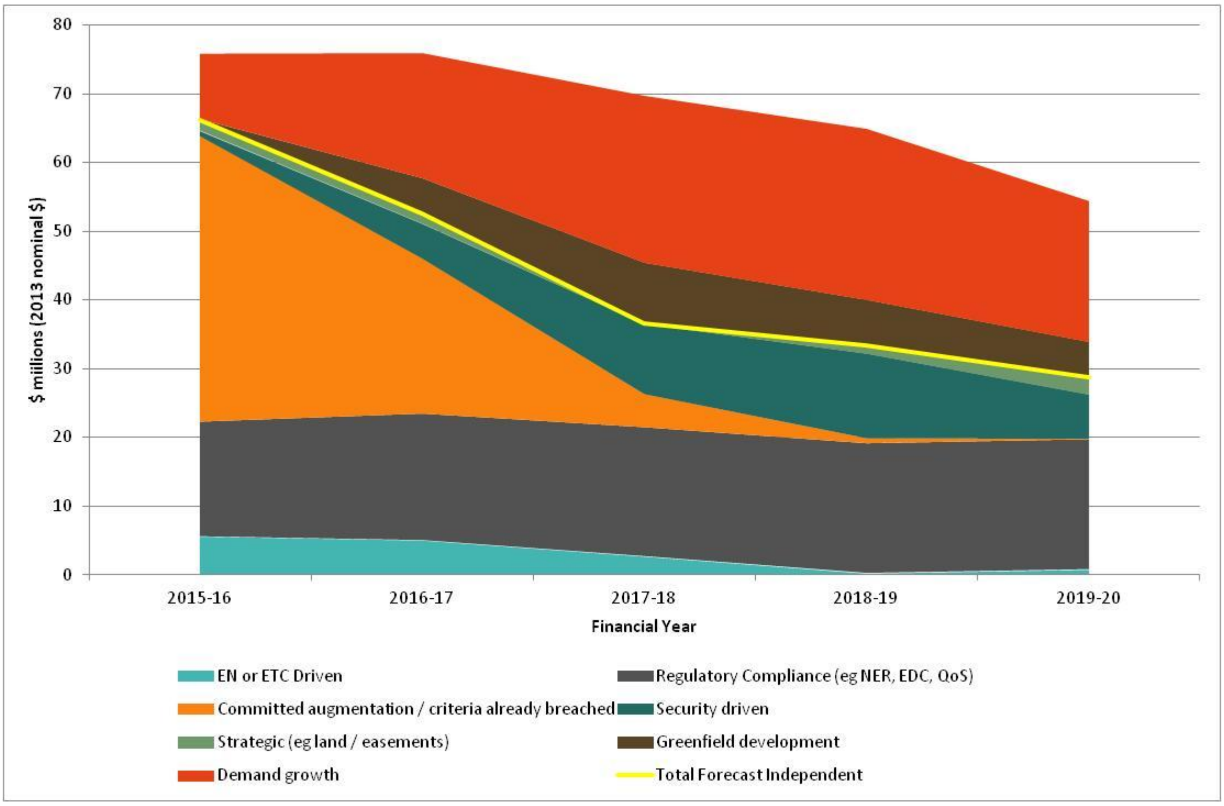


Figure 9: AMP Expenditure Breakdown by Forecast Dependent and Forecast Independent Project Categories.

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 4% 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 580 *MW* 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 27% 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 2013/14. As such, the performance of or need for these projects is independent of future customer demand growth and includes the majority of those projects in progress and due for completion in 2015/16.

This category constitutes approximately 20.5% 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 *AMP*, 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 *AMP*.

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 2% of the proposed capital expenditure within the forthcoming regulatory period.

7.2 Growth dependent project categories

Combined, these categories constitute approximately 37% 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 2015-20 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 AMP. 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 Asset Management Plan - Manual 15 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 one 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 10 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 Asset Management Plan - Manual 15, these are mico 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 10: 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 11: 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 12). 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 12: Consequence Scoring Matrix.

8.3 Risk Categories

The risk ranking methodology employed considers risks (ie likelihhod 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 SF_6 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:

33. Operating voltage;
34. Exposure to live components;
35. Consequence of equipment failure (from a safety perspective only – other consequences may be considered within the other categories);
36. Accessibility by external parties (eg unauthorised access); and
37. 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:

38. the proximity of equipment to water courses;
39. the nature and effect of any fluid insulating mediums' release on the environment (eg SF_6, PCBs, mineral oil or FR3); and
40. 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:

41. Nature of constraint (ie N, N-1 etc);
42. Operating voltage;
43. Equipment failure type considered (transformer, conductor, cable, CB) - typically the worst credible contingent event only will be considered;
44. Load at risk at time of peak (ie MW);
45. Hours per annum at risk;

46. Instantaneous customer numbers at risk;
47. Customer numbers without supply following restoration of healthy transformers;
48. Customer numbers without supply following the performance of feeder transfers;
49. Customer numbers without supply following connection of mobile substation;
50. Total duration of outage (hours);
51. Availability of spares; and
52. 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 proposed total capital expenditure over the 10 year period covered by this *AMP*. Further information on the projects which constitute this expenditure are detailed within the *Regional Development Plans* and Sections 25 and 26 for the *QoS* and *SWER* plans whilst Table 9 provides a summary list of all projects and expenditures over the 2015-20 period by region and project name.

		2010-15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
Connection Points		162.1	5.55	4.98	2.66	0.20	0.82	0.94	3.35	7.17	4.14	0.20
Substations		131.2	31.55	20.80	22.74	17.80	17.43	21.72	18.74	19.04	16.30	20.87
Sub-transmission		54.7	11.80	13.54	3.56	1.08	2.36	7.43	10.36	4.55	10.64	10.59
Distribution Feeders		22.1	7.66	10.32	6.33	6.98	5.14	5.95	6.04	3.32	3.76	1.93
LV and Distribution Transformers (*QoS*)		50.5	11.06	11.06	11.06	11.06	11.06	11.06	11.06	11.06	11.06	11.06
LV Two Way Network		-	2.53	4.08	4.51	4.74	4.72	4.72	4.72	4.72	4.72	4.72
Security of Supply		-	0.11	4.47	9.39	11.51	6.48	0.00	0.00	0.00	0.00	0.00
Other	*NER* Compliance (*PF*, load shedding) Network Planning, Strategic Network Capacity Voltage Regulation	33.0	3.89	5.05	9.10	8.60	3.71	6.57	8.82	5.35	3.61	6.55
Land & Easements		0.2	1.72	1.63	0.37	2.96	2.68	0.21	0.25	0.25	0.19	0.08
Totals		**453.9**	**75.86**	**75.94**	**69.72**	**64.91**	**54.40**	**58.60**	**63.34**	**55.47**	**54.42**	**56.00**

Table 8: Forecast Capacity Related Expenditure[14]

[14] All values are expressed in millions and 2013 nominal dollars.

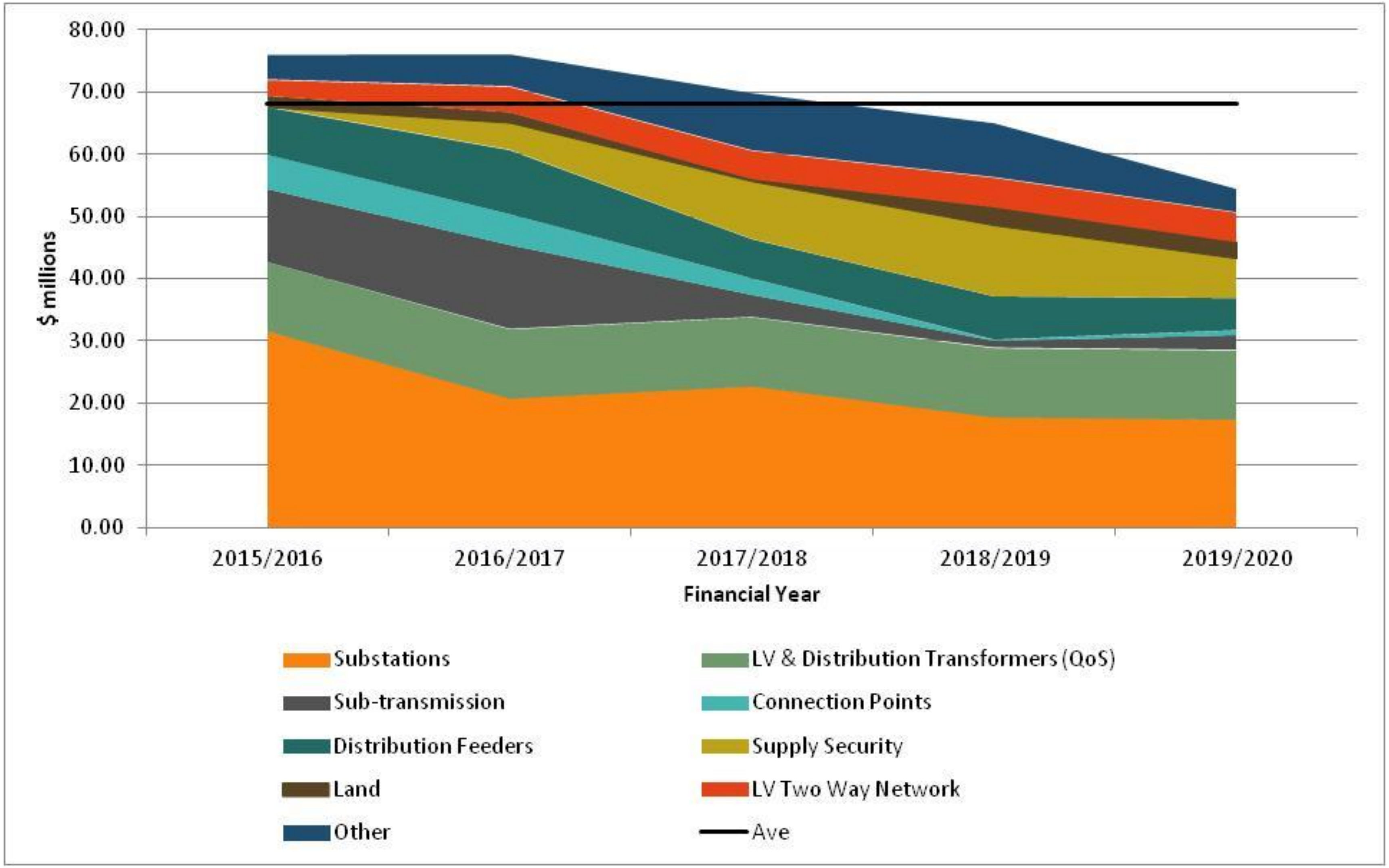


Figure 13: Forecast Expenditure by Area of Work per annum (in 2013 dollars)

2015-20 Project List

Project Name	Project No	Region	Project Type	Project Driver	Expenditure ($ million) 2015/16	2016/17	2017/18	2018/19	2019/20	2015-20 Total
Barossa South Sub Upgrade (Mod 2)	213	Barossa	Substation Capacity - Existing	Committed augmentation / criteria already breached	1.77	1.72	-	-	-	**3.48**
Dorrien 33/11kV substation upgrade	365	Barossa	Substation Capacity - Existing	Committed augmentation / criteria already breached	2.79	-	-	-	-	**2.79**
Lyndoch East Substation (2 x Mod 6)	363	Barossa	Substation Capacity - New	Continued development	-	0.02	1.99	1.97	-	**3.98**
Lyndoch Feeder Tie Switch Upgrade	754	Barossa	Distribution Feeders - Country	Committed augmentation / criteria already breached	0.09	-	-	-	-	**0.09**
Mt Crawford Recloser Upgrade	923	Barossa	Distribution Feeders - Country	Committed augmentation / criteria already breached	-	-	0.07	0.07	-	**0.15**
Rosedale Recloser Upgrade	972	Barossa	Distribution Feeders - Country	Committed augmentation / criteria already breached	0.07	0.07	-	-	-	**0.15**
Stockwell Sub Upgrade (No2 Mod 2 Substation)	153	Barossa	Substation Capacity - Existing	General demand growth	-	-	0.02	1.94	1.92	**3.88**

Project Name	Project No	Region	Project Type	Project Driver	Expenditure ($ million) 2015/16	2016/17	2017/18	2018/19	2019/20	2015-20 Total
East Tce NGM Upgrade	901	CBD	NER Compliance (PF, load shedding)	Regulatory Compliance (eg NER, EDC, QoS)	-	0.10	0.10	-	-	**0.20**
Eliza Street Cable Duct works	913	CBD	Substation Capacity - New	Strategic (eg land / easements)	-	-	-	1.23	2.45	**3.68**
Birdwood Tee-Birdwood 33kV line uprate	736	Eastern Hills	Sub-transmission Capacity - Country	Committed augmentation / criteria already breached	0.07	0.02	-	-	-	**0.08**
Chain of Ponds TF Upgrade	855	Eastern Hills	Substation Capacity - Existing	Continued development	-	-	-	0.04	0.40	**0.44**
Gumeracha TF Upgrade - Upgrade with a 0.5MVA Pole Top TF	854	Eastern Hills	Substation Capacity - Existing	Committed augmentation / criteria already breached	0.32	-	-	-	-	**0.32**
Gumeracha Weir 11kV feeder tie to Hermitage 11kV	883	Eastern Hills	Distribution Feeders - Country	Committed augmentation / criteria already breached	0.11	0.11	-	-	-	**0.23**
Houghton Pole 7.6kV Top Regs Upgrade	713	Eastern Hills	Substation Capacity - Existing	General demand growth	-	-	0.15	0.15	-	**0.30**
Houghton Recloser Upgrade	918	Eastern Hills	Distribution Feeders - Country	Committed augmentation / criteria already breached	0.07	0.07	-	-	-	**0.15**

Project Name	Project No	Region	Project Type	Project Driver	Expenditure ($ million) 2015/16	2016/17	2017/18	2018/19	2019/20	2015-20 Total
Meadows Substation Upgrade	220	Eastern Hills	Substation Capacity - Existing	General demand growth	-	-	0.07	0.12	2.15	**2.33**
Mount Barker East Substation - New	611	Eastern Hills	Substation Capacity - New	Greenfield development	-	-	-	2.52	2.52	**5.04**
Mount Barker South TF2 Connection Point Upgrade	635	Eastern Hills	Connection Point Capacity - Existing	General demand growth	-	-	-	-	0.06	**0.06**
Mount Barker Substation - New Summit 11kV Feeder and MTB-10 and MTB-12 backbone restring	870	Eastern Hills	Distribution Feeders - Country	Continued development	-	1.35	1.35	-	-	**2.69**
Nairne Substation - Nairne 11kV - Hay Valley 11kV feeder tie	872	Eastern Hills	Distribution Feeders - Country	Committed augmentation / criteria already breached	0.18	0.18	-	-	-	**0.35**
Uraidla N-1 Project - Hahndorf Alternative	858	Eastern Hills	Substation Capacity - Existing	Committed augmentation / criteria already breached	0.59	-	-	-	-	**0.59**
Uraidla-Piccadilly 33kV Restring	884	Eastern Hills	Sub-transmission Capacity - Country	General demand growth	-	-	0.05	0.42	0.38	**0.84**

					Expenditure ($ million)					
Project Name	**Project No**	**Region**	**Project Type**	**Project Driver**	**2015/16**	**2016/17**	**2017/18**	**2018/19**	**2019/20**	**2015-20 Total**
Verdun Substation Upgrade	712	Eastern Hills	Substation Capacity - Existing	General demand growth	0.03	0.10	0.88	0.81	-	**1.82**
Verdun Tee-Mylor 33kV Restring	885	Eastern Hills	Sub-transmission Capacity - Country	General demand growth	-	-	-	-	0.05	**0.05**
Caralue Recloser Upgrade	924	Eyre Peninsula	Distribution Feeders - Country	Committed augmentation / criteria already breached	-	-	0.07	0.07	-	**0.15**
Little Swamp Capacity Upgrade (Mod 7)	746	Eyre Peninsula	Substation Capacity - Existing	Committed augmentation / criteria already breached	0.27	0.25	-	-	-	**0.52**
Minnipa Recloser Upgrade	936	Eyre Peninsula	Distribution Feeders - Country	Committed augmentation / criteria already breached	-	-	0.07	0.07	-	**0.15**
Port Lincoln Marina (New Mod 1 Sub)	505	Eyre Peninsula	Substation Capacity - New	Committed augmentation / criteria already breached	0.81	-	-	-	-	**0.81**
Port Neill SWER Conversion	861	Eyre Peninsula	Distribution Feeders - Country	Continued development	-	0.25	1.25	2.00	1.00	**4.50**

Project Name	Project No	Region	Project Type	Project Driver	Expenditure ($ million) 2015/16	2016/17	2017/18	2018/19	2019/20	2015-20 Total
Port Neill Voltage Regulation	385	Eyre Peninsula	Voltage Regulation	Committed augmentation / criteria already breached	0.04	0.04	-	-	-	**0.07**
Warramboo Recloser Upgrade	935	Eyre Peninsula	Distribution Feeders - Country	Committed augmentation / criteria already breached	-	-	0.07	0.07	-	**0.15**
Cape Jervis Sub Upgrade (Mod 3)	235	Fleurieu Peninsula	Substation Capacity - Existing	Committed augmentation / criteria already breached	0.88	0.88	-	-	-	**1.77**
Emu Bay 11kV regulators ex Kingscote	882	Fleurieu Peninsula	Voltage Regulation	General demand growth	-	-	0.03	0.32	0.28	**0.63**
Kingscote 4th Generator	926	Fleurieu Peninsula	Substation Capacity - Existing	Committed augmentation / criteria already breached	2.05	-	-	-	-	**2.05**
Kingscote Power Station NGM	914	Fleurieu Peninsula	NER Compliance (PF, load shedding)	Regulatory Compliance (eg NER, EDC, QoS)	0.10	0.10	-	-	-	**0.20**
Myponga to Square Water Hole 66kV line	898	Fleurieu Peninsula	Supply Security	Security driven	0.11	3.71	7.20	7.20	3.60	**21.81**
Parndana 11kV regulators	881	Fleurieu Peninsula	Voltage Regulation	General demand growth	-	0.03	0.26	0.23	-	**0.52**

					Expenditure ($ million)					
Project Name	Project No	Region	Project Type	Project Driver	2015/16	2016/17	2017/18	2018/19	2019/20	2015-20 Total
Penneshaw 33kV substation 20MVA voltage regulator	515	Fleurieu Peninsula	Voltage Regulation	General demand growth	-	-	-	-	0.04	**0.04**
Salt Cliffs Recloser Upgrade	971	Fleurieu Peninsula	Distribution Feeders - Country	Committed augmentation / criteria already breached	-	0.07	0.07	-	-	**0.15**
Square Water Hole 11kV voltage regs	724	Fleurieu Peninsula	Substation Capacity - Existing	Continued development	-	0.12	0.12	-	-	**0.23**
Yankalilla Substation - Normanville 11kV Feeder Tie	891	Fleurieu Peninsula	Distribution Feeders - Country	Continued development	-	-	0.06	0.57	0.51	**1.14**
Campbelltown Substation 66kV Section CB	290	Metro East	Supply Security	Security driven	-	-	-	0.64	0.64	**1.28**
Glynde Substation - New Substation & 66kV line	161	Metro East	Substation Capacity - New	General demand growth	4.76	9.33	4.70	-	-	**18.79**
Golden Grove North Feeder Upgrade	867	Metro East	Distribution Feeders - Metro	Committed augmentation / criteria already breached	0.31	0.31	-	-	-	**0.62**
Golden Grove Substation - Wynn Vale West 11kV and Greenwith 11kV feeder tie	705	Metro East	Distribution Feeders - Metro	General demand growth	-	-	-	0.32	0.32	**0.64**

Project Name	Project No	Region	Project Type	Project Driver	Expenditure ($ million)					
					2015/16	2016/17	2017/18	2018/19	2019/20	2015-20 Total
Northfield NGM Upgrade	662	Metro East	NER Compliance (PF, load shedding)	Regulatory Compliance (eg NER, EDC, QoS)	-	0.10	0.10	-	-	**0.20**
Northgate Land Purchase	859	Metro East	Substation Capacity - New	Strategic (eg land / easements)	1.50	1.50	-	-	-	**3.00**
Norwood-Kent Town 66kV Line Upgrade	288	Metro East	Sub-transmission Capacity - Metro	General demand growth	-	-	-	0.05	0.05	**0.09**
Elizabeth South Sub - Salisbury Park new 11kV feeder	379	Metro North	Distribution Feeders - Metro	General demand growth	-	0.07	0.15	1.55	1.47	**3.24**
Evanston Gardens Substation	731	Metro North	Substation Capacity - New	Greenfield development	-	-	-	0.10	2.59	**2.69**
Gawler East New Substation	33	Metro North	Substation Capacity - New	Greenfield development	0.16	3.95	7.75	3.95	-	**15.82**
Munno Para Connection Point	333	Metro North	Connection Point Capacity - New	EN or ETC Driven	2.01	-	-	-	-	**2.01**
Two Wells New Mod 1 Substation and Virginia 66kV line	69	Metro North	Substation Capacity - New	Committed augmentation / criteria already breached	4.99	-	-	-	-	**4.99**
Aldinga to Willunga Pole Upgrade	895	Metro South	Sub-transmission Capacity - Metro	Committed augmentation / criteria already breached	0.16	1.40	1.40	-	-	**2.95**
Ascot Park Sub 66kV Line CBs	561	Metro South	Supply Security	Security driven	-	-	-	1.24	1.24	**2.48**

Project Name	Project No	Region	Project Type	Project Driver	Expenditure ($ million) 2015/16	2016/17	2017/18	2018/19	2019/20	2015-20 Total
Clarendon 11kV feeder tie	122	Metro South	Substation Capacity - Existing	Committed augmentation / criteria already breached	0.29	0.29	-	-	-	**0.58**
Glenelg North 2nd line - Morphettville to Plympton tee to Glenelg North	10	Metro South	Sub-transmission Capacity - Metro	Committed augmentation / criteria already breached	0.25	-	-	-	-	**0.25**
Kangarilla Recloser Upgrade	966	Metro South	Distribution Feeders - Metro	Committed augmentation / criteria already breached	0.07	0.07	-	-	-	**0.15**
Maslin Beach Substation (New)	649	Metro South	Substation Capacity - New	Continued development	-	-	0.28	0.33	4.24	**4.86**
McLaren Flat 11kV Feeder Backbone Upgrade	954	Metro South	Distribution Feeders - Metro	General demand growth	0.21	0.21	-	-	-	**0.42**
McLaren Flat Sub Upgrade (Second Mod 1)	123	Metro South	Substation Capacity - Existing	Committed augmentation / criteria already breached	2.60	-	-	-	-	**2.60**
Morphett Vale East to Clarendon 66kV Line Uprate	435	Metro South	Sub-transmission Capacity - Metro	Committed augmentation / criteria already breached	1.89	1.89	-	-	-	**3.79**

					Expenditure ($ million)					
Project Name	**Project No**	**Region**	**Project Type**	**Project Driver**	**2015/16**	**2016/17**	**2017/18**	**2018/19**	**2019/20**	**2015-20 Total**
Morphettville - Plympton Protection Upgrade	927	Metro South	Sub-transmission Capacity - Metro	Committed augmentation / criteria already breached	0.54	-	-	-	-	**0.54**
Nilpeena Avenue 11kV feeder exit upgrade	659	Metro South	Distribution Feeders - Metro	General demand growth	-	0.18	0.18	-	-	**0.36**
Oaklands new 11kV feeder	964	Metro South	Distribution Feeders - Metro	General demand growth	0.41	0.92	0.50	-	-	**1.84**
Oaklands Sub 66kV Line CBs	538	Metro South	Supply Security	Security driven	-	-	1.26	1.26	-	**2.51**
Port Noarlunga to Aldinga Number 2 66kV Line	599	Metro South	Sub-transmission Capacity - Metro	Committed augmentation / criteria already breached	7.76	7.37	-	-	-	**15.13**
Port Stanvac - Noarlunga Centre conductor upgrade	974	Metro South	Sub-transmission Capacity - Metro	General demand growth	-	-	0.05	0.05	1.04	**1.15**
Port Stanvac to Noarlunga Centre Line Uprate	900	Metro South	Sub-transmission Capacity - Metro	General demand growth	0.04	0.37	0.37	-	-	**0.78**
Blackpool to Fulham Water Crossing Upgrade	896	Metro West	Sub-transmission Capacity - Metro	Committed augmentation / criteria already breached	0.10	0.10	-	-	-	**0.20**

Project Name	Project No	Region	Project Type	Project Driver	Expenditure ($ million) 2015/16	2016/17	2017/18	2018/19	2019/20	2015-20 Total
Cavan Substation - New 11kV feeder	694	Metro West	Distribution Feeders - Metro	Committed augmentation / criteria already breached	0.65	0.65	-	-	-	**1.30**
Cheltenham 7.6kV Feeder Conversion to 11kV	555	Metro West	Distribution Feeders - Metro	Continued development	2.19	2.19	-	-	-	**4.38**
Dry Creek Generator Demand Management	928	Metro West	Sub-transmission Capacity - Metro	General demand growth	-	-	-	-	0.13	**0.13**
Glanville to Queenstown Water Crossing Upgrade	897	Metro West	Sub-transmission Capacity - Metro	Committed augmentation / criteria already breached	0.10	0.10	-	-	-	**0.20**
New Osborne NGM Upgrade	902	Metro West	NER Compliance (PF, load shedding)	Regulatory Compliance (eg NER, EDC, QoS)	-	-	-	0.10	0.10	**0.20**
Seaton (new) 66/11kV Substation	667	Metro West	Substation Capacity - New	Greenfield development	-	-	-	-	0.07	**0.07**
Woodville South 7.6kV Feeder Load Relief (convert part feeder to 11kV)	864	Metro West	Distribution Feeders - Metro	Continued development	0.28	0.28	-	-	-	**0.55**
Clare 33/11kV substation upgrade	374	Mid North	Substation Capacity - Existing	Agricultural or mining development	-	0.03	3.09	3.06	-	**6.18**

					Expenditure ($ million)					
Project Name	**Project No**	**Region**	**Project Type**	**Project Driver**	**2015/16**	**2016/17**	**2017/18**	**2018/19**	**2019/20**	**2015-20 Total**
Freeling to Kapunda 33kV line uprate	739	Mid North	Sub-transmission Capacity - Country	Continued development	0.02	0.23	0.20	-	-	**0.45**
Gawler Belt 33/11kV Substation Upgrade (second Mod 1)	596	Mid North	Substation Capacity - Existing	Committed augmentation / criteria already breached	2.54	-	-	-	-	**2.54**
George Town 33/11kV Transformer Station Upgrade (Mod 7)	747	Mid North	Substation Capacity - Existing	General demand growth	-	-	-	0.03	0.27	**0.30**
Hamley Bridge Substation Upgrade (Mod 3)	677	Mid North	Substation Capacity - Existing	General demand growth	-	0.05	0.92	0.87	-	**1.84**
Kapunda Sub Upgrade (second Mod 1)	674	Mid North	Substation Capacity - Existing	Committed augmentation / criteria already breached	1.95	0.19	-	-	-	**2.14**
Mallala sub upgrade	615	Mid North	Substation Capacity - Existing	Committed augmentation / criteria already breached	1.45	1.41	-	-	-	**2.86**
Templers - Wasleys - Mallala 33kV Voltage Regulation	395	Mid North	Voltage Regulation	General demand growth	-	-	-	0.28	0.28	**0.55**

Project Name	Project No	Region	Project Type	Project Driver	Expenditure ($ million)					
					2015/16	2016/17	2017/18	2018/19	2019/20	2015-20 Total
Wasleys - Mallala 33kV Line Uprate	765	Mid North	Sub-transmission Capacity - Country	General demand growth	-	-	0.03	0.28	0.26	**0.57**
Waterloo - Riverton Tee 33kV Line Uprate	761	Mid North	Sub-transmission Capacity - Country	General demand growth	-	0.01	0.11	0.10	-	**0.21**
Geranium to Lameroo 33kV line uprate	738	Murraylands	Sub-transmission Capacity - Country	Committed augmentation / criteria already breached	0.05	0.50	0.45	-	-	**0.99**
Gumpark Recloser Upgrade	931	Murraylands	Distribution Feeders - Country	Committed augmentation / criteria already breached	-	-	0.07	0.07	-	**0.15**
Karoonda Recloser Upgrade	967	Murraylands	Distribution Feeders - Country	Committed augmentation / criteria already breached	0.07	0.07	-	-	-	**0.15**
Lameroo New 33kV Pole Top Regulators	619	Murraylands	Voltage Regulation	General demand growth	0.39	0.39	-	-	-	**0.78**
Mypolonga Substation Upgrade	489	Murraylands	Substation Capacity - Existing	General demand growth	-	0.05	1.04	0.99	-	**2.08**

Project Name	Project No	Region	Project Type	Project Driver	Expenditure ($ million) 2015/16	2016/17	2017/18	2018/19	2019/20	2015-20 Total
Narrung Recloser Upgrade	930	Murraylands	Distribution Feeders - Country	Committed augmentation / criteria already breached	-	-	0.07	0.07	-	**0.15**
Northern Heights 11kV Feeder	696	Murraylands	Distribution Feeders - Country	Committed augmentation / criteria already breached	-	0.50	0.50	-	-	**1.00**
Purnong Recloser Upgrade	973	Murraylands	Distribution Feeders - Country	Committed augmentation / criteria already breached	0.07	0.07	-	-	-	**0.15**
Sherlock to Geranium 33kV line uprate	734	Murraylands	Sub-transmission Capacity - Country	Committed augmentation / criteria already breached	0.05	0.48	0.48	-	-	**1.00**
Tailem Bend to Sherlock 33kV line uprate	737	Murraylands	Sub-transmission Capacity - Country	Committed augmentation / criteria already breached	0.05	0.41	0.41	-	-	**0.87**
Taliem Bend East Recloser Upgrade	925	Murraylands	Distribution Feeders - Country	Committed augmentation / criteria already breached	-	-	-	0.07	0.07	**0.15**
Teal Flat new 33kV Pole Top Voltage Regulators	15	Murraylands	Voltage Regulation	General demand growth	0.36	0.36	-	-	-	**0.72**

					Expenditure ($ million)					
Project Name	**Project No**	**Region**	**Project Type**	**Project Driver**	**2015/16**	**2016/17**	**2017/18**	**2018/19**	**2019/20**	**2015-20 Total**
Glossop Substation - 11kV feeder restring	894	Riverland	Distribution Feeders - Country	Committed augmentation / criteria already breached	0.23	-	-	-	-	**0.23**
Paringa 66/33kV Sub Upgrade	929	Riverland	Substation Capacity - Existing	Committed augmentation / criteria already breached	2.00	-	-	-	-	**2.00**
Pike River Recloser Upgrade	968	Riverland	Distribution Feeders - Country	Committed augmentation / criteria already breached	0.07	0.07	-	-	-	**0.15**
Swan Reach 66/33kV Sub Upgrade	916	Riverland	Substation Capacity - Existing	General demand growth	-	-	0.05	1.25	1.20	**2.50**
Cape Jaffa Substation	571	South East	Substation Capacity - New	Greenfield development	0.10	1.19	1.15	-	-	**2.44**
Glencoe Substation Upgrade	75	South East	Substation Capacity - New	Committed augmentation / criteria already breached	1.04	1.00	-	-	-	**2.04**
Marcollat Recloser Upgrade	917	South East	Distribution Feeders - Country	Committed augmentation / criteria already breached	0.07	0.07	-	-	-	**0.15**

					Expenditure ($ million)					
Project Name	**Project No**	**Region**	**Project Type**	**Project Driver**	**2015/16**	**2016/17**	**2017/18**	**2018/19**	**2019/20**	**2015-20 Total**
Maria Recloser Upgrade	919	South East	Distribution Feeders - Country	Committed augmentation / criteria already breached	0.07	0.07	-	-	-	**0.15**
Mount Burr Upgrade (Mod 7)	745	South East	Substation Capacity - Existing	Committed augmentation / criteria already breached	0.27	0.25	-	-	-	**0.52**
Mount Salt Recloser Upgrade	969	South East	Distribution Feeders - Country	Committed augmentation / criteria already breached	0.07	0.07	-	-	-	**0.15**
Mount Schank 33kV Voltage Regulator	492	South East	Voltage Regulation	Regulatory Compliance (eg NER, EDC, QoS)	-	-	-	-	0.04	**0.04**
Mount Schank North Substation	197	South East	Substation Capacity - New	General demand growth	-	-	0.03	0.08	1.58	**1.69**
Mt Gambier West to Blue Lake Tee 33kV Line Uprate	766	South East	Sub-transmission Capacity - Country	General demand growth	-	-	-	0.01	0.05	**0.06**
Mt Schank to Allendale East 33kV Line Uprate	767	South East	Sub-transmission Capacity - Country	General demand growth	-	-	-	0.02	0.20	**0.22**
Naracoorte 11kV Cap Bank	664	South East	Connection Point Capacity - Existing	EN or ETC Driven	-	-	-	-	0.56	**0.56**

					Expenditure ($ million)					
Project Name	**Project No**	**Region**	**Project Type**	**Project Driver**	**2015/16**	**2016/17**	**2017/18**	**2018/19**	**2019/20**	**2015-20 Total**
Naracoorte to Naracoorte East Tee 33kV Line Uprate	764	South East	Sub-transmission Capacity - Country	General demand growth	-	-	0.02	0.15	0.14	**0.31**
Penola 11kV Regulator	171	South East	Voltage Regulation	General demand growth	-	0.46	0.46	-	-	**0.92**
Penola Tee-Penola 33kV line uprate	735	South East	Sub-transmission Capacity - Country	General demand growth	0.11	0.09	-	-	-	**0.20**
Robe Substation - Robe 11kV feeder tie	893	South East	Distribution Feeders - Country	General demand growth	-	-	0.04	0.40	0.36	**0.80**
Snuggery to Robe 33kV Voltage Support	679	South East	Voltage Regulation	General demand growth	0.10	0.30	4.87	4.67	-	**9.94**
Tintinara East Recloser Upgrade	932	South East	Distribution Feeders - Country	Committed augmentation / criteria already breached	-	-	0.07	0.07	-	**0.15**
Tintinara Recloser Upgrade	937	South East	Distribution Feeders - Country	Committed augmentation / criteria already breached	-	-	0.07	0.07	-	**0.15**
Tintinara Substation upgrade	168	South East	Substation Capacity - New	General demand growth	-	-	-	0.03	0.09	**0.12**

Project Name	Project No	Region	Project Type	Project Driver	Expenditure ($ million)					
					2015/16	2016/17	2017/18	2018/19	2019/20	2015-20 Total
Baroota Connection Point Upgrade	20	Upper North	Connection Point Capacity – Existing	EN or ETC Driven	0.08	2.54	2.46	-	-	**5.07**
Bungama - Pt Pirie #3 33kV Line	80	Upper North	Sub-transmission Capacity - Country	General demand growth	-	-	-	-	0.08	**0.08**
Bungama 33/11kV Upgrade (with Mod 6 33/11kV Substation)	200	Upper North	Substation Capacity - Existing	General demand growth	-	-	-	-	0.07	**0.07**
Gladstone Recloser Upgrade	920	Upper North	Distribution Feeders - Country	Committed augmentation / criteria already breached	-	0.07	0.07	-	-	**0.15**
Huddleston Recloser Upgrade	921	Upper North	Distribution Feeders - Country	Committed augmentation / criteria already breached	-	0.07	0.07	-	-	**0.15**
Jamestown Substation - 11kV feeder exit upgrade	892	Upper North	Distribution Feeders - Country	General demand growth	0.07	0.07	-	-	-	**0.14**
Jamestown Substation Upgrade	756	Upper North	Substation Capacity - Existing	General demand growth	-	-	-	-	0.02	**0.02**
Mount Gunson Connection Point Upgrade	419	Upper North	Connection Point Capacity - Existing	EN or ETC Driven	0.72	-	-	-	-	**0.72**

Project Name	Project No	Region	Project Type	Project Driver	Expenditure ($ million) 2015/16	2016/17	2017/18	2018/19	2019/20	2015-20 Total
Neuroodla Connection Point Upgrade (with 33kV recloser installation)	420	Upper North	Connection Point Capacity - Existing	EN or ETC Driven	0.25	-	-	-	-	**0.25**
Orroroo Recloser Upgrade	970	Upper North	Distribution Feeders - Country	Committed augmentation / criteria already breached	0.07	0.07	-	-	-	**0.15**
Peterborough South Recloser Upgrade	922	Upper North	Distribution Feeders - Country	Committed augmentation / criteria already breached	-	-	0.07	0.07	-	**0.15**
Port Broughton Substation Upgrade	345	Upper North	Substation Capacity - New	General demand growth	-	-	-	-	0.04	**0.04**
Country SWER feeders	455	Various	Distribution Feeders - Country	Committed augmentation / criteria already breached	0.75	-	-	-	-	**0.75**
Country SWER feeders	456	Various	Distribution Feeders - Country	Committed augmentation / criteria already breached	0.90	0.90	-	-	-	**1.81**
Country SWER feeders	457	Various	Distribution Feeders - Country	Committed augmentation / criteria already breached	-	0.72	0.72	-	-	**1.44**

Project Name	Project No	Region	Project Type	Project Driver	Expenditure ($ million)					
					2015/16	2016/17	2017/18	2018/19	2019/20	2015-20 Total
Country SWER feeders	458	Various	Distribution Feeders - Country	General demand growth	-	-	0.70	0.70	-	**1.40**
Country SWER feeders	459	Various	Distribution Feeders - Country	General demand growth	-	-	-	0.70	0.70	**1.40**
Country SWER feeders	460	Various	Distribution Feeders - Country	General demand growth	-	-	-	-	0.70	**0.70**
Design Work	189	Various	Strategic Network Capacity	Regulatory Compliance (eg NER, EDC, QoS)	1.50	-	-	-	-	**1.50**
Design Work	251	Various	Strategic Network Capacity	Regulatory Compliance (eg NER, EDC, QoS)	1.50	1.50	-	-	-	**3.00**
Design Work	252	Various	Strategic Network Capacity	Regulatory Compliance (eg NER, EDC, QoS)	-	1.50	1.50	-	-	**3.00**
Design Work	253	Various	Strategic Network Capacity	Regulatory Compliance (eg NER, EDC, QoS)	-	-	1.50	1.50	-	**3.00**
Design Work	254	Various	Strategic Network Capacity	Regulatory Compliance (eg NER, EDC, QoS)	-	-	-	1.50	1.50	**3.00**
Design Work	255	Various	Strategic Network Capacity	Regulatory Compliance (eg NER, EDC, QoS)	-	-	-	-	1.50	**1.50**

Project Name	Project No	Region	Project Type	Project Driver	Expenditure ($ million)					
					2015/16	2016/17	2017/18	2018/19	2019/20	2015-20 Total
ElectraNet Small Projects	907	Various	Connection Point Capacity - Existing	EN or ETC Driven	0.10	-	-	-	-	**0.10**
ElectraNet Small Projects	908	Various	Connection Point Capacity - Existing	EN or ETC Driven	0.10	0.10	-	-	-	**0.20**
ElectraNet Small Projects	909	Various	Connection Point Capacity - Existing	EN or ETC Driven	-	0.10	0.10	-	-	**0.20**
ElectraNet Small Projects	910	Various	Connection Point Capacity - Existing	EN or ETC Driven	-	-	0.10	0.10	-	**0.20**
ElectraNet Small Projects	911	Various	Connection Point Capacity - Existing	EN or ETC Driven	-	-	-	0.10	0.10	**0.20**
ElectraNet Small Projects	912	Various	Connection Point Capacity - Existing	EN or ETC Driven	-	-	-	-	0.10	**0.10**
Feeder Tie Cable Upgrades	338	Various	Supply Security	Security driven	-	0.76	0.76	-	-	**1.52**
Feeder Tie Cable Upgrades	989	Various	Substation Capacity - Existing	Security driven	-	-	0.85	0.85	-	**1.69**
LV & Distribution Transformers (QoS)	466	Various	LV & Distribution Transformers (QoS)	Regulatory Compliance (eg NER, EDC, QoS)	5.53	-	-	-	-	**5.53**

Project Name	Project No	Region	Project Type	Project Driver	Expenditure ($ million) 2015/16	2016/17	2017/18	2018/19	2019/20	2015-20 Total
LV & Distribution Transformers (QoS)	467	Various	LV & Distribution Transformers (QoS)	Regulatory Compliance (eg NER, EDC, QoS)	5.53	5.53	-	-	-	**11.06**
LV & Distribution Transformers (QoS)	468	Various	LV & Distribution Transformers (QoS)	Regulatory Compliance (eg NER, EDC, QoS)	-	5.53	5.53	-	-	**11.06**
LV & Distribution Transformers (QoS)	469	Various	LV & Distribution Transformers (QoS)	Regulatory Compliance (eg NER, EDC, QoS)	-	-	5.53	5.53	-	**11.06**
LV & Distribution Transformers (QoS)	470	Various	LV & Distribution Transformers (QoS)	Regulatory Compliance (eg NER, EDC, QoS)	-	-	-	5.53	5.53	**11.06**
LV & Distribution Transformers (QoS)	471	Various	LV & Distribution Transformers (QoS)	Regulatory Compliance (eg NER, EDC, QoS)	-	-	-	-	5.53	**5.53**
Mobile Plant	294	Various	Supply Security	Security driven	-	-	0.18	1.18	1.00	**2.35**
Two Way Network Support	978	Various	LV Two Way Network	Regulatory Compliance (eg NER, EDC, QoS)	0.59	-	-	-	-	**0.59**
Two Way Network Support	979	Various	LV Two Way Network	Regulatory Compliance (eg NER, EDC, QoS)	1.94	1.94	-	-	-	**3.88**

					Expenditure ($ million)					
Project Name	**Project No**	**Region**	**Project Type**	**Project Driver**	**2015/16**	**2016/17**	**2017/18**	**2018/19**	**2019/20**	**2015-20 Total**
Two Way Network Support	980	Various	LV Two Way Network	Regulatory Compliance (eg NER, EDC, QoS)	-	2.14	2.14	-	-	**4.27**
Two Way Network Support	981	Various	LV Two Way Network	Regulatory Compliance (eg NER, EDC, QoS)	-	-	2.38	2.38	-	**4.75**
Two Way Network Support	982	Various	LV Two Way Network	Regulatory Compliance (eg NER, EDC, QoS)	-	-	-	2.36	2.36	**4.72**
Two Way Network Support	983	Various	LV Two Way Network	Regulatory Compliance (eg NER, EDC, QoS)	-	-	-	-	2.36	**2.36**
Curramulka 33/7.6kV Transformer Station Upgrade	742	Yorke Peninsula	Substation Capacity - Existing	General demand growth	-	-	0.04	0.40	0.36	**0.80**
Dalrymple - Marion Bay 33kV Voltage Regulation	398	Yorke Peninsula	Voltage Regulation	General demand growth	-	0.28	0.28	-	-	**0.55**
Dalrymple Connection Point Upgrade	412	Yorke Peninsula	Connection Point Capacity - Existing	EN or ETC Driven	2.30	2.25	-	-	-	**4.55**
Dalrymple new 33kV exit	977	Yorke Peninsula	Sub-transmission Capacity – Country	Security driven	0.62	0.59	-	-	-	**1.20**

					Expenditure ($ million)					
Project Name	**Project No**	**Region**	**Project Type**	**Project Driver**	**2015/16**	**2016/17**	**2017/18**	**2018/19**	**2019/20**	**2015-20 Total**
Port Vincent South Mod 3 Substation (New)	750	Yorke Peninsula	Substation Capacity - New	General demand growth	-	-	-	0.03	0.09	**0.12**

Table 9: 2015-20 Project List[15]

[15] All values are expressed in millions and 2013 nominal dollars inclusive of overheads.

10. ADELAIDE CENTRAL REGION – REGIONAL DEVELOPMENT PLAN

The *Adelaide Central Region* is defined by the *Electricity Transmission Code* as the area bounded by West Terrace, South Terrace, East Terrace, and the River Torrens – the region encompasses the Adelaide *Central Business District* (*CBD*). For the purposes of this report, references to the *CBD* shall be taken to mean the *Adelaide Central Region* (*ACR*). Note that the area defined as the *CBD* within this report should not be taken to represent the area defined as the *CBD* within the *Electricity Distribution Code* (this area definition is used for the purposes of reliability reporting only).

A map of this region is shown in Figure 14 while a single line representation of the *network* is shown in Figure 15.

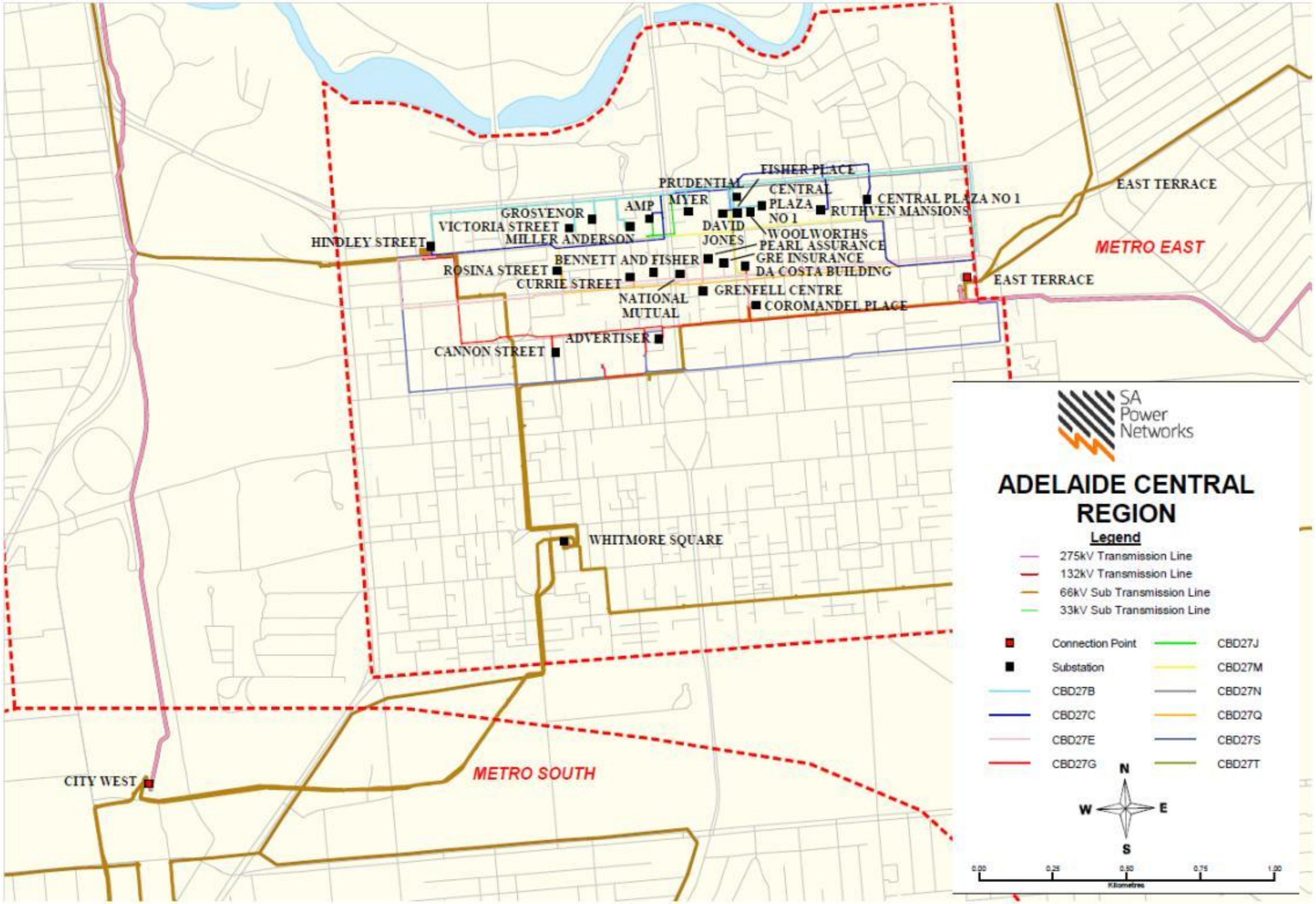


Figure 14: ACR Area Map

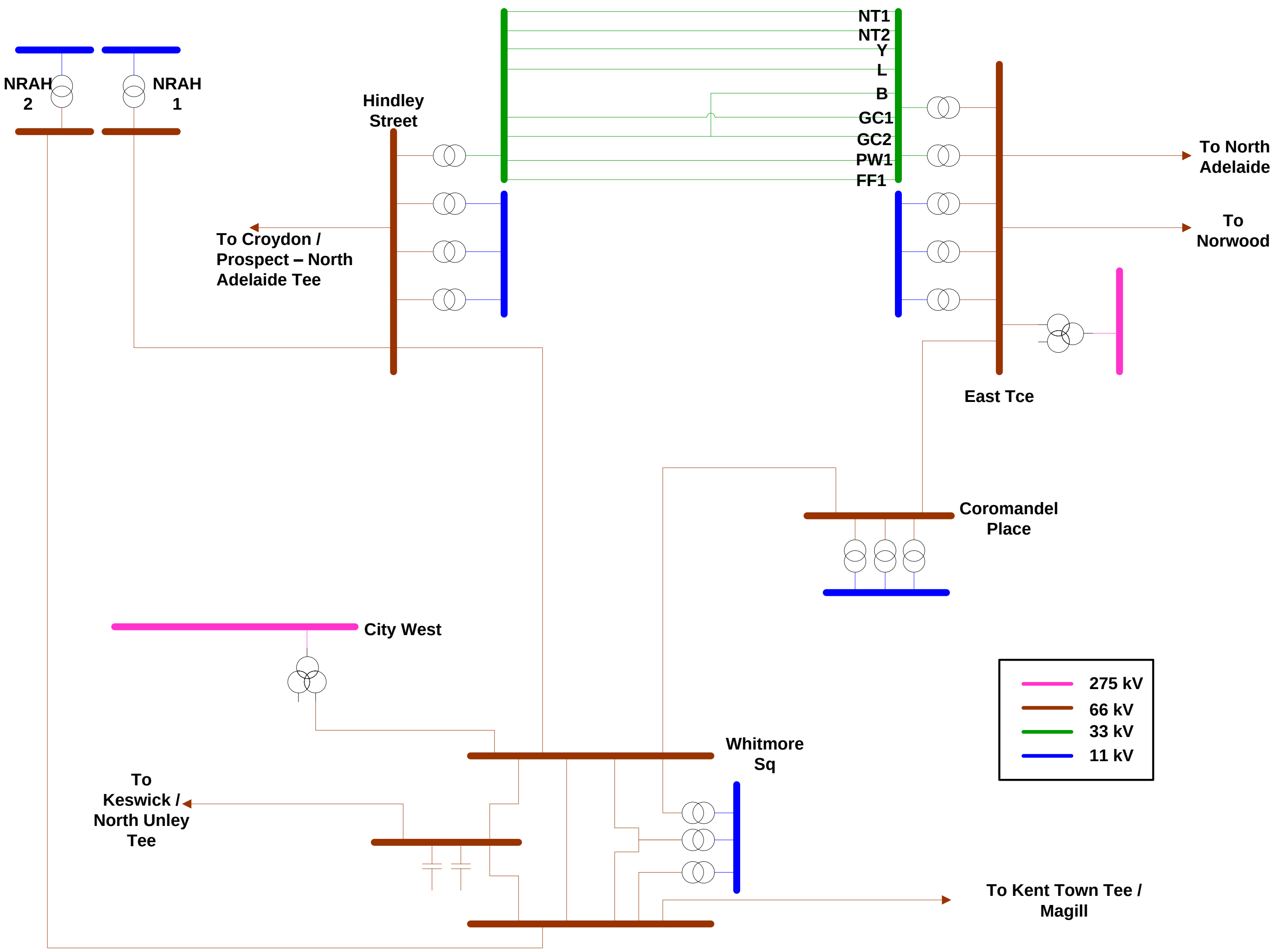


Figure 15: ACR Single Line Diagram

10.1 Region Statistics

Table 10 indicates the general statistics for this region of the state.

Parameter	Value
No of connection points	2 (275/66*kV*)
No of zone subs	8 (4 x 66/11*kV*, 2 x 66/33*kV*, 2 x 33/11*kV*)
Operating voltages	66*kV*, 33*kV*, 11*kV* and 0.4*kV*
Total customers	12,005
No of residential customers (abs /%of region/% of state)	7,442 / 61.8% / 0.9%
No of commercial / industrial customers (abs /%of region/% of state)	4,602 / 38.2% / 0.5%
Area of region (km^2 / % of state)	4 km^2 / 0.002%
Length of 66kV cable (km / % of region 66kV)	6.2 km / 100 %
Length of 66kV conductor (km / % of region 66kV)	0 / 0 %
Length of 33kV cable (km / % of region 33kV)	28.4 km / 100%
Length of 11kV cable (km / % of region 11kV)	183 km / 98.1%
Length of 11kV conductor (km / % of region 11kV)	3.6 km / 1.9%
Installed *PV* inverter capacity (*MW* / % of state)	1.2 *MW* / 0.2%
No of feeders (abs / % urban / % rural short / % rural long)	107 / 100% / 0% / 0%

Table 10: ACR Region Statistics.

10.2 Development History

The *ACR* region has been developed since the initial stages of the state's electrification from the former Adelaide Electric Supply Company (AESCo) prior to the formation of the Electricity Trust of South Australia (ETSA) in 1946 through to privatisation in 1999 and the subsequent creation of ETSA Utilities / *SA Power Networks*.

During this time, the *network* has seen the migration of the *network's* standard operating voltages from 33 and 7.6*kV* to today's 66, 33 and 11*kV networks*. Whilst most of the *ACR network* has been migrated to 66/11*kV*, part of the region's 33*kV network* has been retained to supply those larger loads located within the northern commercial precinct of the region running east / west between East Terrace and Hindley Street *zone substations*.

Prior to 1984, no *connection point*s existed within this region until the construction of the first 275/66kV *connection point* at East Terrace. This *connection point* consists of a single 275/66kV transformer and is supplied at 275kV by a single eight kilometre, 275kV cable emanating from Magill *connection point*. A second such *connection point* (mandated by the former Electricity Supply Industry Planning Council –ESIPC and *ESCOSA's ETC*) known as City West was commissioned in December 2011. This second *connection point* also consists of a single 275/66kV transformer supplied by a single 21 km, 275kV cable emanating from Torrens Island Power Station's (TIPS) 275kV yard.

Significant projects undertaken within the region during the course of the present regulatory period include:

Project Title	Description	Commissioning Year	Cost ($ million)
City West *Connection Point*	Construct a new 275/66*kV connection point* substation west of King William Street to supply the *ACR* region. This new *connection point* was integrated within the existing *ACR* network through the installation of 2.1km of 2 x 2000mm^2 Cu XLPE 66*kV* cables between City West *connection point* and Whitmore Square *zone substation* together with installation of a new 66*kV* GIS switchboard and associated control building at Whitmore Square.	2011	76.4

Table 11: Recent ACR Augmentation Projects

10.3 Connection points and sub-transmission lines

The *ACR* is meshed within and forms part of, the larger Metro East *network* and is primarily supplied via two *connection point*s at East Terrace and City West, with support from Magill and Northfield *connection point*s via the 66*kV sub-transmission lines* connecting the *ACR* to the Metro East *network*. Given the criticality of this region to the entire state as an administrative hub, it planned on a "continuous" *N-1* basis.

Whilst East Terrace *connection point* is a joint use site occupied by both *ElectraNet* and *SA Power Networks*, City West is a separate site located at Keswick (on the border of the Metro East and Metro South regions) and connected to the *ACR network* at *SA Power Networks*' Whitmore Square *zone substation*. Both *connection point*s are radially supplied by single 275*kV* cables emanating from Magill and Torrens Island respectively and contain a single 275/66*kV* transformer for use by the region, however provision exists for additional transformers to be added as and when required at each site. The *ETC* classifies the *ACR*'s *connection point*s as Category 5 sites, meaning they must provide continuous N-1 transformer capacity with restoration of at least 65% of the N capacity within four hours. The *ACR* is the only area classified as Category 5 within the *ETC*, making it unique within the state.

No augmentation of the region's *connection point* transformer capacity is forecast within the time parameters of this *AMP*. A copy of the region's *connection point* forecasts are shown in APPENDIX A – ADELAIDE CENTRAL REGION .

The region's eight *zone substations* are predominantly supplied by an underground *network*. Underground 66*kV* cables operate between East Terrace and Coromandel Place, Coromandel Place and Whitmore Square and between Whitmore Square and Hindley Street *zone substations*. Other sources of 66*kV* supply to these *zone substations* emanate from 66*kV lines* within the Metro East region with Whitmore Square having a normally open tie to the Metro South network for use under *contingency conditions*.

The *ACR* region's 33*kV network* supplies a combination of *zone* (33/11*kV*) and *distribution* (33/0.4*kV*) *substations*. The region's 33*kV network* is supplied at 33*kV* from Hindley Street and East Terrace *zone substations* which contain one 25 *MVA* and two 25 *MVA* 66/33*kV* Y-y auto-transformers respectively. The 33*kV network* typically operates in an arrangement whereby the *distribution substations* comprise 33*kV* connections from two cables, one supplied from East Terrace supplying one transformer and the other supplied from Hindley Street supplying the other transformer with these being meshed at the *LV* level. In the event of a fault of either a 33*kV* cable (with the subsequent loss of a single transformer) or a transformer, all load supplied by the *substation* or *distribution substation* is able to be maintained via the remaining healthy 33*kV* cable and associated transformer. This scheme is of significant age and the sites contain numerous operational, safety and environmental issues associated with clearances, lack of arc fault containment, inability to operate equipment whilst live, asbestos and oil containment etc. Full details of the remediation program for *SA Power Networks'* 33/11*kV zone* and 33/0.4kV *distribution substation*s supplied by the *ACR*'s 33*kV network* is detailed within *AMP* 2.1.07 - *CBD AMP*.

10.4 Zone substations

Electricity is supplied throughout the *ACR* via *zone substations* operating at 66*kV* or 33*kV* stepped down to either 33*kV* or 11*kV*. The region presently consists of eight such *zone substations* namely;

1. East Terrace 66/11*kV* and 66/33*kV*;
2. Hindley Street 66/11*kV* and 66/33*kV*;
3. Coromandel Place 66/11*kV*;
4. Whitmore Square 66/11*kV*;
5. Myer 33/11*kV*; and
6. AMP[16] 33/11kV.

10.4.1 66/11kV zone substations

The region's four 66/11*kV zone substations* each contain three 66/11*kV* transformers operated in parallel. Due to each site's physical space and 11*kV* fault level constraints, each of these sites is already at their ultimate transformer capacity.

Given the continuous *N-1* planning criteria in effect within this region, should the 10% *PoE* demand exceed the *N-1* transformer rating at any of these sites (or in combination if permanent *feeder* transfers can be affected to balance the loads between the *zone substations*), this will trigger the need for a fifth 66/11*kV zone substation* within the region. Based on present forecasts, this is not expected until after the 2020-25 period.

No new or upgrades to, *SA Power Networks'* existing 66/11*kV zone substations* are forecast within the period covered by this *AMP*.

10.4.2 66/33kV zone substations

SA Power Networks' 66/33*kV zone substations* are located at its Hindley Street and East Terrace sites. Hindley Street consists of one 25 *MVA* 66/33*kV* Y-y auto-transformer while East Terrace contains two 25 *MVA* 66/33*kV* Y-y auto-transformers.

No new or upgrades to, *SA Power Networks'* existing 66/33*kV zone substations* are forecast within the period covered by this *AMP*.

[16] Note the AMP zone substation is located within the former Australian Mutual Prvident or AMP building. The term AMP in this context should not be confused with Asset Management Plan.

10.4.3 33/11kV zone substations

The *ACR* contains two 33/11*kV zone substations*, namely, Myer and AMP (this *substation* is contained within the former Australian Mutual Provident building and not to be confused with Asset Management Plan).

Both sites supply multiple customers at 11*kV*, however, neither *substation* provides 11*kV feeders* from which 11/0.4*kV distribution substation*s are supplied. Both sites are only subject to augmentation based on specific customer requests for load increases.

10.5 Feeders

Customers within the *ACR* are supplied from *SA Power Networks' distribution system* via 33 and 11*kV feeders* from the region's *zone substations* which subsequently supply 33/0.4 and 11/0.4*kV distribution substation*s. The *ACR*'s *feeder* system is characterised by cables installed within an extensive duct and manhole system. These *feeders* are extended and upgraded as required to meet customer demand and customer connection requests whilst maintaining the region's *N-1* reliability criteria.

A large number of the 33/0.4kV and 11/0.4kV *distribution substations* are dedicated to individual customers and are therefore classified as connection assets. As such, these installations are only upgraded in response to individual customer demand increases in accordance with the *NECF*.

There are no capacity driven augmentations of the *ACR* region's *feeder network* within the period covered by this *AMP*.

10.6 Land & Other Works

The following additional works within the region have been identified within the 2015-20 period.

Project Timing	Project Name	Work Category	Proposed Solution	Section Ref	2015-20 Cost ($ million)	2020-25 Cost ($ million)	Total Cost ($ million)
2017	East Tce NGM Upgrade	NER Compliance (PF, load shedding)	Recalibrate CTs and VTs on GIS switchboard. Install aux CTs to provide second metering core for check metering.	-	**0.20**	-	0.20
2018	Eliza Street Cable Ducts	Supply security	Relocate third party assets and install ducts in Eliza and Cannon Streets in preparation for future zone substation	-	**3.68**	1.23	4.90
2022 - 2024	East Tce & Whitmore Sq 11*kV* cap banks	NER Compliance	Replace existing 11*kV* cap banks at East Tce and Whitmore Sq *substations* to enable their safe operation in conjunction with installation of *NERs* on 66/11*kV* transformers whilst ensuring adequate *power factor* within the *ACR*.	-	**-**	3.04	3.04

Table 12: ACR Other Works

11. METRO NORTH – REGIONAL DEVELOPMENT PLAN

SA Power Networks' Metro North Region covers the northern suburbs of metropolitan Adelaide which includes the suburbs of Elizabeth and Salisbury of which the latter represents the largest single *LGA* in terms of population. The region stretches from Salisbury in the south, north west to Virginia and north to Evanston. The region's load includes significant heavy industrial loads within the Elizabeth area to agricultural loads (ie market gardens) at Virginia and surrounds. The region presently contains two 275/66*kV* *connection point*s at Para and Parafield Gardens West with a third presently under construction (Munno Para). The latter *connection point* is planned to be commissioned in 2015.

A map of this region is shown in Figure 16 while a single line representation of the *network* is shown in Figure 17.

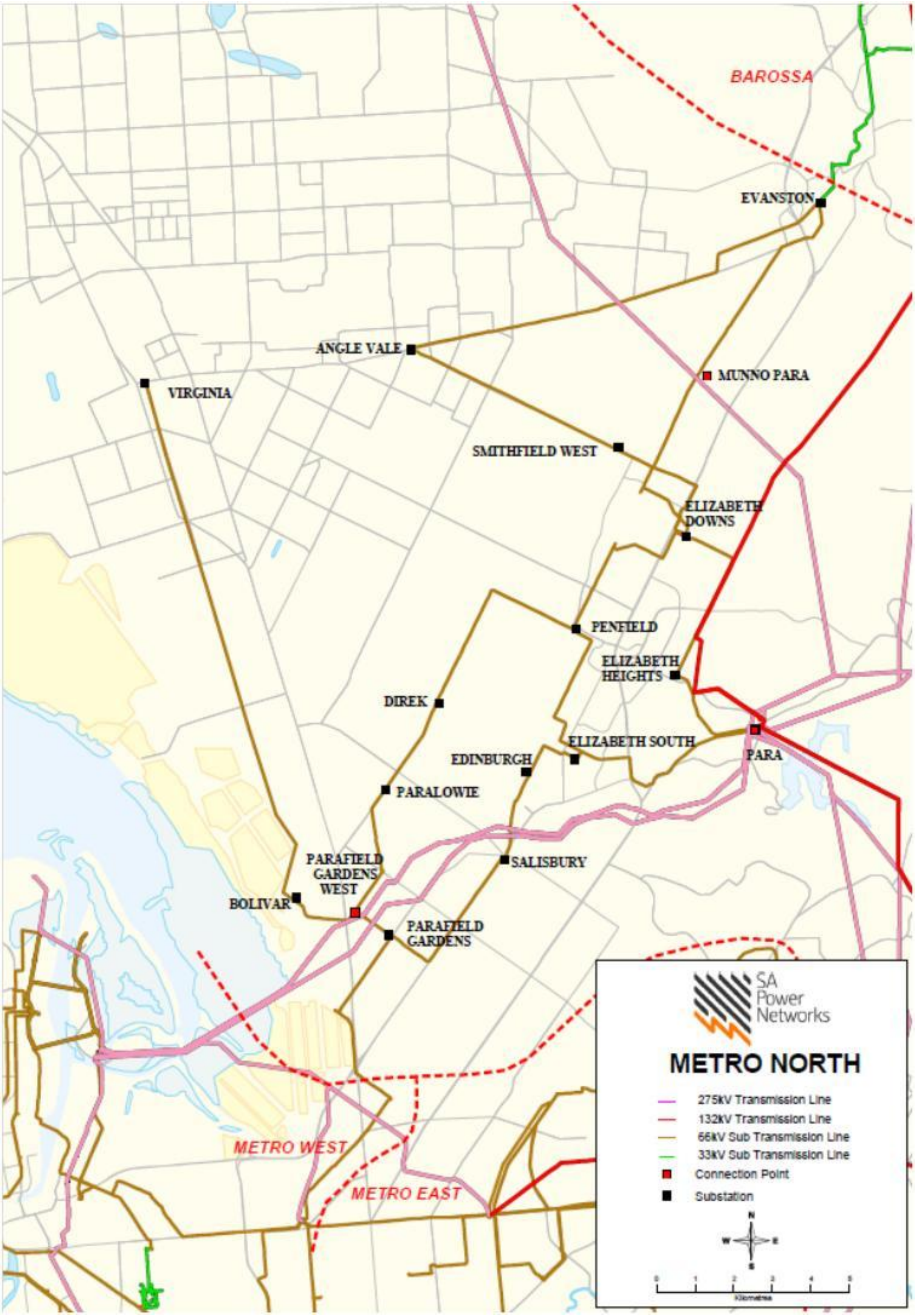


Figure 16: Metro North Area

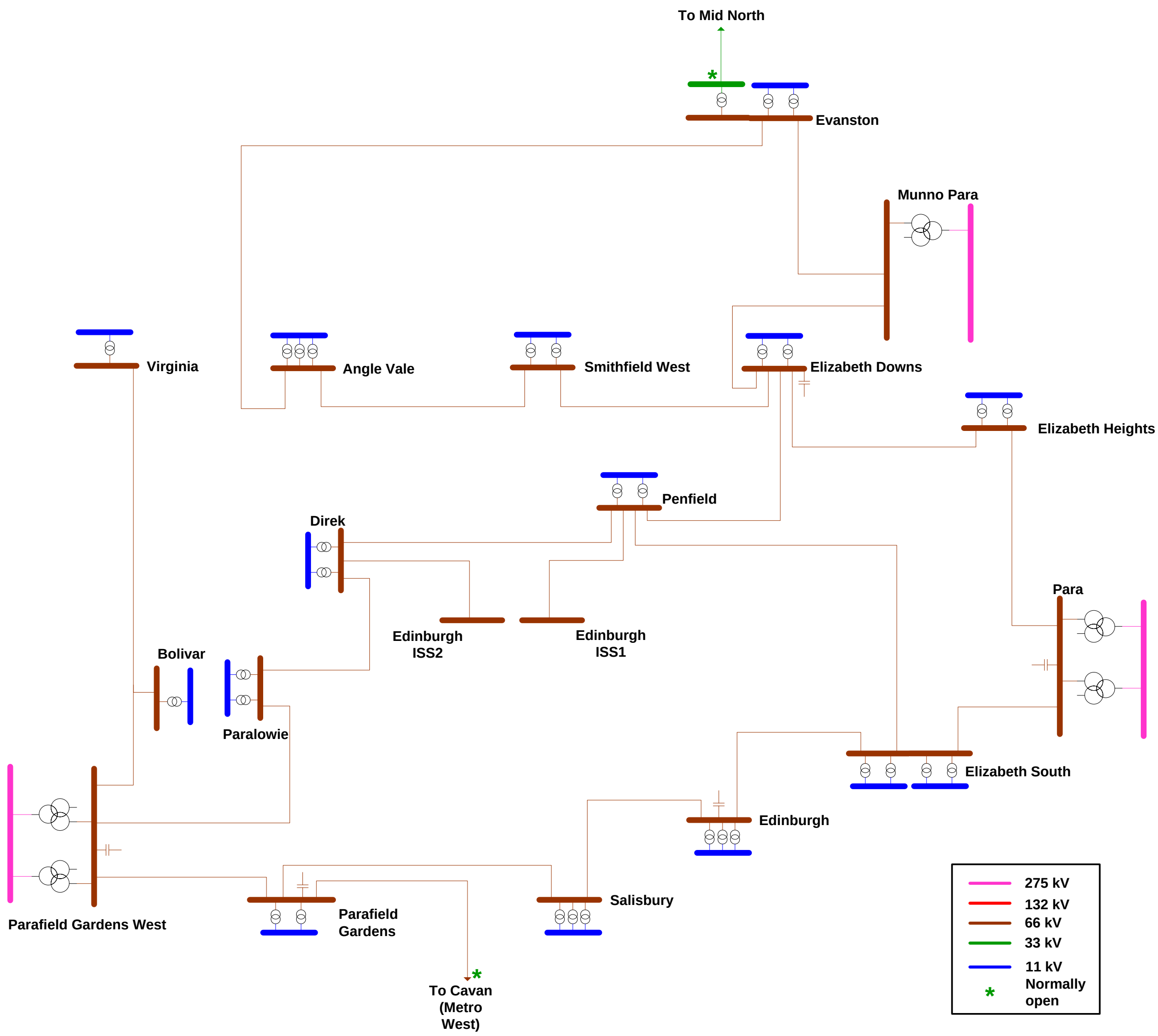


Figure 17: Metro North Single Line Diagram

11.1 Region Statistics

Table 13 below indicates the general statistics for this region of the state.

Parameter	Value
No of connection points	3 (275/66*kV*)
No of zone subs	14 (66/11*kV*), 1 (66/33*kV*)
Operating voltages	66*kV*, 33*kV* and 11*kV*
Total customers	85,245
No of residential customers (abs /%of region/% of state)	78,464 / 92% / 9.2%
No of commercial / industrial customers (abs /%of region/% of state)	6,781 / 8% / 0.8%
Area of region (km^2 / % of state)	418 / 0.18

Parameter	Value
Length of 66kV cable (km / % of region 66kV)	0 / 0
Length of 66kV conductor (km / % of region 66kV)	105 / 100
Length of 11kV cable (km / % of region 11kV)	683 km / 41.5%
Length of 11kV conductor (km / % of region 11kV)	962 km / 58.5%
Length of 19kV cable (km / % of region 19kV)	3.6 km / 2.7%
Length of 19kV conductor (km / % of region 19kV)	126 km / 97.3%
Installed *PV* inverter capacity (*MW* / % of state)	59.4 *MW* / 10.3%
No of feeders (abs / % urban / % rural short / % rural long)	87 / 92% / 8% / 0%

Table 13: Metro North Region Statistics

11.2 Development History

The Metro North region has been largely developed since the formation of the Electricity Trust of South Australia (ETSA) in 1946 through to privatisation in 1999 and the subsequent creation of ETSA Utilities / *SA Power Networks*.

The region was expanded in the early to mid 1950's through the creation of the suburb of Elizabeth. The 11*kV network* servicing the majority of the Elizabeth region consists mainly of underground assets, with only *sub- transmission* and transmission assets being predominantly located above ground level.

The region was previously served by 33*kV* systems which over time have been migrated to 66*kV*. The region still retains one 33*kV* connection at Evanston *zone substation*, however this has only been retained to serve the Barossa region under contingency situations as opposed to normal operation.

Given the highly industrial history of this region, it was one of the first to be converted to 66*kV* supply. The Para *connection point* represents one of the state's primary transmission "hubs" providing interconnections between TIPS, Northern Power Station and the 275*kV* interconnection to Heywood in Victoria.

Historically, the Metro North region has been the fastest growing metropolitan region over the last 10 years. Even with the forecast closure of Holden, the region is expected to remain the fastest growing metropolitan region due to the almost unlimited availability of residential and commercial land for development. In line with the state government's 30 year plan, this region will mostly see Greenfield type developments.

A sample of significant projects undertaken within the region during the course of the 2010-15 regulatory period are shown below. All costs are as incurred or as approved (ie inclusive of overheads).

Project Title	Description	Commissioning Year	Cost ($ million)
Para 66*kV* Upgrade	Thermal uprate of the 66*kV line* exits from Para *connection point* to mitigate overloads under *contingent conditions*.	2010	4.2
Parafield Gardens West 66*kV* Section *CB*	Rebuild of 66*kV* yard at Parafield Gardens West including installation of new 66*kV* section *CB* to mitigate substation plant and 66*kV line* overloads under *contingent conditions*.	2013	6.9
Kilburn to Cavan 66*kV Line*	Construction of new 4km 66*kV* line between Kilburn and Cavan *substations* to de-radialise Cavan and mitigate 66*kV line* overloads in the Metro North region under *contingent conditions*.	2013	9.6
Munno Para 275/66*kV Connection Point* (under construction);	Construction of a new 275/66*kV connection point* inserted within the existing 66*kV sub-transmission network* to mitigate forecast 66*kV network* overloads and bolster supply to the new residential areas in the northern most parts of the region.	2014/15	12.9[17]

Table 14: Recent Metro North Augmentation Projects

11.3 Connection points and sub-transmission lines

The Metro North system is primarily supplied via two joint use, *connection point*s at Para and Parafield Gardens West with a third at Munno Para presently under construction and planned to be commissioned in 2015. These *connection point*s will have a combined normal rating of 870 *MVA* and a notional *N-1* capacity of 693 *MVA* (post completion of Munno Para and assuming ideal sharing between connection points).

These *connection point*s are meshed via *SA Power Networks'* 66*kV sub-transmission network*. Under the *ETC*, these *connection point*s are classified as Category 4 sites and are required to be planned on a *N-1* basis for both transmission lines and transformers.

Given the significance of this region to the state both in terms of customer numbers and industrial importance, *SA Power Networks* plans this region's *sub-transmission network* on a *N-1* basis against the 10% *PoE* forecast. Constraints on the *meshed sub-transmission network* and of *ElectraNet's* 275/66*kV* transformers are determined through modelling of the *network* and analysis using *PSS/E*.

Post implementation of Munno Para *connection point* in 2015, no augmentation of the region's *connection point* transformer capacity is forecast within the time parameters of this *AMP*. A copy of the region's *connection point* forecasts are shown in APPENDIX B – METRO NORTH REGION .

[17] Approval amount

Section Ref	Constraint Type	Constraint Description	Proposed Solution	Constraint Year	Commissioning Year	2015-20 Cost ($ million)	2020-25 Cost ($ million)	Total Cost[18] ($ million)
-	N-1	Loss of one of multiple 66kV lines results in overloads of the remaining lines. Loss of a transformer at Para or Parafield Gardens West connection points causes overload in remaining transformers.	Construct Munno Para *connection point*.	2012	2015	**2.01**	-	12.9

Table 15: Metro North Connection Point Projects

Those *sub-transmission* constraints identified within the forecast period covered by this *AMP* are listed in Table 16.

[18] Total expenditure to end of 2024/25 period

Section Ref	Project Name	Constrained Line(s)	Constraint Type	Constraint Description	Proposed Solution	Constraint Year	Commissioning Year	2015-20 Cost ($ million)	2020-25 Cost ($ million)	Total Cost ($ million)
-	Parafield Gdns to Cavan 66*kV Line* Uprate	Parafield Gdns - Cavan 66*kV*	N-1	Loss of Kilburn – Cavan *line* causes overload of Parafield Gardens – Cavan line	Uprate existing line from T80 to T100.	2027	2027	**0.00**	0.03	0.3

Table 16: Metro North Sub-transmission Projects

11.4 Zone substations

The region's fourteen 66*kV zone substations* are supplied by an overhead 66*kV sub-transmission network* which meshes the region's existing *connection point*s. Until the construction of the Kilburn – Cavan 66*kV* line in 2012, this region was islanded from the other metropolitan 66*kV networks*. The construction of this *line* now provides the ability for Cavan *zone substation* to be supplied from either the Metro North or Metro West regions with the latter becoming Cavan's primary source from 2012 onwards.

The Metro North region contains one 66/33*kV* transformer located at Evanston *zone substation*. This transformer is retained only for the purposes of providing backup to the Barossa region's 33*kV network* for maintenance or under *contingency condition* purposes.

Forecasts for the region's *zone substations* are shown in APPENDIX B – METRO NORTH REGION .

Table 17 lists those *zone substation* constraints identified based on comparison of the *zone substation* forecasts and associated ratings.

Project Timing	Project Name	Limitation / Constraint	Proposed Solution	Section Ref	2015-20 Cost ($ million)	2020-25 Cost ($ million)	Total Cost ($ million)
2015	Two Wells new Mod 1 and Virginia 66*kV Line*	Overload of Virginia *zone substation* under contingent conditions and voltage constraints on the 11*kV feeder* network.	Construct new Two Wells *substation* and a new 66*kV line* from Virginia.	11.4.1	**5.0**		10.08
2017/18	Gawler East New *Substation*	In ability to supply new *URD* area whilst maintaining suitable voltages. Insufficient spare 11*kV feeder CBs* to create new 11*kV feeders* to supply region.	Construct a new 66/11*kV substation* supplied by a new 66*kV line* teed off the Munno Para – Evanston 66kV *line*.	0	**15.82**	-	15.82
2020/21	Evanston Gardens New *Substation*	In ability to supply new *URD* area whilst maintaining suitable voltages. Insufficient spare 11*kV feeder CBs* to create new 11*kV feeders* to supply region.	Construct a new 66/11*kV substation* south of Evanston *substation* supplied at 66*kV* from the existing Munno Para – Evanston 66*kV line*.	11.4.4	**2.69**	7.45	10.14
2022	Blakeview New 32MVA TF Substation	In ability to supply new *URD* area whilst maintaining suitable voltages. Insufficient spare 11*kV feeder CBs* to create new 11*kV feeders* to supply region.	Construct a new 66/11*kV substation* within the Blakeview development supplied at 66*kV* by a new *line* from Munno Para *connection point.*	-	**0.00**	0.67	13.46

Table 17: Metro North Zone Substation Projects

11.4.1 Major Project – Two Wells 66/11kV New Substation

11.4.1.1 Constraint

Virginia 66/11kV Zone Ssubstation contains one 12.5MVA 66/11kV transformer. The measured load in 2014 exceeded the substation's constraint capacity by more than the allowable load at risk (ie more than 3 MVA of load would have remained unsupplied in the event of a single contingency condition after all possible feeder transfer had been utilised). The 50% PoE adjusted load would also exceed the substation's constraint capacity by more than the allowable level of load at risk.

The Virginia Zone Substation supplies an intensive agricultural region (market gardens) north of Adelaide with customer critical irrigation loads. The substation also supplies the townships of Virginia and Two Wells. The Two Wells township is zoned for large scale residential development with at least one developer receiving development approval (DAP) in 2013. SA Power Networks' anticipates a low, but steady growth from the agricultural sector and a higher growth rate from the greenfield residential region over the next 10 years. The 11kV feeder supplying the Two Wells region is very long and has reached its capacity and voltage limits.

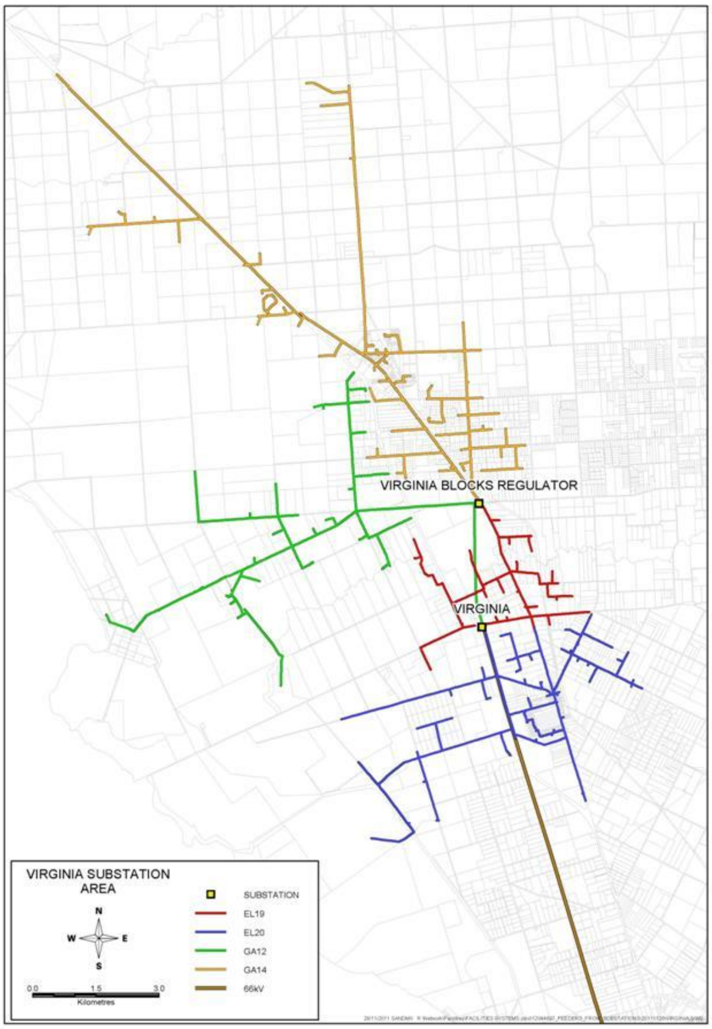


Figure 18: Virginia 66/11kV Zone Substation Supply Area

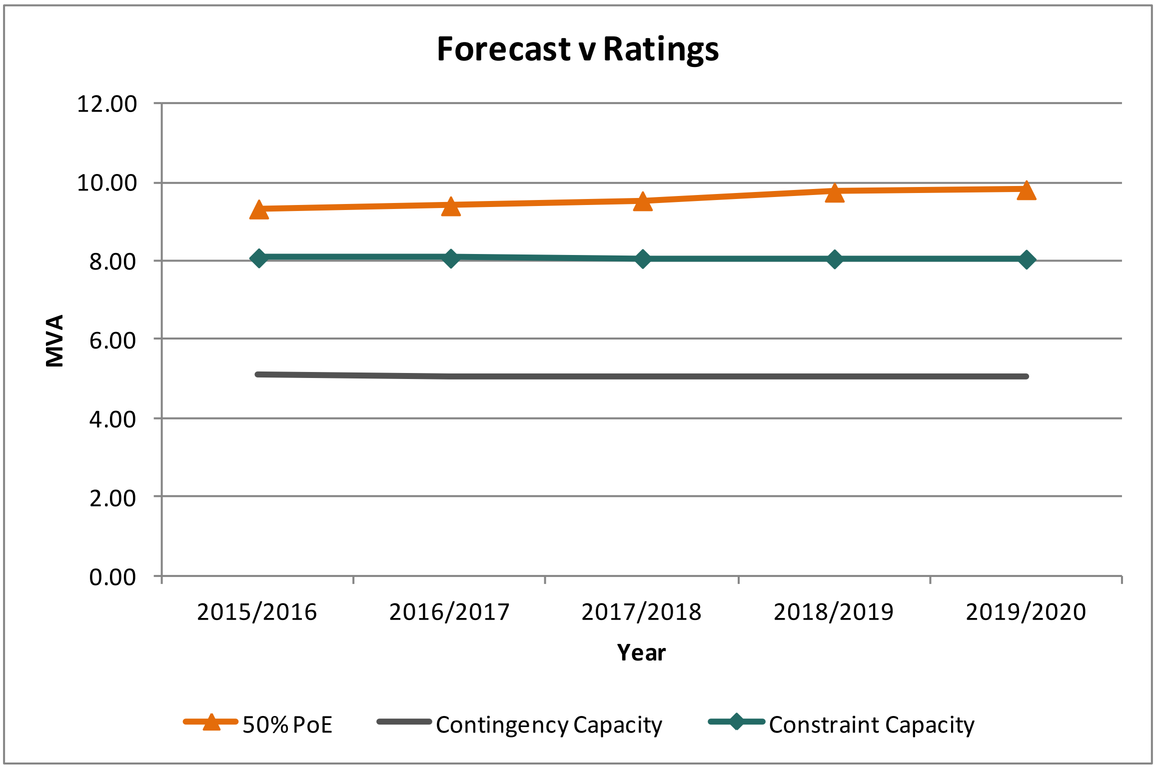


Figure 19: Virginia 66/11kV Zone Substation Load versus Capacity

	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
Forecast* MVA (50% PoE)	9.3	9.3	9.4	9.5	9.8	9.8
Power Factor	0.91	0.91	0.91	0.91	0.91	0.91
Normal Capacity (MVA)	14.9	14.9	14.9	14.9	14.9	14.9
Firm Delivery Capacity (MVA)	0	0	0	0	0	0
Contingency Capacity (MVA)	5.1	5.1	5.1	5.1	5.1	5.1
Load at Risk (MVA)	4.2	4.2	4.3	4.4	4.7	4.7

**Load Forecast includes impact of PV both existing and forecast. The forecast also includes the impact of energy efficiency, state economic and population growth by reconciling each asset's local growth trend with the AEMO July 2014 SA Regional forecast for the next five years.*

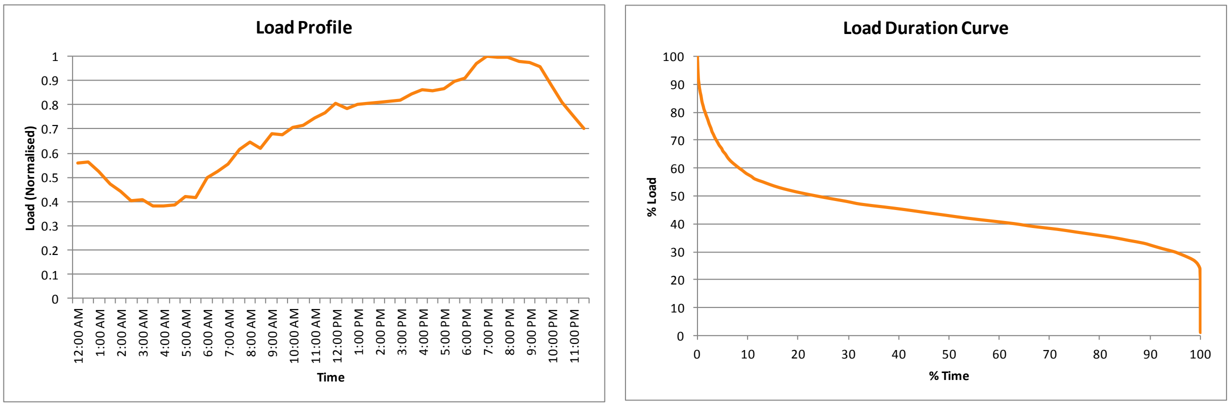
Table 18: Virginia 66/11kV Zone Substation Load Forecast

The measured peak load in 2013/14 was 9.9MVA.

11.4.1.2 Consequences for Customers

Virginia 66/11kV Zone Substation has a contingency capacity of 5.1MVA in 2015/2016. Given a forecast in 2015/2016 of 9.3MVA under 50% PoE conditions, up to 4.2MVA of load may need to be shed in the event of a transformer fault. Approximately 980 customers would remain unsupplied after all possible feeder switching is completed and until a mobile substation could be installed (typically 24 hours). The contingency capacity of Virginia 66/11kV Zone Substation is expected to be exceeded for a total of 4335 hours in 2015/2016 over 357 days per annum.

11.4.1.3 Load Profile



(a) (b)

Figure 20: (a) Virginia 66/11kV Zone Substation Load Profile, (b) Load Duration Curve

11.4.1.4 Regulatory Test

In response to this constraint, a Reasonableness Test was published in accordance with ESCOSA Guideline 12. Reasonableness Test, RT 007-13 was published in November 2013. The Reasonableness Test showed that Demand Management measures could not address the system constraint and that a network solution was required.

11.4.1.5 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.

Improved Feeder Ties:

- Construction of new 11kV Feeders from Virginia Zone Substation to Angle Vale Zone Substation would provide limited improvements to feeder transfer capacity due to the limited capacity of the old small capacity 11kV switchboard at Angle Vale zone substation.
- The future load growth in the Two-Wells region is a great distance from existing substations making it difficult to maintain adequate customer voltage levels and would not be suitable for the planned major residential subdivisions.

11.4.1.6 Options considered to address constraint

The following options have been investigated in accordance with the ESCOSA Guideline 12 to resolve these impending constraints:

Option 1:

- Construct a new Two Wells Zone Substation north of Virginia to provide backup for Virginia and Angle Vale Zone Substations.

Option 2:

- Upgrade Virginia Zone Substation with a second 66/11kV transformer and construct new 11kV feeders north from Virginia Zone Substation towards the Two Wells region.

11.4.1.7 Preferred Solution

The preferred solution based on the regulatory analysis, is to construct a new 66/11kV zone substation at Two Wells (Option 1). The indicative cost for this project is $9.9 million. This project is planned for completion in 2015 and is expected to relieve the constraint in the Two Wells region for 12 years. Refer below for NPV analysis. This solution is also better placed to meet the forecasted major residential development (being created at Two Wells township).

11.4.1.8 Commitment Status

The relevant regulatory process (ESCOSA Guideline 12) was completed in 2013 and SA Power Networks has committed to the project to enable the 2015 commissioning date to be met. This project was included in the pre RIT-D committal list issued to the AER in December 2013.

11.4.1.9 Regulatory Period Expenditure

Approximately $5 million is forecast to be required in the 2015/2020 regulatory control period, with the remaining $4.9 million forecast to be incurred during the 2010/2015 regulatory period.

11.4.1.10Net Present Value Analysis

Option	Description	NPV (Least cost)[19]
1	New Two Wells Substation	-10,050,617
2	Virginia Sub Upgrade with 2nd 12.5MVA TF & 11kV Switchboard	-11,501,866

Table 19: Two Wells NPV Analysis Results

Analysis from Reasonableness Test RT007-13 published November 2013.

11.4.2 Major Project - Greenfields Development in Adelaide Metropolitan Region

Greenfields development regions are those with little or no existing electrical infrastructure, usually located at the existing metropolitan boundaries. These are also regions that are planned to be converted from country to metropolitan (residential URD) land use. For consideration of infrastructure augmentation in the 2015 - 20 period, these greenfield regions also need a committed developer(s), zoning approval for the proposed land use and the commencement of both land sales and building construction. Three such regions were considered in the 2015 - 20 period as potentially meeting this criteria but only two have been included in the submission as highly probable to be required.

[19] Discount rate of 8.98% (real pre tax) over a 15 year evaluation period.

11.4.3 New Gawler East 66/11kV Zone Substation

11.4.3.1 Constraint

A major housing development approximately 3km east of the existing Evanston 66/11kV Zone Substation has been proposed. Little or no SA Power Networks infrastructure exists within the development area. Development has commenced with 0.28MVA of load committed as of June 2014. The development site allows for up to 2,450 allotments and a commercial centre with an ultimate residential demand estimated at 22MVA and 2.5MVA of commercial load.

The nearest zone substation located at Evanston contains two 25MVA 66/11kV transformers. Under 50% PoE conditions, this zone substation's contingency capacity is forecast to be exceeded in 2020/2021, excluding the Gawler East or Evanston Gardens developments. There are currently two new housing developments preparing to utilise the limited capacity at Evanston Substation, in addition to the zone substation's existing supply region of Evanston/Gawler.

The current development rate for the Gawler East development is approximately 35 houses per annum with a projected development rate of 50 dwellings per annum during the 2015-2020 period. Based on this development alone, Evanston zone substation's capacity is forecast to be exceeded by 2018/19. Any deferral solution, such as the construction of new 11kV feeders from Evanston Substation to the new development area will overload Evanston substation. In addition, the proposed Evanston Gardens development (refer to section 11.4.4) will exacerbate this overload.

Ultimately, a new 66/11kV substation is proposed to be located within the new URD development region. The development of this new substation is proposed to be staged such that initially, the site will consist of one 66/11kV transformer, a new 11kV indoor switchboard, new control building and a single 66kV line from the existing Munno Para to Evanston 66kV line. It is proposed to construct three 11kV feeders with appropriate tie points to supply the new load.

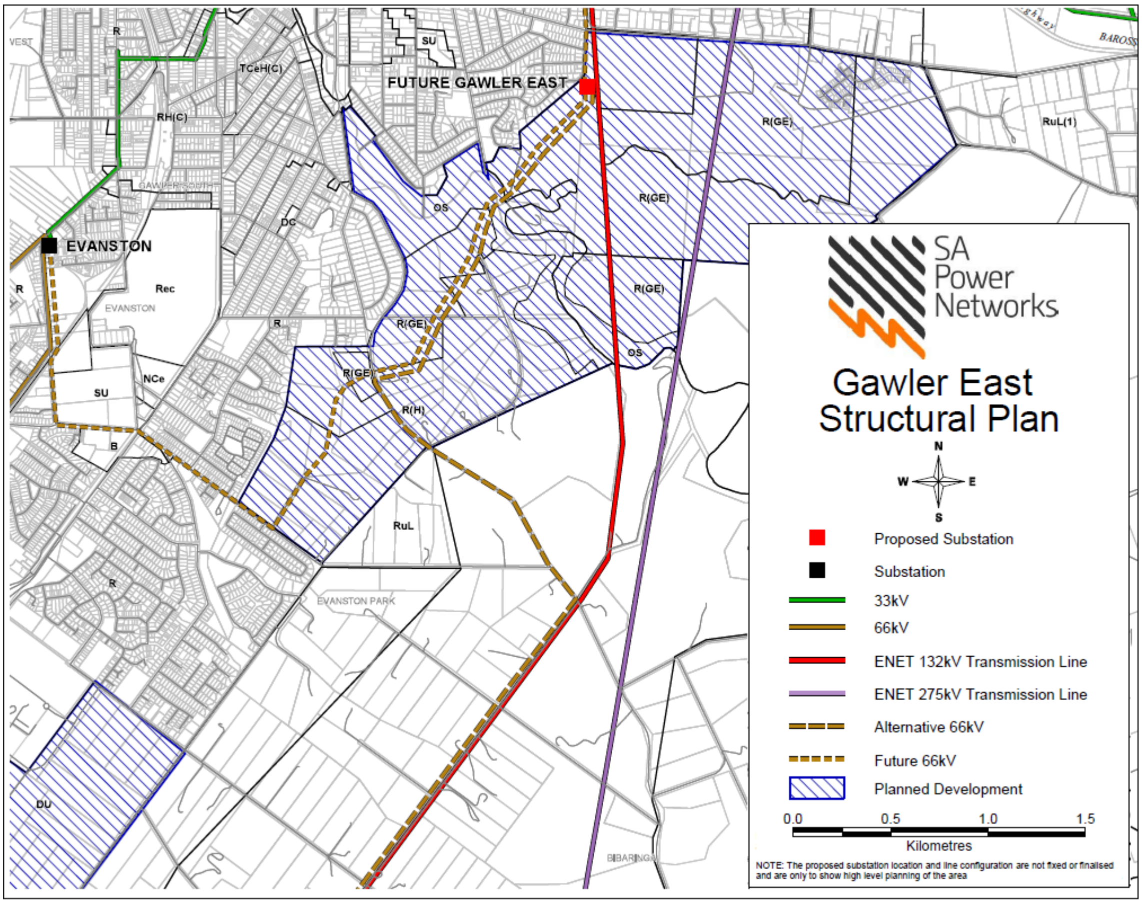


Figure 21: Locality of Future Gawler East 66/11kV Zone Substation

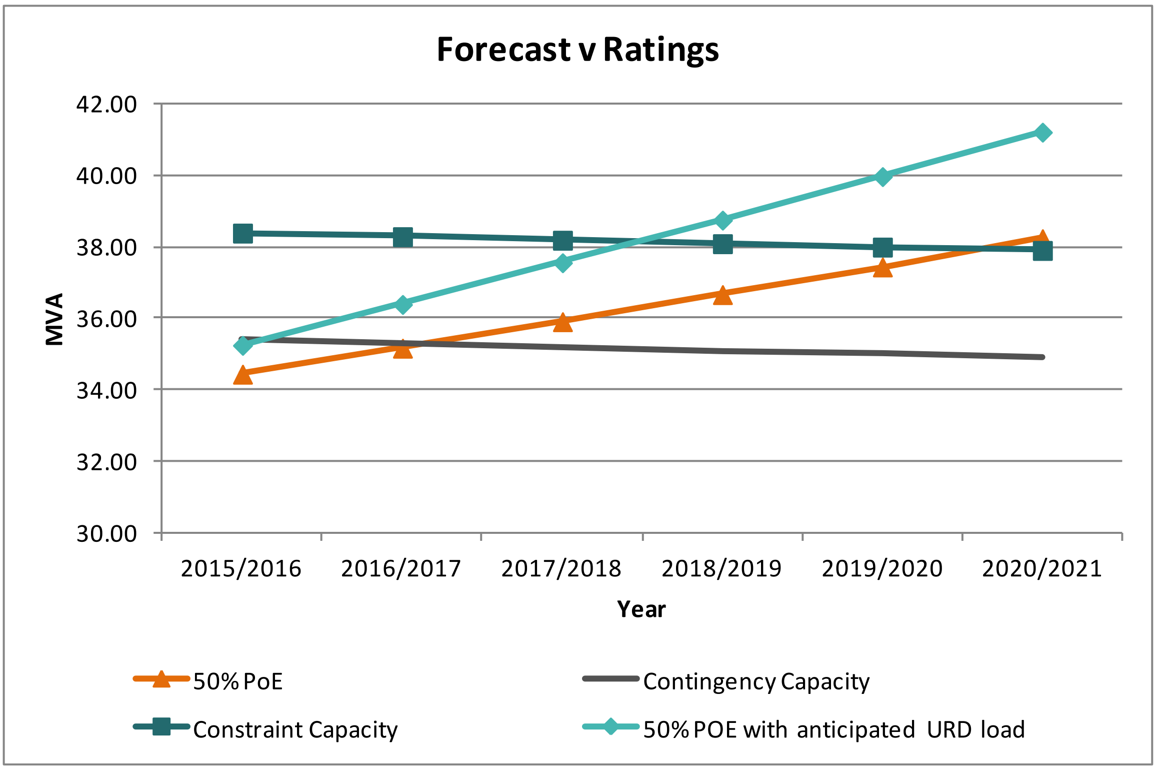


Figure 22: Evanston 66/11kV Load versus Capacity

	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21
Forecast* MVA (50% PoE)	34.4	35.2	35.9	36.7	37.4	38.2
Power Factor	0.94	0.94	0.94	0.94	0.94	0.94
Normal Capacity (MVA)	57.7	57.7	57.7	57.7	57.7	57.7
Firm Delivery Capacity (MVA)	30.5	30.5	30.5	30.5	30.5	30.5
Contingency Capacity (MVA)	35.4	35.3	35.2	35.1	35.0	34.9
Load at Risk (MVA)	0	0	0.7	1.6	2.4	3.3
Forecast MVA (50% PoE) with anticipated Gawler East URD load	35.3	36.4	37.6	38.8	40.0	41.2
Load at Risk (MVA) with anticipated Gawler East URD load	0	1.1	2.4	3.7	5.0	6.3

**Load Forecast includes impact of PV both existing and forecast. The forecast also includes the impact of energy efficiency, state economic and population growth by reconciling each asset's local growth trend with the AEMO July 2014 SA Regional forecast for the next 5 years.*

Table 20: Evanston 66/11kV Load Forecast

Measured load in 2013/14 at Evanston Zone Substation was 35.2MVA.

11.4.3.2 Regulatory Investment Test – Distribution (RIT-D)

As yet, a Non-Network Options Report under the RIT-D has not been published for any of these constraints. A preliminary RIT-D analysis has been undertaken for the constraints and options outlined below. The formal RIT-D process will be performed in line with the NER prior to final project commitment.

11.4.3.3 Deferral Options Considered

The following options were considered to defer the proposed Gawler East 66/11kV Zone Substation:

Power Factor Correction:

- This option is not viable. A 9MVAr, 11kV capacitor bank was installed at Evanston Substation in 2012 for power factor correction and to defer the need for augmentation of Evanston Substation.

Construction of New Feeders and Improved Feeder Ties:

- As an interim solution, the installation of new 11kV feeders from Evanston Substation would allow the initial stages of development to proceed. This includes the construction of a 6km 11kV feeder (5km U/G & 1km O/H). However, new load would be limited to 1MVA as Evanston Zone Substation would then be constrained (within the 2015-20 period). The utilisation of the new 11kV feeder for Gawler East would also impact on deferral options for the Evanston Gardens development as there is only one spare 11kV circuit breaker at Evanston Substation with no space for expansion of the 11kV switchboard.

Evanston Substation Upgrade:

- The upgrade of Evanston substation is not considered feasible (due to site space restrictions) or economical.

11.4.3.4 Options considered to address constraint

The following options have been investigated in accordance with the AER's RIT-D Guidelines to resolve the impending constraint involved with supplying the proposed URD in the Gawler East region:

Option 1: Construct Gawler East 66/11kV Zone Substation

- Construct a new 66/11kV Zone Substation in the Gawler East region requiring a 66kV line extension, new 11kV feeders into the development area and new 11kV feeder ties to Evanston Zone Substation.

Option 2: Construct a new Gawler 33/11kV Zone Substation

- Upgrade the existing 33kV line from Templers to Gawler Belt Tee using 61/3.5 AAAC/1120 conductor. Construct approximately 6km of new 33kV line from Gawler Belt Tee and construct a new 33/11kV zone substation within the Gawler East region. Construct new 11kV feeders from this new zone substation into the development area and new 11kV feeder ties to Evanston Zone Substation to provide back-up under contingency or maintenance conditions.

11.4.3.5 Preferred Solution

The preferred solution, based on a preliminary RIT-D analysis is to construct new 66/11kV zone substation in the Gawler East region with new 11kV feeders into the development area and new 11kV feeder ties to Evanston Zone Substation (Option 1). The indicative cost for this project is $15.8 million.

11.4.3.6 Commitment Status

SA Power Networks has not yet committed to this project. However a preliminary RIT-D analysis has been completed which suggest Option 1 to be the preferred solution. A formal RIT-D will be performed and published prior to the planned construction year when commitment is required for this project.

11.4.3.7 Regulatory Period Expenditure

Approximately $15.8 million is forecast to be required within the 2015 - 2020 regulatory period.

11.4.3.8 Preliminary RIT-D Analysis

Option	Description	NPV[20]
1	Construct new Gawler East 66/11kV with 66kV tee off at Evanston	-6,835,000
2	Upgrade Templers to Gawler Belt 33kV line with line extension to new zone substation	-14,601,000

Table 21: Gawler East RIT-D Analysis Results

[20] Based on use of a 6% discount rate

11.4.4 New Evanston Garden 66/11kV Zone Substation

Another major housing development approximately 3km south of the existing Evanston 66/11kV Zone Substation has been proposed. Little or no SA Power Networks infrastructure exists within the proposed development area. Development has commenced with 0.3MVA of load committed as of June 2014. The development area includes up to 2,900 residential allotments with ultimate demand for the development estimated at 23MVA.

The nearest zone substation at Evanston contains two 25MVA 66/11kV transformers. Under 50% PoE conditions, this zone substation's contingency capacity is forecast to be exceeded in 2020/21 independent of either the Evanston Gardens or Gawler East developments. There are currently two new housing developments preparing to utilise the remaining capacity at Evanston Substation, in addition to the existing region supplied by Evanston Zone Substation in Evanston/Gawler.

The current development rate for Evanston Gardens is approximately 40 homes per annum. This rate is forecast to continue throughout the 2015-20 period. Based on this development alone, Evanston Substation's capacity would be exceeded in 2018/19. In addition, the proposed Gawler East development (refer to section 0) will add to the overload of Evanston Zone Substation.

Ultimately, a new Evanston Gardens Substation is proposed and is to be located within the new URD development region. Initially, this new substation is to include one 66/11kV transformer, new 11kV indoor switchboard housed within a new control building, 66kV line extension from the Munno Para to Evanston 66kV line and 11kV feeders with appropriate tie points to supply the load. The upgrade of Evanston Substation is not considered to be feasible due to both physical (site restrictions) or financial considerations.

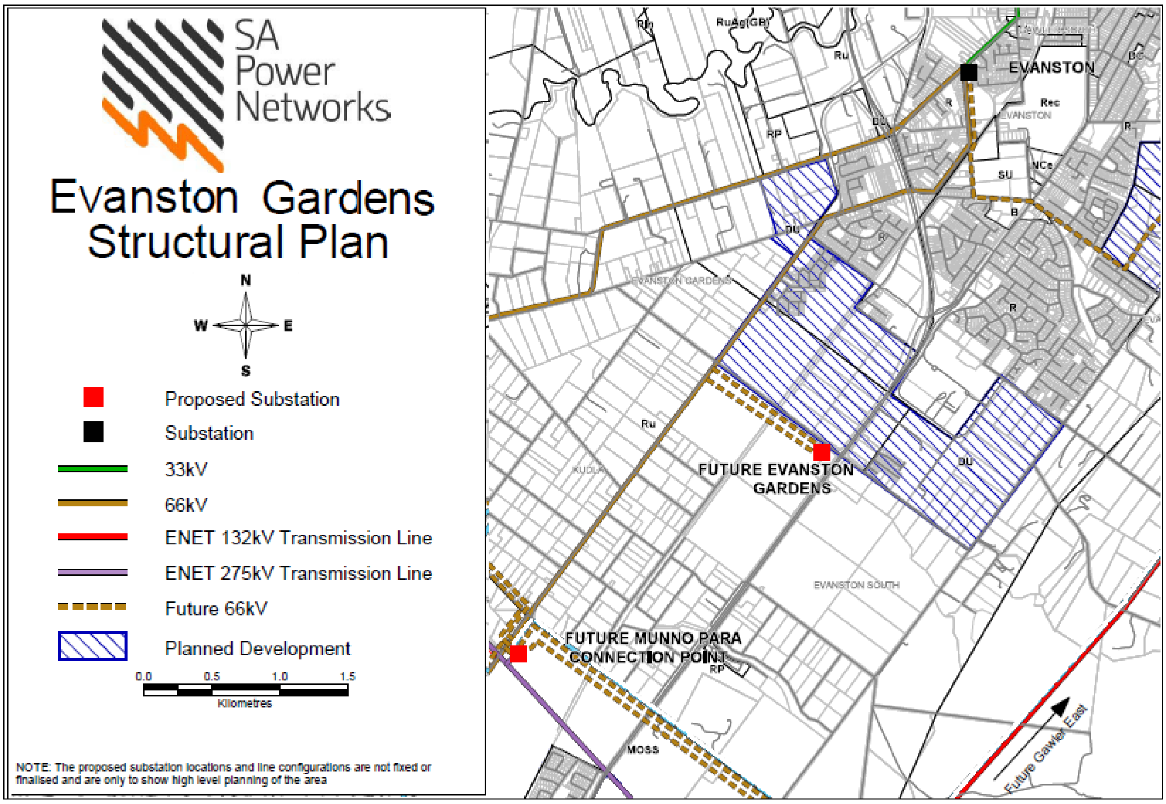


Figure 23: Locality of future Evanston Gardens 66/11kV Zone Substation

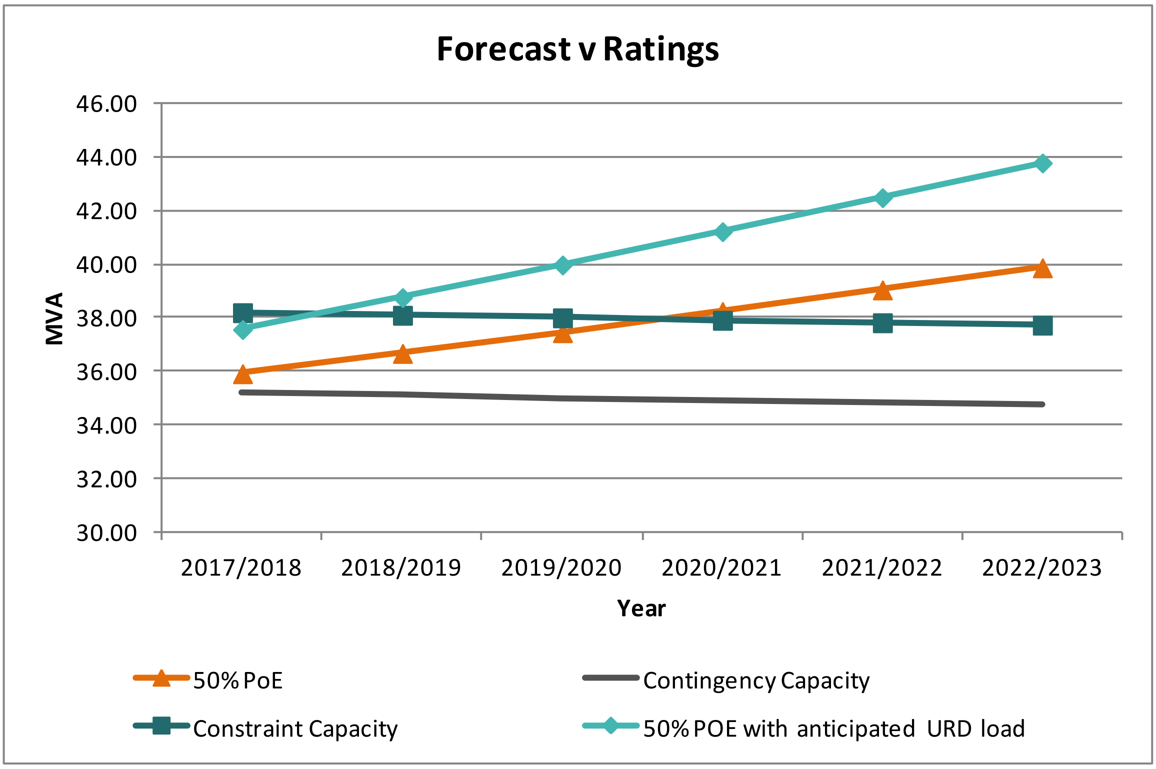


Figure 24: Evanston 66/11kV Load versus Capacity

	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
Forecast* MVA (50% PoE)	35.9	36.7	37.4	38.2	39.0	39.9
Power Factor	0.94	0.94	0.94	0.94	0.94	0.94
Normal Capacity (MVA)	57.7	57.7	57.7	57.7	57.7	57.7
Firm Delivery Capacity (MVA)	30.5	30.5	30.5	30.5	30.5	30.5
Contingency Capacity (MVA)	35.2	35.1	35.0	34.9	34.8	34.7
Load at Risk (MVA)	0.7	1.6	2.4	3.3	4.2	5.2
Forecast MVA (50% PoE) with anticipated Evanston Gardens URD load	37.6	38.8	40.0	41.2	42.5	43.8
Load at Risk (MVA) with anticipated Evanston Gardens URD load	2.4	3.7	5.0	6.3	7.7	9.1

**Load Forecast includes impact of PV both existing and forecast. The forecast also includes the impact of energy efficiency, state economic and population growth by reconciling each asset's local growth trend with the AEMO July 2014 SA Regional forecast for the next 5 years.*

Table 22: Evanston 66/11kV Load Forecast

The measured load at Evanston Zone Substation in 2013/14 was 35.2MVA.

11.4.4.1 Regulatory Investment Test - Distribution

A formal RIT-D has not been undertaken for this constraint. A preliminary RIT-D analysis has been undertaken for the constraints and options outlined below. A formal RIT-D process will be undertaken in line with the NER prior to project commitment.

11.4.4.2 Deferral Options Considered

The following deferral options were considered for the new Evanston Gardens 66/11kV Substation:

Power Factor Correction:

- This option is not viable. A 9MVAr, 11kV capacitor bank was installed at Evanston Substation in 2012 for power factor correction and to defer the augmentation of the site.

Load Transfer and Construction of New Feeder:

- As an interim solution, it is proposed to transfer the load associated with the Gawler East development and existing customers near the Gawler East development from Evanston to the new Gawler East Substation in 2018 (assuming funding is approved by the AER). This will require the construction of a new 11kV feeder from the last remaining 11kV CB at Evanston Substation to the Evanston Gardens region to defer construction of the new Evanston Gardens Substation until 2021. The proposed Gawler East Substation is too remote from the Evanston Gardens development to directly accomodate the Evanston Gardens development's load.

11.4.4.3 Options considered to address constraint

The following options have been investigated in accordance with the NER and AER RIT-D Guidelines to resolve the impending constraint involved with the proposed URD in the Evanston Gardens region:

Option 1:

- Construct a new 66/11kV Zone Substation within the Evanston Gardens development with 66kV line extension (radial initially) from the existing Munno Para to Evanston line, new 11kV feeders into the development area and new 11kV feeder ties to Evanston Zone Substation.

Option 2:

- Construct a new zone substation within the Munno Para Connection Point's 66kV yard consisting initially of a new 32MVA 66/11kV transformer, 11kV switchboard and long express 11kV underground feeders into the development area (approximately 5km each).

11.4.4.4 Preferred Solution

The preferred solution, based on the preliminary RIT-D analysis is to construct a new 66/11kV zone substation within the Evanston Gardens development with new 11kV feeders into the development area and new 11kV feeder ties to the Evanston Zone Substation (Option 1) by 2021. The indicative cost for this project is $10.1 million.

11.4.4.5 Commitment Status

SA Power Networks has not yet committed to this project. However, a preliminary RIT-D analysis has been completed and indicates the preferred solution is to construct Evanston Gardens 66/11kV Zone Substation (Option 1). A formal RIT-D process will be undertaken prior to the implementation of any solution to resolve the constraints projected by this land development.

11.4.4.6 Regulatory Period Expenditure

Based on indicative project costs totalling $10.1 million, approximately $2.6 million is forecast to be required during the 2015-20 regulatory control period, with the remaining $7.5 million forecast within the 2020-25 regulatory period.

11.4.4.7 Preliminary RIT-D Analysis

Option	Description	NPV[21]
1	Construct new Evanston Gardens 66/11kV Zone Substation with 66kV tee off from existing Munno Para-Evanston 66kV line	-5,108,000
2	Construct new Munno Para 66/11kV Zone Substation	-5,236,000

Table 23: Evanston Gardens RIT-D Analysis Results

[21] Based on use of a 6% discount rate

11.5 Feeders

The region's *zone substations* supply 91, 11kV *feeders* serving approximately 85,250 customers via its *distribution substation*s. Table 24 details those *feeder* constraints forecast over the forthcoming five year regulatory control period.

Project Timing	Project Name	Limitation / Constraint	Proposed Solution	Section Ref	2015-20 Cost ($ million)	2020-25 Cost ($ million)	Total Cost[22] ($ million)
2017	Salisbury Park new 11*kV feeder*	In event of fault on the existing Salisbury Plains 11*kV feeder*, unable to transfer all load to adjacent *feeders*.	Construct new Salisbury Park 11*kV feeder* ex Elizabeth South *zone substation*.		**3.24**	-	3.24

Table 24: Metro North Feeder Projects

[22] Total cost to the end of 2014/15 financial year.

11.5.1 Major Project – Salisbury Park New Feeder

11.5.1.1 Constraint

The Salisbury Plains 11kV feeder (SA-14) is supplied from Salisbury 66/11kV Zone Substation and has an N-1 offload capability of 436A in 2015/16. Under 50% PoE conditions, the feeders N-1 offload capacity will be exceeded in 2015/2016.

The forecast growth rate for Salisbury Plains 11kV feeder is 0.2% per annum. In 2013/14, the feeder's load characteristic during peak load times was essentially flat from the period between 6:30pm to 8pm, with the actual peak occurring at 8pm. This is due to the impact of installed PV systems reducing the native demand from earlier in the day and rapidly dropping off between 6-8pm. A check of measured growth at 8pm (PV affects negligible) between 2009/10 and 2013/14 (both approximately 10% PoE years) returns a growth rate of 1.1% per annum and shows that the recent underlying growth at this time exceeds forecast.

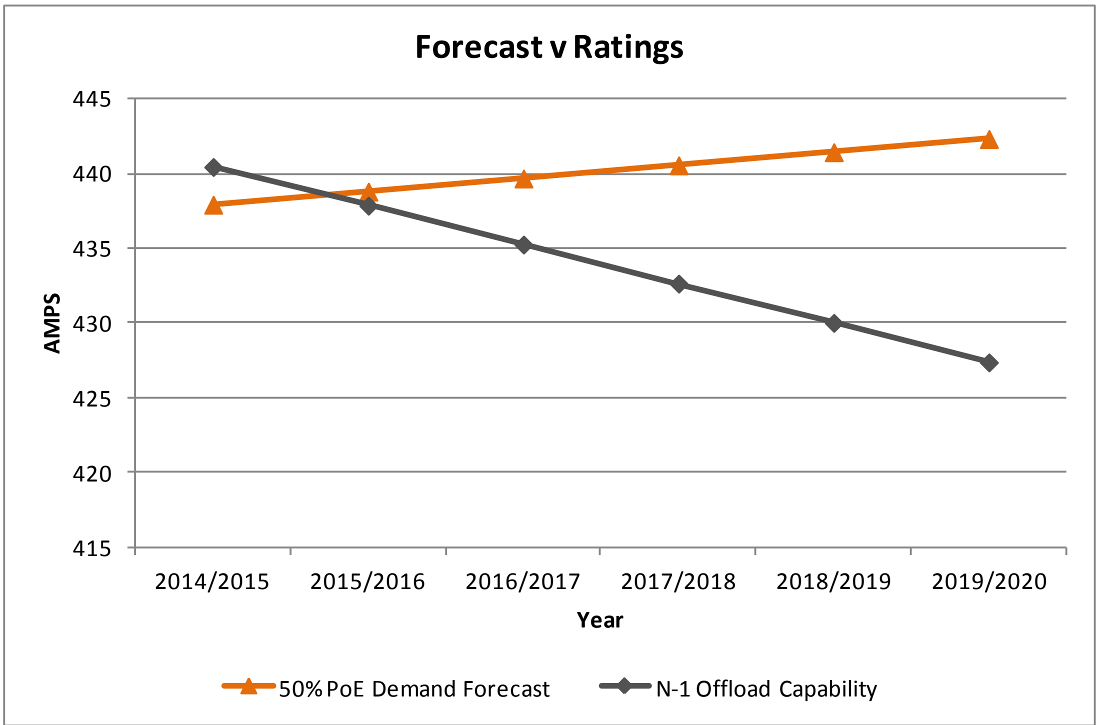


Figure 25: Salisbury Plains 11kV feeder Load versus Capacity

	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
Forecast* Amps (50% PoE)	438	439	440	441	441	442
N-1 Offload Capability (Amps)	440	438	435	433	430	427
N-1 Load at Risk (Amps)	0	1	5	8	11	15

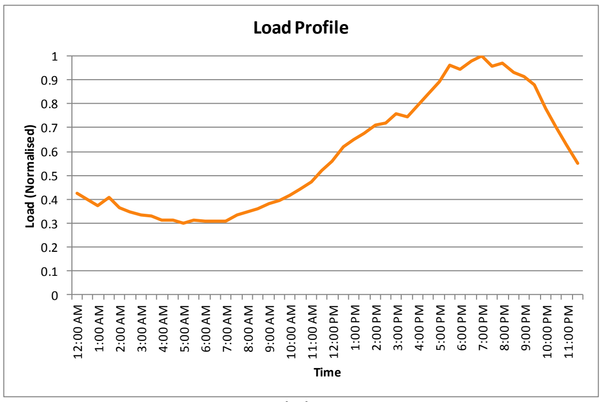
**Load Forecast includes impact of PV both existing and forecast. The forecast also includes the impact of energy efficiency, state economic and population growth by reconciling each asset's local growth trend with the AEMO July 2014 SA Regional forecast for the next 5 years.*

Table 25: Salisbury Park 11kV Feeder Load Forecast

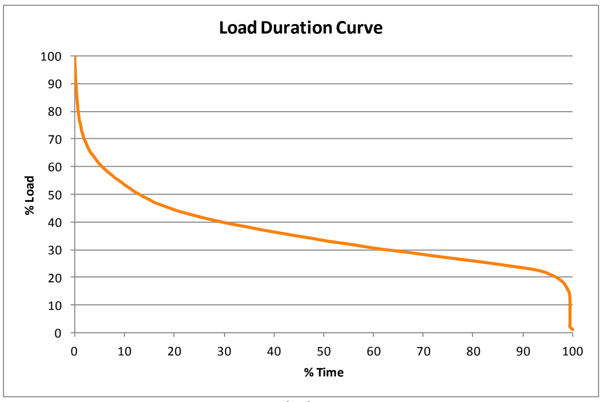
11.5.1.2 Consequences for Customers

The 50% PoE forecast peak demand of the Salisbury Plains 11kV feeder (SA-14) in 2016/17 is 440A, which will exceed its N-1 offload capability of 435A. In the event of cable failure, after all available N-1 offload capacity is exhausted, 5A of load and more than 30 customers would be unsupplied until the cable fault was repaired, increasing to 15A and more than 110 customers by 2019/20. However, due to the discrete number of switching points on a given feeder, it is not possible to load shed an exact amount of customers. In general, it is likely that a larger portion of the feeder would need to be shed. As there are typically 500 customers (ie approx 100A of load) between tie points, the N-1 offload capability of the Salisbury Plains 11kV feeder is expected to be exceeded for a total of three hours in 2017/18 over 2 days per annum increasing to 6 hours in 2019/20 over 4 days per annum.

11.5.1.3 Load Profile



(a)



(b)

Figure 26: (a) Salisbury Plains 11kV feeder Load Profile, (b) Load Duration Curve

11.5.1.4 Deferral Options Considered

Improved Feeder Ties

- All possible feeder ties and associated transfers have been accounted for and included in the N-1 offload capability. The addition of further feeder ties or improvements to existing ties is not feasible due to high existing demand on adjacent feeders.

Demand Side Participation

The use of direct load control technology may be viable which would see the tripping of multiple small air conditioning units can be performed. Recent experiences have shown the costs of such a solution to be approximately $800/kVA per annum. With the application of direct load control technology, it may be economically viable to defer the project until 2019/20 based on 50% PoE conditions.

However, in 10% PoE years such as that experienced in 2013/14, this level of demand side participation will be inadequate and at least 500 customers (ie 100A) will need to be shed under contingent conditions.

11.5.1.5 Options considered to address constraint

The following options have been investigated to resolve the impending constraint:

Option 1:

- Establish a new Salisbury Park 11kV feeder by installing approximately 2.9km of 630mm^2 Al XLPE cable from a spare feeder circuit breaker located at Elizabeth South 66/11kV Zone Substation and transferring load from existing Salisbury Plains and Elizabeth East 11kV feeders.

Option 2:

- Establish a new 11kV feeder at Salisbury 66/11kV Zone Substation by installing approximately 2.8km of 630mm^2 Al XLPE Cable from an existing spare feeder breaker, re-stringing approximately 1km of existing overhead conductor and transferring load from the existing Salisbury Plains and River 11kV feeders.

11.5.1.6 Preferred Solution

The preferred solution based on a net present value analysis, is to implement direct load control technology as part of a Demand Side Participation scheme in 2017 and 2018 to defer the constraint until 2019. The indicative total cost for the implementation of this scheme is $300,000 over the two year period. The preferred option in 2019, is to establish a new Salisbury Park 11kV feeder from Elizabeth South 66/11kV Zone Substation and transfer load from the existing Salisbury Plains and Elizabeth East 11kV feeders. This project is planned for completion in November 2019 and is expected (based on present forecasts) to resolve the constraint on the Salisbury 66/11kV Zone Substation feeders for at lest 10 years. The indicative cost for this project is $2.9 million.

11.5.1.7 Regulatory Period Expenditure

The total estimated $3.2 million is forecast to be spent during the 2015 - 20 regulatory control period.

12. METRO SOUTH – REGIONAL DEVELOPMENT PLAN

SA Power Networks' Metro South Region covers the southern suburbs of metropolitan Adelaide which in terms of area, is the largest of the metropolitan regions. The region stretches south from Keswick in the north to Willunga in the south and west of the hills face to the coast. The region's load includes significant heavy industrial loads at Lonsdale to viticultural loads within McLaren Vale and surrounds.

A map of this region is shown in Figure 27 while a single line representation of the *network* is shown in Figure 28.

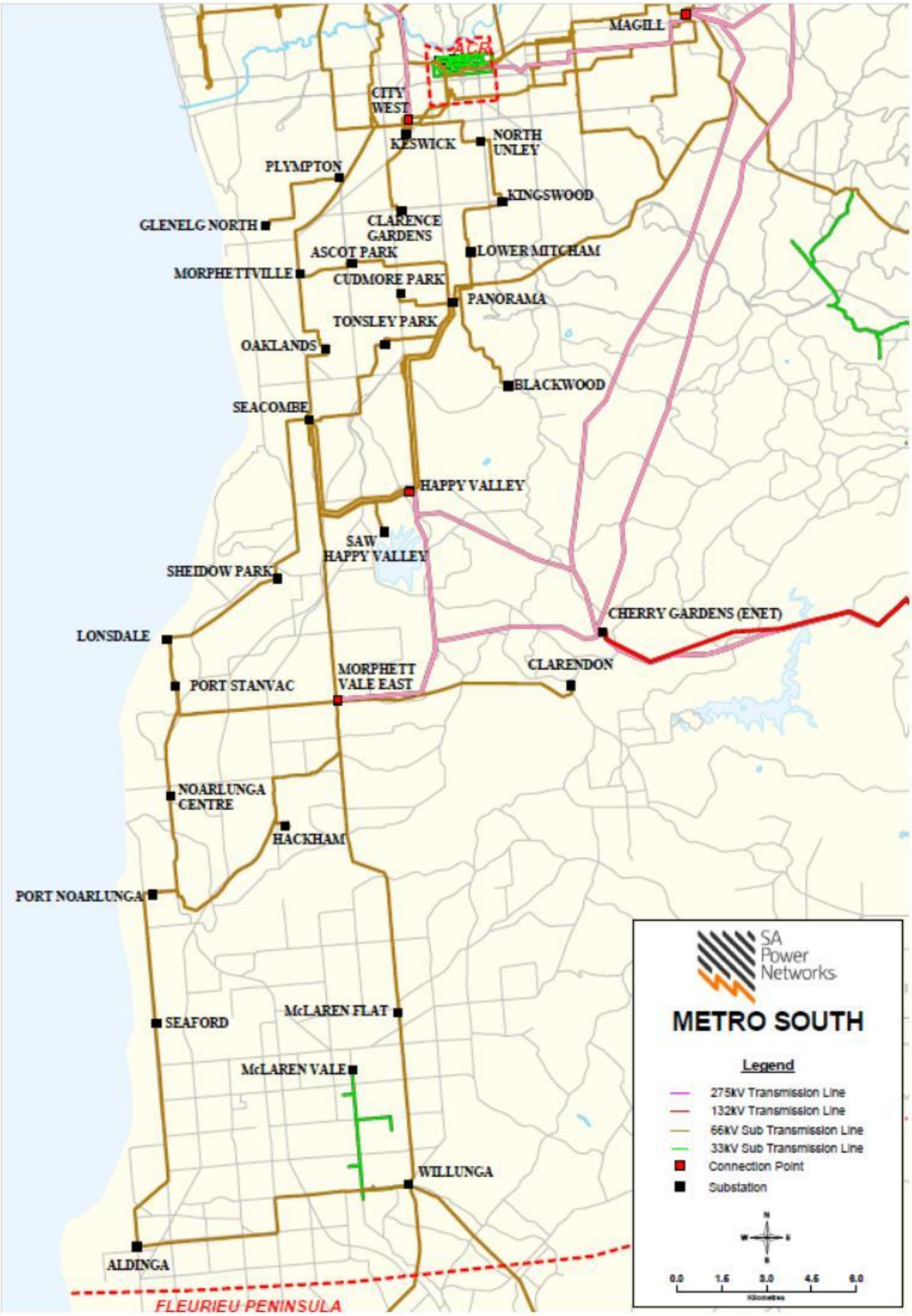


Figure 27: Metro South Area

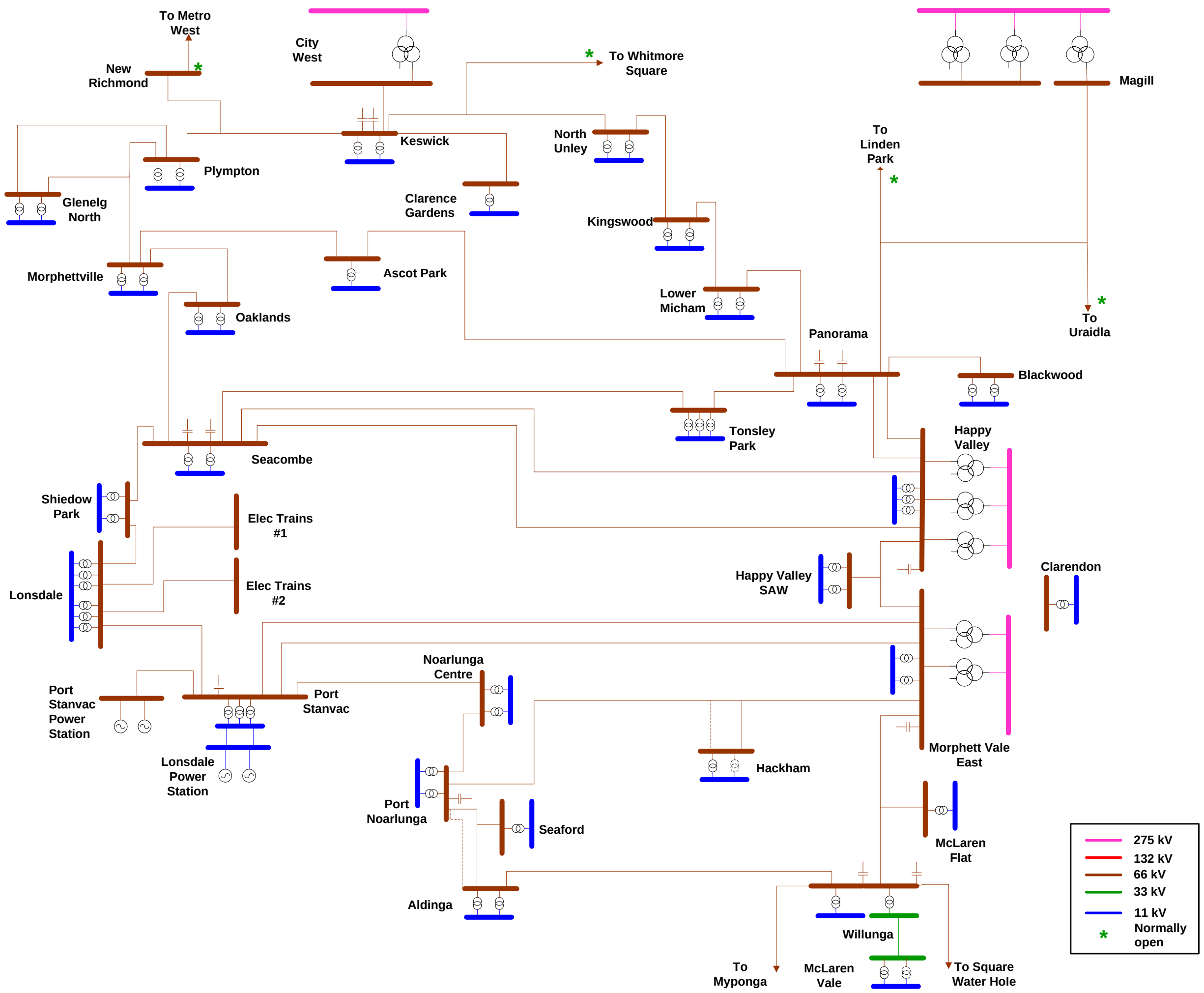


Figure 28: Metro South Single Line Diagram

12.1 Region Statistics

Table 26 indicates the general statistics for this region of the state.

Parameter	Value
No of connection points	4 (275/66*kV*)
No of zone subs	32 (66/11*kV*) (excludes thosein Fleurieu Region)
Operating voltages	66*kV*, 33*kV* and 11*kV*
Total customers	194,789
No of residential customers (abs /%of region/% of state)	180,242 / 92.5% / 21.2%
No of commercial customers (abs /%of region/% of state)	14,547 / 7.5% / 1.7%
Area of region (km^2 / % of state)	661 / 0.29%
Length of 66kV cable (km / % of region 66kV)	19 km/ 9.1%
Length of 66kV conductor (km / % of region 66kV)	190 km / 98.9%
Length of 33kV cable (km / % of region 66kV)	0 km / 0%
Length of 33kV conductor (km / % of region 66kV)	5.3 km / 100%
Length of 11kV cable (km / % of region 11kV)	747 km / 36.4%
Length of 11kV conductor (km / % of region 11kV)	1,305 km / 63.6%
Installed *PV* inverter capacity (*MW* / % of state)	129*MW* / 22.5%
No of feeders (abs / % urban / % rural short / % rural long)	144 / 91.7% / 8.3% / 0%

Table 26: Metro South Region Statistics

12.2 Development History

The Metro South region is the largest metropolitan area both in terms of geographic area and customer numbers. The region has been developed and expanded over time as the region has developed and expanded further south.

The region was originally supplied at 33kV until the mid to late 1950s with the introduction of 66*kV* as a *sub-transmission* voltage and similarly, all *feeders* were originally energised at 7.6*kV* until the introduction of 11*kV* as the standard distribution voltage. No 7.6*kV* systems remain within the region.

The region's first 275/66*kV connection point* was constructed at Happy Valley in 1969 with the second such *connection point* at Morphett Vale East being constructed in 1982. Additional *connection point* capacity was provided from Magill in 2007 with City West *connection point* being commissioned in December 2011.

Significant State Government infrastructure projects have taken place within this region in recent times including the construction of a new *zone substation* at Lonsdale to supply the Adelaide Desalination Plant and 66*kV* connections to supply the Seaford Rail Electrification program. The table below indicates some significant projects which have occurred within the region over the course of the present regulatory period, irrespective of the project dirver (ie capacity, customer driven, safety etc).

Project Title	Description	Commissioning Year	Cost ($ million)
Hackham Substation	Establishment of new 66/11*kV zone substation* consisting of a single 25 *MVA* transformer, 66*kV* cable entry, control building and two section 11*kV* indoor switchboard.	2010	9.2
City West Connection Point	Establishment of a new 275/66*kV connection point* injection into the Metro South region. Installation of two, 2000mm^2 Cu XLPE cables per phase from City West to Keswick *zone sub* and associated protection and *zone sub* upgrade works to facilitate connection and increased fault levels.	2011	76.4
Happy Valley Upgrade	Upgrade of five of this *connection point*'s 66*kV line* exit *CBs* due to increased fault levels associated with the construction of City West *connection point*. Upgrade of the site's bus zone protection and construction of a new masonry control building to house *SA Power Networks'* equipment and two new 11*kV* switchboard sections.	2010/11	7.8
Panorama Sub Upgrade	Upgrade of two transformers from 10 *MVA* to 25 *MVA* units. Construction of a new masonry control room containing a new three section 11*kV* switchboard and associated bus zone and *line* protection.	2012	10.5
Clarence Gardens Sub Upgrade	Upgrade of the existing 10*MVA* transformer with a new 32*MVA* unit, construction of a new masonry control building containing a new 11*kV* switchboard.	2013	8.0
Morphettville – Glenelg North 66kV Line	Construction of a second 66*kV* cable entry to Glenelg North *zone substation* teed off the existing Morphettville – Plympton 66*kV line*. Reconfiguration of the 66*kV* bus at Glenelg North and installation of new *line* exit *CBs* at this site.	2014	8.4[23]

Table 27: Recent Metro South Augmentation Projects

[23] Approved amount

12.3 Connection points and sub-transmission lines

The region is supplied by four 275/66*kV connection point*s located at City West, Magill, Happy Valley and Morphett Vale East. While not considered part of the Metro South area, the Fleurieu Peninsula region is also supplied by these *connection point*s by the 66*kV lines* emanating from Willunga *zone substation*.

The region's *connection point*s have a combined normal rating of 1,527 *MVA* and a notional *N-1* capacity of 1,275 MVA.

These *connection point*s are meshed via *SA Power Networks'* 66*kV sub-transmission network*. Under the *ETC*, these *connection point*s are classified as Category 4 sites and are required to be planned on a *N-1* basis for both transmission lines and transformers.

Given the significance of this region to the state in terms of customer numbers, *SA Power Networks* plans this region's *sub-transmission network* based on a *N-1* basis against the 10% *PoE* forecast. Constraints on the *meshed sub-transmission network* and of *ElectraNet's* 275/66*kV* transformers are determined through modelling of the network and analysis using *PSS/E*.

Within the time period covered by this *AMP*, no augmentation of the region's *connection point* transformer capacity is forecast to be required. A copy of the region's *connection point* forecasts are shown in APPENDIX C – METRO SOUTH REGION .

No *connection point* constraints are forecast within the 2015-25 period.

The region contains 66*kV* ties to the Metro West, Metro East, *ACR* and Eastern Hills regions at New Richmond, Linden Park, Whitmore Square and Uraidla *substations* respectively. Whilst most *zone substations* within the region are meshed, the region contains several radial *zone substations* being Clarendon, Blackwood, Clarence Gardens, Hackham, McLaren Vale, Seaford, McLaren Flat.

Table 28 lists those *sub-transmission line* constraints identified within the region over the forecast period.

Section Ref	Project Name	Constrained Line(s)	Constraint Type	Constraint Description	Proposed Solution	Constraint Year	Commissioning Year	2015-20 Cost ($ million)	2020-25 Cost ($ million)	Total Cost ($ million)
-	Glenelg North 2nd *Line* – Morphettville to Plympton Tee to Glenelg North	Plympton – Glenelg North 66*kV*	N-1	Loss of existing radial 66*kV* supply to Glenelg North results in loss of *zone substation* and inability to fully restore supply via *feeder* transfers	Construct an alternate 66*kV* supply via diverse route to supply Glenelg North.	2015	2015	**0.25**	-	8.70
-	Morphettville - Plympton Protection Upgrade	Morphettville – Plympton 66*kV*	N-1	System security. Enable three ended auto-changeover scheme to Glenelg North.	Replace existing protection at Morphettville and Plympton with new fibre based differential scheme to enable conversion to a three ended auto flip-flop arrangement.	2015	2015	**0.54**	-	1.07
12.3.1	Port Noarlunga to Aldinga # 2 66*kV Line*	Morphett Vale East – Willunga and Port Noarlunga – Aldinga 66*kV*	N-1	Loss of the Port Noarlunga – Aldinga *line* results in overload of the Morphett Vale East – Willunga *line* and vice versa	Convert the existing Port Noarlunga – Aldinga *line* to double circuit.	2013	2016	**15.13**	-	15.84
-	Port Stanvac to Noarlunga Centre *Line* Uprate	Port Stanvac – Noarlunga Centre 66*kV*	N-1	Loss of Morphett Vale East - McLaren Flat - Willunga 66*kV line* overloads Port Stanvac – Noarlunga Centre 66*kV*	Uprate the *line* from T65 to T80.	2013	2016	**0.78**	-	0.82

Section Ref	Project Name	Constrained Line(s)	Constraint Type	Constraint Description	Proposed Solution	Constraint Year	Commissioning Year	2015-20 Cost ($ million)	2020-25 Cost ($ million)	Total Cost ($ million)
-	Morphett Vale East to Clarendon 66*kV Line* Uprate	Morphett Vale East – Clarendon 66kV	N	Overload of Morphett Vale East – Clarendon 66*kV line* under *normal conditions*	Upgrade the *line's* design temperature from 50°C to 80°C	2016	2018	**3.79**	-	3.86
-	Aldinga to Willunga Pole Upgrade	Aldinga – Willunga 66*kV*	N	Mechanical overload of existing *line* poles.	Replace overloaded poles to ensure security of the *line*	2016	2019	**2.95**	-	3.10
-	Whitmore Square Tee to North Unley 66*kV Line* Uprate	Whitmore Tee – North Unley 66*kV*	N-1	Loss of Panorama - Lower Mitcham 66*kV* overloads North Unley - Whitmore Tee 66*kV*	Uprate the *line* from T80 to T100.	2017	2020	**-**	0.13	0.13
-	Port Stanvac - Noarlunga Centre conductor upgrade	Port Stanvac - Noarlunga Centre 66*kV*	N-1	Loss of MVE - Willunga *line* under a high generation scenario overloads the existing conductor designed at its ultimate rating (T100).	Upgrade 2.8km of existing 0.225 ACSR with 61/3.5 AAAC/1120 (Silicon)			**1.15**	1.04	2.18
-	MVE - McLaren Flat conductor upgrade	MVE - McLaren Flat 66*kV*	N-1	Loss of Aldinga - Willunga line causes MVE - McLaren Flat *line* to overload. Existing line already at its ultimate rating	Upgrade 9.4km of existing 244 ACSR with 61/3.5 AAAC/1120 (Silicon) designed for T100.			**-**	7.75	7.75

Section Ref	Project Name	Constrained Line(s)	Constraint Type	Constraint Description	Proposed Solution	Constraint Year	Commissioning Year	2015-20 Cost ($ million)	2020-25 Cost ($ million)	Total Cost ($ million)
-	Aldinga - Willunga conductor upgrade	Aldinga – Willunga 66*kV*	N-1	Loss of MVE - McLaren Flat *line* overloads the Aldinga - Willunga *line* which is already at its ultimate rating	Upgrade 10.5km of conductor on the Aldinga - Willunga line with 61/3.5 AAAC/1120 (Silicon) at T100			-	8.61	8.61

Table 28: Metro South Sub-transmission Line Constraints

12.3.1 Major Project – Port Noarlunga to Aldinga 66kV line #2 & Myponga to Square Water Hole 66kV line.

12.3.1.1 Background

Supply to the Fleurieu Peninsula consists of three components:

53. 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.
54. A 66kV radial line from Willunga substation to Square Water Hole Zone Substation and then onto Victor Harbor and Goolwa Zone Substations;
55. A radial line from Willunga Zone Substation to Myponga, Yankalilla and Cape Jarvis and then via undersea cable to Kangaroo Island.

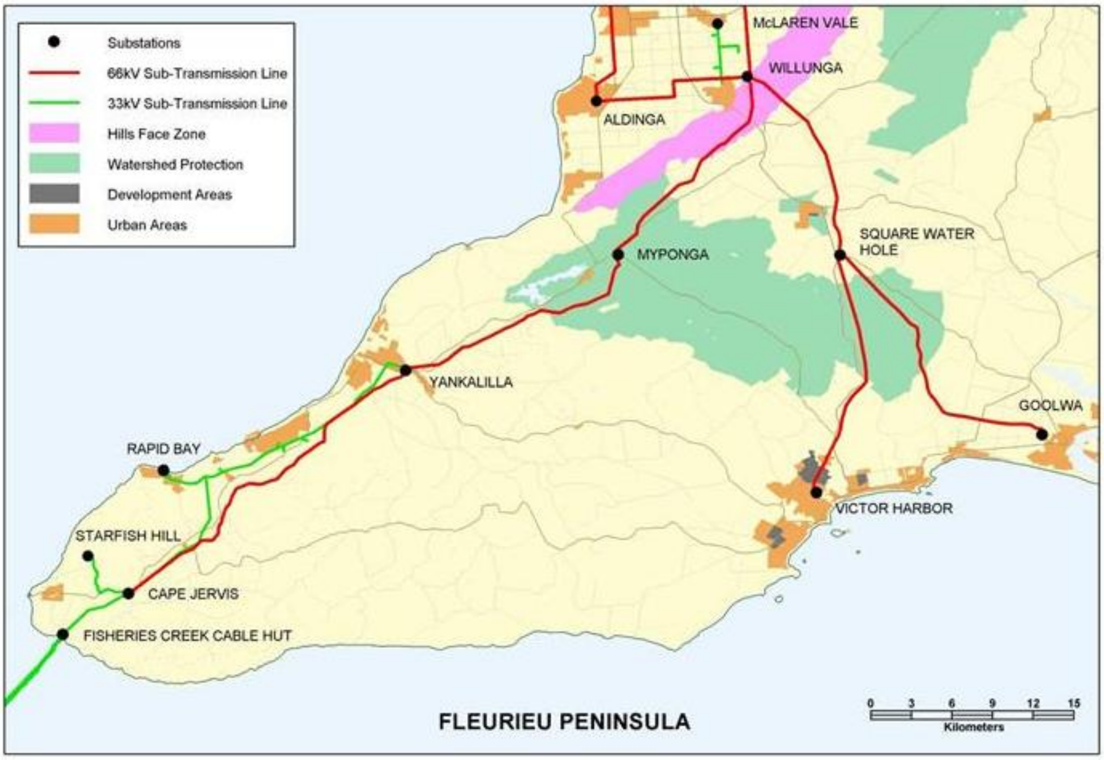


Figure 29: Fleurieu Peninsula Sub-transmission System

12.3.1.2 Constraint

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 2016/17, 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 110% (102 MVA) of its emergency summer rating (93 MVA).

- In 2016/17, 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 110% (101MVA) of its emergency summer rating (92 MVA).

All values are based on measured load as at the 16 January 2014.

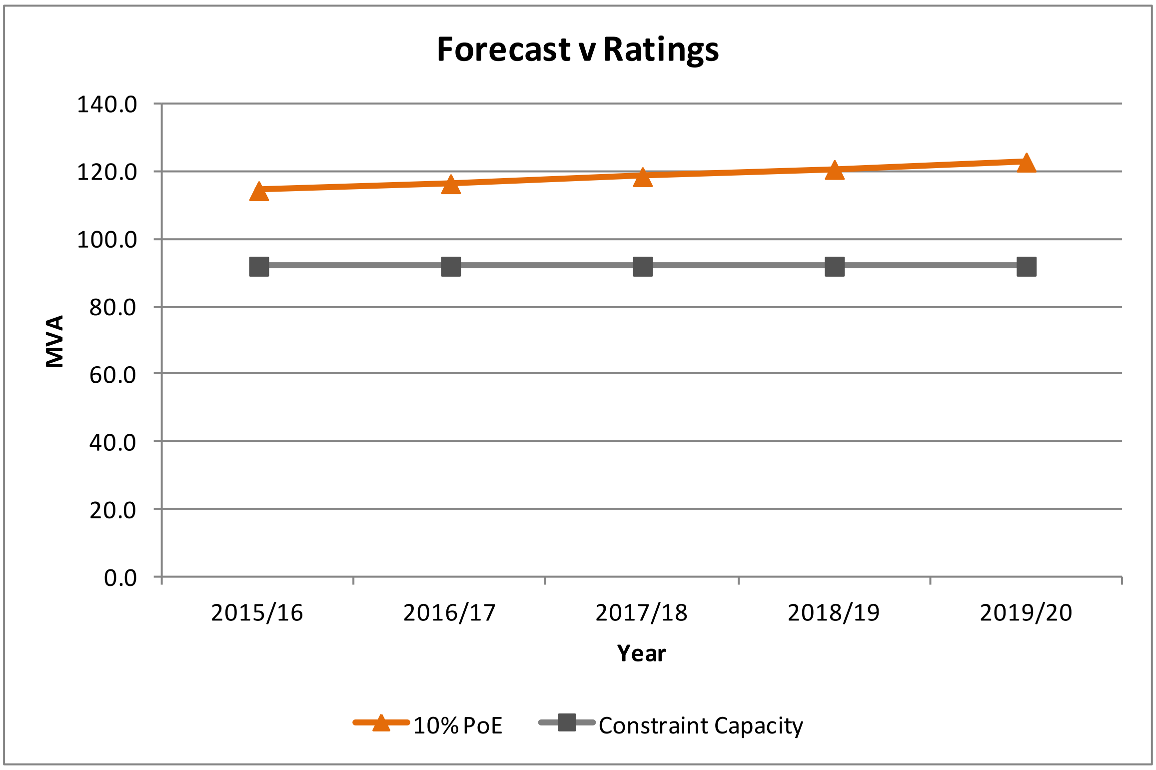


Figure 30: Southern loop Load versus Capacity

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 15 km 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 30 MVA. This first occurred in 2006 during the summer peak and now occurs regularly during both the summer and winter peaks, demonstrated in Figure 31.

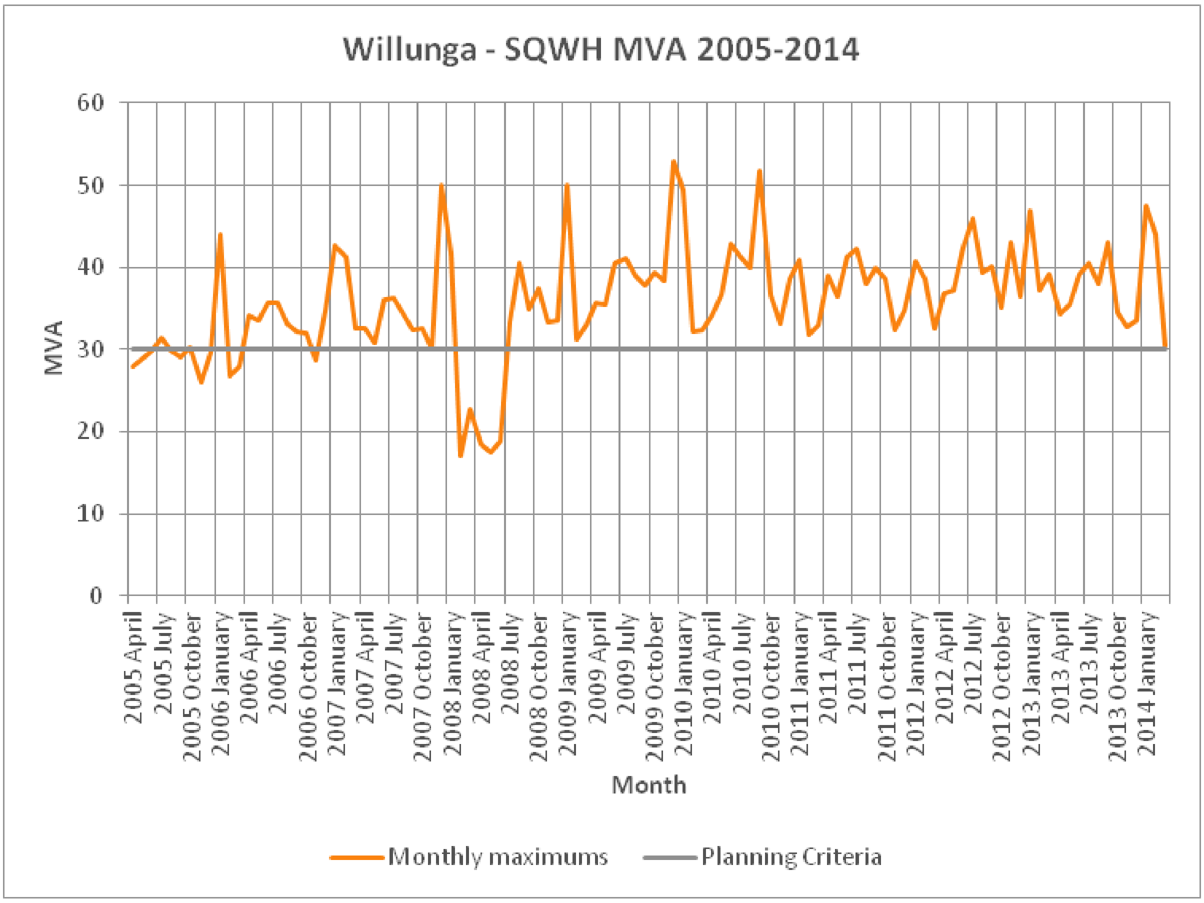


Figure 31: Willunga to Square Water Hole Monthly Maximum Demands

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 22MW and wind farm production (connected at Cape Jervis) at approximately 32 MW. No capacity constraints of the line are forecast in the short to medium term horizon.

12.3.1.3 Consequences for Customers

Southern 66kV Loop

For an outage of either line on the Port Noarlunga – Willunga – Morphett Vale East 66kV network, approximately 9MVA of customer load would need to be shed in the summer of 2016/17 to avoid exceeding the emergency rating of the remaining line. This equates to approximately 2,800 customers who would need to be shed.

Radial 66kV Line Willunga – Square Water Hole

An outage of the Willunga – Square Water Hole 66kV line will impact approximately 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.

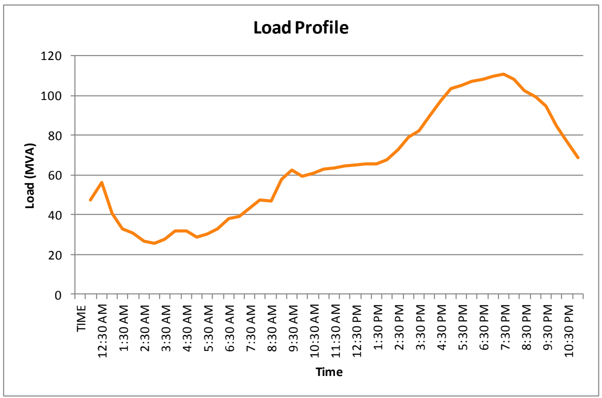
The line traverses a High Bush Fire Risk Area and areas of farm land that is difficult to access during winter. Consequently, there is a significant risk of lengthy delays in restoring the line following a fault that requires heavy vehicle access to remedy.

Radial 66kV Line - Willunga – Myponga

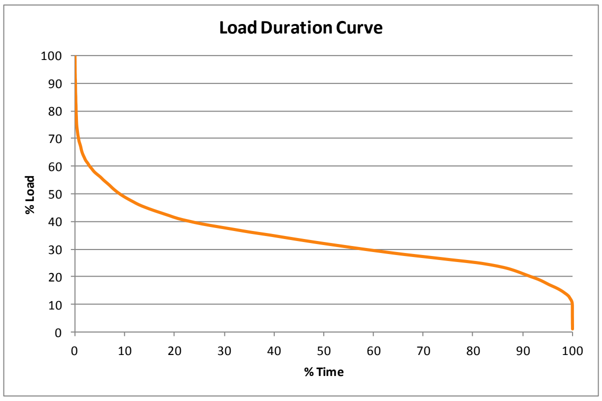
An outage of the Willunga – Myponga 66kV line will impact approximately 9,000 customers, leaving them without supply until the line is restored to service. Due to the distances and the topography there are no practical means of transferring load to other zone substations. The generator station at Kingscote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

12.3.1.4 Load Profile



(a)



(b)

Figure 32: (a) Southern Loop Load Profile, (b) Load Duration Curve

12.3.1.5 Regulatory Investment Test - Distribution

In response to the constraint within the Southern Loop, a Request for Proposals was published in accordance with the NER's former Regulatory Test in 2010. Request for Proposals, RFP 001-10 was published in March 2010.

Several non-network proposals were received 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. Negotiations with this non-network proponent regarding the possible implementation of their non-network solution are ongoing and discussed further below.

12.3.1.6 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.

12.3.1.7 Options considered to address constraint

The following options have been investigated in accordance with the AER's RIT-D Guidelines to resolve the impending constraint within the Metro South region's Southern Loop:

56. Reconfigure the existing single circuit 66kV line between Port Noarlunga and Aldinga to double circuit;
57. Reconfigure the existing single circuit 66kV line between Morphett Vale East and Willunga to double circuit;
58. Upgrade the conductor on both the Port Noarlunga to Aldinga and Morphett Vale East to Willunga lines to achieve a higher capacity.

We have also received a proposal from a third party for a non network solution. This proposal consists of the construction of a 60 MW diesel powered peaking power station south of Square Water Hole Zone Substation to provide network support under 10% PoE conditions. This solution would:

59. Eliminate the constraint on the southern 66kV loop by operating under 10% PoE conditions therefore reducing the demand seen by the sub-transmission network at Willunga Zone Substation.
60. Support the eastern half of the Fleurieu Peninsula following loss of the Willunga – Square Water Hole 66kV line by operating in island mode to maintain supply to Victor Harbor, Goolwa and Square Water Hole Zone Substations.

This non-network solution whilst resolving the overload constraint within the Metro South network, 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.

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:

61. 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.
62. Build a second single circuit line between Willunga and Square Water Hole and another between Willunga and Myponga in parallel with the existing lines;
63. Build new double circuit lines to replace the existing single circuit lines; and

12.3.1.8 Preferred Solution

SA Power Networks has performed a market benefits test according to the former Regulatory Test (equivalent to the RIT-D) of the above options and has concluded that the preferred network solution therefore has two components:

- Reconfiguration of the existing single circuit 66kV line between Port Noarlunga and Aldinga to double circuit in 2016 at a cost of approximately $15.2 million (minimalist solution); and
- Construction of a new 66kV line connecting Square Water Hole to Myponga in 2017 at a cost of approximately $21.6 million.

In addition we have also evaluated the non-network option of a 60 MW 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.

12.3.1.9 Commitment Status

The relevant regulatory process (Regulatory Test) was commenced in 2010 with this project being included within the pre RIT-D committal list issued to the AER in December 2013.

The analysis undertaken suggests the solution with the highest net market benefit is the network solution. As such, both elements of the network solution have been included within SA Power Networks' funding plans. Final commitment to either solution will be subject to finalisation of the Regulatory Test process and further discussion with the non-network proponent.

12.3.1.10 Regulatory Period Expenditure

Approximately $36.9 million is forecast to be required during the 2015-20 regulatory control period consisting of $15.13 million to resolve the constraint within the Metro South region's meshed network and $21.8 million to remove the radial risk exposure at Square Water Hole and Myponga.

12.3.1.11 Preliminary RIT-D Analysis

A detailed preliminary RIT-D analysis has been completed for each of the three options namely:

64. the minimalist network solution;
65. the nominated preferred network solution; and
66. the non-network solution.

This analysis has been conducted over a range of growth rate scenarios and shows the minimalist network solution to be the least cost. The preferred network solution has a greater market benefit with regard to improvement in reliability than the minimal network solution, however it is marginal when compared with the non-network solution. Please refer to detailed prelim RIT-D analysis results.

12.4 Zone substations

Electricity is supplied throughout the Metro South region via 30, 66/11*kV*, one 66/33*kV* and one 33/11*kV zone substations* supplying the 11*kV feeder network* from which the vast majority of customers within the region are supplied at *LV* by *SA Power Networks' distribution substation*s.

Forecasts for the region's *zone substations* are shown in APPENDIX C – METRO SOUTH REGION .

Based on the *zone substation* forecasts, the capacity constraints listed in Table 29 have been identified.

Project Timing	Project Name	Limitation / Constraint	Proposed Solution	Section Ref	2015-20 Cost ($ million)	2020-25 Cost ($ million)	Total Cost ($ million)
2015	McLaren Flat *Sub* Upgrade	Overload of McLaren Flat zone substation under contingent conditions	Install second 66/11*kV* 12.5 *MVA* transformer and associated 11*kV* switchboard at McLaren Flat	12.4.1	**2.60**	-	5.20
2016	Clarendon 11*kV feeder* tie	Overload of Clarendon zone substation under contingent conditions	Install new 11*kV feeder* tie to increase *feeder* transfer capability, thereby deferring *zone substation* upgrade	-	**0.58**	-	0.58
2019 / 2020	Maslin Beach Substation (new)	Overload of Aldinga zone substation under contingent conditions	Construct a new *zone substation* at Maslins Beach consisting of one 12.5 *MVA* 66/11*kV* transformer, 11*kV* switchboard and two new *feeder* exits to increase transfer capability under *contingent conditions*.	12.4.2	**4.30**	4.19	8.49
2021	Clarence Gardens new 11*kV feeder* tie	Overload of Kingswood zone substation under contingent conditions	Construct a new 11*kV* tie between Clarence Gardens and Kingswood *zone substations* to increase *feeder* transfer capacity to defer Kingswood overload.	-	**-**	1.25	1.25

Table 29: Metro South Zone Substation Constraints

12.4.1 Major Project - McLaren Flat 66/11kV Substation Upgrade

12.4.1.1 Constraint

McLaren Flat 66/11kV Zone Substation contains one 12.5MVA 66/11kV transformer. Under 50% PoE conditions, the zone substation's contingency capacity will be exceeded in 2015/2016.

The measured load in 2013/14 exceeded the existing contingency capacity of the zone substation. Future growth for McLaren Flat 66/11kV Zone Substation is driven largely by agricultural and residential developments. The area supplied by McLaren Flat and McLaren Vale substations includes major viticultural loads.

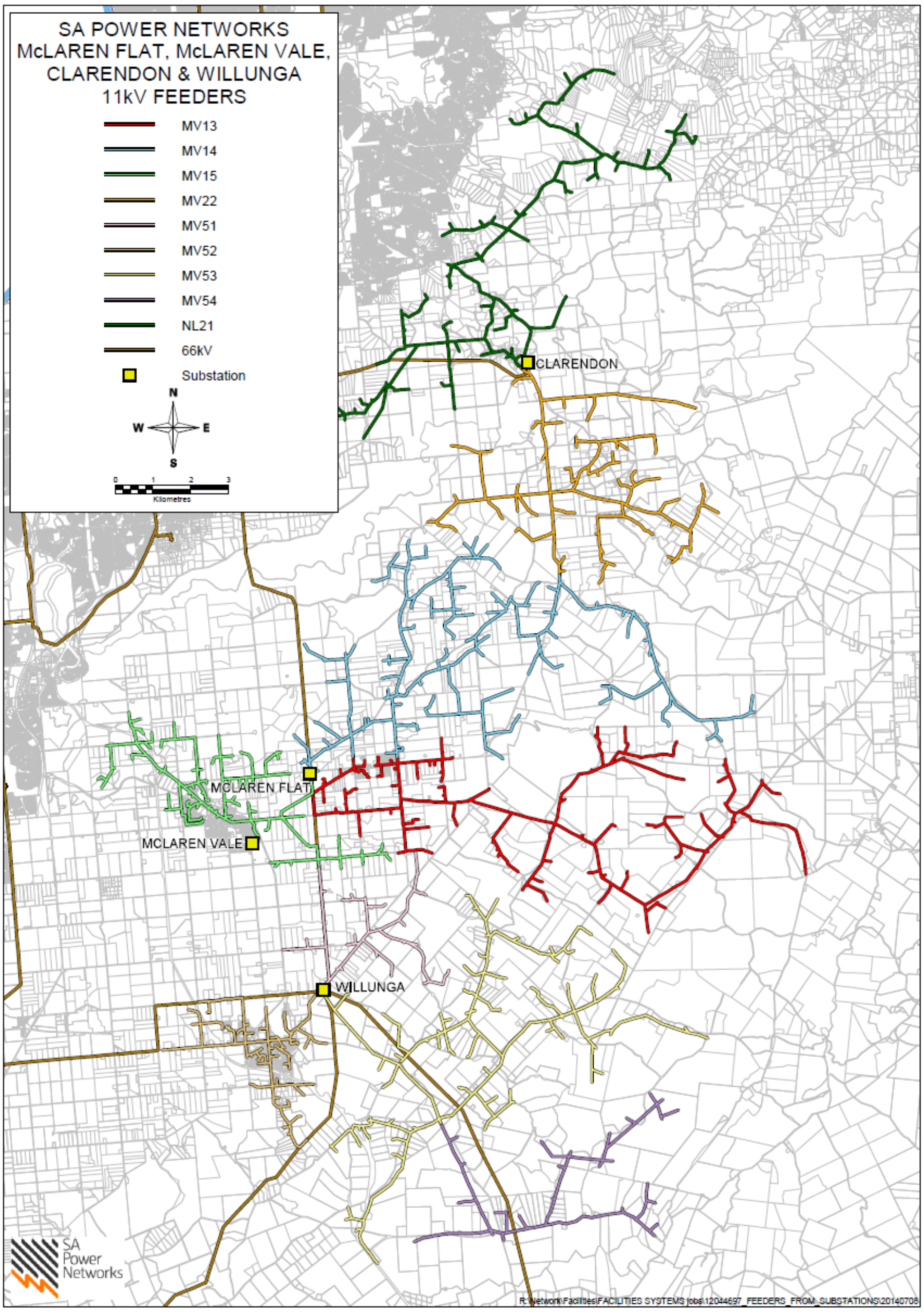


Figure 33 Locality of McLaren Flat 66/11kV Zone Substation

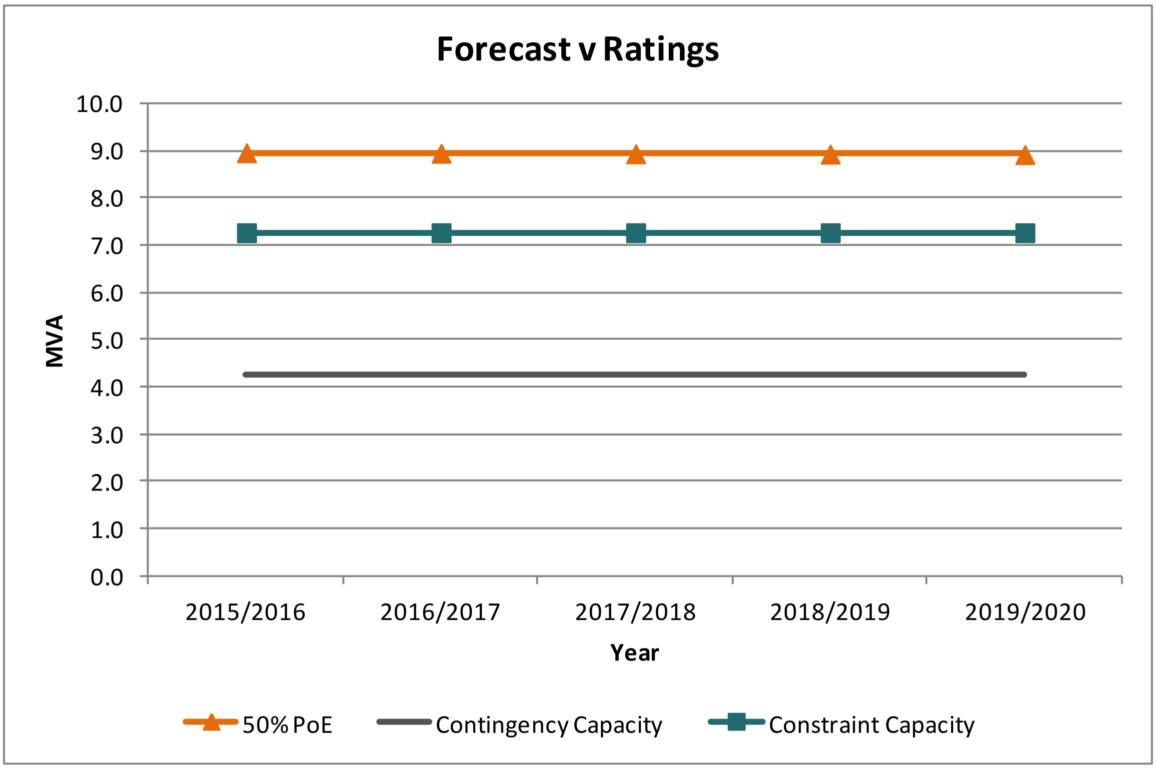


Figure 34 McLaren Flat 66/11kV Zone Substation Load versus Capacity

	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
Forecast* MVA (50% PoE)	9.0	9.0	9.0	8.9	8.9	8.9
Power Factor	0.91	0.91	0.91	0.91	0.91	0.91
Normal Capacity (MVA)	15.5	15.5	15.5	15.5	15.5	15.5
Firm Delivery Capacity (MVA)	0	0	0	0	0	0
Contingency Capacity (MVA)	4.1	4.0	3.8	3.7	3.6	3.4
Load At Risk (MVA)	7.5	5.0	5.1	5.3	5.4	5.5

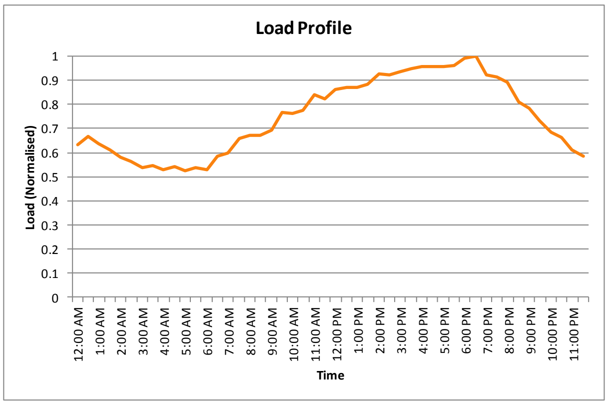
**Load Forecast includes impact of PV both existing and forecast. The forecast also includes the impact of energy efficiency, state economic and population growth by reconciling each asset's local growth trend with the AEMO July 2014 SA Regional forecast for the next 5 years..*

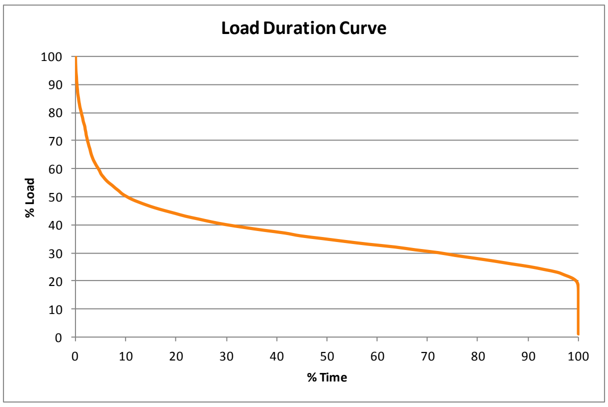
Table 30: McLaren Flat 66/11kV Zone Substation Load Forecast

12.4.1.2 Consequences for Customers

McLaren Flat 66/11kV Zone Substation has a contingency capacity of 4.0 MVA in 2015/2016. Given a forecast in 2015/2016 of 9.0 MVA under 50% PoE conditions, up to 5.0MVA of load may need to be shed for a transformer fault. Approximately 1,300 customers would remain unsupplied after all possible feeder switching is completed until a mobile substation could be installed (typically 24 hours). The contingency capacity of McLaren Flat 66/11kV Zone Substation is expected to be exceeded for a total of 5087 hours in 2015/2016 over 225 days per annum.

12.4.1.3 Load Profile





(a) (b)

Figure 35: (a) McLaren Flat 66/11kV zone substation Load Profile, (b) Load Duration Curve

12.4.1.4 Regulatory Test

In response to this constraint, a Reasonableness Test was published in accordance with ESCOSA Guideline 12. Reasonableness Test, RT 004-13 was published in November 2013. The Reasonableness Test showed that Demand Management measures could not be technically or economically address the system constraint and that a network solution was required.

12.4.1.5 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 and was excluded as a technically viable solution.

Improved Feeder Ties:

- Construction of new 11kV feeders from McLaren Flat Zone Substation to McLaren Vale, Willunga or Clarendon Zone Substations would improve feeder transfer capacity but would also require the upgrade of one or more of these very small surrounding zone substation's installed transformer capacity. The location of Willunga and Clarendon, at over 5km from the McLaren Flat site, also makes the effectiveness of these options extremely limited due to voltage constraints.

12.4.1.6 Options considered to address constraint

The following options were investigated in accordance with the ESCOSA Guideline 12 to resolve these impending constraints:

Option 1

- Upgrade McLaren Flat Zone Substation with a second 66/11kV transformer.

Option 2

- Construct a new 66/11kV zone substation at the existing McLaren Vale 33/11kV site with sufficient 11kV feeder ties to McLaren Flat Zone Substation to allow load to be transferred following the loss of the existing transformer. Significant issues exist with regard to the acquisition of additional land and the need for 66kV line easements due to the surrounding vineyards within the McLaren Vale area.

12.4.1.7 Preferred Solution

The preferred solution, based on the regulatory analysis performed, is to upgrade McLaren Flat 66/11kV Zone Substation with a second 66/11kV transformer (Option 1). The indicative cost for this project is $5.2 million. This project is planned for completion by November 2015 and resolves the identified contingency constraints at McLaren Flat for the foreseeable future.

12.4.1.8 Commitment Status

The relevant regulatory process (ESCOSA Guideline 12) was completed in 2013 and SA Power Networks has committed to the project to meet the November 2015 commissioning date. This project was included in the pre RIT-D committal list submitted to the AER in December 2013.

12.4.1.9 Regulatory Period Expenditure

Approximately $2.6 million is forecast to be required in the 2015-20 regulatory control period, with the remaining $2.6 million forecast to be spent within the 2010-15 regulatory period.

12.4.1.10 Net Present Value Analysis

Option	Description	NPV[24]
1	McLaren Flat 66/11kV upgrade	-9,581,294
2	New 66/11kV Substation at McLaren Vale	-12,327,087

Table 31: McLaren Flat Reasonableness Test Analysis Results

12.4.2 Major Project – Maslin Beach 66/11kV New Substation

12.4.2.1 Constraint

Aldinga 66/11kV Zone Substation contains two 12.5MVA 66/11kV transformers. Aldinga Zone Substation has minimal transfer capability to adjacent zone substations due to its proximity to other zone substations. Under 50% PoE conditions, the zone substation's contingency capacity will be exceeded in 2019/2020. Prior to a transformer constraint (according to the planning criteria) appearing at Aldinga Zone Substation in 2022, two of the four 11kV feeders supplied from this site are forecast to be overloaded by 2020, with the remaining two feeders forecast to become overloaded in 2021 and 2023 respectively.

The forecast growth rate for Aldinga 66/11kV Zone Substation is 3.8% per annum, which is being driven largely by residential subdivisions in the southern suburbs area. The measured underlying growth rate (without PV) from 2008 to 2013 is 8% and shows recent underlying growth exceeds forecast. In 2014, a peak of 18.9MVA was measured at 7.30pm. The effect of PV generation at this time is near zero output and consequently, any future PV growth will have minimal impact on peak demand. Consequently, the augmentation project may be

[24] Analysis from the Reasonableness Test RT004-13, published November 2013

required earlier than expected and the load at risk at peak load times may be three or more MVA higher than the 50% PoE forecast. The load growth in the Aldinga region has been driven by new residential development which is expected to continue for the foreseeable future due to the availability of land for development. Aldinga is located on the fringe areas of Adelaide's southern suburbs and is one of the few areas of available new residential land.

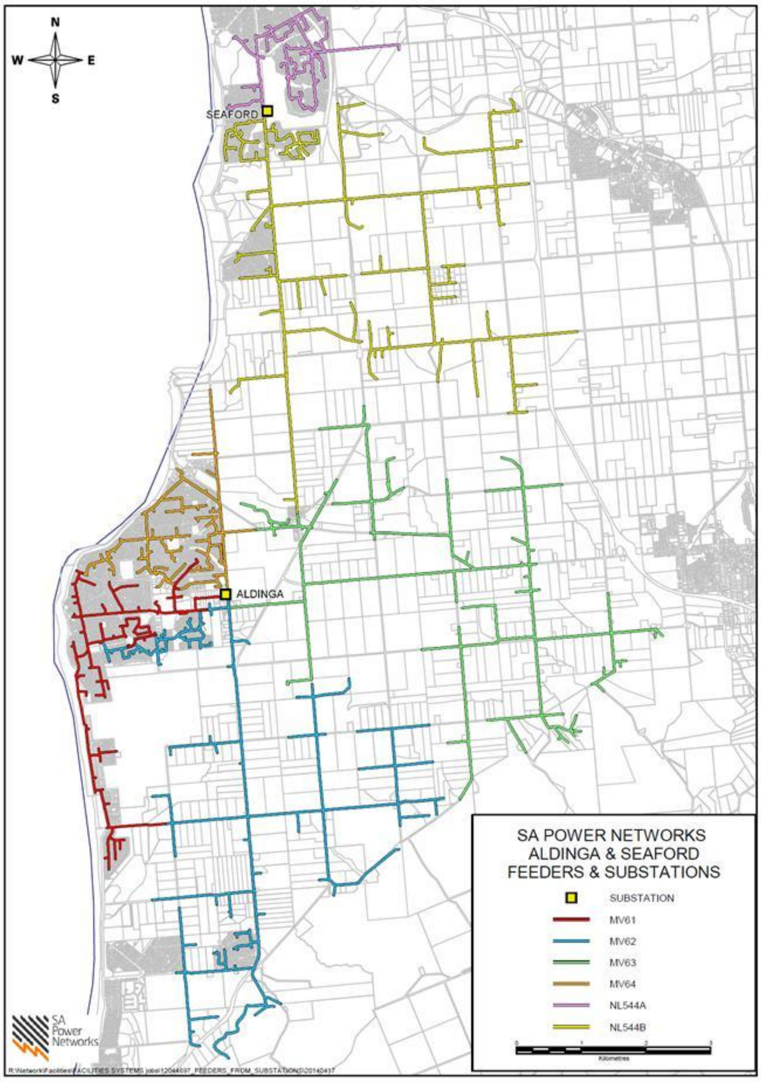


Figure 36: Locality of Aldinga 66/11kV Zone Substation

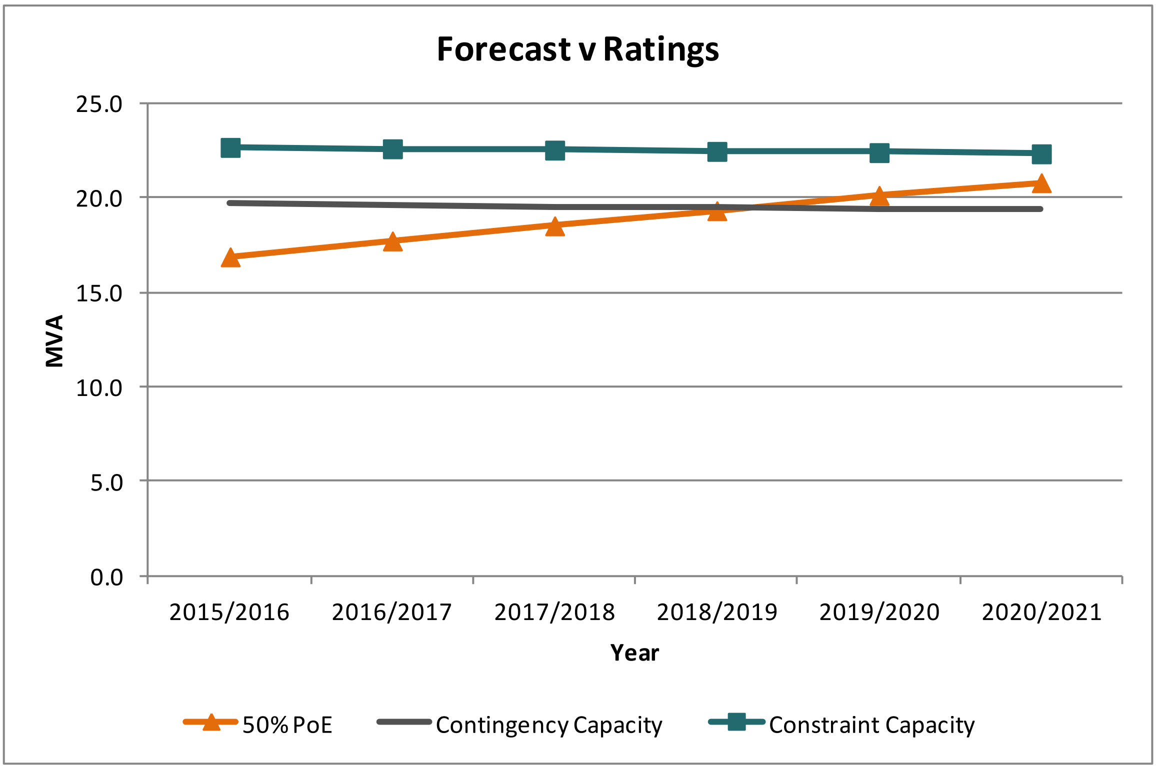


Figure 37: Aldinga 66/11kV Zone Substation Load versus Capacity

	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21
Forecast* MVA (50% PoE)	16.1	16.9	17.7	18.5	19.3	20.2	20.8
Power Factor	0.96	0.96	0.96	0.96	0.96	0.96	0.96
Normal Capacity (MVA)	33.2	33.2	33.2	33.2	33.2	33.2	33.2
Firm Delivery Capacity (MVA)	17.7	17.7	17.7	17.7	17.7	17.7	17.7
Contingency Capacity (MVA)	19.8	19.7	19.6	19.6	19.5	19.4	19.4
Load at Risk (MVA)	0	0	0	0	0	0.8	1.4

**Load Forecast includes impact of PV both existing and forecast. The forecast also includes the impact of energy efficiency, state economic and population growth by reconciling each asset's local growth trend with the AEMO July 2014 SA Regional forecast for the next 5 years.*

Table 32: Aldinga 66/11kV Zone Substation Load Forecast

In addition to Aldinga Zone Substation's contingency capacity constraint, the following 11kV feeders in the Aldinga area are forecast to be overloaded for N-1 during 50% PoE summer load times within the next five years:

- Sellicks Beach 11kV feeder (MV-62) - exceeds its N-1 offload capacity in 2020/21 and normal supply capacity in 2022/23 (supplied from Aldinga Substation).

- Willunga West 11kV feeder (MV-63) - exceeds its N-1 offload capacity in 2020/21 and normal supply capacity in 2024/25 (supplied from Aldinga Substation).
- Aldinga Beach 11kV feeder (MV-61) - exceeds its N-1 offload capacity in 2021/22 and normal supply capacity in 2022/23 (supplied from Aldinga Substation).
- Maslin Beach 11kV feeder (MV-64) - exceeds its N-1 offload capacity in 2023/24 (supplied from Aldinga Substation).

	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21
50% PoE Forecast* (Amps)	302	313	325	338	350	364	377
N-1 Offload Capability (Amps)	388	374	359	396	382	368	354
N-1 Load at Risk (Amps)	0	0	0	0	0	0	24
Feeder Normal Supply Capacity	480	480	480	480	480	480	480
Percentage Overload	0%	0%	0%	0%	0%	0%	0%

**Load Forecast includes impact of PV both existing and forecast. The forecast also includes the impact of energy efficiency, state economic and population growth by reconciling each asset's local growth trend with the AEMO July 2014 SA Regional forecast for the next 5 years.*

Table 33: Sellicks Beach 11kV Feeder Load Forecast

	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21
50% PoE Forecast* (Amps)	102	105	109	314^	325	338	351
N-1 Offload Capability (Amps)	390	384	373	362	356	345	333
N-1 Load at Risk (Amps)	0	0	0	0	0	0	18
Feeder Normal Supply Capacity	480	480	480	480	480	480	480
Percentage Overload	0%	0%	0%	0%	0%	0%	0%

**Load Forecast includes impact of PV both existing and forecast. The forecast also includes the impact of energy efficiency, state economic and population growth by reconciling each asset's local growth trend with the AEMO July 2014 SA Regional forecast for the next 5 years.*
^ Planned load transfer from Maslin Beach 11kV feeder to defer feeder's constraint.

Table 34: Willunga West 11kV Feeder Load Forecast

	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21
50% PoE Forecast* (Amps)	349	362	376	338	351	365	378
N-1 Offload Capability (Amps)	424	408	391	448^	434	418	402
N-1 Load at Risk (Amps)	0	0	0	0	0	0	0
Feeder Normal Supply Capacity	480	480	480	480	480	480	480
Percentage Overload	0%	0%	0%	0%	0%	0%	0%

**Load Forecast includes impact of PV both existing and forecast. The forecast also includes the impact of energy efficiency, state economic and population growth by reconciling each asset's local growth trend with the AEMO July 2014 SA Regional forecast for the next 5 years.*
^ Planned load transfer from Maslin Beach 11kV feeder to defer feeder's constraint.

Table 35: Aldinga Beach 11kV Feeder Load Forecast

	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21
50% PoE Forecast* (Amps)	289	300	312	176^	182	189	196
N-1 Offload Capability (Amps)	425	416	406	303	289	275	260
N-1 Load at Risk (Amps)	0	0	0	0	0	0	0
Feeder Normal Supply Capacity	480	480	480	480	480	480	480
Percentage Overload	0%	0%	0%	0%	0%	0%	0%

**Load Forecast includes impact of PV both existing and forecast. The forecast also includes the impact of energy efficiency, state economic and population growth by reconciling each asset's local growth trend with the AEMO July 2014 SA Regional forecast for the next 5 years.*
^ Planned load transfer to Willunga West 11kV feeder to defer feeder's constraint.

Table 36: Maslin Beach 11kV Feeder Load Forecast

12.4.2.2 Consequences for Customers

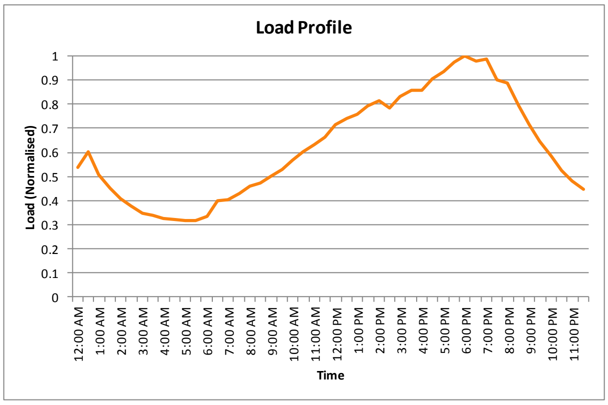
Aldinga 66/11kV Zone Substation has a contingency capacity of 19.4MVA in 2019/20. Given a forecast in 2019/20 of 20.2 MVA under 50% PoE conditions, up to 0.8MVA of load may need to be shed for a transformer failure. Approximately 274 customers would remain unsupplied after all possible feeder switching is completed until a mobile substation could be installed (typically 24 hours). The contingency capacity of Aldinga 66/11kV Zone Substation is expected to be exceeded for a total of 20 hours in 2019/2020 over 2 day per annum.

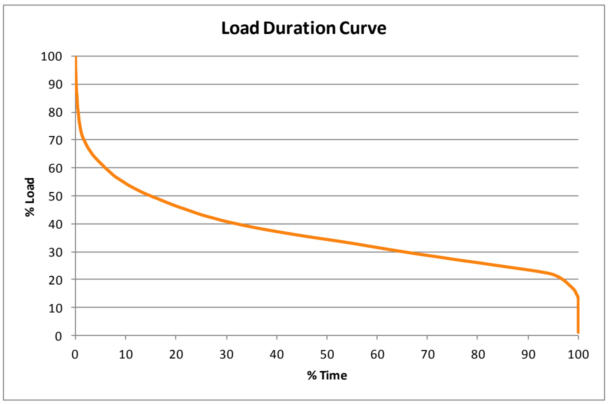
The 50% PoE forecast peak demand exceeds the N-1 offload capacity of Sellicks Beach 11kV feeder (MV-62) in 2020/21. In the event of a cable failure, after all available N-1 transfers have been exhausted, up to 24A of load and 90 customers would be unsupplied until the cable fault was repaired.

The 50% PoE forecast peak demand exceeds the N-1 offload capacity of Willunga West 11kV feeder (MV-63) in 2020/21. In the event of a cable failure, after all available N-1 transfers have been exhausted, up to 18A of load and 30 customers would be unsupplied until the cable fault was repaired.

However, due to the discrete number of switching points on a given feeder, it is not possible to load shed an exact amount of customers. In general, it is likely that a larger portion of the feeder would need to be shed, as there are typically 500 customers between tie points. The offload capability uses the emergency rating of the feeders and supplying zone substations that the customers are connected to and considers all possible options.

12.4.2.3 Load Profile





(a) (b)

Figure 38: (a) Aldinga 66/11kV zone substation Load Profile, (b) Load Duration Curve

Although forecast for 2020 construction, we expect the timing of this project may need to be brought forward as we expect the forecasted load growth rate to be exceeded, as measured in the last five years due to new residential developments.

12.4.2.4 Regulatory Investment Test - Distribution

A formal RIT-D has not yet been performed for this constraint. A preliminary RIT-D analysis has been undertaken for the constraint and options outlined below. A formal RIT-D process will be undertaken in line with the NER and AER Guidelines prior to project commencement.

12.4.2.5 Deferral Options Considered

The following deferral options were considered:

Power Factor Correction:

- Due to the extent of the load at risk and combination of feeder and substation constraints, power factor correction would not address the identified system constraints.

Improved Feeder Ties:

- The construction of new 11kV feeders from Aldinga Zone Substation would improve feeder transfer capacity but would also require the upgrade of Aldinga Zone Substation to make available and utilise this capacity. This was considered within Option 2 below

12.4.2.6 *Options considered to address constraint*

The following options have been investigated in accordance with the AER's RIT-D Guidelines to resolve the impending constraints:

Option 1:

- Construct a new 66/11kV substation at Maslin Beach with new 11kV feeder ties to Aldinga and Seaford Zone Substations.

Option 2:

- Upgrade Aldinga 66/11kV Zone Substation with a new control building, a new 11kV switchboard and two new 11kV feeder exits.

12.4.2.7 *Preferred Solution*

The preferred solution, based on the preliminary RIT-D analysis, is to construct a new 66/11kV substation at Maslin Beach with new 11kV feeder ties to the existing Aldinga and Seaford Zone Substations (Option 1). The indicative cost for this project is $9 million. This project is planned for completion in 2020 and is estimated to resolve the constraints identified in the Maslin Beach/ Aldinga area for at least 10 years.

12.4.2.8 *Commitment Status*

SA Power Networks has not yet committed to the project, however a preliminary RIT-D analysis has been completed the results of which are shown below. This analysis suggests that the most economic solution is to construct a new 66/11kV substation at Maslin Beach (Option 1). A full RIT-D will be conducted prior to the planned construction year of 2020.

12.4.2.9 *Regulatory Period Expenditure*

Approximately $4.5 million is forecast to be required within the 2015-20 regulatory period with the remainder forecast to be incurred within the 2020-25 regulatory period.

12.4.2.10 *Preliminary RIT-D Analysis*

Option	Description	Net Market Benefit[25]
1	Construct new 66/11kV Maslin Beach Substation	-$6,202,000
2	Aldinga 66/11kV Substation Upgrade & new 11kV Feeders	-$7,863,000

Table 37: Maslin Beach RIT-D Analysis Results

[25] Based on the use of a 6% discount rate

12.5 Feeders

The region's *zone substations* provide supply at 11*kV* to 144, 11*kV feeders* serving approximately 195,000 customers. Table 38 details those *feeder* constraints forecast over the forthcoming period.

Project Timing	Project Name	Limitation / Constraint	Proposed Solution	Section Ref	2015-20 Cost ($ million)	2020-25 Cost ($ million)	Total Cost ($ million)
2016	McLaren Flat 11*kV feeder* backbone upgrade	Overload of McLaren Flat *feeder* under *contingent conditions*	Upgrade backbone on adjacent *feeder* (McLaren Flat *feeder*) to increase load transfers capability in event of loss of McLaren Vale *feeder*	-	**0.42**	-	0.42
2016	Oaklands new 11*kV feeder*	Ascot Park *zone sub* overload for N-1	To defer overload of Ascot Park *zone sub* perform the following works, Restring sections of feeders ex Oaklands to temporararily increase existing feeder transfers. Extend existing 11kV switchboard by adding a new 11kV *CB* (assume CB + joggle box) and construct a new 11kV underground feeder exit	0	**1.84**	-	1.84
2016 / 2017	Kangarilla Recloser Upgrade	Recloser trip coil overload for N	Upgrade the Kangarilla Recloser at Clarendon to prevent trip coil overload for N	-	**0.15**	-	0.15
2017	Nilpeena Avenue 11*kV feeder* exit upgrade	Overload of numerous Morphettville *feeders* under *contingent conditions*.	Upgrade the Nilpenna Avenue *feeder* exit.	-	**0.36**	-	0.36

Table 38: Metro South Feeder Constraints

12.5.1 Major Project – Oaklands New Feeder

12.5.1.1 Constraint

The Ascot Park 66/11kV Zone Substation contains one 21MVA 66/11kV transformer (17MVA ONAN). Under 50% PoE conditions, the contingency capacity of the substation will be exceeded in 2018/19.

The measured load in 2013/14 was 17MVA, with 0.6MVA load at risk of being unsupplied in the event of a transformer failure as minimal practical feeder ties are available.

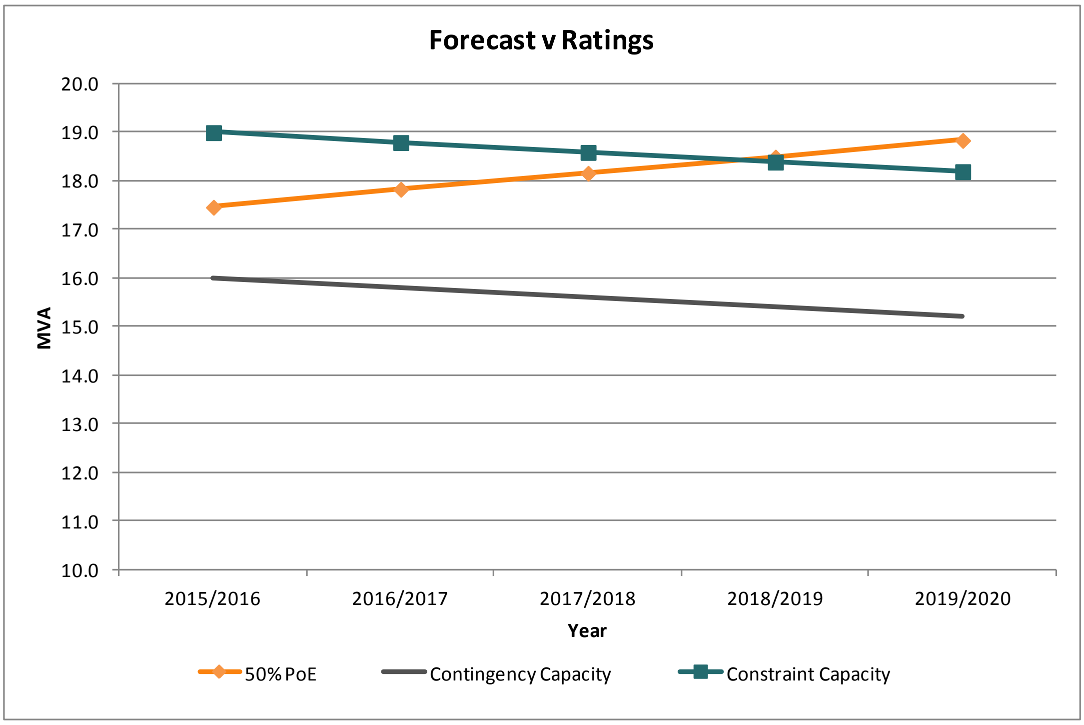


Figure 39: Ascot Park 11kV feeder Load versus Capacity

	2015/16	2016/17	2017/18	2018/19	2019/20
Forecast* MVA (50% PoE)	17.5	17.8	18.2	18.5	18.8
Power Factor	0.96	0.96	0.96	0.96	0.96
Normal Capacity (MVA)	27	27	27	27	27
Firm Delivery Capacity (MVA)	0	0	0	0	0
Contingency Capacity (MVA)	16.0	15.8	15.6	15.4	15.2
Load at Risk (MVA)	1.5	2.0	2.6	3.1	3.6

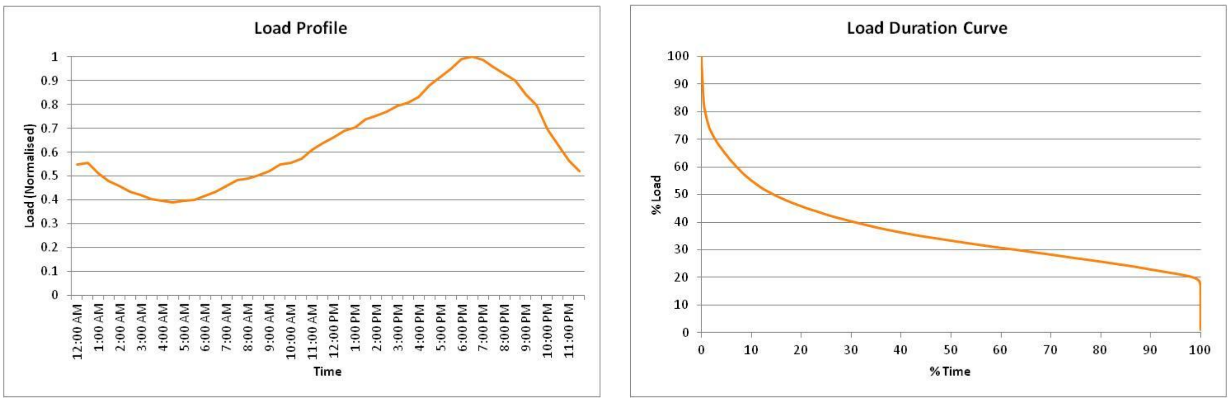
**Load Forecast includes impact of PV both existing and forecast.*

Table 39: Ascot Park 66/11kV Load Forecast

12.5.1.2 Consequences for Customers

Ascot Park 66/11kV Zone Substation is forecast to have a contingency capacity of 15.4MVA in 2018/19. Given a forecast in 2018/19 of 18.5MVA under 50% PoE conditions, up to 3.1MVA of load may need to be shed in the event of a fault of the single transformer. More than 1,600 customers would continue to remain unsupplied following the completion of all possible feeder transfers until a mobile substation could be installed (typically 24 hours). However, due to the discrete number of switching points on a given feeder, it is not possible to load shed an exact amount of customers. In general, it is likely that a larger portion of the feeder would need to be shed. The contingency capacity of Ascot Park 66/11kV Zone Substation is expected to be exceeded for a total of 39 hours in 2018/19 over 10 days per annum.

12.5.1.3 Load Profile



(a) (b)

Figure 40: (a) Ascot Park 66/11kV Zone Substation Load Profile, (b) Load Duration Curve

12.5.1.4 Deferral Options Considered

Power Factor Correction

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

Demand Side Participation

- Due to the large amount of load at risk, demand side participation is not expected to achieve a large enough reduction in load to defer the constraint of Ascot Park 66/11kV Zone Substation.

Improved Feeder Ties

- See Option 1 below.

12.5.1.5 Options considered to address constraint

The following options have been investigated to resolve the impending constraint:

Option 1:

- Improve available transfers from Ascot Park substation to adjacent substations by:

- Constructing a new feeder tie between Edgeworth St 11kV feeder (Ascot Park substation) and Edwardstown 11kV feeder (Clarence Gardens substation).
- Upgrading the feeder exits of the Ackland Gardens 11kV (Cudmore Park substation) and Somerton Park 11kV (Morphettville substation) feeders.
- Establishing a new Oaklands 11kV feeder to transfer load from Mitchell Park 11kV feeder supplied from Tonsley Park substation, increasing the load that can be transferred from Ascot Park Substation to Tonsley Park Substation under N-1 conditions.

Option 2:

- Upgrade Ascot Park 66/11kV Substation by installing an additional 25MVA 66/11kV transformer with three 66kV circuit breakers, an 11kV switchboard and two new 11kV feeder exits.

12.5.1.6 Preferred Solution

The preferred solution, based on a net present value analysis, is to upgrade the feeder tie cpabaility surrounding Ascot Park 66/11kV zone substation (Option 1). The indicative cost for this project is $1.85 million. This project is planned for completion in 2018 and is expected to resolve the identified constraint at the Ascot Park 66/11kV Zone Substation for 10 years.

12.5.1.7 Regulatory Period Expenditure

The total estimated $1.85 million is required in the 2015 - 20 regulatory period.

12.6 Land & Other Works

The following additional works within the region have been identified within the 2015-20 period.

Project Timing	Project Name	Work Category	Proposed Solution	Section Ref	2015-20 Cost ($ million)	2020-25 Cost ($ million)	Total Cost ($ million)
2018	Oaklands 66*kV Line CB*s	Supply security	Install 66*kV line CBs* on each of the two 66*kV line* exits	-	**2.51**		2.51
2019	Ascot Park 66*kV Line CBs*	Supply security	Install 66*kV line CBs* on each of the two 66*kV line* exits	-	**2.48**		2.48
2019 / 2020	Maslin Beach Substation (new)	Land	Procure a parcel of land near Maslin Beach to construct future *substation* on.	12.4.2	**0.56**	-	0.56

Table 40: Metro South Other Works

13. METRO EAST – REGIONAL DEVELOPMENT PLAN

SA Power Networks' Metro East Region covers the eastern suburbs of metropolitan Adelaide. The region stretches south from Golden Grove in the north, Linden Park in the south and west of the hills face to Prospect. The region's load is largely residential and commercial in nature and includes that of the *Adelaide Central Region* which is embedded within the overall region.

A map of this region is shown in Figure 41 while a single line representation of the *network* is shown in Figure 42.

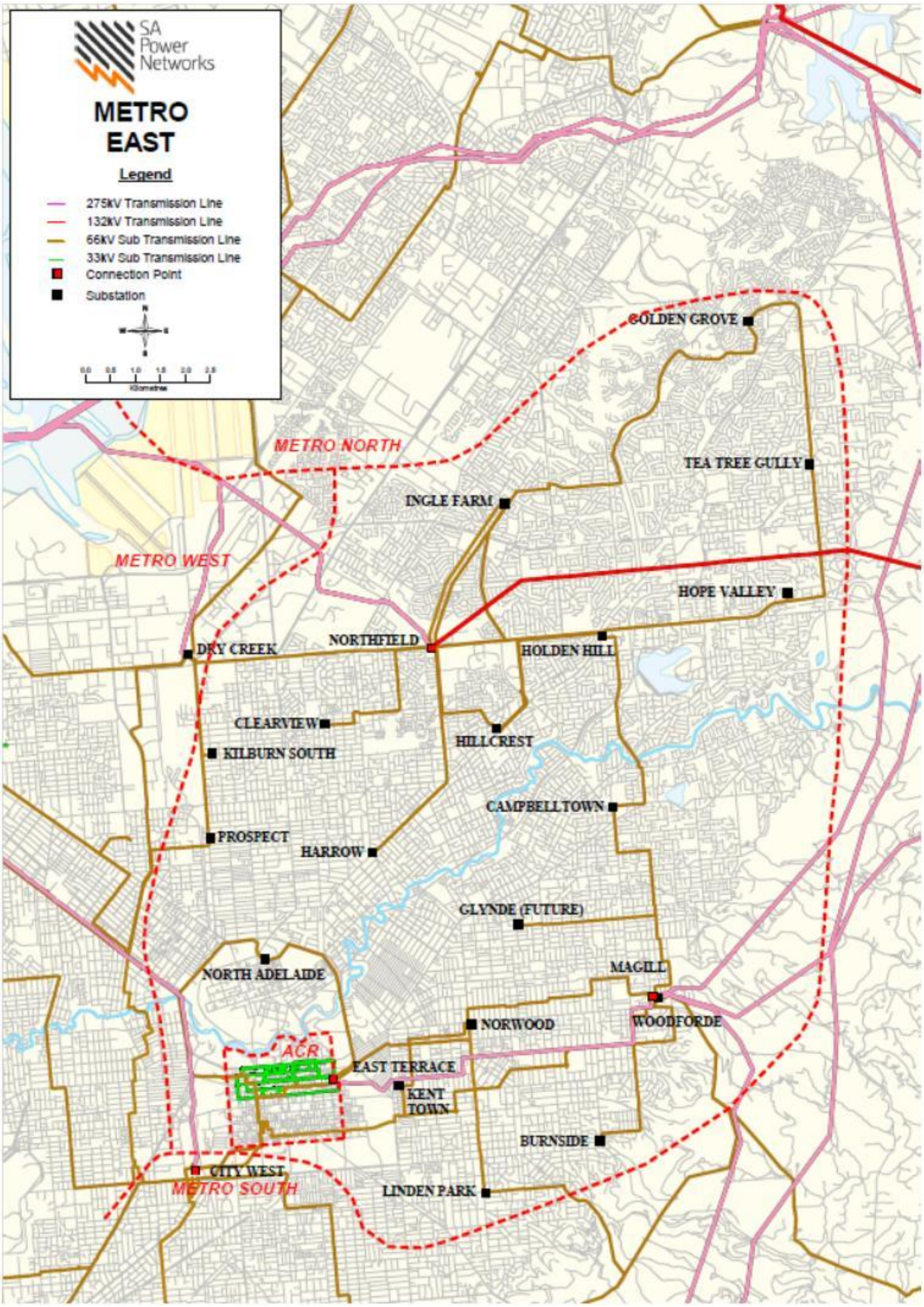


Figure 41: Metro East Map

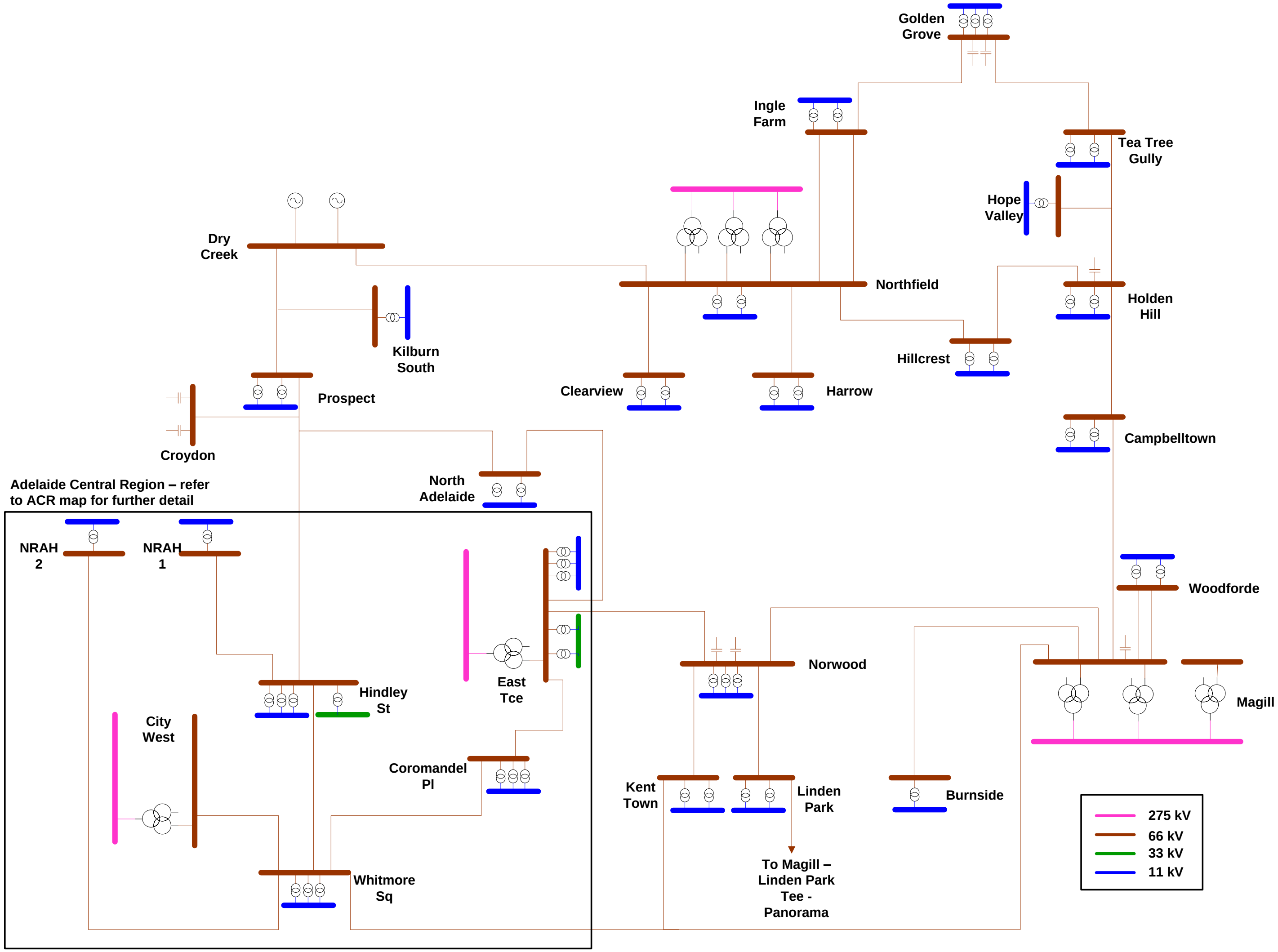


Figure 42: Metro East Single Line Diagram

13.1 Region Statistics

Table 41 indicates the general statistics for this region of the state, inclusive of the *ACR*.

Parameter	Value
No of connection points	4 (275/66*kV*)
No of zone subs	22 (66/11*kV*), 2 (66/33kV), 2 (33/11kV)
Operating voltages	66*kV*, 33*kV* and 11*kV*
Total customers	182,509
No of residential customers (abs /%of region/% of state)	165,342 / 90.6% / 19.5%
No of commercial customers (abs /%of region/% of state)	17,167 / 9.4% / 2.0%
Area of region (km^2 / % of state)	197 / 0.09
Length of 66kV cable (km / % of region 66kV)	17.2 km / 14.9%
Length of 66kV conductor (km / % of region 66kV)	98.2 km / 85.1%
Length of 33kV cable (km / % of region 33kV)	28.4 km/ 100%
Length of 11kV cable (km / % of region 11kV)	721 km / 48.5%
Length of 11kV conductor (km / % of region 11kV)	765 km / 51.5%
Installed *PV* inverter capacity (*MW* / % of state)	107*MW* / 18.6%
No of feeders (abs / % urban / % rural short / % rural long)	178 / 100% / 0% / 0%

Table 41: Metro East Region Statistics

13.2 Development History

The Metro East region was originally supplied at 33*kV* until the mid to late 1950s after which the region was migrated to 66*kV*. Similarly, all *feeders* were originally energised at 7.6*kV* until the introduction of 11*kV* as the standard *feeder* distribution voltage. No 33*kV* or 7.6*kV* systems remain within the region.

The region's first *connection point* at Northfield was converted to 66*kV* operation in 1954 with the second such *connection point* at Magill being converted to 66*kV* operation in 1956. Additional *connection point* capacity was provided from East Terrace in 1984 with City West *connection point* being commissioned in December 2011.

Significant projects conducted within this region over the present Reset period include, irrespective of their driver (ie capacity, asset replacement, customer connection etc) include:

Project Title	Description	Commissioning Year	Cost ($ million)
Hillcrest *Sub* Upgrade	Replace the existing transformers with two new 25 *MVA* 66/11*kV* units and install a new 11*kV* switchboard to mitigate overload under contingent conditions.	2009	7.1
North Adelaide *Substation* Upgrade	Upgrade North Adelaide *zone substation's* existing 10 *MVA* transformers with 32 *MVA* 66/11*kV* units to prevent overloads in event of failure of one of the transformers.	2010	15.4
Tea Tree Gully Line *CBs*	Install a new 66*kV CB* on the existing Holden Hill *line* exit and install new bus zone protection at Tea Tree Gully to prevent loss of the substation in the event of a fault on either of the 66kV lines supplying the site.	2011	1.2
City West Connection Point	Establishment of a new 275/66*kV connection point* injection into the Metro East region. Installation of two, 2000mm^2 Cu XLPE cables per phase from City West to Whitmore Square *zone sub* and associated protection and *zone sub* upgrade works including installation of a new 66kV GIS switchboard to facilitate connection and increased fault levels.	2011	76.2
Kent Town *Sub* Upgrade	Upgrade the existing 21MVA 66/11kV transformer at Kent Town Zone Substation with a 32MVA unit and replace the existing two section 11kV switchboard.	2012	6.4
Northfield – Ingle Farm #2 66*kV Line*	Convert former Northfield – Para 132kV line to 66kV operation and create new 66kV underground entries into Northfield and Ingle Farm Zone Substations to form second Northfield to Ingle Farm 66kV line.	2013	6.9
Kilburn South *Sub* Upgrade	Upgrade existing Kilburn South 10 MVA 66/11kV transformer with a new 32 MVA unit. Install new 11kV switchboard.	2014	8.7[26]

Table 42: Recent Metro East Augmentation Projects

[26] Project in progress - Approved amount.

13.3 Connection points and sub-transmission lines

There are two main 275/66*kV connection point*s serving the Metro East network located at Northfield in the north of the region and Magill in the east, with connections to the associated *ACR* system's 275/66*kV connection point*s at East Terrace and City West. In addition, an 80*MW* power station exists at Dry Creek near Northfield *connection point*. This power station is connected to the *sub-transmission network* via the *ElectraNet* owned 66*kV* bus at the power station site. The forecast loads for the region include the *Adelaide Central Region* (*ACR*) as the *ACR* system is an integral part of the Metro East system.

The region's *connection point*s (including East Terrace and City West) have a combined normal rating of 1,650 *MVA* and a notionally a notional *N-1* capacity of 1,395 *MVA* (assuming transformers share equally).

These *connection point*s are meshed via *SA Power Networks'* 66*kV sub-transmission network*. Under the *ETC*, the Northfield and Magill *connection point*s are classified as Category 4 sites whilst the East Terrace and City West *connection point*s (primarily associated with the *ACR*) are classified as Category 5 sites. Both categories of *connection point* are required to be planned on a *N-1* basis for both transmission lines and transformers.

Given the significance of this region to the state in terms of customer numbers, *SA Power Networks* plans this region's *sub-transmission network* based on a *N-1* basis against the 10% *PoE* forecast. Constraints on the *meshed sub-transmission network* and of *ElectraNet's* 275/66kV transformers are determined through modelling of the network and analysis using *PSS/E*.

Within the time period covered by this *AMP*, no augmentation of the region's *connection point* transformer capacity is forecast to be required. A copy of the region's *connection point* forecasts are shown in APPENDIX D – METRO EAST REGION FORECASTS.

The following *connection point* projects are planned within the region during the period of this plan.

Section Ref	Constraint Type	Constraint Description	Proposed Solution	Constraint Year	Commissioning Year	2015-20 Cost ($ million)	2020-25 Cost ($ million)	Total Cost[27] ($ million)
-	Joint Development Principles	Existing building is owned by *ElectraNet* and contains asbestos. Joint Development Principles recommends the segregation of *EN* and *SA Power Networks* assets.	Construct a new control room at Magill *connection point* to house *SA Power Networks'* protection and control equipment and migrate / upgrade existing 66*kV line* and bus zone protection to new room.	2022	2022	-	3.93	3.93

Table 43: Metro East Connection Point Projects

[27] Total expenditure to end of 2024/25 period

The region contains two 66*kV* ties to the Metro West region and one to the Metro South region at Croydon, Dry Creek and Linden Park substations respectively. These ties are normally only operated either following a contingent event in order to restore supply or when performing 11*kV feeder* ties across regional boundaries. In the latter case, the 66*kV* open point is temporarily closed prior to the closing of a cross region *feeder* open point in order to prevent inter-regional load flows through the 11*kV* network whilst the regions are momentarily connected. Following the completion of such transfers, the *sub-transmission* ties are restored to normal.

Whilst most *zone substations* within the region are meshed, the region contains several radial *zone substations*, namely Clearview, Hope Valley, Harrow and Kilburn South with the planned Glynde *zone substation* (2016), intended to initially be radially supplied. The region also contains two *zone substations* which are supplied using flip/flop arrangements whereby should the primary 66*kV* supply become faulted, the secondary 66*kV* supply is placed into service, thereby resulting in only a momentary interruption to the relevant *substation* (similar to an auto-reclose). These two *substations* are at Linden Park and Kent Town.

Within the forecast period covered by this *AMP*, the following lines have been identified as having constraints within the region:

Section Ref	Project Name	Constrained Line(s)	Constraint Type	Constraint Description	Proposed Solution	Constraint Year	Commissioning Year	2015-20 Cost ($ million)	2020-25 Cost ($ million)	Total Cost ($ million)
-	Norwood to Kent Town 66*kV line* upgrade	Norwood – Kent Town 66*kV*	N-1	Loss of Magill – Kent Town *line* results in overload of Norwood – Kent Town *line.*	Upgrade approx 2.2km of 0.1 ACSR with 61/3.5 AAAC/1120 designed to 100°C. Construct new substation cable entry into Kent Town due to construction of buildings under existing overhead *line* entry.	2018	2021	**0.09**	4.48	4.57

Table 44: Metro East Sub-Transmission Line Constraints

13.4 Zone substations

Electricity is supplied throughout the Metro East region by 22, 66/11*kV zone substations*.

Forecasts for the region's *zone substations* are shown in APPENDIX D – METRO EAST REGION FORECASTS.

The following *zone substation* constraints have been identified within the 2015-25 period covered by this *AMP*:

Project Timing	Project Name	Limitation / Constraint	Proposed Solution	Section Ref	2015-20 Cost ($ million)	2020-25 Cost ($ million)	Total Cost ($ million)
2016	Glynde Substation	Inadequate transformer and feeder capacity under *contingent conditions* (*N-1*) at Campbelltown *zone substation*.	Construct new 66/11*kV* zone substation at Glynde and associated 66*kV* line.	13.4.1	**18.79**	-	18.92
2025	Northgate *Sub* Establishment	Overload of Northfield *zone substation* for normal conditions.	Relocate to new site adjacent to existing Northfield site on land procured from *ElectraNet* and install two new 32 *MVA* transformers to replace the two existing 10 *MVA* units.	-	**-**	0.56	12.43

Table 45: Metro East Zone Substation Constraints

13.4.1 Major Project – Glynde 66/11kV New Substation

13.4.1.1 Constraint

Campbelltown 66/11kV Zone Substation contains two 24MVA 66/11kV transformers. Under 50% PoE conditions, the zone substation's contingency capacity will be exceeded in 2016/17.

The forecast growth rate for Campbelltown 66/11kV Zone Substation is 1.2% per annum, which is being driven largely by residential growth in the eastern suburbs. The measured underlying growth rate (without PV) from 2009/10 to 2013/14 was 1.8% per annum and shows recent underlying growth exceeds forecast. The measured peak load during the summer of 2013/14 was 49.3MVA measured at 7.00pm when PV has a near zero output. Consequently, any further future PV growth will have a minimal impact on the peak demand seen by this zone substation.

The Campbelltown, Norwood, Woodforde and Harrow Zone Substations are all separated by approximately 8km each. These zone substations each supply 11kV feeders into the middle of this area, which are also long and are between 3.5km and 4.5km. Due to their length and their loading, these feeders have quality of supply issues that are more frequent and severe during feeder and substation contingency conditions.

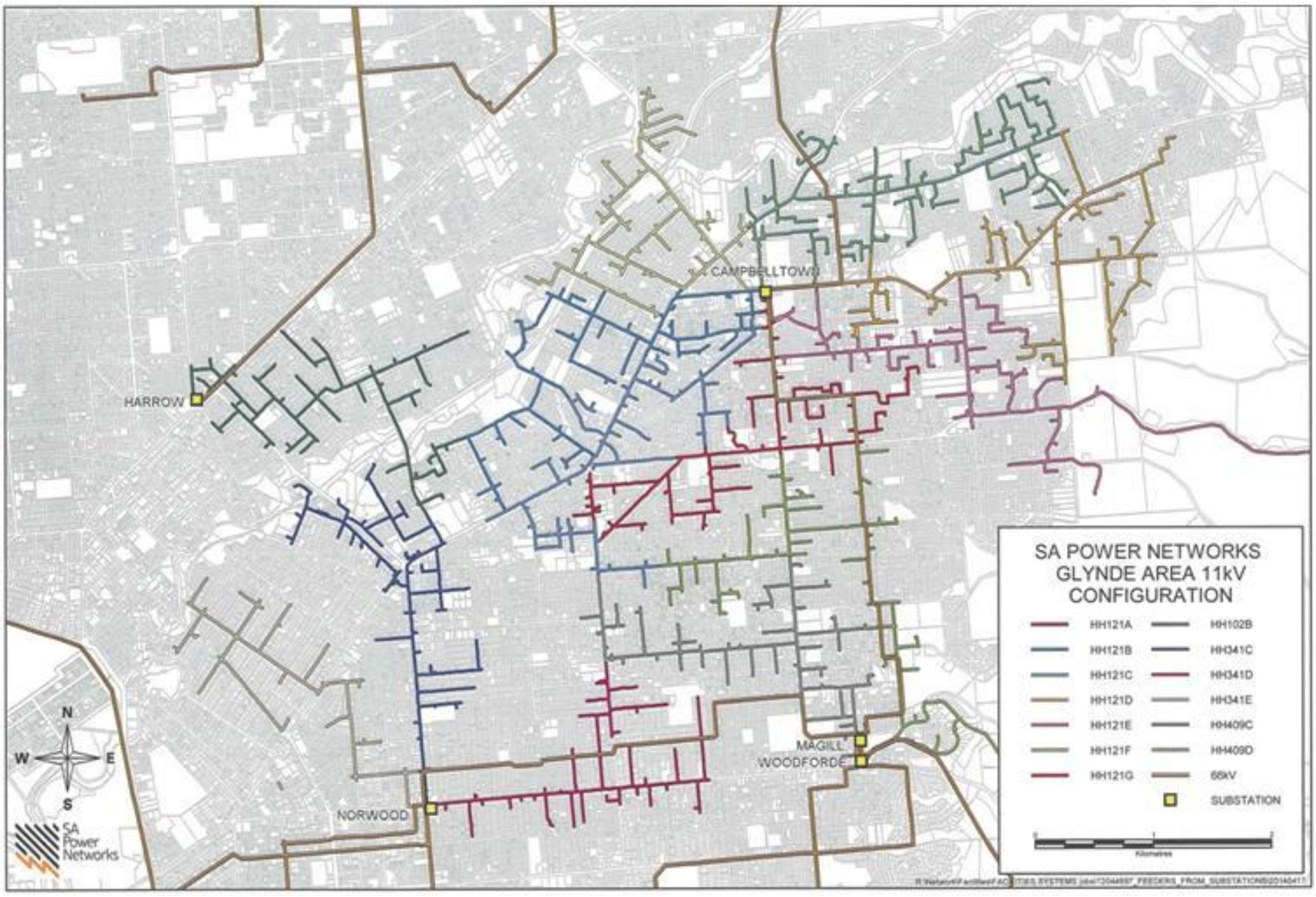


Figure 43: Locality of Campbelltown 66/11kV Zone Substation

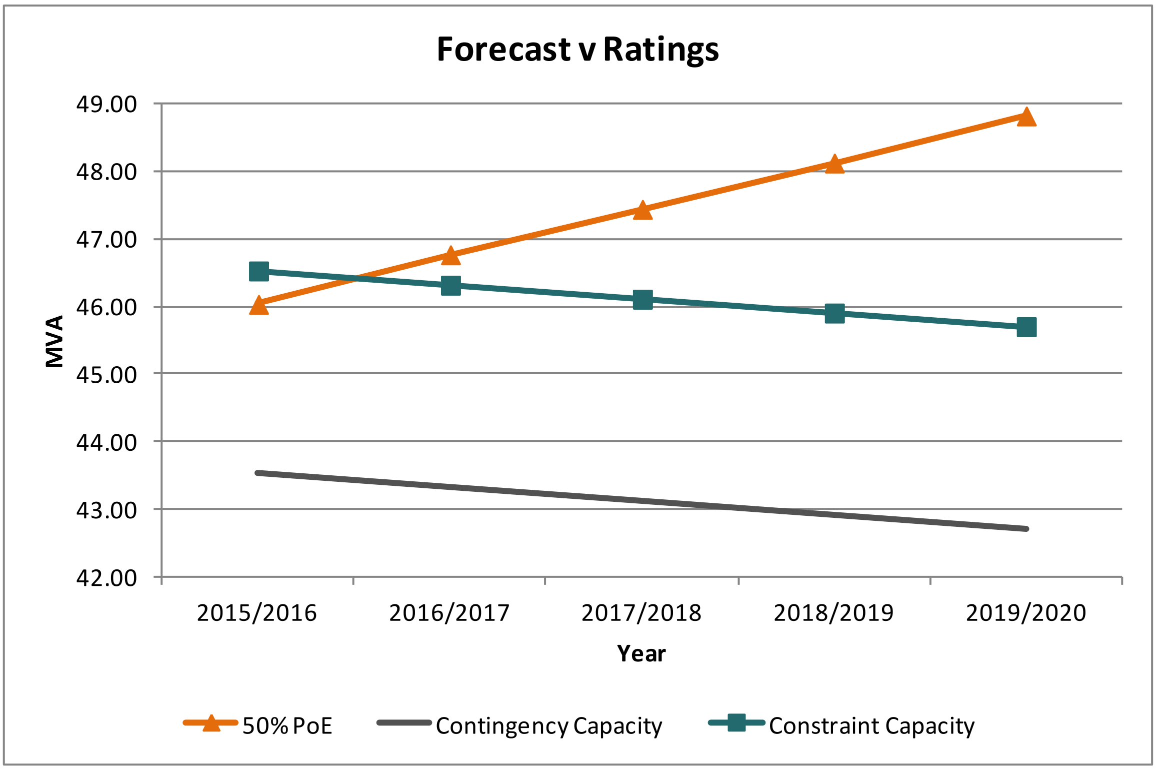


Figure 44: Campbelltown 66/11kV Zone Substation Load versus Capacity

	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
Forecast* MVA (50% PoE)	45.4	46.0	46.8	47.4	48.1	48.8
Power Factor	0.95	0.95	0.95	0.95	0.95	0.95
Normal Capacity (MVA)	57.8	57.8	57.8	57.8	57.8	57.8
Firm Delivery Capacity (MVA)	30.5	30.5	30.5	30.5	30.5	30.5
Contingency Capacity (MVA)	43.7	43.5	43.3	43.1	42.9	42.7
Load at Risk (MVA)	1.7	2.5	3.5	4.3	5.2	6.1

**Load Forecast includes impact of PV both existing and forecast. The forecast also includes the impact of energy efficiency, state economic and population growth by reconciling each asset's local growth trend with the AEMO July 2014 SA Regional forecast for the next 5 years.*

Table 46: Campbelltown 66/11kV Zone Substation Load Forecast

In addition to Campbelltown Zone Substation's contingency capacity constraint, the following 11kV feeders in the Glynde area are forecast to be overloaded during 50% PoE summer load periods within the next five years:

- Clairville 11kV feeder (HH-121G) exceeds its N-1 Offload Capacity in 2015/2016 (supplied from Campbelltown Substation).
- Newton 11kV feeder (HH-121A) exceeds its N-1 Offload Capacity in 2016/2017 and Normal Supply Capacity in 2019/2020 (supplied from Campbelltown Substation).

- Vale Park 11kV feeder (HH-102B) exceeds its N-1 Offload Capacity in 2016/2017 (supplied from Harrow Substation).

	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
Forecast* MVA (50% PoE)	389	396	403	410	417	425
N-1 Offload Capability (Amps)	395	386	377	368	359	349
N-1 Load at Risk (Amps)	0	10	26	42	58	76

Table 47: Clairville 11kV Feeder Load Forecast

	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
Forecast* MVA (50% PoE)	440	448	456	464	472	481
N-1 Offload Capability (Amps)^	471	454	437	420	402	384
N-1 Load at Risk (Amps)	0	0	19	44	70	97
Feeder Normal Supply Capacity	480	480	480	480	480	480
N Capacity Overload	0	0	0	0	0	1

Table 48: Newton 11kV Feeder Load Forecast

	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
Forecast* MVA (50% PoE)	365	368	372	376	379	383
N-1 Offload Capability (Amps)	374	371	368	358	349	339
N-1 Load at Risk (Amps)	0	0	4	18	30	44

Table 49: Vale Park 11kV Feeder Load Forecast

13.4.1.2 Consequences for Customers

Campbelltown 66/11kV Zone Substation has a contingency capacity of 43.1MVA in 2017/2018. Given a forecast in 2017/18 of 47.4MVA under 50% PoE conditions, up to 4.3MVA of load may need to be shed. Approximately 1,200 customers would remain unsupplied after all possible feeder switching is completed until a mobile substation could be installed (typically 24 hours). The rating of Campbelltown 66/11kV Zone Substation is expected to be exceeded for a total of 20 hours in 2017/2018 over 5 days per annum.

However, as the contingency capacity of the Campbelltown Zone Substation is calculated to maximise all available transfers to neighbouring zone substations, during a contingency event at Campbelltown Zone Substation this capacity would be initially much lower. Practically, restoration would occur as quickly as possible by transferring entire 11kV feeders (to save time) to the remaining transformer without exceed its emergency rating. The remaining feeders would then be transferred to other zone substations where possible without exceeding the neighbouring feeder conductor's emergency ratings. Due to the discrete number of switching points on a given feeder, it is not possible to load shed an exact amount of customers. In general, it is likely that a larger portion of the feeder would need to be shed, as there are typically 500 customers between tie points. Once as much load as possible is restored, only then would a more detailed switching program be issued to maximise Campbelltown Zone Substation's contingency capacity.

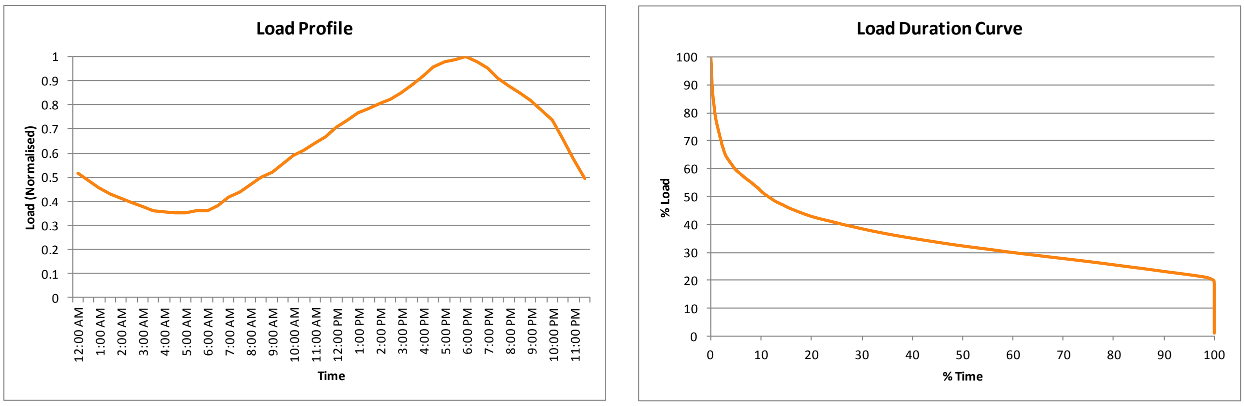
The 50% PoE forecast peak demand exceeds the N-1 offload capacity of Clairville 11kV feeder
(HH-121G) in 2015/16. In the event of a cable failure, after all available N-1 offload capacity has been exhausted, up to 10A of load and 70 customers would be unsupplied until the cable fault was repaired (up to 48 hours). This unsupplied load increases to 76A and 480 customers by 2019/20.

The 50% PoE forecast peak demand exceeds the N-1 offload capacity of Newton 11kV feeder
(HH-121A) in 2016/17. In the event of a cable failure, after all available N-1 offload capacity has been exhausted, up to 19A of load and 85 customers would be unsupplied until the cable fault was repaired (up to 48 hours). This unsupplied load increases to 97A and 400 customers by 2019/20.

The 50% PoE forecast peak demand exceeds the N-1 offload capacity of Vale Park 11kV feeder
(HH-102B) in 2016/17. In the event of a cable failure, after all available N-1 offload capacity has been exhausted, up to 4A of load and 30 customers would be unsupplied until the cable fault was repaired (up to 48 hours). This unsupplied load increases to 44A and 270 customers by 2019/20.

Again, due to the discrete number of switching points on a given feeder, it is not possible to load shed an exact number of customers. In general, it is likely that a larger portion of the feeder would need to be shed, as there are typically 500 customers between tie points. The offload capability uses the emergency rating of the feeders and substations that the customers are connected to and considers all possible options.

13.4.1.3 Load Profile



(a) (b)

Figure 45: (a) Campbelltown 66/11kV Zone Substation Load Profile, (b) Load Duration Curve

13.4.1.4 Regulatory Investment Test - Distribution

In response to this constraint, a Request for Proposals was published in accordance with ESCOSA Guideline 12. Request for Proposals, RFP 002-11 was published in December 2011. No proposals were received and the RFP Evaluation was published in July 2012 which showed the preferred network option to have the lowest NPV.

In light of revised load forecasts, a preliminary RIT-D analysis has been undertaken for the constraint to ensure that the preferred network solution is still the most economic solution. The options considered within the preliminary RIT-D are outlined below.

13.4.1.5 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.

Improved Feeder Ties:

- Construction of new 11kV feeders from Campbelltown, Woodforde, Norwood and/or Harrow 66/11kV Zone Substations into the Glynde area would improve the feeder transfer capacity for Campbelltown Zone Substation and the aforementioned constrained 11kV feeders, but would also require the upgrade of one or more of those Zone Substations in order to supply these feeders. This was considered in Option 1 below.

13.4.1.6 Options considered to address constraint

The following options have been investigated in accordance with the AER's RIT-D Guidelines to resolve the impending constraint:

Option 1:

- Construction of a 66kV line from the existing Campbelltown-Magill 66kV line to the new Glynde 66/11kV Zone Substation site by 2017. The zone substation would be comprised of one 66/11kV 32MVA transformer, 66kV bus work, a new masonry control building housing an 11kV switchboard and site civil works that include earthing and substation screening.
- Minimal 11kV feeder work will be required to establish three initial 11kV feeders as nearby are several of the constrained 11kV feeders.

Option 2:

- Upgrade Campbelltown 66/11kV Zone Substation by replacing the existing transformers with 2x32MVA 66/11kV transformers by 2017.
- In addition, three new 11kV feeder exits to supply the Glynde area will be required with extensive 11kV feeder works using approximately 9km of feeder exit cable to enable the physical dissection of several of the constrained 11kV feeders in the area and to be supplied via spare circuit breakers from Norwood and Campbelltown Zone Substations;

Option 3:

- Upgrade Woodforde 66/11kV Zone Substation by replacing the existing transformers with 2x32MVA 66/11kV transformers, new masonry control building, 11kV switchboard and 66kV bus work by 2017.
- In addition, three new 11kV feeder exits to supply the Glynde area will be required with extensive 11kV feeder works using approximately 9km of feeder exit cable to enable the physical dissection of several of the constrained 11kV feeders in the area and to be supplied via spare circuit breakers from Norwood and the upgraded Woodforde Zone Substations;

Option 4:

- Upgrade Harrow 66/11kV Zone Substation by purchasing additional neighbouring land and replacing the existing transformers with 2x32MVA 66/11kV transformers, new masonry control building and 11kV switchboard by 2017. The neighbouring land is not vacant, consequently the land purchase is likely to be high risk.
- In addition, three new 11kV feeder exits to supply the Glynde area will be required with extensive 11kV feeder works using approximately 9km of feeder exit cable to enable the physical dissection of several of the constrained 11kV feeders in the area and to be supplied via spare circuit breakers from Norwood and the upgraded Harrow Zone Substations. Constructing 11kV feeders from Harrow Zone Substation poses the additional challenge of crossing the Torrens River and is likely to be a high risk option.

13.4.1.7 Preferred Solution

The preferred solution, when the net present value, timing and effectiveness of each option to address the identified constrain is considered, is the construction of a 66kV line from the existing Campbelltown-Magill 66kV line and a new 66/11kV Glynde Zone Substation (Option 1). The indicative cost for this project is $19.2 million. This project is planned for completion in 2017 and is expected to resolve the identified constraints in the Glynde/Campbelltown/Norwood area for more than 15 years.

13.4.1.8 Commitment Status

The relevant regulatory process (ESCOSA Guideline 12) was completed in 2011 and this project was included in the pre RIT-D committal list issued to the AER in December 2013.

In light of revised load forecasts, a preliminary RIT-D analysis has been completed to ensure the preferred network solution is still the most viable with the results shown below. The analysis shows that the most economic solution is to construction of a new 66kV line from the existing Campbelltown-Magill 66kV line and a new 66/11kV Glynde Zone Substation (Option 1).

13.4.1.9 Regulatory Period Expenditure

Approximately $18.8 million is forecast to be required in the 2015-20 regulatory control period, with the remaining $0.4 million forecast to be incurred during the present 2010-15 control period.

13.4.1.10 Preliminary RIT-D Analysis

Option	Description	Net Market Benefit[28]
1	New Glynde 66/11kV Substation and new 11kV feeders	-$18,529,000
2	Campbelltown 66/11kV Substation Upgrade and new 11kV feeders	-$19,913,000
3	Woodforde 66/11kV Substation Upgrade and new 11kV feeders	-$22,232,000
4	Harrow 66/11kV Substation Upgrade and new 11kV feeders	-$26,759,000

Table 50: RIT-D Evaluation Results and Rankings

[28] Based on the use of a 6% discount rate

13.5 Feeders

The region's *zone substations* supply 178, 11*kV feeders* serving approximately 182,500 customers. Table 51 details those feeder constraints forecast over the forthcoming five year reset period.

Project Timing	Project Name	Limitation / Constraint	Proposed Solution	Section Ref	2015-20 Cost ($ million)	2020-25 Cost ($ million)	Total Cost ($ million)
2016	Golden Grove North *Feeder* Upgrade	Overload of Greenwith *feeder* under normal conditions	Extend the Golden Grove South *feeder* and create new tie point and transfer load from Greenwith *feeder*.	13.5.1	**0.62**	-	0.62
2019	Wynn Vale West and Greenwith *Feeder* Tie	Overload of Greenwith *feeder* under normal conditions and Wynn Vale West under contingent conditions and limited transfer flexibility for *feeders* on same bus section.	Create new ties to existing third bus section at Golden Grove to relieve Greenwith and Wynn Vale West *feeders* by installing approximately 420 route metres of new underground cable and two new 11*kV* switching cubicles.	13.5.2	**0.64**	-	0.64

Table 51: Metro East Feeder Constraints

13.5.1 Major Project – Golden Grove North Feeder Upgrade

13.5.1.1 Constraint

Greenwith 11kV feeder (HH-496F) is supplied from the Golden Grove 66/11kV zone substation and has a normal supply capacity of 480A. Under 10% PoE conditions the feeders normal supply capacity and under 50% PoE conditions the feeders N-1 offload capacity will be both exceeded in 2016/2017.

The forecast growth rate for the Greenwith 11kV feeder is 2.7% and the measured average growth rate from 2008-2013 is 1.4%. In 2013/14 the Greenwith 11kV feeder's load characteristic during peak load times was essentially flat from the period between 6:30pm to 8pm with the actual peak occurring at 7pm. This is due to the impact of installed PV reducing the native demand earlier in the day and rapidly dropping off between 6-8pm. A check of measured growth at 8pm (PV near 0) between 2009/10 and 2013/14 (approximately 10% PoE years) returns a growth of 2.7%.

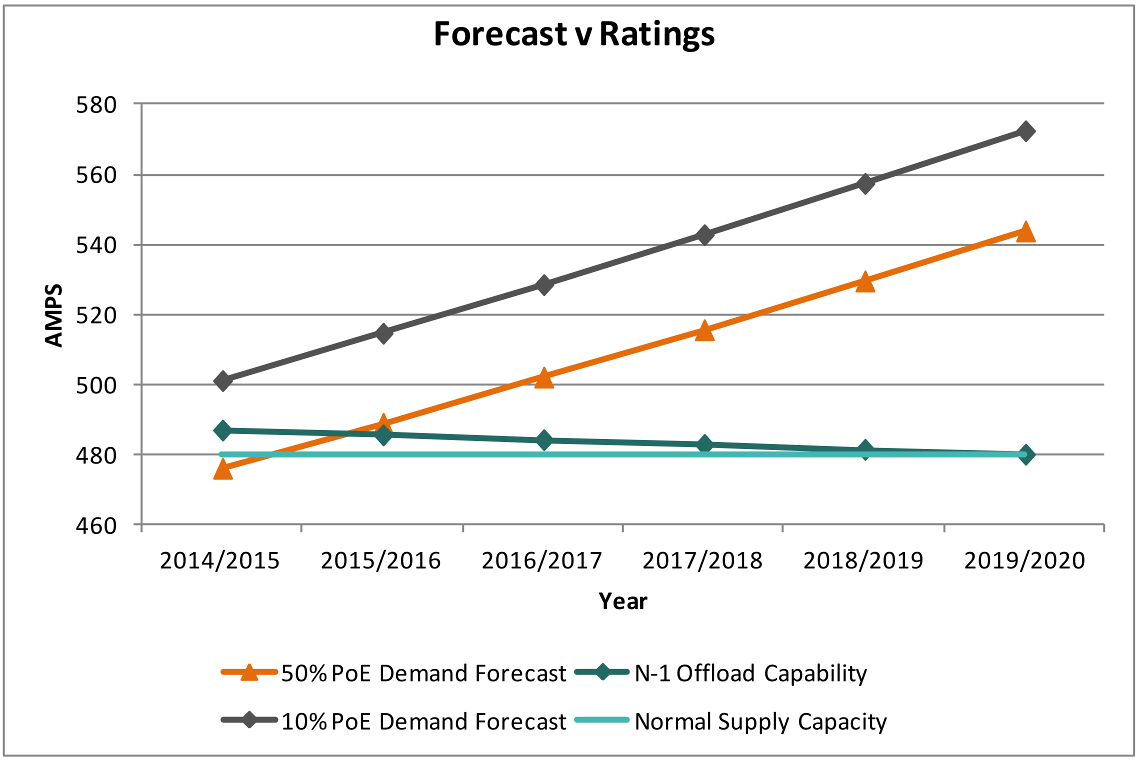


Figure 46: Greenwith 11kV Feeder Load versus Capacity

	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
Forecast* Amps (10% PoE)	501	514	528	543	557	572
Normal Supply Capacity (Amps)	480	480	480	480	480	480
N Load at Risk (Amps)	21	34	48	63	77	92
Forecast* Amps (50% PoE)	476	489	502	516	529	544
N-1 Offload Capability (Amps)	487	485	484	483	481	480
N-1 Load at Risk (Amps)	0	4	18	33	48	64

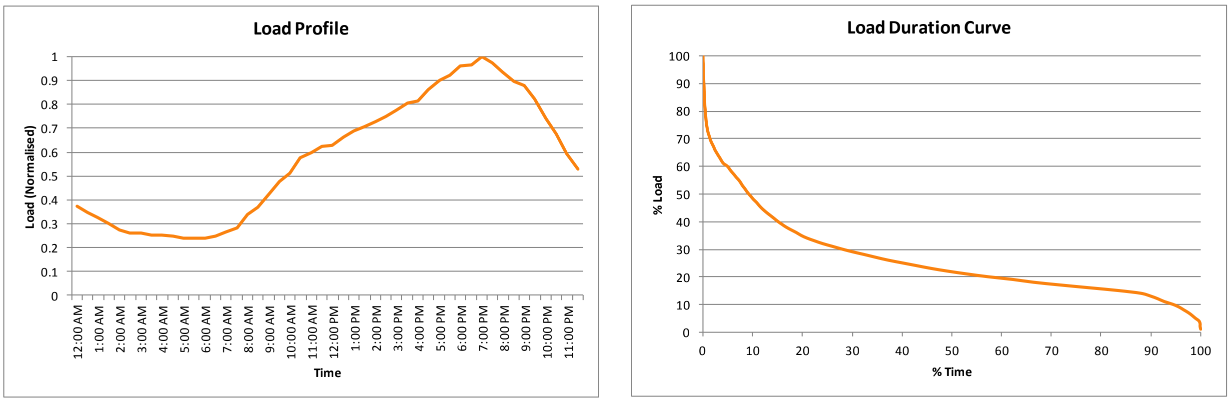
***Load Forecast includes impact of PV both existing and forecast. The forecast also includes the impact of energy efficiency, state economic and population growth by reconciling each asset's local growth trend with the AEMO July 2014 SA Regional forecast for the next 5 years.*

Table 52: Greenwith 11kV feeder Load Forecast

13.5.1.2 Consequences for Customers

The 10% PoE forecast demand already exceeds the normal supply capacity and the 50% PoE forecast peak demand exceeds the N-1 offload capacity of the Greenwith 11kV feeder's exit from 2015/16. In 2016/17, in the event of a cable failure and after all available N-1 offload capacity is exhausted, up to 18A of load and 100 customers would be unsupplied until the cable fault was repaired. However, due to the discrete number of switching points on a given feeder, it is not possible to load shed an exact amount of customers. In general, it is likely that a larger portion of the feeder would need to be shed, as there are typically 500 customers between tie points and 100A. The normal supply capacity of Greenwith 11kV feeder is expected to be exceeded for a total of 9 hours in 2016/17 over five days per annum, increasing up to 21 hours by 2019/20 over eight days per annum. The offload capability uses the emergency rating of the feeders and substations that the customers are connected to and considers all possible options.

13.5.1.3 Load Profile



(a) (b)

Figure 47: (a) Greenwith 11kV feeder Load Profile, (b) Load Duration Curve

13.5.1.4 *Deferral Options Considered*

Improved Feeder Ties

- See Option 1 below. Improving the feeder tie will allow for increased N-1 capacity and the load transfer required to solve the Greenwith 11kV feeder normal supply capacity constraint.

Demand Side Participation

- Due to the large amount of load at risk, demand side participation is not expected to achieve a large enough reduction in load to defer the constraints on the Greenwith 11kV feeder.

13.5.1.5 *Options considered to address constraint*

The following options have been investigated to resolve the impending constraints:

Option 1:

- Upgrade approximately 1.6km of overhead conductor on the Golden Grove North 11kV feeder (HH-496E) and replace two, 11kV switching cubicles. Transfer approximately 100A from Greenwith 11kV feeder to Golden Grove North 11kV feeder.

Option 2:

- Extend the 630mm^2 Al XPLE from existing Golden Grove South 11kV feeder (HH-496J) to the backbone of Greenwith 11kV feeder and transfer load from Greenwith 11kV feeder to Golden Grove South 11kV feeder.

Option 3:

- Establish a new 11kV feeder at Golden Grove 66/11kV Substation by installing a 630mm^2 Al XLPE cable exit from a spare feeder breaker and feeder backbone cable to the backbone of Greenwith 11kV feeder and transfer load from Greenwith 11kV feeder.

13.5.1.6 *Preferred Solution*

The preferred solution, based on net present value analysis is to upgrade and transfer load to the Golden Grove North 11kV feeder (Option 1). The indicative cost for this project is $0.62 million. This project is planned for completion in November 2016 and is expected to resolve the constraint on the Golden Grove 66/11kV zone substation's feeders for 7 years.

13.5.1.7 *Regulatory Period Expenditure*

The total estimated $0.62 million is required during the 2015-20 regulatory control period.

13.5.2 Major Project – Wynn Vale West 11kV Feeder Tie

13.5.2.1 Constraint

Wynn Vale West 11kV feeder (HH-496D) is supplied from the Golden Grove 66/11kV Zone Substation and has a normal supply capacity of 480A. Under 50% PoE conditions, the feeder's N-1 offload capacity will be exceeded in 2014/15.

The forecast growth rate for the Wynn Vale West 11kV feeder is 0.4% per annum with the measured average growth rate from 2008-2013 being 1.4% per annum. In 2013/14, the Greenwith 11kV feeder's load characteristic during peak load times was essentially flat from the period between 6:30pm to 8pm with the actual peak occurring at 7pm. This is due to the impact of installed PV reducing the native demand earlier in the day and rapidly dropping off between 6-8pm.

In addition, in the event of an outage of Bus Zone 8 at Golden Grove Zone Substation, there are no feeder ties to other adjacent zone substation feeders or adjacent Bus Zone feeders supplied from Golden Grove Zone Substation for both the Greenwith (HH-496F) and Rifle Range (HH-496G) 11kV feeders. As a result, multiple 11kV feeders are required to be tied together in order to offload Bus Zone 8 which due to load constraints can only be achieved for short periods during the day at non peak times. At times when this can occur, the number of customers supplied by one 11kV feeder exceeds 5,000 customers which poses significant STPIS penalties should this feeder become faulted.

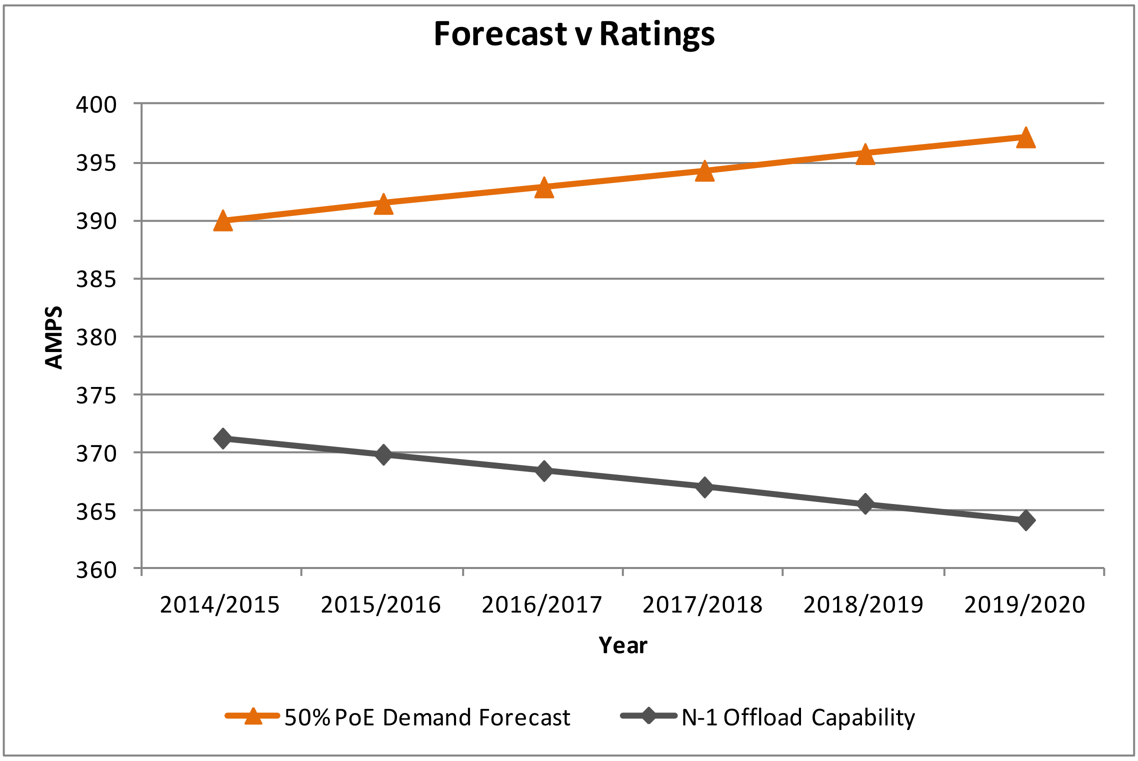


Figure 48: Wynn Vale West 11kV Feeder Load versus Capacity

	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
Forecast* Amps (50% PoE)	390	391	393	394	396	397
N-1 Offload Capability (Amps)	371	370	368	367	366	364
N-1 Load at Risk (Amps)	19	21	25	27	30	33

***Load Forecast includes impact of PV both existing and forecast. The forecast also includes the impact of energy efficiency, state economic and population growth by reconciling each asset's local growth trend with the AEMO July 2014 SA Regional forecast for the next 5 years.*

Table 53: Wynn Vale West 11kV Feeder Load Forecast

13.5.2.2 Consequences for Customers

The 50% PoE forecast demand already exceeds the N-1 offload capacity of Wynn Vale West 11kV feeder in 2014/2015. In 2019/20 in the event of a cable failure and after all available N-1 offload capacity is exhausted, up to 33A of load and 250 customers would remain unsupplied until the cable fault was repaired. However, due to the discrete number of switching points on a given feeder, it is not possible to load shed an exact amount of customers. In general, it is likely that a larger portion of the feeder would need to be shed as there are typically 500 customers between tie points or 100A. The N-1 offload capability of Wynn Vale West 11kV feeder is expected to be exceeded for a total of 84 hours in 2019/20 over 18 days per annum. The offload capability uses the emergency rating of the feeders and zone substation transformers that the customers are connected to and considers all possible options.

13.5.2.3 Load Profile

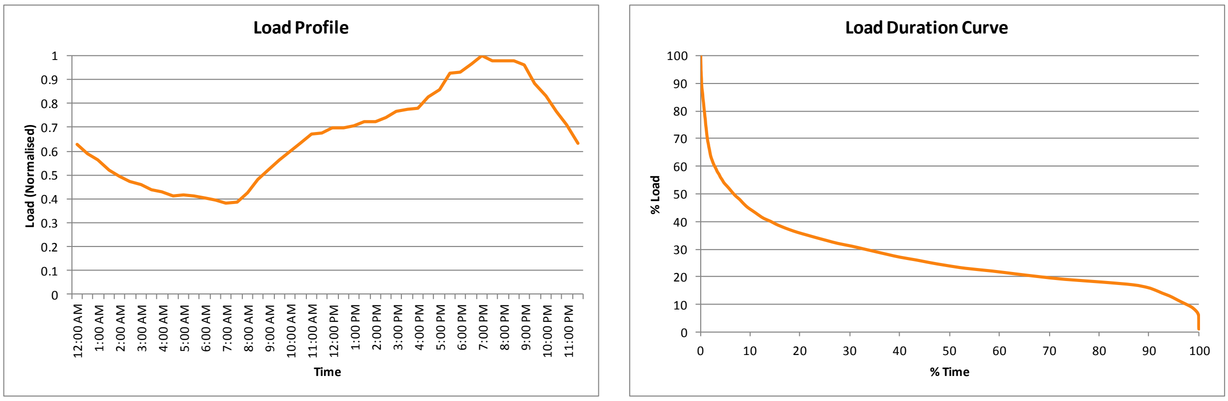


Figure 49: (a) Wynn Vale West 11kV Feeder Load Profile, (b) Load Duration Curve

13.5.2.4 Deferral Options Considered

Improved Feeder Ties

- See option 1 below. Improving the feeder ties will allow for increased N-1 capacity required to resolve the Wynn Vale West 11kV feeder N-1 offload capacity constraint.
- In addition, the project will provide new feeder ties both Greenwith (HH-496F) and Rifle Range (HH-496G) 11kV feeders which are supplied from Bus Zone 8 at Golden Grove Zone Substation and currently only tie to other feeders on Bus Zone 8. These new feeder ties will be to Wynn Vale West 11kV feeder (HH-496D) which is supplied from a different bus zone at Golden Grove Zone Substation.

Demand Side Participation

- Due to the large amount of load at risk, demand side participation is not expected to economically achieve a large enough reduction of load to defer the constraints on the Greenwith 11kV feeder.

13.5.2.5 Options considered to address constraint

The following options have been investigated to resolve the impending constraints:

Option 1:

- Move Wynn Vale West 11kV feeder exit and Greenwith 11kV feeder exit to the third section of 11kV switchboard at Golden Grove Substation. Install switching cubicles at both exits and install an 11kV feeder tie between the two cubicles.

Option 2:

- Extend the 630mm^2 Al XPLE cable from the existing Golden Grove South 11kV feeder (HH-496J) to the backbone of Wynn Vale West 11kV feeder to provide an additional tie and transfer load from Wynn Vale West 11kV feeder to Golden Grove South 11kV feeder.

13.5.2.6 Preferred Solution

The preferred solution, based on a net present value analysis is to transfer the Wynn Vale West 11kV and Greenwith 11kV feeders to the third bus section of 11kV switchboard at Golden Grove Zone Substation with an 11kV feeder tie between the two feeders (option 1). The indicative cost for this project is $0.64 million. This project is planned for completion in 2019 and is expected to resolve the constraint on the Golden Grove 66/11kV Zone Substation feeders for 7 years.

13.5.2.7 Regulatory Period Expenditure

The total estimated expenditure of $0.64 million is required within the 2015-20 regulatory period.

13.6 Land and Other Works

The following land purchases and additional works within the region have been identified within the 2015-20 period.

Project Timing	Project Name	Work Category	Proposed Solution	Section Ref	2015-20 Cost ($ million)	2020-25 Cost ($ million)	Total Cost ($ million)
2017	Northfield NGM Upgrade	NER Compliance	Install aux *CTs* and check metering to three existing 275/66*kV* transformer connections on Northfield's 66*kV* GIS switchboard and calibrate.	-	**0.20**	-	0.20
2017	Magill Sub Control Room	Land	Purchase of land parcel from *ElectraNet* to enable installation of a new *SA Power Networks* owned control building at Magill *connection point.*	-	**0.04**	-	0.04
2019	Northgate Land Purchase	Land	Purchase land adjacent to the existing Northfield *substation* to enable construction of a new *zone substation* to be known as Northgate	-	**3.00**	-	3.00
2019	Campbelltown Substation 66kV Section CB	Supply Security	Add new 66kV section breaker to provide increased substation security for a TF failure.	-	**1.28**	-	1.28

Table 54: Metro East Other Works

14. METRO WEST – REGIONAL DEVELOPMENT PLAN

SA Power Networks' Western Suburbs Region includes the region east from the Adelaide metropolitan coast, extending south to West Beach, south-east to Richmond, north-east to Kilburn, and north-west to LeFevre. The region's load includes significant heavy industrial loads at Kilburn, Kilkenny and around the greater Port Adelaide region.

A map of this region is shown in Figure 50 while a single line representation of the network is shown in Figure 51.

Figure 50: Metro West Map

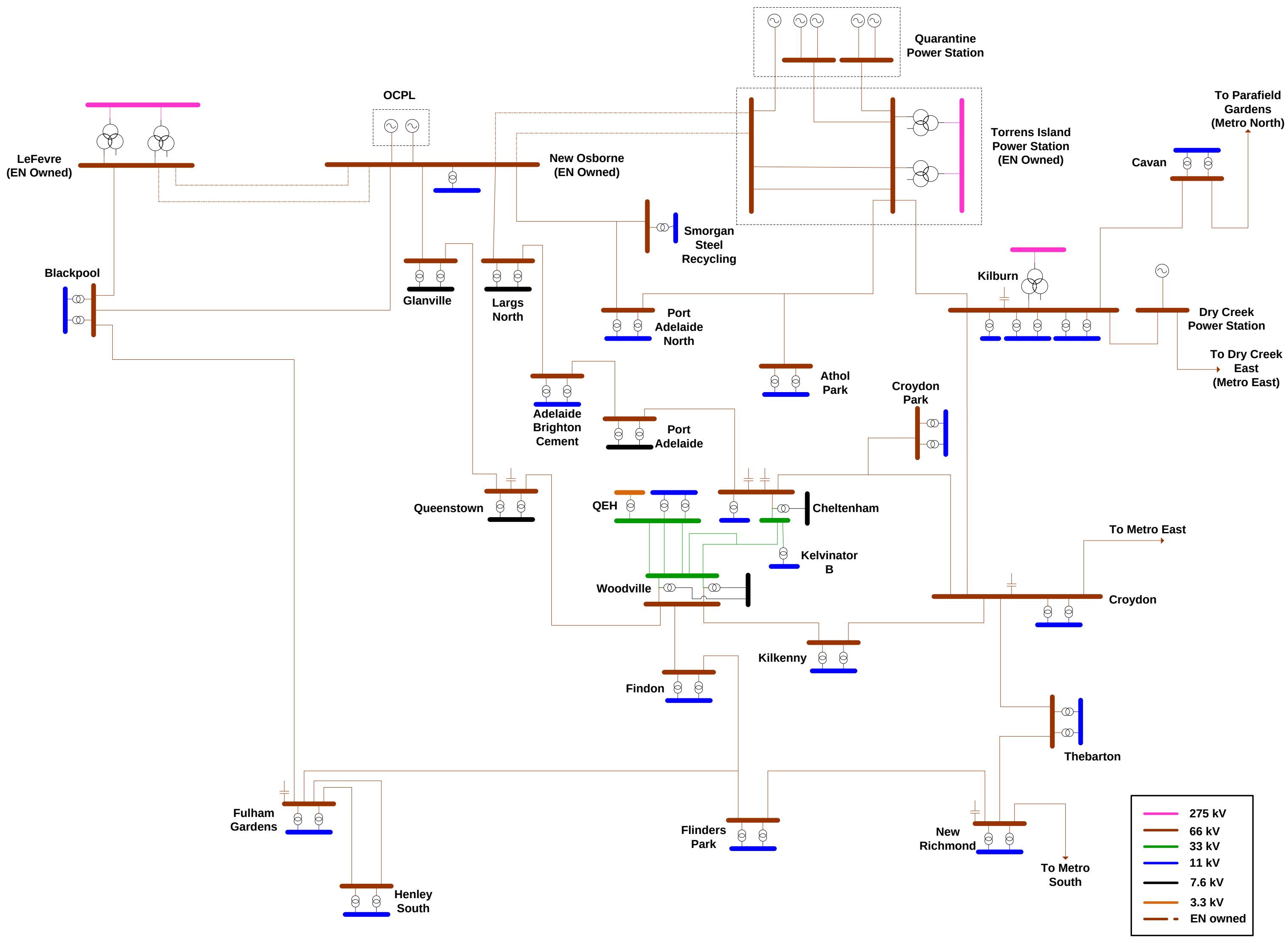


Figure 51: Metro West Single Line Diagram

14.1 Region Statistics

Table 55 indicates the general statistics for this region of the state.

Parameter	Value
No of connection points	4 (275/66*kV*)
No of zone subs	17 (66/11*kV*), 2 (66/33*kV*), 6 (66/7.6*kV*)
Operating voltages	66*kV*, 33*kV*, 11*kV* and 7.6*kV*
Total customers	107,920
No of residential customers (abs /%of region/% of state)	96,145 / 89.1% /11.3%
No of commercial customers (abs /%of region/% of state)	11,775 / 10.9% / 1.4%
Area of region (km^2 / % of state)	157 km^2/ 0.07
Length of 66kV cable (km / % of region 66kV)	6.5 km / 5.5%
Length of 66kV conductor (km / % of region 66kV)	110.9 km / 94.5%
Length of 33kV cable (km / % of region 33kV)	0 km/ 0%
Length of 33kV conductor (km / % of region 33kV)	7.9 km / 100%
Length of 11kV cable (km / % of region 11kV)	345 km / 47%
Length of 11kV conductor (km / % of region 11kV)	389 km / 53%
Length of 7.6kV cable (km / % of region 7.6kV)	84.8 km / 42%
Length of 7.6kV conductor (km / % of region 7.6kV)	119 km / 58%
Installed *PV* inverter capacity (*MW* / % of state)	60.8 *MW* / 10.6%
No of feeders (abs / % urban / % rural short / % rural long)	143 / 100% / 0% / 0%

Table 55: Metro West Region Statistics

14.2 Development History

The Metro West region has been the cornerstone of Adelaide's electricity network since the introduction of electricity supply in 1899. The region has continuously served as one of the primary generation sources from power stations at Osborne to Torrens Island and more recently Pelican Point.

Conversion of the original five, 33*kV lines* from the former Osborne Power Station began in 1952. These *lines* formed the majority of the *sub-transmission network* within Adelaide at this time. The region originally consisted of 33*kV* and 7.6*kV* supply, with the majority of the regions 33*kV zone substations* converted to operation at 66*kV* throughout the course of the 1970's and 1980's. The region maintains a small area supplied at 33*kV* operating between Cheltenham and Woodville *zone substations*. Several of the regions *zone substations* operate at 66*kV* stepped down to 7.6*kV*.

Today, the Torrens Island Power Station (TIPS) *connection point* represents one of the state's primary transmission "hubs" being the largest single power station located within the metropolitan area.

Works conducted within this region over the present Reset period include:

Project Title	Description	Commissioning Year	Cost ($ million)
Cheltenham 66/11*kV* Zone Substation	Installation of a new 25 MVA 66/11*kV* transformer with associated 11*kV* switchboard and conversion of three existing 7.6*kV* feeders to 11*kV* operation.	2010	3.9
Findon – Flinders Park 66*kV* line	Construction of a new 66*kV* line between Findon zone substation and the existing Flinders Park – Fulham Gardens 66*kV* line together with associated protection upgrades at Flinders Park, Fulham Gardens, Findon and Woodville zone substations to support incorporating Findon zone substation within the meshed network.	2011	10.0
TIPS secondary systems upgrade	Upgrade of 66*kV* line protection at Port Adelaide North, Athol Park, Kilburn and New Oborne to match line protection and bus zone protection schemes implemented by ElectraNet at Torrens Island as part of their secondary systems upgrade	2012	2.4
Port Adelaide North line *CB*s	Installation of 66*kV* line *CB*s on both line exits at Port Adelaide North.	2012	2.7
Kilburn – Cavan 66*kV* line	Construction of new 4km 66*kV* line between Kilburn and Cavan substations. Construction of new line exit *CB*s at each site, 66*kV* bus extension at Kilburn and associated protection & control systems.	2012	9.6

Table 56: Recent Metro West Augmentation Projects

14.3 Connection points and sub-transmission lines

There are four main *connection points* in the Metro West region:

1. Torrens Island Power Station (TIPS)
2. Lefevre
3. New Osborne
4. Kilburn

The region also has a significant number of power stations connected to the transmission network, namely:

1. TIPS
2. Pelican Point (at 275*kV*)
3. Dry Creek
4. OCPL

5. Quarantine Power Station (QPS)

The latter three power stations are connected to the *ElectraNet* owned 66*kV* buses at Dry Creek (with direct connection to Kilburn), New Osborne and TIPS respectively. These three power stations can have a significant impact on the flows within *SA Power Networks'* 66*kV sub-transmission network* depending on their level of output at any given time.

Electricity is supplied throughout the Metro West region via *zone substations*. These *substations* are operated at 66*kV* stepped down to 33*kV*, 11*kV*, 7.6*kV* or 3.3*kV*.

The region's *connection point*s have a combined normal rating of 885 *MVA* and a *N-1* capacity of 525 *MVA*.

These *connection point*s are meshed via *SA Power Networks'* 66*kV sub-transmission network*. Under the *ETC*, these *connection point*s are classified as Category 4 sites and are required to be planned on a *N-1* basis for both transmission lines and transformers.

Given the significance of this region to the state in terms of customer numbers, *SA Power Networks* plans this region's *sub-transmission network* based on a *N-1* basis against the 10% *PoE* forecast. Constraints on the *meshed sub-transmission network* and of *ElectraNet's* 275/66*kV* transformers are determined through modelling of the *network* and analysis using *PSS/E*.

Within the time period covered by this *AMP*, no augmentation of the region's *connection point* transformer capacity is forecast to be required. A copy of the region's *connection point* forecasts are shown in APPENDIX E – METRO WEST REGION FORECASTS.

The region contains two 66*kV* ties to the Metro East region, one to the Metro South region and one tie to the Metro North region at Croydon, Dry Creek, New Richmond and Cavan *zone substations* respectively. These ties are normally only operated either following a contingent event in order to restore supply or when performing 11*kV feeder* ties across regional boundaries. In the latter case, the 66*kV* open point is temporarily closed prior to the closing of a cross region feeder open point in order to prevent inter-regional load flows through the 11*kV network* whilst the regions are momentarily connected. Following the completion of such transfers, the *sub-transmission* ties are restored to normal.

Whilst most *zone substations* within the region are meshed, the region contains several radial *zone substations* in Croydon Park and Athol Park.

Section Ref	Project Name	Constrained Line(s)	Constraint Type	Constraint Description	Proposed Solution	Constraint Year	Commissioning Year	2015-20 Cost ($ million)	2020-25 Cost ($ million)	Total Cost ($ million)
-	Blackpool to Fulham Gardens water crossing upgrade	Blackpool – Fulham Gardens 66*kV*	N	Inadequate line clearance across Port River crossing at high tide	Upgrade poles either side of river crossing with larger poles to obtain required clearance	2016	2016	**0.20**	-	0.20
-	Glanville to Queenstown water crossing upgrade	Glanville - Queenstown 66*kV*	N	Inadequate line clearance across Port River crossing at high tide	Upgrade poles either side of river crossing with larger poles to obtain required clearance	2016	2016	**0.20**	-	0.20
-	Dry Creek Generator Demand Management	New Osborne – Largs North & Blackpool – Fulham Gardens 66*kV*	N-1	Loss of either the New Osborne to Largs North or Blackpool to Fulham Gardens lines, overloads the New Osborne to Glanville line, while loss of the New Osborne to Glanville line overloads the New Osborne to Largs North line.	Establish Network Support Agreement with existing generator at Dry Creek to defer establishment of a new Athol Park – Woodville line. Establish SCADA interfaces to enable contract to be managed (ie start / stop commands etc).	2017	2020	**0.13**	0.13	0.26

Table 57: Metro West Sub-Transmission Line Constraints

14.4 Zone substations

Electricity is supplied throughout the Metro West region by 17, 66/11*kV*, two 66/33*kV* and six 66/7.6*kV zone substations*. A small 33*kV* network operates between Cheltenham and Woodville Zone Substations.

Forecasts for the region's *zone substations* are shown in APPENDIX E – METRO WEST REGION FORECASTS.

The following *zone substation* constraints have been identified within the 2015-25 period covered by this *AMP*:

Project Timing	Project Name	Limitation / Constraint	Proposed Solution	Section Ref	2015-20 Cost ($ million)	2020-25 Cost ($ million)	Total Cost ($ million)
2020 – 2022	Seaton 66/11*kV Substation*	Overload of Findon *zone substation* and three existing 11*kV feeders* for normal and *contingent conditions*.	Construct a new 66/11*kV substation* at existing Seaton site consisting of a single 32 *MVA* transformer and associated 11*kV* switchboard together with three new 11*kV feeder* exits.	-	**0.07**	13.80	13.87

Table 58: Metro West Zone Substation Constraints

14.5 Feeders

The region's *zone substations* supply 143, 11*kV* and 7.6*kV feeders* serving approximately 107,920 customers. Table 59 details those *feeder* constraints forecast over the forthcoming five year reset period.

Project Timing	Project Name	Limitation / Constraint	Proposed Solution	Section Ref	2015-20 Cost ($ million)	2020-25 Cost ($ million)	Total Cost ($ million)
2016	Cavan *Substation* – new 11*kV feeder*	Overload of Market, Churchill and Goldsborough *feeder* under normal and *contingent conditions.*	Construct a new 11*kV feeder* ex Cavan *zone substation* and transfer load from Market and Churchill *feeders*.	14.5.1	**1.30**	-	1.30
2016	Cheltenham 7.6*kV* Feeder Conversion to 11*kV*	Overload of Cheltenham 7.6*kV* zone substation transformers under contingent conditions	Convert the existing Finsbury South and Franklin 7.6*kV* *feeders* to 11*kV* and supply from Cheltenham *zone substation's* 66/11*kV* transformer and switchboard.	14.5.2	**4.38**	-	4.38
2016	Woodville South 7.6*kV Feeder* load relief	Inability to backup Woodville South *feeder* under *contingency conditions*.	Convert part of the existing Woodville South *feeder* from operation at 7.6*kV* to 11*kV* and transfer to existing Woodville West 11*kV feeder*.	14.5.3	**0.55**	-	0.55

Table 59: Metro West Feeder Constraints

14.5.1 Major Project – Cavan Substation New Feeder

14.5.1.1 Constraint

The Market 11kV feeder (SA-520F) is supplied from Cavan 66/11kV Zone Substation and has a normal rating of 480A. The Market 11kV feeder primarily supplies industrial customers and has a forecast growth rate of 2.5%. Under 50% PoE conditions, the feeder's normal supply capacity will be exceeded in 2015/16 and the N-1 offload capacity will be exceeded in 2019/20.

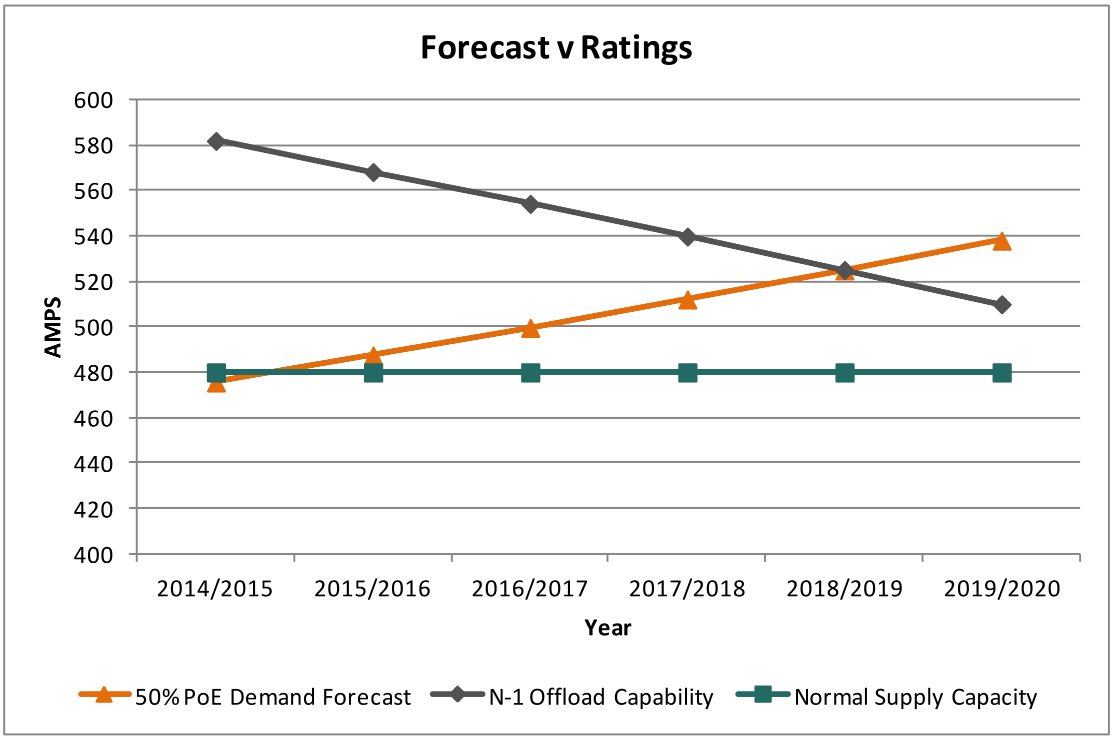


Figure 52: Market 11kV Feeder Load versus Capacity

	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
Forecast* Amps (50% PoE)	476	487	500	512	525	538
Feeder Normal Supply Capacity (Amps)	480	480	480	480	480	480
Percentage Overload	99%	102%	104%	107%	109%	112%
N-1 Offload Capability (Amps)	582	568	554	540	525	510
N-1 Load at Risk (Amps)	0	0	0	0	0	28

**Load Forecast includes impact of PV both existing and forecast. The forecast also includes the impact of energy efficiency, state economic and population growth by reconciling each asset's local growth trend with the AEMO July 2014 SA Regional forecast for the next 5 years.*

Table 60: Market 11kV Feeder Load Forecast

14.5.1.2 Consequences for Customers

The 50% PoE forecast demand for Market 11kV feeder (SA-14) in 2016/17 is 500A, which will exceed its normal rating of 480A.

In the event of a cable failure due to feeder overload, all 31 of the mostly industrial customers will be unsupplied for around 4 hours while implementing the required load transfers. The rating of Market 11kV feeder is expected to be exceeded for a total of 90 hours in 2016/17 over 9 days per annum.

In the event of a cable failure in 2019/20 and after all available N-1 offload capacity is exhausted, 28A of load and more than two industrial customers would be unsupplied until the cable fault was repaired. However, due to the discrete number of switching points on a given feeder, it is not possible to load shed an exact amount of customers. In general, it is likely that a larger portion of the feeder would need to be shed.

14.5.1.3 Load Profile

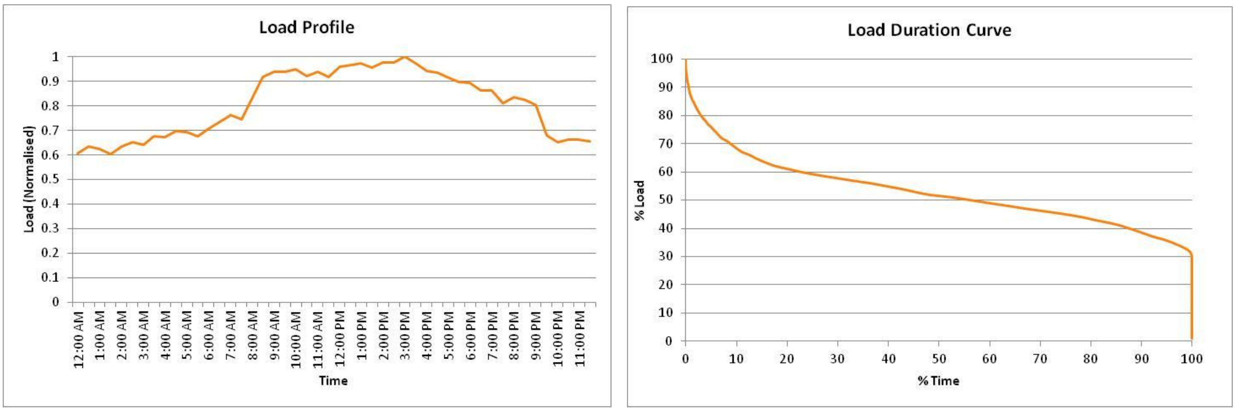


Figure 53: (a) Salisbury Plains 11kV Feeder Load Profile, (b) Load Duration Curve

14.5.1.4 Deferral Options Considered

Feeder Load Transfer

- All possible feeder tie improvements and load transfers are not feasible due to high existing demand on adjacent feeders and unsuitable switching point locations.

Demand Side Participation

- Due to the large amount of load at risk, demand side participation is not expected to achieve a large enough reduction of load to defer the constraint on Market 11kV feeder.

14.5.1.5 Options considered to address constraint

The following options have been investigated to resolve the impending constraint:

Option 1:

- Establish a new 11kV feeder by installing approximately 1.2km of 630mm^2 Al XLPE cable along Levels Rd, Beachwood Ave and Mawson Lakes Blvd to Technology Park 11kV feeder (near DF7907). Transfer part of Stockade 11kV feeder via LS1218 and DF7905, part of Market 11kV feeder via C2292 and C927 and part of Churchill 11kV feeder via A8512 to the new 11kV feeder.

Option 2:

- Establish a new 11kV feeder at Kilburn 66/11kV Substation by installing approximately 3km of 630mm^2 Al XLPE Cable from a spare feeder circuit breaker to split Market 11kV feeder and transfer load from Market, Goldsborough and Churchill 11kV feeders to the new 11kV feeder.

14.5.1.6 Preferred Solution

The preferred solution based on a net present value analysis, is to establish a new 11kV feeder from Cavan 66/11kV Zone Substation and transfer load from the existing Stockade, Market and Churchill 11kV feeders to the new 11kV feeder. This project is planned for completion in November 2016 and is expected to resolve the constraint on the Market 11kV feeder for 10 years. The indicative cost for this project is $1.3 million.

14.5.1.7 Regulatory Period Expenditure

The total estimated $1.3 million is forecast to be spent during the 2015-20 regulatory period.

14.5.2 Major Project – Cheltenham 7.6kV to 11kV Conversion

14.5.2.1 Constraint

The Cheltenham 66/7.6kV Zone Substation contains one 25MVA dual winding 66/33/7.6kV transformer. Under 50% PoE conditions, the contingency capacity of the substation will be exceeded in 2016/17.

The measured load in 2013/14 was 4.35MVA, with 3.5MVA load at risk of being unsupplied in the event of a transformer failure as minimal practical feeder ties are available and SA Power Networks mobile plant cannot be utilised at 66/7.6kV sites.

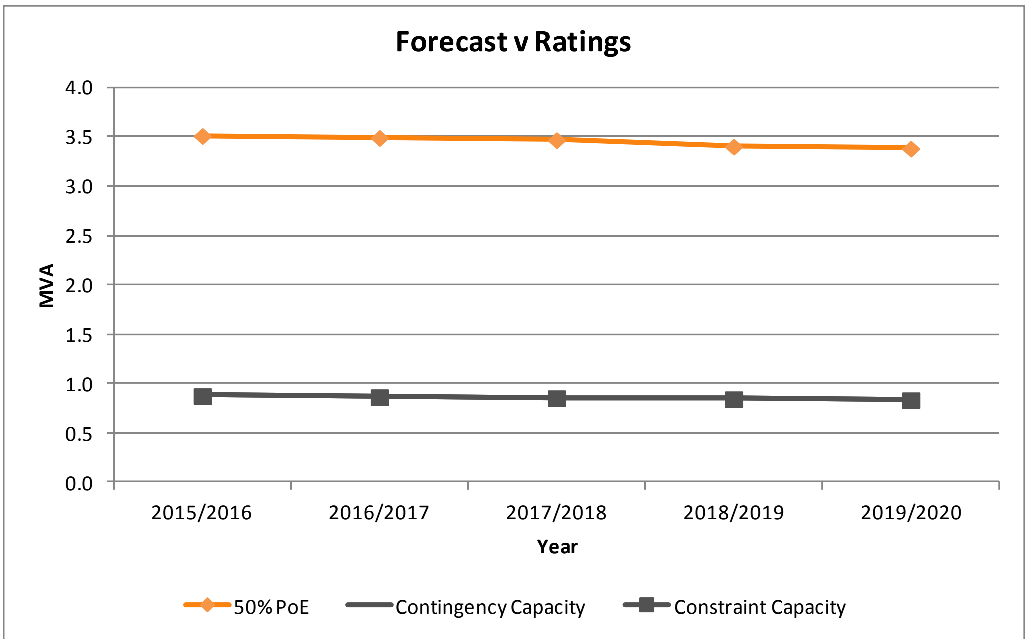


Figure 54: Cheltenham 66/7.6kV Substation Load versus Capacity

	2015/16	2016/17	2017/18	2018/19	2019/20
Forecast* MVA (50% PoE)	3.5	3.5	3.5	3.4	3.4
Power Factor	0.94	0.94	0.94	0.94	0.94
Normal Capacity (MVA)	4.8	4.8	4.8	4.8	4.8
Firm Delivery Capacity (MVA)	0	0	0	0	0
Contingency Capacity (MVA)	0.9	0.9	0.9	0.8	0.8
Load at Risk (MVA)	2.6	2.6	2.6	2.6	2.6

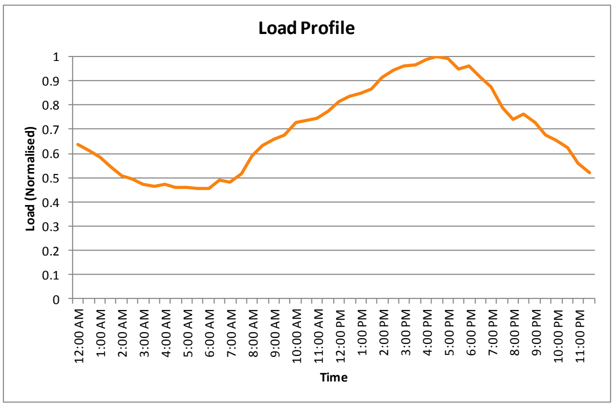
**Load Forecast includes impact of PV both existing and forecast.*

Table 61: Cheltenham 66/7.6kV Load Forecast

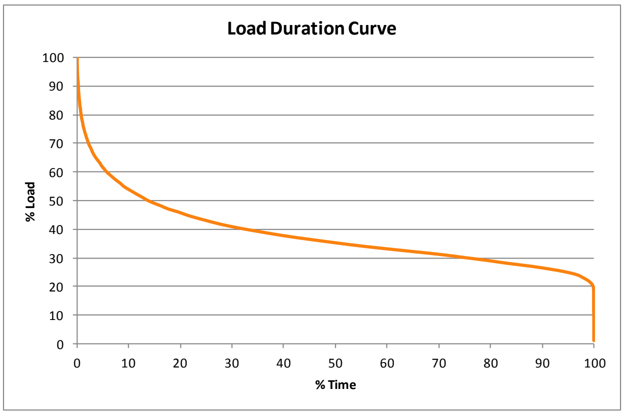
14.5.2.2 Consequences for Customers

Cheltenham 66/7.6kV zone substation has a contingency capacity of 0.9MVA in 2016/17. Given a forecast in 2016/17 of 3.5MVA under 50% PoE conditions, up to 2.6MVA of load may need to be shed for a transformer fault. More than 1200 customers would remain unsupplied after all possible feeder switching is completed. However, due to the discrete number of switching points on a given feeder, it is not possible to load shed an exact amount of customers. In general, it is likely that a larger portion of the feeder would need to be shed. SA Power Networks mobile substations cannot be utilised at 66/7.6kV sites and therefore these customers would remain unsupplied for several days while a replacement substation transformer was installed or large-scale temporary mobile generation connected. The contingency capacity of Cheltenham 66/7.6kV Zone Substation is expected to be exceeded for a total of 8280 hours in 2016/17 over 365 days per annum.

14.5.2.3 Load Profile



(a)



(b)

Figure 55: (a) Cheltenham 66/7.6kV Zone Substation Load Profile, (b) Load Duration Curve

14.5.2.4 Deferral Options Considered

Power Factor Correction

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

Demand Side Participation

- Due to the large amount of load at risk, demand side participation is not expected to achieve a large enough reduction of load to defer the constraint on the Cheltenham 66/7.6kV substation.

Improved Feeder Ties

- See Option 1 below.

14.5.2.5 Options considered to address constraint

The following options have been investigated to resolve the impending constraint:

Option 1:

- Convert Finsbury South 7.6kV and Franklin 7.6kV feeders to 11kV operation by replacing 42 7.6/0.4kV distribution transformers with 11kV equivalents. Install two new 11kV feeder exits and transfer load to Cheltenham 66/11kV substation.

Option 2:

- Upgrade Cheltenham 66/7.6kV substation by installing two new 25MVA 66/7.6kV transformers with two 66kV circuit breakers, new masonry control building, two section 7.6kV switchboard and two new 7.6kV feeder exits.

14.5.2.6 Preferred Solution

The preferred solution, based on a net present value analysis, is to convert the Cheltenham 7.6kV feeder network to 11kV operation (Option 1) as nearby zone substations to the north and east of Cheltenham operate at 11kV. The indicative cost for this project is $4.4 million.

This project is planned for completion in 2016 and is expected to solve the constraint at the Cheltenham 66/7.6kV Zone Substation for at least 10 years.

This project also supports the long-term plan of converting all 7.6kV feeders to 11kV operation and superseding 66/7.6kV substation aged assets (approximately 60 years old).

14.5.2.7 Regulatory Period Expenditure

The total estimated $4.4 million is required during the 2015-20 regulatory control period.

14.5.3 Major Project – Woodville South Feeder Conversion

14.5.3.1 Constraint

Woodville South 7.6kV feeder (AP-351D) is supplied from the Woodville 66/7.6kV Zone Substation and has an N-1 offload capacity of 114A. Under 50% PoE conditions the feeders N-1 offload capacity will be exceeded in 2016/2017.

The measured average growth rate for the Woodville South 7.6kV feeder from 2008 to 2013 was 1.3%. This feeder now peaks at 19:00 (due to PV) and therefore PV will have a minimal impact on this particular feeder in future and the historic growth rate of 1.3% is expected to continue in the long-term.

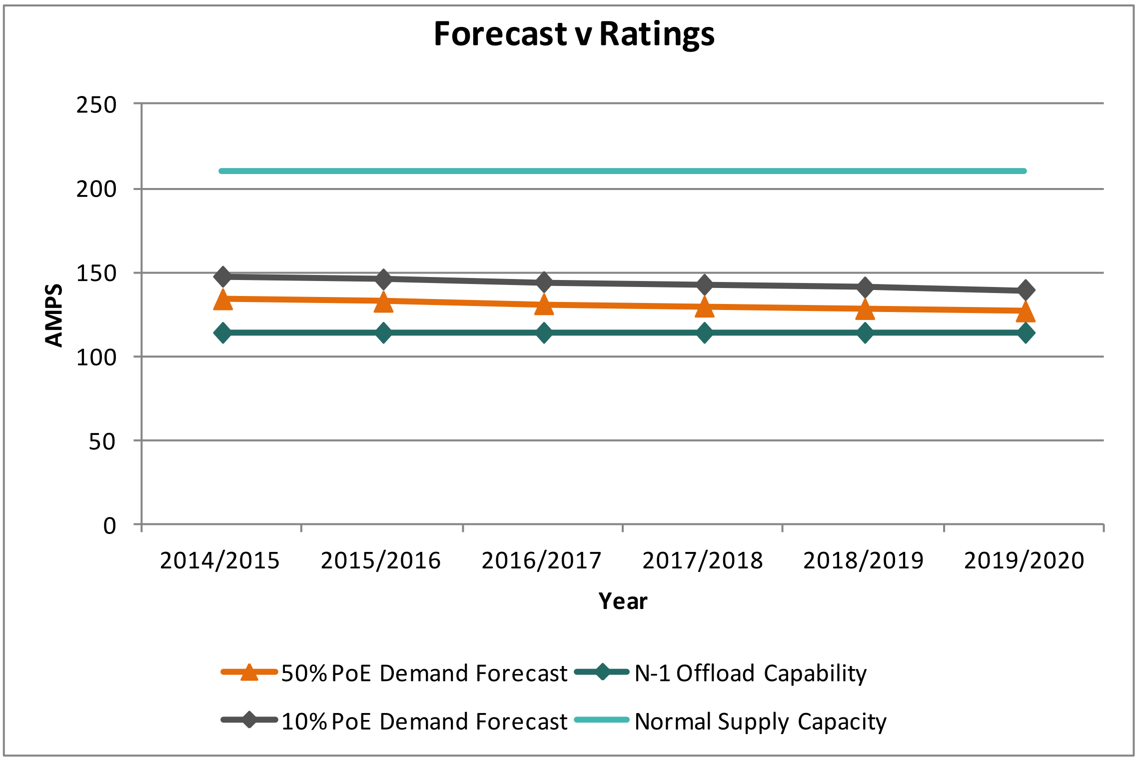


Figure 56: Woodville South 7.6kV Feeder Load versus Capacity

	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
Forecast* Amps (50% PoE)	134	132	131	129	128	127
N-1 Offload Capability (Amps)	114	114	114	114	114	114
N-1 Load at Risk (Amps)	20	18	17	15	14	13

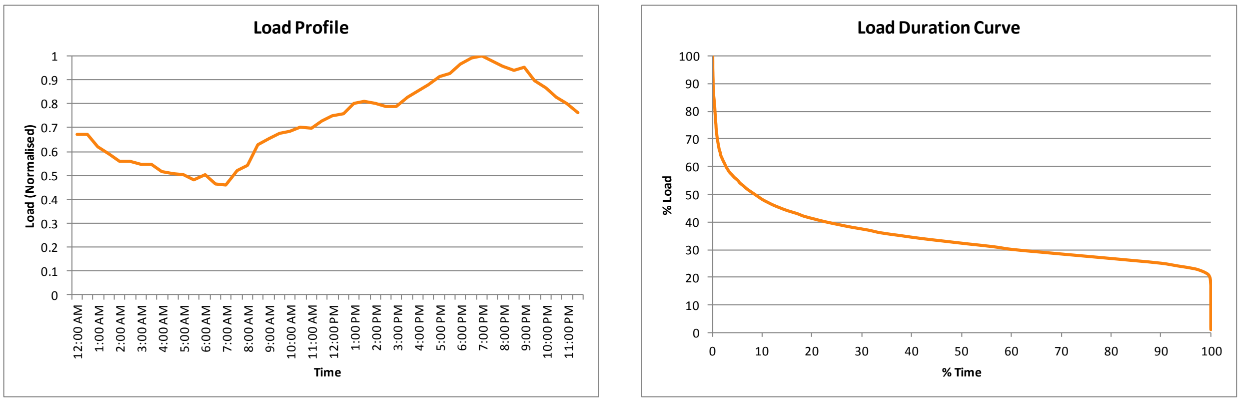
***Load Forecast includes impact of PV both existing and forecast. The forecast also includes the impact of energy efficiency, state economic and population growth by reconciling each asset's local growth trend with the AEMO July 2014 SA Regional forecast for the next 5 years.*

Table 62: Woodville South 7.6kV Feeder Load Forecast

14.5.3.2 Consequences for Customers

The 50% PoE forecast peak demand exceeds the N-1 offload capacity of Woodville South 7.6kV feeder from 2014/2015. In 2016/17 in the event of a cable failure and after all available N-1 offload capacity is exhausted, up to 17A of load and 80 customers would remain unsupplied until the cable fault was repaired. However, due to the discrete number of switching points on a given feeder, it is not possible to load shed an exact amount of customers. In general, it is likely that a larger portion of the feeder would need to be shed, as there are typically 500 customers between tie points and 100A. The N-1 supply capacity of Woodville South 7.6kV feeder is expected to be exceeded for a total of 13 hours in 2016/17 over 8 days per annum. The offload capability uses the emergency rating of the feeders and substations that the customers are connected to and considers all possible options.

14.5.3.3 Load Profile



(a) (b)

Figure 57: (a) Woodville South 7.6kV Feeder Load Profile, (b) Load Duration Curve

14.5.3.4 Deferral Options Considered

7.6kV Feeder Conversion to 11kV Operation

- See option 1 below. This involves converting part 7.6kV feeder to 11kV operation which will allow for increased N-1 capacity and the load transfer required to solve the Woodville South 7.6kV feeder normal supply capacity constraint.

Demand Side Participation

- Due to the large amount of load at risk, demand side participation is not expected to achieve a large enough reduction of load to defer the constraints on the Woodville South 7.6kV feeder.

14.5.3.5 Options considered to address constraint

The following options have been investigated to resolve the impending constraints:

Option 1:

- Convert five distribution transformers on the Woodville South 7.6kV feeder (AP-351D) to 11kV and transfer approximately 60A from Woodville South 7.6kV feeder to Woodville West 11kV Feeder supplied from from Findon Zone Substation.

Option 2:

- Construct a new 7.6kV feeder from Woodville Zone Substation to tie to the Woodville South 7.6kV feeder and increase the available transfers under N-1 conditions.

14.5.3.6 Preferred Solution

The preferred solution, based on net present value analysis is to convert part of the Woodville South 7.6kV feeder to 11kV (option 1). This supports the long term strategy to convert the remaining 7.6kV network within the Western Suburbs to operation at 11kV. The indicative cost for this project is $0.55 million. This project is planned for completion in 2016 and is expected to resolve the constraint on Woodville 66/7.6kV Zone Substation's feeders for at least 15 years.

14.5.3.7 Regulatory Period Expenditure

The total estimated $0.55 million is required within the 2015-20 regulatory period.

14.6 Land and Other Works

The following land purchases and additional works within the region have been identified within the 2015-20 period.

Project Timing	Project Name	Work Category	Proposed Solution	Section Ref	2015-20 Cost ($ million)	2020-25 Cost ($ million)	Total Cost ($ million)
2019	New Osborne *NGM* Upgrade	NER Compliance	Install aux *CTs* and check metering to existing 66*kV* connections on New Osborne's 66*kV* bus and calibrate.	-	**0.20**	-	0.20

Table 63: Metro West Other Works

15. BAROSSA – REGIONAL DEVELOPMENT PLAN

SA Power Networks' Barossa Region serves the Barossa Valley and extends north to Stockwell, south to Williamstown and west to Sandy Creek. The region's load is dominated by the influence of the Barossa Valley and its viticultural activities.

A map of this region is shown in Figure 58 while a single line representation of the *network* is shown in Figure 59.

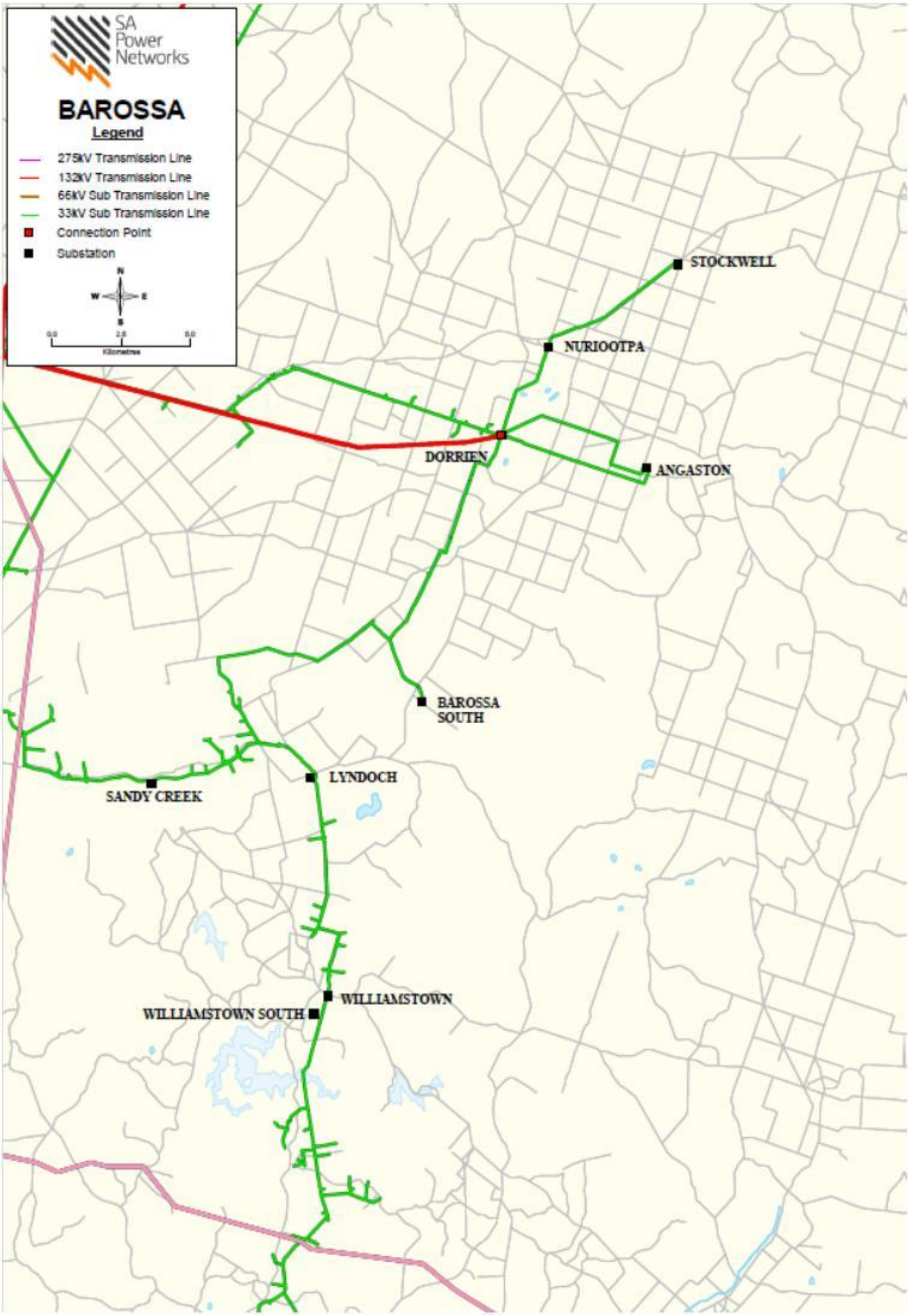


Figure 58: Barossa Region Map

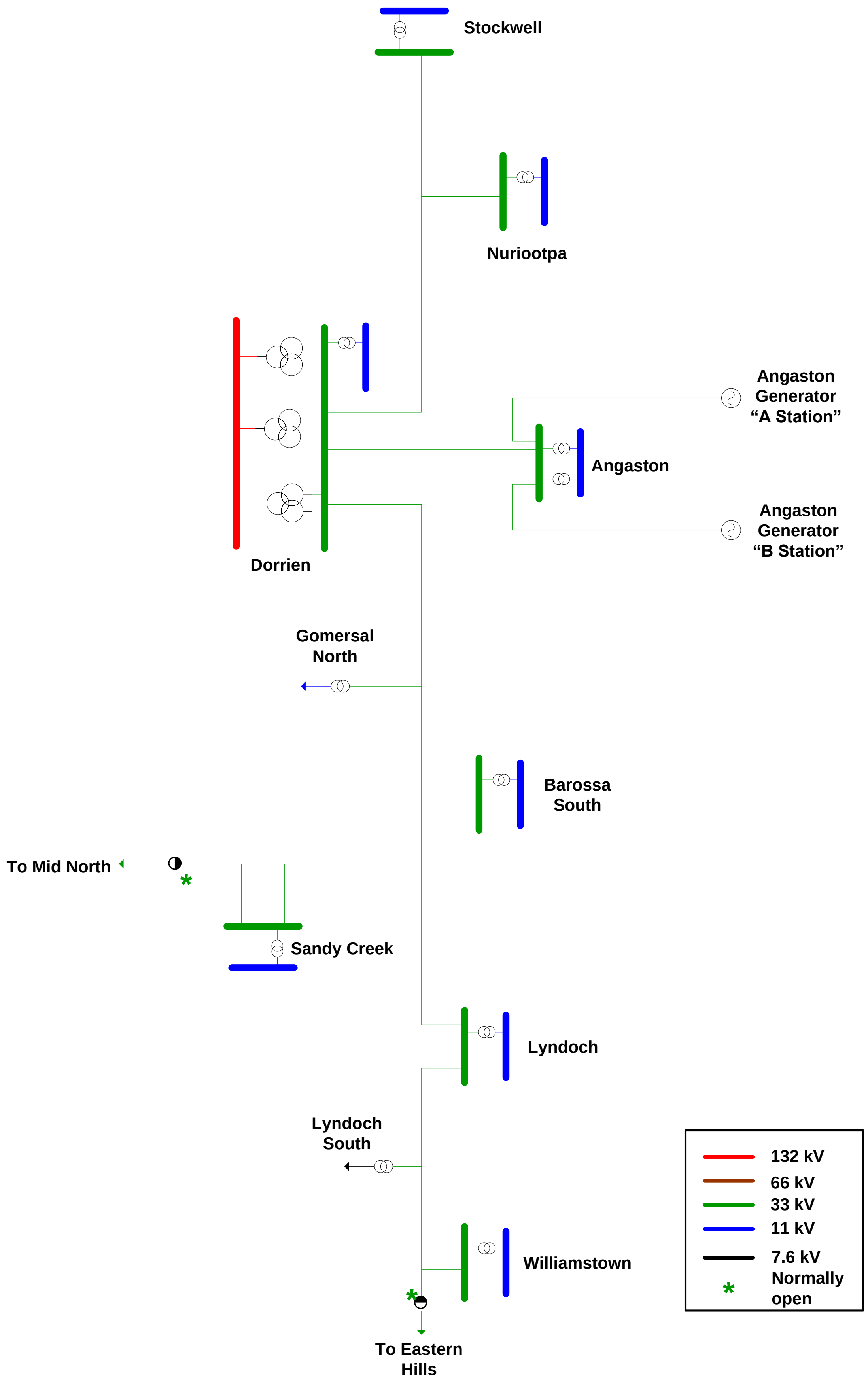


Figure 59: Barossa Single Line Diagram

15.1 Region Statistics

Table 64 indicates the general statistics for this region of the state.

Parameter	Value
No of connection points	1 (132/33*kV*)
No of zone subs	8 (33/11*kV*)
Operating voltages	33*kV* and 11*kV*
Total customers	12,304
No of residential customers (abs /%of region/% of state)	9,927 / 80.7% / 1.2%
No of commercial customers (abs /%of region/% of state)	2,377 / 19.3% / 0.3%
Area of region (km^2 / % of state)	875 km^2 / 0.38%
Length of 33kV cable (km / % of region 33kV)	1.05 km / 1.4%
Length of 33kV conductor (km / % of region 33kV)	74.3 km / 98.6%
Length of 19kV cable (km / % of region 19kV)	0.4 km / 0.15%
Length of 19kV conductor (km / % of region 19kV)	271 km / 99.85%
Length of 11kV cable (km / % of region 11kV)	95.5 km / 14%
Length of 11kV conductor (km / % of region 11kV)	590 km / 86%
Length of 7.6kV cable (km / % of region 11kV)	1.35 km / 3.7%
Length of 7.6kV conductor (km / % of region 11kV)	35 km / 96.3%
Installed *PV* inverter capacity (*MW* / % of state)	11.5 *MW* / 2.0%
No of feeders (abs / % urban / % rural short / % rural long)	20 / 0% / 16.7% / 83.3%

Table 64: Barossa Region Statistics

15.2 Development History

The Barossa region has been largely developed since the formation of the Electricity Trust of South Australia (ETSA) in 1946 through to privatisation in 1999 and the subsequent creation of ETSA Utilities / *SA Power Networks*.

Works conducted within this region over the present Reset period include:

Project Title	Description	Commissioning Year	Cost ($ million)
Dorrien 132kV *Connection Point* Upgrade	Works to facilitate connection of an additional 132/33kV transformer by ElectraNet	2012	1.9

Table 65: Recent Barossa Augmentation Projects

15.3 Connection points and sub-transmission lines

The Barossa region contains one *connection point* located at Dorrien supplied at 132*kV* and stepped down to 33*kV* for use by *SA Power Networks*. The region also contains a significantly sized *embedded generating* installation (50 MW) connected to Angaston *zone substation*.

Electricity is supplied throughout the Barossa via *zone substations*. These substations are operated at 33*kV* stepped down to 11*kV*.

Customers are supplied from *SA Power Networks' distribution system* via 11*kV feeders*, which are supplied from the *zone substations*. These *feeders* are extended and upgraded as required to meet customer demand, and customer connection requests.

The region's *connection point* has a combined normal rating of 216 *MVA* and a *N-1* capacity of 156 *MVA*.

This *connection point* is classified as a Category 4 site and is required to be planned on a *N-1* basis for both transmission lines and transformers.

In accordance with the planning criteria for *sub-transmission lines*, *SA Power Networks* plans this region's *sub-transmission network* based on the 10% *PoE* forecast. Constraints on the radial *sub-transmission network* and of *ElectraNet's* 132/33*kV* transformers are determined through modelling of the *network* and analysis using *PSS/E* and comparison of the forecast to the *connection point*'s normal and emergency ratings.

Within the time period covered by this *AMP*, no augmentation of the region's *connection point* transformer capacity is forecast to be required. A copy of the region's *connection point* forecasts are shown in APPENDIX F – BAROSSA REGION FORECASTS.

The region contains 33*kV* ties to the Metro North, Mid North and Eastern Hills regions. These ties are normally only operated either following a contingent event in order to restore supply or when performing 11*kV feeder* ties across regional boundaries. In the latter case, the 33*kV* open point is temporarily closed prior to the closing of a cross region feeder open point in order to prevent inter-regional load flows through the 11*kV network* whilst the regions are momentarily connected. Following the completion of such transfers, the *sub-transmission ties* are restored to normal.

Within the forecast period covered by this *AMP*, no *lines* have been identified as having constraints within the region.

Table 66 indicates those *sub-transmission lines* forecast to be constrained within the 2015-25 period and the proposed solution.

Section Ref	Project Name	Constrained Line(s)	Constraint Type	Constraint Description	Proposed Solution	Constraint Year	Commissioning Year	2015-20 Cost ($ million)	2020-25 Cost ($ million)	Total Cost ($ million)
-	Angaston to Stockwell 33*kV line* (new *line*)	Dorrien to Stockwell 33*kV*	N	Thermal overload of existing 33*kV line* under normal conditions. *Line* already at its ultimate design rating.	Construct a new 33*kV line* approx 12km between Angaston and Stockwell. Uprate the existing Dorrien to Angaston #1 and #2, 33*kV lines* for operation at 100°C.	2022	2022	-	3.66	3.66

Table 66: Barossa Sub-Transmission Line Constraints

15.4 Zone substations

Electricity is supplied throughout the Barossa region by eight, 33/11*kV zone substations*.

Forecasts for the region's *zone substations* are shown in APPENDIX F – BAROSSA REGION FORECASTS.

The following *zone substation* constraints have been identified within the 2015-25 period covered by this *AMP*.

Project Timing	Project Name	Limitation / Constraint	Proposed Solution	Section Ref	2015-20 Cost ($ million)	2020-25 Cost ($ million)	Total Cost ($ million)
2015	Dorrien 33/11*kV substation* upgrade	Overload of Dorrien and Nuriootpa *zone substations* under *contingent conditions*.	Upgrade Dorrien 33/11*kV zone substation* by installing second 12.5 *MVA* 33/11*kV* transformer and associated 11*kV* switchboard.	15.4.1	**2.79**	-	5.58
2016	Barossa South *Sub* Upgrade	Overload of Barossa South *zone substation* under *contingent conditions*.	Install second 6.25 *MVA* 33/11*kV* transformer and construct approx 2km of new 11*kV feeder*.		**3.48**	-	3.50
2018	Lyndoch East *Substation*	Overload of Lyndoch *zone substation* under contingent conditions	Construct a new 33/11*kV zone substation* consisting of two 3.8 *MVA* 33/11*kV* transformers (one of which is temporarily installed at existing Lyndoch *sub*).	-	**3.98**	-	3.98
2019	Stockwell *Sub* Upgrade	Overload of Stockwell *zone substation* under normal conditions.	Install second 6.25 *MVA* 33/11*kV* transformer and associated 33*kV* and 11*kV* protection.	-	**3.88**	-	3.88
2023	Tanunda 12,5*MVA* 33/11*kV Substation*	Overload of Angaston *zone substation* under normal conditions and overload of Dorrien and Nuriootpa *zone substations* under *contingent conditions*.	Establish a new *zone substation* at an existing site consisting of a single 12.5 *MVA* 33/11*kV* transformer and associated 11*kV* switchboard.	-	**-**	5.32	5.32
2026	Williamstown South 33/11*kV Sub* Upgrade	Overload of Williamstown South *zone substation* under normal conditions	Install second 3.8 *MVA* 33/11*kV* transformer and associated 33*kV* and 11*kV* protection.	-	**-**	0.13	2.51

Table 67: Barossa Zone Substation Constraints

15.4.1 Major Project – Dorrien 33/11kV Substation Upgrade

15.4.1.1 Constraint

Dorrien, Nuriootpa and Angaston 33/11kV Zone Substations are located in the Barossa Region and are supplied from Dorrien 132/33kV Connection Point, see Figure 60.

Dorrien 33/11kV Zone Substation contains one 12.5MVA 33/11kV transformer while Nuriootpa and Angaston 33/11kV Zone Substations contains one and two 12.5MVA 33/11kV transformers respectively. Under 50% PoE conditions, all three zone substation's contingency capacities will be exceeded in 2015/16.

The forecast growth rate at these three substations is 0.3%. Although the wine industry is traditionally one of the large customers in this region, residential development has been driving load growth in recent years.

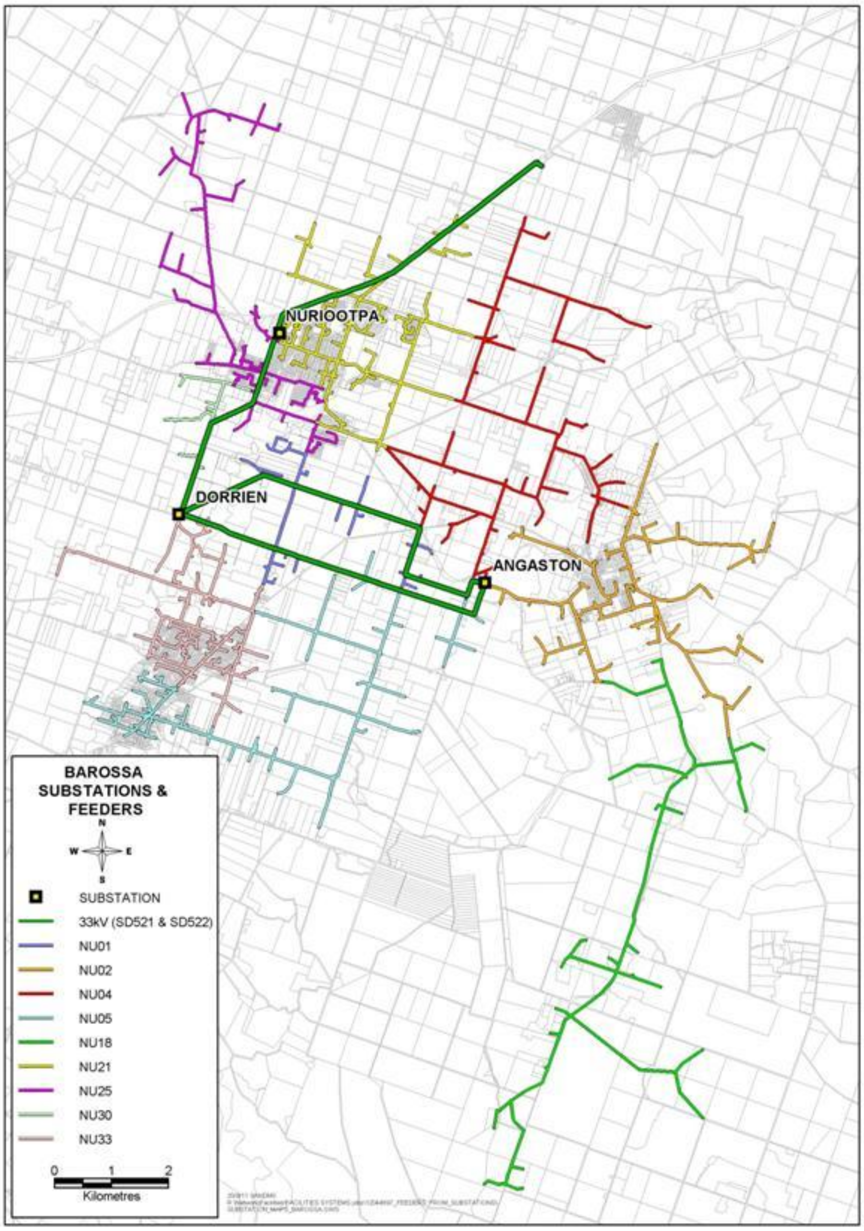


Figure 60: Locality of Dorrien 33/11kV Zone Substation

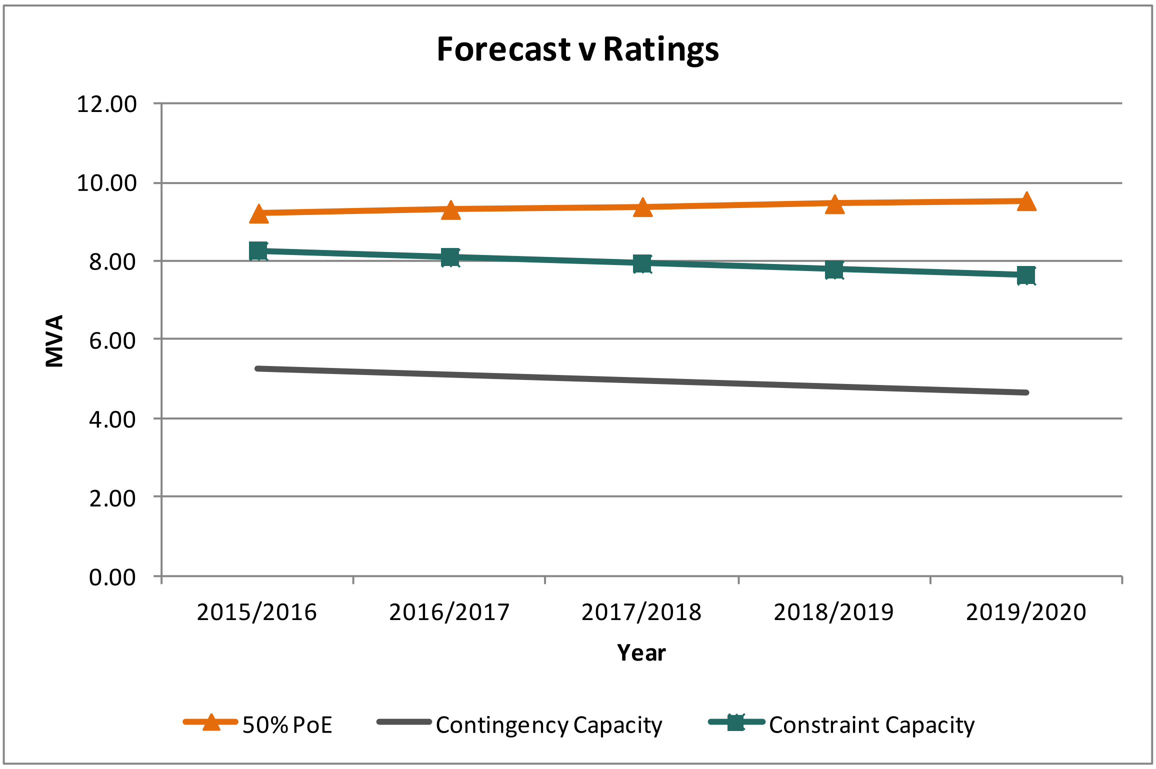


Figure 61: Dorrien 33/11kV Zone Substation Load versus Capacity

	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
Forecast MVA* (50% PoE)	9.2	9.2	9.3	9.4	9.5	9.5
Power Factor	0.97	0.97	0.97	0.97	0.97	0.97
Normal Capacity (MVA)	13.6	13.6	13.6	13.6	13.6	13.6
Firm Delivery Capacity (MVA)	0	0	0	0	0	0
Contingency Capacity (MVA)	5.4	5.3	5.1	4.9	4.8	4.6
Load at Risk (MVA)	3.8	3.9	4.2	4.5	4.7	4.9

**Load Forecast includes impact of PV both existing and forecast. The forecast also includes the impact of energy efficiency, state economic and population growth by reconciling each asset's local growth trend with the AEMO July 2014 SA Regional forecast for the next 5 years.*

Table 68: Dorrien 33/11kV Zone Substation Load Forecast

The measured load in 2013/14 was 9.5MVA.

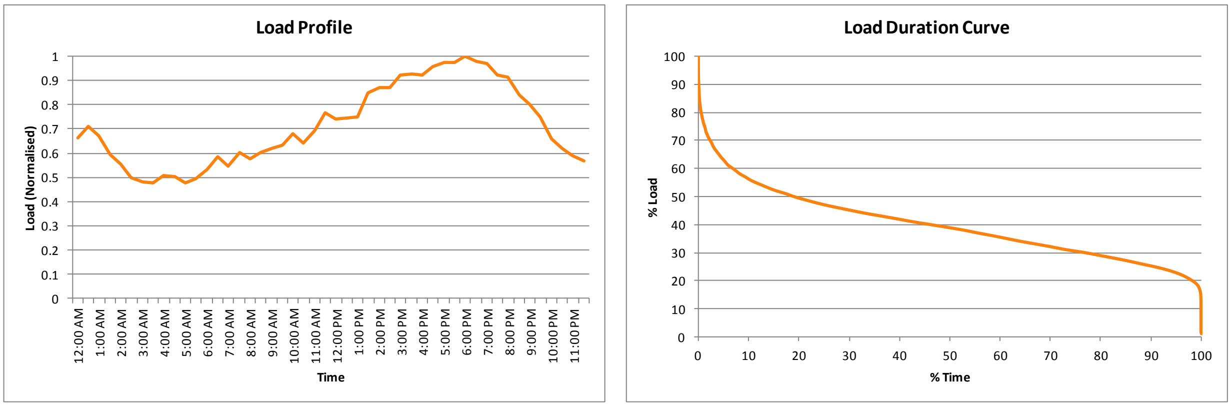
15.4.1.2 Consequences for Customers

Dorrien 33/11kV Zone Substation has a contingency capacity of 5.3MVA in 2015/16. Given a forecast in 2015/16 of 9.2MVA under 50% PoE conditions, up to 3.9MVA of load may need to be shed for a transformer fault. Approximately 1,000 customers would remain unsupplied after all possible feeder switching is completed until a mobile substation could be installed (typically 24 hours). The contingency capacity of Dorrien 33/11kV Zone Substation is expected to be exceeded for a total of 58 hours in 2015/16 over 259 days per annum.

Nuriootpa 33/11kV Zone Substation has a contingency capacity of 4.5MVA in 2015/2016. Given a forecast in 2015/16 of 10.6MVA under 50% PoE conditions, up to 6.1MVA of load may need to be shed for a transformer fault. Approximately 1,700 customers would remain unsupplied after all possible feeder switching is completed until a mobile substation could be installed (typically 24 hours).

Angaston 33/11kV Zone Substation has a contingency capacity of 17.9MVA in 2015/16. Given a forecast in 2015/16 of 18.3MVA under 50% PoE conditions, up to 0.4MVA of load may need to be shed for a transformer fault. Approximately 300 customers would remain unsupplied after all possible feeder switching is completed until a mobile substation could be installed (typically 24 hours).

15.4.1.3 Load Profile



(a) (b)

Figure 62: (a) Dorrien 33/11kV Zone Substation Load Profile, (b) Load Duration Curve

15.4.1.4 Regulatory Test

In response to this constraint, a Reasonableness Test was published in accordance with ESCOSA Guideline 12. Reasonableness Test, RT 005-13 was published in November 2013. The Reasonableness Test showed that Demand Management measures could not address the system constraint and that a network solution was required.

15.4.1.5 Deferral Options Considered

The following deferral options were considered:

Power factor correction:

- The power factors of the Dorrien, Angaston and Nuriootpa loads are near unity, due to the installation of 2 x 3MVAr, 2 x 2.5MVAr and 2 x 3MVAr switched capacitor banks at each substation respectively. Further power factor correction is therefore not feasible.

Improved feeder ties:

- Construction of new 11kV feeders from Dorrien to Nuriootpa and/or Angaston Zone Substations would improve feeder transfer capacity but would also require the upgrade of one or both of the substations to utilise this capacity. This was considered and is discussed further in Option 2 below.

15.4.1.6 Options considered to address constraint

The following options have been investigated in accordance with the ESCOSA Guideline 12 to resolve these impending constraints:

Option 1:

- Upgrade Dorrien Zone Substation with second 33/11kV transformer; and
- Upgrade 11kV feeders between Angaston Zone Substation and Nuriootpa Zone Substation to Dorrien Zone Substation and transfer load.

Option 2:

- Upgrade Nuriootpa Zone Substation with second 33/11kV transformer;
- Upgrade the 33kV line between Dorrien and Nuriootpa Zone Substations; and
- Upgrade 11kV feeders between Angaston and Dorrien Zone Substations to Nuriootpa Zone Substation and transfer load.

15.4.1.7 Preferred Solution

The preferred solution based on the regulatory analysis, is to upgrade Dorrien 33/11kV Zone Substation with second 33/11kV transformer (Option 1). This solution resolves the constraints at Dorrien, Angaston and Nuriootpa with an expected life of seven years following project completion. The indicative cost for this project is $5.6 million. This project is planned for completion in November 2015. Refer below for NPV analysis.

15.4.1.8 Commitment Status

The relevant regulatory process (ESCOSA Guideline 12) was completed in 2013 and SA Power Networks has committed to the project to enable the November 2015 commissioning date to be met. This project was included in the pre RIT-D committal list issued to the AER in December 2013.

15.4.1.9 Regulatory Period Expenditure

Approximately $2.8 million is forecast to be required in the 2015-20 Regulatory Control Period, with the remaining $2.8 million forecast to be spent in the present control period.

15.4.1.10Net Present Value Analysis

Option	Description	NPV[29]
1	Dorrien 33/11*kV* Substation Upgrade	-11,850,898
2	Nuriootpa 33/11*kV* Substation Upgrade	-12,534,024

Table 69: Dorrien NPV Results and Rankings

[29] Based on the use of a 8.98% discount rate over 15 years

15.5 Feeders

The region's *zone substations* supply 20, 11*kV feeders* serving approximately 12,304 customers. Table 70 details those *feeder* constraints forecast over the forthcoming five year reset period.

Project Timing	Project Name	Limitation / Constraint	Proposed Solution	Section Ref	2015-20 Cost ($ million)	2020-25 Cost ($ million)	Total Cost ($ million)
2015	Lyndoch *Feeder* Tie Switch Upgrade	Overload of Lyndoch *zone substation* under *contingent conditions*.	Replace the existing tie switch (DF) with a new switching device to increase rating of tie and transfer load to Barossa South *zone substation*.	-	**0.09**	-	0.19
2016	Stockwell Substation *feeder* tie upgrade	Overload of Stockwell *zone substation* under *contingent conditions*.	In order to defer the overload of Stockwell *zone substation* under contingent conditions it is proposed to upgrade the *feeder* backbone of the *feeders* with ties to Angaston and Nuriootpa *zone substations*.	15.5.1	**1.01**	-	1.06
2016	Rosedale Recloser Upgrade	Overload of existing recloser trip coil (125%) for normal conditions	Upgrade the existing hydraulic recloser with a new 11*kV* recloser to increase rating.	-	**0.15**	-	0.15
2018	Mt Crawford Recloser Upgrade	Overload of existing recloser's trip coil.	Upgrade the existing hydraulic recloser with a new 11*kV* recloser to increase rating.	-	**0.15**	-	0.15

Table 70: Barossa Feeder Constraints

15.5.1 Major Project – Stockwell Feeder Tie Upgrade

15.5.1.1 Constraint

The Stockwell 33/11kV Zone Substation contains one 6.25MVA 33/11kV transformer. Under 50% PoE conditions, the contingency capacity of the substation was exceeded in 2013/14.

The measured load in 2013/14 was 6MVA, with 5.1MVA load at risk of being unsupplied in the event of a transformer failure as minimal practical feeder ties are available.

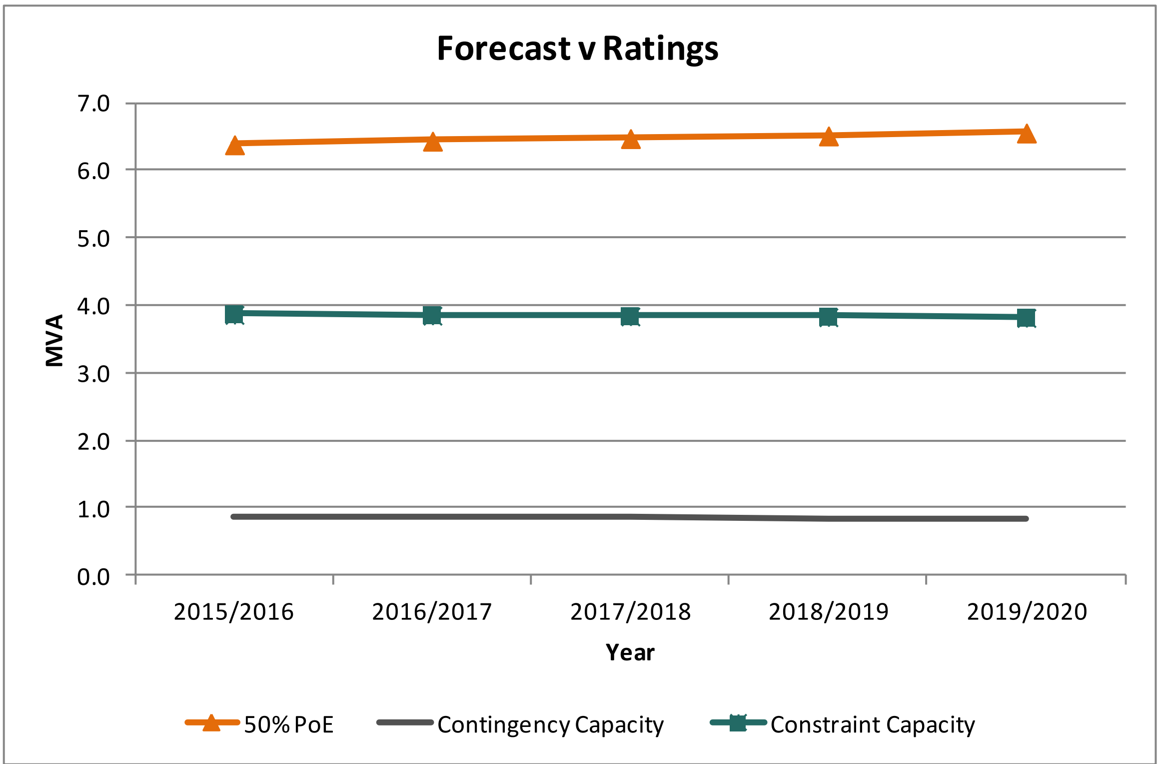


Figure 63: Stockwell 33/11kV Load versus Capacity

	2015/16	2016/17	2017/18	2018/19	2019/20
Forecast* MVA (50% PoE)	6.4	6.5	6.5	6.5	6.6
Power Factor	0.96	0.96	0.96	0.96	0.96
Normal Capacity (MVA)	8.9	8.9	8.9	8.9	8.9
Firm Delivery Capacity (MVA)	0	0	0	0	0
Contingency Capacity (MVA)	0.9	0.9	0.9	0.8	0.8
Load at Risk (MVA)	5.5	5.6	5.6	5.7	5.7

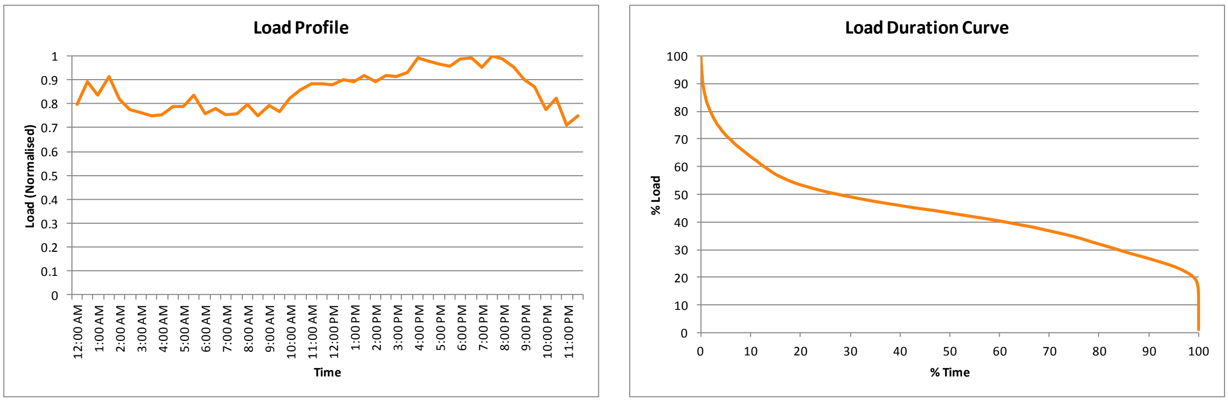
**Load Forecast includes impact of PV both existing and forecast. The forecast also includes the impact of energy efficiency, state economic and population growth by reconciling each asset's local growth trend with the AEMO July 2014 SA Regional forecast for the next 5 years.*

Table 71: Stockwell 33/11kV Load Forecast

15.5.1.2 Consequences for Customers

Stockwell 33/11kV zone substation has a contingency capacity of 0.9MVA in 2015/2016. Given a forecast in 2015/2016 of 6.4MVA under 50% PoE conditions, up to 5.5MVA of load may need to be shed for a transformer fault. More than 670 customers would remain unsupplied after all possible feeder switching is completed until a mobile substation could be installed (typically 24 hours). However, due to the discrete number of switching points on a given feeder, it is not possible to load shed an exact amount of customers. In general, it is likely that a larger portion of the feeder would need to be shed. The contingency capacity of Stockwell 33/11kV zone substation is expected to be exceeded for a total of 8756 hours in 2015/2016 over all 365 days.

15.5.1.3 Load Profile



(a) (b)

Figure 64: (a) Stockwell 33/11kV Zone Substation Load Profile, (b) Load Duration Curve

15.5.1.4 Deferral Options Considered

Power Factor Correction

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

Demand Side Participation

- Due to the large amount of load at risk, demand side participation is not expected to achieve a large enough reduction in load to defer the constraint on the Stockwell 33/11kV Zone Substation.

Improved Feeder Ties

- See Option 1 below.

15.5.1.5 Options considered to address constraint

The following options have been investigated to resolve these impending constraints:

Option 1:

- Upgrade the feeder ties to surrounding Nuriootpa and Angaston 33/11kV Zone Substations by restringing approximately 5km of overhead conductor with 30/7/2.5 ACSR, installing 0.5km of 300mm^2 Al XLPE cable and a single set of 200A 11kV voltage regulators.

Option 2:

- Install a second 6.25MVA OLTC Modular 2 substation for operation in conjunction with the existing Stockwell 33/11kV Modular 2 substation.

15.5.1.6 Preferred Solution

The preferred solution, based on a net present value analysis is to upgrade the feeder ties to Nuriootpa and Angaston 33/11kV Zone Substations (Option 1). The indicative cost for this project is $1.1 million. This project is planned for completion in 2015 and is expected to resolve the constraints at the Stockwell 33/11kV Zone Substation for 5 years.

15.5.1.7 Regulatory Period Expenditure

The total estimated $1.1 million is required during the 2015-20 Regulatory Control Period.

16. EASTERN HILLS – REGIONAL DEVELOPMENT PLAN

SA Power Networks' Eastern Hills Region serves the Adelaide Hills and extends north from Milang to Williamstown, Nairne in the east and west to Crafers. The region's load is dominated by residential loads. Due to significant development of the Mount Barker area in recent times, this region is one of the highest growing areas of the state.

A map of this region is shown in Figure 65 while a single line representation of the network is shown in Figure 66.

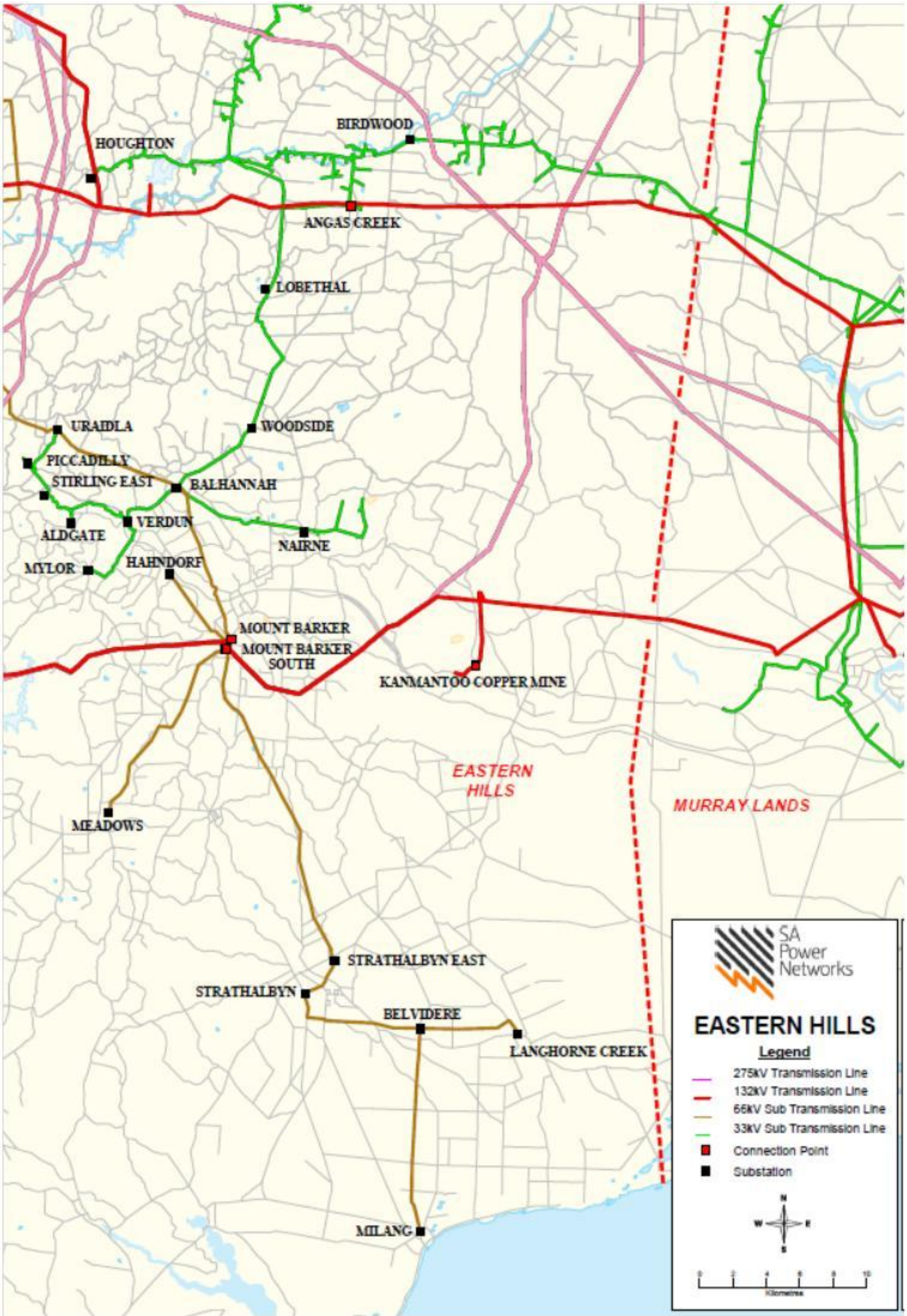


Figure 65: Eastern Hills Map

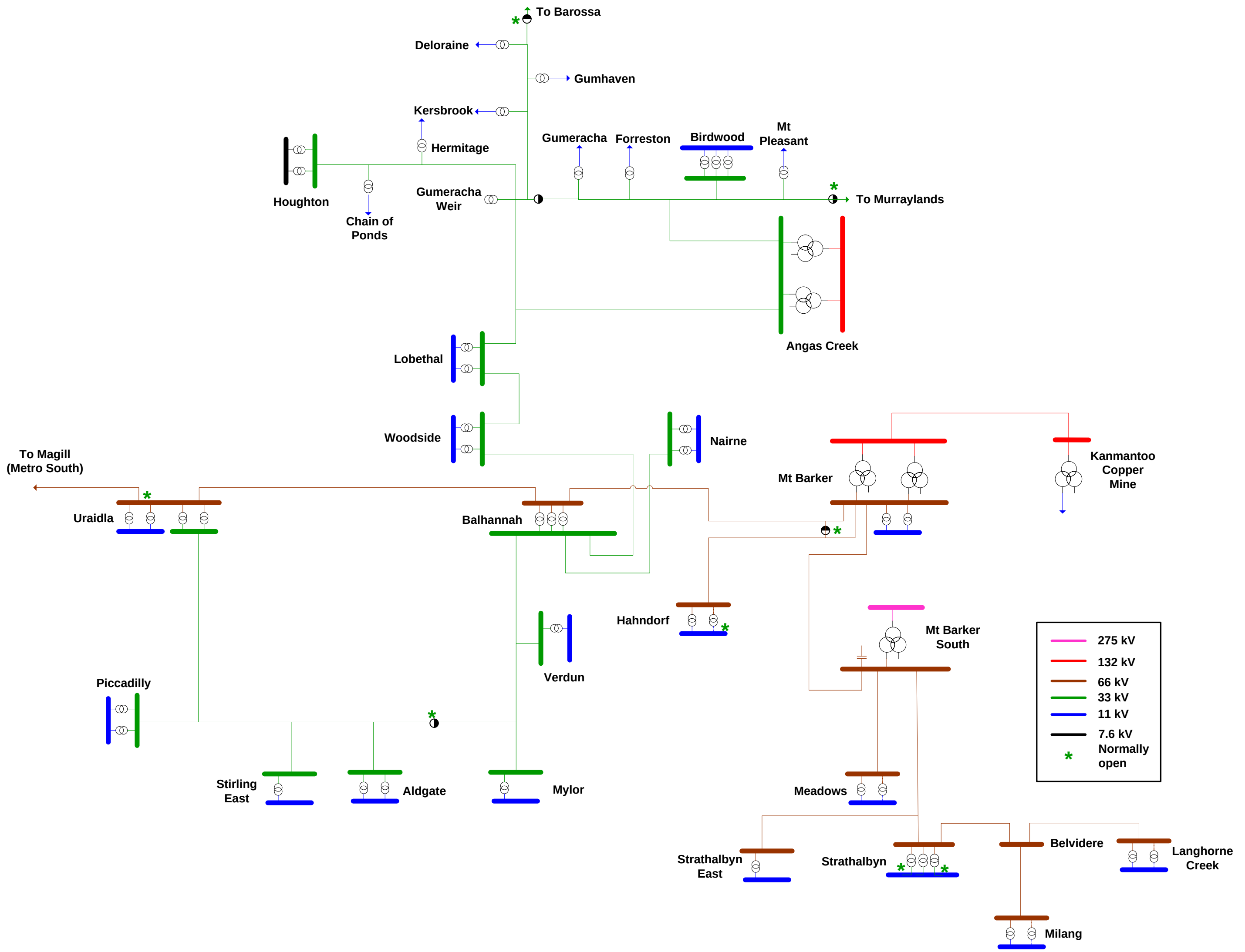


Figure 66: Eastern Hills Single Line Diagram

16.1 Region Statistics

Table 72 indicates the general statistics for this region of the state.

Parameter	Value
No of connection points	4 – 1 (275/66*kV*), 1 (132/66*kV*), 1 (132/33*kV*), 1 (132/11*kV*)
No of zone subs	29 - 2 (66/33*kV*), 13 (66/11*kV*), 13 (33/11*kV*), 1 (33/7.6*kV*),
Operating voltages	66*kV*, 33*kV*, 11*kV* and 7.6*kV*
Total customers	41,140
No of residential customers (abs /%of region/% of state)	33,680 / 81.9% / 4.0%
No of commercial customers (abs /%of region/% of state)	7,460 / 18.1% / 0.9%
Area of region (km^2 / % of state)	2,827 km^2 / 1.23%
Length of 66kV cable (km / % of region 66kV)	0 km / 0%
Length of 66kV conductor (km / % of region 66kV)	95.1 km / 100%
Length of 33kV cable (km / % of region 33kV)	0 km/ 0%
Length of 33kV conductor (km / % of region 33kV)	107.2 km / 100
Length of 19kV cable (km / % of region 19kV)	3.7 km / 0.9%
Length of 19kV conductor (km / % of region 19kV)	409 km / 99.1%
Length of 11kV cable (km / % of region 11kV)	236 km / 10.4%
Length of 11kV conductor (km / % of region 11kV)	2,033 km / 89.6%
Length of 7.6kV cable (km / % of region 7.6kV)	6 km / 9.5%
Length of 7.6kV conductor (km / % of region 7.6kV)	57 km / 90.5%
Installed *PV* inverter capacity (*MW* / % of state)	37.2 *MW* / 6.5%
No of feeders (abs / % urban / % rural short / % rural long)	62 / 3.2% / 51.6% / 45.2%

Table 72: Eastern Hills Region Statistics

16.2 Development History

The Eastern Hills region has been largely developed since the formation of the Electricity Trust of South Australia (ETSA) in 1946 through to privatisation in 1999 and the subsequent creation of ETSA Utilities / *SA Power Networks*.

The region was first supplied at 66*kV* in the early 1950s with construction of a 66*kV line* from Norwood to Balhannah commencing in 1950. Throughout the 1970's the regions *network* was expanded with the establishment of Uraidla, Hahndorf and Meadows *zone substations* in 1972, 1973 and 1976 respectively. This development of this region continued during this period.

In more recent times, the region has seen large amounts of re-development over the last decade with the greater Mount Barker area representing one of the fastest growing regions in state.

Significant works within this region over the present regulatory period include:

Project Title	Description	Commissioning Year	Cost ($ million)
Mount Barker South *Connection Point*	Establishment of a new 275/66*kV* *connection point* at the southern outskirts of Mount Barker. *SA Power Networks'* works included the establishment of a single 66*kV* bus section, a 66*kV* capacitor bank and re-routing and extension of existing 66*kV lines* to connect to the new site.	2011	10.3
Mount Barker *Substation* Upgrade	Replacement of the existing 66/11*kV* transformers with new 32 *MVA* units and the installation of a new two section 11*kV* switchboard and associated protection and *feeder* works.	2011	12.0
Houghton *Substation* Upgrade	Upgrade of the existing 33/7.6*kV* transformer with a new Y *MVA*, 33/7.6-11*kV* dual ratio unit together with new primary and secondary protection devices (reclosers).	2011	1.3
Balhannah 66/33*kV* *Substation* Upgrade	Upgrade the existing 66/33kV transformers at Balhannah with 12.5 MVA units.	2010	1.7
Uraidla 66/33*kV* *Substation* Upgrade	Upgrade the existing 66/33kV transformer with a 25 MVA unit.	2010	4.3
Stirling East *Substation* Upgrade	Upgrade Stirling East Zone Substation by installing a 12.5MVA 33/11kV transformer, new 11kV switchboard section and transfer load from Aldgate and Piccadilly Zone Substations to defer upgrading both sites.	2013	5.8

Table 73: Recent Eastern Hills Augmentation Projects

16.3 Connection points and sub-transmission lines

The Eastern Hills region contains three major and one minor *connection point* located at Mount Barker South, Mount Barker, Angas Creek and Kanmantoo. The first two aforementioned *connection point*s connect to *SA Power Networks' sub-transmission network* at 66*kV* while the latter two sites connect at 33*kV* and 11*kV* respectively. All but Mount Barker South *connection point* are supplied at 132*kV* whilst Mount Barker South is supplied at 275*kV*.

Mount Barker South and Mount Barker *connection points* are meshed via *SA Power Networks' 66kV network* and classed as Category 4 sites within the *ETC*, therefore requiring adequate transmission line and *connection point* transformer capacity to be available under *N-1* conditions. The Angas Creek and Kanmantoo sites are classed as Category 3 and 1 respectively.

The region's *connection point*s have the following normal and *N-1* transformer capacities:

Connection Point	ETC Category	Transformer "N" rating (MVA)	Transformer "N-1" rating (MVA)
Mount Barker South 275/66*kV* & Mount Barker 132/66*kV*[30]	4G	361.6	149.2
Angas Creek 132/33*kV*	4	53.9	32.5
Kanmantoo 132/11*kV*	1	3.0	0

Table 74: Eastern Hills Connection Point Ratings

In accordance with the planning criteria for *sub-transmission lines, SA Power Networks* plans this region's *sub-transmission network* based on the 10% *PoE* forecast. The region operates both 66 and 33*kV lines* at *sub-transmission* level. Constraints on the radial *sub-transmission network* and of *ElectraNet's* transformers are determined through modelling of the *network* and analysis using *PSS/E* and comparison of the forecast to the *connection point*'s normal and emergency ratings.

Within the time period covered by this *AMP*, no augmentation of the region's *connection point* transformer capacity is forecast to be required. A copy of the region's *connection point* forecasts are shown in APPENDIX G – EASTERN HILLS REGION FORECASTS.

The region contains a 33*kV* tie to the Barossa region and a 66*kV* tie to the Metro South region at Uraidla. These ties are normally only operated following a contingent event in order to restore supply.

The following *connection point* works are forecast within the 2015-25 period:

[30] For planning purposes, Mount Barker and Mount Barker South *connection points* are meshed and only considered for augmentation where demand exceeds the combined N-1 rating.

Project Timing	Project Name	Limitation / Constraint	Proposed Solution	Section Ref	2015-20 Cost ($ million)	2020-25 Cost ($ million)	Total Cost ($ million)
2022	Mount Barker South TF2 *Connection Point* Upgrade	Overload of Mount Barker *connection point* transformers following loss of transformer at Mount Barker South *connection point*.	Install second 66*kV* bus section to facilitate connection of second *ElectraNet* 275/66*kV* transformer at Mount Barker South. Works include construction of a second 66*kV line* between Mount Barker and Mount Barker South *connection points*, 66*kV* bus zone protection and a second 66*kV* VT.	-	0.06	6.16	6.22
2023	Kanmantoo *Connection Point* Upgrade	Overload of existing 11*kV* tertiary winding on *ElectraNet's* 132/33/11*kV* transformer at Kanmantoo under normal conditions.	Construct a new 33/11*kV zone substation* at existing Kanmantoo site consisting of a single 12.5 *MVA* transformer and associated 11*kV* switchboard.	-	-	3.38	3.38
2025	Angas Creek *Connection Point* Upgrade	Performance of *SA Power Networks'* works in conjunction with *EN's* planned asset replacement project	Rebuild existing 33*kV* bus and upgrade 33*kV* protection in conjunction with *EN's* asset refurbishment project.	-	-	2.15	4.1

Table 75: Eastern Hills Connection Point Projects

Table 76 indicates those *sub-transmission lines* forecast to be constrained within the 2015-25 period and the proposed solution.

Section Ref	Project Name	Constrained Line(s)	Constraint Type	Constraint Description	Proposed Solution	Constraint Year	Commissioning Year	2015-20 Cost ($ million)	2020-25 Cost ($ million)	Total Cost ($ million)
-	Birdwood Tee – Birdwood 33*kV* *line* uprate	Birdwood Tee to Birdwood 33*kV*	N	Thermal overload of existing 33*kV* *line* under *normal conditions*.	Uprate 1.1km of 33*kV* *line* from design temperature of 50°C to 65° or 80°C operation	2016	2016	**0.08**	-	0.13
-	Uraidla – Piccadilly 33*kV* Restring	Uraidla to Piccadilly 33*kV*	N & N-1	Thermal overload of existing 33*kV* line under *normal* conditions and *contingency conditions*. *Line* already at its ultimate design rating.	Upgrade approx 2.4km of conductor on existing *line* with 30/7/2.5 ACSR (or AAAC equivalent).	2019	2019	**0.84**	-	0.84
-	Verdun Tee – Mylor 33*kV* Restring	Verdun Tee to Mylor 33*kV*	N	Thermal overload of existing 33*kV* *line* under *normal conditions*. *Line* already at its ultimate design rating.	Upgrade approx 5.2km of existing 7/16 Copper conductor with 30/7/2.5 ACSR (or AAAC equivalent).	2021	2021	**0.05**	1.78	1.83

Table 76: Eastern Hills Sub-Transmission Line Constraints

16.4 Zone substations

Electricity is supplied throughout the Eastern Hills region by thirteen 66/11*kV* *zone substations*. The region contains two 66/33*kV* *zone substations* which provide the 33*kV* supply to five of the region's thirteen, 33/11*kV* in an open ring arrangement between Balhannah and Uraidla. The region also contains one 33/7.6*kV* *zone substation*.

Forecasts for the region's zone substations are shown in APPENDIX G – EASTERN HILLS REGION FORECASTS.

The following *zone substation* constraints have been identified within the 2015-25 period covered by this *AMP*:

Project Timing	Project Name	Limitation / Constraint	Proposed Solution	Section Ref	2015-20 Cost ($ million)	2020-25 Cost ($ million)	Total Cost ($ million)
2015	Gumeracha TF Upgrade	Overload of Gumeracha Weir *zone substation* under *normal conditions*.	Upgrade existing 0.15 *MVA* pole mounted 33/11*kV* transformer to 0.5 *MVA* unit.	-	**0.32**	-	0.64
2015	Uraidla *N-1* Upgrade	Overload of Uraidla 66/33 zone substation under contingent conditions.	Install a 32MVA 66/33*kV* transformer, operated on hot standby with auto-changeover scheme in event of failure of the existing 25 *MVA* unit.	-	**0.59**	-	3.4
2018	Houghton 7.6*kV* Pole Top Reg Upgrade	Overload of regulators at Houghton *zone substation* under *normal conditions*.	Install additional set of 7.6*kV* regulators.	-	**0.3**	-	0.3
2020	Chain of Ponds TF Upgrade	Overload of Chain of Ponds and Houghton *zone substations* under *normal conditions*.	Upgrade existing 0.5 *MVA* pole mounted 33/11*kV* transformer to a 1.5 *MVA* unit.	-	**0.44**	0.36	0.80
2020	Meadows *Sub* Upgrade	Overload of Meadows zone substation under normal conditions.	Upgrade Meadows 66/11*kV zone substation* by installing a new 12.5 *MVA* 66/11*kV* transformer and associated 11*kV* switchboard. Leave existing 2 x 2.5 *MVA* transformer on hot standby.		**2.20**	2.09	4.29
2018	Verdun *Substation* Upgrade	Overload of Verdun zone substation under contingent conditions	Upgrade existing 1 *MVA* 33/11*kV* transformer with new 3 *MVA* unit and split existing single *feeder* exit into two distinct *feeder* exits.	-	**1.76**	-	1.76
2024	Forreston TF Upgrade	Overload of Forreston zone substation under normal conditions.	Upgrade existing 1 *MVA* transformer with a new 3 *MVA* padmount transformer.	-	**-**	1.79	1.79
2025	Birdwood 11*kV* Voltage Regulator Upgrade	Overload of Birdwood voltage regulator under *normal conditions*.	Upgrade existing 2.5 *MVA* ground mounted 11*kV* regulator with a 5 *MVA* unit.	-	**-**	0.21	0.39
2025	Gumeracha Weir TF Upgrade	Overload of Gumeracha Weir *zone substation* under *normal conditions*.	Upgrade existing 0.3 *MVA* pole mounted 33/11*kV* transformer to 0.5 *MVA* unit.	-	**-**	0.32	0.64

Project Timing	Project Name	Limitation / Constraint	Proposed Solution	Section Ref	2015-20 Cost ($ million)	2020-25 Cost ($ million)	Total Cost ($ million)
2025	Langhorne Creek *Substation* Upgrade	Overload of Langhorne Creek *zone substation* under *normal conditions*.	Upgrade Langhorne Creek 33/11*kV zone substation* by installing a new 12.5 *MVA* 33/11*kV* transformer and associated 11*kV* switchboard. Leave existing 2.5 *MVA* transformer on hot standby.	-	-	2.44	4.88
2025	Mount Barker East *Substation*	Overload of Nairne zone substation under normal conditions and Mount Barker zone substation under contingent conditions.	Construct a new zone substation initially consisting of a single 32 *MVA* 66/11*kV* transformer and associated 11*kV* switchboard. Construct a new 66*kV line* from Mount Barker South *connection point* approx 6km to the new *substation* site.	-	-	11.15	14.35
2025	Stirling East *Substation* Upgrade	Overload of Stirling East zone substation under contingent conditions.	Install second 12.5 *MVA* 33/11*kV* transformer and second 11*kV* switchboard section.	-	-	2.96	5.64

Table 77: Eastern Hills Zone Substation Constraints

16.5 Feeders

Customers are supplied from *SA Power Networks' distribution system* via 7.6 and 11*kV feeders*, which are supplied from the *zone substations*. These *feeders* are extended and upgraded as required to meet customer demand, customer connection requests and to maintain quality of supply.

During the forthcoming 2015-20 Reset period, the following *feeder* constraints have been identified:

Project Timing	Project Name	Limitation / Constraint	Proposed Solution	Section Ref	2015-20 Cost ($ million)	2020-25 Cost ($ million)	Total Cost ($ million)
2016	Gumeracha Weir 11*kV feeder* tie to Hermitage 11*kV*	Overload of Gumeracha Weir *zone substation* under *normal conditions*.	In order to defer the overload of Gumeracha Weir *zone substation* under *normal conditions* it is proposed to construct approx 400m of new *feeder* to create a new *feeder* tie and transfer load from Gumeracha Weir to Hermitage *zone substation*	-	**0.23**	-	0.23
2016	Houghton Recloser Upgrade	Overload of existing recloser's trip coil following load transfer to feeder under *contingent conditions*.	Upgrade the existing hydraulic recloser with a new 11*kV* recloser to increase rating.	-	**0.15**	-	0.15
2016	Nairne to Hay Valley 11*kV feeder* tie	Overload of Nairne 11*kV feeder* under *contingent conditions*	Construct a new *feeder* tie between existing Nairne and Hay Valley *feeders* to increase *feeder* transfer capability.	-	**0.35**	-	0.35
2017	New Summit 11*kV Feeder* and MTB-10 and MTB-12 backbone restring	Mount Barker 11*kV feeder* under *normal* and *contingent conditions* and Mount Barker Central 11*kV feeder* under *contingent conditions*.	Construct a new *feeder* exit from Mount Barker *zone substation*. Restring approx 360m of existing *feeder* with double circuit 19/3.5 AAC and split load from MTB-10 and 12 across new *feeder*.	16.5.1	**2.69**	-	2.69

Table 78: Eastern Hills Feeder Constraints

16.5.1 Major Project – Summit New Feeder

16.5.1.1 Constraint

Mount Barker 11kV feeder (MTB-12) is supplied from the Mount Barker 66/11kV Zone Substation and has a normal rating of 400A. Under 50% PoE conditions, the feeder's normal capacity and N-1 offload capacity will be both exceeded in 2017/18.

The forecast growth rate for the Mount Barker 11kV feeder is 3.8% per annum which is being driven largely by increased residential development in Mount Barker. In 2013/14, Mount Barker 11kV feeder's load characteristic during peak load times was essentially flat from the period between 6:30pm to 8pm with the actual peak occurring at 7pm. This is due to the impact of installed PV reducing the native demand earlier in the day and rapidly dropping off between 6-8pm. A check of measured growth at 8pm (PV near 0) between 2009/10 and 2013/14 (both approximately 10% PoE years) returns a growth of 4.1% and shows that the recent underlying growth and forecast growth due to residential development will exceed the forecast.

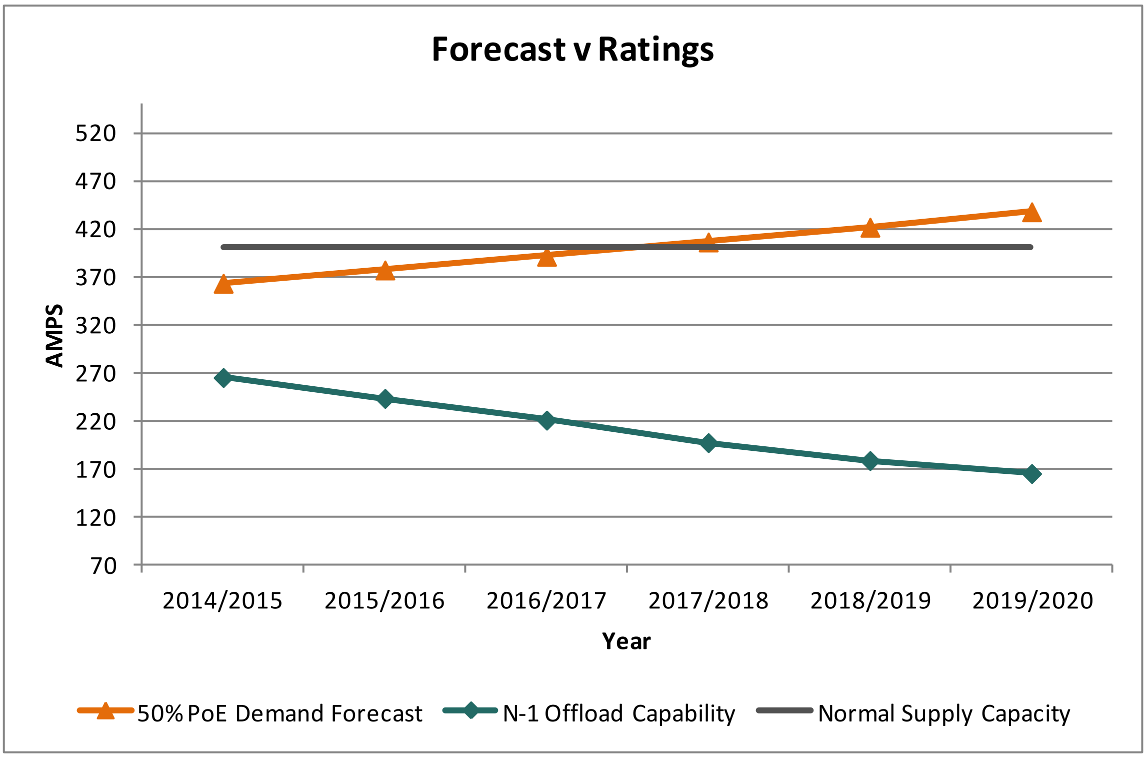


Figure 67: Mount Barker 11kV Feeder Load versus Capacity

	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
Forecast* Amps (50% PoE)	363	377	391	406	422	438
Normal Supply Capacity (Amps)	400	400	400	400	400	400
N Load at Risk (Amps)	0	0	0	6	22	38
N-1 Offload Capability (Amps)	265	243	221	197	178	165
N-1 Load at Risk (Amps)	98	134	170	209	244	273

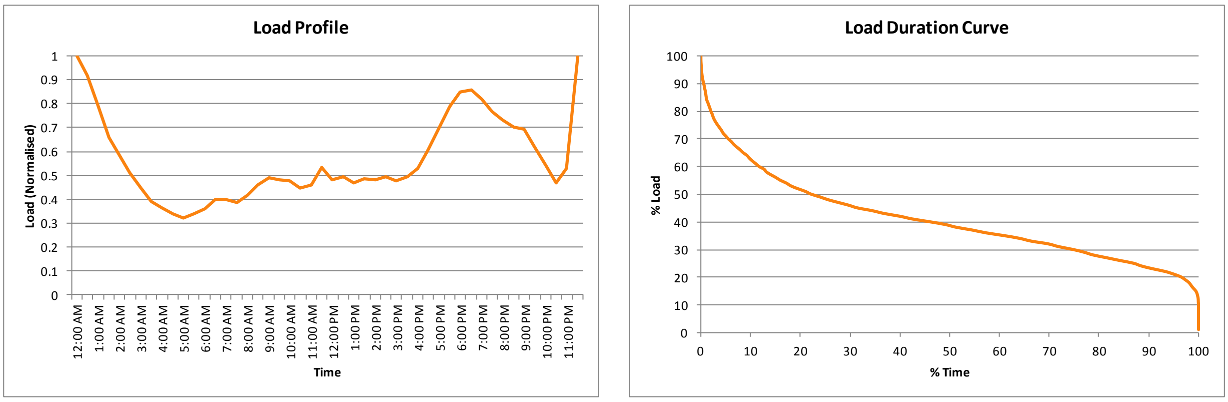
**Load Forecast includes impact of PV both existing and forecast. The forecast also includes the impact of energy efficiency, state economic and population growth by reconciling each asset's local growth trend with the AEMO July 2014 SA Regional forecast for the next 5 years.*

Table 79: Mount Barker 11kV Feeder Load Forecast

16.5.1.2 Consequences for Customers

The 50% PoE forecast demand exceeds the normal capacity and the N-1 offload capacity of the Mount Barker 11kV feeder (MTB-12) in 2017/18. In 2017/2018 in the event of cable failure, after all available N-1 offload capacity is exhausted, up to 209A of load and 1,000 customers would remain unsupplied until the cable fault was repaired. This load at risk increases to 273A and 1,200 customers by 2019/20. However, due to the discrete number of switching points on a given feeder, it is not possible to load shed an exact amount of customers. In general, it is likely that a larger portion of the feeder would need to be shed, as there are typically 500 customers between tie points or 100A. The normal capacity of Mount Barker 11kV feeder is expected to be exceeded for a total of 30 hours in 2017/18 over 39 days per annum increasing to 96 hours in 2019/20 over 134 days per annum. The offload capability uses the emergency rating of the feeders and substations that the customers are shifted to and considers all possible options.

16.5.1.3 Load Profile



(a) (b)

Figure 68: (a) Mount Barker 11kV Feeder Load Profile, (b) Load Duration Curve

16.5.1.4 Deferral Options Considered

Improved Feeder Ties

- No further feeder tie improvements are feasible due to high existing demand on adjacent feeders.

Demand Side Participation

- Due to the large amount of load at risk in 2017/2018, Demand Side Participation is not expected to achieve a large enough reduction of load to defer the constraints on the Mount Barker 11kV feeder (MTB-12).

16.5.1.5 Options considered to address constraint

The following options have been investigated to resolve the impending constraint:

Option 1:

- Establish a new Summit 11kV feeder by installing approximately 2.2km of 630mm^2 Al XLPE cable in existing conduits from Mount Barker 66/11kV Zone Substation and transfer load from both the Mount Barker and Bugle Ranges 11kV feeders to this new feeder.

Option 2:

- Establish a new Mount Barker East Zone Substation including the purchase of new land, one 32MVA 66/11kV transformer, masonry control building, 66kV line works from Mount Barker South Connection Point, 11kV feeder works and associated protection, SCADA and telecommunications. New 11kV feeders from this new zone substation to the development area will relieve both the Mount Barker 11kV and Bugle Ranges 11kV feeders.

16.5.1.6 Preferred Solution

The preferred solution based on a net present value analysis, is to establish a the new Summit 11kV feeder from Mount Barker 66/11kV Zone Substation and transfer load from the existing Mount Barker and Bugle Ranges 11kV feeders. This solution removes the normal capacity and N-1 offload capability constraints for the Mount Barker 11kV feeder. The indicative cost for this project is $2.7 million. This project is planned for completion in November 2017 and is expected to resolve the constraints on the Mount Barker 11kV feeder at Mount Barker 66/11kV Zone Substation for seven years.

16.5.1.7 Regulatory Period Expenditure

The total estimated $2.7 million is expected to be spent within the 2015/20 regulatory period.

16.6 Land and Other Works

The following land purchases and additional works within the region have been identified within the 2015-20 period.

Project Timing	Project Name	Work Category	Proposed Solution	Section Ref	2015-20 Cost ($ million)	2020-25 Cost ($ million)	Total Cost ($ million)
2016	Verdun Substation Upgrade	Land	Purchase additional land to enable the expansion of the existing Verdun site to facilitate its upgrade		**0.06**	-	0.06
2018	Meadows Sub Upgrade	Land	Purchase additional land to enable the expansion of the existing Meadows site to facilitate its upgrade		**0.13**	-	0.13
2020	Mount Barker East *Substation*	Land	Purchase land for future *zone substation* site and easements for associated 66*kV line* between Mount Barker South *connection point* and the final site.	-	**5.04**	-	5.04
2021	Forreston TF Upgrade	Land	Purchase land / easement to enable the upgrade of the existing substation from a pole mounted transformer to a pad mounted unit.		**-**	0.05	0.05
2021	Kanmantoo	Land	Purchase land from *ElectraNet* at the existing Kanmantoo *connection point* site to facilitate construction of a new 33/*11kV zone substation*.	-	**-**	0.12	0.12

Table 80: Eastern Hills Other Works

17. EYRE PENINSULA – REGIONAL DEVELOPMENT PLAN

As its name suggests, *SA Power Networks'* Eyre Peninsula Region serves the Eyre Peninsula from Whyalla in the north, Port Lincoln in the south and Ceduna in the west. The region's load consists of residential, commercial and industrial loads associated with steel production and aquaculture.

A map of this region is shown in Figure 69 while a single line representation of the *network* is shown in Figure 70.

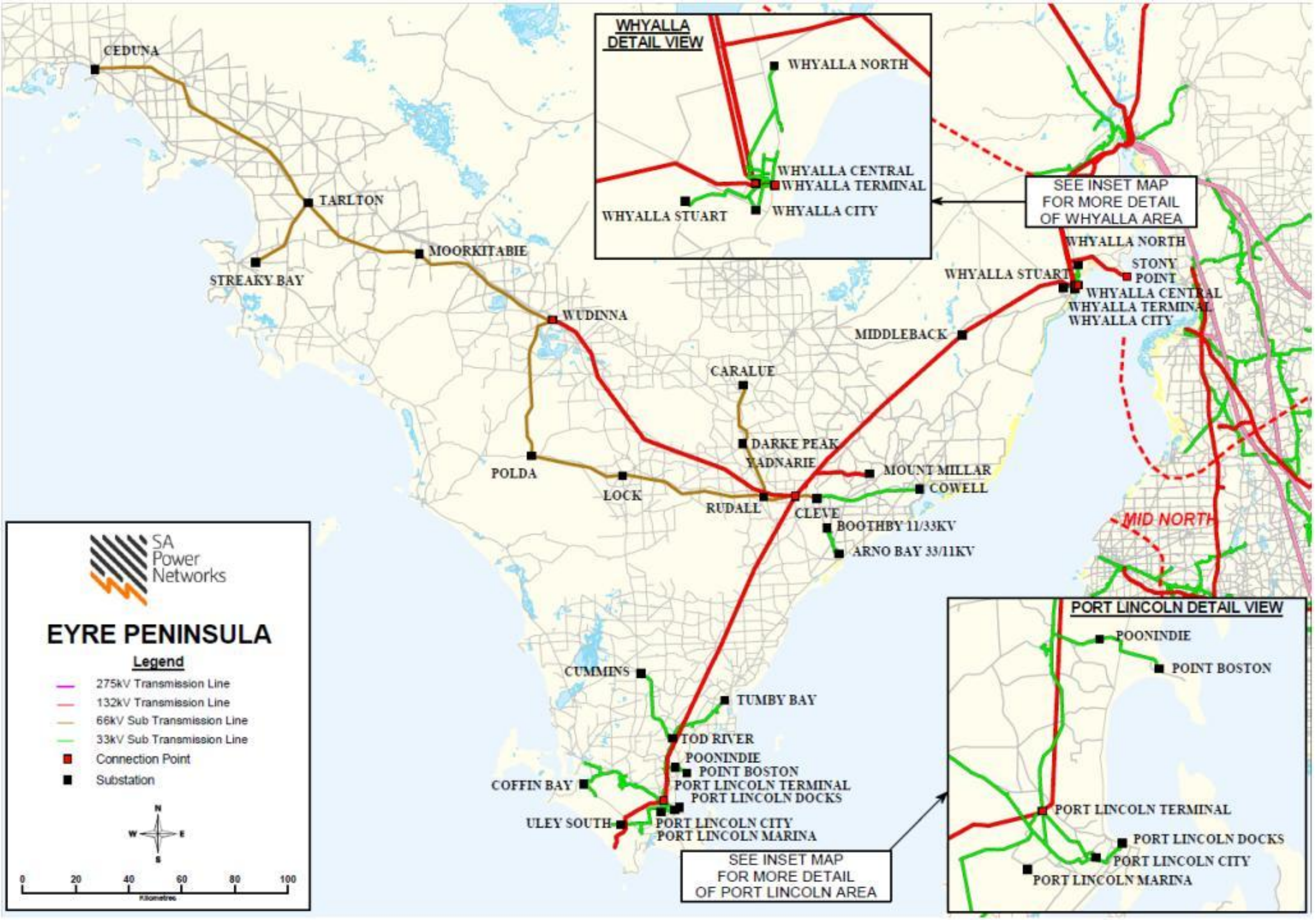


Figure 69: Eyre Peninsula Map

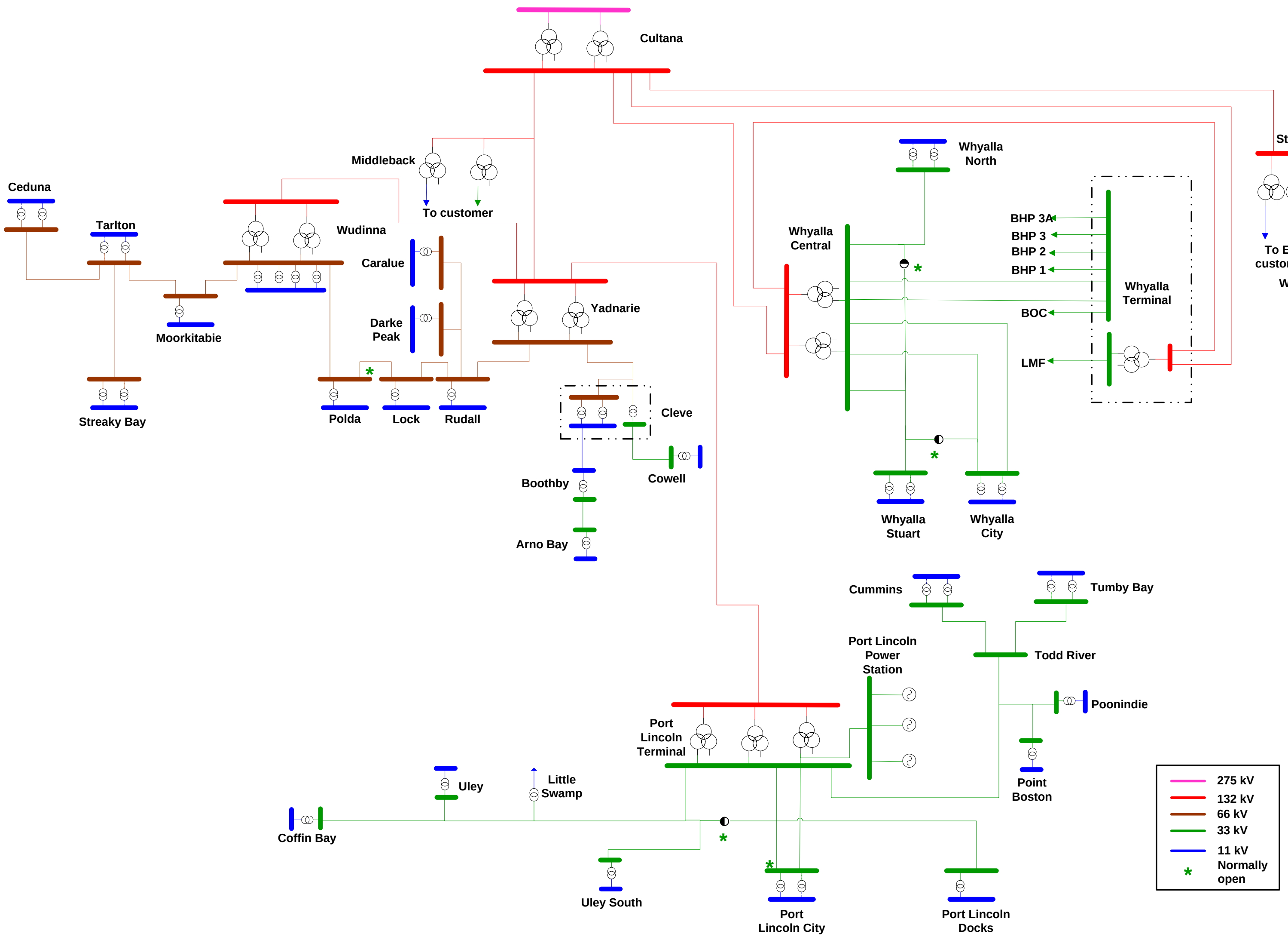


Figure 70: Eyre Peninsula Single Line Diagram

17.1 Region Statistics

Table 81 indicates the general statistics for this region of the state.

Parameter	Value
No of connection points	6 - 2 (132/66*kV*), 3 (132/33*kV*), 1 (132/11*kV*)
No of zone subs	27 - 11 (66/11*kV*), 16 (33/11*kV*)
Operating voltages	66*kV*, 33*kV* and 11*kV*
Total customers	35,538
No of residential customers (abs /%of region/% of state)	28,862 / 81.2 / 3.4%
No of commercial customers (abs /%of region/% of state)	6,676 / 18.8% / 0.8%
Area of region (km^2 / % of state)	61,764 km^2 / 26.78%
Length of 66kV cable (km / % of region 66kV)	0 km / 0%
Length of 66kV conductor (km / % of region 66kV)	457 km / 100%
Length of 33kV cable (km / % of region 33kV)	1.6 km/ 0.7%
Length of 33kV conductor (km / % of region 33kV)	232 km / 99.3%
Length of 19kV cable (km / % of region 19kV)	3 km / 0.04%
Length of 19kV conductor (km / % of region 19kV)	7,139 km / 99.96%
Length of 11kV cable (km / % of region 11kV)	109 km / 7.8%
Length of 11kV conductor (km / % of region 11kV)	1,293 km / 92.2%
Installed *PV* inverter capacity (*MW* / % of state)	27.2 *MW* / 4.72%
No of feeders (abs / % urban / % rural short / % rural long)	57 / 33.3% / 14% / 52.6%

Table 81: Eyre Peninsula Region Statistics

17.2 Development History

The Eyre Peninsula region has been largely developed since the 1970s.

The region has seen the extension of the 275*kV network* as far as *ElectraNet's* Cultana substation from which supply is transformed down to 132*kV* to supply the entire peninsula. The region's 132*kV* transmission network is completely radial from this point.

Works undertaken within this region over the present regulatory period include:

Project Title	Description	Commissioning Year	Cost ($ million)
Wudinna *Connection Point* Upgrade	Installation of a second 132/66*kV* transformer by *ElectraNet*. *SA Power Networks* constructed a new 66*kV* bus section and integrated this site with the existing 66/11*kV* site opposite the 132/66*kV* site.	2012	5.5
Whyalla Central *Connection Point*	Establishment of a new 132/33*kV* *connection point* at Whyalla. *SA Power Networks'* works included the establishment of multiple 33*kV* bus sections and re-routing and extension of existing 33*kV* *lines* to connect Whyalla City, Whyalla Stuart, Whyalla North *zone substations* to the new site as well as *lines* to connect to Whyalla Terminal *connection point*.	2013	15.6
Port Lincoln Marina	Establishment of a new 33/11*kV* *zone substation* at Port Lincoln.	2015	7.1[31]

Table 82: Recent Eyre Peninsula Augmentation Projects

17.3 Connection points and sub-transmission lines

The Eyre Peninsula region contains five major and one minor *connection point* located at Whyalla Central, Whyalla Terminal, Port Lincoln Terminal, Yadnarie, Wudinna and Stony Point. These *connection point*s connect to *SA Power Networks' sub-transmission network* at a combination of 66*kV*, 33*kV* and 11*kV*. All *connection point*s are supplied at 132*kV*. Middleback *connection point* is an unregulated site dedicated to a single customer and is not detailed further within this *AMP*.

The region's *connection point*s have the following normal and *N-1* transformer capacities:

Connection Point	ETC Category	Transformer "N" rating (MVA)	Transformer "N-1" rating (MVA)
Port Lincoln Terminal 132/33*kV*	3	101.4	64
Stony Point 132/11*kV*	1	2.5	0
Whyalla Central 132/33*kV*	4	240	120
Whyalla LMF 132/33*kV*	1	60.5	0
Wudinna 132/66*kV*	2	50	25
Yadnarie 132/66*kV*	2	46.4	27.4

Table 83: Eyre Peninsula Connection Point Ratings

[31] Project in progress – Approved amount

In accordance with the planning criteria for *sub-transmission lines*, *SA Power Networks* plans this region's *sub-transmission network* based on the 10% *PoE* forecast. The region operates both 66 and 33*kV lines* at *sub-transmission* level. Constraints on the *radial sub-transmission network* and of *ElectraNet's* transformers are determined through modelling of the *network* and analysis using *PSS/E* and comparison of the forecast to the *connection point*'s *normal* and *emergency ratings*.

Within the time period covered by this *AMP*, no augmentation of the region's *connection point* transformer capacity is forecast to be required. A copy of the region's *connection point* forecasts are shown in Table 83.

No *sub-transmission lines* are forecast to be constrained within the 2015-25 period.

17.4 Zone substations

The Eyre Peninsula region contains 27 *zone substations* supplied at either 66*kV* or 33*kV* supplying the region's 11*kV feeder* network. A step-up / step down supply arrangement exists between Boothby and Arno Bay whereby a former section of 11*kV* was converted to operation at 33*kV* in order to alleviate voltage constraints which existed when the *line* was supplied at 11*kV*.

These *substation's* forecasts are shown in APPENDIX H – EYRE PENINSULA REGION FORECASTS.

The following *zone substation* constraints have been identified within the 2015-25 period covered by this *AMP*:

Project Timing	Project Name	Limitation / Constraint	Proposed Solution	Section Ref	2015-20 Cost ($ million)	2020-25 Cost ($ million)	Total Cost ($ million)
2015	Port Lincoln Marina	Overload of existing Port Lincoln Docks *zone substation* under *normal conditions* and Port Lincoln City *zone substation* under *contingent conditions*.	Construct a new *zone substation* on an existing site, consisting of a single 12.5 *MVA* 33/11*kV* transformer and associated 11*kV* switchboard and cut substation into existing 11*kV feeder* network. Supply from 33*kV network* via a 1.5km extension.	-	**0.81**	-	7.06
2016	Little Swamp Capacity Upgrade	Overload of Little Swamp *zone substation* under *normal conditions*.	Upgrade the existing 0.15 *MVA* 33/11*kV* pole mounted transformer with a new 0.5 *MVA* unit and install a set of 11*kV* pole top regulators.	-	**0.52**	-	0.55

Table 84: Eyre Peninsula Zone Substation Constraints

17.5 Feeders

Customers are supplied from *SA Power Networks' distribution system* via 11*kV feeders*, which are supplied from the *zone substations*. These *feeders* are extended and upgraded as required to meet customer demand, and customer connection requests.

During the forthcoming 2015-20 Reset period, the following *feeder* constraints have been identified:

Project Timing	Project Name	Limitation / Constraint	Proposed Solution	Section Ref	2015-20 Cost ($ million)	2020-25 Cost ($ million)	Total Cost ($ million)
2018	Caralue Recloser Upgrade	Overload of existing recloser's trip coil following load transfer to *feeder* under *contingent conditions*.	Upgrade the existing hydraulic recloser with a new 11*kV* recloser to increase rating.	-	**0.15**	-	0.15
2018	Minnipa Recloser Upgrade	Overload of existing recloser's trip coil following load transfer to *feeder* under *contingent conditions*.	Upgrade the existing hydraulic recloser with a new 11*kV* recloser to increase rating.	-	**0.15**	-	0.15
2018	Warramboo Recloser Upgrade	Overload of existing recloser's trip coil following load transfer to *feeder* under *contingent conditions*.	Upgrade the existing hydraulic recloser with a new 11*kV* recloser to increase rating.	-	**0.15**	-	0.15
2018 -19	Port Neill *SWER* Conversion	Overload and quality of supply issues associated with the existing three phase *SWER* arrangement supplying Port Neill.	Convert the existing *SWER feeder* to three phase supply at 11*kV*.	-	**4.50**	-	4.50

Table 85: Eyre Peninsula Feeder Constraints

17.6 Land and Other Works

The following land purchases and additional works within the region have been identified within the 2015-20 period.

Project Timing	Project Name	Work Category	Proposed Solution	Section Ref	2015-20 Cost ($ million)	2020-25 Cost ($ million)	Total Cost ($ million)
2016	Port Neill Voltage Regulation	Voltage Regulation	Add *SCADA* to existing 11*kV* voltage regulators supplying Port Neill.		**0.07**	-	0.07

Table 86: Eyre Peninsula Other Works

18. FLEURIEU PENINSULA – REGIONAL DEVELOPMENT PLAN

SA Power Networks' Fleurieu Peninsula Region extends South-east from Willunga to Goolwa and Victor Harbor and south-west to Cape Jervis, including Kangaroo Island. The Fleurieu Peninsula is supplied from the Metro South region, predominantly by the *connection point* at Morphett Vale East.

A map of this region is shown in Figure 71 while a single line representation of the network is shown in Figure 72.

Figure 71: Fleurieu Peninsula Map

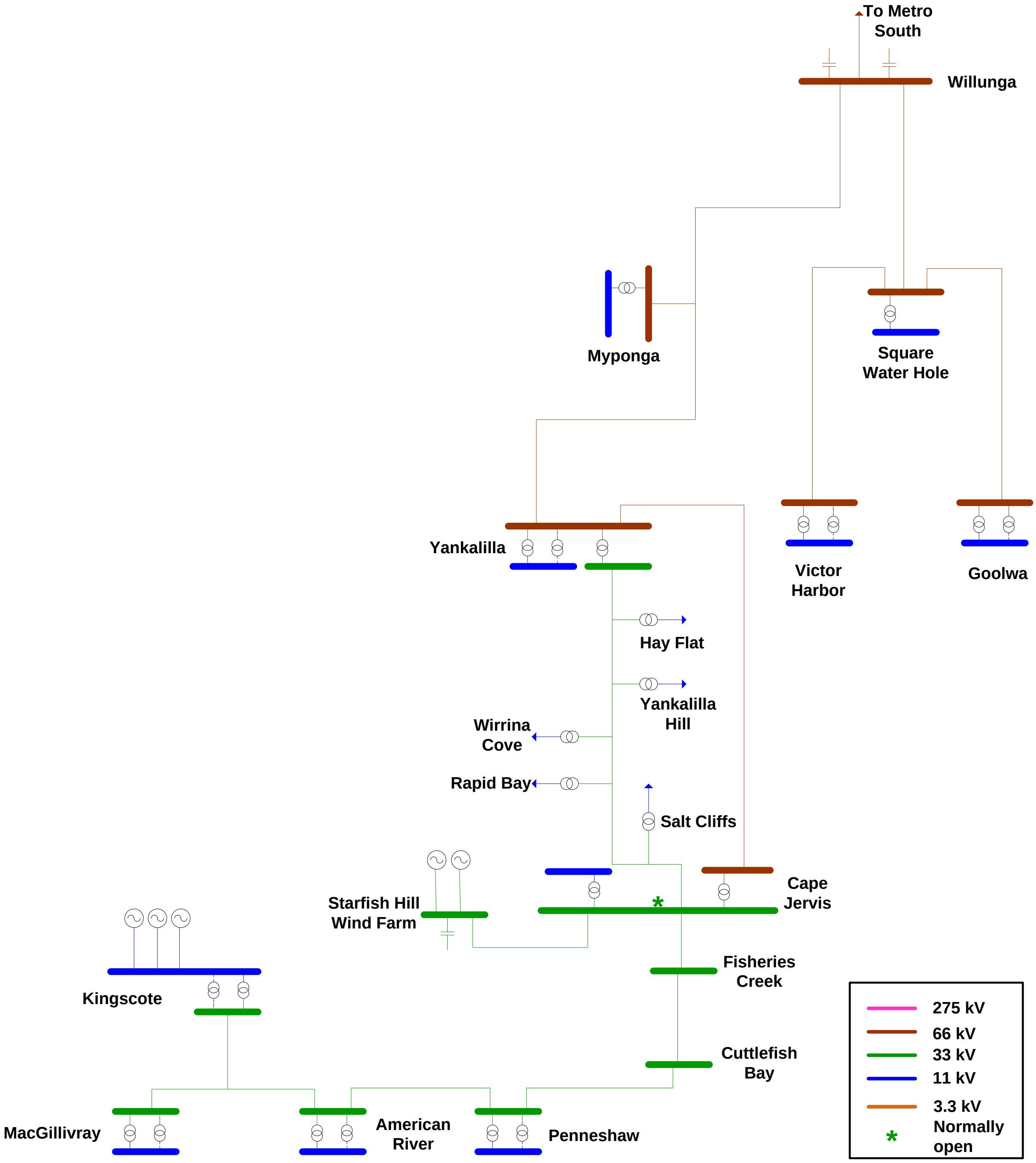


Figure 72: Fleurieu Peninsula Single Line Diagram

18.1 Region Statistics

Table 87 indicates the general statistics for this region of the state.

Parameter	Value
No of connection points	0 (supplied from Metro South region)
No of zone subs	17 - 5 (66/11*kV*), 2 (66/33*kV*), 10 (33/11*kV*)
Operating voltages	66*kV*, 33*kV* and 11*kV*
Total customers	30,704
No of residential customers (abs /%of region/% of state)	26,790 / 87.3% / 3.2%
No of commercial customers (abs /%of region/% of state)	3,914 / 12.7% / 0.5%
Area of region (km^2 / % of state)	6,067 km^2 / 2.6%
Length of 66kV cable (km / % of region 66kV)	0.4 / 0.4%
Length of 66kV conductor (km / % of region 66kV)	113 km / 99.6%
Length of 33kV cable (km / % of region 33kV)	14.6 km/ 12.4%
Length of 33kV conductor (km / % of region 33kV)	103.5 km / 87.6%
Length of 19kV cable (km / % of region 19kV)	4.3 km / 0.4%
Length of 19kV conductor (km / % of region 19kV)	988 km / 99.6%
Length of 11kV cable (km / % of region 11kV)	213 km / 13.5%
Length of 11kV conductor (km / % of region 11kV)	1,366 km / 86.5%
Installed *PV* inverter capacity (*MW* / % of state)	22.9 *MW* / 3.97%
No of feeders (abs / % urban / % rural short / % rural long)	36 / 2.8% / 75% / 22.2%

Table 87: Fleurieu Peninsula Region Statistics

18.2 Development History

The Fleurieu Peninsula region was initially supplied at 33*kV* from Willunga. In 1972, the lines to Square Water Hole, Victor Harbor and Goolwa were converted to operation at 66*kV*, while the 33*kV* line to Yankalilla was converted in 1980.

In 1993, a new 33*kV* submarine cable connecting Kangaroo Island to the mainland was installed to replace the original cable installed circa 1965. In 2003, a new 66*kV* line between Cape Jervis and Yankalilla zone substations constructed to facilitate connection of a new 34MW wind farm near Cape Jervis at 33*kV*. In 2006, a new 6 MW standby power station was commissioned at Kingscote zone substation on Kangaroo Island to provide emergency supply to the island in the event of a fault of the 33*kV* submarine cable.

Works undertaken within this region over the present Reset period include:

Project Title	Description	Commissioning Year	Cost ($ million)
Goolwa 9 MVAr Cap Bank	Installation of 9 MVAr (3+3+3) 11*kV* capacitor bank at Goolwa zone substation.	2012	0.7

Table 88: Fleurieu Peninsula Significant Projects

18.3 Connection points and sub-transmission lines

As previously indicated, this region contains no *connection point*s of it own, but rather is supplied by the Metro South region at 66*kV*.

In accordance with the planning criteria for sub-transmission lines, SA Power Networks plans this region's sub-transmission network based on the 10% PoE forecast. The region operates both 66 and 33*kV* lines at sub-transmission level. Constraints on the radial sub-transmission network are determined through modelling of the network and analysis using PSS/E and comparison of the forecast to the *connection point*'s normal and emergency ratings.

Table 89 indicates those sub-transmission lines forecast to be constrained within the 2015-25 period and the proposed solution.

Section Ref	Project Name	Constrained Line(s)	Constraint Type	Constraint Description	Proposed Solution	Constraint Year	Commissioning Year	2015-20 Cost ($ million)	2020-25 Cost ($ million)	Total Cost ($ million)
12.3.1	Myponga to Square Water Hole 66*kV* line	Willunga to Myponga and Willunga to Square Water Hole.	N-1	Loss of all zone substations south of Myponga and Square Water Hole respectively should either of these lines be faulted.	Construct a new 66*kV* line between Myponga and Square Water Hole to provide back-up source of supply in the event of either line's failure.	2019	2019	**21.81**	-	21.81
-	American River to MacGillivray 33*kV* Line Uprate	American River to MacGillivray 33*kV*	N	Thermal overload of 33*kV* line under normal conditions.	Thermally uprate 17km of line from design temperature of 50°C to 60°C.	2022	2022	**-**	1.50	1.50

Table 89: Fleurieu Peninsula Sub-transmission Line Constraints

18.4 Zone substations

Electricity is supplied throughout the region by five, 66/11*kV*, two 66/33*kV* and ten, 33/11*kV* zone substations.

Forecasts for the region's zone substations are shown in APPENDIX I – FLEURIEU PENINSULA REGION FORECASTS.

The following zone substation constraints have been identified within the 2015-25 period covered by this *AMP*:

Project Timing	Project Name	Limitation / Constraint	Proposed Solution	Section Ref	2015-20 Cost ($ million)	2020-25 Cost ($ million)	Total Cost ($ million)
2015	Kingscote 4th Generator	Insufficient generator capacity at Kingscote Power Station during peak load times in the event of sustained operation due to failure of 33*kV* submarine cable supplying the island..	Install a fourth 2 MW generating unit to match the existing three units.	-	**2.05**	-	4.10
2016	Cape Jervis Sub Upgrade	Overload of Cape Jervis 33/11*kV* zone substation under normal conditions.	Upgrade the existing 0.5 MVA 33/11*kV* transformer with a new 3MVA unit and install a set of 11*kV* pole top regulators.		**1.77**	-	1.77
2017	Square Water Hole 11*kV* Voltage Regs	Overload of Square Water Hole zone substation under contingent conditions.	Install a set of 11*kV* voltage regulators on feeder ex-Myponga zone substation to increase available load transfers under contingent conditions, thereby deferring larger zone sub upgrade..		**0.23**	-	0.23
2024-26	Middleton Sub Establishment	Overload of Goolwa and Victor Harbor zone substations under contingent conditions.	Construct a new zone substation on existing site at Middleton consisting of a single 32MVA 66/11*kV* transformer and new 11*kV* switchboard. Construct a new 66*kV* line approx 4.5km from Goolwa to Middleton.		**-**	0.66	10.23
2025	Parndana Substation	Inadequate voltages under normal conditions	Construct a new 33*kV* line from MacGillivray substation approx 24km to proposed substation site. Construct a new 3MVA 33/11*kV* substation containing 11*kV* voltage regulators and two 11*kV* reclosers.		**-**	3.09	6.08

Table 90: Fleurieu Peninsula Zone Substation Constraints

18.5 Feeders

The region's zone substations supply 36, 11*kV* feeders serving approximately 30,704 customers. Table 91 details those feeder constraints forecast over the forthcoming five year reset period.

Project Timing	Project Name	Limitation / Constraint	Proposed Solution	Section Ref	2015-20 Cost ($ million)	2020-25 Cost ($ million)	Total Cost ($ million)
2015	Salt Cliffs Recloser Upgrade	Trip coil overload (125%) under normal conditions.	Upgrade the Salt Cliffs Recloser at Clarendon to prevent trip coil overload for N	-	**0.15**	-	0.15
2019	Yankalilla Substation – Normanville 11*kV* Feeder Tie	Overload of Normanville feeder under normal conditions.	Construct a new feeder tie between the Normanville and Wattle Flat feeders and transfer load to Wattle Flat feeder.	18.5.1	**1.14**	-	1.14

Table 91: Fleurieu Peninsula Feeder Constraints

18.5.1 Major Project – Normanville 11kV Feeder Tie

18.5.1.1 Constraint

Normanville 11kV feeder (VH-31) is supplied from Yankalilla 66/11kV Zone Substation and supplies approximately 2200 customers. Normanville 11kV feeder has two separate critical radial cables on the 11kV backbone supplying 1.1MVA (approximately 500 customers) and 1.9MVA (approximately 800 customers) of load respectively.

These two radial backbone cables on Normanville 11kV feeder have no feeder transfer options and all customers beyond the radial cables will be unsupplied in the event of a cable fault until repairs can be completed.

According to NICC-804 - Customer's Guide to Supply Arrangements for Large Customer Loads (1MVA or greater), radial cables with more than 1MVA of load must be able to be manually switched by SA Power Networks to an alternative supply if the main supply cable fails.

18.5.1.2 Consequences for Customers

Normanville 11kV feeder (VH-31) supplies approximately 500 customers and 800 customers on two separate radial sections. In the event of a backbone cable failure in one location, up to 1.1MVA of load and 500 customers will be unsupplied until the fault is repaired. In the event of a backbone cable failure in another location, up to 1.9MVA of load and 800 customers will be unsupplied until the fault is repaired or mobile generation plant is installed.

The typical repair time for such a fault could be several days with all customers beyond the radial backbone cable remaining unsupplied until the fault was repaired or large temporary generation installed, typically up to 24 hours after the occurrence of the fault.

18.5.1.3 Deferral Options Considered

Improved Feeder Ties

- Normanville 11kV feeder has no existing feeder ties except to Bald Hills 11kV feeder near the feeder exit – see option 1 below.

Demand Side Participation

- Demand side participation is not expected to resolve the radial constraint on the Normanville 11kV feeder, due to the extent of load that would be unsupplied for a cable failure. This would only be viable if all load could be curtailed.

18.5.1.4 Options considered to address constraint

The following options have been investigated to resolve the constraint:

Option 1:

- Extend approximately 0.9km of 300mm^2 XLPE cable and 1.2km of overhead line along Hay Flat Road to the Normanville 11kV feeder backbone on Main South Road to form a feeder tie loop. Duplicate the other radial 11kV cable (approximately 0.4km) using 300mm^2 XLPE cable.

Option 2:

- Establish a new Greenfield 33/11kV Modular 3 substation (approximately 2.5km South West of Yankalilla Substation), extend new 11kV backbone conductor and cut in to the existing 11kV network. Duplicate the other radial 11kV cable (approximately 0.4km) using 300mm^2 XLPE cable.

18.5.1.5 Preferred Solution

The preferred solution based on a net present value analysis, is to extend approximately 0.9km of 300mm^2 XLPE cable and 1.2km of overhead line along Hay Flat Road to the Normanville 11kV feeder backbone on Main South Road and duplicate the other radial 11kV cable using 300mm^2 XLPE cable (Option 1). The indicative cost for this project is $1.1 million. This project is planned for completion in 2019 and is expected to resolve the radial constraint on the Normanville 11kV feeder for 10 years or more.

18.5.1.6 Regulatory Period Expenditure

The total estimated $1.1 million is required during the 2015-20 regulatory period.

18.6 Land and Other Works

The following land purchases and additional works within the region have been identified within the 2015-20 period.

Project Timing	Project Name	Work Category	Proposed Solution	Section Ref	2015-20 Cost ($ million)	2020-25 Cost ($ million)	Total Cost ($ million)
2016	Kingscote Power Station NGM	NER Compliance	Install National Grid Metering at Kingscote Power Station in compliance with NER.		**0.20**	-	0.20
2018	Parndana 11*kV* Regulators	Voltage Regulation	Install a set of 11*kV* voltage regulators on the Parndana 11*kV* feeder to improve voltage under normal conditions.		**0.52**	-	0.52
2019	Emu Bay 11*kV* regulators	Voltage Regulation	Install an additional set of 11*kV* voltage regulators on the Kingscote 11*kV* feeder near Emu Bay to improve voltage under normal conditions.		**0.63**	-	0.63
2021	Penneshaw 33*kV* substation 20MVA voltage regulator	Voltage Regulation	Install a new 33*kV* 20MVA voltage regulator at Penneshaw zone substation to improve 33*kV* voltages under normal conditions.		**0.04**	4.42	4.46
2022	Parndana Substation	Land	Purchase of land for future zone substation site	-	**-**	0.22	0.22

Table 92: Fleurieu Peninsula Other Works

19. MID NORTH – REGIONAL DEVELOPMENT PLAN

SA Power Networks' Mid North Region includes the area from Evanston extending north to Spalding, and west to Paskeville. There are several *connection point*s in the Mid North region including Templers, Hummocks, Clare North, Brinkworth and Waterloo.

Electricity is supplied to the various towns and localities throughout the Mid North via zone Substations. These zone substations are operated at 33*kV* stepped down to 11*kV* or 7.6*kV*.

Customers are supplied from SA Power Networks' Distribution System via 11*kV* and 7.6*kV* feeders and 19*kV* SWER systems, which are supplied from the zone substations. These Feeders and SWER systems are extended and upgraded as required to meet customer demand and customer connection requests.

A map of this region is shown in Figure 73 while a single line representation of the network is shown in Figure 74.

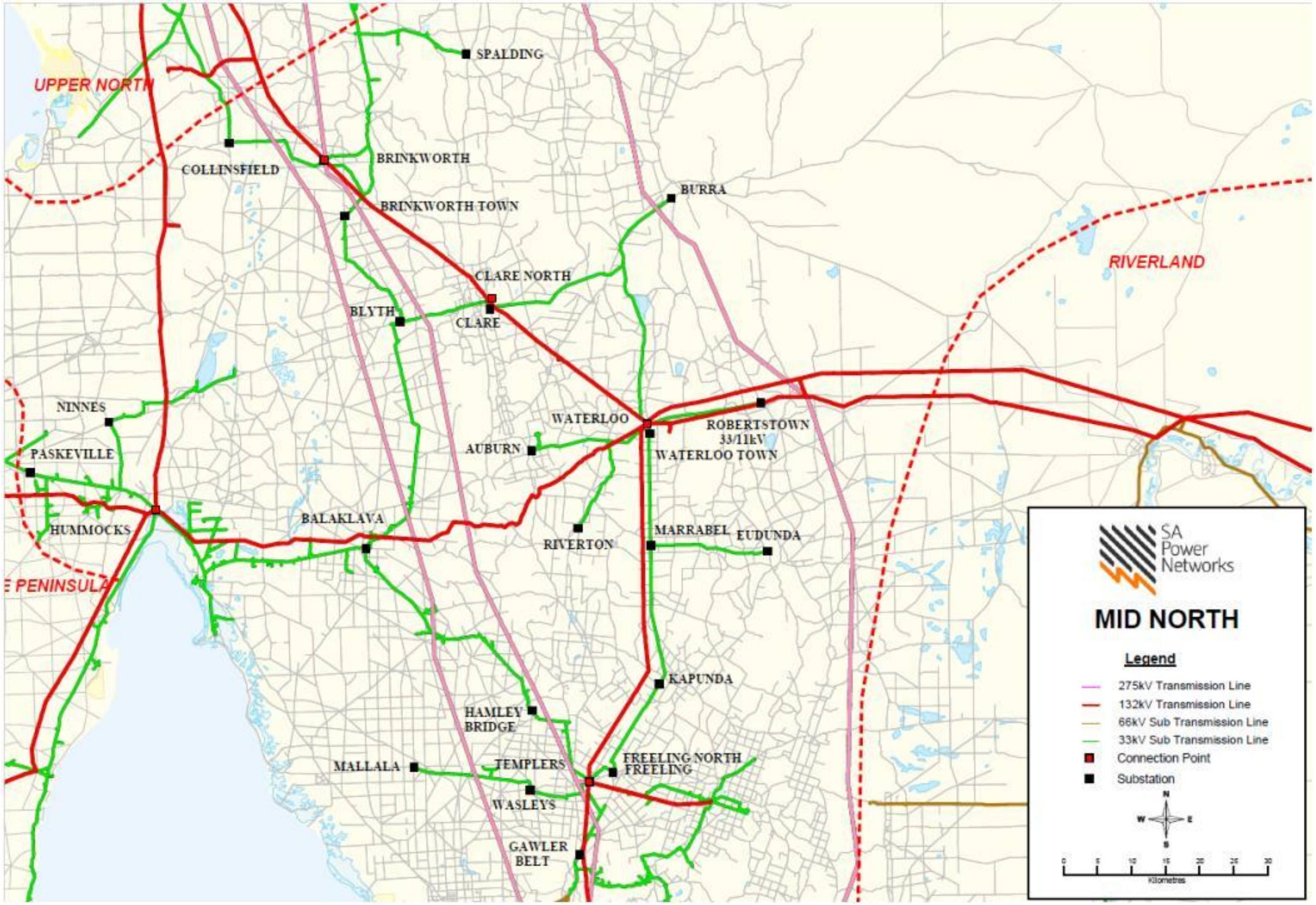


Figure 73: Mid North Map

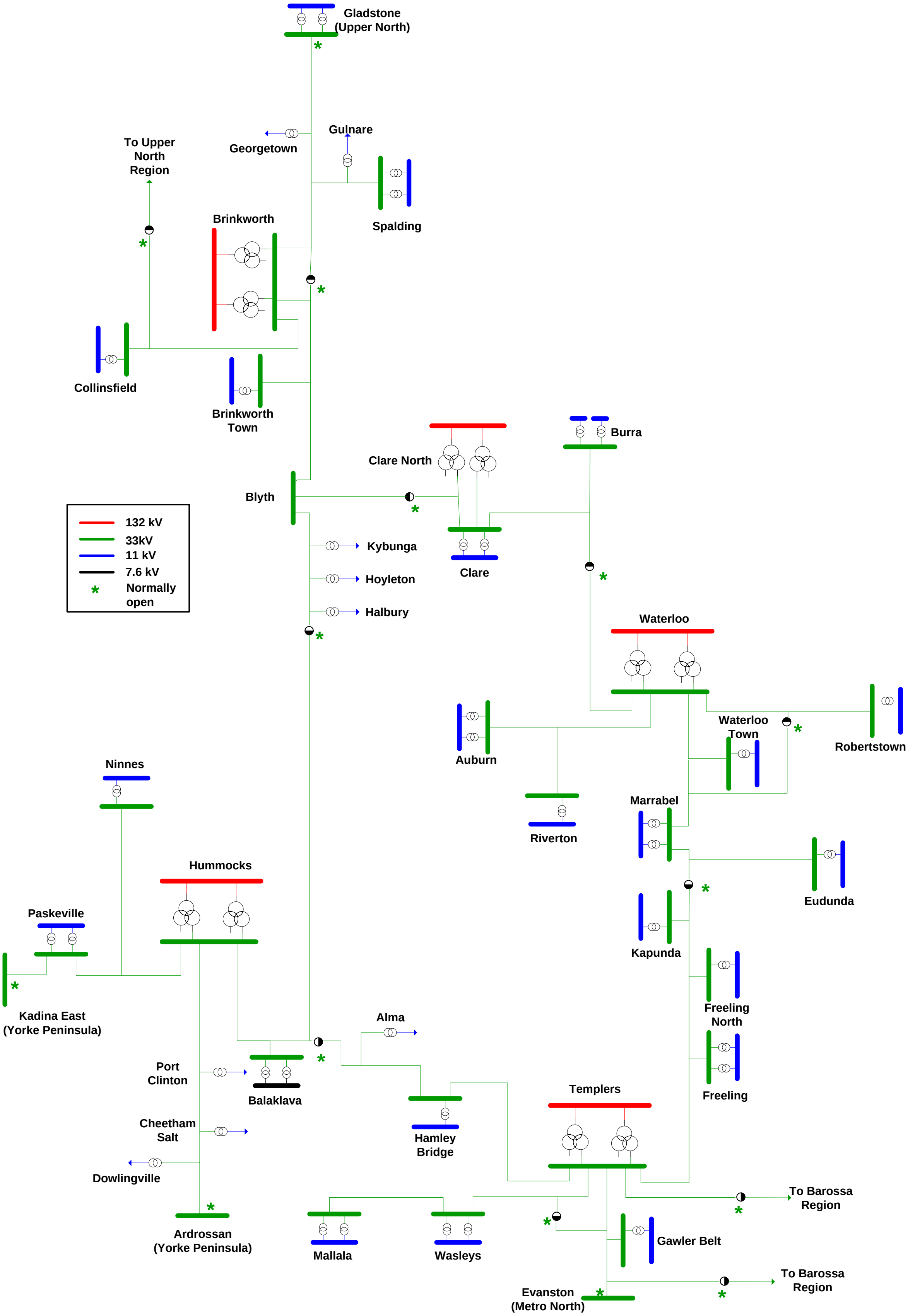


Figure 74: Mid North Single Line Diagram

19.1 Region Statistics

Table 93 indicates the general statistics for this region of the state.

Parameter	Value
No of connection points	5 (132/33*kV*)
No of zone subs	27 - 26 (33/11*kV*), 1 (33/7.6*kV*),
Operating voltages	33*kV*, 11*kV* and 7.6*kV*
Total customers	22,881
No of residential customers (abs /%of region/% of state)	17,381 / 76% / 2%
No of commercial customers (abs /%of region/% of state)	5,500 / 24% / 0.6%
Area of region (km^2 / % of state)	12,937 km^2 / 5.61%
Length of 33kV cable (km / % of region 33kV)	1.95 km / 0.3%
Length of 33kV conductor (km / % of region 33kV)	392 km / 99.7%
Length of 19kV cable (km / % of region 19kV)	13.4 km / 0.3%
Length of 19kV conductor (km / % of region 19kV)	4,321 km / 99.7%
Length of 11kV cable (km / % of region 11kV)	100 km / 6.7%
Length of 11kV conductor (km / % of region 11kV)	1,390 km / 93.3%
Length of 7.6kV cable (km / % of region 11kV)	2.7 km / 20.5%
Length of 7.6kV conductor (km / % of region 11kV)	10.6 km / 79.5%
Installed *PV* inverter capacity (*MW* / % of state)	18.9 *MW* / 3.28%
No of feeders (abs / % urban / % rural short / % rural long)	48 / 0% / 12.5% / 87.5%

Table 93: Mid North Region Statistics

19.2 Development History

The Mid North region has been largely developed since the formation of the Electricity Trust of South Australia (ETSA) in 1946 through to privatisation in 1999 and the subsequent creation of ETSA Utilities / SA Power Networks.

Extensive works were undertaken in the late 1940 and early 1950s establishing 132*kV* lines throughout the region to supply the Yorke Peninsula and connect Playford Power Station (at Port Augusta in the Upper North region) to metropolitan Adelaide via the likes of Hummocks and Waterloo *connection point*s.

Works within this region over the present Reset period include:

Project Title	Description	Commissioning Year	Cost ($ million)
Clare North Connection Point	Establishment by ElectraNet of a new 1325/33*kV* *connection point* north of Clare. SA Power Networks' works included the expansion of Clare zone substation, and re-routing and extension of existing 33*kV* lines to connect to the new *connection point* to the *distribution network*.	2010	6.8
Balaklava 33/7.6*kV* Substation Upgrade	Installation of a second 2.5 MVA, 33/11-7.6*kV* transformer.	2011	2.2
Freeling North 33/11*kV* Substation	Construction of a new 33/11*kV* zone substation comprising a 3.8 MVA transformer and two new 11*kV* reclosers.	2011	2.8
Riverton 33/11*kV* Substation	Construction of a new 33/11*kV* zone substation comprising a 3 MVA transformer and one new 11*kV* feeder supplied by a new X km section of 33*kV* line.	2013	2.3
Hummocks *Connection Point* Upgrade	Upgrade of 33*kV* infrastructure (ie bus, line breakers, protection schemes etc) associated with ElectraNet's upgrade of this *connection point*'s transformer capacity.	2013	8.2
Waterloo *Connection Point* Upgrade	Upgrade of 33*kV* infrastructure (ie bus, line breakers, protection schemes etc) associated with ElectraNet's replacement of its 132/33*kV* transformers.	2013	7.5

Table 94: Mid North Region Statistics

19.3 Connection points and sub-transmission lines

The Mid North region contains five *connection point*s located at Templers, Hummocks, Waterloo, Clare North and Brinkworth. All are supplied at 132*kV* and connect to SA Power Networks' at 33*kV*.

All five of the region's *connection point*s are classed as Category 4 sites by the ETC, therefore requiring adequate transmission line and *connection point* transformer capacity to be available under N-1 conditions.

The region's *connection point*s have the following normal and N-1 transformer capacities:

Connection Point	ETC Category	Transformer "N" rating (MVA)	Transformer "N-1" rating (MVA)
Brinkworth 132/33*kV*	4	24.6	13.7
Clare North 132/33*kV*	4	80	40
Hummocks 132/33*kV*	4	50	25
Templers 132/33*kV*	4	147.6	79.8
Waterloo 132/33*kV*	4	50	25

Table 95: Recent Mid North Augmentation Projects

In accordance with the planning criteria for sub-transmission lines, SA Power Networks plans this region's sub-transmission network based on the 10% PoE forecast. The region operates both 66 and 33*kV* lines at sub-transmission level. Constraints on the radial sub-transmission network and of ElectraNet's transformers are determined through modelling of the network and analysis using PSS/E and comparison of the forecast to the *connection point*'s normal and emergency ratings.

Within the time period covered by this *AMP*, no augmentation of the region's *connection point* transformer capacity is forecast to be required. A copy of the region's *connection point* forecasts are shown in APPENDIX J – MID NORTH REGION FORECASTS

The region contains a 33*kV* ties to the Yorke Peninsula, Upper North, Barossa and Metro North regions. These ties are normally only operated following a contingent event in order to restore supply to the affected portion of the region. No *connection point*s are forecast to be constrained within the 2015 – 25 period.

Table 96 indicates those sub-transmission lines forecast to be constrained within the 2015-25 period and the proposed solution.

Section Ref	Project Name	Constrained Line(s)	Constraint Type	Constraint Description	Proposed Solution	Constraint Year	Commissioning Year	2015-20 Cost ($ million)	2020-25 Cost ($ million)	Total Cost ($ million)
-	Freeling to Kapunda 33*kV* line uprate	Freeling to Kapunda 33*kV*	N	Thermal overload of 33*kV* line under normal conditions.	Thermally uprate 15km of line from design temperature of 50°C to 60°C or 80°C.	2017	2017	**0.45**	-	0.45
-	Waterloo to Riverton 33*kV* Line Uprate	Waterloo to Riverton 33*kV*	N	Thermal overload of 33*kV* line under normal conditions.	Thermally uprate 7km of line from design temperature of 50°C to 80°C.	2018	2018	**0.21**	-	0.21
-	Wasleys to Mallala 33*kV* Line Uprate	Wasleys to Mallala 33*kV*	N	Thermal overload of 33*kV* line under normal conditions.	Thermally uprate 18.5km of line from design temperature of 50°C to 60°C.	2019	2019	**0.57**	-	0.57

Table 96: Mid North Sub-transmission Line Constraints

19.4 Zone substations

Electricity is supplied throughout the Mid North region by 26, 33/11*kV* and one 33/7.6*kV* zone substations.

Forecasts for the region's zone substations are shown in APPENDIX J – MID NORTH REGION FORECASTS.

The following zone substation constraints have been identified within the 2015-25 period covered by this *AMP*:

Project Timing	Project Name	Limitation / Constraint	Proposed Solution	Section Ref	2015-20 Cost ($ million)	2020-25 Cost ($ million)	Total Cost ($ million)
2015	Gawler Belt 33/11*kV* Substation Upgrade	Overload of Gawler Belt zone substation under contingent conditions.	Upgrade Gawler Belt zone substation by installing a second 12.5MVA 33/11*kV* transformer and associated 11*kV* switchboard.	19.4.2	**2.54**	-	5.18
2015	Kapunda Sub Upgrade	Overload of Kapunda zone substation under contingent conditions.	Upgrade Kapunda zone substation by installing a second 12.5MVA transformer and associated 11*kV* switchboard.	-	**2.14**		3.90
2016	Mallala Sub Upgrade	Overload of Mallala zone substation under normal conditions	Replace existing 2MVA transformer with a 3.8MVA unit and upgrade 3km of 11*kV* feeder.	-	**2.86**		2.90
2018	Clare 33/11*kV* substation upgrade	Overload of Clare zone substation under contingent conditions.	Upgrade Clare zone substation by replacing existing 5MVA transformers with new 12.5MVA units and new 11*kV* switchboard.	19.4.1	**6.18**	-	6.18
2018	Hamley Bridge Substation Upgrade	Overload of Hamley Bridge zone substation under normal conditions	Upgrade Hamley Bridge zone substation by installing a second 3.8MVA 33/11*kV* transformer.	-	**1.84**	-	1.84
2020	George Town 33/11*kV* transformer station Upgrade	Overload of George Town zone substation under normal conditions.	Upgrade existing 0.15MVA 33/11*kV* pole mounted transformer with a new 0.5MVA unit.	-	**0.30**	0.25	0.55

Project Timing	Project Name	Limitation / Constraint	Proposed Solution	Section Ref	2015-20 Cost ($ million)	2020-25 Cost ($ million)	Total Cost ($ million)
2022	Waterloo Town 33/11*kV* Upgrade	Overload of Waterloo Town zone substation under normal conditions	Upgrade Waterloo Town zone substation by replacing existing 0.5MVA transformer with a new 1MVA 33/11*kV* unit.	-	-	0.32	0.32
2024	Dublin 33/11*kV* Modular 3 Substation (New)	Overload of Mallala zone substation under normal conditions.	Establish a new zone substation at Dublin consisting of a 3MVA 33/11*kV* padmounted transformer, 11*kV* regulator and two 11*kV* reclosers.		-	3.23	3.23

Table 97: Mid North Zone Substation Constraints

19.4.1 Major Project – Clare 33/11kV New Substation

19.4.1.1 Constraint

Clare 33/11kV Zone Substation contains two 5MVA 33/11kV transformers. Under 50% PoE conditions, the zone substation's contingency capacity will be exceeded in 2018/19.

The forecast growth rate for Clare 33/11kV Zone Substation is 0.6% per annum, which is being driven largely by residential and agricultural growth. The Clare region has several intensive agricultural industries such as viticulture.

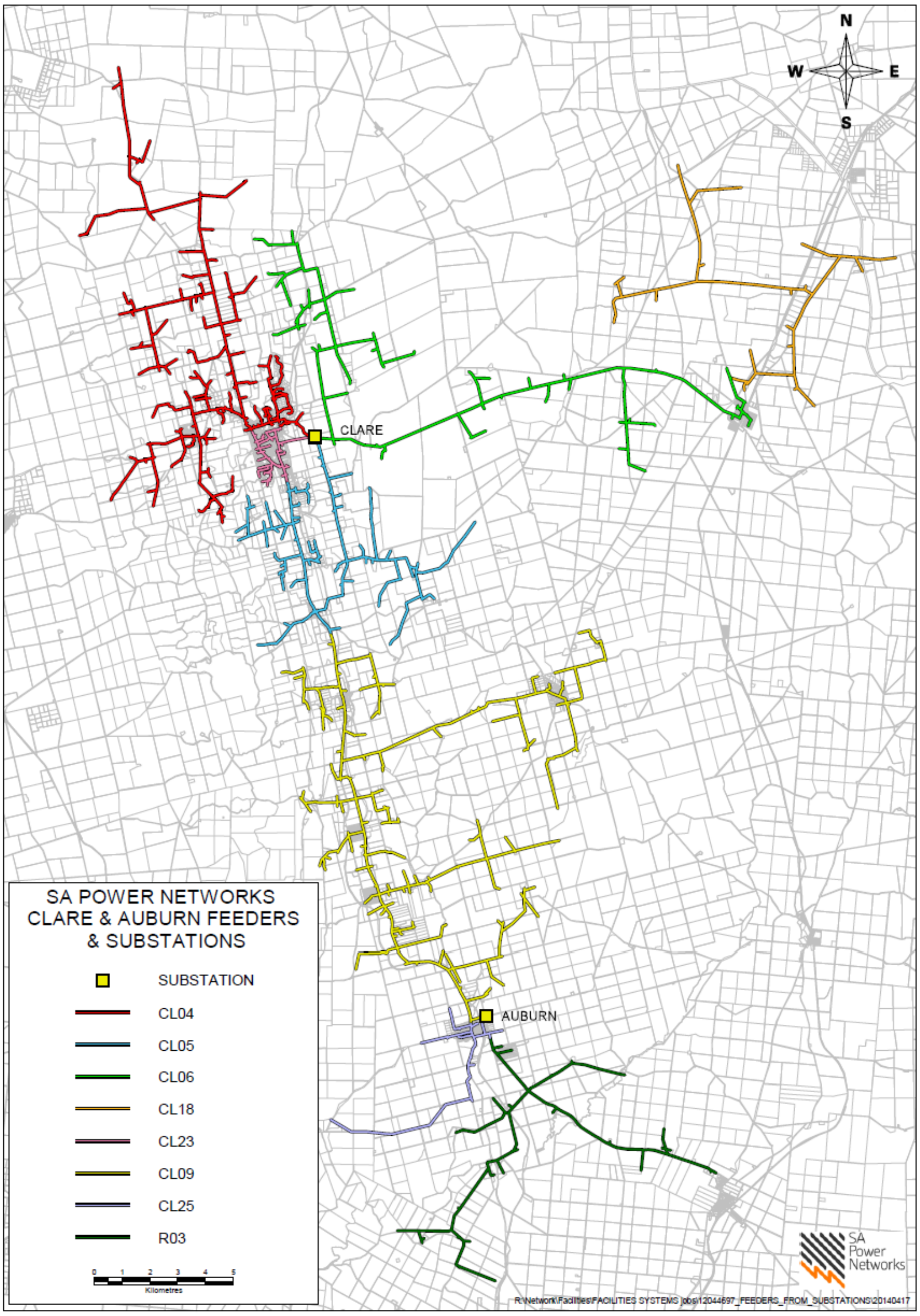


Figure 75: Locality of Clare and Auburn 33/11kV Zone Substation

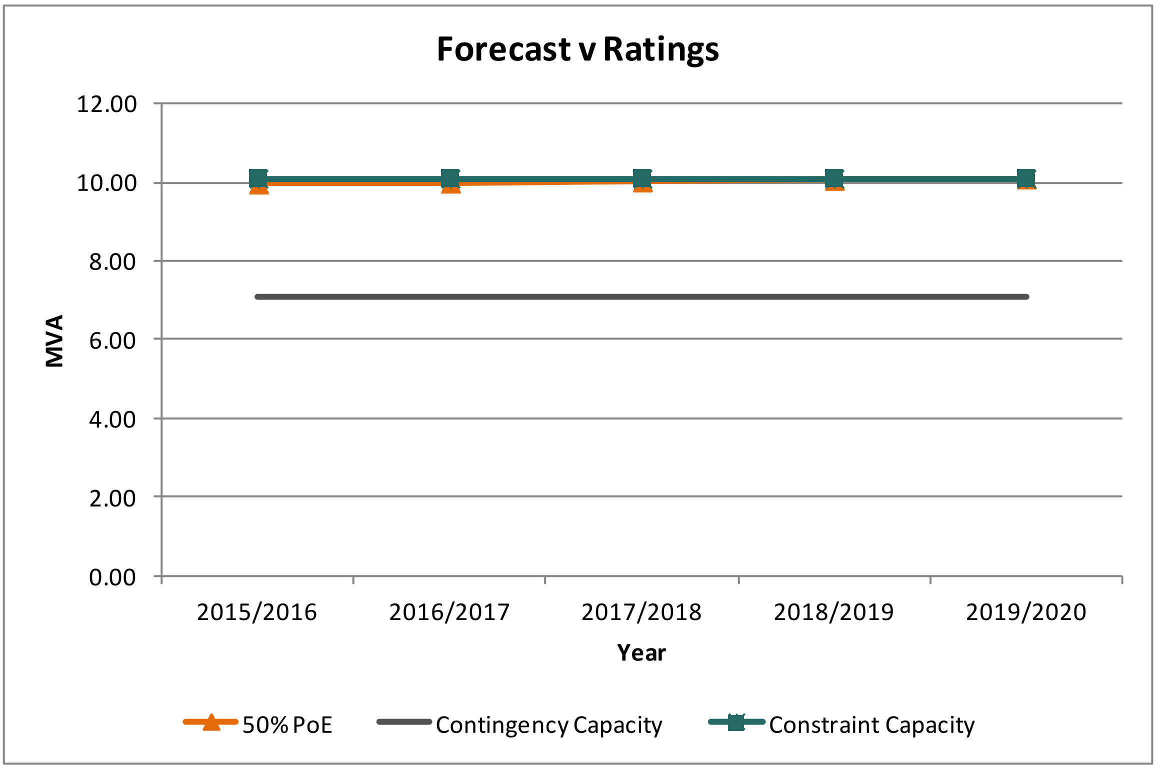


Figure 76: Clare 33/11kV Zone Substation Load versus Capacity

	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
Forecast* MVA (50% PoE)	10.0	10.0	10.0	10.0	10.1	10.1
Power Factor	0.96	0.96	0.96	0.96	0.96	0.96
Normal Capacity (MVA)	12.6	12.6	12.6	12.6	12.6	12.6
Firm Delivery Capacity (MVA)	7.1	7.1	7.1	7.1	7.1	7.1
Contingency Capacity (MVA)	7.1	7.1	7.1	7.1	7.1	7.1
Load at Risk (MVA)	2.9	2.9	2.9	2.9	3.0	3.0

**Load Forecast includes impact of PV both existing and forecast. The forecast also includes the impact of energy efficiency, state economic and population growth by reconciling each asset's local growth trend with the AEMO July 2014 SA Regional forecast for the next 5 years.*

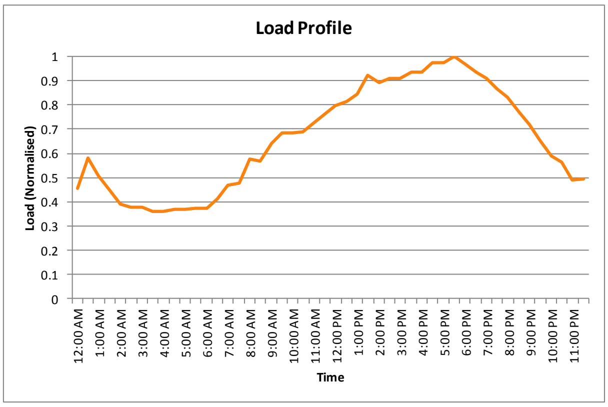
Table 98: Clare 33/11kV Zone Substation Load Forecast

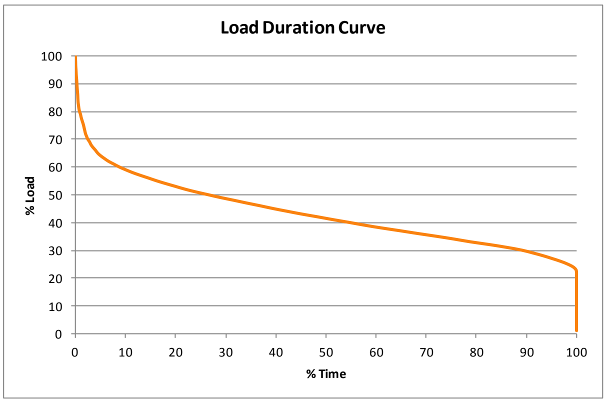
The measured load in 2013/14 was 10.4MVA, exceeding the 2014/15 50% PoE forecast.

19.4.1.2 Consequences for Customers

Clare 33/11kV Zone Substation has a contingency capacity of 7.1MVA in 2018/19. Given a forecast in 2018/19 of 10.1MVA under 50% PoE conditions, up to 3MVA of load may need to be shed for a transformer fault. Approximately 1,300 customers would remain unsupplied after all possible feeder switching is completed until a mobile substation is installed (typically 24 hours). The rating of Clare 33/11kV Zone Substation is expected to be exceeded for a total of 196 hours in 2018/19 over 32 days per annum.

19.4.1.3 Load Profile





(a) (b)

Figure 77: (a) Clare 33/11kV Zone Substation Load Profile, (b) Load Duration Curve

19.4.1.4 Regulatory Investment Test - Distribution

A formal RIT-D has not yet been performed for this constraint. A preliminary RIT-D analysis has been undertaken for the constraint and options outlined below. A formal RIT-D document will be published in line with the NER and the AER's RIT-D Guidelines prior to project commitment.

19.4.1.5 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.

Improved Feeder Ties:

- Construction of new 11kV feeders from Clare 33/11kV Zone Substation to Auburn 33/11kV Zone Substation would provide improvements to feeder transfer capacity but would also require the upgrade of Auburn 33/11kV Zone Substation to utilise this capacity. This was considered within Option 2 below.

19.4.1.6 Options considered to address constraint

The following options have been investigated in accordance with the AER's RIT-D Guidelines to resolve the impending constraint:

Option 1:

- Upgrade Clare 33/11kV Zone Substation with two 12.5MVA 33/11kV transformers, a new control building and a new two section 11kV switchboard.

Option 2:

- Upgrade Auburn 33/11kV Zone Substation by installing a two Modular 6, substations (ie 2 x 3.8MVA transformers) to be replace the existing transformers and the construction of new 11kV feeders to increase the feeder transfer capacity between Auburn and Clare Zone Substations.

Option 3:

- Install 5MW of generation at Clare 33/11kV Zone Substation to provide network support.

19.4.1.7 Preferred Solution

The preferred solution, based on a preliminary regulatory analysis, is to Upgrade Clare 33/11kV Zone Substation (Option 1). The indicative cost for this project is $6.2 million. This project is planned for completion in 2018 and will solve the constraint at Clare Zone Substation for more than 15 years.

19.4.1.8 Commitment Status

SA Power Networks has not yet committed to the project. However, a preliminary RIT-D analysis has been completed and results shown below. The analysis shows that the most economic solution is to upgrade Clare 33/11kV Zone Substation (Option 1). A formal RIT-D will be published prior to the planned construction year of 2018.

19.4.1.9 Regulatory Period Expenditure

Approximately $6.2 million is forecast to be required in the 2015/2020 regulatory reset period.

19.4.1.10Preliminary RIT-D Analysis

Option	Description	Net Market Benefit[32]
1	Clare 33/11kV Substation Upgrade	-$3,412,000
2	Auburn Substation 2 x Mod 6	-$5,285,000
3	Install 5MW generator	-$6,325,000

Table 99: Dorrien NPV Results and Rankings

19.4.2 Major Project – Gawler Belt Substation Upgrade

19.4.2.1 Constraint

Gawler Belt 33/11kV Zone Substation contains one 12.5MVA 33/11kV transformer. Under 50% PoE conditions, the zone substation's contingency capacity will be exceeded in 2015/16.

The forecast growth rate for Gawler Belt 33/11kV Zone Substation is 0.4% per annum, which is being driven by residential development, commercial and industrial load growth in the Mid North Region. This is a new residential growth area and significantly higher growth rates can be expected than elsewhere within the region.

[32] Based on the use of a 6% discount rate over 10 years

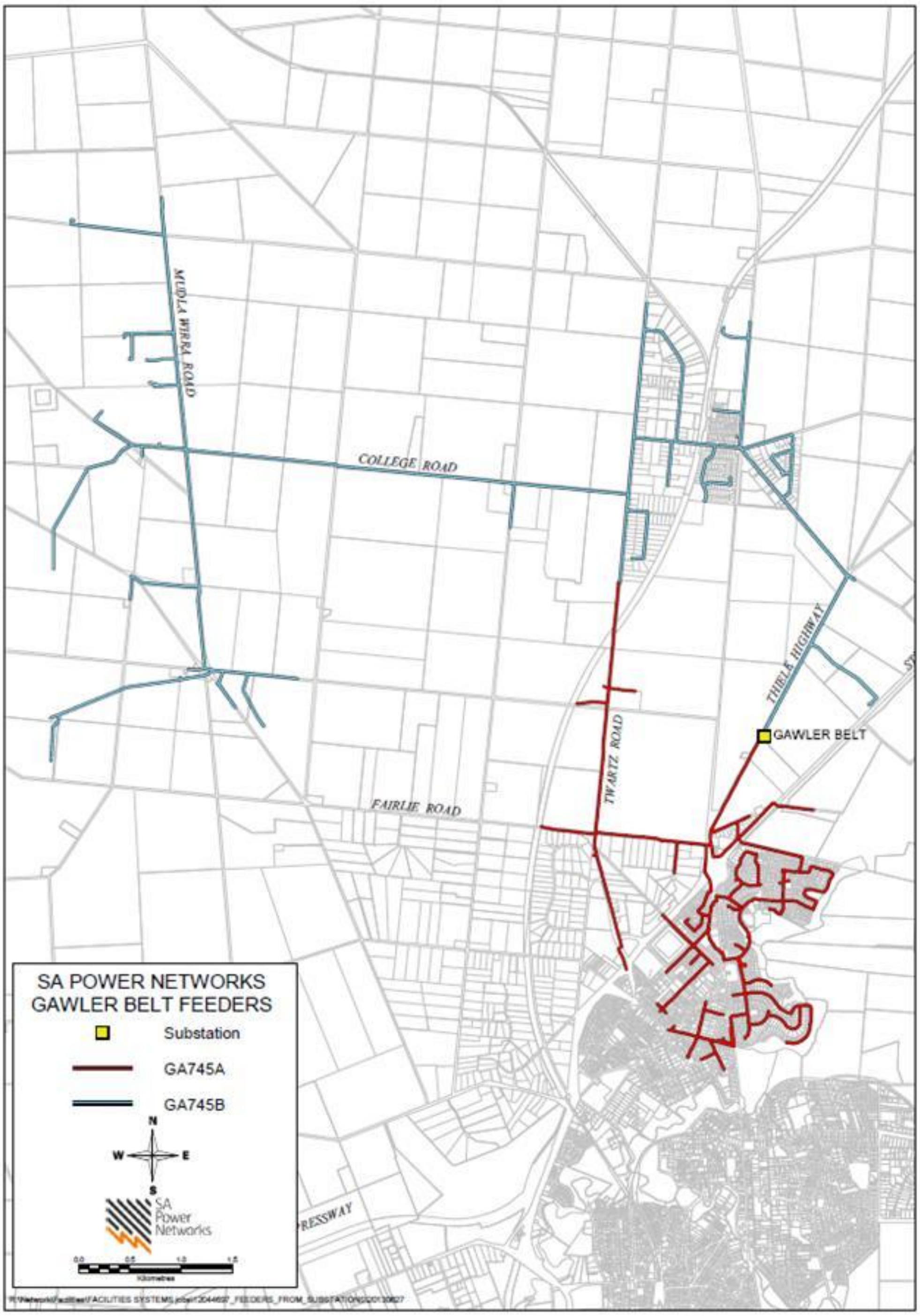


Figure 78: Locality of Gawler Belt 33/11kV Substation

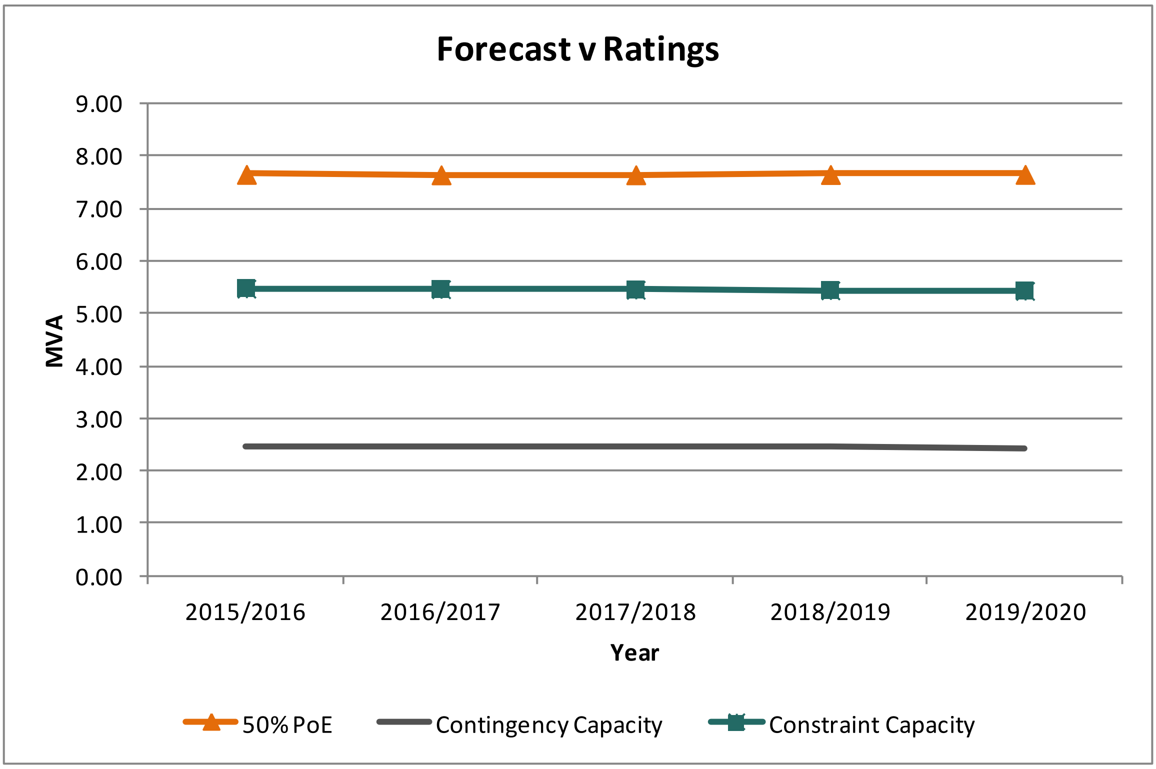


Figure 79: Gawler Belt 33/11kV Load versus Capacity

	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
Forecast* MVA (50% PoE)	7.7	7.7	7.7	7.7	7.7	7.7
Power Factor	0.95	0.95	0.95	0.95	0.95	0.95
Normal Capacity (MVA)	14.6	14.6	14.6	14.6	14.6	14.6
Firm Delivery Capacity (MVA)	0	0	0	0	0	0
Contingency Capacity (MVA)	2.5	2.5	2.5	2.5	2.5	2.4
Load at Risk (MVA)	5.2	5.2	5.2	5.2	5.2	5.3

**Load Forecast includes impact of PV both existing and forecast. The forecast also includes the impact of energy efficiency, state economic and population growth by reconciling each asset's local growth trend with the AEMO July 2014 SA Regional forecast for the next 5 years.*

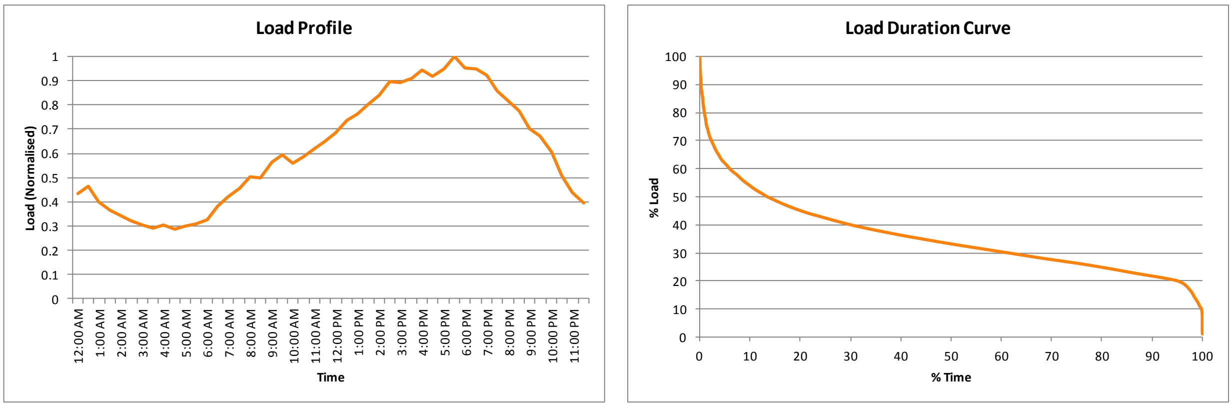
Table 100: Gawler Belt 33/11kV Load Forecast

Measured load in 2013/14 was 8.5MVA, exceeding the 2014/15 forecast.

19.4.2.2 Consequences for Customers

Gawler Belt 33/11kV Zone Substation has a contingency capacity of 2.5MVA in 2015/16. Given a forecast in 2015/16 of 7.7MVA under 50% PoE conditions, up to 5.2MVA of load may need to be shed for a transformer fault. Approximately 1,500 customers would remain unsupplied after all possible feeder switching is completed until a mobile substation could be installed (typically 24 hours). The contingency capacity of Gawler Belt 33/11kV Zone Substation is expected to be exceeded for a total of 5,969 hours in 2015/16 over 365 days per annum.

19.4.2.3 Load Profile



(a) (b)

Figure 80: (a) Gawler Belt 33/11kV Zone Substation Load Profile, (b) Load Duration Curve

19.4.2.4 Regulatory Test

In response to this constraint, a Reasonableness Test was published in accordance with ESCOSA Guideline 12. Reasonableness Test, RT 003-13 was published in November 2013. The Reasonableness Test showed that Demand Management measures could not economically address the system constraint and that a network solution was required.

19.4.2.5 Deferral Options Considered

Power Factor Correction

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

Improved Feeder Ties

- Construction of new 11kV feeders from Gawler Belt to Wasleys and/or Evanston Zone Substations would improve feeder transfer capacity but would also require the upgrade of one or both of the Zone Substations to utilise this capacity. This was considered in Option 2 below.

19.4.2.6 Options considered to address constraint

The following options have been investigated in accordance with the ESCOSA Guideline 12 to resolve these impending constraints:

Option 1:

- Install a second 12.5MVA 33/11kV transformer at Gawler Belt Zone Substation (in case of failure of the existing 33/11kV substation transformer) along with one new 11kV feeder connecting to the existing 11kV feeder network;

Option 2:

- Establish a new greenfield 12.5MVA 33/11kV Modular 1 zone substation at Hewitt (approximately 2.5km south of Gawler Belt Zone Substation), upgrade 11kV feeder backbone conductor and cut in to the existing 11kV network (increase transfer capacity by approximately 7MVA).

19.4.2.7 Preferred Solution

The preferred solution based on the regulatory analysis, is to install a second 12.5MVA transformer at Gawler Belt Zone Substation along with one new 11kV feeders connecting to the existing 11kV network (Option 1). The indicative cost for this project is $5.2 million. This project is planned for completion in November 2015 and is expected to resolve the contingency constraint within the Gawler Belt area for approximately 17 years. Refer below for NPV analysis

19.4.2.8 Commitment Status

The relevant regulatory process (ESCOSA Guideline 12) was completed in 2013 and SA Power Networks has committed to the project to enable the 2015 commissioning date to be met. This project was included in the pre RIT-D committal list issued to the AER in December 2013.

19.4.2.9 Regulatory Period Expenditure

Approximately $2.6 million is forecast to be required in the 2015-20 regulatory control period, with the remaining $2.6 million forecast for the 2010 - 15 regulatory period.

19.4.2.10Regulatory Period Expenditure

Option	Description	NPV[33]
1	Gawler Belt 33/11kV Substation Upgrade	-5,183,000
2	New Greenfield 12.5MVA 33/11kV Modular 1 Substation at Hewett	-6,103,311

Table 101: Gawler Belt NPV Results and Rankings

19.5 Feeders

Customers are supplied from SA Power Networks Distribution System via 7.6 and 11*kV* feeders, which are supplied from the zone substations. These feeders are extended and upgraded as required to meet customer demand, customer connection requests and to maintain quality of supply.
During the forthcoming 2015-20 Reset period, no feeder constraints have been identified.

[33] Analysis results from Reasonableness Test RT003-13 published November 2013.

19.6 Land and Other Works

The following land purchases and additional works within the region have been identified within the 2015-20 period.

Project Timing	Project Name	Work Category	Proposed Solution	Section Ref	2015-20 Cost ($ million)	2020-25 Cost ($ million)	Total Cost ($ million)
2019	Templers – Wasleys – Mallala 33*kV* Voltage Regulation	Voltage Regulation	Install a set of 200A pole top voltage regulators near Wasleys to improve 33*kV* volts at Mallala..	-	**0.55**	-	0.55
2015	Dublin 33/11*kV* Modular 3 Substation (New)	Land	Purchase land for new zone substation	-	**-**	0.07	0.07

Table 102: Mid North Other Works

20. Murraylands - Regional Development Plan

SA Power Networks' Murraylands Region consists of the region from Swan Reach in the North to Coonalpyn in the south and extends to Pinnaroo and eastwards to Narraung. There are three main *connection point*s in the Murraylands: Mannum, Mobilong and Tailem Bend. A map of this region is contained in Appendix A.

Electricity is supplied to the various towns and localities throughout the Murraylands via *Distribution substation*s. These Substations are operated at 33*kV* stepped down to 11*kV* (7.6*kV* at Mannum) and are upgraded when load exceeds capacity.

Customers are supplied from SA Power Networks' Distribution System via 33*kV* Lines, 7.6*kV* and 11*kV* Feeders and 19*kV* SWER systems, which are supplied from *Distribution substation*s. These Lines, Feeders and SWER systems are extended and upgraded as required to meet customer demand, customer connection requests and to maintain quality of supply.

A map of this region is shown in Figure 81 while a single line representation of the network is shown in Figure 82.

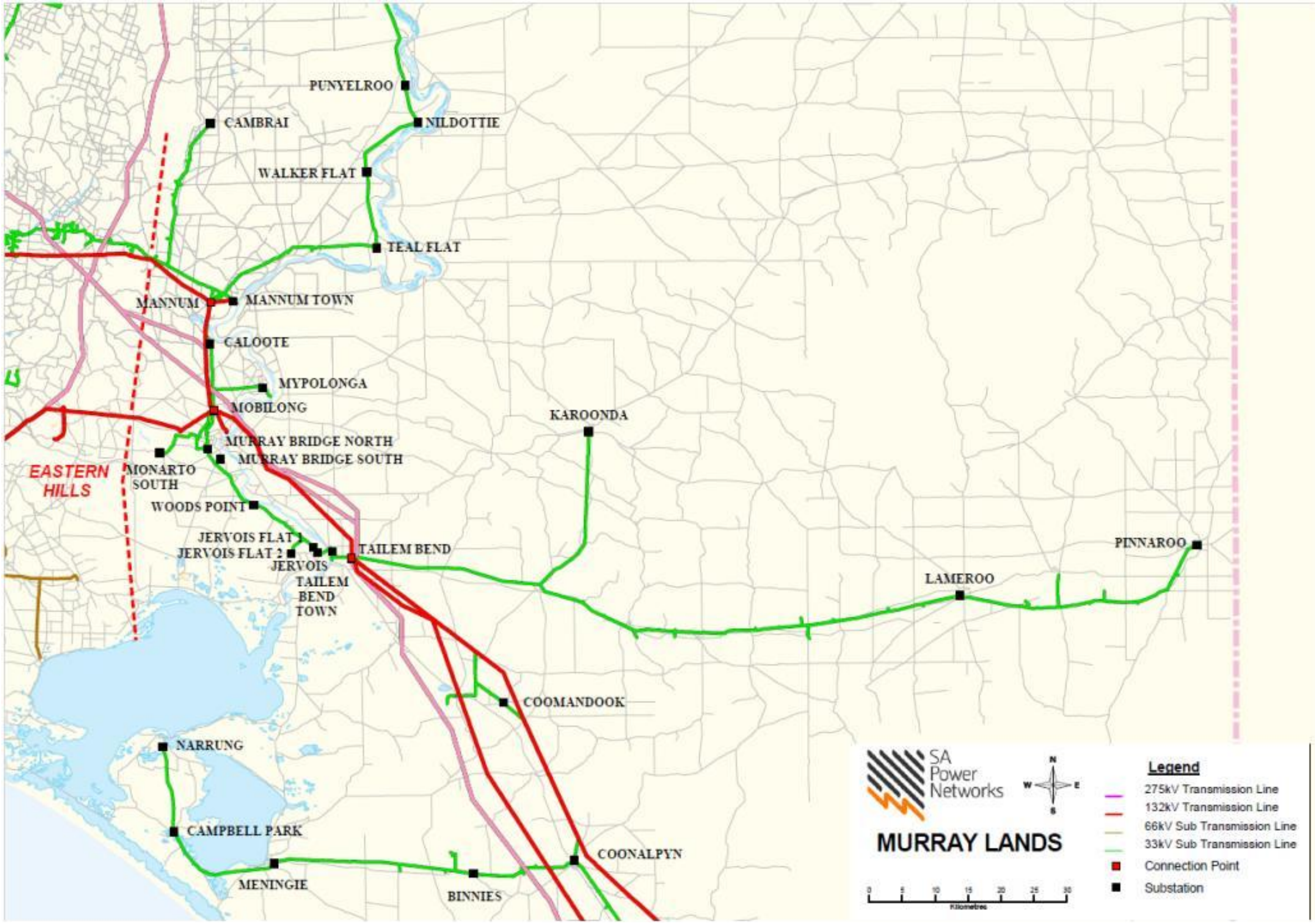


Figure 81: Murraylands Map

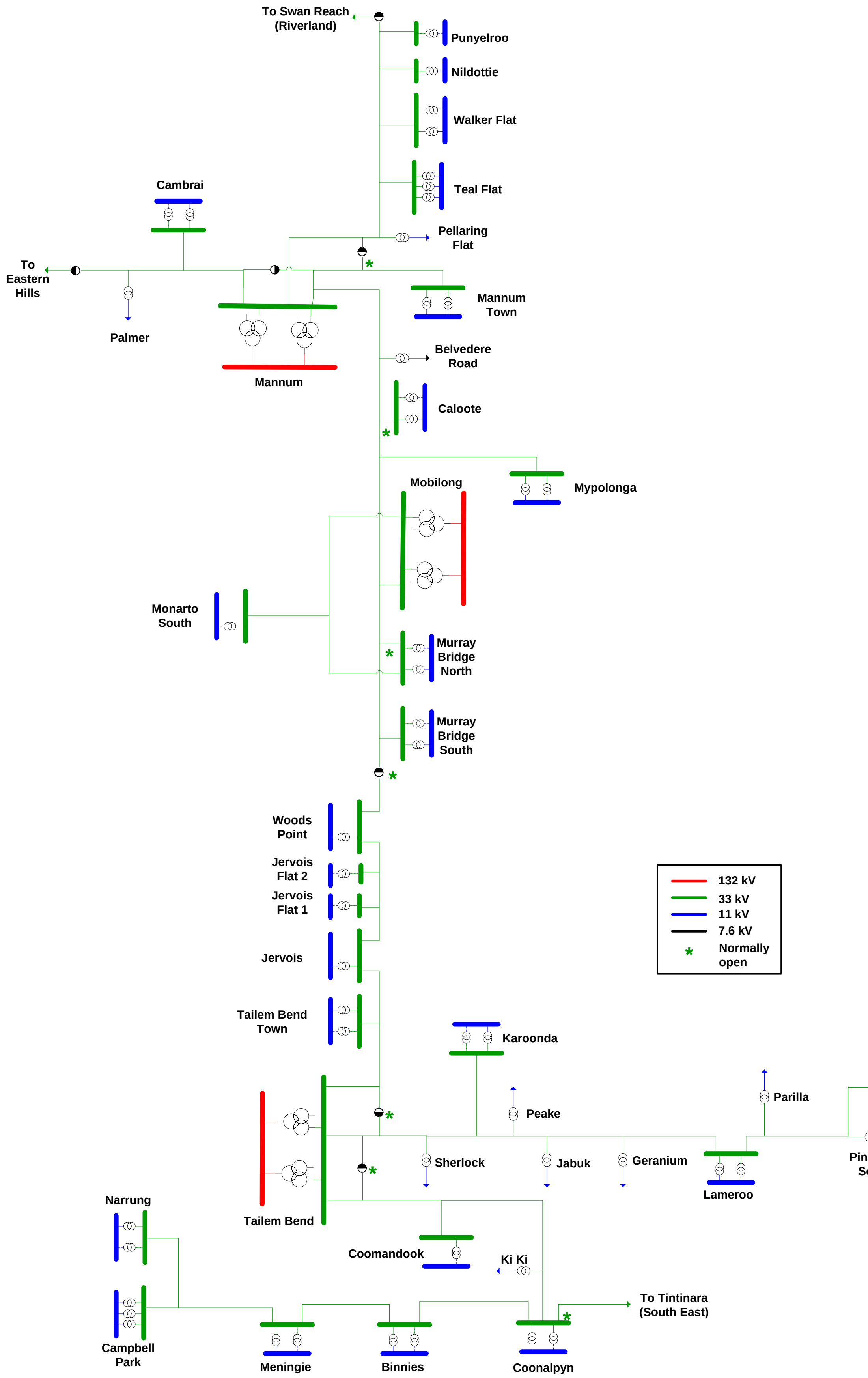


Figure 82: Murraylands Single Line Diagram

20.1 Region Statistics

Table 103 indicates the general statistics for this region of the state.

Parameter	Value
No of connection points	3 (132/33*kV*)
No of zone subs	35 - 34 (33/11*kV*), 1 (33/7.6*kV*),
Operating voltages	33*kV*, 11*kV* and 7.6*kV*
Total customers	22,723
No of residential customers (abs /%of region/% of state)	17,386 / 76.5% / 2%
No of commercial customers (abs /%of region/% of state)	5,337 / 23.5% / 0.6%
Area of region (km^2 / % of state)	18835 km^2 / 8.2%
Length of 33kV cable (km / % of region 33kV)	0.5 km / 0.1%
Length of 33kV conductor (km / % of region 33kV)	540 km / 99.9%
Length of 19kV cable (km / % of region 99kV)	4.7 km/ 0.1%
Length of 19kV conductor (km / % of region 19kV)	4,077 km / 99.9%
Length of 11kV cable (km / % of region 11kV)	67 km / 6.2%
Length of 11kV conductor (km / % of region 11kV)	1,025 km / 93.8%
Length of 7.6kV cable (km / % of region 11kV)	8.3 km / 19.6%
Length of 7.6kV conductor (km / % of region 11kV)	34 km / 80.4%
Installed *PV* inverter capacity (*MW* / % of state)	16.46 *MW* / 2.86%
No of feeders (abs / % urban / % rural short / % rural long)	54 / 0% / 5.6% / 94.4%

Table 103: Murraylands Region Statistics

20.2 Development History

The Murraylands region has been largely developed since the formation of the Electricity Trust of South Australia (ETSA) in 1946 through to privatisation in 1999 and the subsequent creation of ETSA Utilities / SA Power Networks.

Much of the region was originally supplied by local generation schemes operated by local councils with ETSA purchasing many of these networks. A 33*kV* line between Mannum and Murray Bridge was completed in 1953 with the first 132*kV* transmission line to the region was constructed between Northfield and Mannum in 1954. The region's network of sub-transmission lines and zone substations was gradually expanded throughout the 1960s and 70s.

No significant works have been conducted within this region over the present Reset period.

20.3 Connection points and sub-transmission lines

The Mid North region contains three *connection point*s located at Mannum, Mobilong and Tailem Bend. All are supplied at 132*kV* and connect to SA Power Networks' at 33*kV*.

All three of the region's *connection point*s are classed as Category 4 sites by the ETC, therefore requiring adequate transmission line and *connection point* transformer capacity to be available under N-1 conditions.

The region's *connection point*s have the following normal and N-1 transformer capacities:

Connection Point	ETC Category	Transformer "N" rating (MVA)	Transformer "N-1" rating (MVA)
Mannum 132/33*kV*	4	40	21
Mobilong 132/33*kV*	4	114.3	57.2
Tailem Bend 132/33*kV*	4	60	32.5

Table 104: Murraylands Connection Point Capacities

In accordance with the planning criteria for sub-transmission lines, SA Power Networks plans this region's sub-transmission network based on the 10% PoE forecast. The region operates 33*kV* lines at sub-transmission level. Constraints on the radial sub-transmission network and of ElectraNet's transformers are determined through modelling of the network and analysis using PSS/E and comparison of the forecast to the *connection point*'s normal and emergency ratings.

Within the time period covered by this *AMP*, no augmentation of the region's *connection point* transformer capacity is forecast to be required. A copy of the region's *connection point* forecasts are shown in APPENDIX K – MURRAYLANDS REGION FORECASTS.

The region contains a 33*kV* ties to the Riverland, Eastern Hills and South East regions. These ties are normally only operated following a contingent event in order to restore supply to the affected portion of the region. No *connection point*s are forecast to be constrained within the 2015 – 25 period.

Table 105 indicates those sub-transmission lines forecast to be constrained within the 2015-25 period and the proposed solution.

Section Ref	Project Name	Constrained Line(s)	Constraint Type	Constraint Description	Proposed Solution	Constraint Year	Commissioning Year	2015-20 Cost ($ million)	2020-25 Cost ($ million)	Total Cost ($ million)
-	Tailem Bend to Sherlock 33*kV* Line Uprate	Tailem Bend to Sherlock 33*kV*	N	Thermal overload of 33*kV* line under normal conditions.	Thermally uprate 30km of line from design temperature of 50°C to 80°C.	2017	2017	**1.0**	-	1.05
-	Sherlock to Geranium 33*kV* Line Uprate	Sherlock to Geranium 33*kV*	N	Thermal overload of 33*kV* line under normal conditions.	Thermally uprate 34km of line from design temperature of 50°C to 60°C.	2017	2017	**0.87**	-	0.92
-	Geranium to Lameroo 33*kV* Line Uprate	Geranium to Lameroo 33*kV*	N	Thermal overload of 33*kV* line under normal conditions.	Thermally uprate 32.5km of line from design temperature of 50°C to 60°C or 80°C.	2017	2017	**0.99**	-	0.99

Table 105: Murraylands Sub-transmission Line Constraints

20.4 Zone substations

Electricity is supplied throughout the Murraylands region by 34, 33/11*kV* and one 33/7.6*kV* zone substations.

Forecasts for the region's zone substations are shown in APPENDIX K – MURRAYLANDS REGION FORECASTS.

The following zone substation constraints have been identified within the 2015-25 period covered by this *AMP*:

Project Timing	Project Name	Limitation / Constraint	Proposed Solution	Section Ref	2015-20 Cost ($ million)	2020-25 Cost ($ million)	Total Cost ($ million)
2018	Mypolonga Sub Upgrade	Overload of Mypolonga zone substation under normal conditions	Upgrade Mypolonga zone substation by replacing the existing two 1MVA transformers with a single 3MVA 33/11*kV* padmount transformer and new 11*kV* reclosers.	-	**2.08**	-	2.08
2025	Monarto South Substation Upgrade	Overload of Monarto South zone substation under contingent conditions.	Upgrade Monarto South zone substation by installing a second 12.5MVA 33/11*kV* transformer and associated 11*kV* switchboard.		**-**	2.08	4.17

Table 106: Murraylands Zone Substation Constraints

20.5 Feeders

Customers are supplied from SA Power Networks Distribution System via 7.6 and 11*kV* feeders, which are supplied from the zone substations. These feeders are extended and upgraded as required to meet customer demand, customer connection requests and to maintain quality of supply.

During the forthcoming 2015-20 Reset period, the following feeder constraints have been identified:

Project Timing	Project Name	Limitation / Constraint	Proposed Solution	Section Ref	2015-20 Cost ($ million)	2020-25 Cost ($ million)	Total Cost ($ million)
2016	Karoonda Recloser Upgrade	Overload of recloser trip coil (125% of rating) under normal conditions.	Upgrade the Karoonda Recloser at Clarendon to prevent trip coil overload for N.	-	**0.15**	-	0.15
2016	Purnong Recloser Upgrade	Overload of recloser trip coil (125%) for normal conditions	Upgrade the Purnong Recloser at Teal Flat to prevent trip coil overload for N	-	**0.15**	-	0.15
2017	Northern Heights 11*kV* Feeder	Overload of Monarto South zone substation under contingent conditions and overlaod of Meatworks and Thomas Street 11*kV* feeders under normal conditions in 2014 and 2019 respectively.	Construct a new feeder exit from Murray Bridge North zone substation and approx 2.5km of new 11*kV* feeder to increase feeder transfers and defer overload of Monarto zone sub and relieve overloads on existing feeder network.		**1.00**	-	1.00
2018	Gumpark Recloser Upgrade	Overload of existing recloser's trip coil following load transfer to feeder under contingent conditions.	Upgrade the existing hydraulic recloser with a new 11*kV* recloser to increase rating.	-	**0.15**	-	0.15

Project Timing	Project Name	Limitation / Constraint	Proposed Solution	Section Ref	2015-20 Cost ($ million)	2020-25 Cost ($ million)	Total Cost ($ million)
2018	Narrung Recloser Upgrade	Overload of existing recloser's trip coil following load transfer to feeder under contingent conditions.	Upgrade the existing hydraulic recloser with a new 11*kV* recloser to increase rating.	-	**0.15**	-	0.15
2019	Tailem Bend East Recloser Upgrade	Overload of existing recloser's trip coil following load transfer to feeder under contingent conditions.	Upgrade the existing hydraulic recloser with a new 11*kV* recloser to increase rating.	-	**0.15**	-	0.15

Table 107: Murraylands Feeder Constraints

20.5.1 Major Project – Northern Heights Feeder Upgrade

20.5.1.1 Constraint

The Meatworks 11kV feeder (MB-21) is supplied from Murray Bridge North 33/11kV zone substation. Under 50% PoE conditions the feeders' N-1 offload capacity is forecast to be exceeded in 2017/18.

The forecast growth rate for Meatworks 11kV feeder excluding a committed major customer load increase is 0.9% per annum. The measured average growth rate for the Meatworks 11kV feeder is 7% between 2008 and 2013 and shows that the recent underlying growth far exceeds forecast. Consequently, the augmentation project may be required earlier than planned.

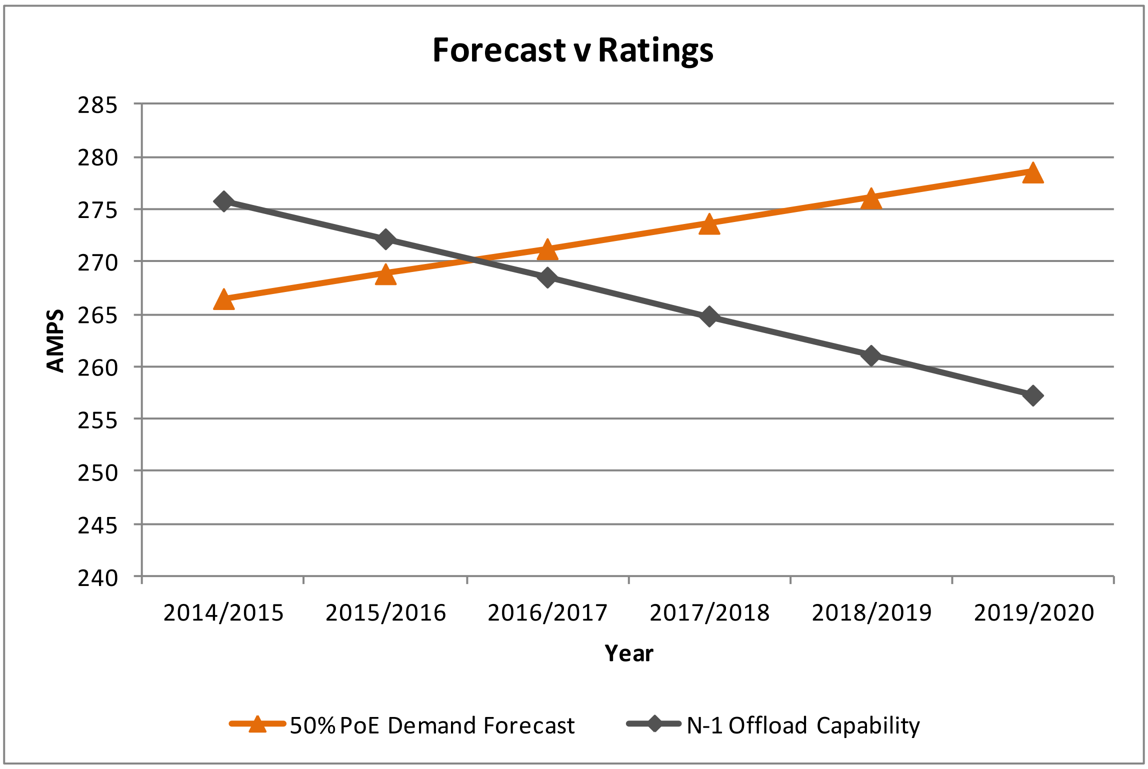


Figure 83: Meatworks 11kV Feeder Load versus Capacity

	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
Forecast* Amps (50% PoE)	266	269	271	274	276	279
N-1 Offload Capability (Amps)	276	272	269	265	261	257
N-1 Load at Risk (Amps)	0	0	3	9	15	22

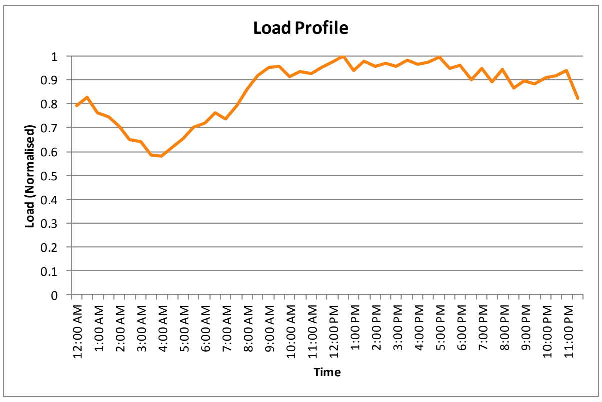
**Load Forecast includes impact of PV both existing and forecast. The forecast also includes the impact of energy efficiency, state economic and population growth by reconciling each asset's local growth trend with the AEMO July 2014 SA Regional forecast for the next 5 years.*

Table 108: Meatworks 11kV Feeder Load Forecast

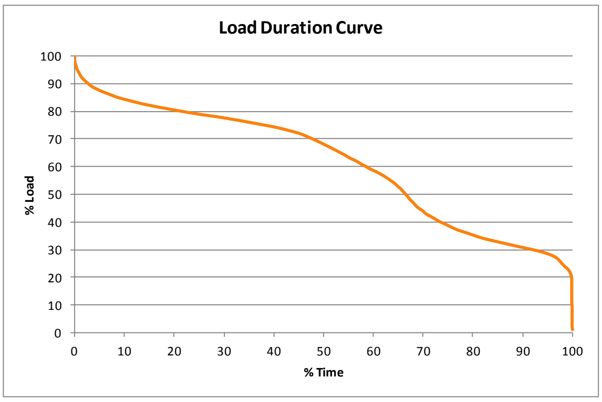
20.5.1.2 Consequences for Customers

The 50% PoE forecast demand of the Meatworks 11kV feeder in 2017/18 is 274A, which will exceed the N-1 offload capability of 265A. In the event of cable failure and after all available N-1 offload capacity is exhausted, up to 9A of load or 14 customers would be unsupplied until the cable fault was repaired, increasing to 21A and 33 customers in 2019/20. However, due to the discrete number of switching points on a given feeder, it is not possible to load shed an exact amount of customers. In general, it is likely that a larger portion of the feeder would need to be shed. The N-1 offload capability of Meatworks 11kV feeder is expected to be exceeded for a total of 19 hours in 2017/18 over 11 days per annum increasing to 100 hours in 2019/20 over 38 days per annum. The offload capability applies the emergency rating of the feeders and substation transformers that the customers are shifted to and considers all possible options. The Meatworks feeder supplies a major customer that requires uninterrupted supply due to their 24/7 business.

20.5.1.3 Load Profile



(a)



(b)

Figure 84: (a) Meatworks 11kV Feeder Load Profile, (b) Load Duration Curve

20.5.1.4 Deferral Options Considered

Improved Feeder Ties

- See options 1 and 2 below.

Demand Side Participation

- Due to the large amount of load at risk, demand side participation is not expected to achieve a large enough reduction of load to defer the constraint on the Meatworks 11kV feeder.

20.5.1.5 Options considered to address constraint

The following options have been investigated to resolve the impending constraint:

Option 1:

- Upgrade the backbone of the Northern Heights 11kV feeder (MB-20) supplied from Murray Bridge North 33/11kV Zone Substation by restringing approximately 1.7km of overhead conductor and replacing 250m of underground cable. The upgrade of overhead conductor will improve the capability of the existing feeder tie between the Meatworks, Monarto South (MB-92) and Northern Heights 11kV feeders.

Option 2:

- Establish a new 11kV feeder from Murray Bridge North 33/11kV Zone Substation by installing 2.6km of 630mm^2 Al XLPE cable feeder backbone, transfer load from Meatworks 11kV and Thomas Street 11kV feeders and install 0.4km of overhead conductor to provide a feeder tie to Monarto South 11kV feeder.

20.5.1.6 Preferred Solution

The preferred solution based on a net present value analysis is to upgrade the backbone of the Northern Heights 11kV feeder from Murray Bridge North 33/11kV zone substation by restringing overhead conductor and replacing underground cable (option 1). The indicative cost for this project is $1 million. This project is planned for completion in 2017 and is expected to resolve the constraint on the Murray Bridge 11kV Zone Substation’s feeders for eight years.

20.5.1.7 Regulatory Period Expenditure

The total estimated $1 million is required within the 2015 - 20 regulatory ceset period.

20.6 Land and Other Works

The following land purchases and additional works within the region have been identified within the 2015-20 period.

Project Timing	Project Name	Work Category	Proposed Solution	Section Ref	2015-20 Cost ($ million)	2020-25 Cost ($ million)	Total Cost ($ million)
2016	Lameroo 33*kV* Pole Top Voltage Regulators	Voltage Regulation	Install a set of 200A 33*kV* pole top voltage regulators prior to Lameroo to improve 33*kV* volts at Lameroo and Pinnaroo.	-	**0.78**	-	0.78
2016	Teal Flat new 33*kV* Pole Top Voltage Regulators	Voltage Regulation	Install a set of 200A 33*kV* pole top voltage regulators between Mannum and Teal Flat to improve 33*kV* volts at Nildottie and Punyelroo.	-	**0.72**	-	0.72
2021	Pinnaroo 11*kV* Pole Top feeder regulation	Voltage Regulation	Upgrade existing 100A 11*kV* regulators at Pinnaroo with a set of 200A 11*kV* pole top voltage regulators to improve 11*kV* volts on Pinnaroo feeders.	-	**-**	0.87	0.87
2024	Mobilong Sub Control Room	Land	Purchase land from ElectraNet to enable installation of SA Power Networks owned pre-fab control room at Mobilong *connection point*.	-	**-**	0.17	1.0

Table 109: Murraylands Other Works

21. RIVERLAND – REGIONAL DEVELOPMENT PLAN

SA Power Networks' Riverland Region covers the region from Berri that extends north-west to Morgan, south-west to Swan Reach, and north-east to Renmark and Paringa. There are two main *connection point*s in the Riverland region at Berri and North West Bend.

Electricity is supplied to the various towns and localities throughout the Riverland via zone substations. These substations are operated at either 66*kV* or 33*kV* stepped down to 11*kV*.

Customers are supplied from SA Power Networks' Distribution System via 33*kV* and 11*kV* Feeders and 19*kV* SWER systems, which are supplied from zone Substations. These Feeders and SWER systems are extended and upgraded as required to meet customer demand and customer connection requests.

A map of this region is shown in Figure 85 while a single line representation of the network is shown in Figure 86.

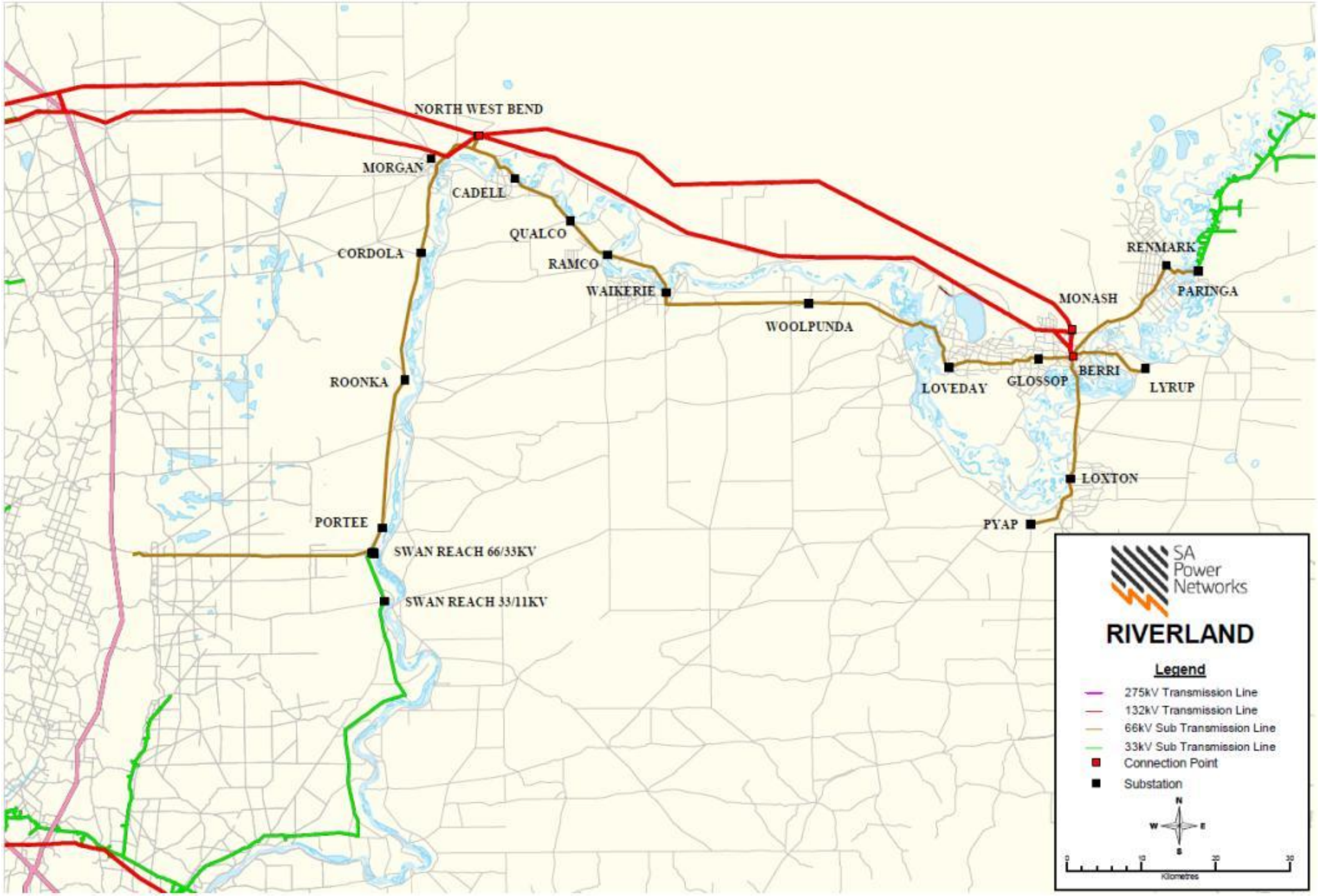


Figure 85: Riverland Map

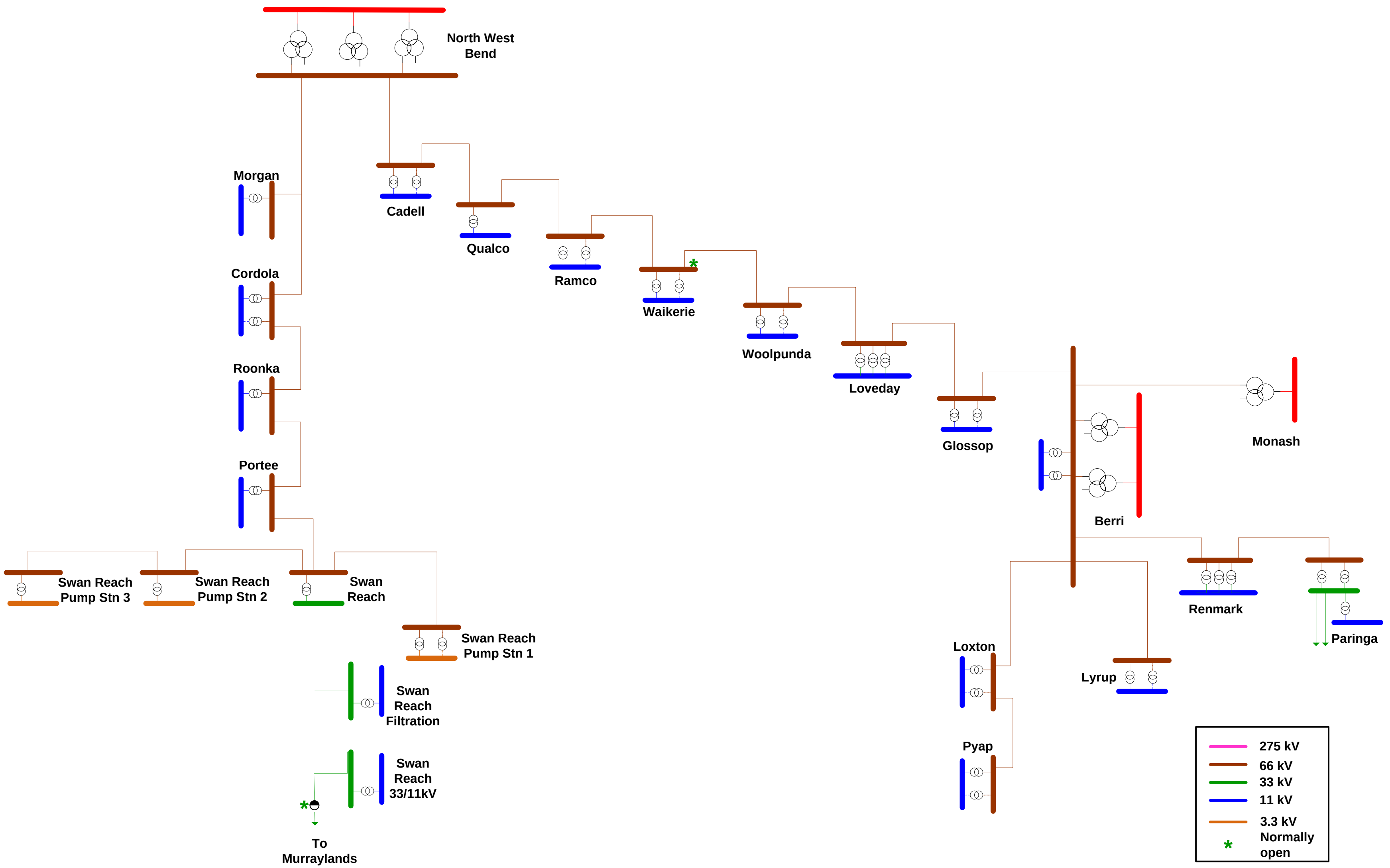


Figure 86: Riverland Single Line Diagram

21.1 Region Statistics

Table 110 indicates the general statistics for this region of the state.

Parameter	Value
No of connection points	2 (132/66*kV*)
No of zone subs	24 - 16 (66/11*kV*), 2 (66/33*kV*), 3 (33/11*kV*), 3 (66/3.3*kV*)
Operating voltages	66*kV*, 33*kV*, 11*kV* and 3.3*kV*
Total customers	23,706
No of residential customers (abs /%of region/% of state)	17,412 / 73.4% / 2.1%
No of commercial customers (abs /%of region/% of state)	6,294 / 26.6% / 0.7%
Area of region (km^2 / % of state)	11,682 km^2 / 5.1%
Length of 66kV cable (km / % of region 66kV)	0.1 km / 0.04%
Length of 66kV conductor (km / % of region 66kV)	256 / 99.96%
Length of 33kV cable (km / % of region 33kV)	0 km/ 0%
Length of 33kV conductor (km / % of region 33kV)	7.4 km / 100%
Length of 19kV cable (km / % of region 19kV)	0.9 km / 0.1%
Length of 19kV conductor (km / % of region 19kV)	1,264 km / 99.9%
Length of 11kV cable (km / % of region 11kV)	114 km / 7.1%
Length of 11kV conductor (km / % of region 11kV)	1,497 km / 92.9%
Installed *PV* inverter capacity (*MW* / % of state)	23 *MW* / 4%
No of feeders (abs / % urban / % rural short / % rural long)	52 / 7.7% / 90.4% / 1.9%

Table 110: Riverland Region Statistics

21.2 Development History

The Riverland region has been largely developed since the formation of the Electricity Trust of South Australia (ETSA) in 1946 through to privatisation in 1999 and the subsequent creation of ETSA Utilities / SA Power Networks.

Much of the region was originally supplied by a local generation schemes operated at Berri, Loveday and Waikerie. The local 66*kV* network was extended throughout the early 1950s until connection to the main grid via 66*kV* in approximately 1952. The region continued to be supported by local generation until 1954 when the last local power station at Berri was closed and injection at 132*kV* was completed at North West Bend. This 132*kV* supply was extended to Berri in 1955. The region's network of sub-transmission lines and zone substations was gradually expanded from this time to today.

Only relatively minor works have been performed within this region over the present Reset period. These works include:

Project Title	Description	Commissioning Year	Cost ($ million)
North West Bend Protection Upgrade	Upgrade of the line protection at North West Bend	2013	0.7

Table 111: Recent Riverland Augmentations

21.3 Connection points and sub-transmission lines

The Riverland region contains two *connection point*s located at North West Bend and Berri. Both are supplied at 132*kV* and connect to SA Power Networks' at 66*kV*. Berri's 132/66*kV* transformer capacity is supplemented by an additional transformer at Monash and connected to Berri's 66*kV* bus via 66*kV* lines owned by ElectraNet. A DC interconnector known as Murraylink also connects to Monash's 132*kV* bus.

Both of the region's *connection point*s are classed as Category 4 sites by the ETC, therefore requiring adequate transmission line and *connection point* transformer capacity to be available under N-1 conditions.

The region's *connection point*s have the following normal and N-1 transformer capacities:

Connection Point	ETC Category	Transformer "N" rating (MVA)	Transformer "N-1" rating (MVA)
Berri 132/66*kV*	4	190	140
North West Bend 132/66*kV*	4	73.6	55.6

Table 112: Riverland Connection Point Transformer Capacities

In accordance with the planning criteria for sub-transmission lines, SA Power Networks plans this region's sub-transmission network based on the 10% PoE forecast. The region operates 33*kV* lines at sub-transmission level. Constraints on the radial sub-transmission network and of ElectraNet's transformers are determined through modelling of the network and analysis using PSS/E and comparison of the forecast to the *connection point*'s normal and emergency ratings.

Within the time period covered by this *AMP*, no augmentation of the region's *connection point* transformer capacity is forecast to be required. A copy of the region's *connection point* forecasts are shown in APPENDIX L – RIVERLAND REGION FORECASTS.

Table 113 details those *connection point* projects forecast within the 2015-25 period.

Project Timing	Project Name	Limitation / Constraint	Proposed Solution	Section Ref	2015-20 Cost ($ million)	2020-25 Cost ($ million)	Total Cost ($ million)
2023	North West Bend Sub Control Room	Presence of SA Power Networks' assets within ElectraNet owned control room.	Install a new pre-fab control building at North West Bend *connection point* to house SA Power Networks' protection and control assets.	-	**-**	0.78	0.78

Table 113: Riverland Connection Point Projects

The region contains a single 33*kV* tie to the Murraylands region near Swan Reach. This tie is normally only operated following a contingent event in order to restore supply to the affected portion of the region. No *connection point*s are forecast to be constrained within the 2015 – 25 period.

There are no sub-transmission lines forecast to be constrained within the region over the 2015-25 period.

21.4 Zone substations

Electricity is supplied throughout the Riverland region by 16, 66/11*kV*, two, 66/33*kV*, three, 33/11*kV* and three 66/3.3*kV* zone substations. These latter three substations are dedicated to supplying individual customers.

Forecasts for the region's zone substations are shown in APPENDIX L – RIVERLAND REGION FORECASTS.

The following zone substation constraints have been identified within the 2015-25 period covered by this *AMP*:

Project Timing	Project Name	Limitation / Constraint	Proposed Solution	Section Ref	2015-20 Cost ($ million)	2020-25 Cost ($ million)	Total Cost ($ million)
2015	Paringa 66/33*kV* Sub Upgrade	Overload of Paringa 66/33*kV* zone substation under contingent conditions.	Replace existing hot standby transformer with a new 32MVA 66/33*kV* transformer. Place existing primary transformer into hot standby.	-	**2.0**	-	4.0
2019	Swan Reach 66/33*kV* Sub Upgrade	Overload of Swan Reach 66/33*kV* zone substation under contingent conditions.	Install a 12.5MVA 66/33*kV* transformer taken from Paringa.	-	**2.50**	-	2.50
2023	Waikerie Substation Upgrade	Overload of Waikerie 66/33*kV* zone substation under normal and contingent conditions.	Upgrade Waikerie zone substation by replacing the two existing 5MVA transformers with 12.5MVA units. Construct new control room and install new 11*kV* switchboard sections.		**-**	6.83	6.83

Table 114: Riverland Zone Substation Constraints

21.5 Feeders

Customers are supplied from SA Power Networks Distribution System via 11*kV* feeders, which are supplied from the zone substations. These feeders are extended and upgraded as required to meet customer demand, customer connection requests and to maintain quality of supply.

During the forthcoming 2015-20 Reset period, the following feeder constraints have been identified:

Project Timing	Project Name	Limitation / Constraint	Proposed Solution	Section Ref	2015-20 Cost ($ million)	2020-25 Cost ($ million)	Total Cost ($ million)
2015	Glossop Substation – 11*kV* feeder restring	Overload of Berri Winery feeder under normal conditions.	Upgrade 1.5km of backbone conductor on the Glossop feeder and replace 120m of 95mm^2 cable with 300mm2 and transfer load from overloaded feeder to upgraded feeder.	-	**0.23**	-	0.45
2016	Pike River Recloser Upgrade	Trip coil overload (125%) for normal conditions	Upgrade the Pike River Recloser at Lyrup to prevent trip coil overload for N	-	**0.15**	-	0.15

Table 115: Riverland Feeder Constraints

21.6 Land and Other Works

The following land purchases and additional works within the region have been identified within the 2015-20 period.

Project Timing	Project Name	Work Category	Proposed Solution	Section Ref	2015-20 Cost ($ million)	2020-25 Cost ($ million)	Total Cost ($ million)
2023	North West Bend VAr suuport	NER Compliance	Install a 2MVAr 11*kV* capacitor bank at a zone substation supplied by North West Bend *connection point* to improve power factor above 0.95.	-	-	0.11	0.11

Table 116: Riverland Other Works

22. SOUTH EAST – REGIONAL DEVELOPMENT PLAN

SA Power Networks' South East Region services the region from Tintinara in the North to Port MacDonnell in the south. It extends westwards to the coast and eastwards to the Victorian border. There are seven main *connection point*s in the South East: Keith, Kincraig, Penola West, Snuggery Industrial, Snuggery Rural, Mount Gambier and Blanche.

A map of this region is shown in Figure 87 while a single line representation of the network is shown in Figure 88.

Figure 87: South East Map

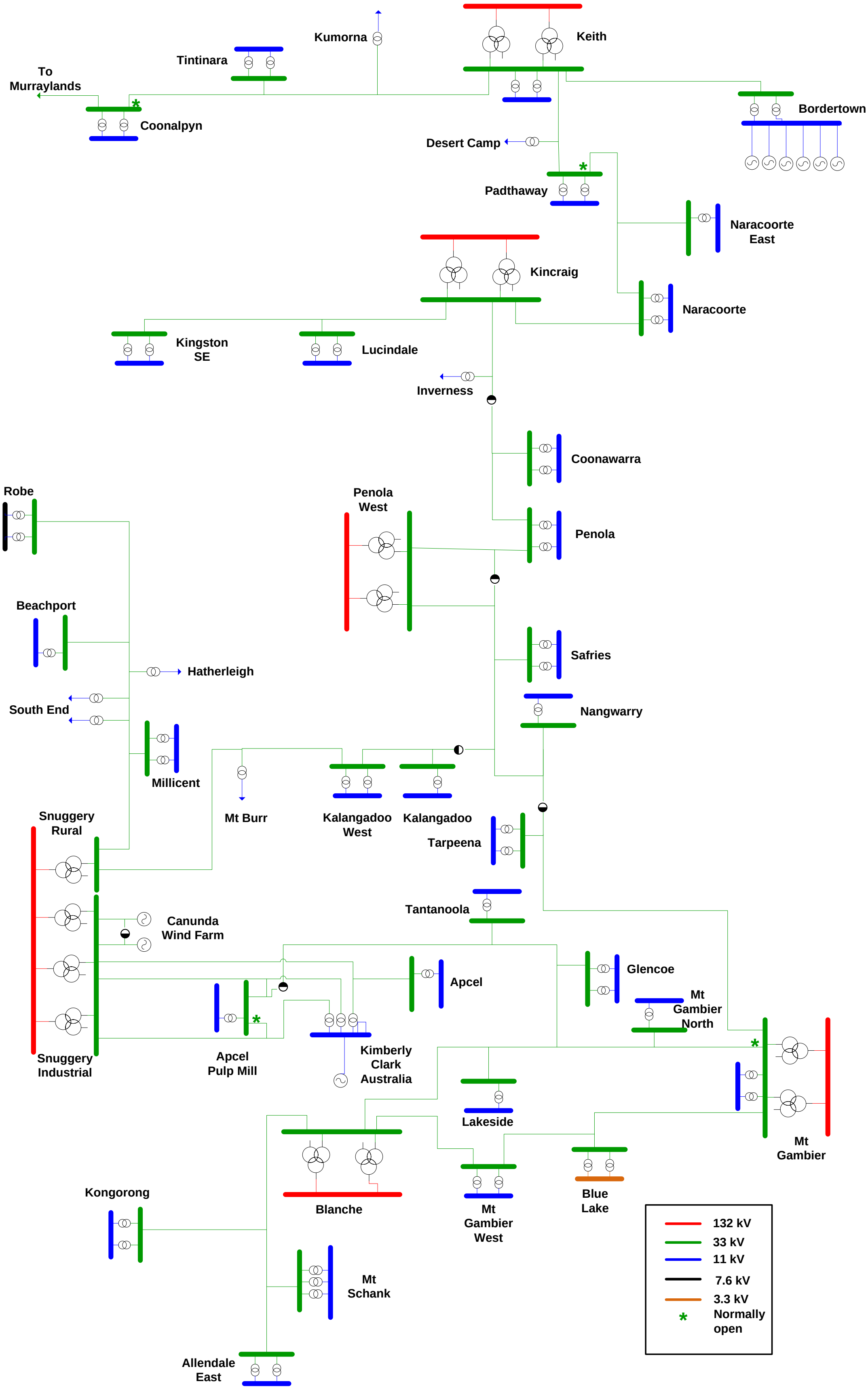


Figure 88: South East Single Line Diagram

22.1 Region Statistics

Table 117 indicates the general statistics for this region of the state.

Parameter	Value
No of connection points	7 (132/33*kV*)
No of zone subs	40 - 38 (33/11*kV*), 1 (33/7.6*kV*), 1 (33/3.3*kV*)
Operating voltages	33*kV*, 11*kV*, 7.6*kV* and 3.3*kV*
Total customers	40,889
No of residential customers (abs /%of region/% of state)	30,601 / 74.8% / 3.6%
No of commercial customers (abs /%of region/% of state)	10,288 / 25.2% / 1.2%
Area of region (km^2 / % of state)	24,808 km^2 / 10.76%
Length of 33kV cable (km / % of region 33kV)	1.7 km/ 0.2%
Length of 33kV conductor (km / % of region 33kV)	717 km / 99.8%
Length of 19kV cable (km / % of region 19kV)	10.3 km / 0.2%
Length of 19kV conductor (km / % of region 19kV)	4,327 km / 99.8%
Length of 11kV cable (km / % of region 11kV)	161 km / 4.4%
Length of 11kV conductor (km / % of region 11kV)	3,542 km / 95.6%
Length of 7.6kV cable (km / % of region 7.6kV)	4.7 km / 17%
Length of 7.6kV conductor (km / % of region 7.6kV)	22.8 km / 83%
Installed *PV* inverter capacity (*MW* / % of state)	22.2 *MW* / 3.9%
No of feeders (abs / % urban / % rural short / % rural long)	64 / 7.8% / 18.8% / 73.4%

Table 117: South East Region Statistics

22.2 Development History

The South East region has been largely developed since the formation of the Electricity Trust of South Australia (ETSA) in 1946 through to privatisation in 1999 and the subsequent creation of ETSA Utilities / SA Power Networks.

Much of the region was originally supplied by a local generation schemes with a power station operated at Mount Gambier using oil as the primary fuel source until 1957 until its conversion to use wood as the primary fuel. Another power station at Nangwarry was commissioned in 1961 connected to Mount Gambier via a 66*kV* line which was later converted to operation at 33*kV* in 1965 before being decommissioned in 1976.

The first of two 132*kV* lines from Tailem Bend to Mount Gambier was constructed in 1962 connecting the region to the main grid with the second being constructed in 1972. The 275*kV* interconnector with Victoria was first energised in 1989.

The following works have been performed within the region over the present Reset period:

Project Title	Description	Commissioning Year	Cost ($ million)
Penola West Connection Point	Construction of 33*kV* line to integrate new *connection point* within the *distribution network*.	2010	4.2
Naracoorte East Substation	Establishment of a new 12.5 MVA 33/11*kV* zone substation east of Naracoorte supplied by a new X km 33*kV* line.	2013	7.6
Mount Gambier North	Establishment of a new X MVA 33/11*kV* zone substation	2013	6.0
Bordertown Power Station	Connection of a new X MW generating station at Bordertown to provide network support during peak or contingent conditions.	2013	6.4

Table 118: Recent South East Region Augmentation Projects

22.3 Connection points and sub-transmission lines

The South East region contains seven *connection point*s located at Keith, Kincraig, Penola West, Snuggery Industrial, Snuggery Rural, Blanche and Mount Gambier. All are supplied at 132*kV* and connect to SA Power Networks' at 33*kV*.

Six of the region's seven *connection point*s are classed as Category 4 sites by the ETC with the seventh being a Category 3 site. This therefore requires adequate transmission line and *connection point* transformer capacity to be available under N-1 conditions.

The region's *connection point*s have the following normal and N-1 transformer capacities:

Connection Point	ETC Category	Transformer "N" rating (MVA)	Transformer "N-1" rating (MVA)
Blanche 132/33*kV*	4	126.3	61.5
Keith 132/33*kV*	4	58.9	37
Kincraig 132/33*kV*	4	51.6	30.5
Mount Gambier 132/33*kV*	4	63.3	32.5
Penola West 132/33*kV*	4	50	25
Snuggery Industrial 132/33*kV*	4	86.4	60
Snuggery Rural 132/33*kV*	3	28.8	0

Table 119: South East Connection Point Transformer Capacities

In accordance with the planning criteria for sub-transmission lines, SA Power Networks plans this region's sub-transmission network based on the 10% PoE forecast. The region operates 33*kV* lines at sub-transmission level. Constraints on the radial sub-transmission network and of ElectraNet's transformers are determined through modelling of the network and analysis using PSS/E and comparison of the forecast to the *connection point*'s normal and emergency ratings.

Within the time period covered by this *AMP*, no augmentation of the region's *connection point* transformer capacity is forecast to be required. A copy of the region's *connection point* forecasts are shown in APPENDIX M – SOUTH EAST REGION .

Project Timing	Project Name	Limitation / Constraint	Proposed Solution	Section Ref	2015-20 Cost ($ million)	2020-25 Cost ($ million)	Total Cost ($ million)
2020	Naracoorte 11*kV* Cap Bank	Overload of Kincraig *connection point*'s 132/33*kV* transformers under contingent conditions.	Install a 6 MVAr 11*kV* cap bank at Naracoorte zone sub to defer *connection point* upgrade.	-	**0.56**	0.56	1.12

Table 120: South East Connection Point Projects

The region contains a single 33*kV* tie to the Murraylands region at Coonalpyn. This tie is normally only operated following a contingent event in order to restore supply to the affected portion of the 33*kV* network. No *connection point*s are forecast to be constrained within the 2015 – 25 period.

Table 121 indicates those sub-transmission lines forecast to be constrained within the 2015-25 period and the proposed solution.

Section Ref	Project Name	Constrained Line(s)	Constraint Type	Constraint Description	Proposed Solution	Constraint Year	Commissioning Year	2015-20 Cost ($ million)	2020-25 Cost ($ million)	Total Cost ($ million)
-	Penola Tee to Penola 33*kV* Line Uprate	Penola Tee to Penola 33*kV*	N	Thermal overload of 33*kV* line under normal conditions.	Thermally uprate 7.2km of line from design temperature of 50°C to 60°C.	2016	2016	**0.2**	-	0.22
-	Naraccorte to Naracoorte East Tee 33*kV* Line Uprate	Naracoorte to Naracoorte East Tee 33*kV*	N	Thermal overload of 33*kV* line under normal conditions.	Thermally uprate 10km of line from design temperature of 50°C to 60°C.	2019	2019	**0.31**	-	0.31
-	Mount Gambier West to Blue Lake Tee 33*kV* Line Uprate	Mount Gambier West to Blue Lake 33*kV*	N	Thermal overload of 33*kV* line under normal conditions.	Thermally uprate 3.3km of line from design temperature of 50°C to 60°C.	2020	2020	**0.06**	0.05	0.11
-	Mount Schank to Allendale East 33*kV* Line Uprate	Mount Schank to Allendale East 33*kV*	N	Thermal overload of 33*kV* line under normal conditions.	Thermally uprate 13.2km of line from design temperature of 50°C to 60°C.	2020	2020	**0.22**	0.18	0.40
-	Kincraig to Naracoorte 2nd 33*kV* Line	Kincraig to Naracoorte 33*kV*	N	Thermal overload of 33*kV* line under normal conditions.	Construct a new 4km, 33*kV* line between Kincraig and Naracoorte. Install new line *CB*s and assoc line protection.	2022	2022	**-**	3.84	3.84

Table 121: South East Sub-transmission Line Projects

22.4 Zone substations

Electricity is supplied throughout the South East region by 38, 33/11*kV*, one 33/7.6*kV* and one 33/3.3*kV* zone substations. The latter substation is dedicated to supplying an individual customer.

Forecasts for the region's zone substations are shown in APPENDIX M – SOUTH EAST REGION .

The following zone substation constraints have been identified within the 2015-25 period covered by this *AMP*:

Project Timing	Project Name	Limitation / Constraint	Proposed Solution	Section Ref	2015-20 Cost ($ million)	2020-25 Cost ($ million)	Total Cost ($ million)
2016	Mount Burr Upgrade	Overload of Mount Burr 33/11*kV* zone substation under normal conditions.	Replace existing 0.3MVA pole mount transformer with new 0.5MVA 33/11*kV* transformer.	-	**0.52**	-	0.55
2016	Glencoe Substation Upgrade	Overload of Glencoe 33/11*kV* zone substation under normal conditions.	Construct a new 3MVA 33/11*kV* zone substation on a new site at Glencoe supplied by approx 1.5km of new 33*kV* overhead line.	-	**2.00**	-	2.00
2017	Cape Jaffa Substation	Overload of Kingston SE 33/11*kV* zone substation under normal conditions.	Construct a new 3MVA 33/11*kV* zone substation on a new site at Cape Jaffa supplied by approx 2km of new 33*kV* overhead line.	-	**2.39**	-	2.39
2020	Mount Schank North Substation	Overload of Mount Schank 33/11*kV* zone substation under normal conditions.	Construct a new 3MVA 33/11*kV* zone substation on a new site north of existing Mount Schank site, supplied by approx 7km of new 33*kV* overhead line.		**1.63**	1.53	3.17
2021	Tintinara Sub Upgrade	Overload of Tintinara 33/11*kV* zone substation under normal conditions.	Construct a new 3MVA 33/11*kV* zone substation on a new site at Tintinara supplied by approx 0.5km of new 33*kV* overhead line.		**0.07**	1.75	1.82
2023	Bordertown 33*kV* DVAr	Poor 33*kV* voltage under normal conditions	Install dynamic reactive support at Bordertown zone substation to improve 33*kV* voltages.		**-**	3.00	3.00

Table 122: South East Zone Substation Constraints

22.5 Feeders

Customers are supplied from SA Power Networks Distribution System via 11*kV* feeders, which are supplied from the zone substations. These feeders are extended and upgraded as required to meet customer demand, customer connection requests and to maintain quality of supply.

During the forthcoming 2015-20 Reset period, the following feeder constraints have been identified:

Project Timing	Project Name	Limitation / Constraint	Proposed Solution	Section Ref	2015-20 Cost ($ million)	2020-25 Cost ($ million)	Total Cost ($ million)
2016	Marcollat Recloser Upgrade	Overload of existing recloser's trip coil following load transfer to feeder under contingent conditions.	Upgrade the existing hydraulic recloser with a new 11*kV* recloser to increase rating.	-	**0.15**	-	0.15
2016	Maria Recloser Upgrade	Overload of existing recloser's trip coil following load transfer to feeder under contingent conditions.	Upgrade the existing hydraulic recloser with a new 11*kV* recloser to increase rating.	-	**0.15**	-	0.15
2016	Mount Salt Recloser Upgrade	Overload of recloser trip coil rating (125%) for normal conditions	Upgrade the Mount Salt Recloser at Mount Schank to prevent trip coil overload for N	-	**0.15**	-	0.15
2018	Tintinara Recloser Upgrade	Overload of existing recloser's trip coil following load transfer to feeder under contingent conditions.	Upgrade the existing hydraulic recloser with a new 11*kV* recloser to increase rating.	-	**0.15**	-	0.15
2018	Tintinara East Recloser Upgrade	Overload of existing recloser's trip coil following load transfer to feeder under contingent conditions.	Upgrade the existing hydraulic recloser with a new 11*kV* recloser to increase rating.	-	**0.15**	-	0.15
2019	Robe Substation – Robe 7.6*kV* feeder tie	Overload of Robe feeder under normal conditions.	Construct a new 7.6*kV* tie between existing Robe and Long Beach feeders and perform permanent transfer from Robe feeder.	22.5.1	**0.80**	-	0.80

Table 123: South East Feeder Constraints

22.5.1 Major Project – Robe Feeder Tie

22.5.1.1 Constraint

Robe 7.6kV feeder (MI-08) is supplied from Robe 33/7.6kV Zone Substation and has a normal capacity of 271A. Under 10% PoE conditions the feeder's normal capacity will be exceeded in 2019/20. The Robe 7.6kV feeder has no feeder transfer capability due it operating at 7.6kV and all 1,023 customers will remain unsupplied until any fault is repaired.

The forecast growth rate for Robe 7.6kV feeder is 1.3% per annum. The measured average growth rate from 2008 to 2013 was 7.7% and shows that the recent underlying growth far exceeds forecast indicating this particular feeders' forecast may be underestimated and the planned augmentation project may be required earlier than expected.

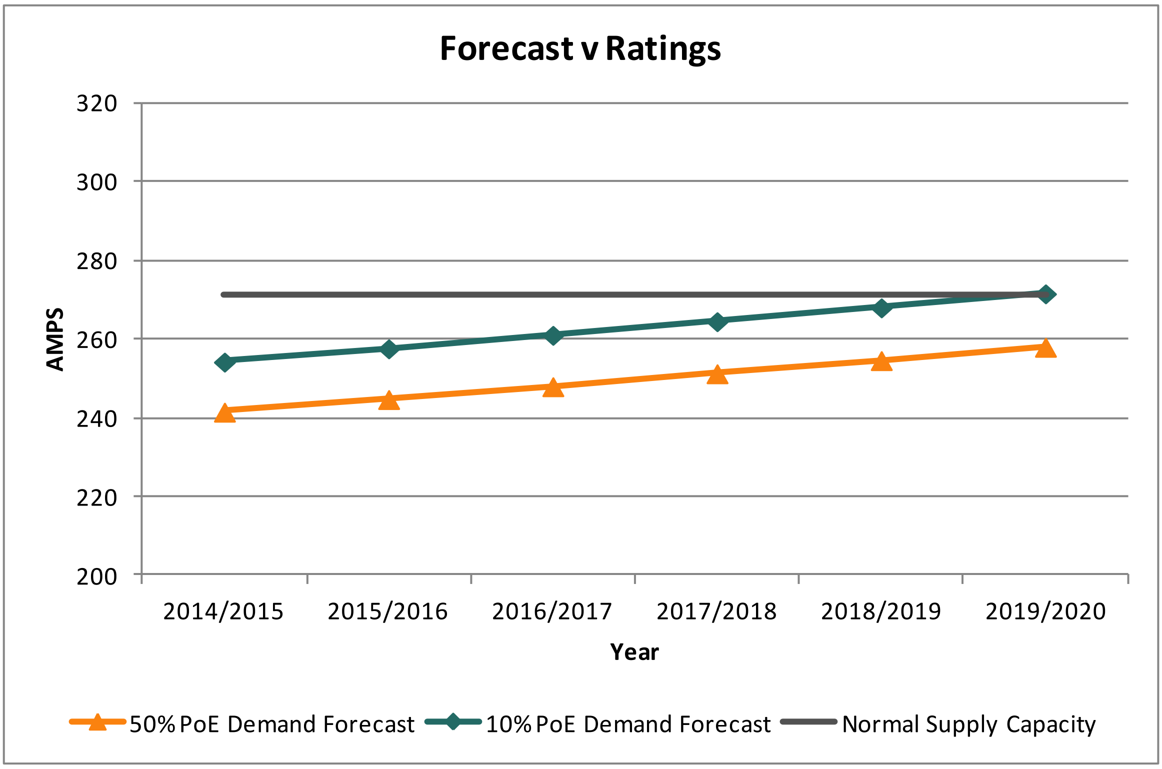


Figure 89: Robe 7.6kV Feeder Load versus Capacity

	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
Forecast* Amps (10% PoE)	254	258	261	265	268	272
Normal Supply Capacity (Amps)	271	271	271	271	271	271
Load at Risk (Amps)	0	0	0	0	0	1
Forecast* Amps (50% PoE)	242	245	248	251	255	258
N-1 Offload Capability (Amps)^	0	0	0	0	0	0
N-1 Load at Risk (Amps)	242	245	248	251	255	258

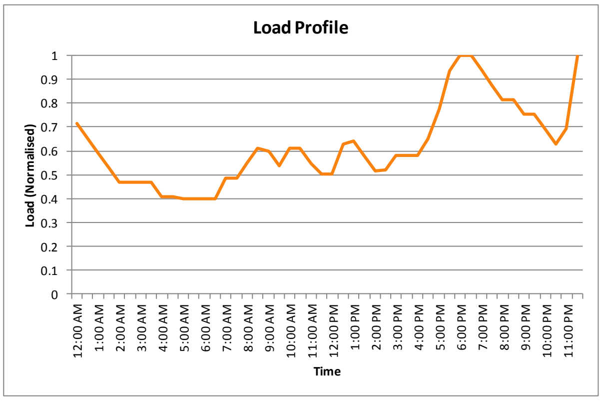
**Load Forecast includes impact of PV both existing and forecast. The forecast also includes the impact of energy efficiency, state economic and population growth by reconciling each asset's local growth trend with the AEMO July 2014 SA Regional forecast for the next 5 years.*
^No feeder Transfer Capability

Table 124: Robe 7.6kV Feeder Load Forecast

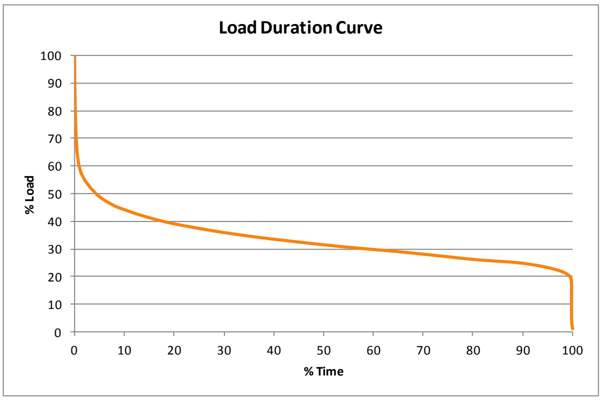
22.5.1.2 Consequences for Customers

The 10% PoE forecast demand for the Robe 7.6kV feeder in 2019/20 is 272A, which will exceed the feeder's normal capacity of 271A. In the event of a feeder exit failure, up to 272A of load and 1,023 customers will be unsupplied until the fault is repaired. The normal capacity of Robe 7.6kV feeder is expected to be exceeded for a total of 1 hour in 2019/20 over 1 day per annum. The typical repair time for such a fault would be 12 hours with all customers unsupplied until the fault was repaired.

22.5.1.3 Load Profile



(a)



(b)

Figure 90: (a) Robe 7.6kV Feeder Load Profile, (b) Load Duration Curve

22.5.1.4 Deferral Options Considered

Improved Feeder Ties

- Robe 7.6kV feeder has no existing feeder ties – see option 1 below.

Demand Side Participation

- Due to the amount of load at risk, demand side participation is not expected to achieve a large enough reduction of load to defer the constraint on the Robe 7.6kV feeder.

22.5.1.5 Options considered to address constraint

The following options have been investigated to resolve the impending constraint:

Option 1:

- Upgrade the Long Beach 7.6kV feeder (MI-13) by installing approximately 100m of 300mm^2 Al XLPE cable, 1.4km of overhead conductor, four 7.6kV load switches, a 7.6kV midline recloser and a 7.6kV midline 300A voltage regulator to provide a tie point to transfer load from Robe 7.6kV feeder.

Option 2:

- Establish new 7.6kV feeder at Robe 33/7.6kV Zone Substation by installing a new feeder exit recloser, approximately 3.7km of new 7.6kV overhead conductor, restringing existing Robe 7.6kV overhead conductor as required and transferring load from Robe 7.6kV feeder.

22.5.1.6 Preferred Solution

The preferred solution based on a net present value analysis, is to upgrade the Long Beach 7.6kV feeder and establish a tie point to Robe 7.6kV feeder to transfer load (option 1). The indicative cost for this project is $0.8 million. This project is planned for completion in 2019 and is expected to resolve the normal capacity constraint on the Robe 7.6kV feeder for 10 years. As an additional benefit, the feeder tie will also provide N-1 capability for both of Robe Zone Substation's 7.6kV feeders which was not previously available.

22.5.1.7 Regulatory Period Expenditure

The total estimated $0.8 million is required within the 2015-20 regulatory control period.

22.6 Land and Other Works

The following land purchases and additional works within the region have been identified within the 2015-20 period.

Project Timing	Project Name	Work Category	Proposed Solution	Section Ref	2015-20 Cost ($ million)	2020-25 Cost ($ million)	Total Cost ($ million)
2015	Glencoe Substation Upgrade	Land	Purchase land in preparation for new zone substation site.	-	**0.04**	-	0.08
2015	Cape Jaffa Substation	Land	Purchase land in preparation for new zone substation site.	-	**0.05**	-	0.09
2017	Penola 11*kV* Regulator	Voltage Regulation	Upgrade existing ground mounted 2.5MVA 11*kV* regulator with three new 300A pole mounted units to mitigigate overload under normal conditions.	-	**0.92**	-	0.92
2018	Snuggery to Robe 33*kV* Voltage Support	Voltage Regulation	Establish a peak lopping generator station near Robe to improve voltages under normal conditions. Costs allow for land acquisition and construction of two 1MW generators with associated switching yard.	22.6.1	**9.94**	-	9.94
2018	Mount Schank North Substation	Land	Purchase land in preparation for new zone substation site.	-	**0.06**	-	0.06
2019	Tintinara Sub Upgrade	Land	Purchase land in preparation for new zone substation site.	-	**0.06**	-	0.06
2021	Keith to Padthaway 33*kV* Regulation	Voltage Regulation	Install a set of 200A pole top voltage regulators near Padthaway.	-	**-**	0.92	0.92
2022	Mount Schank 33*kV* Voltage Regulator	Voltage Regulation	Establish a new 20MVA ground mounted 33*kV* regulator upstream of Mount Schank township.	-	**0.04**	2.72	2.76

Table 125: South East Other Works

22.6.1 Major Project – Snuggery to Robe 33kV Voltage Support

22.6.1.1 Constraint

Robe 33kV Zone Substation is supplied from Snuggery Connection Point via a single radial 33kV sub-transmission line. The normal capacity of the sub-transmission line was exceeded by measured load in 2013/14, two years earlier than expected under 10% PoE conditions.

The sub-transmission line's normal capacity also restricts the voltage support available to the 33kV line and the two 7.6kV feeders supplied from Robe Substation. Minimum voltage levels of 89% of the required 33kV and 7.6kV system voltages were measured in 2013/14 on numerous occasions.

The forecast growth rate for the Snuggery to Robe 33kV sub-transmission line is 0.7% which is being driven by residential and holiday home growth in the South East coastal region.

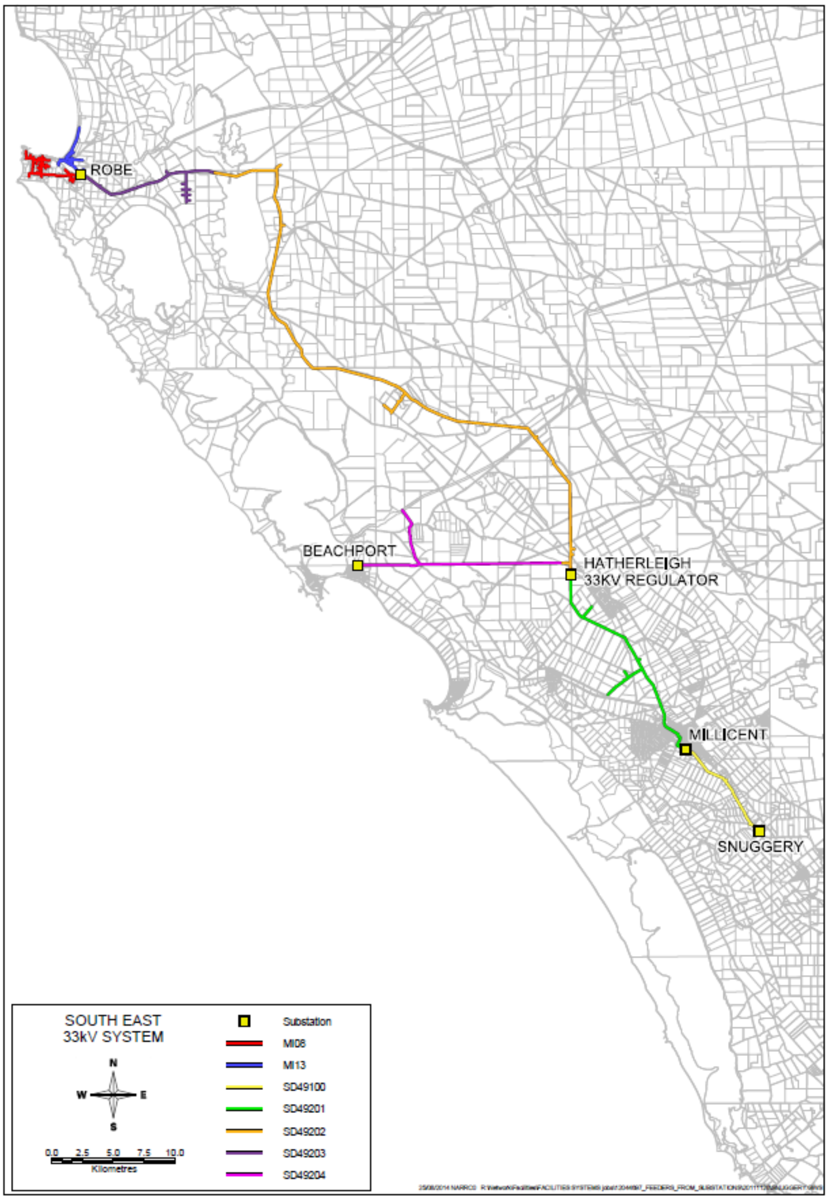


Figure 91: Locality of Snuggery Connection Point and Robe Zone Substation

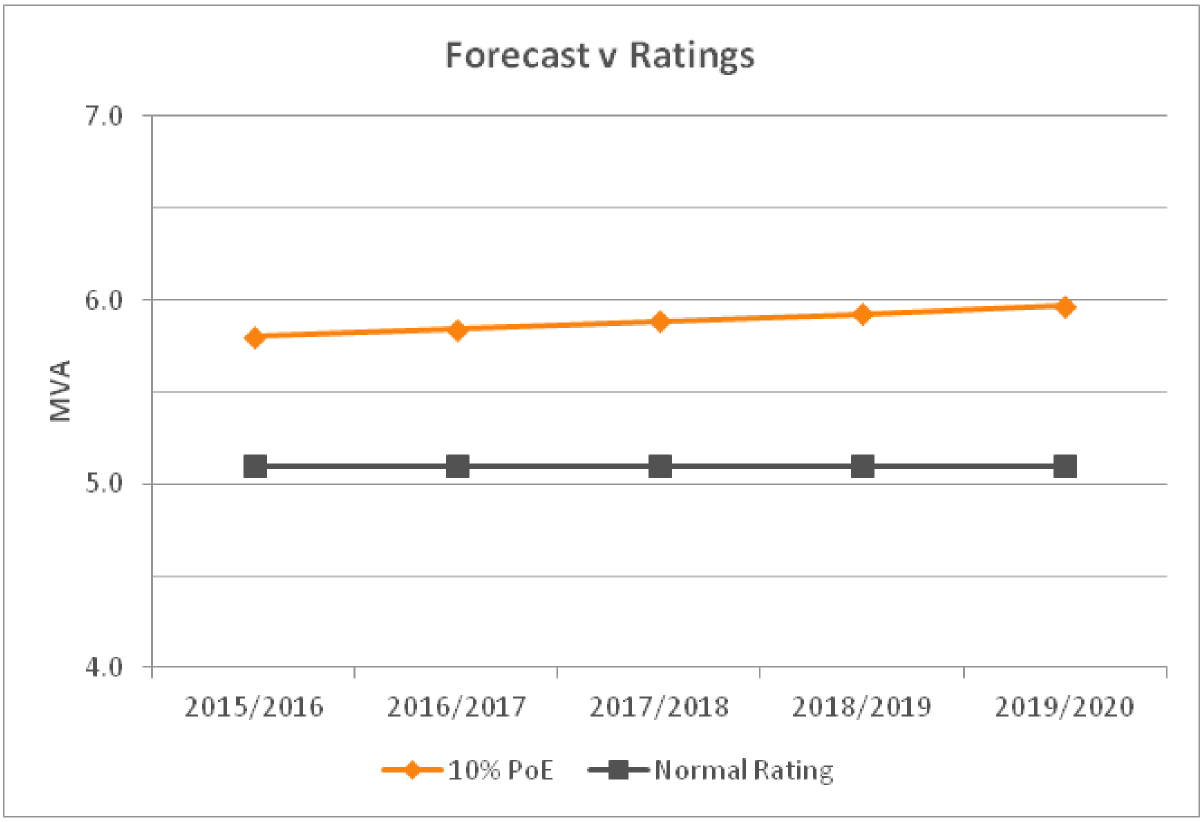


Figure 92: Snuggery to Robe 33kV Sub-transmission Line Load versus Capacity

	2015/16	2016/17	2017/18	2018/19	2019/20
Forecast MVA (10% PoE)	5.8	5.8	5.9	5.9	6.0
Normal Capacity (MVA)	5.1	5.1	5.1	5.1	5.1
Percentage Overload	114%	115%	116%	117%	118%

**Load Forecast includes impact of PV both existing and forecast. The forecast also includes the impact of energy efficiency, state economic and population growth by reconciling each asset's local growth trend with the AEMO July 2014 SA Regional forecast for the next 5 years.*

Table 126: Snuggery to Robe 33kV Sub-transmission Load Forecast

Measured load in 2013/14 was 5.7MVA.

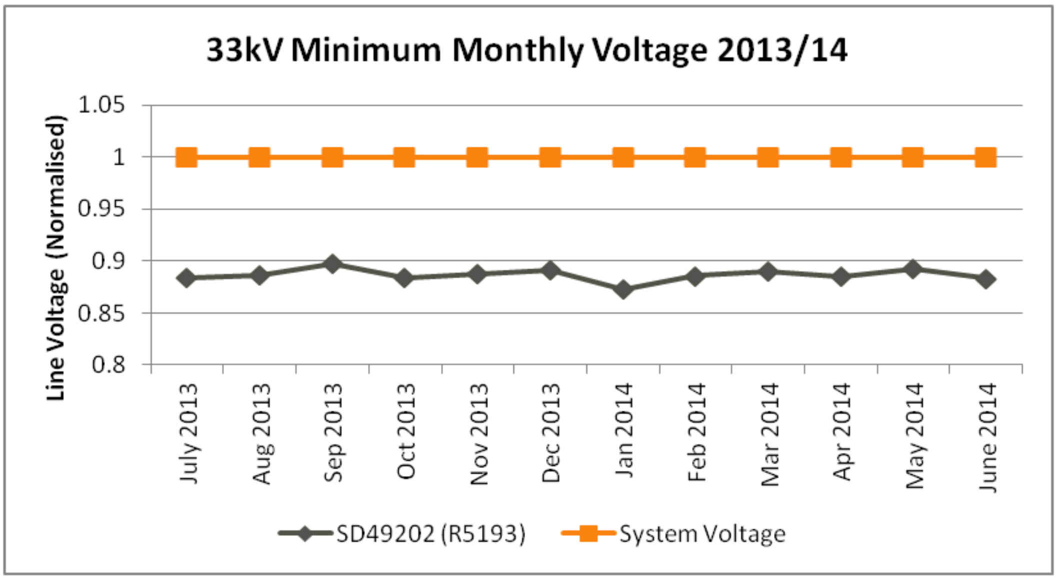


Figure 93: Snuggery to Robe 33kV Sub-transmission Line Minimum Voltage Profile

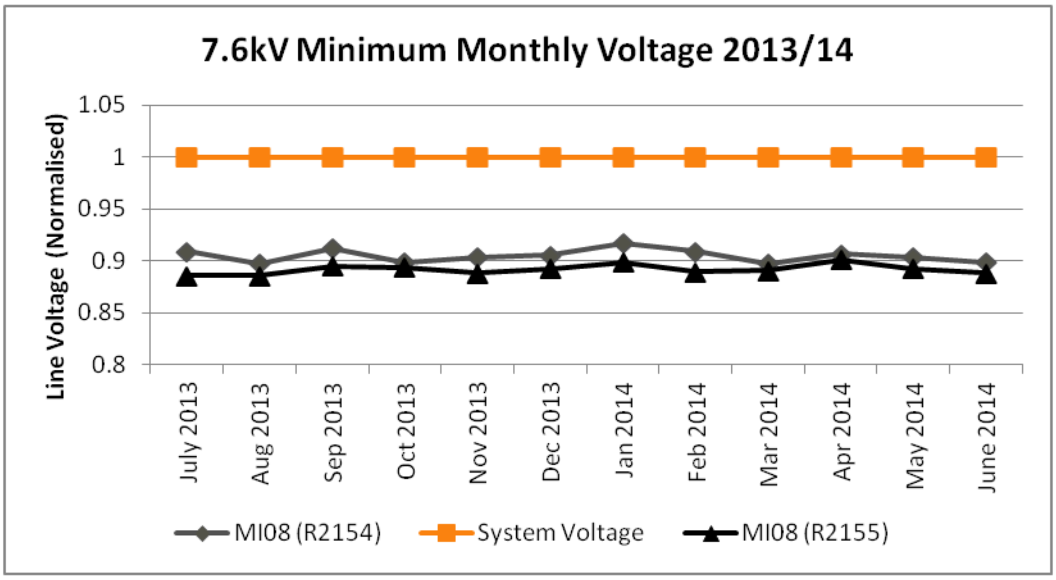


Figure 94: Robe 7.6kV Feeders Minimum Voltage Profile

22.6.1.2 Consequences for Customers

The Snuggery to Robe 33kV sub-transmission line has a normal capacity of 5.1MVA. Given a forecast in 2018/19 of 5.9MVA under 10% PoE conditions, up to 0.8MVA of load may need to be shed affecting up to 407 customers. The rating of the Snuggery-Robe 33kV line is expected to be exceeded for a total of 10 hours in 2014/15 over 3 days per annum. The 33kV and 7.6kV voltage constraint were also measured in 2013/14 on numerous occasions affecting customers directly connected to the Snuggery to Robe 33kV line (via 33/0.4kV distribution substations and SWER) and 7.6kV feeders at Robe Zone Substation.

22.6.1.3 Load Profile

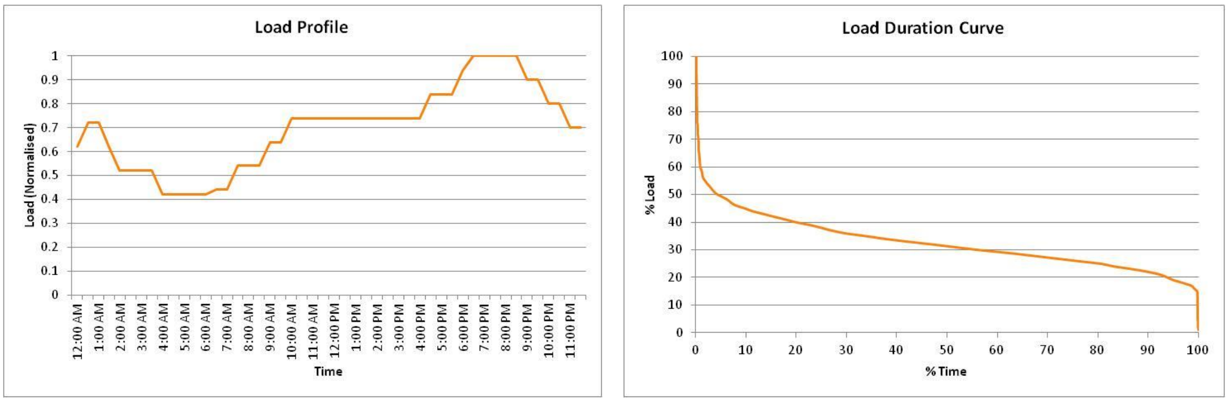


Figure 95: (a) Hatherleigh to Robe 33kV Line Load Profile, (b) Load Duration Curve

22.6.1.4 Regulatory Investment Test - Distribution

A RIT-D has not been formally performed for any of these constraints. A preliminary RIT-D analysis has been undertaken for the constraints and options outlined below. A formal RIT-D will be performed in line with the NER and AER RIT-D Guidelines prior to project commitment.

22.6.1.5 Deferral Options Considered

The following deferral option was considered:

Power Factor Correction:

- Not applicable. A 7.6kV capacitor bank has already been installed at Robe Substation for power factor correction.

22.6.1.6 Options considered to address constraint

The following options have been investigated in accordance with the AER's RIT-D Guidelines to resolve the impending thermal and voltage constraint:

Option 1:

Non Network Solution

Purchase land near Robe and construct a new 33kV peak lopping generator station to provide network support. Establish communication link between upstream Snuggery Connection Point Substation and other upstream 33kV circuit breakers or reclosers to the generator site.

Option 2:

Network Solution

Extend approximately 67km of new 33kV line from Hatherleigh Regulator Station to Robe Zone Substation including a new 33kV recloser and three phase pole top voltage regulator.

Extend approximately 5km of new 33kV line from Hatherleigh Regulator Station to Hatherleigh (MI25) SWER feeder including a new 33kV recloser.

22.6.1.7 Preferred Solution

The preferred solution, based on a preliminary RIT-D analysis is the non-network solution of using a peak lopping generator station to provide network support. The indicative cost for this project is $9.9 million, with some of this cost possibly being converted to Opex if a suitable offer is received from a third party to provide this network support as part of the RIT-D process. This project is planned for completion in 2018.

22.6.1.8 Commitment Status

SA Power Networks has not yet committed to this project. However a preliminary RIT-D analysis has been undertaken producing the results shown below. The analysis suggests that the preferred option is a non-network solution consisting of a peak lopping generator station (Option 1). A formal RIT-D and Non-Network Options Report will be published prior to the planned construction year when commitment is required for the project.

22.6.1.9 Regulatory Period Expenditure

Approximately $9.9 million is forecast to be required during the 2015-20 regulatory control period.

22.6.1.10Preliminary RIT-D Analysis

Option	Description	Net Market Benefit[34]
1	Purchase land near Robe and establish a new 33kV peak lopping generator station	-5,169,000
2	Extend approximately 67km of new 33kV line from Hatherleigh Regulator Station to Robe Substation	-5,693,000

Table 127: Snuggery to Robe RIT-D Analysis Results

23. UPPER NORTH – REGIONAL DEVELOPMENT PLAN

SA Power Networks' Upper North Region comprises the region north of Port Pirie and Bungama to Leigh Creek. *Connection point*s are located at Baroota, Bungama, Davenport West, Leigh Creek South, Mount Gunson, Neuroodla and Port Pirie. The region supports mining, agricultural communities and smelting operations.

A map of this region is shown in Figure 96 while a single line representation of the network is shown in Figure 97.

[34] Based on the use of a 6% discount rate over 10 years

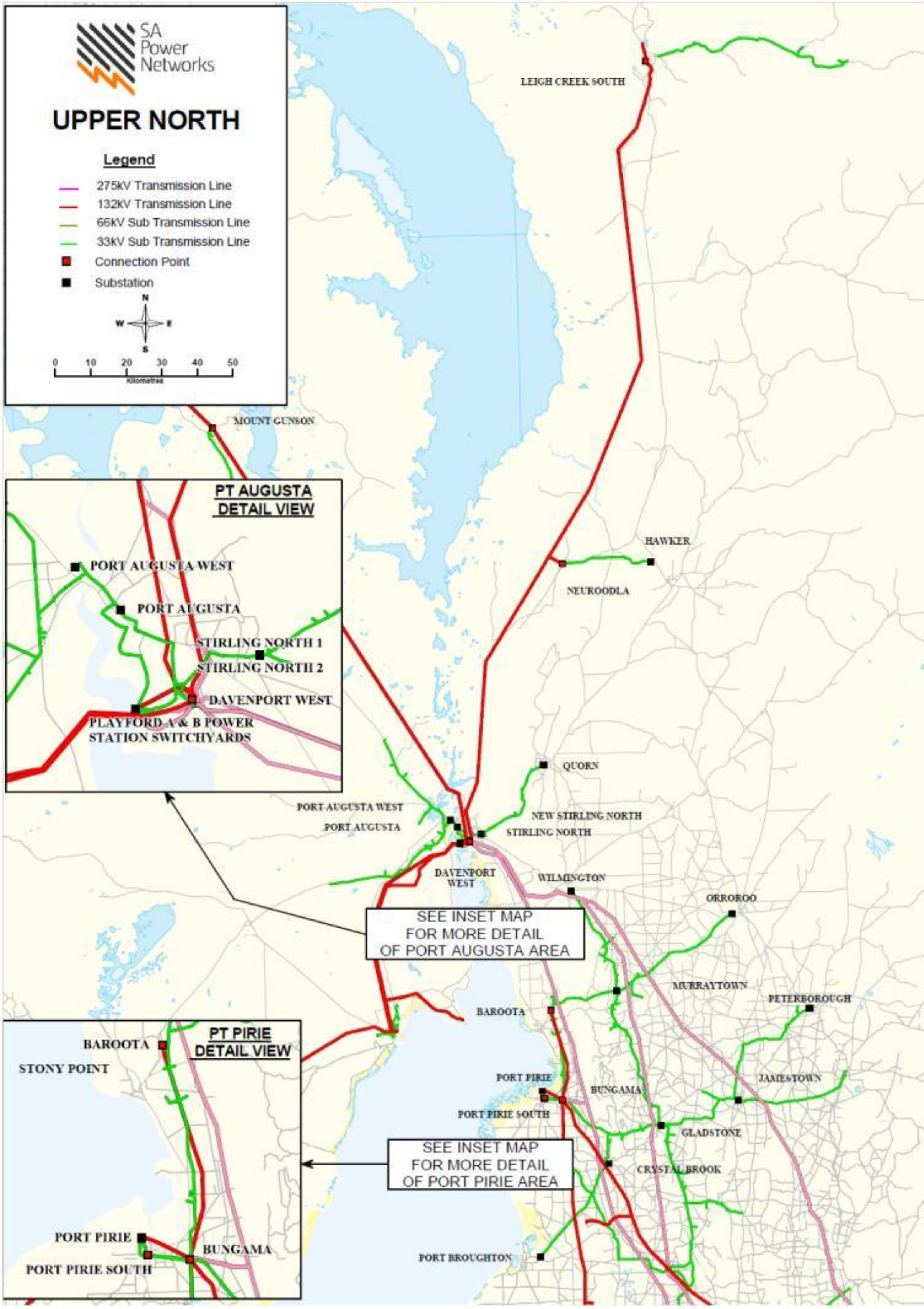


Figure 96: Upper North Map

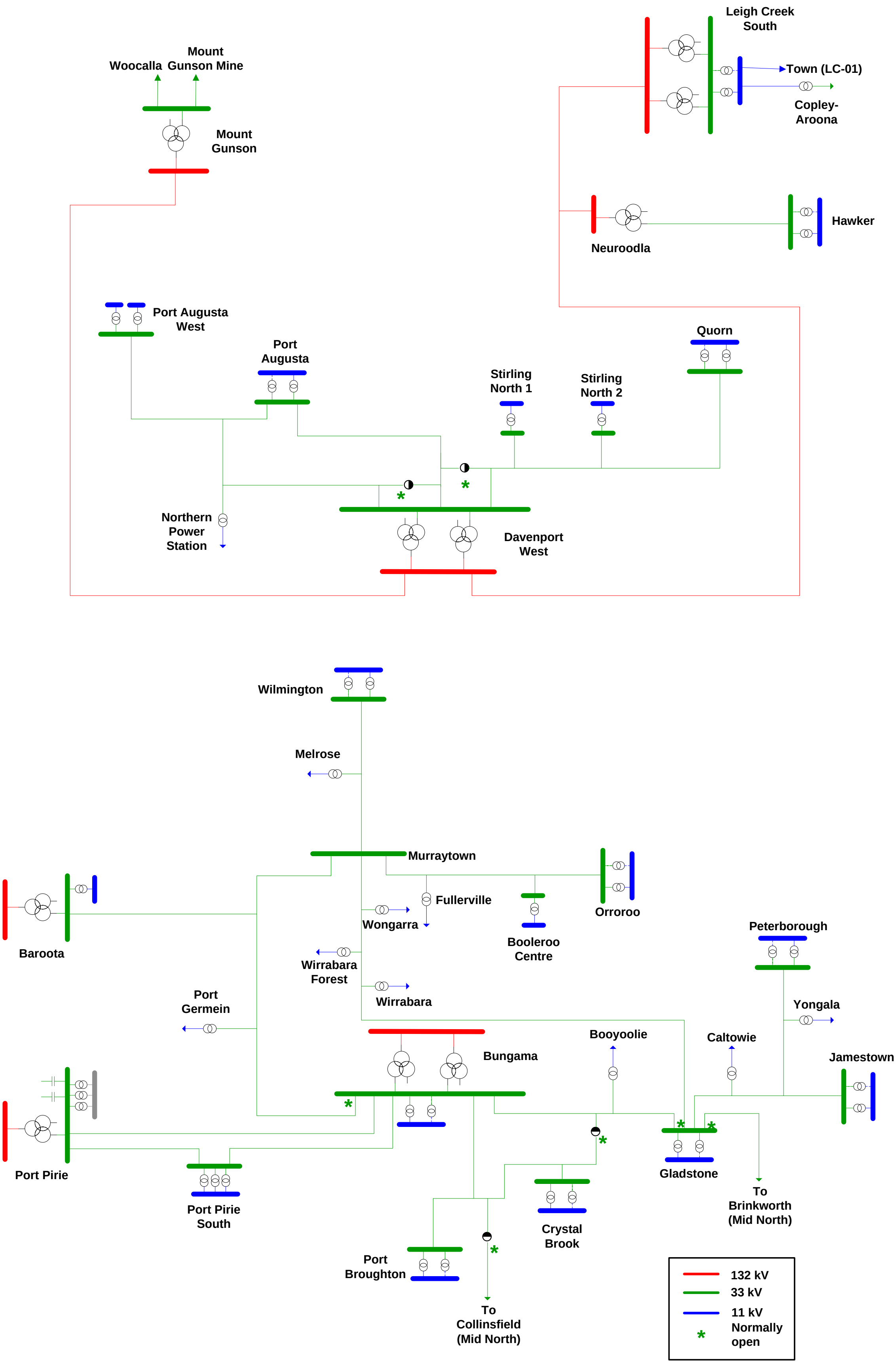


Figure 97: Upper North Single Line Diagram

23.1 Region Statistics

Table 128 indicates the general statistics for this region of the state.

Parameter	Value
No of connection points	7 (132/33*kV*)
No of zone subs	28 (33/11*kV*)
Operating voltages	33*kV* and 11*kV*
Total customers	27,800
No of residential customers (abs /%of region/% of state)	22,967 / 82.6% / 2.7%
No of commercial customers (abs /%of region/% of state)	4,833 / 17.4% / 0.6%
Area of region (km^2 / % of state)	82,817 km^2 / 36%
Length of 33kV cable (km / % of region 33kV)	0.6 km/ 0.1%
Length of 33kV conductor (km / % of region 33kV)	523 km / 99.9%
Length of 19kV cable (km / % of region 19kV)	6.9 km / 0.2%
Length of 19kV conductor (km / % of region 19kV)	4,271 km / 99.8%
Length of 11kV cable (km / % of region 11kV)	81 km / 10.6%
Length of 11kV conductor (km / % of region 11kV)	685 km / 89.4%
Installed *PV* inverter capacity (*MW* / % of state)	23.4 *MW* / 4.1%
No of feeders (abs / % urban / % rural short / % rural long)	45 / 17.8% / 6.7% / 75.6%

Table 128: Upper North Region Statistics

23.2 Development History

The Upper North region has been largely developed since the formation of the Electricity Trust of South Australia (ETSA) in 1946 through to privatisation in 1999 and the subsequent creation of ETSA Utilities / SA Power Networks.

Much of the region was originally supplied by a local generation schemes until the construction of Playford Power Station in 1954 and the construction of 132*kV* lines connecting the region to metropolitan Adelaide. In the mid 1980s, another power station in Northern Power Station was placed into service. The introduction of 275*kV* in the mid to late 1960s saw construction of 275*kV* lines from Playford Power Station to Para and Magill.

The following works have been performed within the region over the present Reset period:

Project Title	Description	Commissioning Year	Cost ($ million)
Davenport West Connection Point	Construction of 33*kV* infrastructure to integrate replacement of Playford Power Station *connection point* with new Davenport West.	2010	7.3
Port Augusta West TF2	Installation of a second 12.5 MVA 33/11*kV* transformer and associated 11*kV* switchboard.	2011	3.5
Stirling North 2	Establishment of a new X MVA 33/11*kV* zone substation to supplement the existing Stirling North site.	2011	1.0
Hughes Gap Regulator	Construction of a new 20 MVA, 33*kV* regulator station at Hughes Gap to provide voltage support to the Crystal Brook and Gladstone systems.	2013	2.6

Table 129: Recent Upper North Augmentations

23.3 Connection points and sub-transmission lines

The Upper North region contains seven *connection point*s located at Baroota, Bungama, Davenport West, Leigh Creek South, Mount Gunson, Neuroodla and Port Pirie. All are supplied at 132*kV* and connect to SA Power Networks' at 33*kV*. The Bungama and Port Pirie *connection point*s are meshed via the 33*kV* network and therefore considered as one site for forecast and planning purposes.

Three of the region's seven *connection point*s are classed as Category 4 sites by the ETC with the remainder being Category 1 sites. The criteria for Category 4 sites requires adequate transmission line and *connection point* transformer capacity to be available under N-1 conditions while for the Category 1 sites, adequate transmission line and *connection point* transformer capacity is only required to be available under N conditions.

The latest version of the ETC requires the conversion of Baroota from Category 1 to Category 2 by 1 December 2017. This change requires the provision of N-1 transformer capacity. It is expected that ElectraNet will install a second transformer in 2017, with SA Power Networks performing works at its 33*kV* yard to accommodate this additional transformer – refer to Section 23.3.1 for further details.

The region's *connection point*s have the following normal and N-1 transformer capacities:

Connection Point	ETC Category	Transformer "N" rating (MVA)	Transformer "N-1" rating (MVA)
Baroota 132/33*kV*	1	11.8	0
Bungama / Port Pirie 132/33*kV*	4G	192	140
Davenport West 132/33*kV*	4	120	60
Leigh Creek South 132/33*kV*	1	10	5
Mount Gunson 132/33*kV*	1	5	0
Neuroodla 132/33*kV*	1	5	0

Table 130: Upper North Connection Point Transformer Capacities

In accordance with the planning criteria for sub-transmission lines, SA Power Networks plans this region's sub-transmission network based on the 10% PoE forecast. The region operates 33*kV* lines at sub-transmission level. Constraints on the radial sub-transmission network and of ElectraNet's transformers are determined through modelling of the network and analysis using PSS/E and comparison of the forecast to the *connection point*'s normal and emergency ratings.

A copy of the region's *connection point* forecasts are shown in APPENDIX N – UPPER NORTH REGION FORECASTS.

Project Timing	Project Name	Limitation / Constraint	Proposed Solution	Section Ref	2015-20 Cost ($ million)	2020-25 Cost ($ million)	Total Cost ($ million)
2015	Neuroodla *Connection Point* Upgrade	Works in conjunction with asset replacement works being undertaken by ElectraNet at the *connection point*.	Install a new 33*kV* recloser at *connection point* and reconfigure an existing SWER downstream..	-	**0.25**	-	0.52
2015	Mount Gunson *Connection Point* Upgrade	Works in conjunction with asset replacement works being undertaken by ElectraNet at the *connection point*.	Upgrade existing 33*kV CB*s and associated protection scheme in conjunction with ElectraNet works.	-	**0.72**	-	1.44
2017	Baroota *Connection Point* Upgrade	ETC category change from Category 1 to Category 2 *connection point*.	ElectraNet to install second 132/33*kV* transformer. SA Power Networks in conjunction with ElectraNet works required to upgrade 33*kV* bus, associated protection and line exits to facilitate connection of new transformers to the distribution network.	23.3.1	**5.07**	-	5.07

Table 131: Upper North Connection Point Projects

The region contains two 33*kV* ties to the Mid North region. These ties are normally only operated following a contingent event in order to restore supply to the affected portion of the 33*kV* network.

Table 132 indicates those sub-transmission lines forecast to be constrained within the 2015-25 period and the proposed solution.

Section Ref	Project Name	Constrained Line(s)	Constraint Type	Constraint Description	Proposed Solution	Constraint Year	Commissioning Year	2015-20 Cost ($ million)	2020-25 Cost ($ million)	Total Cost ($ million)
-	Bungama – Port Pirie #3 33*kV* Line	Bungama – Port Pirie #1 & #2 33*kV*	N-1	Thermal overload of #1 circuit in the event of loss of #2 circuit and vice versa.	Construct a third 33*kV* circuit approx 8km between Bungama and Port Pirie.	2021	2021	**0.08**	5.37	5.45
-	Davenport West to Port Augusta Line Upgrades	Davenport West to Port Augusta #1 & #2 33*kV*	N-1	Thermal overload of #1 circuit in the event of loss of #2 circuit and vice versa.	Upgrade the existing 33*kV* line exits emanating from Davenport West *connection point* to the point of the first significant load take off.	2024	2024	**-**	5.02	5.02

Table 132: Upper North Sub-transmission Line Projects

23.3.1 Major Project – Baroota 132/33kV Connection Point

23.3.1.1 Constraint

From 1 July 2013, the ETC classifies the Baroota Connection Point as category 2 with an effective date of 1 December 2017. The Category 2 reliability classification requires ElectraNet to provide "N-1" equivalent transformer capacity sufficient to meet 100% of contracted agreed maximum demand (AMD).

Baroota 132/33kV Connection Point presently contains one 10MVA 132/33kV transformer and in order to comply with the ETC Category 2, ElectraNet plans to rebuild Baroota Connection Point consisting of two 10MVA 132/33kV transformers.

As part of this upgrade, SA Power Networks will be required to undertake work to connect to this additional infrastructure.

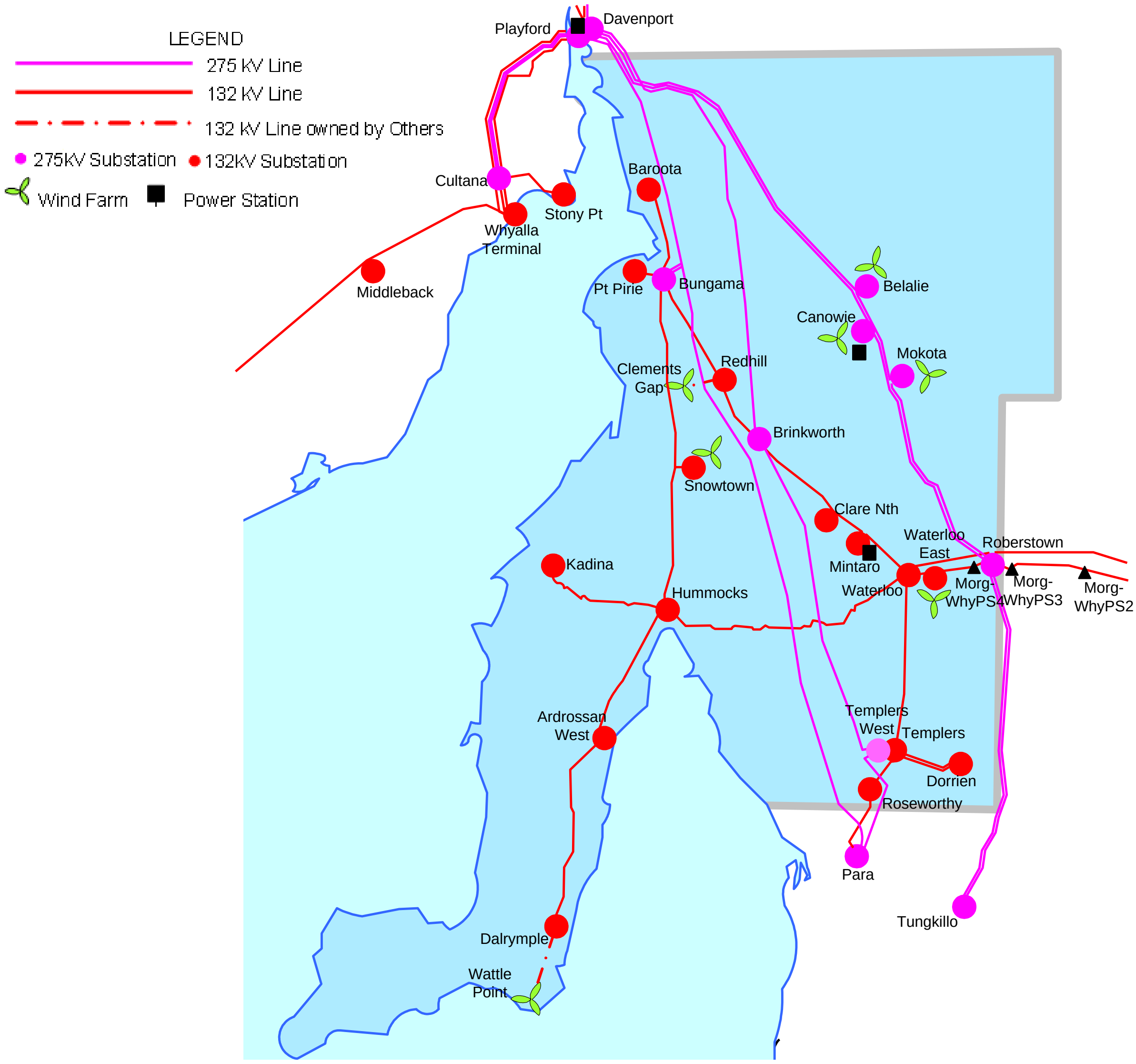


Figure 98: Locality of Baroota 132/33kV Connection Point[35]

[35] Figure sourced from ElectraNet.

23.3.1.2 Regulatory Investment Test - Transmission

A Project Specification Consultation Report (PSCR) has been published by ElectraNet for this project under the RIT-T guidelines.

23.3.1.3 Deferral Options Considered

There are no credible deferral options. Refer to RIT-T: Project Specification Consultation Report relating to the Baroota Connection Point Upgrade available from ElectraNet's website (www.electranet.com.au).

23.3.1.4 Options considered to address constraint

The following options have been investigated in accordance with the *AER*'s RIT-T Guidelines to resolve the impending constraint:

Option 1:

- Relocate and construct the 33kV yard containing two 33kV feeder at the new site for the Baroota 132/33kV Connection Point in conjunction with the ElectraNet upgrade.

Option 2:

- Rebuild the existing site by rebuilding and expanding the 33kV yard which includes installing 2 x 33kV line exits and constructing approximately 1km of 33kV overhead line.

As this project requires the performance of a RIT-T, the preferred solution must present that option with the highest net market benefit.

23.3.1.5 Preferred Solution

The preferred solution, based on the RIT-T analysis, is to relocate and construct the 33kV yard containing two 33kV line exits at the new site for the Baroota 132/33kV Connection Point in conjunction with the ElectraNet upgrade (Option 1). The indicative cost for SA Power Networks portion of this project is $5.1M. This project is planned for completion in 2017 and will solve the ETC constraint at Baroota Connection Point.

23.3.1.6 Commitment Status

This project is currently in the consultation phase of the RIT-T process and therefore not yet committed. However, it is expected that a non-network solution will not be viable and Option 1 above will proceed.

23.3.1.7 Regulatory Period Expenditure

Approximately $5.1 million is forecast to be required during the 2015-20 period.

23.4 Zone substations

Electricity is supplied throughout the Upper North region by 28, 33/11*kV* zone substations.

Forecasts for the region's zone substations are shown in APPENDIX N – UPPER NORTH REGION FORECASTS.

The following zone substation constraints have been identified within the 2015-25 period covered by this *AMP*:

Project Timing	Project Name	Limitation / Constraint	Proposed Solution	Section Ref	2015-20 Cost ($ million)	2020-25 Cost ($ million)	Total Cost ($ million)
2021	Bungama 33/11*kV* Upgrade	Overload of Bungama 33/11*kV* zone substation under normal conditions.	Replace existing two 0.5MVA transformers with a new 3MVA padmounted unit.	-	**0.07**	1.59	1.66
2022	Jamestown Substation Upgrade	Overload of Jamestown zone substation under normal conditions.	Upgrade the existing two 1.5MVA transformers with new 3.8MVA units.	-	-	3.83	3.83
2022	Port Broughton Substation Upgrade	Overload of Port Broughton zone substation under normal and contingent conditions.	Construct a new zone substation closer to existing township consisting of a single 12.5MVA transformer and 11*kV* switchboard.	-	-	7.92	7.92
2023	Crystal Brook Substation Upgrade	Overload of Crystal Brook zone substation under normal conditions.	Upgrade site using two 3.8MVA transformers and associated 11*kV* reclosers.	-	-	3.83	3.83
2025	Orroroo Sub Upgrade	Overload of Orroroo zone substation under normal conditions.	Upgrade the existing two 1MVA transformers with a new 3MVA padmounted unit.	-	-	0.57	1.13
2025	Port Pirie South Cap Banks	Overload of Port Pirie South zone substation under contingent conditions.	Install a 6MVAr, 11*kV* capacitor bank to reduce reactive load and defer major substation augmentation.	-	-	0.38	0.77
2025	Wilmington Sub Upgrade	Overload of Wilmington zone substation under normal conditions.	Upgrade the existing two 0.5MVA transformers with a new 2.5MVA unit and upgrade existing 11*kV* regulator and 11*kV* recloser.	-	-	0.53	1.06

Table 133: Upper North Zone Substation Constraints

23.5 Feeders

Customers are supplied from SA Power Networks Distribution System via 11*kV* feeders, which are supplied from the zone substations. These feeders are extended and upgraded as required to meet customer demand, customer connection requests and to maintain quality of supply.

During the forthcoming 2015-20 Reset period, the following feeder constraints have been identified:

Project Timing	Project Name	Limitation / Constraint	Proposed Solution	Section Ref	2015-20 Cost ($ million)	2020-25 Cost ($ million)	Total Cost ($ million)
2016	Jamestown Substation – 11*kV* feeder exit upgrade	Overload of Jamestown 11*kV* feeder under normal conditions.	Upgrade approximately 200m of existing overhead feeder exit conductor.	-	**0.14**	-	0.14
2016	Orroroo Recloser Upgrade	Overload of existing trip coil (125%) for normal conditions	Upgrade the Orroroo Recloser to prevent trip coil overload for N	-	**0.15**	-	0.15
2017	Gladstone Recloser Upgrade	Overload of existing recloser's trip coil following load transfer to feeder under contingent conditions.	Upgrade the existing hydraulic recloser with a new 11*kV* recloser to increase rating.	-	**0.15**	-	0.15
2017	Huddleston Recloser Upgrade	Overload of existing recloser's trip coil following load transfer to feeder under contingent conditions.	Upgrade the existing hydraulic recloser with a new 11*kV* recloser to increase rating.	-	**0.15**	-	0.15
2018	Peterborough South Recloser Upgrade	Overload of existing recloser's trip coil following load transfer to feeder under contingent conditions.	Upgrade the existing hydraulic recloser with a new 11*kV* recloser to increase rating.	-	**0.15**	-	0.15

Table 134: Upper North Feeder Constraints

23.6 Land and Other Works

The following land purchases and additional works within the region have been identified within the 2015-20 period.

Project Timing	Project Name	Work Category	Proposed Solution	Section Ref	2015-20 Cost ($ million)	2020-25 Cost ($ million)	Total Cost ($ million)
2020	Jamestown Substation Upgrade	Land	Purchase additional land to enable upgrade of the existing Jamestown zone substation.	-	**0.02**	0.02	0.04
2020	Port Broughton Substation Upgrade	Land	Purchase additional land to enable upgrade of the existing Port Broughton zone substation.	-	**0.04**	0.04	0.08
2021	Jamestown 33*kV* Regulator	Voltage Regulation	Install a set of two 200A 33*kV* voltage regulators near Jamestown on the 33*kV* line to Peterborough to rectify 33*kV* and subsequent 11*kV* voltage issues at Peterborough zone substation.	-	**-**	0.77	0.77

Table 135: Upper North Other Works

24. YORKE PENINSULA – REGIONAL DEVELOPMENT PLAN

SA Power Networks' Yorke Peninsula Region includes the area west of Paskeville to Wallaroo and south to Marion Bay at the foot of Yorke Peninsula. There are three *Connection point*s within the Yorke Peninsula region located at Dalrymple, Ardrossan West and Kadina East.

The region is dominated by agriculture (predominantly wheat farming) and tourism, with many of the peninsula's towns being popular holiday home areas.

A map of this region is shown in Figure 99 while a single line representation of the network is presented in Figure 100.

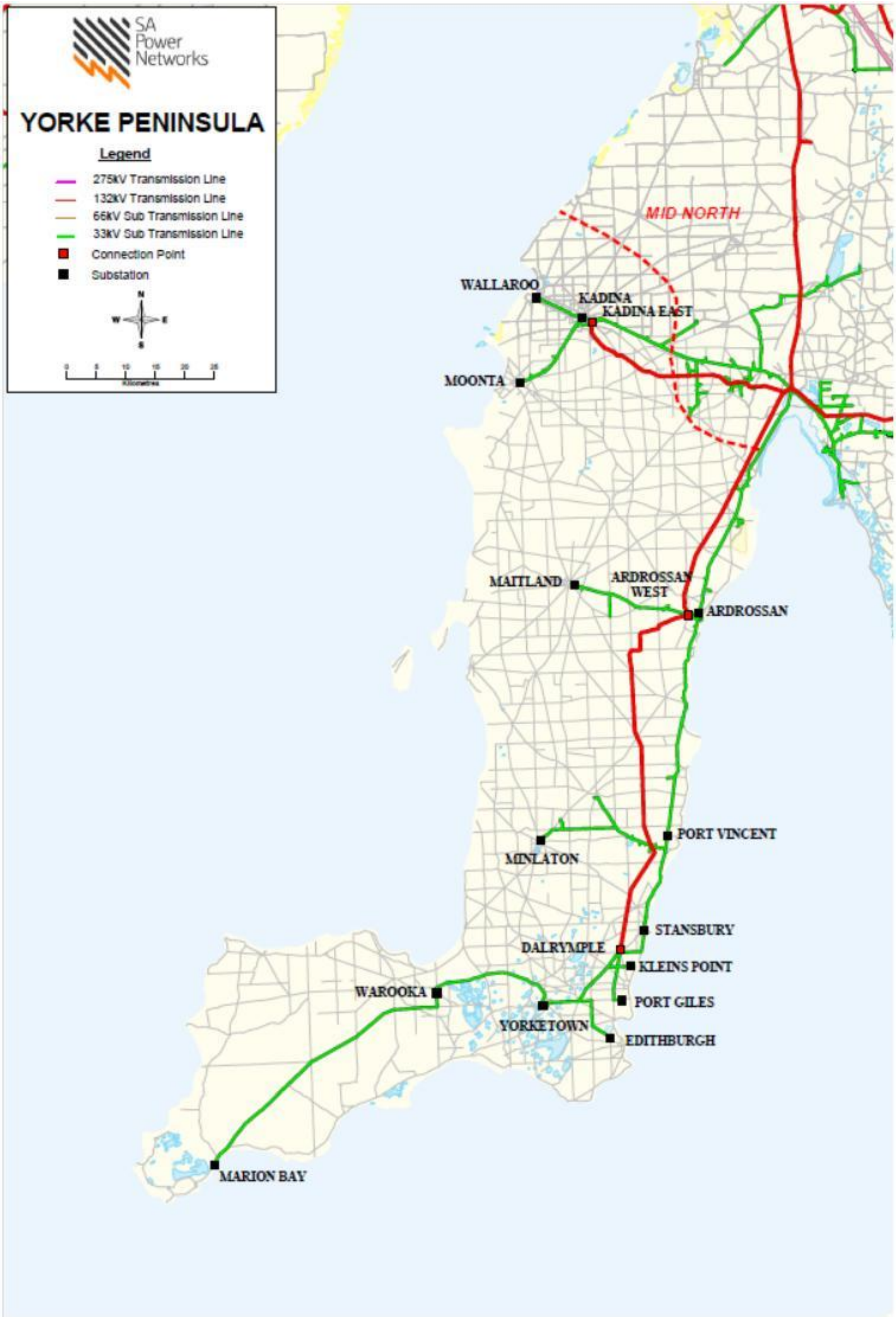


Figure 99: Yorke Peninsula Map

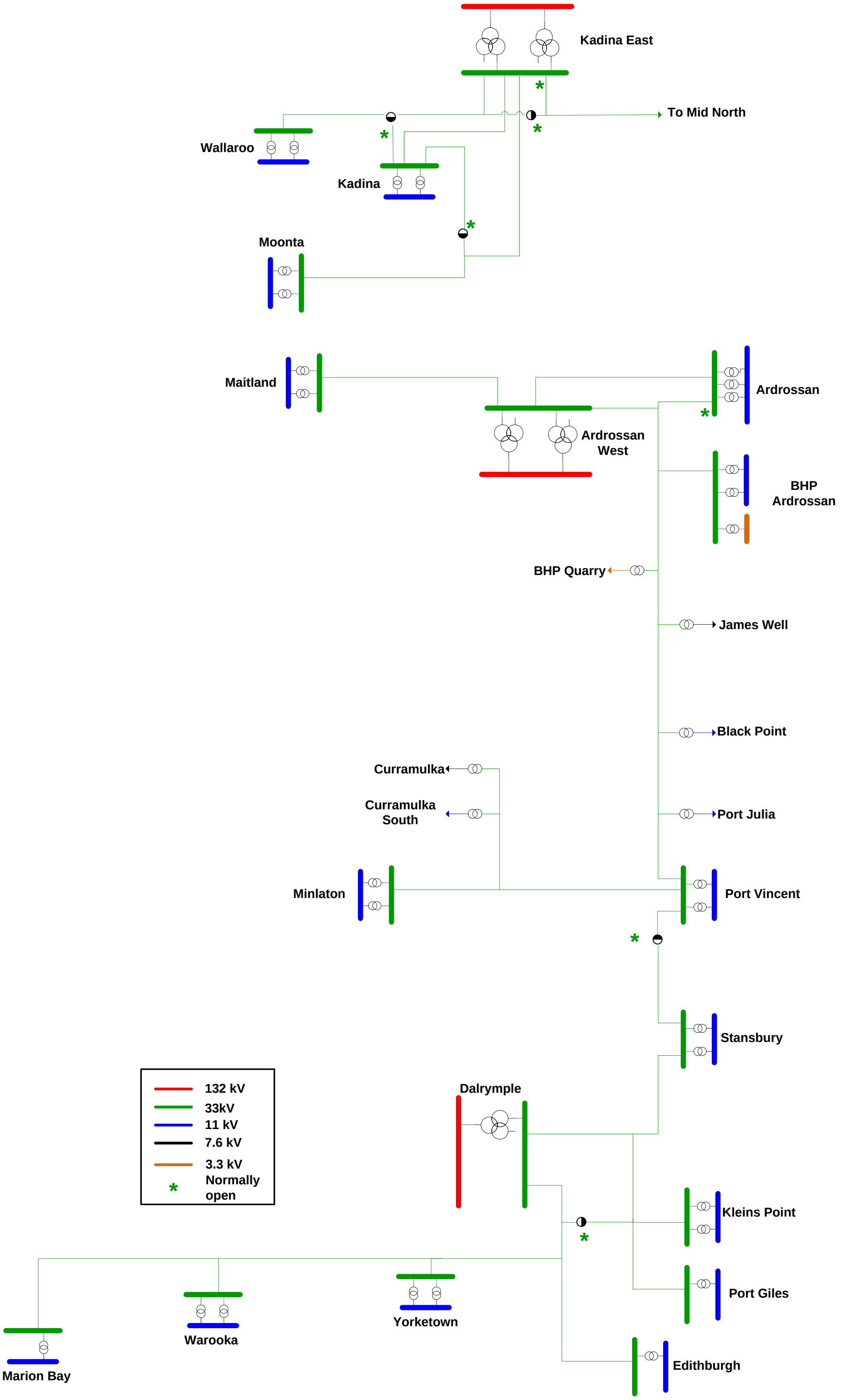


Figure 100: Yorke Peninsula Single Line Diagram

24.1 Region Statistics

Table 136 indicates the general statistics for this region of the state.

Parameter	Value
No of connection points	3 (132/33*kV*)
No of zone subs	22 – 18 (33/11*kV*), 2 (33/7.6*kV*), 2 (33/3.3*kV*)
Operating voltages	33*kV*, 11*kV*, 7.6*kV* and 3.3*kV*
Total customers	20,426
No of residential customers (abs /%of region/% of state)	17,657 / 86.4% / 2.1%
No of commercial customers (abs /%of region/% of state)	2,769 / 13.6% / 0.3%
Area of region (km^2 / % of state)	6,552 km^2 / 2.8%
Length of 33kV cable (km / % of region 33kV)	1.8 km/ 0.4%
Length of 33kV conductor (km / % of region 33kV)	431 km / 99.6%
Length of 19kV cable (km / % of region 19kV)	8.3 km / 0.5%
Length of 19kV conductor (km / % of region 19kV)	1,836 km / 99.5%
Length of 11kV cable (km / % of region 11kV)	79.4 km / 12%
Length of 11kV conductor (km / % of region 11kV)	587 km / 88%
Length of 7.6kV cable (km / % of region 7.6kV)	0 km / 0%
Length of 7.6kV conductor (km / % of region 7.6kV)	7.4 km / 100%
Installed *PV* inverter capacity (*MW* / % of state)	16.5 *MW* / 2.9%
No of feeders (abs / % urban / % rural short / % rural long)	30 / 0% / 23.3% / 76.7%

Table 136: Yorke Peninsula Region Statistics

24.2 Development History

The Yorke Peninsula region has been largely developed since the formation of the Electricity Trust of South Australia (ETSA) in 1946 through to privatisation in 1999 and the subsequent creation of ETSA Utilities / SA Power Networks.

Prior to 1953, the region was primarily supplied by local generation schemes which were purchased by ETSA from the local authorities while the 33*kV* network originating from Hummocks in the Mid North region was constructed. The majority of the 33*kV* network serving the region was constructed largely between 1950 and 1953.

The region's first connection to the 132*kV* transmission network occurred in 1973 with the construction of the Hummocks to Ardrossan West line with the Kadina East and Dalrymple *connection points* being commission in 1988 and 1992 respectively.

The following works have been performed within the region over the present Reset period:

Project Title	Description	Commissioning Year	Cost ($ million)
Kadina East *Connection Point* Upgrade	Upgrade of 33*kV* infrastructure to integrate installation of a second 132/33*kV* transformer at Kadina East in accordance with the ETC category change.	2011	6.2
Ardrossan West *Connection Point* Upgrade	Upgrade of 33*kV* infrastructure to integrate installation of a second 132/33*kV* transformer at Ardrossan West in accordance with the ETC category change.	2012	4.9
Stansbury Sub Upgrade	Installation of a new 2.5 MVA 33/11*kV* transformer to replace the existing two 0.5 MVA transformers.	2011	1.2
Warooka Sub Upgrade	Installation of a second 2.5 MVA 33/11*kV* transformer.	2012	1.0

Table 137: Recent Yorke Peninsula Augmentation Projects

24.3 Connection points and sub-transmission lines

The Yorke Peninsula region contains three *connection point*s located at Ardrossan West, Dalrymple and Kadina East. All are supplied at 132*kV* and connect to SA Power Networks' at 33*kV*.

Two of the region's *connection point*s are classed as Category 2 sites by the ETC with the remainder being a Category 1 site. The criteria for Category 2 sites requires adequate transmission line capacity for N conditions with *connection point* transformer capacity to be available under N-1 conditions while for the Category 1 sites, adequate transmission line and *connection point* transformer capacity is only required to be available under N conditions.

The latest version of the ETC requires the conversion of Dalrymple from Category 1 to Category 2 by 1 December 2016. This change requires the provision of N-1 transformer capacity. It is expected that ElectraNet will install a second transformer in 2016, with SA Power Networks performing works at its 33*kV* yard to accommodate this additional transformer – refer to 24.3.1 for further details.

The region's *connection point*s have the following normal and N-1 transformer capacities:

Connection Point	ETC Category	Transformer "N" rating (MVA)	Transformer "N-1" rating (MVA)
Ardrossan West 132/33*kV*	1	62	32.5
Dalrymple 132/33*kV*	4G	31	0
Kadina East 132/33*kV*	4	120	60

Table 138: Yorke Peninsula Connection Point Transformer Capacities

In accordance with the planning criteria for sub-transmission lines, SA Power Networks plans this region's sub-transmission network based on the 10% PoE forecast. The region operates 33*kV* lines at sub-transmission level. Constraints on the radial sub-transmission network and of ElectraNet's transformers are determined through modelling of the network and analysis using PSS/E and comparison of the forecast to the *connection point*'s normal and emergency ratings.

A copy of the region's *connection point* forecasts are shown in Appendix O – Yorke Peninsula Region Forecasts.

Project Timing	Project Name	Limitation / Constraint	Proposed Solution	Section Ref	2015-20 Cost ($ million)	2020-25 Cost ($ million)	Total Cost ($ million)
2016	Dalrymple *Connection Point* Upgrade	ETC category change from Category 1 to Category 2 *connection point*.	ElectraNet to install second 132/33*kV* transformer. SA Power Networks in conjunction with ElectraNet works required to upgrade 33*kV* bus, associated protection and line exits to facilitate connection of new transformers to the distribution network.	24.3.1	**4.55**	-	4.60

Table 139: Yorke Peninsula Connection Point Projects

The region contains two 33*kV* ties to the Mid North region at Kadina East (to Paskeville) and at Ardrossan zone substation (to Hummocks). These ties are normally only operated following a contingent event in order to restore supply to the affected portion of the 33*kV* network. No sub-transmission lines within the region are forecast to be constrained within the 2015-25 period.

24.3.1 Major Project – Dalrymple 132/33kV Connection Point

24.3.1.1 Constraint

From 1 July 2013, the ETC classifies Dalrymple Connection Point as category 2 with an effective date of 1 December 2016. Category 2 requires ElectraNet to provide “N-1” equivalent transformer capacity sufficient to meet 100% of contracted agreed maximum demand (AMD).

Dalrymple 132/33kV Connection Point presently contains one 25MVA 132/33kV transformers and in order to comply with the ETC Category 2, ElectraNet proposes to upgrade the site by installing a second 25MVA 132/33kV transformer.

As part of this upgrade, SA Power Networks will be required to undertake work to enable this additional capacity to connect to the distribution network.

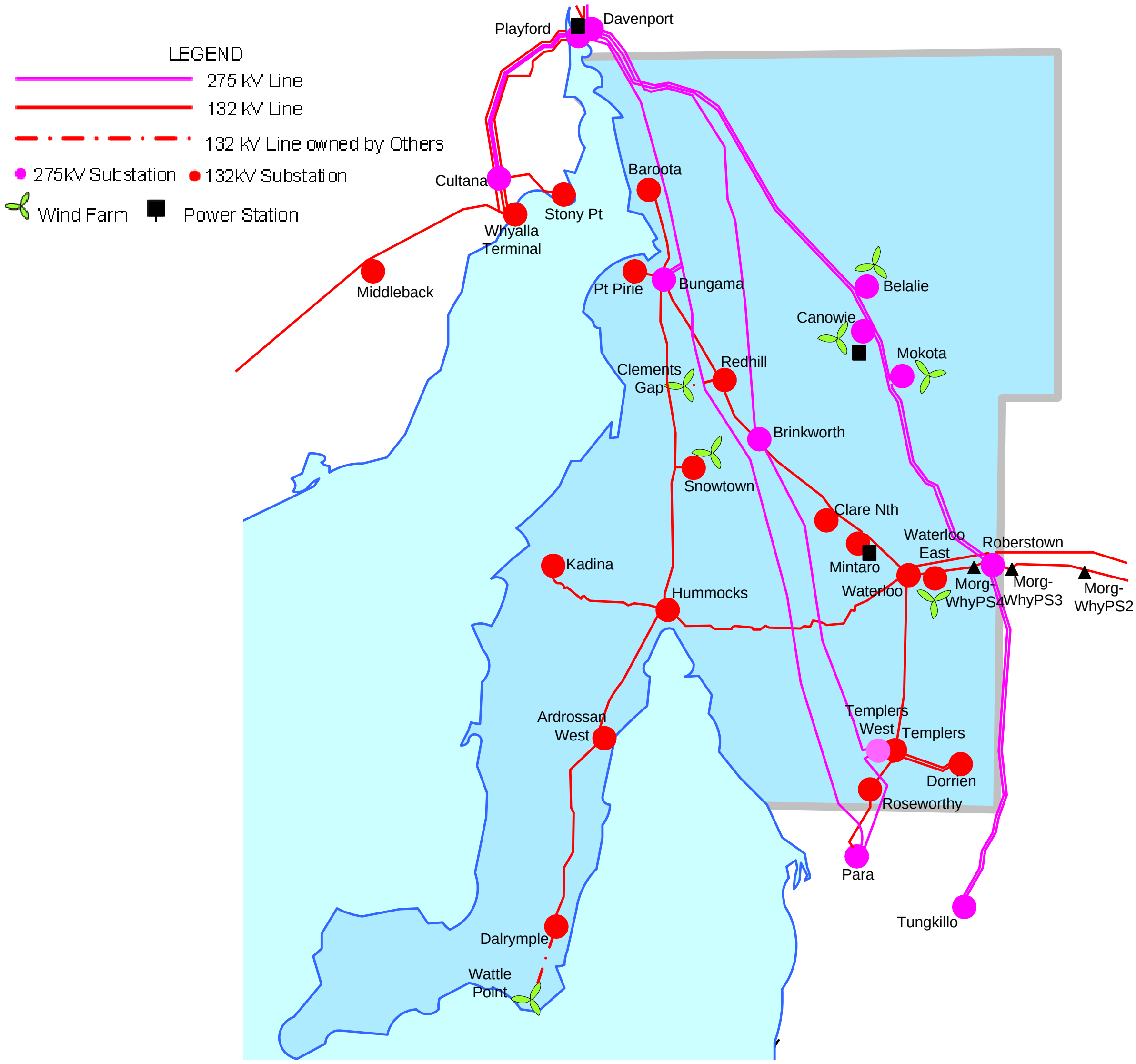


Figure 101: Locality of Dalrymple 132/33kV Connection Point[36]

[36] Figure sourced from ElectraNet

24.3.1.2 Regulatory Investment Test - Transmission

A Project Specification Consultation Report (PSCR) and Project Assessment Conclusions Report (PACR) have been published by ElectraNet for this project in accordance with the NER and AER's RIT-T guidelines.

24.3.1.3 Deferral Options Considered

There are no credible deferral options. Refer to the RIT-T PSCR and PACR available from ElectraNet's website (www.electranet.com.au).

24.3.1.4 Options considered to address constraint

The following options have been investigated in accordance with the *AER*'s RIT-T Guidelines to resolve the impending constraint:

Option 1:

- Upgrade the 33kV switchgear at Dalrymple 132/33kV Connection Point in conjunction with the ElectraNet upgrade at the existing site.

Option 2:

- Relocate SA Power Networks' equipment to a new site approximately 1km from existing site and rebuild 33kV switchgear plus one new 33kV feeder exit in conjunction with the ElectraNet upgrade.

As this project requires a RIT-T, the preferred solution chosen must represent the option with the highest net market benefit.

24.3.1.5 Preferred Solution

The preferred solution, based on the RIT-T analysis, is to upgrade the 33kV switchgear at Dalrymple 132/33kV Connection Point in conjunction with ElectraNet's augmentation works (Option 1). The indicative cost for SA Power Networks' portion of this project is $4.6 million. In conjunction with this project, SA Power Networks proposes to install a new 33kV line exit at Dalrymple. This project is planned for completion in 2016 and will meet the ETC's reliability category requirements specified for Dalrymple Connection Point.

24.3.1.6 Commitment Status

The RIT-T: Project Assessment Conclusions Report has been published for this project and the preferred solution has been committed for construction in 2016.

24.3.1.7 Regulatory Period Expenditure

Approximately $6 million is forecast to be required during the 2015-20 period.

24.4 Zone substations

Electricity is supplied throughout the Yorke Peninsula region by 18, 33/11*kV*, one 33/7.6*kV* and two 33/3.3*kV* zone substations. The two 33/3.3*kV* zone substations supply single customers.

Forecasts for the region's zone substations are shown in Appendix O – Yorke Peninsula Region Forecasts.

The following zone substation constraints have been identified within the 2015-25 period covered by this *AMP*:

Project Timing	Project Name	Limitation / Constraint	Proposed Solution	Section Ref	2015-20 Cost ($ million)	2020-25 Cost ($ million)	Total Cost ($ million)
2019	Curramulka 33/7.6*kV* Transformer Station Upgrade	Overload of Curramulka 33/7.6*kV* zone substation under normal conditions.	Replace existing 0.2MVA pole mounted transformer with a new 0.5MVA unit.	-	**0.80**	-	0.80
2021	Port Vinvent South Mod 3 Substation (new)	Overload of Port Vincent zone substation under normal conditions.	Establish a new zone substation on new site south of Port Vincent consisting of a new 3MVA 33/11*kV* transformer and associated 11*kV* reclosers. Extend existing 33*kV* network approx 2km to proposed new site.	-	**0.06**	2.12	2.18

Table 140: Yorke Peninsula Zone Substation Constraints

24.5 Feeders

Customers are supplied from SA Power Networks Distribution System via 11*kV* and 7.6*kV* feeders, which are supplied from the zone substations. These feeders are extended and upgraded as required to meet customer demand, customer connection requests and to maintain quality of supply.

During the forthcoming 2015-20 Reset period, no feeder constraints have been identified.

24.6 Land and Other Works

The following land purchases and additional works within the region have been identified within the 2015-20 period.

Project Timing	Project Name	Work Category	Proposed Solution	Section Ref	2015-20 Cost ($ million)	2020-25 Cost ($ million)	Total Cost ($ million)
2017	Dalrymple – Marion Bay 33*kV* Voltage Regulation	Voltage Regulation	Install a set of two 200A 33*kV* voltage regulators near Yorketown zone substation to rectify 33*kV* and subsequent 11*kV* voltage issues at Yorketown zone substation.	-	**0.55**	-	0.55
2019	Port Vinvent South Mod 3 Substation (new)	Land	Purchase of land to enable construction of new zone substation south of Port Vincent	-	**0.07**	-	0.07

Table 141: Upper North Other Works

25. QUALITY OF SUPPLY AND LOW VOLTAGE NETWORK DEVELOPMENT PLAN

25.1 Summary

The Quality of Supply (QoS) Team forms part of Network Planning Branch within Network Management Division. The QoS team's principle aim is to ensure that customer and network supply quality complies with relevant Australian Standards, statutory requirements (eg EDC) and general electricity industry and SA Power Networks' supply standards.

Key themes for this AMP are:

1. the collection of greater levels of transformer monitoring data to assist in LV network planning;
2. improving voltage regulation;
3. enabling a two way power flow for new customer and network technologies; and
4. managing those existing assets associated with the LV network and ensuring they are operated within acceptable limits.

The customer's expectation is that SA Power Networks knows the condition of the LV network at any time. Similarly, these expectations are changing with the rapid uptake in PV generation. Network upgrades to support a two-way network were universally supported by customers at stakeholder workshops and surveys conducted by SA Power Networks.

The QoS Team has two principal areas of work:

1. Operationally QoS ensures customer's quality of supply enquiries are responded to in a timely manner. In 2012/13 there were 2,555 customer enquiries referred to QoS for follow up and remediation solutions – refer to Figure 102 below showing the number of customer enquiries since July 2004.
2. Low voltage network planning - mainly aimed at ensuring the LV network, consisting of 72,500 distribution transformers and associated mains and services have adequate capacity and the power quality complies with our Supply Standards to serve SA Power Network's 840,000 customers.

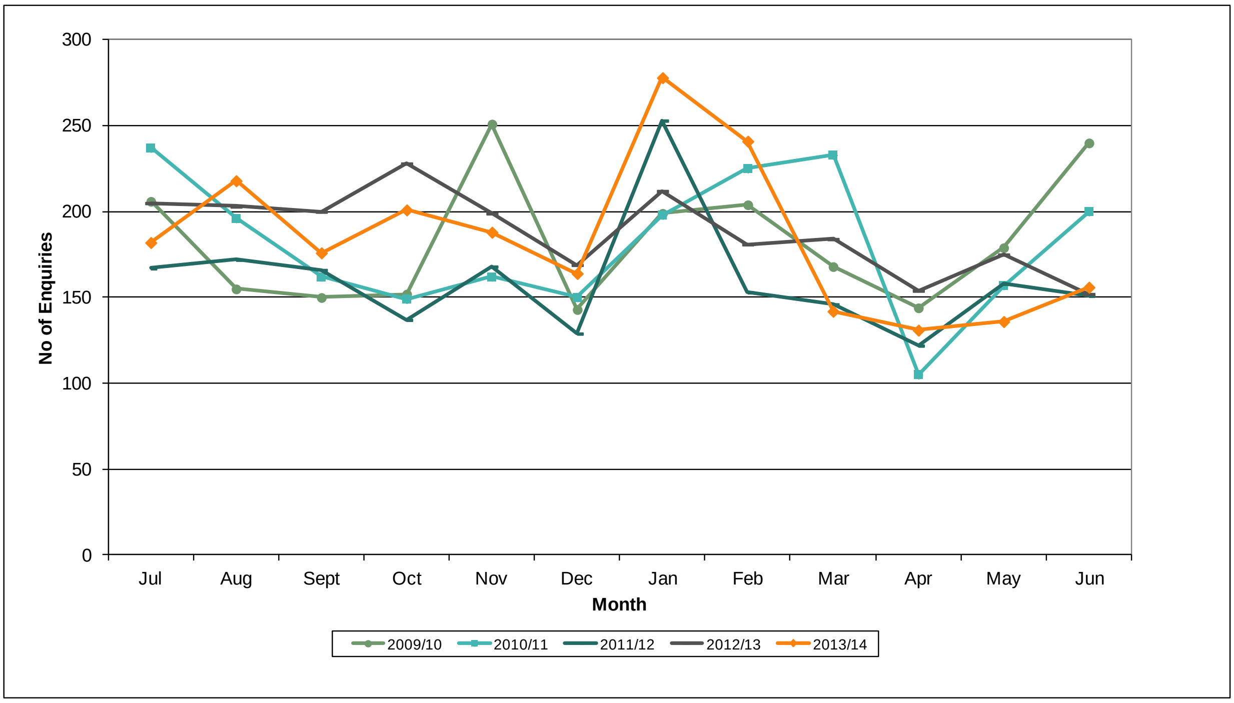


Figure 102: Annual QoS Enquiries Per Month

Compliance with Quality of Supply Standards includes resolving issues with steady state voltage levels, voltage fluctuations, flicker, voltage dips, voltage unbalance, voltage differences between neutral - earth (including shock reports) and harmonic content of voltage and current waveforms.

Adequately funded management of the LV network is essential to ensure customer's can connect both their loads, such as air-conditioners and their embedded generation, such as solar PV systems to the distribution network. The low voltage network must be prepared for the adoption of future technologies such as the connection of energy storage systems, electric vehicles and other controllable loads. To adequately manage the LV network, in addition to SCADA data on the high voltage network, QoS proposes to install permanent metering equipment on targeted assets within the LV and SWER network (presently installed on less than 3% of all distribution transformers). To date, no significant expenditure on monitoring has occurred within the 2010-2015 period. The aim is to improve visibility of the LV and SWER networks by continuously monitoring transformer loads, voltage regulator status to assist us in maintaining customer's voltage levels within Standards, by enabling SCADA on voltage regulation equipment at both substations and mid-lines devices and where appropriate, installing new HV and LV regulators.

This AMP discusses the business as usual expenditure required to meet our existing workloads and obligations to respond to customer equiries and pro-actively forecast and implement changes to the network to ensure these network capabilities are maintained.

In addition, to business as usual expenditure (based on historical expenditure), QoS proposes additional capital and operating expenditure to implement much needed long term distribution transformer (power quality) and voltage regulation monitoring. This additional expenditure is required to ensure our regulatory obligations continue to be met in all parts of the network, ensure timely capital expenditure and facilitate the provision of a two way power network to enable new customer side technologies.

This submission can be read in conjunction with four relevant business cases:

1. LV Monitoring Business Case;

2. Voltage Regulation Business Case;
3. Remote Voltage Control Business Case; and
4. Tariff and Metering Business Case

The total annual average capital expenditure within this submission for QoS activities is $15.17 million per annum resulting in a total spend over the 2015-20 regulatory period of $75.87 million – these figures are in $2013 (real) and inclusive of all overheads.

In addition to the details contained within the business cases referred to above, we are proposing a new strategic initiative to enable power quality data from customer smart meters as a long-term platform to extend power quality monitoring beyond the distribution substation's transformer, to the extremeties of the LV network where customers are connected. This initiative is described in detail in another document, the Tariff and Metering business case.

25.1.1 2015 - 2020 LV Network Capacity Plan

Table 142 below summarises thosee components making up the total plan. These components are detailed further within the body of this AMP. As far as possible, historical average costs expressed in 2013 dollars and inclusive of overheads, have been used to determine the forecast expenditure required over the next five years. No allowance for inflation has been included in this data presented.

Submission Components		2015/2016	2016/2017	2017/2018	2018/2019	2019/2020
QoS Projects (Major and Minor Work)	Based on Historic LV, Distribution Transformers and QoS activities.	8.39	8.39	8.39	8.39	8.39
QoS Projects (QSI Minor works and miscellaneous)		0.36	0.36	0.36	0.36	0.36
QoS Team (FTE) Labour		1.30	1.30	1.30	1.30	1.30
QoS Team Supplementary Labour (Design, Analysis, Engineering)		0.75	0.75	0.75	0.75	0.75
PowerMonic replacement tester program		0.26	0.26	0.26	0.26	0.26
LV & Distribution Transformers (QoS) Total		***11.06***	***11.06***	***11.06***	***11.06***	***11.06***
LV regulation (SVR/LVR - PV management)	Additional Expenditure for Two Way Network	0.42	0.53	0.42	0.42	0.42
HV regulation (PQ visibility, voltage control, Code compliance)		0.86	1.40	1.89	2.11	2.10
Long term transformer monitors (PQ visibility, Code compliance)		1.03	1.71	1.76	1.76	1.76
Additional HV regulation reverse power flow remediation		0.22	0.44	0.44	0.44	0.44
Two Way Network Total		***2.53***	***4.08***	***4.51***	***4.73***	***4.72***
Total Submission Forecast ($2013M including overheads)		**13.59**	**15.14**	**15.57**	**15.79**	**15.78**

Table 142: QoS Expenditure Summary

Table 143 below shows the historic expenditure on QoS projects.

Year	Actual QoS Projects ($nom,inclusive of overheads)	Actual QoS Projects ($2013, inclusive of overheads)
2009/10	9.39	10.33
2010/11	8.57	9.13
2011/12	9.90	10.22
2012/13	9.65	9.65
Average ($ millions)	**9.38**	**9.83**

Table 143: QoS Historic Expenditure

SA Power Networks are forecasting the same number of major QoS remediations over the forthcoming regulatory control period as has been experienced on average over this present control period (ie an average 257 major QoS remediations per year, at the same average unit cost). Combined with those fixed costs of operating the QoS group (eg LV planning, analysis and design) the historic average expenditure is $11.06 million per annum. However, the historic rate of expenditure is likely to be below that required to avoid numerous customer supply failures during extreme heat events, as shown during the 2013/14 summer during which SA Power Networks experienced 27 distribution transformer failures and in excess of 400 fuse operations due to overload.

To assist in the efficient management of this issue and the significantly growing problem of the two way network (introduction of new customer technologies), it is proposed to implement targeted new network technologies. These new technologies include targeted transformer monitoring, using 3G telecommunications and additional voltage regulation at the HV and LV level. These new network technologies will be compatible with the advanced distribution management system (ADMS) presently under development and expected to be operational in 2016. These strategies will assist us to proactively manage the LV network and enable two way power flows necessary for new technologies such as solar PV, energy storage, electric vehicle charging and other controllable loads.

The total annual average capital expenditure within this AMP is $15.17 million at a total of $75.87 million over the 2015-20 regulatory period – these figures are in $2013 (real) and inclusive of all overheads.

The following QoS LV Network plan details the requirements to maintain Regulatory compliance, assist to provide a two way network and provides background information in support of these proposals.

25.2 Maintaining Power Quality

25.2.1 QoS Projects (Major and Minor Works)

To remediate customer enquiries received by the Quality of Supply Team, distribution transformers need to be upgraded or new transformers installed (infill) as those existing assets are identified as overloaded. Associated with these distribution transformer projects is often the need to upgrade either the HV and/or LV mains to improve both network capacity and customer's quality of supply (ie reduce voltage drop). In addition, both HV and LV voltage regulators (HVR, LVR) may also be required, particularly in country locations.

25.2.1.1 Major Works

Table 144 shows data obtained from SA Power Networks' SAP system, in line with the *AER's* Category Analysis RIN, detailing the actual cost of Quality of Supply project work between 2009 and 2013. Where possible, the continued use of refurbished pole mounted and pad-mounted transformers, significantly reduces the average capex and unit cost compared of augmentation compared with the use of new transformers.

Historical QS project expenditure	2008/09	2009/10	2010/11	2011/12	2012/13	Average
Transformer QoS projects (number)	308	292	265	222	230	263
Transformers installed (number)	289	292	265	210	226	257
Total QoS project costs (actual $M)	8.60	9.00	8.06	6.36	7.13	7.83
Total QoS project costs ($M2013)	9.77	9.91	8.59	6.57	7.13	8.39

Table 144: QoS Historic Major Works Expenditure

25.2.1.2 Minor Works (QSI)

The `quantities and costs associated with the performance of minor remediation works (REMI) completed per annum shown in Table 145 are based on the average number of minor works completed by the Quality of Supply Investigations Team (Field Services) and Depots (Field Services) between 2009 and 2013. The assumption has been made that 10% of all minor works conducted are capitalised (eg. LV mains and service mains, road crossings and other miscellaneous works etc) with the remainder being allocated to opex (eg. load and voltage testing, analysing, load balancing, adjust voltage taps on transformers). Refer APPENDIX Z.

Forecast	2015/16	2016/17	2017/18	2018/19	2019/20
Minor remediation (REMI) job numbers (average)	650	650	650	650	650
Average cost ($ refer APPENDIX Z)	5,520	5,520	5,520	5,520	5,520
Total Cost ($M,2013)	3.60	3.60	3.60	3.60	3.60
Assumption is 10% capital (average $M,2013)	0.36	0.36	0.36	0.36	0.36

Table 145: QoS Historic Minor Works Expenditure

25.2.2 The QoS and LV Planning Team

The Quality of Supply Team consists of a manager (overhead cost not included in this AMP) an administration officer, two engineers who undertake network analysis, generation connection analysis and LV planning, three analysts who undertake testing and monitoring analysis for customer/survey work and recommend remediation and report project expenditure. Much of the design (scoping and line design) and construction of QoS capital work is contracted out. All of these costs are capitalised. It is proposed to maintain the present resource levels (ie 6 FTE's plus the manager) to manage all QoS functions (absorb additional monitoring and data management). The historical expenditure in 2012/13 was $1.3 million. Contract labour resources may be used for project design, engineering and analysis equating to approximately $0.75 million.

Capex	2015/16	2016/17	2017/18	2018/19	2019/20
QoS Administration (1)					
LV Planning (2 engineers)					
QoS Analysis & QoS Project management (3 Analysts)					
Total QS & LV Planning Labour (capitalised $2013M)	**1.30**	**1.30**	**1.30**	**1.30**	**1.30**
Part time Contract Engineer	0.10	0.10	0.10	0.10	0.10
Part time Contract Line designs (Electel, DPD, NPO or PLD)	0.65	0.65	0.65	0.65	0.65
Total Network design and analysis costs ($2013M)	**0.75**	**0.75**	**0.75**	**0.75**	**0.75**

Table 146: QoS Team Costs

25.2.3 Low Voltage Network (PowerMonic) Test Equipment Replacement Program

Quality of Supply (QoS) request Field Services Quality of Supply Investigation team (QSI) and country depots to undertake short term load and voltage testing on an as needs basis. QSI and country depots use GridSense PM15 testing devices that are now obsolete, without service and parts support. A 10 year replacement program (asset life is approximately 10 years) is used to manage all of our portable load and voltage measurement equipment. This replacement program is costed below and is imperative to ensure data accuracy, implementation of cost effective solutions and maintain maximum testing device availability (minimal testers in for maintenance/repair) to test for compliance with the Distribution Code. Load and voltage measurements of the LV network are taken to verify customer and LV management requirements. SA Power Networks tests and calibrates its testing units and monitors within its own NATA certified laboratory.

PowerMonic Testers Replacement Program	2015/16	2016/17	2017/18	2018/19	2019/20	Ave unit cost ($)	Total program Cost ($M)
PowerMonic (GridSense) PM15, 20,30,40 Replacement Program PM35	14	14	14	14	14	11,670	0.82
Additional depot testers PM35, 45	6	6	6	6	6	16,000	0.48
Total Replacement Costs ($M)	**0.26**	**0.26**	**0.26**	**0.26**	**0.26**		**1.30**

Table 147: Test Equipment Replacement Program Expenditure.

The 10 year replacement program for unserviceable testing devices (PM15's), commenced in 2011. Table 148 shows the historic load and voltage (PM15) replacement program expenditure (direct cost invoiced) to date.

Delivery Date	Quantity	Testing Unit Type	Total Direct Cost Invoices ($) – excl OHs
12/05/2011	21	PM35 – with remote comms, associated equipment	198,737
31/10/2011	20	PM35 – with remote comms, associated equipment	160,198
17/07/2012	21	PM35, associated equipment	178,295
30/06/2014	25	PM35, associated equipment	219,906

Table 148: Historic Test Equipment Replacement Expenditure.

The current register of load and voltage test devices is shown in Table 149 with their in-service dates:

Register Description	Stock	2001 - 2005	2007	2010	2011	2012	2014
Units to be replaced							
Poly logger	32	32					
PM-15	103	103					
PM-20	8	8					
PM-30	8	8					
PM-40	14		6	8			
PM-45	1			1			
Existing replacements							
PM-35 (PM15 replacements)	46					21	25
PM-35C (PM15 replacements)	41				41		
Total	**253**	**151**	**6**	**9**	**41**	**21**	**25**

Table 149: Existing Test Equipment Register

There are 253 test devices presently in stock within the register. Of these, 157 (ie 32+103+8+8+6) were purchased in or prior to 2007 and will require replacement during the next 5 year period, as test devices have a 10 year serviceable life. Eighty seven (ie 41+21+25) PM15 units have been replaced during the present RCP, leaving a further 48 (ie 32+103-87) PM15 and 22 other units (ie 8 x PM20+8 x PM30+6 x PM40 units) to be replaced. QoS agreed to requests from depot personnel to supply an additional 26, PM35 test units for country depots to assist with their increasing need to test in response to customer enquiries. In addition, four sophisticated loggers, such as the PM45 (or equivalent), are required for neutral displacement and electric shock testing in country regions. The total replacement and new tester purchase costs of $1.3 million over the next five years allows (ie $0.26 million per annum) for 70 existing units to be replaced (26 PM35 and 4 PM45 (or equivalent eg PQ Box - 100)) and the acquisition of a further 30 new units totalling 100 units.

25.2.4 Low Voltage Regulation

It is often more cost effective to provide LV regulation rather than other HV solutions where country customers have voltage levels in excess of limits prescribed within AS60038. This is increasingly the case where individual or small groups (up to 20) customers are exporting electricity to the network from their solar PV installations at low load periods on high impedance networks (ie long distances to the distribution transformer) resulting in elevated voltages ain excess of AS60038 limits. The use of LV regulation in many cases may provide the lowest cost and fastest resolution to high and low voltage problems by regulating the voltage (using a high efficiency toroidal buck/boost transformer) at the point of consumption. An AC-AC converter raises or lowers the incoming voltage to maintain a constant output voltage. These devices facilitate two way power flows by controlling steady state voltages (eg to 245V) thereby enabling customers to operate and benefit from their new technologies. Without LV regulation, some customer quality of supply issues are unresolvable without the performance of costly major network augmentation. As customers install more new technologies, this problem will get significantly worse. This has been borne out by recent LV network modelling studies of the possible future impact of higher penetrations of distributed energy resources.

Single phase low voltage regulators (LVR) have been used extensively by other distributors in Australia since 2011. The first single phase (LVR) and three phase LV regulators (SVR), were installed by SA Power Networks in 2011 and 2014 respectively. The SVR was developed by Queensland DNSPs in conjunction with University research and development.

Table 150 shows the costs associated with installing additional LV voltage regulation equipment to improve power quality, resolve customer enquiries and enable a two way power flow network. Since 2011, QoS has installed single phase LV regulators for single customers. The 2013/14 implementation rate was 24 LVR units. This rate is expected to continue over the 2015-20 period.

The quantities proposed below are incremental above those QoS currently install and based on considered analysis from solutions to recent customer enquiries. Note some solutions may also require a replacement pole.

Voltage Regulation	2015/16	2016/17	2017/18	2018/19	2019/20	Ave unit cost ($M)	Total Program Cost ($M)
Installed LVR2 (single phase LV)	24	24	24	24	24	10,000	1.20
Installed SVR (3 phase LV)	6	6	6	6	6	30,000	1.01
Total Cost ($M)	0.42	0.53	0.42	0.42	0.42		2.21

Table 150: Forecast Low Voltage Regulator Installation Rates and Expenditure.

In conjunction with solar PV export generation, the LVR regulates and maintains voltage at the point of consumption (the household) while allowing solar generated current, through an AC-AC converter, to be exported to the LV network. The success of these units has enabled solar generation, two way networks and compliant voltage levels.

25.2.5 High Voltage Regulation

It is proposed to undertake three separate HV regulation projects between 2015 and 2020. All three will utilise the ADMS system when it becomes operational in 2016.

25.2.5.1 Remote Voltage Control Project (RVCP) at Metropolitan Zone Substations

As solar PV penetration increases, it is likely that widespread customer enquiries concerning high voltage caused by solar PV will significantly increase. The number of high voltage customer enquiries has gone from near zero to 300 per year over the last four years. Based on our future LV (DER – distributed energy resource) modelling, it is expected that this will continue to increase over the next 10 years, as PV penetration increases. The modelling performed indicates that older overhead networks (ie higher impedance of small conductors) incur voltage issues when PV penetration exceeds 25% to 30% of the network's capacity. Generally, lower impedance underground cable networks are not expected to incur the same issues at similar penetration levels. For the metropolitan regions, a cost effective global substation voltage regulation solution is proposed. The impact of PV penetration can be seen in the daily load profiles on two selected trial feeders (Hackham West 11*kV* connected to Hackham Zone Substation and Marlborough 11*kV* connected to Fulham Gardens Zone Substation).

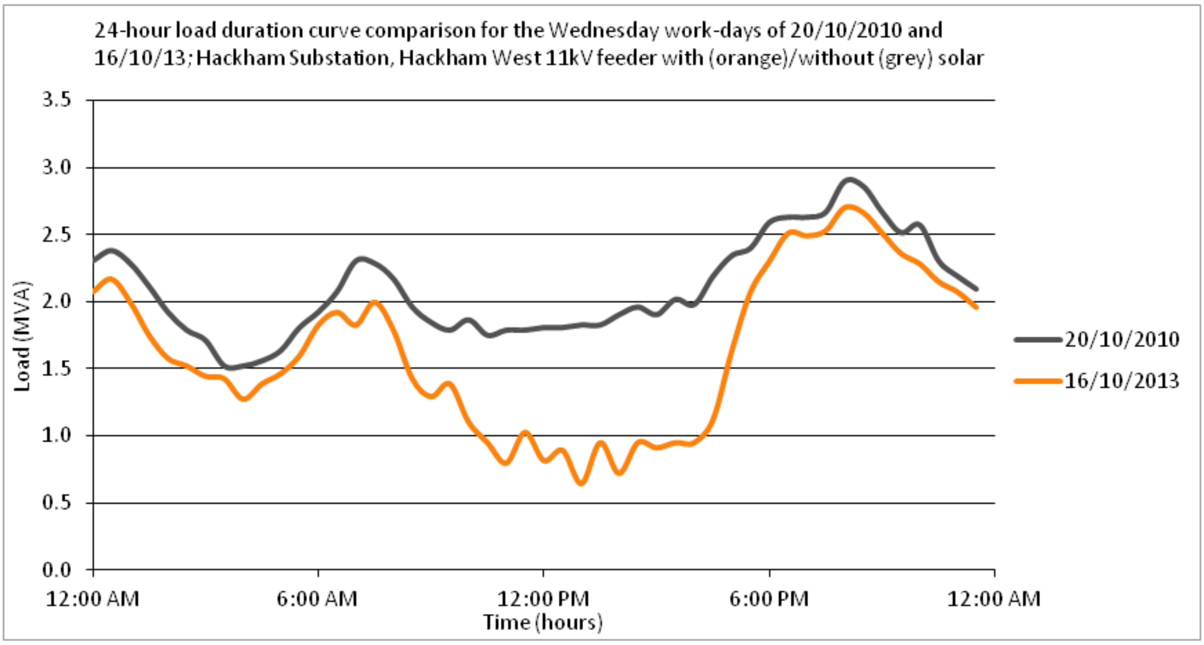


Figure 103: Hackham West Feeder Load Profile with and without PV

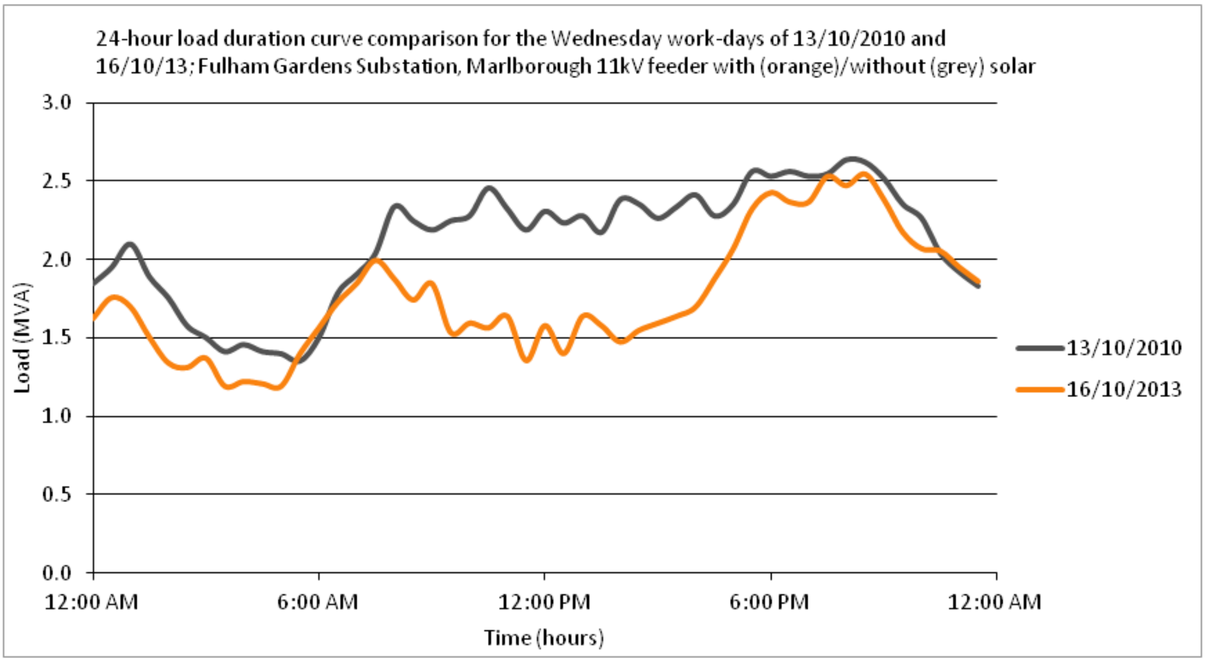


Figure 104: Marlborough Feeder Load Profile with and without PV

In essence, depending on the time of day and time of year, at SCADA controlled metropolitan zone substations with high PV penetrations (eg >20%) versus forecast maximum demand, it is proposed to control the zone substation's bus voltage set point to a lower value at or around times of high solar output and restore the bus voltage set point to previous standard values at lower PV output times times (1700h to 2100h). As solar generated power exports increase, so does the network over voltage. Changing weather patterns can produce voltage variations in high PV penetration areas. It is proposed to install remote voltage set point control at 20 metropolitan zone substations over the 2015-20 period to provide greater control over bus voltages due to high PV penetration feeders. Ultimately, this set point control via SCADA will need to be matched to changing weather patterns, feeder loads and PV penetration levels. There are 85 feeders connected to the 20 zone substations earmarked for implementation of this scheme. Voltage monitoring and LV network modelling will determine appropriate voltage set point levels.

Design of a suitable solution is planned to commence in 2014/15. Two operational trials will be conducted in 2015/16 and 2016/17 at metropolitan substations with different AVR's (ie voltage relays) at an estimated cost in the order of $0.4 million. Following successful completion of these trials, it is proposed to roll-out this functionality to an additional 18 zone substations. To measure end of feeder distribution transformer voltage levels and the effectiveness of this solution, it is planned to install end of line (EOL) monitoring on the 20 zone substation's 85 feeders. Refer APPENDIX P metro substations selected based on >20% PV penetration levels and >2,000 customers and APPENDIX V (feeders connected to these substations for EOL monitoring).

Further details are available in the relevant business case A5: Remote Voltage Control (metro subs) project.

25.2.5.2 Remote Voltage Control Project (RVCP) at Country Zone Substations

Most of SA Power Networks' larger country zone substations have SCADA monitoring of their HV assets. Those without SCADA which also have a SSD number are proposed to be SCADA enabled within the next 10 years (refer to AMP 2.1.02). However those sites which do not have a SSD (typically transformers less than 1MVA) and are not SCADA enabled are not catered for within AMP 2.1.02. To improve voltage level visibility, where there is none at present and maintain compliance with AS60038 voltage levels, it is proposed to implement this solution at 10 non-SCADA country substations, SCADA enabled pole top voltage regulators for voltage level visibility and set point control (refer to APPENDIX Q). This proposal must be read in conjunction with AMP2.1.02. Those substations with SCADA can be implemented via ADMS. For those without SCADA, it is proposed to add SCADA controlled pole top regulators. These are proposed to be deployed on a prioritised basis to those locations with multiple voltage variation enquiries.

Further details are available in the relevant business case for this RVCP (country subs) project.

25.2.5.3 Remote Voltage Control Project (RVCP) on Country Feeders with existing line HVR

To increase voltage level visibility and set point control, it is proposed to retrofit SCADA to 63 existing high voltage line regulators out of the 309 HV line voltage regulators presently in service. Those HV regulators selected are based on them having suitable CL5/6 controllers to enable a SCADA retrofit. Improved line / feeder voltage visibility and regulator operation status will greatly assist customer service and the provision of a two way network (refer APPENDIX R).

Further details are available in the relevant business case for this RVCP (country feeders line VR) project.

25.2.5.4 HVR Upgrades

It is proposed to include within this AMP, provision to replace a total of 25 HVR units, 10 on the SWER network and 15 on the 11kV feeder network with greater than 30% solar PV penetration. The total capex required is $1.98 million over the 2015-20 period. Refer to section 25.3.13 below and APPENDIX Z for further details.

The replacement program is triggered by customer high voltage enquiries where the existing HVR can not accommodate bi-directional power flow and as a consequence the HVR will need to be upgraded or replaced.

Table 151 below shows the proposed HV voltage regulation solutions proposed expenditures.

VOLTAGE REGULATION	2015/16	2016/17	2017/18	2018/19	2019/20	Ave unit cost ($M)	Total program cost ($M)
RVCP at metro zone substations	1	1	6	6	6	0.20	3.96
RVCP at country zone substations	2	2	2	2	2	0.14	1.40
RVCP on country feeders with existing HVR	13	13	13	12	12	0.05	3.00
HVR Upgrades - 3 phase 11kV - SWER	 3 2	 3 2	 3 2	 3 2	 3 2	 0.095 0.058	1.98
Total Capital Costs ($M 2013)	**1.08**	**1.84**	**2.33**	**2.55**	**2.54**		**10.34**

Table 151: HV Voltage Regulation Installation and Expenditure Forecasts.

25.2.6 Permanent Distribution Transformer & Voltage Regulation Asset Monitoring

The EDC obligates SA Power Networks to comply with the voltage levels specified in AS60038. These are a nominal 230V phase to neutral and 400V phase to phase plus 10% (253V and 440V) and minus 6% (216V and 376V). There are several other supply standards with which SA Power Networks must comply most notably, voltage unbalance (LV - 2%, HV – 1%) and total harmonic distortion (THD).

Although our SCADA system is able to monitor a large proportion of our major HV assets, we have not historically monitored the LV network other than in response to specific customer enquiries. Historically, SA Power Networks rely on customers to enquire about unacceptable power quality before QoS undertake short term load and voltage tests to confirm customer's enquiries relating to power quality. These number 150 per month on average (Figure 102). A significant proportion of these enquiries are from country customers. Customer Stakeholder Workshops undertaken as part of SA Power Networks' Rest preparation indicate that it is no longer generally acceptable that SA Power Networks reactively respond to customer supply quality enquiries. A far more pro-active approach is expected by customers. To achieve this, it is proposed to use strategic long term distribution substation transformer monitoring to improve power quality visibility within the LV network. The more distribution transformers monitored, the more proactive SA Power Networks can be at ensuring power quality standards are maintained. All expenditure must continue to be based on actual measured test results from either short term or long term monitoring of transformer and customer service point load and voltage. Figure 103 indicates the sustained increase in QoS related customer enquiries in recent times.

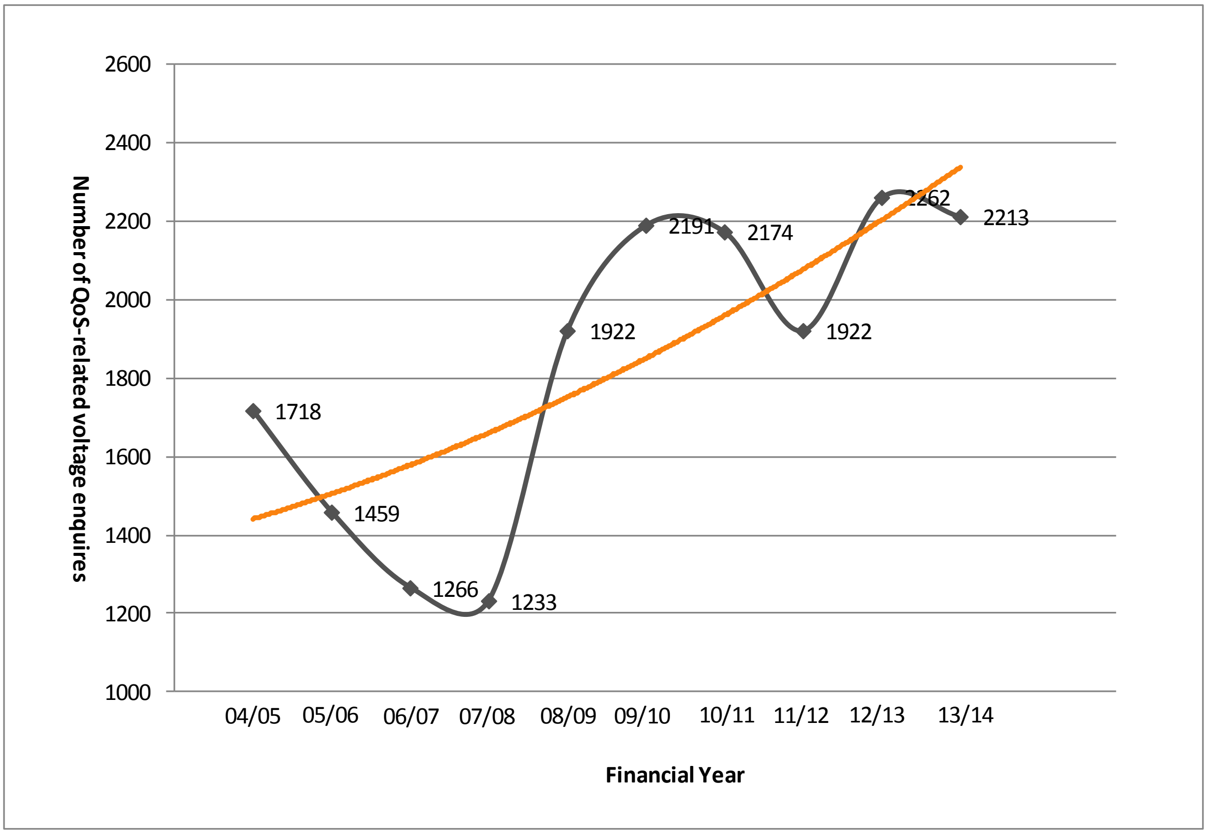


Figure 105: QoS Enquiries Received by Financial Year.

New remotely downloadable load monitoring devices are now available and their deployment across the LV network will significantly improve our regulatory compliance and enable pro-active LV network management with the benefit of improved quality of supply to customers. These devices will monitor load and voltage levels in each phase, phase imbalance and capture any significant supply interference or variation. Without this monitoring we cannot ensure general on-going compliance to the requirements of the EDC.

In addition, QoS propose to enable the SCADA function, where possible on existing HV line voltage regulators (HVR) and to all new HVR plant installed within non SCADA enabled country zone substations to assist QoS monitor voltage regulation and voltage regulator operational status on country feeders. Pro-actively remediating non-compliant voltage levels through this monitoring of the load, voltage and status of HVR plant is expected to significantly reduce the level of power quality customer enquiries made to our call centre.

The benefit of HV and LV network transformer and regulator permanent monitoring is to optimise the future quality of supply expenditure and ensure best value for money for our customers. Further details are available in the relevant business cases for these projects.

At the end of the five year program, the following specific installations are proposed and as listed in the attachments to this plan:

25.2.6.1 SWER (start & EOL) – 740 HV LV monitors – see Attachment D for locations

SWER systems are generally long, high impedance single phase networks, typically constructed using 3/12 SC/GZ or 3/10 Alumoweld conductor (or metric equivalent). These systems are typically located in sparsely populated rural locations generally supplied via SWER isolating transformers from the 33kV sub-transmission or 11kV feeder networks. SA Power Networks owns and operates 430 SWER systems. SWER systems are generally considered weak networks (max rating 150 or 200kVA) with limitations imposed on customer connections - up to 25kVA load per connection and up to 5kW of PV generation per connection. These limitations are in part due to the voltage fluctuations expected with larger connections to these networks. SA Power Networks has no knowledge of the real time HV and LV voltage levels on these rural and remote SWER networks. To ensure compliance with our Statutory voltage obligations (ie EDC), we propose to install 740 permanent monitors at the secondary side of each SWER isolating transformer and at the end of each SWER line (this may require the use of more than one monitor per SWER system). The benefit of this permanent monitoring installation is the provision of greater visibility of voltage levels, demand and other QoS parameters, thereby assisting SA Power Networks to better enable a two way network for improved customer service.

25.2.6.2 Country zone substations/feeders - non SCADA – 65 LV monitors – see Attachment E for locations

Most of the SA Power Networks' larger country zone substations have SCADA for HV assets or will have SCADA in the next 5 to 10 years (refer to AMP2.1.02). However, many smaller zone substations (typically transformers less than 1MVA) do not have SCADA. It is proposed to install HV monitoring at those zone substations not covered within AMP 2.1.02. At these sites, we have no real time knowledge of the HV voltage levels on the rural networks supplied by these zone substations. At present, these sites are monitored over summer on a three year rotational logging program. The benefit of instituting permanent real time HV monitoring of these installations is the provision of greater visibility of voltage levels, asset load demands for forecasting and regulatory reporting purposes.

25.2.6.3 Country feeders EOL – 460 LV monitors – see Attachment F for locations

QoS have no knowledge of the real time voltage levels on our rural feeders, with the worst case being at the end of the feeder. Many of our rural feeders have HV voltage regulators installed, however in many instances, these are not SCADA enabled and therefore we have no visibility of their performance. This can occassionally cause field crews to suspect local issues and undertake voltage tests when in fact the voltage issues are caused by the upstream HV regulator that is either out of service or operating incorrectly. As a consequence, we cannot ensure compliance with statutory voltage obligations (ie EDC). As such, QoS propose to install permanent monitors at the end of selected feeders suspected to have quality of supply and two way network issues. The benefit of these permanent monitoring installations is greater visibility of voltage and asset load levels, to ensure Electricity Distribution Code compliance with AS60038 and assist the enabling a two way network for improved customer service.

25.2.6.4 Metro feeders EOL – 85 HV monitors – see Attachment G for locations

It is proposed to install remote substation bus voltage set point control using SCADA at 20 selected metropolitan zone substations (refer to section 25.2.5.1 above) with high solar PV penetrations. To ensure voltage levels at the end of these feeders (worst case) are compliant with the EDC's requirements, QoS propose to install additional permanent monitors. These monitors are to indicate the veracity of our zone substation bus voltage set point control at these selected zone substations. The benefit of these permanent monitoring installations is greater visibility of voltage levels ensuring Electricity Distribution Code compliance with AS60038, thereby assisting in enabling a two way network for improved customer service.

25.2.6.5 Metro pad-mount (ground level) distribution transformers – 635 LV monitors – see Attachment H for locations

Remediating overloads of pad-mount transformers is costly and time consuming. The timing of this capital expenditure is critical as unplanned work is less cost efficient than planned work. QoS have selected 635 pad-mounted distribution transformers out of the total population of 7,270 pad-mounted units within the metropolitan area for the installation of permanent monitoring. Those pad-mount transformers selected were selected based on meeting all of the following criteria:

1. greater anameplate capacity than 100kVA;
2. have multi customer connections;
3. have solar PV connection(s); and
4. have a calculated peak loading (based on ADMD analysis – refer 25.3.2 below) greater than 100% of the nameplate normal rating in 2014.

These transformers invariably supply more than one and up to four LV circuits.

The significant benefits of this permanent distribution transformer monitoring program are detailed in the relevant business cases for these projects. Generally the benefits include:

- optimised capital expenditure – with upgrade solutions only being triggered when measured demand exceeds the planning criteria and minimises the likelihood of asset failure due to overload (capex saving);
- assist in determing alternative solutions to augmentation such as LV transfers between interconnected distribution substations;
- an opex saving from reduced temporary testing;
- greater visibility of voltage levels and load balance enabling pro-active remediation and improved LV network management;
- compliance with regulatory obligations eg Electricity Distribution Code (AS60038);
- assist in enabling a two way power flow network through improved data quality that enables better analysis during the assessment phase of customer connection enquiries related to the connection of new technologies; and
- assist in provision of improved customer service through improved quality of supply and improved reliability of supply through the prevention of disconnections of customer's solar inverter installations due to voltage excursions beyond the capability of the inverter.

Table 152 shows the number of permanent monitors installations proposed under this plan as well as the total program expenditure forecasts.

Monitor Allocation	2015/16	2016/17	2017/18	2018/19	2019/20	Ave unit cost ($)	Total Program ($M)
SWER (start & EOL) – 740 LV monitors	76	166	166	166	166	3,600	2.66
Country substations - non SCADA – 65 HV monitors	5	15	15	15	15	15,000	1.10
Country feeders EOL – 460 LV monitors	48	103	103	103	103	3,600	1.65
Metro feeders EOL – 85 LV monitors	9	19	19	19	19	3,600	0.31
Metro pad-mount transformers – 635 LV monitors	63	143	143	143	143	3,600	2.30
Monitoring Capital Costs ($M)	**1.03**	**1.71**	**1.76**	**1.76**	**1.76**		**8.02**

Table 152: Permanent Monitoring Installation and Expenditure Forecasts

25.2.6.6 Transformer Monitoring Data Management

By 2020, it is proposed to have approximately 2,200 permanently installed power quality data monitors taking half hourly readings across multiple parameters that are compatible for inclusision within SA Power Networks' SCADA system's database. The data from these monitors will be polled by IP addresses and uploaded to a SA Power Networks owned secure virtual server. A program will interrogate this data on a daily basis to identify any QoS threshold breaches (eg loads over 130% of transformer nameplate rating and voltages outside prescribed limits or voltage unbalance sustained for more than 1 minute). These excursions can be displayed and appear on the responsible officer's (ie QoS Analyst) desktop screen. The primary users of this data are the QoS Analysts and Distribution Planning Engineers. The data storage requirement is approximately 31GB per year or 155GB over 5 years.

	Number of monitors	Data per unit/month	Total Data per month	Total Data per annum	Total Data (5 years)
HV FEEDER	65	1.4 MB	91.0MB	1.09 GB	5.5 GB
LV SWER	740	566 kB	486.76MB	5.84 GB	29.2 GB
LV COUNTRY FEEDER EOL	460	1.7 MB	783.7 MB	9.4 GB	47.0 GB
LV METRO EOL	85	1.7 MB	144.5 MB	1.73 GB	8.7 GB
PAD MOUNT LV	635	1.7 MB	1.08 GB	12.95 GB	64.7 GB
TOTAL	**1,985**	**7 MB**		**31 GB**	**155 GB**

Table 153: LV Monitoring Data Storage Requirements

25.2.7 Strategic monitoring using smart meters

During the 2015-20 period our standard meters for new customer connections and meter replacements are proposed tol be 'smart ready'; capable of providing remote power quality data in addition to standard energy consumption data provided these meters are fitted with the addition of a low-cost telecommunications module. In addition, the AEMC's proposed rule change in relation to contestability in metering services may come into force during the period, and is expected to stimulate a 'market led' rollout of smart meters by retailers in South Australia.

The transition to smart meters provides a long-term opportunity for DNSPs to achieve more widespread power quality monitoring of the LV network in a highly cost-effective manner. We propose to capture this opportunity through a strategic initiative to access power quality data from such smart meter where installed at customer's premises. This will involve enabling a subset of 'smart ready' meters as power quality (PQ) monitors at targeted locations within the LV network and establishing the systems required to access PQ data streams from meters installed by third parties.

As legacy meters are progressively replaced with smarter meters, this will develop a strategic platform to extend power quality monitoring beyond the distribution transformer, to the extremities of the LV network. This strategic initiative is described in further detail within the Tariff and Metering business case.

25.3 Low Voltage Network Management

The following is supplied as background information further in support this AMP's proposals related to management of the LV network and general QoS.

25.3.1 Supply Standards

For the purposes of this Asset Management Plan related to QoS, the broader issues of power quality are in line with the requirements of the South Australian Electricity Distribution Code (EDC) and the following standards:

- Steady-state voltage at the customer's supply point, as per AS 60038 and AS61000.3.100
- Voltage fluctuations at the customer's point of supply, in accordance with AS/NZS 61000.3.3, 3.5 and 3.7
- Voltage unbalance factor in three-phase supplies, as per SA Power Networks' supply standards (ie Manual 24)
- Harmonic voltages at the point of common coupling as per AS/NZS 61000.3.2, 3.6 and AS 2279[37.]

25.3.2 LV Planning Methodology

SA Power Network's distribution substation transformer population represents a major investment for the business. The Quality of Supply team maintains a database of all of the relevant distribution transformer data. This database's data is sourced from a combination of SAP and GIS on a quarterly basis. This data includes the number and type of customers supplied by each distribution transformer, the rating of each distribution transformer and its status. Each time the QoS database is opened, it is automatically updated with actual data uploaded from linked spreadsheets containing, transformer test data, transformer (long term) monitoring data, SAP (solar PV inverter data), works tracker data (ie QoS work notifications and status), OMS data (summer LV fuse operation), GIS functional location data, SAP data (transformer capacity, voltage ratio).

Where transformer overloads (ie breaches of distribution transformer planning criteria) are identified and cannot be managed through the performance of minor works (eg load transfers, tap changes etc), a major works project is initiated and issued for remediation construction either through the upgrade of the existing distribution transformer, the installation of an infill transformer solutions or the implementation of improved voltage regulation (HVR and SVR/LVR). QoS has developed a dynamic analysis model that continuously updates transformer loading confirmed by testing and completed remediations works.

Historically, QoS has forecast distribution transformer loads based on an assigned ADMD (After Diversity Maximum Demand) according to the area within which the transformer resides, (approx. total population of 72,500 distribution transformers) based on a view of the connected customer's expected maximum demands and number of connected customers. When the total average ADMD multiplied by the number of connected customers is compared to the transformer capacity the resultant utilisation (ie % loading) directs QoS as to those assets to be subjected to temporary load monitoring to confirm actual

[37] Whilst AS-2279 is now obsolete and superseded by the AS/NZS 61000 series of standards, the EDC continues to make reference to it and therefore needs to be complied with.

transformer load. QoS has also commenced used of a new simulation model (TLF - Transformer Load Forecast) to simulate customer energy usage behaviour in geographic locations close to transformer locations. It should be noted that the QoS group does not augment the network based on ADMD based utilisation forecasts or the TLF analysis in isolation. Rather, network investment is based on measured tested/monitored load values and other quality of supply considerations, such as voltage levels and customer enquiries which are also subject to verifaction through measurement.

Historically QoS assigned an ADMD according to the customer base, depending on total average household floor size. These values translate to an average ADMD allocation per customer, per transformer. Measured loads assist to refine our initial ADMD assignment.

Household Size - Average	ADMD (kVA per customer)	Services per 200/315kVA transformer	Maximum Distance 0.06-7/375 ACSR
Villas, townhouses, apartments, flats (<12 squares/110m^2)	2.5	80/120	320
Small to medium houses (12-20 squares/110-185m^2)	3.5	60/80	320
Medium to Large houses (20-30squares/185-280m^2)	4.5	45/65	300
Large houses (>30 squares/280m^2)	6.0	30/50	280

Table 154: ADMD by Dwelling Type

QoS has developed a new approach, by working with consultants ISD Analytics Pty Ltd, in an attempt to improve the accuracy of forecasting the utilisation of each distribution transformer. In fact the new approach replaces the ADMD methodology, for relevant transformers above 63kVA, generally supplying more than 10 customers, with a Transformer Load Forecast (TLF) Model. The data is updated every three months based on data from SA Power Networks' GIS and the TLF Model data is available throughout SA Power Networks for use by those officers wanting to know distribution transformer forecast loads. The TLF comprises two layers:

1. Consumer Behavioural Layer: this layer relies on census data, which is updated every five years by and available from the Australian Bureau of Statistics (ABS), to construct a profile of each individual customer (ie household units and their occupants), which then allows the diverse range of customers' household activities and appliance usage to be simulated throughout the day. The model considers the types of appliances used by different households, the occupancy of household members during the day (ie work and school), the types of household activities that the occupants undertake throughout the day (such as meals, washing and cleaning, entertainment, etc), and the appliance usage to satisfy day to day activities (eg air-conditioning, oven, TVs, lights, etc).

2. Geographical Layer: distribution transformer geographical locations are overlayed with small census regions (ie SA1), down to 200 to 400 customers, in order to identify and allocate/connect the most likely customer types/profiles to each transformer. The resultant appliance power consumption from each household connected to the distribution transformer represents the total estimated power load. The peak demand in extreme temperatures represents the transformer load forecast.

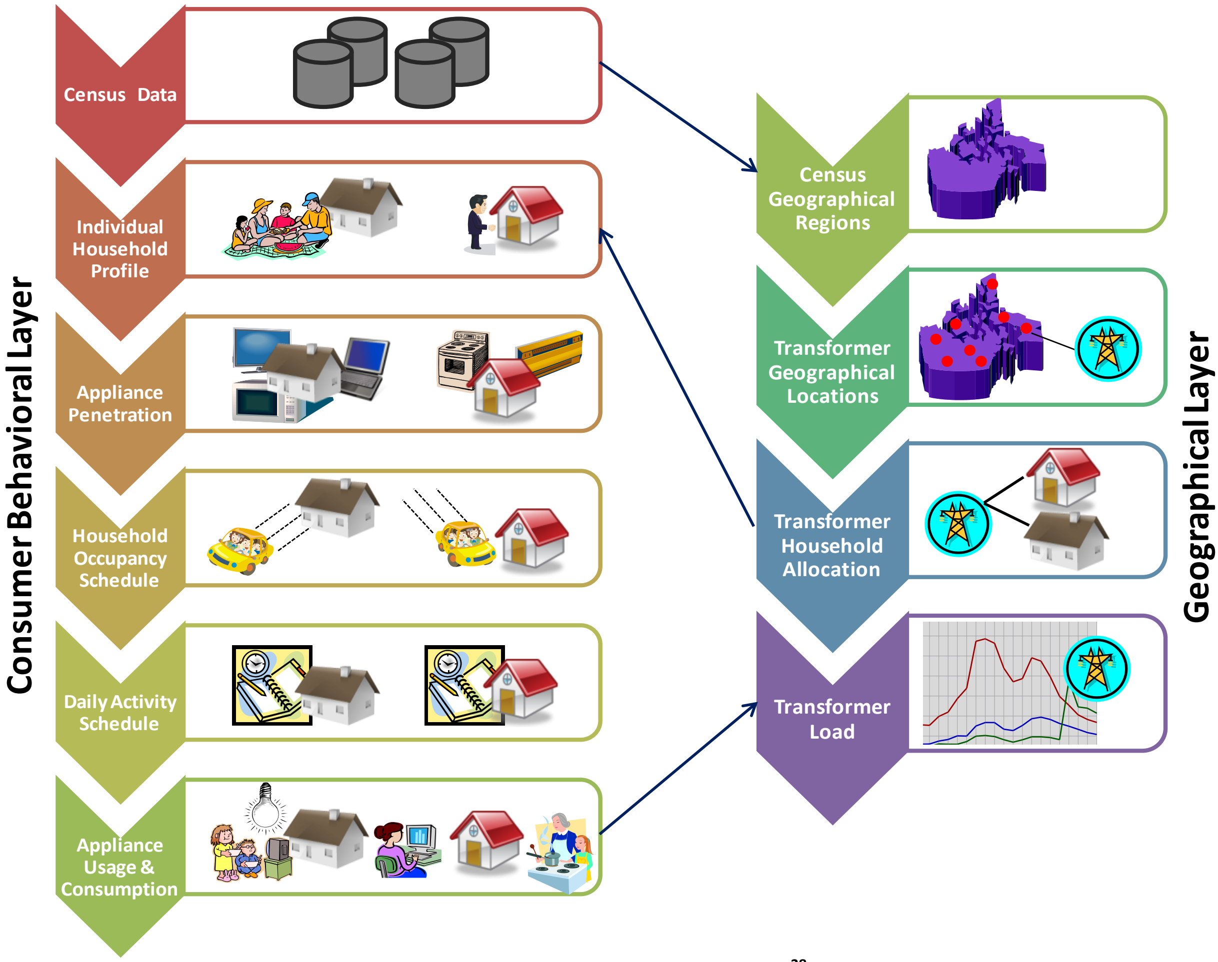


Figure 106: ISD Load Forecast Model Layers[38.]

Both the ADMD and TLF data results are used to determine where a short term (one week) load and voltage test should be undertaken to confirm the calculated transformer loads. However, since these tests may not be undertaken within the distribution transformer's peak load period, the measured loads are escalated using a K factor to seasonally adjust the measured demands to those expected during peak load conditions. QoS designs the LV network for operation under peak loading conditions. The K factor is calculated using SCADA data of the feeder and is the quotient of peak load (updated database after summer each year) and recorded feeder load (updated daily database from SCADA readings). K factors are not applied to country load and voltage tests.

[38] reproduced from ISD Transformer Load Forecasting Model Final Report (May 2014)

25.3.3 QoS Constraint Identification and Remediation Process

To assist in explaining the QoS process the following high level flow diagrams have been developed:

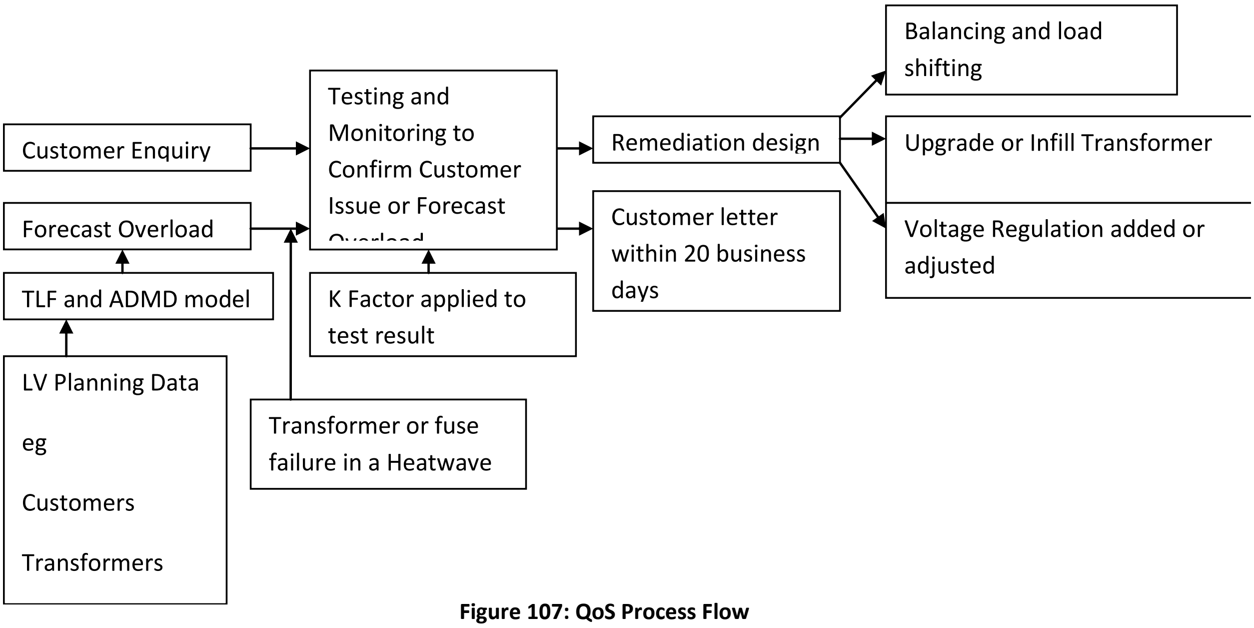


Figure 107: QoS Process Flow

25.3.4 Customer's Quality of Supply

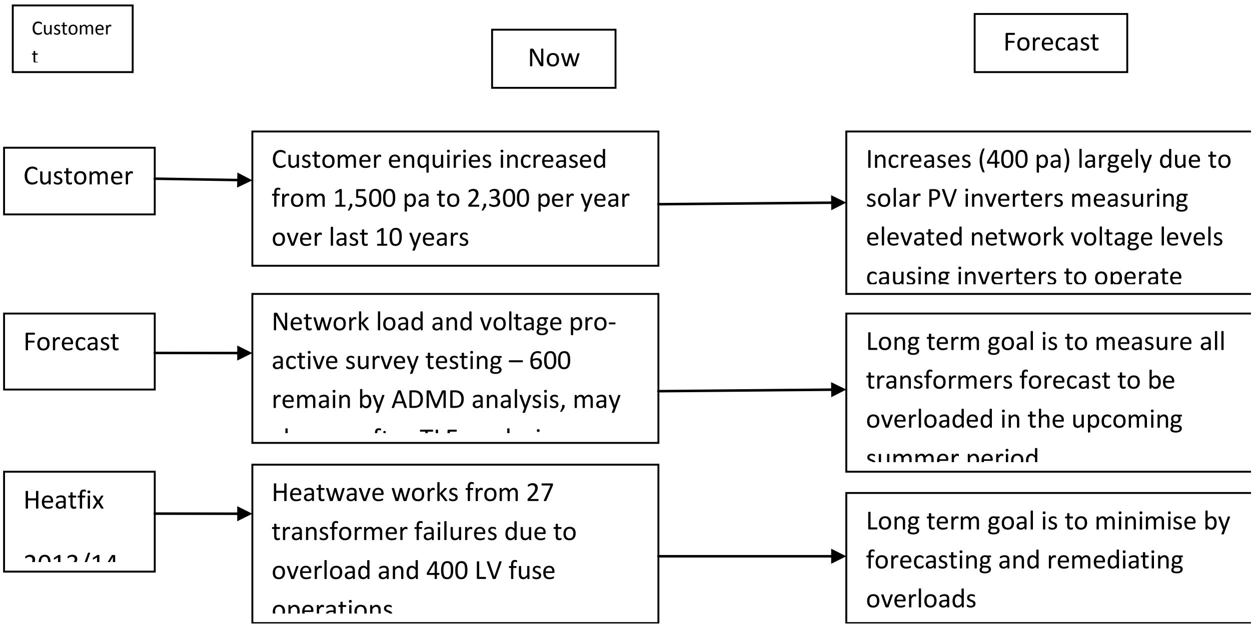


Figure 108: QoS Issues Map

The network is most stressed during heatwave conditions. The actions taken since the extended heatwave in 2008/09 have demonstrated improved performance of the LV network (ie fewer HV and LV fuse operations due to overload and less transformer failures) however, these are still not at a satisfactory level. The advent of solar PV and the consequential increasing customer expectations result in an increase in the number of unsatisfied customers where two way networks are restricted by the capability of the localised network. Whilst, SA Power Networks has placed a greater emphasis on the LV network and QoS issues in general within this regulatory control period than in the past, the unprecedented changes in this area due to the uptake of PV generation systems has resulted in customers concluding that we are not funding this asset area sufficiently. The long term goal is to stabilise the level of customer enquiries, manage the two way network and pro-actively manage the LV network to address issues before they are reported by customers.

In order to manage QoS enquiries, this AMP proposes to maintain present levels of expenditure on the remediation of the LV network with some relatively minor additional expenditure to improve the monitoring of the network to better manage increasing customer expectations and drive the management of the LV network more pro-actively. This additional expenditure provides for the following measures to be implemented:

- installation of cost effective LV regulators in problem areas to eliminate the backlog of these 'hard to fix' customer enquiries;
- addition of strategically located zone and distribution transformer monitoring; and
- addition of 'smart' voltage management solutions to assist enabling a two way network – these include substation voltage set point control and regulation, line HV voltage regulation, SCADA monitoring and control, short and long HV and LV transformer voltage monitoring, Volt/Var optimisation equipment, SVR and LVR voltage regulation in the LV network and the installation of 'smart' customer meters with power quality measurement capability.

25.3.5 LV Planning Criteria

For planning purposes, SA Power Networks has historically considered a distribution transformer to be overloaded when the peak load exceeded a set planning criteria. In certain instances, the rating of the transformer fusing may be less than the rating of the transformer, in which case the rating of the transformer is taken to be the lower of the transformer's nameplate rating and the rating of the transformer fuse rating. This is most common with pad-mounted transformers due to the de-rating effects of temperature within the enclosure during heatwave conditions.

In reality, however, the demand on the electricity distribution network does not remain at a constant level, but varies during the course of any given day, generally peaking in the afternoon, and tapering off dramatically in the early hours of the morning. Due to that cyclic nature of the load, and the thermal inertia of the oil-filled, iron-cored transformers supplying it, the transformers are may be able to be loaded above their nameplate ratings for short periods of time during the day with low detrimental effect. SA Power Networks rely upon this inherent overload capability as it continues its' remedial program to address overloads on the LV network. The proposed strategy is to progressively reduce the number of overloaded distribution transformers through the installation of replacement or infill units thereby increasing the network's distribution transformer capacity. As would be expected, it is planned to target the most highly loaded transformers first. The implication of overloading distribution transformers is illustrated graphically below.

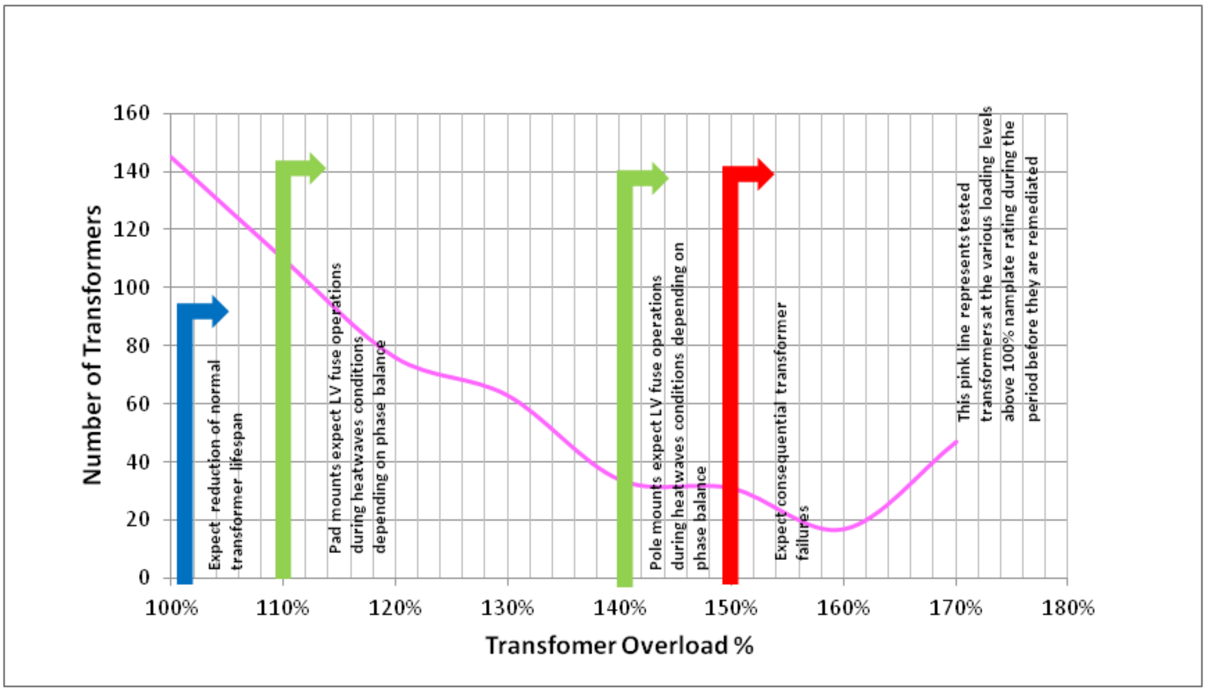


Figure 109: Distribution Transformer Overload Implications

In order to determine the load levels at which SA Power Networks should plan and operate its various distribution substation transformers, SA Power Networks undertook an exercise to examine the normal cyclic and long-time emergency ratings of those pole and pad-mounted transformers being purchased under the present supply contracts with its transformer suppliers. A commercially available program called Transformer Load Simulator v3.2 (TLS) which SA Power Networks uses to rate the larger transformers within zone substations was used to analyse a sample of smaller LV distribution transformers to determine their normal and long time emergency cyclic ratings. TLS applies the input data supplied to it to the formulae contained in AS2374.7-1997 to determine the cyclic rating capability of transformers.

To further validate those ratings, SA Power Networks provided the manufacturer of its pole mounted transformers with temperature and load profile data for those transformers in service in order to independently determine what their rating results were. The manufacturer suggested that the rating applied should be calculated in accordance with the loading tables provided in Section 3.4 of AS2374.7-1997, “Loading Guide for Oil-Immersed Power Transformers”.

In remediating the forecast overloaded transformers QoS has taken into account the likely load growth and unbalance factors expected over the last five years and the data inaccuracies. Figure 108 indicates the distribution transformer load levels at which QoS group instituted remedial actions in 2012/13. The present planning criteria related to distribution substation transformers is:

1. remediate pole mounted transformers loaded in excess of 130% of their nameplate rating; or
2. remediate those pad mounted transformers loadedin excess of 100% of nameplate rating.

Where distribution substation transformers are loaded above these planning criteria ranges, QoS either upgrades them to a higher capacity or installs an additional infill transformer subject to verification of the forecast loading through load testing. Where distribution substation transformers have been remediated at load levels below 100% of nameplate, this has been performed to improve the relevant customer's quality of supply for reasons that are not capacity related (eg existing transformer's available voltage tapping range is not suitable). It is also in some instances more economical to install an infill transformer and split the existing LV network rather than upgrade the LV mains.

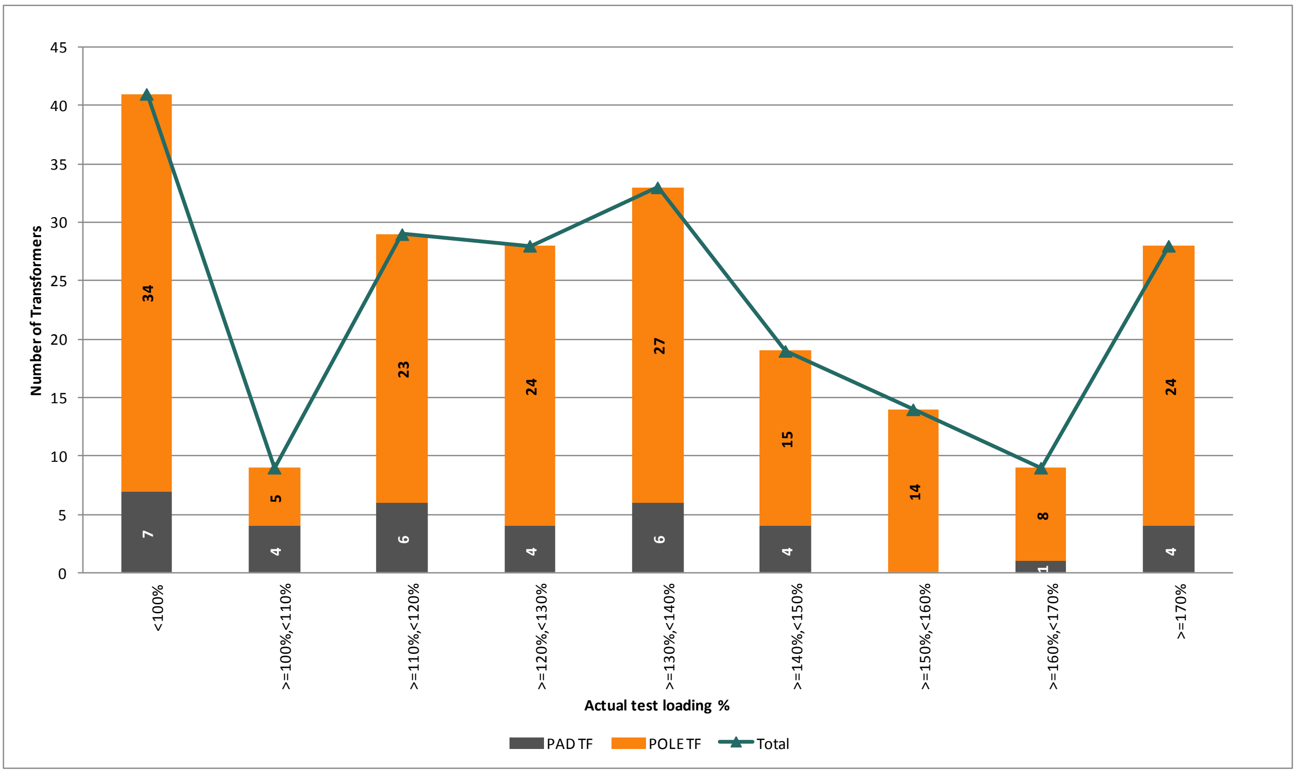


Figure 110: Distribution Substation Transformer Remediated in 2012/13 According to Measured Utilisation

As a general comment it should be noted that SA Power Networks has approximately 72,500 distribution substation transformers, with the majority being outside the metropolitan area, serving only a small number of customers. It is possible that more than 70% of the distribution transformers (ie more than 50,000) in SA Power Networks' distribution network connect to fewer than five customers.

25.3.6 Heatfix Works

During the 2013/14 summer period, remediations following the summer's heatwaves (referred to as Heatfix work) equated to $1 million worth of capital works which is included in the Table 142 above as Major and Minor Project Works. QoS takes into account within the planning process, the performance during peak loading conditions (such as summer hot weather), any consequent distribution transformer HV or LV fuse operations of overloaded distribution transformers or LV circuits. During these situations (ie heatwaves), the performance of the distribution transformer and LV network population is reported daily to management. Heatfix remediation projects are then initiated for inclusion within the QS Major and Minor Project Work budget allocations.

25.3.7 Distribution Transformer Failures due to Overload

QoS reports those distribution transformer failures suspected to be due to overload (only) during the summer months. The transformer's failure is often due to low oil levels creating excessive temperatures and subsequent failure. The overload exacerbates the effects of any previous elevated load / temperature events leading to eventual failure. Failure of the distribution transformer will not usually occur straight away but is inevitable after subsequent heat (high load) events. A leaking or damaged transformer may be noted by SA Power Networks' Asset Inspectors. A failed transformer is normally replaced by Field Services under breakdown maintenance conditions. Where oil leaks before, during or at failure are significant, SA Power Networks' Environmental Branch are notified to be involved in any environmental impact assessment. The most recent transformer specification does not allow any transformer casing seal oil leakage.

	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14
Number of transformer failures	74	61	67	88	23	22	25	12	27

Table 155: Number of Transformer Failures, Due to Overloads, Occurring During Heatwaves

25.3.8 Transformer Remediation Analysis

Table 156 below represents all transformers greater than 100kVA, allocated to each metropolitan council area that require survey load testing according to ADMD analysis. The total pad and pole mounted transformers on an ADMD basis to have loads greater than their nameplate ratings and in particular those transformers that are currently exceeding the planning criteria for pad-mounts (>130% of nameplate) and pole mounts (>100% of nameplate) confirmed by actual test results.

Suburbs within those council areas are used instead of zone substations/feeders because socially/economically selecting ADMD on this basis is more relevant from a planning perspective. feeders often cross suburbs and are dynamic, changing regularly with changing open points and abnormal operations due to faults causing loadings to change across the connected distribution transformers. Within the metropolitan area using suburbs made more sense from a QoS planning perspective. QoS believes that the additional (to the historical ADMD approach) method to forecast transformer loading using the Transformer Load Forecasting model accounts for these locational variations by utilising census data and a geographical location set of data to match transformer locations within suburbs and census areas populated down to 200 to 400 people.

Metro Councils	No. TF Metro	Survey test reqd	Tested >100% (Pad+Pole)	Total Pad TF test >100%	Total Pole TF test >130%	Total Pad Metro	Total Pole Metro
Adelaide	540					531	9
North Adelaide	88	9	2	2	1	78	10
Adelaide Hills Council	523	59	4	0	3	99	424
City of Burnside	510	138	31	2	5	177	333
City of Campbelltown	463	176	9	0	5	195	268
City of Charles Sturt	1885	514	42	1	13	993	892
Town of Gawler	343	52	3	1	1	182	161
City of Holdfast Bay	222	71	11	1	6	84	138
City of Marion	547	205	23	4	4	282	265
City of Mitcham	790	94	34	7	10	254	536
Norwood_Payneham_St Peters	406	84	53	11	9	174	232
City of Onkaparinga	1551	440	14	1	5	896	655
City of Pt Adelaide Enfield	1468	285	50	3	14	773	695
City of Prospect	185	81	6	0	0	46	139
City of Salisbury	1413	301	35	16	8	932	481
City of Tea Tree Gully	818	225	19	9	5	564	254
City of Unley	155	33	12	1	5	75	80
City of West Torrens	395	86	42	7	13	185	210
City of Playford	1027	116	47	44	11	750	277
Total	**13329**	**2969**	**437**	**110**	**118**	**7270**	**6059**

Table 156: Distribution Transformer Test Results by Adelaide Council Area.

Table 157 summarises the transformer survey testing program results.

Total SA Power Networks transformers in Metro & Country (all transformers)	72,500
Metro transformers (>100kVA) supplying multiple customers	13,329
Forecast overloaded Metro transformers >nominal rating – based on ADMD analysis	2,969
Forecast overloaded Metro transformers >nominal rating – based on ISD analysis	618
Completed survey tests average 780 per annum (2009 – 2013)	3,900
Tested overloaded transformer remediations (>planning criteria) in the metropolitan area (>=100kVA) issued for construction (at February 2014)	228

Table 157: Distribution Transformer Survey Testing and Forecast Results.

Table 158 summarises the historical survey testing completed between 2009 – 2013.

	2009	2010	2011	2012	2013	Total survey tests compl 2009-2013	Average per annum
Metro survey tests completed per year	646	878	841	795	741	3,901	780

Table 158: Load Surveys Conducted Between 2009 and 2013.

25.3.9 Remediation Progress and Field Services Backlog of Work Outstanding

Figure 111 below illustrates the progress of the remediation of forecast overloaded distribution transformers confirmed by testing results up to February 2014. Both pole mounted and pad-mounted transformers are represented. The graph is dynamic and will change each month as remediation work progresses.

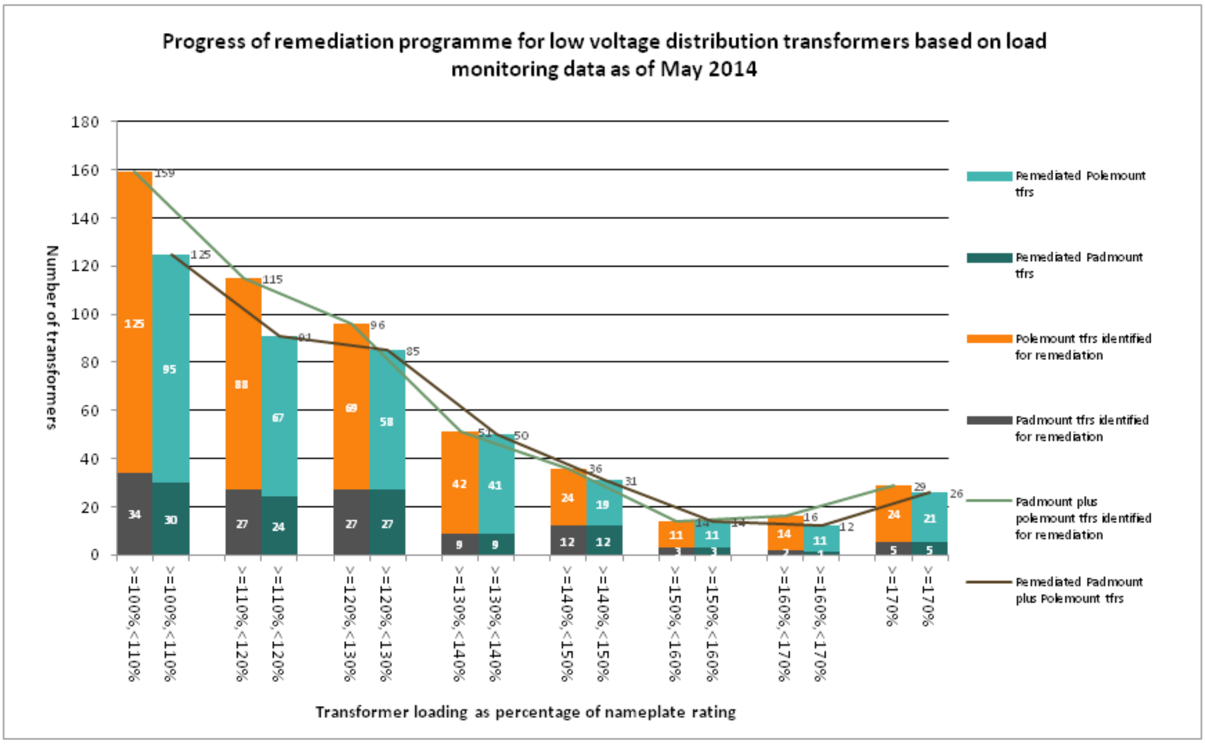


Figure 111: Distribution Transformer Remediation Works as at 2013/14

25.3.10 Planned Improvements in LV Planning

25.3.10.1 ADMD/TLF Modelling

To improve the correlation between calculated average ADMD allocated to each transformer and test results and heatwave fuse operations QoS has developed (refer ISD consultancy report May 2014) an additional method to compare with the historical ADMD approach to forecast overloaded transformers prior to survey (short term) testing. The TLF modelling approach uses a simulation model that considers customer's energy use behaviour and geographic locational data in conjunction with census data (refer 25.3.2).

25.3.10.2 K-Factor

In an attempt to validate or improve the correlation between feeder loads and transformer loads and to account for variances in loading from one season to the next, a small sample analysis of specific transformers applied K-factors was carried out. The analysis results show a reasonable correlation with the K-factor method used as long as the analyst takes into account environmental factors such as seasonal timing (school holidays, commercial and industrial considerations), feeder abnormalities etc. It was noted based on the small sample taken that on average, the K factor method slightly under estimated transformer peak demand. Analysis has demonstrated the benefits of installing targeted permanent transformer monitoring on assets forecast to become overloaded. Details on how the feeder K –factors are derived from SCADA are available in the K – Factor – User Reference Guide.

25.3.10.3 LV Future (Distributed Energy Resources) Modelling

Modelling was undertaken using Powerfactory to model 15 representative feeders across four types of network (ie SWER, metropolitan – old, new and rural) with a range of DER (distributed energy resources such as solar PV, electric vehicle, energy storage and controllable loads). Certain feeders in both the old and new overhead categories showed similar results due to the similarity of the high impedance overhead conductors used within these networks. Those networks within the newer underground areas (comprised mainly of XLPE Aluminium cable) do not show any voltage regulation issues whereas the most overvoltage issues were seen in the old underground areas which are comprised largely of older much higher impedance Copper cables. Unacceptable voltage levels can occur where PV penetration is excessive. Unacceptable voltage imbalance can occur where the amount of PV connected is unevenly distributed across the 3 phases. SA Power Networks have predominantly 433/248V nominal voltage distribution transformers making maintaining voltage levels at within the specified tolerances at times of minimal load (ie during the day) in areas with high PV penetration levels extremely difficult. This challenge has resulted in a recommendation to purchase future transformers already tapped 2.5% lower than the existing neutral tap value to enable SA Power Networks to lower the distribution transformer's output voltage during these times. Consideration however needs to be given to the need to equally maintain adequate voltages during high demand periods which becomes difficult using fixed tap distribution transformers. In addition, it is proposed to install targeted transformer monitoring and targeted voltage regulation to minimise the impacts from widespread DER.

25.3.11 Solar PV Network Impacts

SA Power Networks currently has 215,000 such systems connected to its network as at June 2014. With 840,000 residential customers this represents 26% penetration (based on system/customer numbers). SA Power Networks has monitored PV related customer high voltage enquiries. In the 12 months between May 2012 to May 2013, there were 408 solar PV related high voltage enquiries representing 0.3% of all metered solar PV connections. Between May 2013 to May 2014 there were 297 enquiries with these enquiries peaking during springtime as seen in Figure 112.

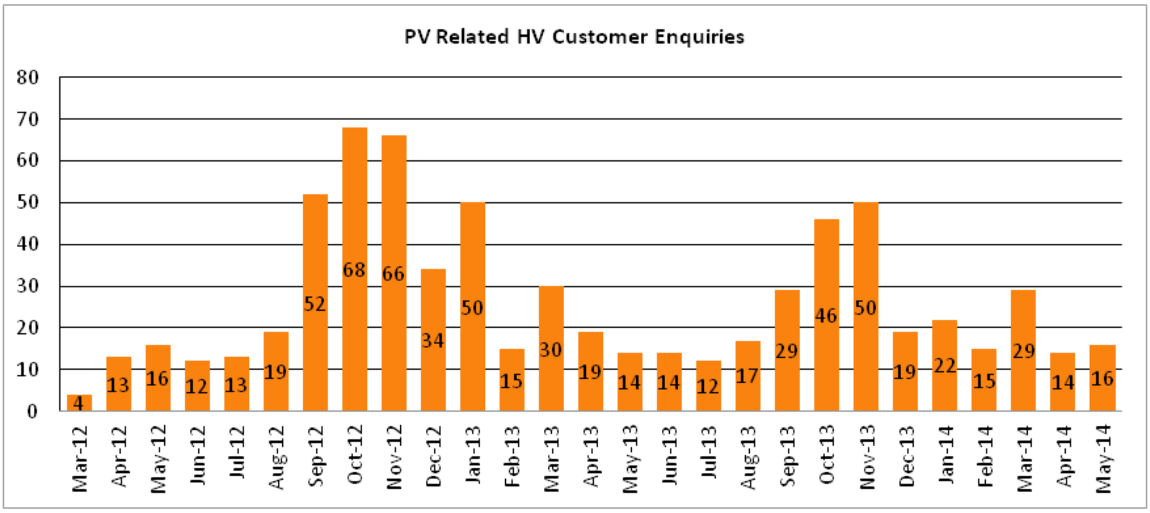


Figure 112: PV Related Enquiries to QoS Between 2012 and 2014.

A detailed customer voltage enquiry analysis of PV related high voltage customer enquiries received in 2012 was conducted in 2013. At that time, there were 88,390 metropolitan PV installations and 43,780 country PV installations. In 2012, QoS received 186 PV related HV enquiries from country based customers and 110 PV related HV enquiries from those within metropolitan Adelaide. Of these enquiries, just over one third were found to be customer related issues (eg consumer's mains too small and often too long); with 62 (33%) of these being located in country areas and 47 (43%) in the metropolitan Adelaide.

There are potentially varying degrees of network impacts as PV penetration levels increase above 20%. These impacts depend on installation size, location in the network, network impedance and customer loads. Increased network voltage monitoring will be essential to pro-actively mitigate issues arising in areas of high PV penetration. The potential impact of varying degrees of PV penetration is seen in Figure 113 below.

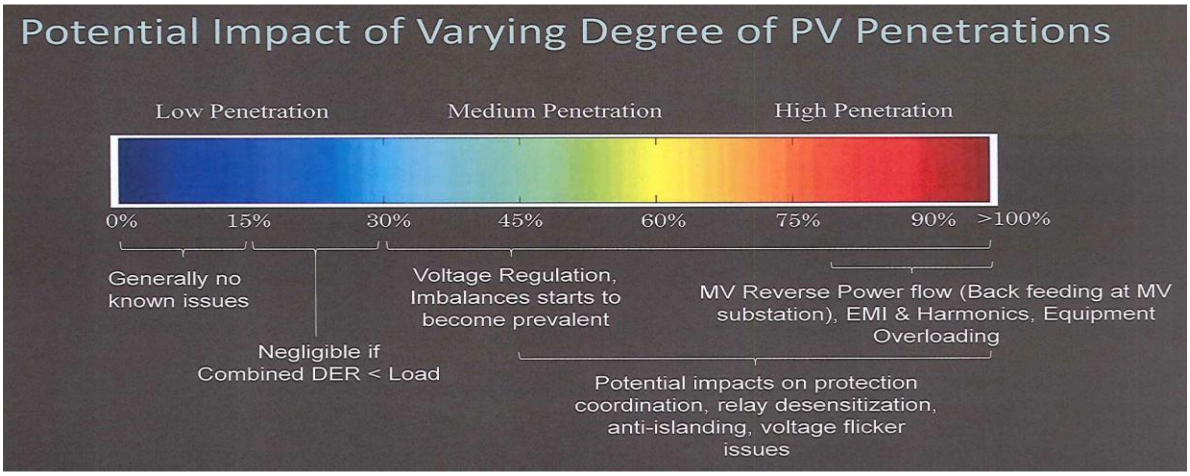


Figure 113: Impact on Networks at Varying PV Penetration Rates

To date, the power quality impacts from solar PV have been limited to some voltage rise above inverter set points and above the upper boundary of standard voltage levels (253V) – usually in high impedance parts of the network and/or instances of inadequately sized consumer's mains installations. Interstate experiences appear to indicate increasing issues associated with PV penetrations in excess of 30%. Preliminary LV modelling indicates that with various combinations of distributed energy resources (DER) such as PV, electric vehicles, energy storage and controllable loads have the potential to create power quality issues that breach current quality of supply standards.

Figure 114 below shows the PV penetration as a proportion of the distribution transformers ratings for the approximately, 72,500 distribution transformers connected to the network from January to April 2014. These penetration volumes are expected to continue to increase despite the State Government suspending the availability of Feed in Tarriff incentives to all new connections from September 2013.

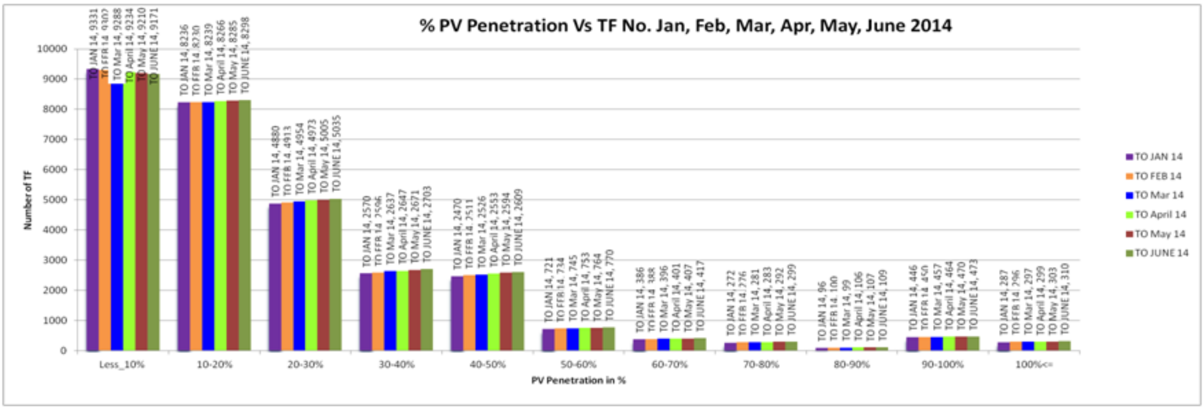


Figure 114: Distribution Transformer PV Penetration Rates.

In order to remediate potential issues associated with increasing PV penetration levels, QoS has included within its plans, various solutions such as upgrading the HV and/or LV network, upgrading to distribution transformers with off-load taps and installing additional voltage regulation. Other higher PV penetration impact solutions such as balancing load/generation across available phases and tapping down transformers are included as operating expenditure proposals. These solutions are viable at penetration rates up to 30%. It is recognised that beyond this penetration level, a more extensive voltage control solution will be required. LV modelling considering all distributed energy resources will confirm where remediation solutions are required.

Reverse power flow network effects from solar PV generation are seen at penetration levels above 20 to 30%. Included in this plan is a provision to replace high voltage regulators where they incapable of supporting bi-directional power flows (refer section 25.2.5.4). Another reverse power effect is the inability for standby generators to supply customers during a mains outage (eg a cable fault) if solar PV is generating reverse power flows. This may be mitigated by setting the standby generator frequency outside of the PV inverter frequency causing it to remain shut down.

25.3.12 Reverse Power and Two Way Power Flow – an illustration

The Figure 115 and Figure 116 below illustrate pad mount transformer HH428D T33024 for two weeks during the 2013 summer. Red trace=kW, blue=kVA, green=kVAr. Temperatures were:

8/02	9/02	10/02	11/02	12/02	13/02	14/02
28.3	28	26.3	28.3	31.2	33.8	34.3

Table 159: Daily Maximum Temperature in 8–14 February 2013.

Figure 115 illustrates how real power (kW) can be reversed (this is what we mean by the term 2 way power flow), due to solar PV generation and apparent power (kVA) and reactive power (kVAr) can remain positive. The red trace below zero illustrates reverse power flow.

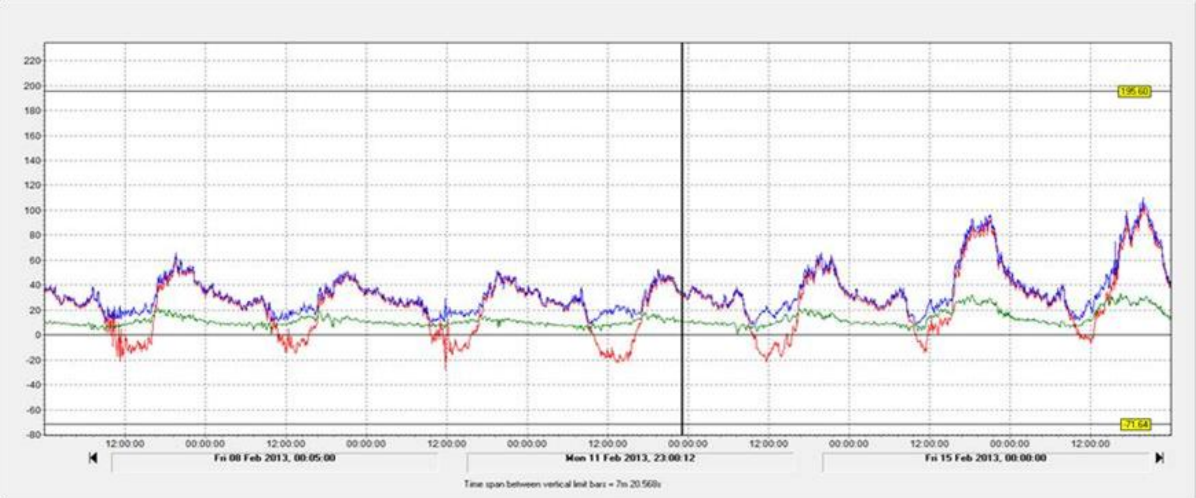


Figure 115: Padmount Transformer Load Recording – part 1.

15/2	16/2	17/2	18/2	19/2	20/2	21/2
36	37.1	39.2	40.5	26.6	28.4	32.1

Table 160: Daily Maximum Temperature 15-21 February 2013

Figure 116 illustrates where a cool change follows a hot few days and (18/2 – 40.5C to 19/2 – 26.6C) with consequent reverse power flow when air-conditioning loads are reduced but solar PV generation is maintained.

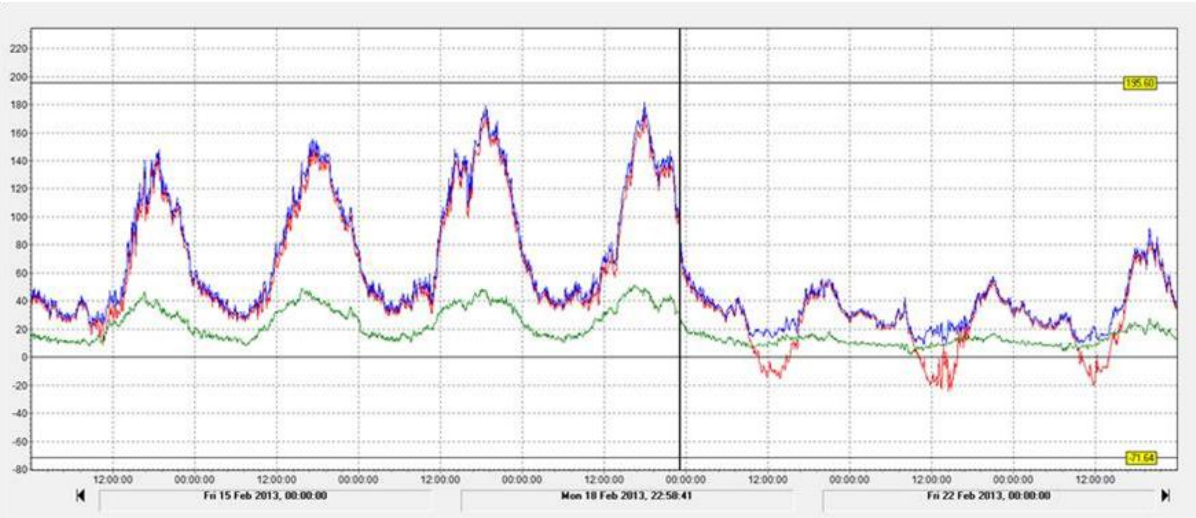


Figure 116: Padmount Transformer Load Recording – part 2.

LVR power flow - PV installation

The graph below taken from a PQ logger installed at an LVR (low voltage regulator) demonstrates the effect an LVR has on voltage and power flow on a customer's solar PV installation. The black trace indicates the regulated voltage on the customer's side of the LVR. The regulated voltage is maintained at a predetermined voltage set point on the customer side however the voltage is boosted on the unregulated side to a higher level (red trace) to allow the customer to export power whilst the customer voltage is maintained at a constant level. Note the power flow at minus 6kW indicates power flowing back to the grid from the customer.

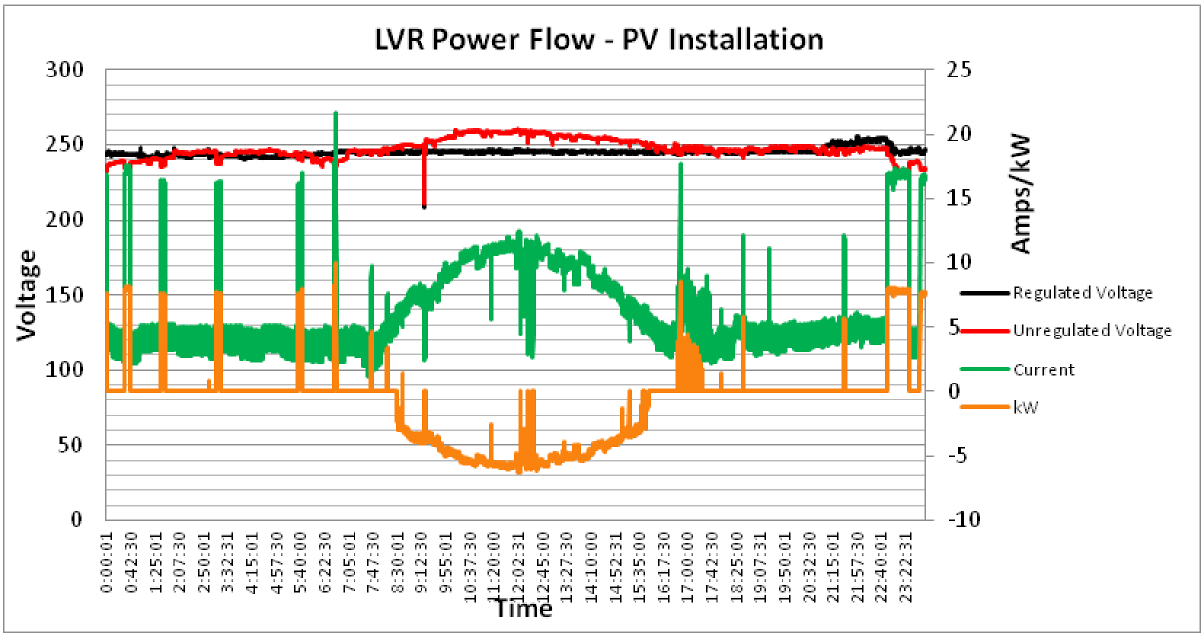


Figure 117: Effect of LVR on Consumer Voltage.

25.3.13 Replacing existing HVR with bi-directional HVR (with CL6 controllers SCADA connected)

Increasing solar PV penetration (greater than 30%) on country feeders (refer Figure 113 above) is generating reverse power flows and related customer enquiries concerning elevated voltages above AS60038 Standard (>253V). Some existing line high voltage regulators (HVR) cannot accept reverse power flows and will need to be replaced with more modern installations (with CL6 controllers that are SCADA enabled).

SA Power Networks has 309 HVR on the SWER (40%) and 11kV (60%) networks. Some short term remediation at supply transformers with off-load tapping facilities has been implemented to reduce output voltages and low voltage regulators (LVR) have been installed to assist the provision of reverse power flow capability. However, in the longer term, with increasing solar PV penetration a more universal solution is required to maintain feeder voltage (HV) regulation.

It is proposed to include in this AMP a provision to replace a total of 25 HVR units, 10 in the SWER network and 15 in the 11kV network where there is greater than 30% solar PV penetration. The total capex required (refer Attachment APPENDIX P) is $2 million over five years.

The replacement program will be triggered by customer high voltage enquiries where the HVR can not accept bi-directional power flow and as a consequence the HVR will need to be replaced.

25.3.14 Electric Vehicle (EV) Penetration Impact

QoS is not expecting significant LV network impact in the 2015-2020 period from EV penetration into the LV network at 2% take up by 2020. However, SA Power Networks needs to prepare the LV network for the forecast rise in EV penetration to 10% by 2025 and potentially 25% by 2030 (refer ISD Report, October 2013).

Also refer to the DSP Final Report, Appendix A, Trial XI, Electric Vehicles, June 2014.

Plug in hybrids, traditional hybrids and internal combustion vehicles may dominate the Australian light vehicle market with battery (only) powered vehicles at low volumes possibly due to driver concern about charging station availability. We may expect the majority of residential charging to be done in the off peak early hours of the morning with appropriate tariff incentives.

	2015/16	2016/17	2017/18	2018/19	2019/20
EV Uptake	6,064	7,718	10,007	13,561	21,092
Total Vehicles	1,056,917	1,056,917	1,056,917	1,056,917	1,056,917
% EV	0.57	0.73	0.95	1.28	2.00

Table 161: Forecast EV Uptake Rates

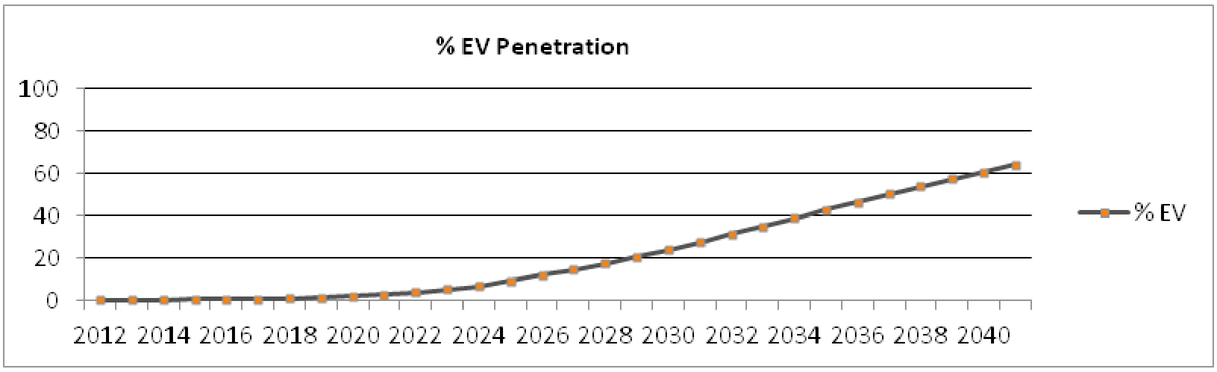


Figure 118: Forecast Percentage of Electric Vehicle Penetration.

Vehicle Type	2015/16	2016/17	2017/18	2018/19	2019/20
ICE - New Internal Combustion Engine	97.1	96.5	95.2	92.7	84.6
BEV - New Battery Electric Vehicle	0.6	0.6	0.7	0.6	0.6
HEV - New Hybrid Electric Vehicle	1.2	1.7	2.7	4.7	9.3
PHEV - New Plug-in Hybrid Electric Vehicle	1.0	1.2	1.5	2.1	5.4

Table 162: New Vehicle Purchase Breakdown (in %)

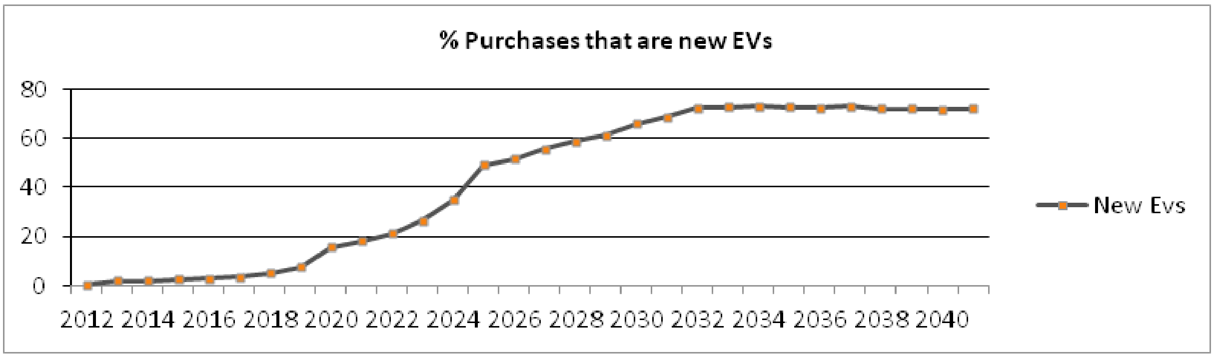


Figure 119: Forecast Electric Vehicle Purchases.

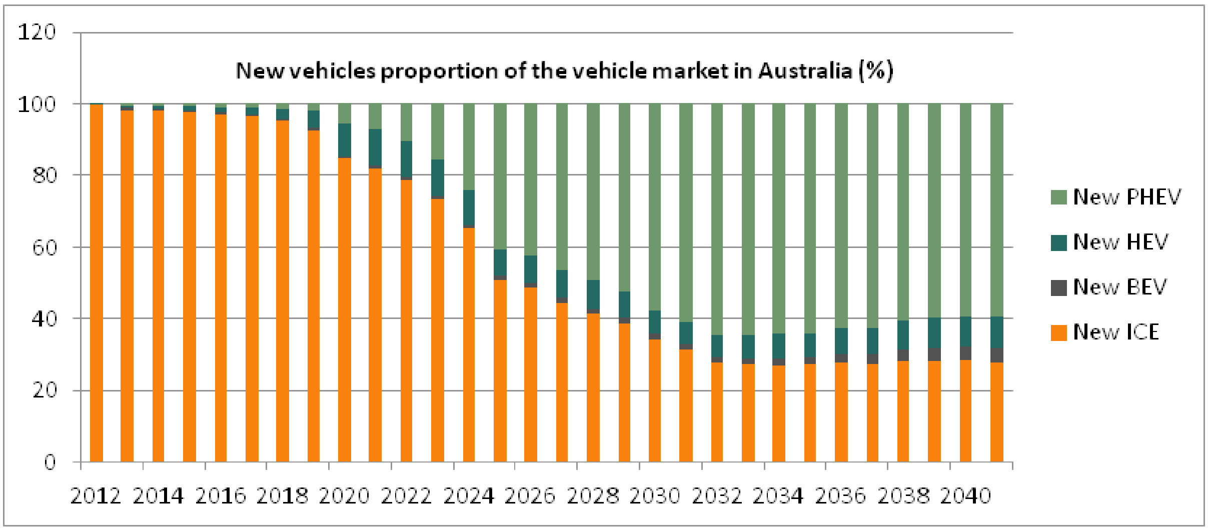


Figure 120: Forecast of Vehicle Types.

In summary, it is expected that the LV network impact from electric vehicle charging will increase significantly in the 2020-2025 regulatory period. No additional allowance made for LV network impact the 2015-2020 regulatory period for electric vehicles. However, is expected will be necessary in the 2020 – 2025 period.

25.3.15 Energy Storage (ES) Penetration Impact Mitigation

Distribution engineers anticipate increasing challenges managing high penetrations of solar photovoltaics on the local distribution system. Energy storage systems can provide local voltage and VAR support, and manage intermittent variation in photovoltaic loads. These benefits will certainly have value where solar generation is concentrated on the distribution system, but that value is difficult to quantify as alternative strategies for managing concentrated photovoltaics are still being developed.

Further ES studies are needed to assess the energy storage impact on the LV network however this is unlikely to be detrimental to network performance. ES using Lithium-Ion batteries will become more significant as the purchase price for ES reduces. Factors influencing battery price may be associated with the worldwide use of Lithium-Ion batteries in battery electric vehicles. As we can see from the above studies, this is likely to be a factor post 2020.

At this stage the ES already in the network is mainly using traditional Lead Acid batteries however several businesses, are marketing Li-Ion battery solutions. These installations are having negligible impact on the network at the time of writing and it is expected that this will carry through the regulatory period to at least 2020. Any impact will be absorbed into the Major and Minor Works capex allocation in Table 1 above. No additional allowance made for LV network impact the 2015-2020 regulatory period for electric vehicles. However, expect will be necessary in the 2020 – 2025 period.

25.3.16 The Future – Solar PV with Energy Storage (ES)

2014 sees the beginning of a new era for the solar PV industry in SA without significant favourable subsidies and premium feed in tariffs (FiT) – finished 30 September 2013. In the short term Retailers will continue to offer the statutory, about 8c/kWh incentive and commercial customers will continue to receive subsidies. With an average ES system size between 3kW and 5kW many new customers, without network FiT may look to store their energy for night time use.

A typical home energy system, pictured below, could include: 3 kW Solar System, 3kW Inverter, 10.7kWh Lithium-ion Battery Pack and a Home Monitoring Device (pictured left). Although all of these products are available in the market, energy storage is still cost prohibitive for many residential customers. Financial options such as leasing may become more common although not generally the Australian way. The historical distribution network is in gradual transition from a central generation and distribution network model to a local distributed energy resources model with network back up.

Figure 121: Future Energy Devices[39]

The Customer's Home of the Future

Maintaining power quality standards remains a high priority customer expectation. The home of the future could well include:

- Onsite generation used to supply electricity and heat with excess electricity exported to the grid for sale to Retailers.
- Solar PV harnessing energy from the sun, generating electricity for home use and thermal energy for water heating.
- Mini and micro wind turbines suited to the suburban environment will increasingly be installed
- Electric vehicles will be increasingly plugging in to re-charge batteries that offer a source of energy storage.
- Energy management systems will be a standard feature in many homes, co-ordinating local generation, energy storage and the consumption of energy.

[39] Pictures from Energeia's Report – Solar Market Insights Sept 2013

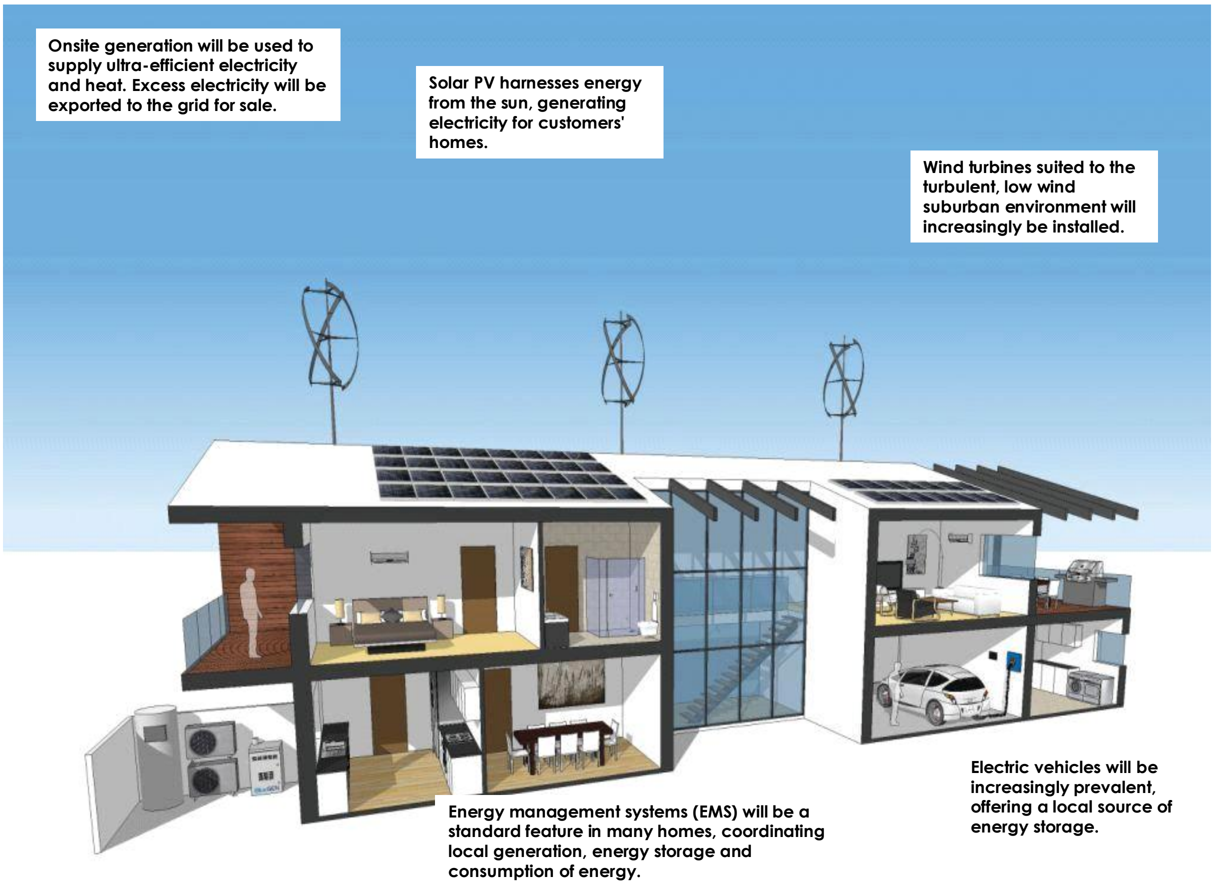


Figure 122: Home of the Future[40].

The table below summarises the customer initiatives, material impacts and plan.

Customer Initiative	Material impact period	Planned Remediation Expenditure in 2015-2020	Strategic Plan
Embedded generation	2015-2020	Yes	Targeted voltage regulation and transformer monitoring
Electric vehicle chargers	2020-2015	No	Targeted voltage regulation and transformer monitoring
Energy storage	2020-2025	No	Targeted voltage regulation and transformer monitoring

Table 163: Possible Customer Intiative, Impacts and Strategies.

[40] Source SA Power Networks' Future Operating Model 2013

26. SWER SYSTEM DEVELOPMENT PLAN

26.1 Executive Summary

The Quality of Supply (QoS) Team forms part of Network Planning Branch within the larger Network Management Division. The QoS Team's principle aim is to ensure that customer and network supply quality complies with relevant statutory and regulatory requirements, Australian Standards and industry practices.

The QoS team has two principal areas of work. Operationally, QoS ensures customer's quality of supply enquiries are adressed. The QoS group also monitors and plans SA Power Networks' SWER network. This is mainly aimed at ensuring the SWER network, consisting of 430 SWER systems (with SWER isolating transformers, distribution transformers and associated mains and services) have adequate capacity and that the power quality of these systems comply with our supply standards. A key focus is to ensure customers connected to these networks have access to a two way power network that allows power flows, from loads and embedded generators.

Compliance with Quality of Supply standards includes resolving issues associated with steady state voltage levels, voltage fluctuations, flicker, voltage sag, voltage unbalance, voltage differences between neutral and earth (including shock reports) and harmonic content of voltage and current waveforms.

SWER systems can have positive growth even though the region they are in has zero or negative growth (refer load forecast). Often SWER systems need to be upgraded for quality of supply reasons including voltage variations/fluctuations, length of the SWER or other reasons. These upgrades commonly take one of two forms:

1. Splitting of a single SWER into two separate SWER systems; or
2. Conversion of either all or part of the SWER system to 11kV.

Adequately funded management of the SWER network is essential to ensure customer's can connect both their loads, such as air-conditioners and their embedded generation, such as solar PV systems. The SWER network must be prepared for the future connection of energy storage installations and electric vehicle charging. To adequately manage the network, in addition to SCADA data on the high voltage network, QoS proposes to install power quality metering on the SWER network. This means monitoring transformer loads, strategic voltage regulator and recloser status and maintaining customer's voltage levels within Standards.

Table 164 shows the historical expenditure on the SWER network over the last 5 years, equating to an average of $1.41M per year in $2013.

Historical Expenditure	2008/09	2009/10	2010/11	2011/12	2012/13
SWER Network Expenditure ($M2013)	0.17	0.19	0.92	4.12	1.67

Note: Costs include all Overheads, real ($2013)

Table 164: Historic Expenditure on SWER Augmentations

Table 165 shows a Summary Table 2015 - 2020 SWER Capacity Plan Submission, equating to an average $1.5 million per annum. The total 2015-2020 SWER Capacity Plan is $7.5 million over five years.

Work Descriptor	2015/16	2016/17	2017/18	2018/19	2019/20
SWER Network Funding (Based on 2013 Estimated $M Costs)	$1.815	$1.48	$1.4	$1.4	$1.4

Note: Costs include all Overheads , real ($2013)

Table 165: Forecast SWER Augmentation Expenditure

In addition to this SWER Capacity Plan, it is planned to convert Port Neill ($4.5 million), Dublin ($0.3 million) and Port Parham ($0.4 million) Townships from SWER supply to a traditional 11kV supply – refer to APPENDIX AB and APPENDIX AC below.

26.2 Background

SA Power Networks has 441 SWER (Single Wire Earth Return) systems in the rural areas of SA. The post war Playford Government developed the Electricity Trust of South Australia (ETSA) in 1946, initially serving the Adelaide metro area with local councils serving the country areas. Amalgamations through to the 1980's saw councils slowly relinquish their electricity networks to ETSA. Widespread 19kV SWER networks were first installed in the 1950's as a cost effective electricity supply network to service rural customers. SWERs are generally supplied from either 33kV or 11kV networks.

Land use has changed across many areas of SA since the installation of these networks resulting in high growth rates along coastal areas, housing developments enveloping farming acreages and an ageing population, developing river and coastal shack areas, for retirement living. Customers have an expectation that the SWER networks are managed (not overloaded) to ensure their capability to supply customer's needs within supply quality standards. An increasing need is the capability of two way power flows that enable customers to export their generated energy (solar PV) into the network.

About 90 pole mounted SWER isolating transformers are routinely load tested on a rotational program every year – limited by the availability of testing devices. To replace this short term testing program, SA Power Networks proposes to install metering on these systems to enable us to continuously monitor the loads on selected isolating transformers (long term monitoring). Remotely readable long term LV monitors will be installed at the start and end of line at 740 sites. The key assumption is that we can load SWER isolating transformers up to 120 to 130% of their nameplate rating, after which a 100 and 150kVA transformer requires upgrading to a maximum of 200kVA. An existing overloaded 200kVA SWER isolating transformer will require a SWER system to be split into two SWER systems. The planning criteria applied to the SWER network designates that a constraint requiring augmentation of the SWER network exists where:

- the load on the SWER isolating transformer is greater than 120% of the nameplate rating.
- Generally where a 200kVA isolating transformer's nameplate rating is exceeded by 30%, QoS plan to split the SWER to reduce the load on the isolating transformer whilst ensuring the protection system is still effective under all operating conditions – sometimes this requires extension of the 33kV or 11kV network.
- Further consideration is given to those systems where a number of QoS related customer enquiries are received regarding voltage levels. These often result in

installation of additional HV or LV voltage regulation. Load growth is more prevalent on those SWER systems supplying coastal or riverside shack areas where customers have developed their properties.

For a 200kVA SWER isolating transformer, we allow up to 120% cyclic peak load of 13.65 A at 19kV or a 15A recloser coil sensitivity with 30A pick up. Such a high pickup means the SWER length is limited, as is the allowable pole footing resistance, unless we install additional mid-line reclosers (only practicable if load is evenly distributed – ie not all at one end). The question of what solution to use becomes a normal feeder upgrade question. Guidelines include:

1. Any solution should last for five or more years;
2. The chosen solution should be lowest NPV;
3. The chosen solution should meet any relevant guidelines eg the protection listed above, quality of supply standards such as voltage levels – do EOL voltage levels require a voltage regulator.

The capacity of a SWER Network is dependent on the rating of the SWER isolating transformer. Upgrades to the SWER Network are based on converting SWER to 11kV or upgrading the existing isolating transformer to a 200kVA unit and the installation of a SCADA enabled line recloser or installing voltage regulation and improved protection systems where necessary or splitting the existing SWER network and creating an additional SWER network.

26.3 2015-2020 SWER Remediation Program

The 2015-2020 SWER Remediation Program uses the number of projects each year and the average unit costs in Table 166 below. The transformer loadings will be confirmed by load monitoring and an analysis of QS customer voltage enquiries. The average unit costs below are based on recent SWER projects undertaken, however in each case, a SCADA enabled line recloser has been added. Unit costs for these reclosers range from $54,000 to $77,000 to upgrade existing SWER E-type recloser to a SWER Nulec electronic reclosers with SCADA control. The unit cost used is $65,000 per installation (in $2013 inclusive of overheads). When a specific SWER design is completed its estimated cost will be reflected in the capacity plan. Table 166 below shows the typical unit costs for each augmentation method.

Solution Option	Ave Unit Cost ($) (incl all overheads)
Upgrade SWER Isolating Transformer	35,000
SCADA enabled recloser	65,000
Split SWER	Project specific
Extend 11kV and split SWER	Project specific

Table 166: SWER Remediation Costs

In the tables below the selection of projects is based on three month SWER tests undertaken over 6 months between December 2013 and May 2014. The peak load in Amps and as a percentage of the SWER isolating transformer capacity is recorded as is the date of the peak load. These recordings are downloaded from the testing device and placed on SA Power Networks' intranet.

APPENDIX AA below represents those SWERs that have had their SWER isolating transformers tested above 110% of their nameplate rating sorted in order of their percentage overload. The solution assumed is to upgrade the 100kVA or 150kVA SWER isolating transformer to a 200kVA unit with a SCADA connected electronic protection line recloser. Whilst this allows for further customer load growth over regulatory period, other factors (eg power quality and enabling a two way network) also need to be considered.

APPENDIX AB below represents a number of SWER networks where customers have made voltage complaint enquiries and a simple SWER isolating transformer upgrade will not adequately resolve the quality of supply issues. The solutions considered, before detailed design and analysis has been undertaken, are to extend the 11kV network in some cases and split the SWER system by adding another SWER isolating transformer. Each individual project will have an approved business case. APPENDIX AA and APPENDIX AB costs are summed in Table 165 above.

Significant SWER augmentation projects over the period include:

Makin SWER ($1.5 million) – near Bordertown (BT23), where customers have complained to their MP, Council and Industry Ombudsman concerning widespread low voltages at peak load times due to the length of the SWER network, despite installed voltage regulation devices and the number of customers supplied from the SWER, overloading the isolating transformer by 54% above nameplate rating. Sheep farmers complain of wool presses not having sufficient power (excessive voltage drop under load) to operate. Network modelling indicates that a suitable solution is to extend the 11kV by 16km and split the SWER into two systems. A general comment is that high voltage regulators do not assist in an efficient two way network due to their relatively slow response and reverse power flow issues. The SWER split will add an additional isolating transformer, to create two shorter SWERs.

Lake Bonney SWER (MI17) – this system has been heavily loaded (8.6A) since at least 2001. This system supplies a rural area, including dairies, east of Lake Bonney and Millicent. The isolating transformer was tested to be 29% overloaded. It is proposed to upgrade the SWER isolating transformer and recloser and split the existing system by adding an additional transformer and recloser to create a new SWER. Extend the 11kV to the new isolating transformer and split the SWER. Construction is planned for 2017/18 and is estimated to cost $0.315 million.

Weetulta SWER (MT02) on Yorke Peninsula – it is proposed to split the SWER and add another transformer and recloser for a new SWER, as the 200kVA SWER isolating transformer was tested to be 17% overloaded. Yorke Peninsula is seen as a growing area within 2 hours drive from Adelaide and is likely to see load growth over the next 5 years. Construction is planned for 2019/20 and is estimated to cost $0.4 million.

Dublin Township SWER (GA24) – It is proposed that this SWER system, is converted to 11kV for an estimated $0.4 million with construction in 2017/18. The system runs through the main street and some of the LV areas are overloaded creating low voltage problems. There are potentially safety and operational issues. Existing 11kV is nearby the main street. This project will improve customer service, enable a two way network and assist the township to attract new developments and bring their electricity supply arrangements in line with the majority of other SA country towns.

Elwomple SWER (MB64) - it is proposed to split the SWER and add another transformer and recloser for a new SWER, as the 200kVA SWER isolating transformer was tested to be 17% overloaded. The Murraylands is seen as potentially a growing area within 1.5 hours drive from Adelaide and is likely to see load growth over the next 5 years. Construction is planned for 2019/20 and is estimated to cost $0.4 million.

Port Parham Township/Webb Beach SWER (GA17) – It is proposed that this system, west of Windsor and Mallala, is converted to 11kV for an estimated $0.4 million with construction in 2017/18. The SWER runs through the main street and some of the LV areas of the SWER transformers are tied together because of low voltage problems. There are potential safety and operational issues. Existing 11kV is nearby the main street. This project will improve customer service, enable a two way network and attract new developments and bring their electricity supply arrangements in line with the majority of other SA country towns.

In addition to the program below, it is proposed to convert the Port Neill Township SWER system from three 19kV SWER systems to 11kV. This work is estimated to cost $4.5 million and is proposed to commence design in 2015 with construction in 2015/16. This project will assist the township to attract new developments and bring their electricity supply arrangements in line with the majority of other SA country towns. This proposed project will improve operational safety and supply reliability. This project has a separate business case.

27. APPENDIX A – ADELAIDE CENTRAL REGION FORECASTS

27.1 Zone Substation Forecasts

Zone Substation	Forecast Basis	Units	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2012/22	2022/23	20223/24	2024/25
Coromandel Place 11kV	10% PoE	MVA	54.2	53.5	52.7	52.0	51.3	50.4	49.6	48.8	48.0	47.3
	50% PoE		51.0	50.4	49.8	49.2	48.7	48.0	47.3	46.6	45.9	45.3
East Terrace 11kV	10% PoE	MVA	43.7	43.1	42.5	41.9	41.2	40.6	39.9	39.3	38.6	38.0
	50% PoE		41.0	40.5	40.0	39.5	39.0	38.4	37.8	37.3	36.8	36.2
Hindley Street 11kV	10% PoE	MVA	42.4	41.8	41.2	40.6	40.0	39.4	38.8	38.1	37.5	36.9
	50% PoE		39.5	39.1	38.6	38.2	37.7	37.2	36.6	36.1	35.6	35.1
Whitmore Square 11kV	10% PoE	MVA	43.0	42.3	41.7	41.0	40.4	39.8	39.1	38.5	37.8	37.2
	50% PoE		39.9	39.4	38.9	38.4	37.9	37.3	36.8	36.2	35.7	35.2
East Terrace 33kV	10% PoE	MVA	16.3	16.1	15.8	15.6	15.4	15.1	14.9	14.7	14.4	14.2
	50% PoE		15.4	15.3	15.1	14.9	14.7	14.5	14.3	14.1	13.9	13.7
Hindley Street 33kV	10% PoE	MVA	9.4	9.3	9.2	9.0	8.9	8.8	8.6	8.5	8.3	8.2
	50% PoE		8.9	8.8	8.7	8.6	8.5	8.4	8.3	8.1	8.0	7.9

Table 167: ACR Zone Substation Forecasts

28. APPENDIX B – METRO NORTH REGION FORECASTS

28.1 Connection Point Forecasts

Forecast Basis	Units	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
10% PoE	MVA	325.0	329.0	319.9	328.7	332.5	336.3	339.9	343.4	346.9	350.2
	PF	1.00	1.00	1.00	1.00	1.00	1.00	0.99	0.99	0.99	0.99

Table 168: Metro North Connection Point Forecasts

28.2 Zone Substation Forecasts

Zone Substation	Forecast Basis	Units	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2012/22	2022/23	20223/24	2024/25
Angle Vale 11kV	10% PoE	MVA	18.7	19.0	19.3	19.5	19.7	19.8	19.9	20.0	20.1	20.2
	50% PoE		17.2	17.5	18.0	18.2	18.5	18.7	18.9	19.1	19.3	19.4
Bolivar 11kV	10% PoE	MVA	[redacted]									
	50% PoE											
Direk 11kV	10% PoE	MVA	24.7	24.6	24.7	24.7	24.6	24.6	24.6	24.6	24.6	24.6
	50% PoE		22.9	22.8	23.0	22.9	22.9	22.9	22.9	22.9	22.9	22.9
Edinburgh 11kV	10% PoE	MVA	18.1	18.2	8.9	8.9	9.0	9.1	9.1	9.2	9.3	9.3
	50% PoE		17.3	17.4	8.0	8.0	8.1	8.2	8.3	8.3	8.4	8.5
Elizabeth Downs 11kV	10% PoE	MVA	49.4	50.6	52.2	53.4	54.7	56.0	57.2	58.5	59.7	60.9
	50% PoE		44.5	45.6	47.1	48.2	49.4	50.6	51.8	52.9	54.1	55.2
Elizabeth Heights 11kV	10% PoE	MVA	20.2	20.3	20.5	20.6	20.7	20.7	20.7	20.7	20.7	20.8
	50% PoE		18.3	18.4	18.7	18.7	18.8	18.9	18.9	19.0	19.0	19.0
Elizabeth South 11kV	10% PoE	MVA	20.1	20.3	11.8	12.0	12.3	12.6	12.8	13.1	13.4	13.7
	50% PoE		18.6	18.5	9.6	9.5	9.4	9.4	9.4	9.3	9.3	9.3
Evanston 11kV	10% PoE	MVA	38.3	39.3	40.4	41.3	42.2	43.0	43.7	44.5	45.2	45.9
	50% PoE		34.9	35.9	37.2	38.1	39.2	40.0	40.8	41.7	42.5	43.3

Zone Substation	Forecast Basis	Units	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2012/22	2022/23	20223/24	2024/25
Parafield Gardens 11kV	10% PoE	MVA	26.3	27.0	27.8	33.9	34.5	35.1	35.6	36.0	36.5	37.0
	50% PoE		24.3	25.1	25.9	32.1	32.8	33.4	33.9	34.4	34.9	35.4
Paralowie 11kV	10% PoE	MVA	17.9	18.1	18.4	18.6	18.8	18.9	19.1	19.2	19.3	19.5
	50% PoE		16.9	17.2	17.6	17.9	18.2	18.4	18.7	18.9	19.2	19.4
Penfield 11kV	10% PoE	MVA	35.8	36.4	37.3	37.8	38.4	39.2	39.9	40.6	41.2	41.9
	50% PoE		33.1	33.6	34.4	34.9	35.5	36.1	36.8	37.4	38.0	38.6
Salisbury 11kV	10% PoE	MVA	57.7	57.7	58.1	58.0	58.0	58.2	58.3	58.5	58.6	58.7
	50% PoE		52.7	52.7	53.1	53.0	52.9	53.0	53.1	53.2	53.3	53.3
Virginia 11kV	10% PoE	MVA	10.4	10.5	10.7	10.8	11.0	11.0	11.1	11.1	11.2	11.2
	50% PoE		9.4	9.5	9.6	9.6	9.7	9.7	9.7	9.7	9.7	9.7

Table 169: Metro North Zone Substation Forecasts

29. APPENDIX C – METRO SOUTH REGION FORECASTS

29.1 Connection Point Forecasts

Forecast Basis	Units	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
10% PoE	MVA	639.8	641.6	642.7	643.8	645.1	644.2	643.4	642.6	641.8	641.0
	PF	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00

Table 170: Metro South Connection Point Forecasts

29.2 Zone Substation Forecasts

Zone Substation	Forecast Basis	Units	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2012/22	2022/23	20223/24	2024/25
Aldinga 11kV	10% PoE	MVA	19.5	20.4	21.4	22.3	23.3	24.1	24.8	25.6	26.4	27.1
	50% PoE		16.9	17.8	18.6	19.4	20.2	20.9	21.5	22.2	22.8	23.4
Ascot Park 11kV	10% PoE	MVA	20.3	20.7	21.0	21.3	21.7	21.9	22.1	22.3	22.6	22.8
	50% PoE		17.5	17.9	18.2	18.5	18.9	19.1	19.3	19.5	19.8	20.0
Blackwood 11kV	10% PoE	MVA	26.2	26.2	26.1	26.0	25.9	25.8	25.6	25.5	25.3	25.1
	50% PoE		22.2	21.9	21.5	21.2	20.9	20.4	20.1	19.7	19.3	18.9
Clarence Gardens 11kV	10% PoE	MVA	18.5	18.5	18.6	18.6	18.6	18.5	18.4	18.3	18.2	18.2
	50% PoE		15.9	15.9	15.9	15.9	15.9	15.8	15.7	15.6	15.5	15.4
Clarendon 11kV	10% PoE	MVA	2.9	2.9	3.0	3.0	3.1	3.1	3.1	3.1	3.1	3.1
	50% PoE		2.5	2.6	2.6	2.6	2.7	2.7	2.7	2.7	2.7	2.7
Cudmore Park 11kV	10% PoE	MVA	17.5	17.1	16.8	16.5	16.2	15.9	15.6	15.3	15.1	14.8
	50% PoE		15.8	15.4	15.0	14.6	14.2	13.8	13.5	13.1	12.7	12.4
Glenelg North 11kV	10% PoE	MVA	17.3	17.5	17.8	18.0	18.2	18.3	18.4	18.5	18.6	18.7
	50% PoE		15.3	15.6	15.8	16.1	16.4	16.5	16.6	16.8	16.9	17.1

Zone Substation	Forecast Basis	Units	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2012/22	2022/23	20223/24	2024/25
Hackham 11kV	10% PoE	MVA	13.4	13.4	13.4	13.3	13.3	13.2	13.2	13.1	13.1	13.0
	50% PoE		11.6	11.6	11.6	11.6	11.6	11.5	11.4	11.4	11.3	11.3
Happy Valley 11kV	10% PoE	MVA	32.8	32.7	32.6	32.4	32.3	32.1	31.8	31.6	31.4	31.2
	50% PoE		28.4	28.3	28.1	28.0	27.9	27.7	27.5	27.3	27.1	26.9
Happy Valley SAW	10% PoE	MVA	[redacted]									
	50% PoE											
Keswick 11kV	10% PoE	MVA	37.9	38.0	38.0	38.0	38.0	37.9	37.7	37.6	37.5	37.4
	50% PoE		34.5	34.5	34.4	34.3	34.2	34.0	33.8	33.6	33.4	33.2
Kingswood 11kV	10% PoE	MVA	47.9	48.1	48.3	48.4	48.6	48.6	48.6	48.6	48.7	48.7
	50% PoE		41.7	42.0	42.2	42.4	42.6	42.7	42.7	42.8	42.8	42.9
Lonsdale 11kV	10% PoE	MVA	[redacted]									
	50% PoE											
Lower Mitcham 11kV	10% PoE	MVA	19.2	19.3	19.3	19.3	19.3	19.3	19.3	19.3	19.3	19.3
	50% PoE		16.5	16.4	16.3	16.1	16.0	15.9	15.8	15.7	15.5	15.4
McLaren Flat 11kV	10% PoE	MVA	10.5	10.6	10.7	10.9	11.0	11.1	11.2	11.4	11.5	11.6
	50% PoE		9.0	9.0	9.0	9.0	8.9	8.9	9.0	9.0	9.0	9.0
McLaren Vale 11kV	10% PoE	MVA	2.5	2.5	2.6	2.6	2.7	2.7	2.8	2.8	2.8	2.9
	50% PoE		2.1	2.2	2.2	2.3	2.4	2.4	2.4	2.4	2.5	2.5
Morphett Vale East 11kV	10% PoE	MVA	32.0	31.5	30.9	30.4	29.9	29.2	28.6	27.9	27.3	26.6
	50% PoE		28.0	27.7	27.3	27.0	26.6	26.1	25.6	25.1	24.6	24.2
Morphettville 11kV	10% PoE	MVA	22.8	23.0	23.2	23.4	23.6	23.6	23.7	23.8	23.8	23.9
	50% PoE		20.1	20.3	20.4	20.5	20.6	20.6	20.7	20.7	20.7	20.7
Noarlunga Centre 11kV	10% PoE	MVA	17.7	17.4	17.1	16.8	16.6	16.3	16.0	15.8	15.5	15.3
	50% PoE		16.3	16.2	16.1	16.0	15.8	15.7	15.6	15.5	15.4	15.3
North Unley 11kV	10% PoE	MVA	18.5	18.3	18.1	17.9	17.7	17.6	17.4	17.2	17.0	16.8
	50% PoE		16.4	16.2	16.1	15.9	15.7	15.5	15.3	15.1	14.9	14.8

Zone Substation	Forecast Basis	Units	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2012/22	2022/23	20223/24	2024/25
Oaklands 11kV	10% PoE	MVA	42.6	42.7	42.6	42.6	42.6	42.4	42.1	41.9	41.7	41.4
	50% PoE		37.4	37.4	37.3	37.2	37.1	36.8	36.5	36.2	35.9	35.6
Panorama 11kV	10% PoE	MVA	23.4	23.4	23.5	23.5	23.5	23.5	23.4	23.4	23.3	23.3
	50% PoE		20.4	20.5	20.5	20.6	20.6	20.6	20.6	20.5	20.5	20.5
Plympton 11kV	10% PoE	MVA	19.5	19.2	19.0	18.7	18.4	18.1	17.7	17.4	17.0	16.7
	50% PoE		17.3	17.0	16.8	16.5	16.2	15.9	15.5	15.2	14.9	14.5
Port Noarlunga 11kV	10% PoE	MVA	28.0	28.8	29.6	30.3	31.1	31.7	32.3	32.9	33.5	34.0
	50% PoE		24.9	25.8	26.6	27.4	28.2	28.8	29.4	30.0	30.6	31.2
Port Stanvac 11kV	10% PoE	MVA	36.2	36.0	35.6	35.2	34.9	34.3	33.7	33.1	32.6	32.0
	50% PoE		32.7	32.3	31.8	31.3	30.9	30.2	29.4	28.8	28.1	27.4
Seacombe 11kV	10% PoE	MVA	40.4	40.8	41.1	41.5	41.8	41.9	42.0	42.1	42.2	42.3
	50% PoE		35.5	35.7	35.9	36.0	36.2	36.1	36.1	36.0	36.0	35.9
Seaford 11kV	10% PoE	MVA	7.0	7.2	7.3	7.4	7.5	7.5	7.6	7.6	7.6	7.7
	50% PoE		6.1	6.4	6.7	6.9	7.2	7.4	7.6	7.7	7.9	8.1
Sheidow Park 11kV	10% PoE	MVA	22.7	22.7	22.7	22.7	22.7	22.6	22.6	22.5	22.4	22.4
	50% PoE		20.1	20.2	20.4	20.5	20.6	20.7	20.8	20.9	20.9	21.0
Tonsley Park 11kV	10% PoE	MVA	21.0	20.9	20.8	20.6	20.5	20.4	20.2	20.1	20.0	19.9
	50% PoE		18.6	18.4	18.2	18.0	17.8	17.6	17.4	17.2	17.0	16.8
Valente 11kV	10% PoE	MVA	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
	50% PoE		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Willunga 11kV	10% PoE	MVA	4.3	4.2	4.2	4.1	4.0	4.0	3.9	3.8	3.7	3.7
	50% PoE		3.7	3.7	3.6	3.6	3.5	3.4	3.4	3.3	3.2	3.2
Willunga 33kV	10% PoE	MVA	2.7	2.8	2.9	2.9	3.0	3.0	3.1	3.1	3.1	3.2
	50% PoE		2.4	2.5	2.5	2.6	2.6	2.7	2.7	2.7	2.8	2.8

Table 171: Metro South Zone Substation Forecasts

30. APPENDIX D – METRO EAST REGION FORECASTS

30.1 Connection Point Forecasts

Forecast Basis	Units	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
10% PoE	MVA	723.5	721.2	718.8	716.5	714.3	712.4	710.7	709.0	707.3	705.7
	PF	1.00	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.98	0.98

Table 172: Metro East Connection Point Forecasts

30.2 Zone Substation Forecasts

Zone Substation	Forecast Basis	Units	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2012/22	2022/23	20223/24	2024/25
Burnside 11kV	10% PoE	MVA	13.8	13.9	13.9	14.0	14.0	14.0	14.1	14.1	14.2	14.2
	50% PoE		12.0	12.0	12.0	12.0	12.0	12.1	12.1	12.1	12.1	12.2
Campbelltown 11kV	10% PoE	MVA	52.8	53.5	54.3	55.0	55.7	56.3	56.9	57.5	58.0	58.6
	50% PoE		46.1	46.9	47.5	48.2	48.9	49.5	50.0	50.6	51.1	51.6
Clearview 11kV	10% PoE	MVA	22.2	22.3	22.4	22.5	22.6	22.6	22.7	22.7	22.8	22.9
	50% PoE		19.3	19.4	19.5	19.6	19.6	19.7	19.8	19.9	19.9	20.0
Golden Grove 11kV	10% PoE	MVA	48.5	48.5	48.5	48.6	48.6	48.7	48.8	48.9	49.1	49.2
	50% PoE		43.3	43.3	43.3	43.4	43.4	43.5	43.7	43.8	44.0	44.1
Harrow 11kV	10% PoE	MVA	19.9	20.0	20.1	20.1	20.2	20.3	20.3	20.4	20.4	20.5
	50% PoE		17.5	17.6	17.7	17.8	17.9	18.0	18.1	18.2	18.3	18.4
Hillcrest 11kV	10% PoE	MVA	37.3	37.4	37.5	37.7	37.8	37.9	38.0	38.1	38.2	38.3
	50% PoE		33.3	33.3	33.4	33.5	33.6	33.6	33.7	33.8	33.8	33.9
Holden Hill 11kV	10% PoE	MVA	39.4	39.5	39.7	39.8	40.0	40.2	40.4	40.6	40.8	41.0
	50% PoE		35.3	35.4	35.5	35.6	35.7	35.8	36.0	36.2	36.3	36.5
Hope Valley 11kV	10% PoE	MVA	20.0	19.8	19.7	19.6	19.4	19.2	19.1	18.9	18.7	18.5
	50% PoE		17.4	17.3	17.2	17.1	17.0	16.9	16.7	16.6	16.4	16.3

Zone Substation	Forecast Basis	Units	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2012/22	2022/23	20223/24	2024/25
Ingle Farm 11kV	10% PoE	MVA	38.5	38.5	38.5	38.6	38.6	38.8	39.0	39.1	39.3	39.5
	50% PoE		34.6	34.7	34.8	34.8	34.9	35.1	35.3	35.5	35.7	35.9
Kent Town 11kV	10% PoE	MVA	37.5	37.8	38.1	38.3	38.6	39.0	39.3	39.7	40.0	40.4
	50% PoE		33.2	33.3	33.3	33.4	33.5	33.7	33.9	34.0	34.2	34.4
Kilburn South 11kV	10% PoE	MVA	12.5	12.4	12.4	12.3	12.2	12.2	12.1	12.0	12.0	11.9
	50% PoE		11.3	11.2	11.1	11.1	11.0	10.9	10.8	10.8	10.7	10.6
Linden Park 11kV	10% PoE	MVA	40.7	40.7	40.6	40.5	40.4	40.3	40.1	40.0	39.8	39.7
	50% PoE		34.9	34.8	34.6	34.5	34.4	34.2	34.0	33.8	33.6	33.4
North Adelaide 11kV	10% PoE	MVA	24.7	24.5	24.4	24.2	24.1	24.0	23.9	23.8	23.7	23.7
	50% PoE		22.2	22.1	21.9	21.8	21.7	21.6	21.5	21.4	21.3	21.3
Northfield 11kV	10% PoE	MVA	20.1	19.8	19.6	19.3	19.1	19.0	19.0	18.9	18.8	18.7
	50% PoE		17.8	17.5	17.3	17.2	17.0	16.9	16.9	16.9	16.8	16.8
Norwood 11kV	10% PoE	MVA	57.6	57.4	57.2	57.1	56.9	56.8	56.7	56.7	56.6	56.5
	50% PoE		50.4	50.2	49.9	49.7	49.5	49.4	49.2	49.1	49.0	48.9
Prospect 11kV	10% PoE	MVA	32.4	31.9	31.5	31.0	30.6	30.5	30.3	30.2	30.1	29.9
	50% PoE		29.1	28.9	28.7	28.5	28.3	28.3	28.4	28.5	28.6	28.7
Tea Tree Gully 11kV	10% PoE	MVA	35.2	35.4	35.6	35.8	36.0	36.1	36.3	36.4	36.5	36.6
	50% PoE		31.3	31.5	31.8	32.0	32.2	32.4	32.6	32.8	33.0	33.1
Woodforde 11kV	10% PoE	MVA	41.1	41.2	41.2	41.3	41.4	41.5	41.6	41.6	41.7	41.8
	50% PoE		35.4	35.6	35.7	35.9	36.1	36.2	36.4	36.6	36.7	36.9

Table 173: Metro East Zone Substation Forecasts

31. APPENDIX E – METRO WEST REGION FORECASTS

31.1 Connection Point Forecasts

Forecast Basis	Units	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
10% PoE	MVA	420.5	417.4	414.7	407.2	404.5	403.1	401.7	400.3	399.0	397.8
	PF	0.99	0.99	0.99	0.98	0.98	0.98	0.98	0.98	0.98	0.98

Table 174: Metro West connection point forecasts

31.2 Zone Substation Forecasts

Zone Substation	Forecast Basis	Units	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2012/22	2022/23	20223/24	2024/25
Adelaide Brighton Cement 11kV	10% PoE	MVA	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	50% PoE		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Athol Park 11kV	10% PoE	MVA	17.8	17.4	17.1	16.8	16.5	16.4	16.3	16.3	16.2	16.1
	50% PoE		16.3	16.0	15.7	15.3	15.0	14.9	14.8	14.7	14.6	14.6
Blackpool 7.6kV	10% PoE	MVA	14.2	14.0	13.9	13.7	13.6	13.4	13.3	13.1	12.9	12.8
	50% PoE		12.7	12.5	12.4	12.2	12.1	12.0	11.8	11.7	11.5	11.4
Cavan 11kV	10% PoE	MVA	42.6	43.4	44.6	39.9	40.8	41.8	42.9	44.0	45.1	46.2
	50% PoE		38.8	39.5	40.6	35.8	36.6	37.6	38.5	39.5	40.5	41.6
Cheltenham 7.6kV	10% PoE	MVA	4.0	3.9	3.9	3.9	3.8	3.8	3.8	3.7	3.7	3.7
	50% PoE		3.5	3.5	3.5	3.4	3.4	3.4	3.4	3.3	3.3	3.3
Cheltenham 11kV	10% PoE	MVA	4.8	4.9	5.0	5.1	5.2	5.3	5.4	5.5	5.6	5.7
	50% PoE		4.2	4.3	4.4	4.5	4.6	4.7	4.8	4.9	5.0	5.1
Cheltenham 33kV	10% PoE	MVA	3.9	3.9	3.9	3.8	3.8	3.8	3.7	3.7	3.6	3.6
	50% PoE		4.0	3.9	3.9	3.9	3.8	3.8	3.8	3.7	3.7	3.7
Croydon 11kV	10% PoE	MVA	27.7	27.1	26.6	26.1	25.6	25.3	24.9	24.6	24.4	24.1
	50% PoE		25.5	24.9	24.4	23.9	23.4	23.1	22.8	22.5	22.2	21.9

Zone Substation	Forecast Basis	Units	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2012/22	2022/23	20223/24	2024/25
Croydon Park 11kV	10% PoE	MVA	18.9	18.4	18.0	17.5	17.1	16.9	16.7	16.5	16.3	16.1
	50% PoE		17.2	16.7	16.3	15.9	15.4	15.2	15.0	14.8	14.6	14.5
Findon 11kV	10% PoE	MVA	20.7	20.5	20.4	20.2	20.0	19.9	19.8	19.7	19.5	19.4
	50% PoE		18.8	18.6	18.5	18.3	18.1	18.0	17.9	17.8	17.7	17.6
Flinders Park 11kV	10% PoE	MVA	23.0	23.1	23.2	23.3	23.4	23.6	23.7	23.9	24.0	24.2
	50% PoE		20.8	21.0	21.1	21.2	21.4	21.5	21.7	21.9	22.0	22.2
Fulham Gardens 11kV	10% PoE	MVA	39.6	39.7	39.9	39.9	40.0	40.2	40.3	40.4	40.5	40.6
	50% PoE		34.8	34.9	34.9	35.0	35.0	35.1	35.2	35.2	35.3	35.3
Glanville 7.6kV	10% PoE	MVA	12.8	12.7	12.7	12.6	12.6	12.6	12.5	12.5	12.4	12.4
	50% PoE		11.2	11.2	11.1	11.1	11.0	10.9	10.9	10.8	10.7	10.6
Henley South 11kV	10% PoE	MVA	32.3	32.4	32.4	32.5	32.5	32.6	32.6	32.7	32.8	32.8
	50% PoE		28.7	28.8	28.9	29.0	29.1	29.2	29.3	29.4	29.4	29.5
Kilburn 11kV	10% PoE	MVA	45.3	44.6	43.8	43.0	42.2	41.4	40.6	39.8	39.1	38.3
	50% PoE		43.6	43.0	42.3	41.7	41.0	40.3	39.6	38.9	38.3	37.6
Kilburn - Bradken 11kV	10% PoE	MVA	[redacted]									
	50% PoE											
Kilburn - Bus B (CMP) 11kV	10% PoE	MVA										
	50% PoE											
Kilkenny 11kV	10% PoE	MVA	14.2	13.7	13.2	12.7	12.3	12.0	11.6	11.3	11.0	10.7
	50% PoE		12.9	12.3	11.7	11.1	10.5	10.0	9.6	9.1	8.7	8.3
Largs North 7.6kV	10% PoE	MVA	14.2	14.2	14.1	14.1	14.0	14.0	13.9	13.8	13.8	13.7
	50% PoE		12.6	12.5	12.5	12.4	12.3	12.2	12.2	12.1	12.0	11.9
LeFevre 11kV	10% PoE	MVA	9.4	9.3	9.2	9.1	9.0	8.9	8.8	8.7	8.6	8.5
	50% PoE		9.4	9.4	9.3	9.2	9.2	9.1	9.0	8.9	8.8	8.7
New Osborne 11kV	10% PoE	MVA	[redacted]									
	50% PoE											

Zone Substation	Forecast Basis	Units	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2012/22	2022/23	20223/24	2024/25
New Richmond 11kV	10% PoE	MVA	33.1	33.0	32.9	32.8	32.7	32.7	32.7	32.7	32.7	32.7
	50% PoE		30.1	30.0	30.0	30.0	30.0	30.0	30.1	30.2	30.3	30.3
Port Adelaide 7.6kV	10% PoE	MVA	12.3	12.1	12.0	11.8	11.6	11.6	11.5	11.4	11.3	11.2
	50% PoE		11.2	11.0	10.8	10.7	10.5	10.4	10.3	10.2	10.1	10.1
Port Adelaide North 11kV	10% PoE	MVA	26.2	26.3	26.3	26.3	26.4	26.4	26.5	26.5	26.6	26.6
	50% PoE		24.4	24.5	24.6	24.6	24.7	24.8	24.9	24.9	25.0	25.1
Queenstown 7.6kV	10% PoE	MVA	13.8	13.6	13.4	13.2	13.1	13.0	12.9	12.8	12.7	12.6
	50% PoE		12.3	12.2	12.0	11.8	11.7	11.6	11.5	11.4	11.3	11.2
Smorgon Steel Recycling 11kV	10% PoE	MVA	[redacted]									
	50% PoE											
Thebarton 11kV	10% PoE	MVA	30.9	30.6	30.4	30.2	30.0	29.9	29.8	29.7	29.6	29.5
	50% PoE		28.7	28.4	28.2	27.9	27.7	27.5	27.4	27.3	27.1	27.0
Woodville 7.6kV	10% PoE	MVA	7.8	7.8	7.7	7.6	7.6	7.6	7.6	7.6	7.5	7.5
	50% PoE		6.8	6.8	6.7	6.7	6.6	6.6	6.7	6.7	6.7	6.7
Woodville 33kV	10% PoE	MVA	8.2	8.1	8.1	8.0	7.9	7.8	7.7	7.6	7.5	7.5
	50% PoE		7.9	7.8	7.8	7.7	7.6	7.6	7.5	7.4	7.3	7.2

Table 175: Metro West Substation Forecasts

32. APPENDIX F – BAROSSA REGION FORECASTS

32.1 Connection Point Forecasts

Forecast Basis	Units	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
10% PoE	MVA	62.0	61.9	61.7	61.4	61.3	60.9	60.6	60.4	60.1	59.8
	PF	0.97	0.97	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.95

Table 176: Metro North Connection Point Forecasts

32.2 Zone Substation Forecasts

Zone Substation	Forecast Basis	Units	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2012/22	2022/23	20223/24	2024/25
Angaston 11kV	10% PoE	MVA	19.7	19.4	19.1	18.9	18.6	18.3	18.1	17.8	17.6	17.4
	50% PoE		18.3	18.0	17.7	17.4	17.1	16.8	16.6	16.3	16.1	15.8
Barossa South 11kV	10% PoE	MVA	7.4	7.4	7.5	7.5	7.5	7.5	7.4	7.4	7.4	7.4
	50% PoE		6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.8	6.8	6.8
Dorrien 11kV	10% PoE	MVA	10.1	10.2	10.2	10.2	10.2	10.1	10.1	10.0	10.0	10.0
	50% PoE		9.2	9.3	9.4	9.5	9.6	9.6	9.6	9.6	9.6	9.6
Gomersal North 11kV	10% PoE	MVA	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
	50% PoE		0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Lyndoch 11kV	10% PoE	MVA	3.7	3.7	3.8	3.8	3.8	3.9	3.9	3.9	4.0	4.0
	50% PoE		3.3	3.3	3.3	3.4	3.4	3.4	3.4	3.5	3.5	3.5
Lyndoch South 11kV	10% PoE	MVA	0.5	0.5	0.5	0.5	0.4	0.4	0.4	0.4	0.4	0.4
	50% PoE		0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Nuriootpa 11kV	10% PoE	MVA	11.7	11.7	11.7	11.7	11.6	11.6	11.6	11.6	11.6	11.6
	50% PoE		10.6	10.5	10.4	10.3	10.2	10.1	10.1	10.0	9.9	9.8
Stockwell 11kV	10% PoE	MVA	6.8	6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9
	50% PoE		6.4	6.5	6.5	6.5	6.6	6.6	6.6	6.6	6.6	6.6

Zone Substation	Forecast Basis	Units	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2012/22	2022/23	20223/24	2024/25
Williamstown 11kV	10% PoE	MVA	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.1	3.1	3.1
	50% PoE		2.9	2.9	2.9	2.9	2.9	2.9	2.8	2.8	2.8	2.8

Table 177: Barossa Zone Substation Forecasts

33. APPENDIX G – EASTERN HILLS REGION FORECASTS

33.1 Connection Point Forecasts

Connection Point	Forecast Basis	Units	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2012/22	2022/23	20223/24	2024/25
Angas Creek 33kV	10% PoE	MVA	19.0	18.9	18.9	18.8	18.8	18.7	18.6	18.5	18.5	18.4
		PF	0.93	0.93	0.93	0.93	0.92	0.92	0.92	0.92	0.92	0.92
Kanmantoo 11kV	10% PoE	MVA	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6
		PF	0.95	0.94	0.94	0.94	0.93	0.93	0.93	0.93	0.92	0.92
Mount Barker / Mount Barker South 66kV	10% PoE	MVA	103.1	104.8	106.3	107.8	109.3	110.4	111.5	112.5	113.5	114.5
		PF	1.00	1.00	0.99	0.99	0.99	0.99	0.98	0.98	0.98	0.98

Table 178: Eastern Hills Connection Point Forecasts

33.2 Zone Substation Forecasts

Zone Substation	Forecast Basis	Units	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	20223/24	2024/25
Aldgate 11kV	10% PoE	MVA	7.3	7.4	7.5	7.6	7.6	7.7	7.8	7.8	7.9	7.9
	50% PoE		7.4	7.5	7.6	7.7	7.8	7.9	7.9	8.0	8.1	8.1
Balhannah 33kV	10% PoE	MVA	23.6	24.7	25.6	26.6	27.6	28.4	29.1	29.9	30.6	31.3
	50% PoE		21.5	22.6	23.5	24.5	25.5	26.3	27.0	27.8	28.5	29.2
Birdwood 11kV	10% PoE	MVA	2.4	2.3	2.3	2.3	2.2	2.2	2.2	2.2	2.1	2.1
	50% PoE		2.1	2.1	2.1	2.1	2.0	2.0	2.0	1.9	1.9	1.9
Brukunga 11kV	10% PoE	MVA	0.5	0.5	0.5	0.5	0.5	0.5	0.6	0.6	0.6	0.6
	50% PoE		0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Chain of Ponds 11kV	10% PoE	MVA	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
	50% PoE		0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Deloraine 11kV	10% PoE	MVA	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
	50% PoE		0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.3	0.3	0.3
Forreston 11kV	10% PoE	MVA	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
	50% PoE		0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
Gumeracha 11kV	10% PoE	MVA	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
	50% PoE		0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Gumeracha Weir 11kV	10% PoE	MVA	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
	50% PoE		0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Gumhaven 11kV	10% PoE	MVA	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
	50% PoE		0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Hahndorf 11kV	10% PoE	MVA	4.8	4.7	4.6	4.6	4.5	4.5	4.4	4.3	4.3	4.2
	50% PoE		4.3	4.3	4.2	4.2	4.2	4.1	4.1	4.1	4.1	4.0
Hermitage 11kV	10% PoE	MVA	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
	50% PoE		0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Houghton 7.6kV	10% PoE	MVA	3.2	3.2	3.3	3.3	3.4	3.5	3.5	3.6	3.7	3.7
	50% PoE		2.8	2.9	3.0	3.0	3.1	3.1	3.2	3.2	3.3	3.4

Zone Substation	Forecast Basis	Units	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	20223/24	2024/25
Kersbrook 11kV	10% PoE	MVA	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
	50% PoE		0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Langhorne Creek 11kV	10% PoE	MVA	5.9	5.9	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.1
	50% PoE		5.3	5.3	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.5
Lobethal 11kV	10% PoE	MVA	6.8	6.6	6.5	6.4	6.2	6.2	6.1	6.0	6.0	5.9
	50% PoE		6.2	6.1	6.0	5.9	5.7	5.7	5.6	5.6	5.5	5.5
Meadows 11kV	10% PoE	MVA	6.2	6.4	6.6	6.8	7.0	7.2	7.4	7.5	7.7	7.9
	50% PoE		5.7	5.9	6.1	6.4	6.6	6.8	6.9	7.1	7.3	7.4
Milang 11kV	10% PoE	MVA	4.4	4.5	4.5	4.6	4.6	4.7	4.7	4.8	4.9	4.9
	50% PoE		4.0	4.0	4.1	4.1	4.2	4.2	4.3	4.3	4.4	4.4
Mount Barker 11kV	10% PoE	MVA	22.5	23.4	24.3	25.2	26.0	26.8	27.6	28.4	29.1	29.8
	50% PoE		19.9	20.7	21.4	22.2	22.9	23.6	24.3	24.9	25.5	26.1
Mount Pleasant 11kV	10% PoE	MVA	1.7	1.6	1.6	1.6	1.6	1.5	1.5	1.5	1.5	1.5
	50% PoE		1.5	1.5	1.4	1.4	1.4	1.4	1.4	1.4	1.3	1.3
Mylor 11kV	10% PoE	MVA	2.6	2.6	2.6	2.7	2.7	2.7	2.8	2.8	2.8	2.9
	50% PoE		2.3	2.3	2.4	2.4	2.4	2.5	2.5	2.5	2.5	2.6
Nairne 11kV	10% PoE	MVA	6.9	6.9	6.9	7.0	7.0	7.1	7.3	7.4	7.5	7.6
	50% PoE		6.0	6.0	6.0	6.0	6.1	6.1	6.2	6.3	6.4	6.4
Piccadilly 11kV	10% PoE	MVA	2.3	2.3	2.3	2.3	2.4	2.4	2.4	2.5	2.5	2.5
	50% PoE		2.0	2.1	2.1	2.1	2.1	2.2	2.2	2.2	2.2	2.3
Stirling East 11kV	10% PoE	MVA	9.6	9.8	9.9	10.0	10.1	10.3	10.4	10.5	10.6	10.8
	50% PoE		8.7	8.8	8.9	9.0	9.1	9.2	9.3	9.5	9.6	9.7
Strathalbyn 11kV	10% PoE	MVA	9.5	9.6	9.7	9.7	9.8	9.8	9.8	9.8	9.8	9.8
	50% PoE		8.5	8.6	8.7	8.8	8.9	9.0	9.0	9.1	9.1	9.1
Strathalbyn East 11kV	10% PoE	MVA	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	50% PoE		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Uraidla 11kV	10% PoE	MVA	6.1	6.1	6.2	6.2	6.3	6.3	6.4	6.4	6.4	6.5
	50% PoE		5.5	5.6	5.7	5.8	5.8	5.9	5.9	6.0	6.0	6.1

Zone Substation	Forecast Basis	Units	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	20223/24	2024/25
Uraidla 33kV	10% PoE	MVA	14.7	14.6	14.5	14.3	14.2	14.0	13.9	13.7	13.6	13.4
	50% PoE		13.1	13.0	12.8	12.6	12.5	12.3	12.2	12.0	11.8	11.7
Verdun 11kV	10% PoE	MVA	1.2	1.2	1.2	1.3	1.3	1.3	1.4	1.4	1.4	1.5
	50% PoE		1.0	1.1	1.1	1.1	1.2	1.2	1.2	1.3	1.3	1.3
Woodside 11kV	10% PoE	MVA	9.0	9.1	9.2	9.2	9.3	9.4	9.4	9.5	9.5	9.5
	50% PoE		8.1	8.1	8.2	8.3	8.3	8.3	8.4	8.4	8.4	8.4

Table 179: Eastern Hills Zone Substation Forecasts

34. APPENDIX H – EYRE PENINSULA REGION FORECASTS

34.1 Connection Point Forecasts

Connection Point	Forecast Basis	Units	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2012/22	2022/23	20223/24	2024/25
Port Lincoln Terminal 33kV	10% PoE	MVA	34.9	34.7	34.7	34.6	34.5	34.9	35.2	35.6	35.9	36.2
		PF	0.97	0.97	0.96	0.96	0.96	0.96	0.96	0.96	0.95	0.95
Stony Point 11kV	10% PoE	MVA	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
		PF										
Whyalla Central / Terminal 33kV	10% PoE	MVA	79.0	79.0	78.9	78.9	78.8	78.8	78.7	78.7	78.6	78.6
		PF	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93
Wudinna 66kV	10% PoE	MVA	13.8	13.6	13.5	13.3	13.2	13.1	13.0	12.9	12.8	12.7
		PF	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98
Yadnarie 66kV	10% PoE	MVA	7.9	7.9	7.9	8.0	8.0	8.0	7.9	7.9	7.9	7.9
		PF	1.00	1.00	1.00	1.00	1.00	1.00	1.00	0.99	0.99	0.99

Table 180: Eyre Peninsula Connection Point Forecasts

34.2 Zone Substation Forecasts

Zone Substation	Forecast Basis	Units	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2012/22	2022/23	20223/24	2024/25
Arno Bay 11kV	10% PoE	MVA	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
	50% PoE		0.8	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
Boothby 33kV	10% PoE	MVA	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
	50% PoE		0.8	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
Caralue 11kV	10% PoE	MVA	2.4	2.4	2.4	2.3	2.3	2.3	2.3	2.2	2.2	2.2
	50% PoE		2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3
Ceduna 11kV	10% PoE	MVA	7.2	7.1	7.0	6.9	6.8	6.8	6.8	6.7	6.7	6.7
	50% PoE		6.4	6.3	6.2	6.1	6.0	6.0	5.9	5.9	5.9	5.8
Cleve 11 kV	10% PoE	MVA	2.8	2.8	2.8	2.9	2.9	2.9	2.9	2.9	2.9	2.9
	50% PoE		2.6	2.7	2.8	2.8	2.9	3.0	3.0	3.1	3.1	3.2
Cleve 33kV	10% PoE	MVA	2.3	2.3	2.3	2.3	2.3	2.3	2.4	2.4	2.4	2.4
	50% PoE		1.8	1.7	1.7	1.6	1.5	1.4	1.3	1.2	1.1	1.0
Coffin Bay 11kV	10% PoE	MVA	1.4	1.3	1.3	1.3	1.2	1.2	1.2	1.2	1.2	1.2
	50% PoE		1.1	1.1	1.1	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Cowell 11kV	10% PoE	MVA	2.5	2.5	2.5	2.6	2.6	2.6	2.6	2.6	2.6	2.6
	50% PoE		2.2	2.3	2.4	2.4	2.5	2.5	2.6	2.6	2.7	2.7
Cummins 11kV	10% PoE	MVA	2.3	2.3	2.3	2.3	2.2	2.3	2.3	2.3	2.3	2.3
	50% PoE		2.1	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Darke Peak 11kV	10% PoE	MVA	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
	50% PoE		0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Little Swamp 11kV	10% PoE	MVA	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
	50% PoE		0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Lock 11kV	10% PoE	MVA	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
	50% PoE		0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Moorkitabie 11kV	10% PoE	MVA	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.7	0.7
	50% PoE		0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7

Zone Substation	Forecast Basis	Units	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2012/22	2022/23	20223/24	2024/25
Point Boston 11kV	10% PoE	MVA	0.9	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
	50% PoE		0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Polda 11kV	10% PoE	MVA	0.6	0.6	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
	50% PoE		0.6	0.6	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Poonindie 11kV	10% PoE	MVA	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
	50% PoE		0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Port Lincoln City 11kV	10% PoE	MVA	15.3	15.2	15.1	15.1	15.0	15.1	15.2	15.3	15.4	15.5
	50% PoE		13.5	13.4	13.2	13.1	13.0	13.0	13.1	13.1	13.1	13.2
Port Lincoln Docks 11kV	10% PoE	MVA	9.6	9.5	9.5	9.5	9.4	9.6	9.7	9.9	10.1	10.2
	50% PoE		8.6	8.5	8.3	8.2	8.1	8.2	8.3	8.4	8.5	8.6
Rudall 11kV	10% PoE	MVA	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
	50% PoE		0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Streaky Bay 11kV	10% PoE	MVA	3.3	3.3	3.3	3.2	3.2	3.2	3.2	3.2	3.1	3.1
	50% PoE		3.0	3.0	2.9	2.9	2.9	2.9	2.9	2.8	2.8	2.8
Tarlton 11kV	10% PoE	MVA	0.7	0.7	0.7	0.7	0.6	0.6	0.6	0.6	0.6	0.6
	50% PoE		0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Tumby Bay 11kV	10% PoE	MVA	2.6	2.7	2.7	2.7	2.8	2.8	2.9	2.9	2.9	3.0
	50% PoE		2.4	2.4	2.4	2.5	2.5	2.5	2.6	2.6	2.6	2.7
Uley 11kV	10% PoE	MVA	1.3	1.3	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
	50% PoE		1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.3
Uley South 11kV	10% PoE	MVA	0.6	0.6	0.6	0.6	0.6	0.6	0.7	0.7	0.7	0.7
	50% PoE		0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Whyalla City 11kV	10% PoE	MVA	20.8	20.8	20.7	20.7	20.6	20.6	20.6	20.6	20.6	20.6
	50% PoE		18.3	18.3	18.2	18.2	18.2	18.2	18.2	18.2	18.2	18.2
Whyalla LMF 33kV	10% PoE	MVA	[redacted]									
	50% PoE											
Whyalla North 11kV	10% PoE	MVA	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
	50% PoE		0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9

Zone Substation	Forecast Basis	Units	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2012/22	2022/23	20223/24	2024/25
Whyalla Stuart 11kV	10% PoE	MVA	18.0	17.8	17.7	17.5	17.4	17.2	17.0	16.9	16.7	16.6
	50% PoE		16.1	15.9	15.8	15.7	15.5	15.4	15.2	15.1	14.9	14.8
Wudinna 11kV	10% PoE	MVA	2.1	2.1	2.1	2.0	2.0	2.0	1.9	1.9	1.9	1.9
	50% PoE		1.9	1.9	1.9	1.9	1.9	1.8	1.8	1.8	1.7	1.7

Table 181: Eyre Peninsula Zone Substation Forecasts

35. APPENDIX I – FLEURIEU PENINSULA REGION FORECASTS

35.1 Connection Point Forecasts

Not applicable – refer Metro South connection point forecast.

35.2 Zone Substation Forecasts

Zone Substation	Forecast Basis	Units	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2012/22	2022/23	20223/24	2024/25
American River 11kV	10% PoE	MVA	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
	50% PoE		0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Cape Jervis 11kV	10% PoE	MVA	0.6	0.6	0.6	0.6	0.7	0.7	0.7	0.7	0.7	0.7
	50% PoE		0.5	0.6	0.6	0.6	0.6	0.6	0.6	0.7	0.7	0.7
Cape Jervis 33kV	10% PoE	MVA	7.9	8.0	8.1	8.2	8.3	8.4	8.5	8.6	8.8	8.9
	50% PoE		7.1	7.2	7.3	7.4	7.5	7.6	7.7	7.7	7.9	8.0
Goolwa 11kV	10% PoE	MVA	12.3	12.2	12.1	12.1	12.0	12.2	12.3	12.5	12.6	12.8
	50% PoE		10.6	10.5	10.4	10.4	10.3	10.5	10.6	10.8	10.9	11.1
Hay Flat 11kV	10% PoE	MVA	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
	50% PoE		0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Kingscote 11kV	10% PoE	MVA	3.2	3.3	3.4	3.5	3.5	3.6	3.6	3.7	3.8	3.8
	50% PoE		3.0	3.2	3.3	3.4	3.5	3.6	3.6	3.7	3.8	3.9
MacGillivray 11kV	10% PoE	MVA	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1
	50% PoE		1.9	1.9	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Myponga 11kV	10% PoE	MVA	5.5	5.5	5.5	5.4	5.4	5.3	5.3	5.2	5.2	5.1
	50% PoE		4.9	4.9	4.9	4.8	4.8	4.8	4.7	4.7	4.6	4.6
Penneshaw 11kV	10% PoE	MVA	0.8	0.8	0.8	0.8	0.8	0.9	0.9	0.9	0.9	0.9
	50% PoE		0.8	0.8	0.8	0.8	0.8	0.9	0.9	0.9	0.9	0.9
Rapid Bay 11kV	10% PoE	MVA	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
	50% PoE		0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Salt Cliffs 11kV	10% PoE	MVA	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
	50% PoE		0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2

Zone Substation	Forecast Basis	Units	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2012/22	2022/23	20223/24	2024/25
Second Valley 11kV	10% PoE	MVA	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
	50% PoE		0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Square Water Hole 11kV	10% PoE	MVA	4.2	4.3	4.3	4.3	4.4	4.4	4.4	4.4	4.4	4.5
	50% PoE		3.8	3.8	3.9	3.9	4.0	4.0	4.1	4.1	4.1	4.1
Victor Harbor 11kV	10% PoE	MVA	21.3	21.1	21.1	21.0	21.0	21.2	21.5	21.8	22.0	22.3
	50% PoE		18.5	18.3	18.3	18.2	18.1	18.4	18.7	18.9	19.2	19.5
Wirrina Cove 11kV	10% PoE	MVA	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
	50% PoE		0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Yankalilla 11kV	10% PoE	MVA	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.6	6.6
	50% PoE		5.8	5.8	5.8	5.8	5.8	5.7	5.7	5.7	5.7	5.7
Yankalilla 33kV	10% PoE	MVA	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
	50% PoE		1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
Yankalilla Hill 11kV	10% PoE	MVA	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
	50% PoE		0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02

Table 182: Fleurieu Peninsula Zone Substation Forecasts

36. APPENDIX J – MID NORTH REGION FORECASTS

36.1 Connection Point Forecasts

Connection Point	Forecast Basis	Units	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2012/22	2022/23	20223/24	2024/25
Brinkworth 33kV	10% PoE	MVA	4.6	4.5	4.5	4.4	4.4	4.3	4.2	4.2	4.1	4.1
		PF	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98
Clare North 33kV	10% PoE	MVA	13.4	13.4	13.4	13.3	13.3	13.3	13.3	13.3	13.3	13.3
		PF	0.92	0.92	0.92	0.91	0.91	0.91	0.92	0.92	0.92	0.93
Hummocks 33kV	10% PoE	MVA	14.3	14.2	14.0	13.9	13.8	13.7	13.7	13.6	13.6	13.5
		PF	0.93	0.93	0.93	0.92	0.92	0.92	0.91	0.91	0.91	0.91
Templers 33kV	10% PoE	MVA	31.1	30.9	30.8	30.7	30.6	30.5	30.5	30.5	30.4	30.4
		PF	0.94	0.94	0.95	0.95	0.95	0.96	0.96	0.96	0.95	0.95
Waterloo 33kV	10% PoE	MVA	8.9	8.8	8.7	8.6	8.5	8.3	8.2	8.1	8.0	7.9
		PF	0.95	0.95	0.95	0.94	0.94	0.94	0.94	0.93	0.93	0.93

Table 183: Mid North Connection Point Forecasts

36.2 Zone Substation Forecasts

Zone Substation	Forecast Basis	Units	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2012/22	2022/23	20223/24	2024/25
Alma 11kV	10% PoE	MVA	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
	50% PoE		0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Auburn 11kV	10% PoE	MVA	3.4	3.4	3.3	3.3	3.3	3.2	3.2	3.2	3.1	3.1
	50% PoE		3.1	3.0	3.0	3.0	2.9	2.9	2.9	2.8	2.8	2.8
Balaklava 7.6kV	10% PoE	MVA	3.1	3.0	3.0	3.0	3.0	3.0	2.9	2.9	2.9	2.9
	50% PoE		2.8	2.7	2.7	2.7	2.7	2.7	2.7	2.6	2.6	2.6
Brinkworth Town 11kV	10% PoE	MVA	0.9	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.7
	50% PoE		0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Burra 11kV	10% PoE	MVA	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1
	50% PoE		3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7
Cheetham Salt 11kV	10% PoE	MVA	1.1	1.1	1.1	1.2	1.2	1.2	1.2	1.3	1.3	1.3
	50% PoE		1.0	1.0	1.0	1.0	1.1	1.1	1.1	1.1	1.2	1.2
Clare 11kV	10% PoE	MVA	11.1	11.1	11.2	11.2	11.2	11.3	11.4	11.5	11.6	11.7
	50% PoE		10.0	10.0	10.0	10.1	10.1	10.2	10.3	10.3	10.4	10.5
Collinsfield 11kV	10% PoE	MVA	0.7	0.7	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
	50% PoE		0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.5	0.5	0.5
Dowlingville 11kV	10% PoE	MVA	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
	50% PoE		0.04	0.04	0.04	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Eudunda 11kV	10% PoE	MVA	2.1	2.1	2.0	2.0	2.0	2.0	1.9	1.9	1.9	1.9
	50% PoE		1.9	1.9	1.8	1.8	1.8	1.8	1.8	1.7	1.7	1.7
Freeling 11kV	10% PoE	MVA	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
	50% PoE		0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Freeling North 11kV	10% PoE	MVA	2.3	2.2	2.2	2.1	2.1	2.0	2.0	2.0	2.0	1.9
	50% PoE		2.1	2.0	2.0	1.9	1.9	1.8	1.8	1.8	1.8	1.7
Gawler Belt 11kV	10% PoE	MVA	8.4	8.4	8.5	8.5	8.5	8.5	8.6	8.7	8.7	8.8
	50% PoE		7.7	7.7	7.7	7.7	7.7	7.7	7.8	7.8	7.8	7.9

Zone Substation	Forecast Basis	Units	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2012/22	2022/23	20223/24	2024/25
Georgetown 11kV	10% PoE	MVA	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
	50% PoE		0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Gulnare 11kV	10% PoE	MVA	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
	50% PoE		0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Halbury 11kV	10% PoE	MVA	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
	50% PoE		0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Hamley Bridge 11kV	10% PoE	MVA	2.7	2.6	2.6	2.6	2.6	2.6	2.5	2.5	2.5	2.5
	50% PoE		2.4	2.4	2.4	2.3	2.3	2.3	2.3	2.3	2.3	2.2
Hoyleton 11kV	10% PoE	MVA	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
	50% PoE		0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Kapunda 11kV	10% PoE	MVA	5.8	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.8
	50% PoE		5.3	5.3	5.3	5.3	5.2	5.2	5.3	5.3	5.3	5.3
Kybunga 11kV	10% PoE	MVA	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
	50% PoE		0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Mallala 11kV	10% PoE	MVA	4.5	4.6	4.7	4.8	4.9	5.0	5.1	5.2	5.3	5.5
	50% PoE		4.0	4.1	4.2	4.3	4.4	4.5	4.6	4.7	4.8	4.9
Marrabel 11kV	10% PoE	MVA	2.2	2.2	2.2	2.2	2.1	2.1	2.1	2.1	2.0	2.0
	50% PoE		2.0	2.0	2.0	1.9	1.9	1.9	1.9	1.9	1.8	1.8
Ninnes 11kV	10% PoE	MVA	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.8	0.8	0.8
	50% PoE		0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Paskeville 11kV	10% PoE	MVA	0.3	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4
	50% PoE		0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Port Clinton 11kV	10% PoE	MVA	0.7	0.7	0.7	0.7	0.7	0.7	0.8	0.8	0.8	0.8
	50% PoE		0.6	0.6	0.6	0.6	0.7	0.7	0.7	0.7	0.7	0.7
Riverton 11kV	10% PoE	MVA	2.4	2.4	2.3	2.3	2.3	2.3	2.3	2.2	2.2	2.2
	50% PoE		2.1	2.1	2.1	2.1	2.1	2.1	2.0	2.0	2.0	2.0
Robertstown 11kV	10% PoE	MVA	1.0	1.0	1.0	0.9	0.9	0.9	0.9	0.9	0.9	0.9
	50% PoE		0.9	0.9	0.9	0.8	0.8	0.8	0.8	0.8	0.8	0.8

Zone Substation	Forecast Basis	Units	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2012/22	2022/23	20223/24	2024/25
Sandy Creek 11kV	10% PoE	MVA	1.8	1.7	1.7	1.6	1.6	1.6	1.5	1.5	1.5	1.5
	50% PoE		1.6	1.6	1.5	1.5	1.4	1.4	1.4	1.4	1.3	1.3
Spalding 11kV	10% PoE	MVA	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.9	0.9
	50% PoE		0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.8
Wasleys 11kV	10% PoE	MVA	2.4	2.3	2.3	2.3	2.3	2.3	2.3	2.2	2.2	2.2
	50% PoE		2.1	2.1	2.1	2.1	2.1	2.0	2.0	2.0	2.0	2.0
Waterloo Town 11kV	10% PoE	MVA	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.4	0.4
	50% PoE		0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4

Table 184: Mid North Zone Substation Forecasts

37. APPENDIX K – MURRAYLANDS REGION FORECASTS

37.1 Connection Point Forecasts

Connection Point	Forecast Basis	Units	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2012/22	2022/23	20223/24	2024/25
Mannum 33kV	10% PoE	MVA	13.1	13.1	13.2	13.2	13.3	13.3	13.3	13.3	13.3	13.3
		PF	0.95	0.96	0.96	0.95	0.95	0.95	0.95	0.94	0.95	0.95
Mobilong 33kV	10% PoE	MVA	43.3	43.4	43.6	43.8	43.9	44.4	44.8	45.2	45.6	46.0
		PF	0.94	0.96	0.95	0.95	0.95	0.94	0.94	0.94	0.93	0.93
Tailem Bend 33kV	10% PoE	MVA	21.9	21.7	21.4	21.2	21.0	20.7	20.4	20.1	19.8	19.5
		PF	0.97	0.97	0.97	0.97	0.97	0.97	0.96	0.96	0.96	0.96

Table 185: Murraylands Connection Point Forecasts

37.2 Zone Substation Forecasts

Zone Substation	Forecast Basis	Units	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2012/22	2022/23	20223/24	2024/25
Belvedere Road 7.6kV	10% PoE	MVA	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
	50% PoE		0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Binnies 11kV	10% PoE	MVA	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
	50% PoE		0.3	0.3	0.3	0.3	0.3	0.2	0.2	0.2	0.2	0.2
Caloote 11kV	10% PoE	MVA	1.9	1.9	1.9	1.9	1.9	1.8	1.8	1.8	1.8	1.7
	50% PoE		1.7	1.7	1.7	1.7	1.7	1.7	1.6	1.6	1.6	1.6
Cambrai 11kV	10% PoE	MVA	1.0	1.0	1.0	1.0	1.0	0.9	0.9	0.9	0.9	0.9
	50% PoE		0.9	0.9	0.9	0.9	0.9	0.8	0.8	0.8	0.8	0.8
Campbell Park 11kV	10% PoE	MVA	1.5	1.4	1.4	1.4	1.4	1.4	1.4	1.3	1.3	1.3
	50% PoE		1.3	1.3	1.3	1.3	1.3	1.2	1.2	1.2	1.2	1.2

Zone Substation	Forecast Basis	Units	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2012/22	2022/23	20223/24	2024/25
Coomandook 11kV	10% PoE	MVA	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.4	0.4	0.4
	50% PoE		0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Coonalpyn 11kV	10% PoE	MVA	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.3	0.3
	50% PoE		0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Geranium 11kV	10% PoE	MVA	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
	50% PoE		0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Jabuk 11kV	10% PoE	MVA	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
	50% PoE		0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Jervois 11kV	10% PoE	MVA	2.5	2.4	2.4	2.3	2.3	2.2	2.2	2.1	2.1	2.0
	50% PoE		2.4	2.4	2.3	2.3	2.2	2.2	2.1	2.1	2.0	2.0
Jervois Flat 1 11kV	10% PoE	MVA	[redacted]									
	50% PoE											
Jervois Flat 2 11kV	10% PoE	MVA										
	50% PoE											
Karoonda 11kV	10% PoE	MVA	0.8	0.8	0.8	0.8	0.7	0.7	0.7	0.7	0.7	0.7
	50% PoE		0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.6	0.6	0.6
Ki Ki 11kV	10% PoE	MVA	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
	50% PoE		0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Lameroo 11kV	10% PoE	MVA	1.3	1.3	1.3	1.3	1.3	1.3	1.2	1.2	1.2	1.2
	50% PoE		1.2	1.2	1.2	1.2	1.1	1.1	1.1	1.1	1.1	1.1
Mannum Town 7.6kV	10% PoE	MVA	4.3	4.3	4.3	4.3	4.3	4.4	4.4	4.4	4.4	4.4
	50% PoE		3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9
Meningie 11kV	10% PoE	MVA	2.2	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1
	50% PoE		2.0	2.0	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1
Monarto South 11kV	10% PoE	MVA	5.6	5.5	5.4	5.3	5.2	5.1	5.1	5.0	4.9	4.8
	50% PoE		5.2	5.1	5.0	4.9	4.8	4.8	4.7	4.6	4.5	4.4
Murray Bridge North 11kV	10% PoE	MVA	17.9	18.1	18.3	18.5	18.7	19.1	19.4	19.8	20.1	20.4
	50% PoE		16.3	16.4	16.6	16.8	17.0	17.3	17.6	17.9	18.2	18.5

Zone Substation	Forecast Basis	Units	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2012/22	2022/23	20223/24	2024/25
Murray Bridge South 11kV	10% PoE	MVA	16.0	15.9	15.8	15.8	15.7	15.8	15.9	15.9	16.0	16.1
	50% PoE		14.0	13.9	13.9	13.8	13.7	13.8	13.8	13.8	13.9	13.9
Mypolonga 11kV	10% PoE	MVA	2.4	2.5	2.5	2.6	2.6	2.7	2.7	2.8	2.9	2.9
	50% PoE		2.2	2.2	2.3	2.3	2.4	2.4	2.5	2.5	2.6	2.6
Narrung 11kV	10% PoE	MVA	1.7	1.6	1.6	1.6	1.6	1.6	1.5	1.5	1.5	1.5
	50% PoE		1.5	1.5	1.5	1.4	1.4	1.4	1.4	1.4	1.4	1.3
Nildottie 11kV	10% PoE	MVA	2.7	2.7	2.7	2.7	2.6	2.6	2.6	2.6	2.6	2.6
	50% PoE		2.5	2.5	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4
Palmer 11kV	10% PoE	MVA	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
	50% PoE		0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Peake 11kV	10% PoE	MVA	0.2	0.2	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.1
	50% PoE		0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Pellaring Flat 11kV	10% PoE	MVA	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
	50% PoE		0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Pinnaroo 11kV	10% PoE	MVA	1.6	1.6	1.6	1.6	1.5	1.5	1.5	1.5	1.5	1.4
	50% PoE		1.5	1.4	1.4	1.4	1.4	1.4	1.4	1.3	1.3	1.3
Pinnaroo South 11kV	10% PoE	MVA	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
	50% PoE		0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Punyelroo 11kV	10% PoE	MVA	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
	50% PoE		0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Sherlock 11kV	10% PoE	MVA	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
	50% PoE		0.03	0.03	0.03	0.03	0.03	0.02	0.02	0.02	0.02	0.02
Tailem Bend Town 11kV	10% PoE	MVA	3.1	3.1	3.1	3.0	3.0	2.9	2.9	2.9	2.8	2.8
	50% PoE		2.8	2.8	2.7	2.7	2.7	2.7	2.6	2.6	2.6	2.5
Teal Flat 11kV	10% PoE	MVA	3.4	3.5	3.5	3.6	3.6	3.6	3.7	3.7	3.8	3.8
	50% PoE		3.1	3.1	3.2	3.2	3.2	3.3	3.3	3.4	3.4	3.4
Walker Flat 11kV	10% PoE	MVA	1.8	1.8	1.8	1.9	1.9	1.9	1.9	1.9	1.9	1.9
	50% PoE		1.6	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7

Zone Substation	Forecast Basis	Units	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2012/22	2022/23	20223/24	2024/25
Woods Point 11kV	10% PoE	MVA	3.2	3.2	3.1	3.0	3.0	2.9	2.8	2.7	2.7	2.6
	50% PoE		3.0	2.9	2.9	2.8	2.7	2.6	2.5	2.5	2.4	2.3

Table 186: Murraylands Zone Substation Forecasts

38. APPENDIX L – RIVERLAND REGION FORECASTS

38.1 Connection Point Forecasts

Connection Point	Forecast Basis	Units	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2012/22	2022/23	20223/24	2024/25
Berri 66kV	10% PoE	MVA	97.7	96.7	95.7	94.7	93.7	92.7	91.8	90.9	90.0	89.1
		PF	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97
North West Bend 66kV	10% PoE	MVA	28.1	27.8	27.5	27.1	26.8	26.4	26.0	25.6	25.3	24.9
		PF	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98

Table 187: Riverland Connection Point Forecasts

38.2 Zone Substation Forecasts

Zone Substation	Forecast Basis	Units	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2012/22	2022/23	20223/24	2024/25
Berri 11kV	10% PoE	MVA	11.4	11.1	10.7	10.4	10.0	9.9	9.7	9.5	9.3	9.1
	50% PoE		10.5	10.1	9.8	9.4	9.1	8.9	8.8	8.6	8.4	8.3
Cadell 11kV	10% PoE	MVA	2.4	2.4	2.4	2.3	2.3	2.3	2.3	2.2	2.2	2.2
	50% PoE		2.2	2.2	2.1	2.1	2.1	2.1	2.0	2.0	2.0	2.0
Cordola 11kV	10% PoE	MVA	2.0	2.0	2.0	2.0	1.9	1.9	1.9	1.9	1.9	1.8
	50% PoE		1.8	1.8	1.8	1.8	1.8	1.7	1.7	1.7	1.7	1.6
Glossop 11kV	10% PoE	MVA	9.9	9.9	9.7	9.6	9.6	9.4	9.3	9.1	9.0	8.9
	50% PoE		10.0	9.9	9.8	9.7	9.6	9.5	9.3	9.2	9.1	9.0
Loveday 11kV	10% PoE	MVA	12.1	11.9	11.7	11.4	11.2	11.0	10.7	10.5	10.3	10.0
	50% PoE		10.9	10.7	10.5	10.3	10.2	9.9	9.7	9.5	9.3	9.1
Loxton 11kV	10% PoE	MVA	12.9	12.7	12.5	12.4	12.2	12.1	11.9	11.8	11.7	11.6
	50% PoE		11.8	11.7	11.5	11.4	11.3	11.1	11.0	10.9	10.8	10.8

Zone Substation	Forecast Basis	Units	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2012/22	2022/23	20223/24	2024/25
Lyrup 11kV	10% PoE	MVA	5.3	5.2	5.2	5.1	5.1	5.0	5.0	5.0	4.9	4.9
	50% PoE		4.8	4.7	4.7	4.6	4.6	4.5	4.5	4.5	4.4	4.4
Morgan 11kV	10% PoE	MVA	1.1	1.1	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
	50% PoE		1.0	1.0	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
Paringa 11kV	10% PoE	MVA	2.5	2.5	2.5	2.5	2.5	2.5	2.4	2.4	2.4	2.4
	50% PoE		2.3	2.3	2.2	2.2	2.2	2.2	2.2	2.2	2.1	2.1
Paringa 33kV	10% PoE	MVA	12.7	12.9	13.1	13.3	13.4	13.5	13.6	13.7	13.8	13.9
	50% PoE		11.5	11.7	11.8	12.0	12.1	12.2	12.2	12.3	12.4	12.4
Portee 11kV	10% PoE	MVA	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
	50% PoE		0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Pyap 11kV	10% PoE	MVA	8.1	8.0	7.9	7.7	7.6	7.4	7.2	7.1	6.9	6.8
	50% PoE		7.2	7.1	7.0	6.8	6.7	6.5	6.4	6.2	6.1	6.0
Qualco 11kV	10% PoE	MVA	2.8	2.8	2.8	2.7	2.7	2.7	2.6	2.6	2.6	2.5
	50% PoE		2.5	2.5	2.5	2.5	2.4	2.4	2.4	2.3	2.3	2.3
Ramco 11kV	10% PoE	MVA										
	50% PoE											
Renmark 11kV	10% PoE	MVA	19.6	19.5	19.3	19.2	19.1	19.1	19.1	19.1	19.0	19.0
	50% PoE		18.0	17.9	17.7	17.6	17.5	17.5	17.4	17.4	17.4	17.3
Roonka 11kV	10% PoE	MVA	2.0	2.0	2.0	2.0	1.9	1.9	1.9	1.9	1.9	1.8
	50% PoE		1.8	1.8	1.8	1.8	1.8	1.7	1.7	1.7	1.7	1.6
Swan Reach Pumping Stations #1, 2 & 3 Total	10% PoE	MVA	[redacted]									
	50% PoE											
Swan Reach 11kV	10% PoE	MVA	1.3	1.3	1.3	1.3	1.2	1.2	1.2	1.2	1.2	1.1
	50% PoE		1.2	1.2	1.2	1.2	1.2	1.2	1.1	1.1	1.1	1.1
Swan Reach 33kV	10% PoE	MVA	2.7	2.7	2.7	2.6	2.6	2.6	2.5	2.5	2.5	2.4
	50% PoE		2.5	2.4	2.4	2.4	2.3	2.3	2.3	2.3	2.2	2.2

Zone Substation	Forecast Basis	Units	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2012/22	2022/23	20223/24	2024/25
Swan Reach Filtration 11kV	10% PoE	MVA	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	50% PoE		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Waikerie 11kV	10% PoE	MVA	7.5	7.5	7.4	7.3	7.2	7.2	7.2	7.1	7.1	7.1
	50% PoE		6.9	6.8	6.7	6.6	6.5	6.4	6.4	6.3	6.3	6.2
Woolpunda 11kV	10% PoE	MVA	6.5	6.4	6.4	6.3	6.2	6.2	6.1	6.1	6.0	5.9
	50% PoE		5.8	5.8	5.7	5.7	5.6	5.6	5.5	5.4	5.4	5.3

Table 188: Riverland Zone Substation Forecasts

39. APPENDIX M – SOUTH EAST REGION FORECASTS

39.1 Connection Point Forecasts

Connection Point	Forecast Basis	Units	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2012/22	2022/23	20223/24	2024/25
Blanche 33kV	10% PoE	MVA	34.6	35.0	35.3	35.6	35.9	36.1	36.2	36.4	36.6	36.8
		PF	0.92	0.92	0.92	0.92	0.92	0.92	0.91	0.91	0.91	0.91
Keith 33kV	10% PoE	MVA	25.3	25.4	25.5	25.6	25.6	25.6	25.5	25.4	25.3	25.2
		PF	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.93	0.93	0.93
Kincraig 33kV	10% PoE	MVA	24.3	24.4	24.6	24.7	24.8	24.9	25.0	25.0	25.1	25.1
		PF	0.94	0.94	0.93	0.93	0.93	0.93	0.93	0.98	0.98	0.98
Mt Gambier 33kV	10% PoE	MVA	22.0	21.7	21.4	21.2	20.9	20.9	20.9	20.9	20.9	20.9
		PF	0.93	0.92	0.92	0.92	0.92	0.92	0.91	0.91	0.91	0.90
Penola West 33kV	10% PoE	MVA	6.3	6.2	6.1	6.0	5.9	5.8	5.7	5.7	5.6	5.5
		PF	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.95	0.95	0.95
Snuggery Industrial 33kV	10% PoE	MVA	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4
		PF	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95
Snuggery Rural 33kV	10% PoE	MVA	17.2	17.3	17.5	17.6	17.7	17.8	18.0	18.1	18.2	18.4
		PF	0.92	0.91	0.91	0.91	0.92	0.91	0.92	0.92	0.92	0.92

Table 189: South East Connection Point Forecasts

39.2 Zone Substation Forecasts

Zone Substation	Forecast Basis	Units	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2012/22	2022/23	20223/24	2024/25
Allendale East 11kV	10% PoE	MVA	4.5	4.5	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4
	50% PoE		4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1
Apcel 11kV	10% PoE	MVA	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	50% PoE		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Apcel Pulp Mill 11kV	10% PoE	MVA	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	50% PoE		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Beachport 11kV	10% PoE	MVA	1.2	1.2	1.2	1.2	1.3	1.3	1.3	1.3	1.3	1.3
	50% PoE		1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.2	1.2	1.2
Blue Lake 3.3kV	10% PoE	MVA	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	50% PoE		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Bordertown 11kV	10% PoE	MVA	11.5	11.6	11.6	11.7	11.7	11.7	11.7	11.7	11.7	11.7
	50% PoE		10.6	10.6	10.7	10.8	10.9	10.8	10.8	10.8	10.8	10.8
Coonawara 11kV	10% PoE	MVA	3.5	3.4	3.4	3.3	3.3	3.2	3.2	3.1	3.1	3.0
	50% PoE		3.4	3.4	3.3	3.3	3.2	3.2	3.1	3.1	3.0	3.0
Desert Camp 11kV	10% PoE	MVA	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
	50% PoE		0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Glencoe 11kV	10% PoE	MVA	1.3	1.3	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.5
	50% PoE		1.2	1.2	1.2	1.2	1.2	1.3	1.3	1.3	1.3	1.3
Hatherleigh 11kV	10% PoE	MVA	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
	50% PoE		0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Inverness 11kV	10% PoE	MVA	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
	50% PoE		0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
Kalangadoo 11kV	10% PoE	MVA	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
	50% PoE		0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Kalangadoo West 11kV	10% PoE	MVA	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
	50% PoE		1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0

Zone Substation	Forecast Basis	Units	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2012/22	2022/23	20223/24	2024/25
Keith 11kV	10% PoE	MVA	5.8	5.8	5.8	5.8	5.8	5.8	5.7	5.7	5.6	5.6
	50% PoE		5.2	5.2	5.2	5.3	5.3	5.2	5.2	5.2	5.2	5.1
Kimberly Clark 33kV	10% PoE	MVA	[redacted]									
	50% PoE											
Kingston 11kV	10% PoE	MVA	3.9	4.0	4.0	4.0	4.1	4.1	4.1	4.2	4.2	4.2
	50% PoE		3.5	3.6	3.6	3.6	3.7	3.7	3.7	3.8	3.8	3.8
Kongorong 11kV	10% PoE	MVA	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
	50% PoE		0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
Kurmorna 11kV	10% PoE	MVA	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
	50% PoE		0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Lakeside 11kV	10% PoE	MVA	4.3	4.3	4.2	4.2	4.1	4.1	4.0	3.9	3.9	3.8
	50% PoE		4.3	4.2	4.2	4.2	4.1	4.1	4.0	4.0	3.9	3.8
Lucindale 11kV	10% PoE	MVA	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6
	50% PoE		1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
Millicent 11kV	10% PoE	MVA	6.0	5.9	5.9	5.9	5.8	5.8	5.9	5.9	5.9	5.9
	50% PoE		5.4	5.3	5.3	5.2	5.1	5.1	5.1	5.1	5.1	5.1
Mount Burr 11kV	10% PoE	MVA	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
	50% PoE		0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Mount Gambier 11kV	10% PoE	MVA	14.3	14.0	13.8	13.6	13.4	13.4	13.4	13.4	13.5	13.5
	50% PoE		13.2	12.8	12.5	12.2	11.9	11.8	11.8	11.7	11.6	11.5
Mount Gambier West 11kV	10% PoE	MVA	16.6	16.8	17.0	17.1	17.3	17.5	17.7	17.8	18.0	18.1
	50% PoE		16.1	16.2	16.2	16.3	16.3	16.4	16.4	16.4	16.5	16.5
Mount Schank 11kV	10% PoE	MVA	3.6	3.7	3.8	3.9	3.9	4.0	4.1	4.2	4.3	4.3
	50% PoE		3.3	3.3	3.4	3.5	3.5	3.6	3.7	3.8	3.8	3.9
Mt Gambier North 11kV	10% PoE	MVA	9.6	9.7	9.8	9.8	9.9	10.0	10.0	10.1	10.2	10.3
	50% PoE		8.7	8.7	8.8	8.9	8.9	9.0	9.0	9.1	9.2	9.2

Zone Substation	Forecast Basis	Units	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2012/22	2022/23	20223/24	2024/25
Nangwarry 11kV	10% PoE	MVA	1.0	0.9	0.9	0.9	0.8	0.8	0.8	0.7	0.7	0.7
	50% PoE		1.1	1.0	1.0	1.0	0.9	0.9	0.8	0.8	0.8	0.7
Naracoorte 11kV	10% PoE	MVA	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2
	50% PoE		11.0	11.0	11.0	11.0	11.0	11.0	11.1	11.1	11.1	11.2
Naracoorte East 11kV	10% PoE	MVA	5.9	6.0	6.0	6.0	6.0	6.1	6.1	6.1	6.1	6.2
	50% PoE		5.4	5.4	5.4	5.4	5.4	5.5	5.5	5.5	5.5	5.5
Padthaway 11kV	10% PoE	MVA	4.8	4.8	4.8	4.7	4.7	4.7	4.6	4.6	4.6	4.5
	50% PoE		4.3	4.3	4.3	4.3	4.2	4.2	4.2	4.1	4.1	4.1
Penola 11kV	10% PoE	MVA	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8
	50% PoE		2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8
Robe 7.6kV	10% PoE	MVA	3.5	3.5	3.5	3.6	3.6	3.6	3.6	3.6	3.6	3.7
	50% PoE		3.1	3.1	3.1	3.2	3.2	3.3	3.3	3.3	3.3	3.4
Safries 11kV	10% PoE	MVA	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	50% PoE		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
South End 11kV	10% PoE	MVA	0.5	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
	50% PoE		0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Tantanoola 11kV	10% PoE	MVA	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.9	0.9	0.9
	50% PoE		0.7	0.7	0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.8
Tarpeena 11kV	10% PoE	MVA	4.5	4.5	4.5	4.5	4.5	4.4	4.4	4.4	4.4	4.3
	50% PoE		4.1	4.1	4.0	4.0	4.0	4.0	4.0	3.9	3.9	3.9
Tintinara 11kV	10% PoE	MVA	1.2	1.2	1.2	1.2	1.3	1.3	1.3	1.3	1.3	1.3
	50% PoE		1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.2	1.2	1.2

Table 190: South East Zone Substation Forecasts

40. APPENDIX N – UPPER NORTH REGION FORECASTS

40.1 Connection Point Forecasts

Connection Point	Forecast Basis	Units	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2012/22	2022/23	20223/24	2024/25
Baroota 33kV	10% PoE	MVA	7.8	7.8	7.7	7.7	7.7	7.6	7.6	7.5	7.5	7.5
		PF	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97
Leigh Creek South 33kV	10% PoE	MVA	1.6	1.6	1.5	1.5	1.5	1.5	1.5	1.4	1.4	1.4
		PF	0.94	0.94	0.94	0.94	0.94	0.94	0.94	0.94	0.94	0.94
Mt Gunson 33kV	10% PoE	MVA	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
		PF	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99
Neuroodla 33kV	10% PoE	MVA	1.0	1.0	1.0	1.0	1.0	1.0	0.9	0.9	0.9	0.9
		PF	0.90	0.89	0.89	0.89	0.89	0.89	0.89	0.89	0.88	0.88
Davenport West 33kV	10% PoE	MVA	29.4	28.8	28.4	28.0	27.5	27.4	27.4	27.3	27.2	27.2
		PF	0.98	0.98	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97
Pirie – Bungama 33kV	10% PoE	MVA	59.0	75.8	76.1	76.4	76.7	77.0	77.3	77.6	77.9	78.2
		PF	0.94	0.94	0.94	0.93	0.93	0.93	0.93	0.93	0.93	0.93

Table 191: Upper North Connection Point Forecasts

40.2 Zone Substation Forecasts

Zone Substation	Forecast Basis	Units	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2012/22	2022/23	20223/24	2024/25
Baroota 11kV	10% PoE	MVA	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
	50% PoE		0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Booleroo Centre 11kV	10% PoE	MVA	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
	50% PoE		0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Booyoolie 11kV	10% PoE	MVA	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
	50% PoE		0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Bungama 11kV	10% PoE	MVA	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
	50% PoE		1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Caltowie 11kV	10% PoE	MVA	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
	50% PoE		0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Crystal Brook 11kV	10% PoE	MVA	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1
	50% PoE		1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9
Fullarville 11kV	10% PoE	MVA	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
	50% PoE		0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Gladstone 11kV	10% PoE	MVA	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
	50% PoE		2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3
Hawker 11kV	10% PoE	MVA	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
	50% PoE		0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Jamestown 11kV	10% PoE	MVA	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1
	50% PoE		2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8
Melrose 11kV	10% PoE	MVA	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
	50% PoE		0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Orroroo 11kV	10% PoE	MVA	1.5	1.5	1.5	1.5	1.5	1.5	1.4	1.4	1.4	1.4
	50% PoE		1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
Peterborough 11kV	10% PoE	MVA	2.0	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9
	50% PoE		1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.6	1.6	1.6

Zone Substation	Forecast Basis	Units	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2012/22	2022/23	20223/24	2024/25
Playford - NPS 11kV	10% PoE	MVA	1.4	1.4	1.4	1.4	1.4	1.3	1.3	1.3	1.3	1.3
	50% PoE		1.3	1.3	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
Port Augusta 11kV	10% PoE	MVA	14.9	14.6	14.3	14.0	13.8	13.7	13.6	13.6	13.5	13.4
	50% PoE		13.7	13.4	13.1	12.9	12.6	12.6	12.5	12.5	12.4	12.4
Port Augusta West TF1 11kV	10% PoE	MVA	5.6	5.5	5.5	5.4	5.3	5.3	5.3	5.2	5.2	5.2
	50% PoE		5.2	5.1	5.0	4.9	4.9	4.9	4.8	4.8	4.8	4.8
Port Augusta West TF2 11kV	10% PoE	MVA	1.8	1.7	1.7	1.6	1.6	1.6	1.6	1.6	1.6	1.6
	50% PoE		1.6	1.5	1.5	1.5	1.4	1.4	1.4	1.4	1.4	1.4
Port Broughton 11kV	10% PoE	MVA	3.2	3.1	3.1	3.1	3.0	3.0	3.0	3.0	3.0	3.0
	50% PoE		2.7	2.6	2.6	2.6	2.6	2.5	2.5	2.5	2.5	2.5
Port Germein 11kV	10% PoE	MVA	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.0
	50% PoE		1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.9	0.9	0.9
Port Pirie 6.6kV	10% PoE	MVA	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	50% PoE		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Port Pirie South 11kV	10% PoE	MVA	21.0	20.7	20.5	20.3	20.0	19.9	19.8	19.7	19.6	19.5
	50% PoE		18.2	18.0	17.7	17.5	17.3	17.2	17.1	17.0	17.0	16.9
Quorn 11kV	10% PoE	MVA	2.1	2.0	2.0	2.0	2.0	2.0	2.0	1.9	1.9	1.9
	50% PoE		1.9	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.7	1.7
Stirling North 1 11kV	10% PoE	MVA	0.5	0.4	0.4	0.3	0.3	0.3	0.3	0.3	0.3	0.3
	50% PoE		0.5	0.4	0.3	0.3	0.2	0.2	0.2	0.2	0.2	0.2
Stirling North 2 11kV	10% PoE	MVA	1.5	1.5	1.5	1.4	1.4	1.4	1.4	1.4	1.4	1.4
	50% PoE		1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.2	1.2
Wilmington 11kV	10% PoE	MVA	0.8	0.8	0.8	0.8	0.7	0.7	0.7	0.7	0.7	0.7
	50% PoE		0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Wirrabara Forest 11kV	10% PoE	MVA	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
	50% PoE		0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7

Zone Substation	Forecast Basis	Units	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2012/22	2022/23	20223/24	2024/25
Wirrabara South 11kV	10% PoE	MVA	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
	50% PoE		0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Wongyarra 11kV	10% PoE	MVA	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
	50% PoE		0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Yongala 11kV	10% PoE	MVA	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
	50% PoE		0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1

Table 192: Upper North Zone Substation Forecasts

41. Appendix O – Yorke Peninsula Region Forecasts

41.1 Connection Point Forecasts

Connection Point	Forecast Basis	Units	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2012/22	2022/23	20223/24	2024/25
Ardrossan West 33kV	10% PoE	MVA	12.5	10.4	10.6	10.7	10.9	11.1	11.4	11.6	11.9	12.1
		PF	0.90	0.92	0.92	0.92	0.92	0.91	0.91	0.91	0.90	0.92
Dalrymple 33kV	10% PoE	MVA	8.1	10.3	10.2	10.2	10.2	10.2	10.3	10.4	10.4	10.5
		PF	0.98	0.98	0.97	0.97	0.96	0.96	0.95	0.95	0.94	0.95
Kadina East 33kV	10% PoE	MVA	26.3	26.5	26.7	26.9	27.1	27.4	27.8	28.1	28.5	28.8
		PF	0.95	0.95	0.95	0.94	0.94	0.94	0.94	0.93	0.93	0.93

Table 193: Yorke Peninsula Connection Point Forecasts

41.2 Zone Substation Forecasts

Zone Substation	Forecast Basis	Units	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2012/22	2022/23	20223/24	2024/25
Ardrossan 11kV	10% PoE	MVA	2.2	2.1	2.2	2.2	2.2	2.3	2.3	2.4	2.4	2.5
	50% PoE		1.9	1.8	1.8	1.9	1.9	1.9	2.0	2.1	2.1	2.2
BHP Ardrossan 11 kV	10% PoE	MVA	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	50% PoE		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
BHP Ardrossan 3.3 kV	10% PoE	MVA	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	50% PoE		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Black Point 11kV	10% PoE	MVA	0.6	0.6	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.8
	50% PoE		0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.7	0.7	0.7

Zone Substation	Forecast Basis	Units	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2012/22	2022/23	20223/24	2024/25
Curramulka 7.6kV	10% PoE	MVA	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
	50% PoE		0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Curramulka South 7.6kV	10% PoE	MVA	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
	50% PoE		0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Edithburgh 11kV	10% PoE	MVA	1.1	1.1	1.1	1.0	1.0	1.0	1.0	1.0	1.0	1.0
	50% PoE		0.9	1.0	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
James Well 7.6kV	10% PoE	MVA	0.4	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
	50% PoE		0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5
Kadina 11kV	10% PoE	MVA	9.2	9.2	9.1	9.1	9.1	9.2	9.3	9.4	9.5	9.6
	50% PoE		8.2	8.2	8.2	8.2	8.2	8.2	8.3	8.4	8.5	8.6
Kleins Point 11kV	10% PoE	MVA	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
	50% PoE		1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
Maitland 11kV	10% PoE	MVA	3.5	3.4	3.3	3.3	3.2	3.2	3.2	3.2	3.1	3.1
	50% PoE		3.1	2.9	2.9	2.8	2.8	2.8	2.8	2.8	2.8	2.7
Marion Bay 11kV	10% PoE	MVA	0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
	50% PoE		0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Minlaton 11kV	10% PoE	MVA	2.0	1.9	1.9	1.9	1.9	2.0	2.0	2.0	2.1	2.1
	50% PoE		1.8	1.7	1.7	1.7	1.8	1.8	1.9	1.9	1.9	2.0
Moonta 11kV	10% PoE	MVA	8.5	8.7	8.8	9.0	9.2	9.4	9.6	9.7	9.9	10.1
	50% PoE		7.5	7.6	7.8	8.0	8.1	8.3	8.5	8.7	8.8	9.0
Port Giles 11kV	10% PoE	MVA	1.9	1.9	1.9	1.9	1.9	1.9	2.0	2.0	2.0	2.0
	50% PoE		1.7	1.7	1.7	1.7	1.7	1.8	1.8	1.8	1.8	1.8
Port Julia 11kV	10% PoE	MVA	0.5	0.5	0.5	0.6	0.6	0.6	0.6	0.6	0.6	0.6
	50% PoE		0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.6	0.6
Port Vincent 11kV	10% PoE	MVA	1.6	1.6	1.6	1.7	1.7	1.7	1.8	1.8	1.8	1.9
	50% PoE		1.4	1.4	1.5	1.5	1.5	1.6	1.6	1.6	1.7	1.7
Stansbury 11kV	10% PoE	MVA	0.9	0.9	0.9	0.9	0.8	0.8	0.8	0.8	0.8	0.8
	50% PoE		0.8	0.8	0.8	0.7	0.7	0.7	0.7	0.7	0.7	0.7

Zone Substation	Forecast Basis	Units	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2012/22	2022/23	20223/24	2024/25
Wallaroo 11kV	10% PoE	MVA	8.1	8.1	8.1	8.2	8.2	8.3	8.4	8.4	8.5	8.6
	50% PoE		7.2	7.2	7.2	7.2	7.2	7.3	7.4	7.5	7.5	7.6
Warooka 11kV	10% PoE	MVA	1.7	1.8	1.8	1.8	1.8	1.9	1.9	1.9	1.9	1.9
	50% PoE		1.5	1.6	1.6	1.6	1.6	1.7	1.7	1.7	1.7	1.7
Yorketown 11kV	10% PoE	MVA	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
	50% PoE		1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5

Table 194: Yorke Peninsula Zone Substation Forecasts

42. APPENDIX P

Remote Substation Voltage Set Point Control Project (20 sites over 5 years).

Trial Number	ZONE SUBSTATION	Number of Transformers	Number of Customers	AVR	Combined Normal Cyclic Rating (MVA)	Forecast Max Demand in 2013/14 (MW) - source DAPR 10% POE forecast	Minimum spring load (MW)	Date and Time of minimum	Total PV penetration (MW)	% Penetration (PV cf transformer capacity) 2013/14	PV % pa= 2020/21	15.0%
Trial 1	HACKHAM	1	5,959	DRMCC	30	16.6	0.04	14/11/2013 2:30	3.95	13%	10.51	35%
Trial 2	FULHAM GARDENS	2	12,254	AVE4	51	36.1	4.09	19/09/2013 13:00	11.23	22%	29.87	59%
3	HOPE VALLEY	1	6,759	DRMCC	30	18.6	-0.66	1/11/2013 13:30	4.27	14%	11.36	38%
4	SEAFORD	1	3,099	2V162	15	8.5	-2.41	15/10/2013 13:30	2.29	15%	6.09	41%
5	MORPHETT VALE EAST	2	13,588	AVE3	61	32.9	0.09	14/11/2013 13:30	9.34	15%	24.84	41%
6	VICTOR HARBOR	2	11,670	DRMCC	69.8	25.7	0.00	1/09/2013 1:30	7.09	10%	18.86	27%
7	BLACKPOOL	2	5,738	MK20	21	14.2	1.02	12/11/2013 13:30	3.7	18%	9.84	47%
8	HAPPY VALLEY	2	10,511	2V164	61	33	0.74	14/11/2013 14:30	8.5	14%	22.61	37%
9	ALDINGA	2	6,835	MK20	32.6	17.9	0.80	15/10/2013 13:30	4.44	14%	11.81	36%
10	PARAFIELD GARDENS	2	9,399	DRMCC	24.6	18.8	0.00	1/09/2013 6:00	4.63	19%	12.32	50%
11	LARGS NORTH	2	5,424	MK20	27.2	14.2	1.42	24/11/2013 13:00	3.47	13%	9.23	34%
12	SHEIDOW PARK	2	8,182	MK20	32.8	26.8	0.72	12/11/2013 13:00	6.41	20%	17.05	52%
13	GOLDEN GROVE	3	14,644	MK20	91	45.6	2.29	7/10/2013 14:00	10.27	11%	27.32	30%
14	NORTHFIELD	2	5,396	AVE3	28.7	18.4	1.29	10/11/2013 13:30	3.97	14%	10.56	37%
15	BLACKWOOD	2	9,159	AVE3	61	26.9	2.02	30/10/2013 13:30	5.7	9%	15.16	25%
16	PORT NOARLUNGA	2	9,503	DRMCC	60	26.3	3.34	8/10/2013 0:00	5.51	9%	14.66	24%
17	GLANVILLE	2	5,210	AVE3	17.2	13.4	1.38	8/11/2013 14:30	2.75	16%	7.32	43%
18	TEA TREE GULLY	2	11,228	AVE3	49.6	32.9	3.26	7/10/2013 13:30	6.63	13%	17.64	36%
19	EVANSTON	2	10,570	AVE	61	34.4	4.70	13/10/2013 14:00	6.79	11%	18.06	30%

Trial Number	ZONE SUBSTATION	Number of Transformers	Number of Customers	AVR	Combined Normal	Forecast Max Demand in	Minimum spring load	Date and Time of minimum	Total PV penetration	% Penetration (PV cf	PV % pa=	15.0%
20	INGLE FARM	2	13,014	AVE3	55	35.1	4.87	7/10/2013 13:00	6.92	13%	18.41	33%
21	GOOLWA	2	6,253	AVE3	25	14.7	0.00	1/09/2013 1:30	4.47	18%	11.89	48%

43. APPENDIX Q

VOLTAGE REGULATION - Retrofit SCADA to 63 line regulators with suitable controllers (CL5/6).

Region	Substation name	Feeder	Feeder ID	Feeder Coordinates	VR
Eastern Hills	Houghton	Houghton	GU13	N5	VR125
Eastern Hills	Mt. Pleasant	Mt. Pleasant	GU32	P11	VR200
Eastern Hills	Mt. Pleasant	Springton	GU34	G3	VR468
Eastern Hills	Mt. Pleasant	Cookes Hill	GU37	G8	VR127
Eastern Hills	Mount Barker	Mt. Barker	MTB11	M3	VR199
Eastern Hills	Mount Barker	Bugle Ranges	MTB13	E12	VR129
Eastern Hills	Woodside	Lenswood	MTB54	T10	VR360
Eyre	Ceduna	Smoky Bay	CD4	B8	VR084
Eyre	Ceduna	Penong	CD5	C7	VR062
Eyre	Caralue	Kimba	CV08	M7	VR376
Eyre	Caralue	Kimba	CV08	F10	VR375
Eyre	Cowell	Cowell T/ship	CV753A	Y5	VR085
Eyre	Cowell	Cowell T/ship	CV753A	F6	VR510
Eyre	Cowell	Cowell T/ship	CV753A	C7	VR511
Eyre	Arno Bay	Arno Bay	CV757A	F5	VR423
Eyre	Streaky Bay	Streaky Bay	SB01	F7	VR507
Eyre	Streaky Bay	Streaky Bay	SB01	N4	VR503
Eyre	Streaky Bay	Haslam	SB15	E7	VR411
Eyre	Streaky Bay	Calca	SB17	B8	VR006
Eyre	Streaky Bay	Calca	SB17	D8	VR007
Eyre	Polda	Elliston	W04	P9	VR384
Eyre	Polda	Elliston	W04	E5	VR514
Eyre	Moorkitabie	Venus Bay	W06	M5	VR381
Fleurieu	Kingscote	Kingscote	KI31	O3	VR159
Fleurieu	Parndana	Parndana	KI42	D7	VR421
Fleurieu	Parndana	Parndana	KI42	H7	VR160
Fleurieu	Parndana	Parndana	KI42	Q10	VR204
Fleurieu	Langhorne Creek	Hartley	ST41	M9	VR355
Fleurieu	Langhorne Creek	Hartley	ST41	E6	VR443
Mid North	Jamestown	Jamestown	G02	O9	VR064
Murraylands	Meningie	Coorong 19Kv SWER	CN25	N5	VR172
Murraylands	Coomandook	KiKi 19kV SWER	CN53	N5	VR202
Riverland	Paringa	Murtho 33kV	LX21	M6	VR434
Riverland	Pyap	Pata	LX52	D9	VR148
South East	Kongorong	Carpenter Rocks	MG32	E8	VR363
South East	Robe	Robe 7.6kV	MI08	C8	VR431
South East	Millicent	Southend	MI16	C7	VR366

Region	Substation name	Feeder	Feeder ID	Feeder Coordinates	VR
South East	Naracoorte	McIntosh	NA2	K8	VR378
South East	Naracoorte East	Cadgee	NA3	N12	VR527
South East	Naracoorte East	Kybylite	NA4	H11	VR076
South East	Naracoorte	Joanna	NA8	Q4	VR077
South East	Padthaway	Padthaway	NA12	N8	VR347
Upper North	Orroroo	Orroroo	G17	Q9	VR104
Upper North	Hawker	Wilpena 19kV SWER	HK02	C3	VR542
Upper North	Port Augusta West	Stokes	PA5	N7	VR213
Upper North	Port Augusta West	Stokes	PA5	L12	VR374
Yorke	Warooka	Point Turton	YK17	D7	VR438
Yorke	Maitland	South Maitland	MT01	E7	VR442
Yorke	Maitland	South Maitland	MT01	D3	VR441
Yorke	Maitland	Weetulta 19kV	MT02	C5	VR111
Yorke	Maitland	Weetulta 19kV	MT02	H7	VR467
South East	Keith	Keith	BT06	L3	VR163
South East	Keith	Keith	BT06	G5	VR164
South East	Keith	Keith	BT06	F7	VR165
South East	Keith	Keith	BT06	E2	VR418
South East	Bordertown	Mundulla	BT03	J3	VR162
South East	Bordertown	Teatrick	BT04	M8	VR428
South East	Bordertown	Teatrick	BT04	L1	VR427
Yorke	Moonta	Moonta	KA03	J8	VR440
Yorke	Port Broughton	Port Broughton	KA22	G9	VR345
Upper North	Gladstone	Laura	G05	F2	VR100
Upper North	Bungama	Warnertown	PP05	E2	VR453
Upper North	Bungama	Napperby	PP06	C9	VR105

44. APPENDIX R

Transformer Monitoring - SWER (start & EOL) – 740 LV monitors locations.

SWER NAME	ISOLATING TRANSFORMER	START OF FEEDER MONITOR REQD	EOL TRANSFORMER NO. 1	EOL LV MONITOR NO. 1 CO-ORD	EOL TRANSFORMER NO. 2	EOL LV MONITOR NO. 2 CO-ORD
ALAWOONA 19kV SWER	LX52-28	YES	37	H11		
ALFORD NO 1 19kV SWER	KA29-21	YES	50	Q8		
ALFORD NO 2 19kV SWER	KA29-22	YES	45	B1		
ALLENDALE 19kV SWER	NU20-68	YES	46	B10		
ALMA 19kV SWER	SD371-44	YES	76	G3		
AMERICAN RIVER 11kV	SSD-314	YES	57	A2		
ANDREWS 19kV SWER	CL01-32	YES	48	G11		
APOINGA 19KV SWER	SD362-1	YES	51	C11		
APPILA NORTH 19kV SWER	SD312-39	YES	11	A9		
APPILA SOUTH 19kV SWER	SD312-37	YES	52	B1		
ARMY RANGE 19kV SWER	MB32-67	YES	52	F12		
ARTHURTON 19kV SWER	MT03-24	YES	37	A3		
ASH 19kV SWER	WHY07-62	YES	11	F11		
AVENUE 19kV SWER	NA13-121	NO	21	H3		
BAGOT WELL 19kV SWER	NU06-52	NO	51	A1		
BALAKLAVA 19kV SWER	SD371-41	YES	52	O6		
BALGOWAN 19kV SWER	MT22-40	YES	12	H4	13	E8
BANGOR 19kV SWER	SD311-30	NO	51	N12		
BAUDIN BEACH 19kV SWER	SD443-2	YES	38	A8		
BEEAMMA 19kV SWER	BT04-135	YES	40	A11		
BEETALOO VALLEY 19kV SWER	G05-60	YES	31	F12		
BELLUM 19kV SWER	SD482-15	NO	53	C8		
BELTANA 19kV SWER	LC2-35	YES	32	Q8		
BENARA 19kV SWER	MG05-167	NO	42	B10		
BEWS NORTH 19kV SWER	LM41-4	YES	63	F1		
BEWS SOUTH 19kV SWER	SD407-18	YES	44	D11		
BIG BEND 19kV SWER	SD391-17	YES	34	C3		
BIG HEATH 19 kV SWER	NA13-123	NO	35	B3		
BINNIES 19kV SWER	SD403-13	YES	32	L12		
BISCUIT FLAT 19kV SWER	SD492-43	NO	35	E10		
BLACK HILL 19kV SWER	M82-9	YES	66	Q5		
BLACK POINT 19kV SWER	SD352-17	YES	31	H7		
BLACK ROCK 19kV SWER	G17-10	NO	46	A5		
BLACKFELLOW CAVES 19kV SWER	MG16-3	NO	17	H5		
BLACKFORD 19kV SWER	NA51-56	NO	56	D3		
BLYTH 19kV SWER	SD332- 11	NO	33	E2		
BOLINGVBROKE 19kV SWER	PL34-22	YES	40	B2		
BOOBOROWIE 19kV SWER	CL01-34	YES	47	H12		
BOOKALOO 19kV SWER	PA32-1	YES	17	F1		
BOOL LAGOON 19kV SWER	NA09-111	NO	48	H6		
BOOLEROO 19kV SWER	SD313-15	YES	44	D12		

SWER NAME	ISOLATING TRANSFORMER	START OF FEEDER MONITOR REQD	EOL TRANSFORMER NO. 1	EOL LV MONITOR NO. 1 CO-ORD	EOL TRANSFORMER NO. 2	EOL LV MONITOR NO. 2 CO-ORD
BOORS PLAIN 19kV SWER	SD344-79	YES	22	H7		
BOOTHBY - MANN 19kV SWER	SD551-1	YES	32	D1		
BORDA 19kV SWER	KI42-67	YES	54	Q6		
BORRIKA 19kV SWER	MB41-22	NO	53	B2		
BOWILLIA 19kV SWER	SD332-90	NO	31	G10		
BRAY 19kV SWER	SD492-45	NO	31	A9		
BRAYFIELD 19kV SWER	CM03-55	YES	17	G10		
BREMER 19kV SWER	MTB81-41	NO	65	H5		
BRIMBAGO 19kV SWER	BT06-131	YES	41	A1		
BRIMPTON LAKE 19kV SWER	CM02-104	YES	51	H12		
BRINKLEY 19kV SWER	MB12-65	YES	83	H9		
BROADVIEW 19kV SWER	BT15-44	YES	48	A7		
BROOKER 19kV SWER	CM02-102	YES	53	A4		
BUCKLEBOO 19kV SWER	CV08-49	YES	48	N2		
BULL ISLAND 19kV SWER	SD462-3	NO	47	B1		
BUNBURY 19kV SWER	BT26-54	NO	45	P7		
BURDETT 19kV SWER	MB32-66	YES	42	A4		
BURGOYNE 19kV SWER	CD05-105	YES	7	H3		
BURRA 19kV	BU06-12	YES	40	B1		
BURRUNGULE 19kV SWER	MG05-166	NO	36	E2		
BUTE NO 1 19kV SWER	KA26-28	YES	41	B1		
BUTE NO 2 19kV SWER	KA26-29	YES	67	P5		
BUTLER - DIXON 19kV SWER	CM03-65	YES	61	A3		
CALCA 19kV SWER	SB02-22	YES	47	H8		
CALOMBA 19kV SWER	GA28-48	YES	36	B7		
CALTOWIE 19kV SWER	SD322-36	YES	1	B1		
CAMPOONA 19KV SWER	SD531-36	YES	28	P1		
CANNAWIGARA BT-2	BT02-203	YES	19	G12		
CANOWIE BELT 19kV SWER	SD322-7	YES	11	A1		
CANTARA 19kV SWER	NA51-70	NO	72	F1		
CAPE DOUGLAS 19kV SWER	MG35-18	NO	42	H7		
CAPE JAFFA 19kV SWER	NA52-59	NO	43	F11		
CARALUE 19kV SWER	CV08-46	YES	32	B3		
CAREW 19kV SWER	SD452-1	YES	42	H7		
CARINA 19kV SWER (SOUTH)	W02-41	YES	34	D12	12	Q5
CAROLINE 19kV SWER	MG19-96	NO	35	B10		
CARRIBIE 19kV SWER	YK17-47	YES	33	A1		
CASSINI 19kV SWER	KI42-16	YES	53	C1		
CHANDADA EAST 19kV SWER	SB03-104	NO	40	B12		
CHANDADA WEST 19kV SWER	SB02-21	YES	28	A6		
CHARLTON 19kV SWER	PL10-38	YES	44	H12		
CHARRA 19kV SWER	CD05-103	NO	23	P11		
CHETWYND 19kV SWER	SD495-14	NO	34	C1		

SWER NAME	ISOLATING TRANSFORMER	START OF FEEDER MONITOR REQD	EOL TRANSFORMER NO. 1	EOL LV MONITOR NO. 1 CO-ORD	EOL TRANSFORMER NO. 2	EOL LV MONITOR NO. 2 CO-ORD
CLAYWELLS 19kV	SD492-48	YES	29	E2	21	P1
CLEMENTS GAP 19kV SWER	SD324-5	YES	14	H5		
COCKALEECHIE NORTH 19kV SWER	CM02-101	YES	31	A2		
COLEBATCH 19kV SWER	CN72-13	YES	63	Y6		
COLTON - WARD (NORTH) 19kV SWER	W04-44	YES	45	O1		
COMAUM 19kV SWER	NA32-116	NO	47	C1		
CONCORDIA 19kV SWER	SD375-78	NO	40	F12		
COOKS 19kV SWER	GU32-165	NO	41	C12		
COOLA 19kV SWER	MG16-6	NO	39	G2		
COOMBE 19kV SWER	CN72-12	YES	38	A11		
COONALPYN 19kV SWER	CN81-21	YES	63	C4		
COORONG 19kV SWER	CN24-50	NO	69	C12		
COPEVILLE 19kV SWER	M71-61	NO	43	A9		
COPPER HILL 19kV SWER	KA27-9	YES	36	A12		
CORNY POINT 19kV SWER	YK17-38	YES	34	N11		
COULTA 19kV SWER	CM01-108	YES	51	M10	44	P2
CRADOCK 19kV SWER	HK01-18	YES	44	A1		
CRANEFORD 19kV SWER	GU32-98	NO	57	H3		
CROMER 19kV SWER	GU31-133	NO	61	D4		
CROWER 19kV SWER	NA13-122	YES	44	A12		
CULBURRA 19kV SWER	SD-451	YES	65	Q11		
CUNGENA 19kV SWER	SB03-105	NO	42	D12		
CURRAMULKA EAST 19KV	MT24-3	YES	51	Q6		
CUSTON 19kV SWER	BT04-138	YES	23	D3		
DALRYMPLE 19kV SWER	YK23-36	YES	29	A1		
DALRYMPLE 19kV SWER		YES				
DENIAL BAY 19kV SWER	CD05-100	YES	31	H12		
DISMAL SWAMP 19 kV SWER	MG7-9	NO	36	D11		
DONOVANS 19kV SWER	MG19-95	NO	16	A3		
DUBLIN 19kV SWER	GA28-45	YES	33	A1		
DUBLIN TOWNSHIP 19kV SWER	GA28-49	YES	14	G11		
DUDLEY 19kV SWER	SD443-2	YES	74	E9		
DUNCAN 19kV SWER	KI42-66	YES	26	L12	61	A3
DUTTON BAY 19kV SWER	PL33-46	YES	58	Q8		
EDEOWIE 19kV SWER	HK01-19	YES	13	K4		
ELBOW HILL 19kV SWER	SD531-4	YES	26	B8		
ELWOMPLE 19kV SWER		YES				
EMU BAY 19kV SWER	KI31-78	YES	66	D5		
EMU LEG 19KV	CD02-101	YES	21	B3		
EURELIA 19kV SWER	G17-42	YES	25	N8		
FAIRVIEW 19kV SWER	SD462-1	YES	38	G1		
FARRELL FLAT 19kV SWER	CL6-87	YES	23	E4		
FIELD 19kV SWER	SD403-12	YES	17	C4	42	F13

SWER NAME	ISOLATING TRANSFORMER	START OF FEEDER MONITOR REQD	EOL TRANSFORMER NO. 1	EOL LV MONITOR NO. 1 CO-ORD	EOL TRANSFORMER NO. 2	EOL LV MONITOR NO. 2 CO-ORD
FISHERMANS BAY - MUNDOORA	KA22-41	YES	32	A12		
FLORIETON 19kV SWER	BU11-19	NO	14	C1		
FOUL BAY 19kVSWER	SD355-1	YES	49	B4		
FURNER 19kV SWER	SD492-49	NO	62	E12		
GALGA 19kV SWER	M71-63	YES	55	A4		
GEEGEELA 19kV SWER	BT04-137	YES	63	B2		
GERANIUM 19kV SWER	SD406-13	YES	66	C1		
GERMAN TOWN 19kV SWER	GA15-60	YES	40	E3		
GIBSON PENINSULA 19kV SWER	SB01-7	YES	47	D7		
GNADENBURG 19kV SWER	NU02-80	NO	30	C10		
GOMERSAL 19kV SWER	NU31-17	NO	51	F1		
GRACE PLAINS 19kV SWER	GA13-18	YES	20	A7		
GREEN PATCH 19kV SWER	PL34-23	YES	28	H8		
GREENWAYS 19kV SWER	SD492-46	YES	40	C1		
HALBURY 19kV SWER	SD332-78	YES	25	F1		
HALBURY EAST 19kV SWER	SD332-79	YES	61	B4		
HALLETT 19kV SWER	BU06-15	YES	32	C1		
HANSON 19kV SWER	BU06-10	YES	44	Q5		
HARDWICKE BAY 19kV SWER	YK7-28	YES	21	H6		
HARDWICKE BAY SOUTH 19kV SWER	YK7-8	YES	15	C5		
HARROGATE 19kV SWER	MTB53-120	NO	64	G5		
HART 19kV SWER		YES				
HASLAM 19kV SWER		YES				
HATHERLEIGH 19kV SWER	SD492-50	NO	34	A12		
HILL RIVER 19kV SWER	CL-86	NO	46	G3		
HILL RIVER SOUTH 19kV SWER		NO				
HITCHCOCK PLAIN 19kV SWER	SD324-12	YES	7	D9		
HOLDER 19kV SWER	WK43-24	YES	49	H10		
INKERMAN 19kV SWER	SD341-55	YES	31	D12		
ISLAND BEACH 19kV SWER	SD443-1	YES	21	B12	31	H9
JABUK 19kV SWER	SD406-12	YES	50	E1		
JAMESTOWN 19kV SWER	SD322-38	YES	54	H12		
JEFFERIES 19kV SWER	SD403-11	YES	32	H7		
JOHNBURGH 19kV SWER	G17-53	NO	41	Z6	23	G1
KAINTON NO 1 19kV SWER	SD344-39	YES	40	H8		
KAIWARRA 19kV SWER	BT26-56	YES	39	H10		
KALANBI 19kV SWER	CD05-101	YES	31	G2		
KALDOONERA 19kV SWERR	W08-1	YES	22	H3		
KANGAROO FLAT 19KV SWER	GA30-19	YES	43	G10		
KAPPAKOOLA 19kV SWER	W01-31	YES	35	E11		
KEILIRA 19kV SWER	BT22-53	YES	74	H2		
KELLIDIE BAY 19kV SWER	PL33-47	YES	34	G11		
KELLY 19kV SWER	CV08-48	YES	66	A4		

SWER NAME	ISOLATING TRANSFORMER	START OF FEEDER MONITOR REQD	EOL TRANSFORMER NO. 1	EOL LV MONITOR NO. 1 CO-ORD	EOL TRANSFORMER NO. 2	EOL LV MONITOR NO. 2 CO-ORD
KIELPA 19kV SWER	CV05-3	YES	50	A7		
KIKI 19kV SWER	CN51-14	YES	67	A9		
KONGOLIA 19kV SWER	M41-24	YES	43	C1		
KOONGAWA 19kV SWER	W01-32	YES	38	B11		
KOONIBBA 19kV SWER	CD05-11	YES	7	F7		
KOONUNGA 19kV SWER	NU15-116	NO	37	G3		
KOPPIO 19kV SWER	CM35-15	YES	41	H6		
KORUNYE 19kV SWER	GA14-125	YES	23	A8		
KULKAMI 19kV SWER	SD407-17	YES	60	E1		
LAKE BONNEY 19kV SWER		NO				
LAKE ELIZA 19kV SWER	SD492-41	NO	29	A7	21	C12
LAKE GEORGE 19kV SWER	MI14-48	YES	50	F1		
LAKE HAWDON 19kV SWER	SD492-44	NO	39	B1		
LAKE LEAKE 19kV SWER	MG12-22	NO	36	A10		
LAKE ORMEROD 19kV SWER	NA7-126	NO	62	H12		
LAMEROO 19kV SWER	SD408-9	YES	72	N1		
LEGGS LANE 19kV SWER	NA13-124	NO	34	C12		
LEIGHTON 19kV SWER	BU06-11	YES	56	A1		
LEWIS 19kV SWER	SD-451	YES	46	C2		
LINWOOD 19kV SWER	SD371- 46	NO	52	A3		
LOCHABER 19kV SWER	BT22-52	YES	50	A10		
LOCHIEL NO 1 19kV SWER	SD344-56	YES	49	A9		
LOCHIEL NO 2 19kV SWER	SD344-57	YES	40	C1		
LONG ISLAND 19kV SWER	SD492-42	NO	35	H3		
LONG PLAINS 19kV SWER	GA28-47	YES	39	E3		
LOUTH BAY 19kV SWER	PL15-96	YES	11	D2		
LOWAN VALE 19kV SWER	BT02-201	YES	42	A1		
LOWER LIGHT 19kV SWER	GA14-124	YES	34	A4		
LOXTON SOUTH 19kV SWER	LX43-1	YES	33	A8		
LUCKY BAY 19kV SWER		YES				
Lyndhurst SWER	LC2-37	YES	17	A12		
MACGILLIVRAY 19kV SWER	KI41-93	YES	42	F8		
MAGGEA 19kV SWER	M51-53	NO	36	B8		
MAITLAND 19kV SWER	MT03-26	YES	19	Q5	16	B4
MAKIN 19kV SWER	BT6-130	NO	26	J7	40	B1
MALINONG 19 kV SWER	CN22-27	YES	68	H4		
MALLALA SOUTH 19kV SWER	GA28-40	YES	17	D8		
MAMBRAY CREEK 19kV SWER	PP07-18	YES	7	B9		
MANGALO 19KV SWER	SD531-39	YES	59	N1		
MANNANARIE 19kV SWER	SD322-40	YES	34	O3		
MARNE VALLEY 19kV SWER	M41-27	YES	39	D12		
MARRABEL 19kV SWER	R10-34	YES	54	D12		
MAYURRA 19kV SWER	MI20-109	NO	76	A11		

SWER NAME	ISOLATING TRANSFORMER	START OF FEEDER MONITOR REQD	EOL TRANSFORMER NO. 1	EOL LV MONITOR NO. 1 CO-ORD	EOL TRANSFORMER NO. 2	EOL LV MONITOR NO. 2 CO-ORD
MEANEY HILL 19kV SWER	SD372-3	NO	23	H8		
MELROSE 19kV SWER	SD314-11	YES	10	D2		
MENINGIE 19kV SWER	SD403-10	YES	48	A1		
MENZIES 19kV SWER	KI41-22	YES	74	B11		
MERRITON NORTH 19kV SWER	SD324-8	YES	56	A2	52	Q3
MERRITON SOUTH 19kV SWER	SD324-7	YES	22	Q4		
MESSAMURRY 19kV SWER	SD462-4	NO	39	A4		
MIDDLE BEACH 19kV SWER	GA14-121	YES	26	F10		
MIDDLE BEACH 19kV SWER	GA28-39	YES	14	F6		
MILANG 19kV SWER	ST23-57	NO	42	D4		
MILLENDELLA 19kV SWER	SD392-56	YES	83	A9		
MILTALIE 19KV SWER	CV753A-40	YES	44	H2		
MINLACOWIE 19kV SWER	YK7-30	YES	29	B8		
MINLATON NORTH 19kV SWER	YK20-43	YES	14	D9		
MINLATON SOUTH 19kV SWER	SD353-49	YES	52	C9		
MITCHELLVILLE 19KV SWER	CV753A-41	NO	48	A3		
MONARTO 19kV SWER	MB92-36	YES	85	H12		
MONULTA 19kV SWER	NU15-117	NO	32	F7		
MOODY 19kV SWER	CM03-66	YES	21	F5	43	A3
MOONTA 19kV SWER	SD512-30	YES	44	K12		
MOORLANDS 19kV SWER	SD402-1	YES	75	H7		
MOOROOK 19kV SWER	LX53-111	YES	37	F2		
MORAMBRO 19kV SWER	NA2-76	NO	25	H2		
MORCHARD 19kV SWER	SD313-18	NO	44	G1		
MORTLOCK 19kV SWER	CM01-107	YES	46	B3		
MOUNT BRYAN NORTH 19kV SWER	BU06-14	YES	30	F3		
MOUNT DAMPER 19kV SWER	W04-43	NO	55	O11		
MOUNT HOPE 19kV SWER	CM02-105	NO	45	G2		
MT BRYAN EAST19kV SWER	BU06-13	NO	56	A9		
MT CHARLES 19kV SWER	BT6-132	YES	61	H5		
MT OLINTHUS 19kV SWER	SD531-3	YES	17	A4		
MT PLEASANT 19kV SWER	GU38-21	NO	41	A2		
MT. McINTYRE 19kV SWER	SD495-12	NO	40	H5		
MUIRHEAD RANGE 19kV SWER	MI32-120	NO	42	B12		
MUNDOORA NO 1 19kV SWER	KA19-42	YES	38	A9		
MUNDOORA NO 2 19kV SWER	KA20-46	YES	39	G1		
MURDINGA 19kV SWER	W03-13	YES	37	A10		
MURLONG 19kV SWER	W03-11	YES	64	A9		
NACKARA - NANTABIBIE 19kV SWER	G40-50	NO	29	F1		
NALYAPPA 19kV SWER	KA03-1	YES	54	H11		
NARRIDY NORTH 19kV SWER	GA14-124	YES	34	G6		
NARRIDY SOUTH 19kV SWER		YES	42			

SWER NAME	ISOLATING TRANSFORMER	START OF FEEDER MONITOR REQD	EOL TRANSFORMER NO. 1	EOL LV MONITOR NO. 1 CO-ORD	EOL TRANSFORMER NO. 2	EOL LV MONITOR NO. 2 CO-ORD
NAVVY HILL 19kV SWER	GA14-85	YES	14	F4		
NEECHY FLAT 19kV	MG16-5	NO	17	H5		
NENE VALLEY 19kV SWER	MG34-59	NO	24	G11		
NETHERTON 19kV SWER	CN51-15	YES	62	D2		
NEWLANDS 19kV SWER	KI42-69	YES	78	Q11		
NINNES 19kV SWER	KA26-30	YES	53	Q6		
NOOLOOK 19kV SWER	NA52-60	NO	44	A9		
NOONAMEENA 19kV SWER	CN26-40	YES	26	D7		
NORTH BOWMANS 19kV SWER	SD341-59	YES	65	E1		
NUNJIKOMPITA 19kV SWER	SB03-106	YES	39	H5		
ONE STICK BAY 19kV SWER	PA05-103	YES	48	C10		
OWEN 19kV SWER	SD371-43	YES	59	F8		
PALLAMANA 19kV SWER	MB99-24	YES	52	H3		
PARILLA NORTH 19kV SWER	SD408-12	NO	71	M3		
PARILLA SOUTH 19kV SWER	SD408-10	YES	32	H12		
PARINGA - GORDON 19kV SWER	LX32-12	YES	39	A3		
PARRAKIE 19kV SWER	SD407-16	YES	57	F12		
PARROT HILL 19kV SWER	NU02-79	NO	32	C5		
PARSONS BEACH 19kV SWER	SD353-44	YES	35	H12		
PARTACOONA 19kV SWER	PA08-28	NO	37	A1		
PARUNA 19kV SWER	LX52-27	YES	30	L8	43	D11
PASCOE 19kV SWER	CV05-2	YES	15	A4		
PATA EAST 19kV SWER	SSD-243	YES	42	B7		
PATA SOUTH 19kV SWER	SSD-243	YES	9	E9		
PATA WEST 19kV SWER	SSD-243	YES	45	Q7		
PEEBINGA 19kV SWER	LM61-21	NO	41	E1		
PEKINA 19kV SWER	SD313-17	YES	59	E12		
PENTON VALE 19kV SWER	YK23-44	YES	64	H7		
PERPONDA EAST 19kV SWER	MB41-23	YES	55	B5		
PERPONDA WEST 19kV SWER	MB41-24	YES	39	H3		
PETERSVILLE NO 1 19kV SWER	SD351-12	YES	45	A4		
PETERSVILLE NO 2 19kV SWER	SD351-11	YES	41	G8		
PETHERICK 19kV SWER	SD453-1	YES	43	H8		
PILDAPPA 19kV SWER	W02-43	YES	15	E1		
PINE HILL 19kV SWER	BT04-134	YES	23	D3		
PINERY 19kV SWER	SD371-42	YES	58	H12		
PINKAWILLINIE 19kV SWER	CV08-47	NO	43	N1		
PINKERTON PLAINS 19kV SWER	GA29-20	YES	33	D4		
PINNAROO NORTH 19kV SWER	LM61-20	YES	48	G3		
PINNAROO SOUTH 19kV SWER	SD408-14	YES	37	L12		
PIRIE 19kV SWER	PP04-130	YES	51	O5		
POINT LOWLY 19kV SWER	WHY16-1	YES	33	B1		
POINT PASS 19kV SWER	R09-46	YES	70	K12		

SWER NAME	ISOLATING TRANSFORMER	START OF FEEDER MONITOR REQD	EOL TRANSFORMER NO. 1	EOL LV MONITOR NO. 1 CO-ORD	EOL TRANSFORMER NO. 2	EOL LV MONITOR NO. 2 CO-ORD
POONINDIE 19kV SWER	PL15-95	YES	36	D1	6	H12
PORT JULIA 19kV SWER	MT24-4	YES	14	B6		
PORT NEIL 19kV SWER (3PHASE)	Refer	separate	document			
PORT NEIL 19kV SWER (3PHASE)	Refer	separate	document			
PORT NEIL 19kV SWER (3PHASE)	Refer	separate	document			
PORT PARHAM SOUTH 19kV SWER	GA28-43	YES	10	C12		
PORT PRIME 19kV SWER	GA28-44	YES	45	H8		
PORTERS LAGOON 19kV SWER	CL01-32	YES	16	B12	28	G11
PRICE 19kV SWER	SD343-17	YES	56	A2		
PUZZLE PARK 19kV SWER	MB12-66	YES	21	E2		
PYGERY 19kV SWERR	W02-39	YES	32	H9		
QUORN NORTH 19 kV SWER	PA08-29	YES	27	C3		
QUORN SOUTH 19kV SWER	SD543-48	NO	34	A1		
RED BANKS 19kV SWER	GA13-17	YES	25	C8		
RED BLUFF 19kV SWER	BT01-36	YES	41	B1		
REEDY CREEK 19kV SWER	NA51-57	YES	50	B12		
REEVES PLAINS 19kV SWER	GA15-59	YES	27	D6		
RENDELSHAM 19kV SWER	MI20-112	NO	36	F1		
RIVERTON 19kV SWER	R04-110	YES	41	H4		
RIVOLI BAY 19kV SWER	SD492-51	NO	27	E12		
ROBERTSTOWN 19kV SWER	R09-45	YES	59	A10		
ROCKLEIGH 19kV SWER	M21-195	YES	44	A9	58	H2
ROSEDALE - SHEA - OAK LOG 19kV SWER	NU19-37	NO	37	A9		
ROSEWORTHY 19kV SWER	GA31-19	NO	41	D12		
RUDALL 19kV SWER	CV03-3	YES	42	P9		
SALT CREEK 19kV SWER	CN72-14	NO	24	J9	29	Q10
SANDERSTON 19kV SWER	SD392-55	YES	63	A11		
SANDILANDS 19kV SWER	SD352-19	YES	40	G2		
SEBASTOPOL 19kV SWER	SD492-55	NO	57	G1		
SEDDON 19kV SWER	KI42-38	YES	56	G11		
SENIOR 19kV SWER	BT1-19	YES	37	A1		
SETTLERS ROAD 19kV SWER	SD482-14	NO	29	G8		
SHANNON 19kV SWER	CM02-103	YES	43	H2		
SHEOK FLAT 19KV	SD352-22	YES	29	E5		
SHERLOCK 19kV SWER	SD405-9	YES	75	B5		
SHERWOOD 19kV SWER	BT02-202	YES	45	A1		
SHOAL BAY 19kV SWER	KI41-28	YES	75	A1		
SKILLY 19kV SWER	CL25-27	YES	50	H6		
SMEATON 19kV SWER	CV05-4	YES	33	E1		
SMOKY BAY 19kV SWER	CD03-100	YES	26	E12		
SNOWTOWN 19kV SWER	CL20-4	YES	21	A8	23	H11
SOLOMON 19kV SWER	CV08-50	YES	27	A3	59	Q4
SOMERSET 19kV SWER	NU17-69	NO	36	A7		

SWER NAME	ISOLATING TRANSFORMER	START OF FEEDER MONITOR REQD	EOL TRANSFORMER NO. 1	EOL LV MONITOR NO. 1 CO-ORD	EOL TRANSFORMER NO. 2	EOL LV MONITOR NO. 2 CO-ORD
SOUTH BOWMANS 19kV SWER	SD341-58	YES	39	H12		
SOUTH BUNGAMA 19kV SWER	PP06-74	YES	22	D11		
SPALDING 19kV SWER	CL14- 01	YES	14	B4		
SPRING GULL 19kV SWER	SD332-18	NO	35	B7		
SPRINGTON 19kV SWER	GU32-81	NO	65	C2		
STENHOUSE BAY 19kV SWER	SD355-2	YES	41	H11		
STOKES 19kV SWER	CM03-54	YES	28	G3		
STONEFIELD 19kV SWER	NU15-115	YES	55	B2		
STONEFIELD 19kV SWER	NU15-133	YES	55	A10		
STRATHALBYN 19kV SWER	ST13-3	NO	53	P8		
SUTHERLANDS 19kV SWER	R14-59	YES	49	A4		
TAILEM BEND 19kV SWER	MB61-16	YES	65	A2		
TARLEE 19kV SWER	R21-96	YES	58	A2		
TARNMA 19kV SWER	R13-33	YES	33	G7		
TEPKO 19kV SWER	M21-194	YES	49	H3		
TEROWIE 19kV SWER	SD322-35	YES	14	Q12		
THE GAP 19kV SWER	NA12-69	NO	39	A6		
THOMAS PLAINS 19kV SWER	SD344-45	YES	24	E12	24	Q4
THORNLEA 19kV SWER	SD492-47	NO	39	A7		
TICKERA 19kV SWER	KA29-20	YES	28	E1		
TICKERA TOWNSHIP 19kV SWER	KA29-24	YES	17	E3		
TOOLIGIE 19kV SWER	W07-4	NO	39	Q6		
TOWITTA 19kV SWER	M41-26	YES	84	A2		
TOWNSEND 19kV SWER	SD462-2	NO	41	H6		
TUNGKILLO 19kV SWER	SD381-33	NO	47	H9		
ULYERRA 19kV SWER	W03-12	YES	47	B2		
VERRAN 19kV SWER	CV02-5	YES	29	H11		
VIVONNE BAY 19kV SWER	KI42-68	YES	38	B11		
WALLABROOK 19kV SWER	NA3-129	YES	41	G3		
WALLAROO 19kV SWER	KA05-1	YES	38	G6		
WALLAROO PLAINS 19kV SWER	KA02-60	YES	37	E3		
WANBI NORTH 19kV SWER	LX52-29	YES	45	H5		
WANBI SOUTH 19kV SWER	LX52-30	YES	30	H7		
WARCOWIE 19kV SWER	HK01-21	YES	20	A1		
WARRACHIE 19kV SWER	W07-3	YES	21	H9		
WARRAMBOO 19kV SWER	W01-30	YES	31	B8		
WARRENBEN 19kV SWER	SD355-38	YES	47	H7		
WARUNDA 19kV SWER	PL10-37	YES	24	G4		
WATERHOUSE 19kV SWER	SD492-40	NO	64	G1		
WATERLOO 19kV SWER	SD361-7	YES	71	J5		
WATTS GULLY 19kV SWER	SD383-21	NO	17	H11		
WAURALTEE 19kV SWER	MT1-47	YES	38	A5		
WEETULTA 19kV SWER	MT03-25	YES	44	G4		

SWER NAME	ISOLATING TRANSFORMER	START OF FEEDER MONITOR REQD	EOL TRANSFORMER NO. 1	EOL LV MONITOR NO. 1 CO-ORD	EOL TRANSFORMER NO. 2	EOL LV MONITOR NO. 2 CO-ORD
WEST COWIE 19kV SWER	YK17-36	YES	26	F2		
WHARMINDA 19kV SWER	SD551-4	YES	43	H10		
WHITWARTA 19kV SWER	SD341-61	YES	49	P7		
WILD DOG CREEK 19kV SWER	SD314-13	YES	48	G8		
WILD HORSE PLAINS 19kV SWER	GA28-46	YES	51	H2		
WILDELOO 19kV SWER	CM01-106	YES	40	B3		
WILLALO 19kV SWER	CL01-33	YES	65	A1		
WILLOWIE 19kV SWER	SD313-16	YES	48	H4		
WILMINGTON NORTH 19kV SWER	PA10-51	YES	22	A7		
WILMINGTON SOUTH 19kV SWER	PA10-50	YES	42	E12		
WILPENA19kV SWER	HK01-20	YES	12	C1		
WINNINOWIE 19kV SWER	SD543-11	YES	21	Q2		
WIRRULLA SOUTH 19kV SWER	SB03-107	YES	38	H4		
WITERA 19kV SWER	W06-22	YES	13	H9	39	B1
WOODS POINT 19kV SWER	MB81-99	YES	53	G12		
WOOLSHED FLAT 19kV SWER	GA13-19	YES	43	G8		
WORLDS END	N/A	YES	16	H1		
WUDINNA HILL 19kV SWER	W01-33	YES	19	A6		
WYNARKA 19kV SWER	SD405-8	YES	62	Q7		
WYNARLING 19kV SWER	BT26-55	YES	34	F12		
YACKA 19kV SWER	SD331-42	YES	37	E2	24	P4
YADLAMALKA 19kV SWER	SD543-50	NO	13	A1		
YADNARIE 19kV SWER	CV02-46	YES	24	H8		
YALLUNDA FLAT 19kV SWER	CM35-116	YES	21	D1		
YALPARA 19kV SWER	G17-54	NO	23	A7	12	F1
YANGYA 19kV SWER	SD322-34	YES	13	A1	73	A12
YANINEE 19kV SWER	W02-40	YES	40	H12	12	E1
YARANYACKA 19kV SWER	CM03-56	YES	48	A4		
YORKTOWN 19kV	YK18-32	YES	34	H5		

45. APPENDIX S

Transformer Monitoring - Country substations/feeders - non SCADA – 65 HV monitors locations.

Alphabetic Order	SSD/Feeder ID	Region	Pole top/Ground level?	Number of Feeders	Recloser	Regulator?	KV IN	KV OUT	Number & Size of transformers	SCADA	Max Demand	Monitor required?	Routine Load & Voltage Tests	Comments
Alma	R22	Mid North	PT	1	N	N	33	11				**1**	Yes	
Auburn	SSD190	Mid North	GL	2	Y	VR353	33	11	1x1.5			**2**	Yes	
Beachport	SSD274	South East	G	1	R1040	N	33	11	1x1.0			**1**	Yes	Proposed HVR installation
Belvedere Road	M14	Murraylands	PT	1	R1749	N	33	7.6				**1**	Yes	
Binnies	SSD203	Murraylands	G	1	R876	N	33	11	2x0.3			**1**	Yes	
Birdwood	SSD229	Eastern Hills	G	2	Y	GL	33	11	3x1.0			**2**	Yes	
Black Point	MT13	Yorke	PT	1	R1893	N	33	11	1x0.2			**1**	Yes	
Booleroo Centre	SSD726	Mid North	G	1	R1411	N	33	11	1x1.0			**1**	Yes	Proposed HVR installation
Booyoolie	G27	Mid North	PT	1	N	N	33	11				**1**	Yes	
Brinkworth Town Reg	SSD302	Mid North	GL	2	Y	VR463	11	11	1.0			**2**	Yes	
Brukunga	MTB71	Eastern Hills	PT	1	R1982	N	33	11	1x0.5			**1**	Yes	
Burra	SSD342	Mid North	G	3	Y	OLTCx2	33	11	2x5			**3**	Yes	
Cadell	SSD168	Riverland	G	1	R780	N	66	11	2x1.0			**1**	Yes	
Caltowie	G24	Mid North	PT	1	R1688	N	33	11				**1**	Yes	
Cambrai	SSD740	Murraylands	G	1	R1516	VR196	33	11	2x0.3			**1**	Yes	
Campbell Park	SSD455	Murraylands	G	3	Y	VR174	33	11	2x0.5			**3**	Yes	Separate reg on each feeder exit
Chain of Ponds	GU12	Eastern Hills	PT	1	N	N	33	11	1x0.3			**1**	Yes	
Clarendon 11kV	SSD120	Fleurieu	G	2	Y	OLTC	66	11	1x2.5			**2**	Yes	
Collinsfield	SSD181	Mid North	G	2	Y	GL	33	11	2x1.0			**2**	Yes	
Coomandook	SSD718	Murraylands	G	1	R1521	VR357	33	11	1x0.5			**1**	Yes	
Cordola	SSD289	Riverland	G	1	R1169	N	66	11	2x1.0			**1**	Yes	

Alphabetic Order	SSD/Feeder ID	Region	Pole top/Ground level?	Number of Feeders	Recloser	Regulator?	KV IN	KV OUT	Number & Size of transformers	SCADA	Max Demand	Monitor required?	Routine Load & Voltage Tests	Comments
Cowell	SSD753	Eyre	GL	1	R1928	VR085	33	11		Yes			Yes**	No voltage reading
Crystal Brook	SSD460	Mid North	G	1	R1406	VR405	33	11	2x1.0			1	Yes	
Curramulka	MT05	Yorke	PT	1	N	N	33	7.6				1	Yes	
Curramulka South	MT20	Yorke	PT	1	N	N	33	7.6				1	Yes	
Darke Peak	SSD269	Eyre	G	2	Y	N	66	11	1x0.5			2	Yes	
Deloraine	GU15	Eastern Hills	PT	1	R1399	VR506	33	11	1x0.3			1	Yes	
Desert Camp	BT32	South East	PT	1	N	N	33	11				1	Yes	
Dowlingville	MT04	Yorke	PT	1	R1676	N	33	11				1	Yes	
Edithburgh Reg	SSD180	Yorke	G	1	R1555	GL	11	11	1.0	Yes			Yes**	No voltage reading
Eudunda	SSD192	Mid North	G	2	Y	GL	33	11	1x1.5			2	Yes	
Forreston	GU21	Eastern Hills	PT	1	R1541	N	33	11	1x0.2			1	Yes	
Freeling	SSD376	Mid North	G	2	Y	N	33	11	2x1.5			2	Yes	
Fullerville	G37	Mid North	PT	1	N	N	33	11				1	Yes	
Georgetown	G22	Mid North	PT	1	N	N	33	11				1	Yes	
Gladstone	SSD371	Upper North	G	3	Y	GL	33	11	2x1.0			3	Yes	
Glencoe	SSD295	South East	G	1	R1261	VR341	33	11	2x0.5			1	Yes	
Gomersal North	SSD712	Barossa	PT	1	R1822	VR191	33	11				1	Yes	
Gulnare	G26	Upper North	PT	1	R1724	N	33	11				1	Yes	
Gumeracha	GU24	Eastern Hills	PT	1	N	N	33	11				1	Yes	
Gumeracha Weir	GU11	Eastern Hills	PT	1	N	N	33	11	1x0.15			1	Yes	
Gumhaven	GU19	Eastern Hills	PT	1	N	N	33	11				1	Yes	
Halbury	R24	Mid North	PT	1	N	N	33	11				1	Yes	
Hatherleigh	MI25	South East	PT	1	N	VR367	33	11				1	Yes	
Hawker	SSD716	Upper North	G	1	R1746	N	33	11				1	Yes	Proposed HVR installation

Alphabetic Order	SSD/Feeder ID	Region	Pole top/Ground level?	Number of Feeders	Recloser	Regulator?	KV IN	KV OUT	Number & Size of transformers	SCADA	Max Demand	Monitor required?	Routine Load & Voltage Tests	Comments
Hermitage	GU18	Eastern Hills	PT	1	R2041	N	33	11				1	Yes	
Houghton PT Reg	SSD463	Eastern Hills	PT	2	Y	VR131	7.6	7.6				2	Yes	
Hoyleton	CL21	Mid North	PT	1	R1517	N	33	11				1	Yes	
Inverness	NA35	South East	PT	1	R1754	VR161	33	11				1	Yes	
Jabuk	LM12	Murraylands	PT	1	N	N	33	11				1	Yes	
James Well	MT21	Yorke	PT	1	R1984	N	33	7.6				1	Yes	
Jamestown PT Reg	SSD459	Upper North	PT	1	R2140	VR064	11	11				1	Yes	proposed SCADA enable HVR
Kalangadoo - CHH Mill	SSD543	South East	GL	1	N	GL	33	11	1x1.5			1	Yes	Bulk Supply + 1 feeder
Kalangadoo West	SSD283	South East	G	2	Y	GL	33	11	2x0.5			2	Yes	
Karoonda	SSD472	Murraylands	G	1	Y	N	33	11	2x0.5			1	Yes	Proposed HVR installation
Kersbrook	GU14	Eastern Hills	PT	1	N	N	33	11	1x0.3			1	Yes	Proposed HVR installation
Ki Ki	CN91	Murraylands	PT	1	N	VR181	33	11				1	Yes	
Kingston (SE)	SSD299	South East	G	2	Y	GL	33	11	2x1.5			2	Yes	
Klein Point	SSD419	Yorke	G	1	R1163	GL	33	11	2x1.5			1	Yes	
Kongorong	SSD321	South East	G	1	R1284	GL	33	11	2x0.5			1	Yes	
Kumorna	CN61	Murraylands	PT	1	R1661	N	33	11	1x0.5			1	Yes	
Kybunga	CL02	Mid North	PT	1	R1529	N	33	11				1	Yes	
Lameroo	SSD206	Murraylands	G	1	Y	GL	33	11	2x1.0			1	Yes	
Langhorne Creek	SSD242	Fleurieu	G	4	Y	OLTC	66	11	2x2.5			4	Yes	
Leigh Creek South	SSD440	Upper North	G	2	Y	OLTC	33	11	2x2.5			2	Yes	
Little Swamp	PL11	Eyre	PT	1	R927	N	33	11				1	Yes	
Lock	SSD266	Eyre	G	2	Y	GL	66	11	1x1.0			2	Yes	
Lucindale	SSD288	South East	G	2	Y	GL	33	11	2x1.5			2	Yes	
Lyndoch PT Reg	SSD362	Barossa	PT	1	N	VR204	11	11				1	Yes	

Alphabetic Order	SSD/Feeder ID	Region	Pole top/Ground level?	Number of Feeders	Recloser	Regulator?	KV IN	KV OUT	Number & Size of transformers	SCADA	Max Demand	Monitor required?	Routine Load & Voltage Tests	Comments
Lyndoch South	SSD362	Barossa	PT	1	R2082	N	33	7.6				**1**	Yes	Proposed HVR installation
Lyrup	SSD236	Riverland	G	3	Y	OLTC	66	11	2x2.5			**3**	Yes	
Mallala	SSD186	Mid North	G	2	Y	GL	33	11	2x1.0			**2**	Yes	
Mannum Town	SSD468	Murraylands	G	2	Y	VR388	33	7.6	2x2.5			**2**	Yes	Separate reg on each feeder exit
Marion Bay	SSD497	Yorke	G	1	R1578	GL	33	11	1x1.0			**1**	Yes	
Marrabel	SSD343	Mid North	G	2	Y	GL	33	11	2x1.5			**2**	Yes	
Melrose	G35	Upper North	PT	1	R1723	N	33	11				**1**	Yes	
Milang	SSD238	Fleurieu	G	3	Y	OLTC	66	11	2x2.5	-		**3**	Yes	
Moorkitabie	SSD334	Eyre	G	2	Y	GL	66	11	1x1.0			**2**	Yes	
Morgan	SSD715	Riverland	G	1	R1353	N	66	11	1x1.0			**1**	Yes	
Mount Burr 11kV	MI22	South East	PT	1	N	N	33	11	1x0.3			**1**	Yes	
Mount Pleasant	SSD714	Eastern Hills	PT	1	R1826	VR200	33	11				**1**	Yes	proposed SCADA enable HVR
Mount Schank	SSD713	South East	G	1	R1827	VR080	33	11	3x1.0			**1**	Yes	
Murraytown Reg	SSD228	Upper North	G			GL	33	33	10			**NO**	Yes	33kV regulator station
Nangwarry Reg	SSD271	South East	G	1	R2093	VR473	33	33	10		Yes	**1**		
Narrung	SSD454	Murraylands	G	3	Y	VR176	33	11	2x1			**3**	Yes	Separate reg on each feeder exit
Ninnes	SSD461	Yorke	G	1	R725	N	33	11	1x1.0			**1**	Yes	
Orroroo	SSD172	Upper North	G	1	R1103	VR104	33	11	2x1.0			**1**	Yes	proposed SCADA enable HVR
Padthaway	SSD157	South East	G	3	Y	OLTC	33	11	2x5.0			**3**	Yes	
Palmer	M31	Murraylands	PT	1	N	N	33	11				**1**	Yes	
Parilla	LM53	Murraylands	PT	1	R1685	VR183	33	11				**1**	Yes	
Paskeville	SSD388	Yorke	G	2	Y	N	33	11	2x0.5			**2**	Yes	
Peake	LM11	Murraylands	PT	1	N	N	33	11				**1**	Yes	
Pellaring Flat	M101	Murraylands	PT	1	N	N	33	11				**1**	Yes	

Alphabetic Order	SSD/Feeder ID	Region	Pole top/Ground level?	Number of Feeders	Recloser	Regulator?	KV IN	KV OUT	Number & Size of transformers	SCADA	Max Demand	Monitor required?	Routine Load & Voltage Tests	Comments
Penneshaw PT Reg	SSD163	Fleurieu	G	2	Y	VR195	11	11				**2**	Yes	
Penola	SSD197	South East	G	3	Y	GL	33	11	2x1.5	Yes			Yes	No voltage reading
Pinnaroo	SSD174	Murraylands	G	2	Y	GL	33	11	2x1.0			**2**	Yes	
Pinnaroo South	LM55	Murraylands	PT	1	R1686	N	33	11				**1**	Yes	
Poonindie	SSD717	Eyre	PT	1	R1823	VR071	33	11	1x1.5			**1**	Yes	
Port Clinton	MT17	Yorke	PT	1	R1825	N	33	11				**1**	Yes	
Port Germein	PP08	Upper North	PT	1	N	VR209	33	11	2x0.3			**1**	Yes	
Port Giles	SSD498	Yorke	G	2	Y	N	33	11	1x2.5			**2**	Yes	
Port Julia	MT24	Yorke	PT	1	R2089	VR113	33	11				**1**	Yes	
Port Vincent Reg	SSD244	Yorke	GL	1	R1078	GL	11	11	1.0	Yes			Yes**	No voltage reading
Portee	SSD276	Murraylands	G	1	R777	GL	66	11	1x0.5			**1**	Yes	
Punyelroo	SSD464	Murraylands	PT	1	R1515	VR170	33	11	1x0.5			**1**	Yes	
Qualco	SSD287	Riverland	G	2	Y	OLTC	66	11	1x3.5			**2**	Yes	
Quorn	SSD482	Upper North	G	1	R1412	VR081	33	11	1x2.5 1x1.0			**1**	Yes	
Ramco	SSD152	Riverland	G	3	Y	OLTC	66	11	2x3.5			**3**	Yes	
Rapid Bay 11kV	VH61	Fleurieu	PT	1	N	N	33	11				**1**	Yes	
Rapid Bay 3.3kV	SSD523	Fleurieu	G	1	N	N	33	3.3	1x0.6 2x0.75			**NO**	Yes	Customer Bulk supply
Robertstown	SSD275	Mid North	G	1	R736	N	33	11	1x1.0			**1**	Yes	
Roonka	SSD300	Riverland	G	2	Y	OLTC	66	11	1x1.0			**2**	Yes	
Rudall	SSD174	Eyre	G	1	N	N	66	11	1x0.5			**1**	Yes	
Safries Reg	SSD541	South East	G	1	N	GL	11	11	3			**NO**	Yes	Customer Bulk supply
Salt Cliffs	VH72	Fleurieu	PT	1	N	N	33	11				**1**	Yes	
Sandy Creek	SSD755	Barossa	G	2	Y	N	33	11	1x1.0			**2**	Yes	Proposed HVR installation
Second Valley	VH51	Fleurieu	PT	1	N	N	33	11				**1**	Yes	Proposed HVR installation

Alphabetic Order	SSD/Feeder ID	Region	Pole top/Ground level?	Number of Feeders	Recloser	Regulator?	KV IN	KV OUT	Number & Size of transformers	SCADA	Max Demand	Monitor required?	Routine Load & Voltage Tests	Comments
Sherlock	MB51	Murraylands	PT	1	N	N	33	11				**1**	Yes	
South End	MI16	South East	PT	1	R1043	VR366	33	11				**1**	Yes	
Spalding	SSD204	Mid North	G	2	Y	GL	33	11	2x1.0			**2**	Yes	
Streaky Bay	SSD336	Eyre	G	2	Y	OLTC	66	11	2x2.5		Yes	**2**		
Swan Reach 33KV	SSD212	Riverland	G	1	R4768	N	66	33	1x13.3			**NO**	Yes	33kV regulator station
Swan Reach PT Reg	SSD469	Riverland	GL	1	R2100	VR509	11	11				**1**	Yes	
Swan Reach SAW Filtration Reg	SSD430	Riverland	G	1	N	GL	11	11	2.5		Yes	**NO**		1 Customer on feeder
Tailem Bend Town	SSD303	Murraylands	G	2	Y	N	33	11	2x1.5			**2**	Yes	
Tantanoola	SSD256	South East	G	1	R1045	VR342	33	11	1x0.5			**1**	Yes	
Tarlton	SSD335	Eyre	G	1	Y	GL	66	11	2x0.5			**1**	Yes	
Tarpeena	SSD338	South East	G	2	Y	OLTC	33	11	2x5.0			**2**	Yes	
Teal Flat	SSD312	Murraylands	G	2	Y	GL	33	11	3x1.0			**2**	Yes	
Tintinara	SSD291	Murraylands	G	2	Y	N	33	11	2x0.5			**2**	Yes	
Uley	SSD222	Eyre	PT	1	R924	VR098	33	11	1.0			**1**	Yes	
Uley South	SSD485	Eyre	G	1	R919	N	33	11				**1**	Yes	
Verdun	SSD719	Eastern Hills	G	2	Y	N	33	11	1x1.0			**2**	Yes	
Walker Flat	SSD466	Riverland	G	1	R1338	VR188	33	11	2x1.0			**1**	Yes	
Wallaroo	SSD304	Yorke	G	2	Y	OLTC	33	11	2x6.25	Yes			Yes**	No voltage reading
Warooka Reg	SSD354	Yorke	G	2	Y	GL	11	11	1.0	Yes			Yes**	No voltage reading
Wasleys	SSD185	Mid North	G	3	Y	N	33	11	2x1.0			**3**	Yes	Proposed HVR installation
Williamstown	SSD202	Barossa	G	2	Y	GL	33	11	1x1.5			**2**	Yes	
Wilmington	SSD223	Upper North	G	1	R871	GL	33	11	2x0.5			**1**	Yes	
Wirrabara Forest	G04	Upper North	PT	1	R1838	VR210	33	11				**1**	Yes	
Wirrabara South	G33	Upper North	PT	1	N	N	33	11				**1**	Yes	

Alphabetic Order	SSD/Feeder ID	Region	Pole top/Ground level?	Number of Feeders	Recloser	Regulator?	KV IN	KV OUT	Number & Size of transformers	SCADA	Max Demand	Monitor required?	Routine Load & Voltage Tests	Comments
Wirrega 33kV Reg	SSD285	South East	G			GL	33	33	20.0		Yes	**NO**		33kV regulator station
Wirrina	VH35	Fleurieu	GL	1	R1745	N	33	11	1x1.5			**1**	Yes	
Wongyarra	G19	Upper North	PT	1	N	N	33	11				**1**	Yes	
Woolpunda	SSD245	Riverland	G	2	Y	OLTC	66	11	2x7.5	-		**2**	Yes	
Wudinna 11kV	SSD778	Eyre	G	2	Y	GL	66	11	4x1.0			**2**	Yes	
Yankalilla Hill	VH37	Fleurieu	PT	1	N	N	33	11				**NO**	Yes	1 Customer on feeder
Yongala	G43	Upper North	PT	1	R1693	N	33	11				**1**	Yes	
Yorketown Reg	SSD169	Yorke	G	2	Y	GL	11	11	2	Yes			Yes**	No voltage reading

46. APPENDIX T

Transformer Monitoring - Country feeders EOL – 460 LV monitors locations.

REGION	SUBSTATION	FEEDER NAME	FEEDER No	EOL TF NUMBER 1	FEEDER PLAN COORDINATES	EOL TF NUMBER 2	FEEDER PLAN COORDINATES	MONITORS REQD	COMMENTS
RIVERLAND	LOVEDAY	LOVEDAY	**BM-11**	194	K5	29	C8	**2**	TF29 downstream of VR134
RIVERLAND	LOVEDAY	MOOROOK	**BM-12**	20	V5	38	C8	**2**	TF 38 downstream of VR135
RIVERLAND	LOVEDAY	BARMERA	**BM-13**	81	J4			**1**	
RIVERLAND	LOVEDAY	COBDOGLA	**BM-15**	23	J1			**1**	
RIVERLAND	LOVEDAY	BARMERA NORTH	**BM-21**	39	A1			**1**	
RIVERLAND	GLOSSOP	MONASH	**BM-31**	114	G2			**1**	
RIVERLAND	GLOSSOP	BERRI FRUIT JUICES	**BM-32**	13	H8			**1**	
RIVERLAND	GLOSSOP	GLOSSOP	**BM-33**	51	H7	244	M1	**2**	TF244 downstream of VR515
RIVERLAND	GLOSSOP	WINKIE	**BM-34**	33	N12			**1**	
RIVERLAND	BERRI	BERRI	**BM-41**	9	D7			**1**	
RIVERLAND	BERRI	BERRI CANNERY	**BM-42**	55	A1			**1**	
RIVERLAND	BERRI	BERRI EAST	**BM-43**	7	A11			**1**	
RIVERLAND	BERRI	BERRI WEST	**BM-44**	130	W9	173	X3	**2**	TF173 downstream of VR139
RIVERLAND	RENMARK	RENMARK	**BM-51**	15	A8			**1**	
RIVERLAND	RENMARK	RENMARK PUMPING STATION	**BM-52**	28	X10			**1**	
RIVERLAND	RENMARK	SALT CREEK	**BM-53**	49	A8			**1**	
RIVERLAND	RENMARK	CALPERNUM	**BM-54**	29	Z9			**1**	
RIVERLAND	RENMARK	RENMARK WEST	**BM-55**	74	F12			**1**	
RIVERLAND	RENMARK	COOLTONG	**BM-56**	70	J3			**1**	
RIVERLAND	RENMARK	CHAFFEY PUMPING STATION	**BM-57**	44	H2			**1**	

REGION	SUBSTATION	FEEDER NAME	FEEDER No	EOL TF NUMBER 1	FEEDER PLAN COORDINATES	EOL TF NUMBER 2	FEEDER PLAN COORDINATES	MONITORS REQD	COMMENTS
SOUTH EAST	BORDERTOWN	BORDERTOWN	**BT-01**	11	G1			**1**	
SOUTH EAST	BORDERTOWN	CANNAWIGARA	**BT-02**	207	W12			**1**	
SOUTH EAST	BORDERTOWN	MUNDULA	**BT-03**	55	X12			**1**	
SOUTH EAST	BORDERTOWN	TEATRICK	**BT-04**	2	D6	20	A4	**2**	
SOUTH EAST	KEITH	KEITH	**BT-06**	85	A12	17	Z3	**2**	
SOUTH EAST	PADTHAWAY	PARSONS	**BT-15**	5	O1			**1**	
SOUTH EAST	PADTHAWAY	MARCOLLAT	**BT-22**	1	H3			**1**	
SOUTH EAST	KEITH	KEITH SOUTH	**BT-26**	111	C11			**1**	
MID NORTH	BURRA	BURRA	**BU-01**	22	H5			**1**	
MID NORTH	BURRA	MOUNT BRYAN	**BU-06**	5	D2			**1**	
EYRE	CEDUNA	THEVENARD	**CD-01**	35803	Q9			**2**	
EYRE	CEDUNA	CEDUNA	**CD-02**	10	F12			**1**	
EYRE	CEDUNA	KONGWIRRA	**CD-03**	TC49809	F7			**1**	
MID NORTH	SPALDING	BOOBOROWIE	**CL-01**	16	D5			**1**	
MID NORTH	KYBUNGA	KYBUNGA	**CL-02**	10	A7			**1**	
MID NORTH	CLARE	NORTH CLARE	**CL-04**	72	Q11			**1**	
MID NORTH	CLARE	PENWORTHAM	**CL-05**	29	F9			**1**	
MID NORTH	CLARE	FARRELL FLAT	**CL-06**	33	B6			**1**	
MID NORTH	AUBURN	WATERVALE	**CL-09**	55	B2			**1**	
MID NORTH	SPALDING	SPALDING	**CL-14**	5	E1			**1**	
MID NORTH	COLLINSFIELD	REDHILL	**CL-15**	27	F9			**1**	
MID NORTH	BRINKWORTH TOWN	CONDOWIE	**CL-16**	22	M11			**1**	
MID NORTH	BRINKWORTH TOWN	BRINKWORTH	**CL-17**	20	G2			**1**	
MID NORTH	COLLINSFIELD	SNOWTOWN	**CL-20**	6	H11			**1**	
MID NORTH	HOYLETON	HOYLETON	**CL-21**	11	A10			**1**	

REGION	SUBSTATION	FEEDER NAME	FEEDER No	EOL TF NUMBER 1	FEEDER PLAN COORDINATES	EOL TF NUMBER 2	FEEDER PLAN COORDINATES	MONITORS REQD	COMMENTS
MID NORTH	CLARE	CLARE	**CL-23**	12	G3			**1**	
MID NORTH	AUBURN	AUBURN	**CL-25**	16	H9			**1**	
EYRE	CUMMINS	EDILLILIE	**CM-01**	17	N12	3	O2	**2**	
EYRE	CUMMINS	YEELANNA	**CM-02**	13	L6			**1**	
EYRE	TUMBY BAY	TUMBY BAY DISTRICT	**CM-04**	10	H5			**1**	Single phase only
EYRE	TUMBY BAY	TUMBY BAY TOWNSHIP	**CM-05**	18	C9			**1**	Possibly not reqd - short feeder
MURRAYLANDS	BINNIES	BINNIES	**CN-11**	12353	F1			**1**	Ground level TF
MURRAYLANDS	MENINGIE	MMENINGIE NORTH	**CN-22**	16	C2			**1**	
MURRAYLANDS	MENINGIE	MENINGIE WEST	**CN-26**	39	H7			**1**	
MURRAYLANDS	CAMPBELL PARK	CAMPBELL PARK	**CN-31**	16	B11			**1**	
MURRAYLANDS	CAMPBELL PARK	REEDY POINT	**CN-32**	27	B3			**1**	
MURRAYLANDS	CAMPBELL PARK	PELICAN POINT	**CN-33**	30	M7			**1**	
MURRAYLANDS	NARRUNG	NARRUNG	**CN-41**	32	D10			**1**	
MURRAYLANDS	NARRUNG	POINT MCLEAY	**CN-42**	24	A4	19	F4	**2**	TF24 downstream of VR177
MURRAYLANDS	NARRUNG	GUMPARK	**CN-43**	20	H10			**1**	
SOUTH EAST	KURMORNA	KURMORNA	**CN-61**	32	A7			**1**	
SOUTH EAST	TINTINARA	TINTINARA	**CN-71**	13	H9			**1**	
MURRAYLANDS	COONALPYN	COONALPYN	**CN-81**	15	D4			**1**	
MURRAYLANDS	KI-KI	KI-KI	**CN-91**	7	G7			**1**	
EYRE	CLEVE	CLEVE	**CV-01**	6	E11			**1**	
EYRE	CLEVE	BOOTHBY	**CV-02**	6	D9			**1**	
EYRE	RUDALL	RUDALL	**CV-03**	35407	A9			**1**	
EYRE	DARKE PEAK	DARKE PEAK	**CV-04**	1	A4			**1**	
EYRE	CARALUE	KIMBA	**CV-08**	11	B7			**1**	
EYRE	COWELL	COWELL TOWNSHIP	**CV-753A**	44	A7			**1**	

REGION	SUBSTATION	FEEDER NAME	FEEDER No	EOL TF NUMBER 1	FEEDER PLAN COORDINATES	EOL TF NUMBER 2	FEEDER PLAN COORDINATES	MONITORS REQD	COMMENTS
EYRE	ARNO BAY	ARNO BAY TOWNSHIP	**CV-757A**	43	E12			**1**	
UPPER NORTH	GLADSTONE	GLADSTONE	**G-01**	9	H7			**1**	
UPPER NORTH	JAMESTOWN	JAMESTOWN	**G-02**	20	A8			**1**	
UPPER NORTH	BOOLEROO	BOOLEROO CENTRE	**G-03**	13	G7			**1**	
UPPER NORTH	WIRRABARA FOREST	WIRRABARA FOREST	**G-04**	6	Q10			**1**	
UPPER NORTH	GLADSTONE	LAURA	**G-05**	29	N1			**1**	
UPPER NORTH	ORROROO	ORROROO	**G-17**	37	C2			**1**	
MID NORTH	GEORGETOWN	GEORGETOWN	**G-22**	1	A8			**1**	
UPPER NORTH	CALTOWIE	CALTOWIE	**G-24**	5	H7			**1**	
UPPER NORTH	GLADSTONE	HUDDLESTON	**G-34**	19	O8			**1**	
UPPER NORTH	MELROSE	MELROSE	**G-35**	4	F5			**1**	
UPPER NORTH	PETERBOROUGH	PETERBOROUGH NORTH	**G-40**	13	A8			**1**	
UPPER NORTH	PETERBOROUGH	PETERBOROUGH SOUTH	**G-41**	15	D2			**1**	
BAROSSA	WILLIAMSTOWN	MT CRAWFORD	**GA-03**	82	F1			**1**	
BAROSSA	SANDY CREEK	SANDY CREEK	**GA-05**	76	B12			**1**	
BAROSSA	WILLIAMSTOWN	WILLIAMSTOWN	**GA-08**	71	P2	137	L3	**2**	Both transformers single phase
BAROSSA	LYNDOCH	LYNDOCH	**GA-09**	4	H12			**1**	
BAROSSA	LYNDOCH SOUTH	LYNDOCH SOUTH	**GA-10**	32	A5	11	G11	**2**	TF11 single phase
BAROSSA	WASLEYS	WASLEYS WEST	**GA-13**	8	H5			**1**	
BAROSSA	SANDY CREEK	ROSEDALE	**GA-23**	29	C2			**1**	
BAROSSA	MALLALA	MALLALA	**GA-27**	11	D11			**1**	
BAROSSA	MALLALA	WINDSOR	**GA-28**	59	H4			**1**	T/F 17 downstream of VR096
BAROSSA	WASLEYS	WASLEYS NORTH	**GA-29**	14	C1			**1**	
BAROSSA	WASLEYS	WASLEYS EAST	**GA-30**	4	E5			**1**	

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BAROSSA	FREELING	TEMPLERS	GA-31	15	M7			1	
BAROSSA	GAWLER BELT	HEWETT	GA-745A	39	T11			1	
BAROSSA	GAWLER BELT	KINGSFORD	GA-745B	31	N4	57	W12	2	TF57 downstream of VR464
EASTERN HILLS	GUMERACHA WEIR	GUMERACHA WEIR	GU-11	9	G2			1	
EASTERN HILLS	CHAIN OF PONDS	CHAIN OF PONDS	GU-12	14	H11			1	
EASTERN HILLS	HOUGHTON	HOUGHTON	GU-13	62	C2			1	
EASTERN HILLS	KERSBROOK	KERSBROOK	GU-14	29	H5			1	
EASTERN HILLS	DELORAINE	DELORAINE	GU-15	22	E9			1	
EASTERN HILLS	HOUGHTON	INGLEWOOD	GU-17	40	H8			1	
EASTERN HILLS	HERMITAGE	HERMITAGE	GU-18	13	D4			1	
EASTERN HILLS	FORRESTON	FORRESTON	GU-21	33	A1			1	
EASTERN HILLS	BIRDWOOD	BIRDWOOD	GU-31	50	T8	123	F5	2	
EASTERN HILLS	MOUNT PLEASANT	MOUNT PLEASANT	GU-32	95	B3	72	D10	2	
EASTERN HILLS	BIRDWOOD	BLACK SNAKE	GU-38	200	E2			1	
EASTERN HILLS	LOBETHAL	KENTON VALLEY	GU-41	85	D5			1	
EASTERN HILLS	LOBETHAL	LOBETHAL	GU-42	36	A5			1	
EASTERN HILLS	LOBETHAL	CUDLEE CREEK	GU-43	63	O1			1	
UPPER NORTH	HAWKER	HAWKER	HK-01	15	K12			1	
MID NORTH	WALLAROO	WALLAROO EAST	KA-01	31	F12			1	Urban feeder
MID NORTH	WALLAROO	WALLAROO WEST	KA-02	37	E2			1	Urban feeder
MID NORTH	MOONTA	MOONTA	KA-03	51	W5			1	Urban feeder
MID NORTH	MOONTA	MOONTA BAY	KA-04	66	M4			1	Urban feeder
MID NORTH	KADINA	WALLAROO MINES	KA-05	45	A3			1	Urban feeder
MID NORTH	KADINA	KADINA	KA-06	30	A3			1	

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UPPER NORTH	PORT BROUGHTON	PORT BROUGHTON	**KA-22**	35	H12			1	
MID NORTH	PASKEVILLE	PASKEVILLE	**KA-23**	19	F2			1	
MID NORTH	NINNES	BUTE	**KA-26**	13	D1			1	
MID NORTH	PASKEVILLE	THRINGTON	**KA-27**	21	H12			1	
MID NORTH	KADINA	ALFORD	**KA-29**	15	C4			1	
FLEURIEU PENINSULA	PENNESHAW	PENNESHAW	**KI-11**	16	A8	62	A5	2	
FLEURIEU PENINSULA	AMERICAN RIVER	AMERICAN RIVER	**KI-21**	17	A2			1	
FLEURIEU PENINSULA	AMERICAN RIVER	GYPSUM QUARRY	**KI-22**	2	B8			1	
FLEURIEU PENINSULA	KINGSCOTE	KINGSCOTE	**KI-31**	85	Q2			1	
FLEURIEU PENINSULA	KINGSCOTE	BROWNLOW	**KI-32**	32	A3			1	
FLEURIEU PENINSULA	MACGILLIVRAY	CYGNET RIVER	**KI-41**	18	G3			1	
UPPER NORTH	LEIGH CREEK SOUTH	TOWN 1	**LC-01**	24	E12			1	
MURRAYLANDS	PEAKE	PEAKE	**LM-11**	8	B2			1	
MURRAYLANDS	JABUK	JABUK	**LM-12**	3	A7			1	
MURRAYLANDS	GERANIUM	GERANIUM	**LM-21**	4	E9			1	
MURRAYLANDS	LAMEROO	LAMEROO	**LM-41**	23	D3			1	
MURRAYLANDS	PARILLA	PARILLA	**LM-53**	21	A5			1	
MURRAYLANDS	PINNAROO SOUTH	PINNAROO SOUTH	**LM-55**	7	C9			1	
MURRAYLANDS	PINNAROO	PINNAROO NORTH	**LM-61**	19	A5			1	
MURRAYLANDS	PINNAROO	PINNAROO EAST	**LM-62**	13	A5			1	
RIVERLAND	PARINGA	PARINGA SOUTH	**LX-24**	23	B11			1	
RIVERLAND	PARINGA	PARINGA TOWN	**LX-25**	13	A12			1	
RIVERLAND	LYRUP	PIKE RIVER	**LX-31**	25	A6			1	
RIVERLAND	LYRUP	LYRUP SOUTH	**LX-32**	11	G10			1	
RIVERLAND	LYRUP	GURRA	**LX-34**	101	Y12			1	

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RIVERLAND	LOXTON	LOXTON NORTH	**LX-41**	102	C11	106	P2	**2**	
RIVERLAND	LOXTON	LOXTON EAST	**LX-42**	6	D11			**1**	
RIVERLAND	LOXTON	LOXTON	**LX-43**	8	H10	22	Z8	**2**	
RIVERLAND	PYAP	LOXTON WEST	**LX-51**	38	G11			**1**	
RIVERLAND	PYAP	PATA	**LX-52**	8	Q9			**1**	
RIVERLAND	PYAP	NEW RESIDENCE	**LX-53**	45	P2			**1**	
MURRAYLANDS	PELLARING FLAT	PELLARING FLAT	**M-101**	6	A6			**1**	
MURRAYLANDS	MANNUM TOWN	MANNUM NORTH	**M-11**	32	D1			**1**	
MURRAYLANDS	MANNUM TOWN	MANNUM SOUTH	**M-13**	50	E11			**1**	
MURRAYLANDS	BELVEDERE ROAD	BELVEDERE ROAD	**M-14**	6	B6			**1**	
MURRAYLANDS	CALOOTE	CALOOTE	**M-21**	161	T1	107	B12	**2**	
MURRAYLANDS	PALMER	PALMER	**M-31**	4	F11			**1**	
MURRAYLANDS	CAMBRAI	CAMBRAI	**M-41**	15	C3			**1**	
MURRAYLANDS	SWAN REACH	SWAN REACH	**M-51**	17	G10			**1**	
MURRAYLANDS	PUNYELROO	PUNYELROO	**M-61**	17	E1			**1**	
MURRAYLANDS	NILDOTTIE	NILDOTTIE	**M-71**	70	C1			**1**	
MURRAYLANDS	WALKER FLAT	WALKER FLAT	**M-81**	11	H12			**1**	
MURRAYLANDS	TEAL FLAT	TEAL FLAT	**M-91**	50	Q4			**1**	
MURRAYLANDS	TEAL FLAT	PURNONG	**M-92**	49	H10			**1**	
MURRAYLANDS	MURRAY BRIDGE SOUTH	RIVERVIEW	**MB-11**	35	H3			**1**	Urban feeder
MURRAYLANDS	MURRAY BRIDGE SOUTH	MURRAY GARDENS	**MB-12**	30	H6			**1**	Urban feeder
MURRAYLANDS	MURRAY BRIDGE SOUTH	SWANPORT	**MB-13**	48	M9			**1**	Urban feeder
MURRAYLANDS	MURRAY BRIDGE SOUTH	HILL STREET	**MB-15**	50	A9			**1**	Urban feeder
MURRAYLANDS	MURRAY BRIDGE SOUTH	MARKET PLACE	**MB-17**	23360	C2			**1**	Urban feeder
MURRAYLANDS	MURRAY BRIDGE NORTH	THOMAS ST	**MB-22**	8	U10	56	B6	**2**	

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MURRAYLANDS	MURRAY BRIDGE NORTH	WARATAH AVE	**MB-23**	7	C3			1	
	MURRAY BRIDGE NORTH	MURRAY BRIDGE EAST	**MB-24**	27				1	
	MURRAY BRIDGE NORTH	MURRAY BRIDGE EAST	**MB-24**	120	P9			1	
	MURRAY BRIDGE NORTH	TOORA	**MB-27**	55	G2			1	
	MURRAY BRIDGE NORTH	LONG FLAT	**MB-28**	86	T2			1	
MURRAYLANDS	MYPOLONGA	MYPOLONGA	**MB-31**	48	E1			1	
MURRAYLANDS	MYPOLONGA	SUNNYSIDE	**MB-32**	40	M12			1	
MURRAYLANDS	KAROONDA	KAROONDA	**MB-41**	19	D5			1	
MURRAYLANDS	TAILEM BEND TOWN	TAILEM BEND EAST	**MB-61**	5	G3			1	
MURRAYLANDS	TAILEM BEND TOWN	TAILEM BEND WEST	**MB-62**	17	Q1			1	
	TAILEM BEND TOWN	WELLINGTON EAST	**MB-63**	28	H11			1	
MURRAYLANDS	JERVOIS	JERVOIS	**MB-71**	21	H2			1	
MURRAYLANDS	JERVOIS	WELLINGTON	**MB-72**	72	Y11	15	N2	2	
MURRAYLANDS	WOODS POINT	WOODS POINT/Monteith	**MB-81**	33	A11	84	W2	2	
MURRAYLANDS	WOODS POINT	MONTEITH	**MB-82**	32	C11			1	
MURRAYLANDS	MONARTO SOUTH	WHITE HILL	**MB-91**	2	A6			1	
MURRAYLANDS	MONARTO SOUTH	MONARTO SOUTH	**MB-92**	1	B9			1	
SOUTH EAST	MOUNT GAMBIER WEST	AERODROME	**MG-02**	26	H5			1	
SOUTH EAST	MOUNT GAMBIER	YAHL	**MG-03**	144	F8			1	
SOUTH EAST	MOUNT GAMBIER	GLENBURNIE	**MG-04**	25	A8			1	
SOUTH EAST	MOUNT GAMBIER WEST	COMPTON	**MG-05**	157	B9			1	
SOUTH EAST	GLENCOE	GLENCOE	**MG-06**	75	U7	165	Z4	2	
SOUTH EAST	TARPEENA	TARPEENA	**MG-07**	19	H11			1	
SOUTH EAST	MOUNT GAMBIER WEST	MOORAK	**MG-10**	139	F10			1	

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SOUTH EAST	MOUNT GAMBIER NORTH	MILLEL	**MG-11**	94	A8			1	
SOUTH EAST	KALANGADOO WEST	KOORINE	**MG-12**	69	A6			1	
SOUTH EAST	MOUNT GAMBIER NORTH	MINGBOOL	**MG-13**	34	A10			1	
SOUTH EAST	NANGWARRY	MUDDY FLAT	**MG-15**	19	B1			1	Single phase transformer
SOUTH EAST	ALLENDALE EAST	PORT MACDONNELL	**MG-17**	19	G9			1	
SOUTH EAST	ALLENDALE EAST	EIGHT MILE CREEK	**MG-19**	88	B6	62	P8	2	
SOUTH EAST	PENOLA	PENOLA	**MG-22**	91	F1			1	
SOUTH EAST	NANGWARRY	NANGWARRY	**MG-23**	8	E4			1	
SOUTH EAST	PENOLA	MACKINNON SWAMP	**MG-26**	12	B12			1	Single phase transformer
SOUTH EAST	KALANGADOO WEST	RIDDOCH	**MG-27**	50	D11			1	
SOUTH EAST	PENOLA	MONBULLA	**MG-28**	26	K7			1	
SOUTH EAST	PENOLA	WATTLE RANGE	**MG-29**	68	Z7			1	Single phase transformer
SOUTH EAST	KONGORONG	CARPENTER ROCKS	**MG-32**	69	H7	106	Q5	2	
SOUTH EAST	MOUNT SCHANK	MOUNT SALT	**MG-34**	80	N4			1	
SOUTH EAST	MOUNT GAMBIER NORTH	PEEWEENA	**MG-38**	28	G2			1	
SOUTH EAST	MOUNT GAMBIER	NORTH TCE	**MG-39**	43	O1			1	
SOUTH EAST	MOUNT GAMBIER WEST	SUTTONTOWN	**MG-41**	71	F12			1	Urban feeder
SOUTH EAST	MOUNT GAMBIER	WIRELESS RD	**MG-42**	55	L4			1	
SOUTH EAST	MOUNT GAMBIER WEST	BROWNES ROAD	**MG-43**	5	H5			1	Urban feeder
SOUTH EAST	MOUNT GAMBIER	STURT ST	**MG-44**	6	J8			1	Urban feeder
SOUTH EAST	MOUNT GAMBIER WEST	SHEPHERDSON ROAD	**MG-45**	30127	A6			1	Urban feeder
SOUTH EAST	MOUNT GAMBIER	LAKE TCE	**MG-46**	1	P3			1	
SOUTH EAST	MOUNT GAMBIER NORTH	CORRIEDALE PARK	**MG-52**	24	K4			1	
SOUTH EAST	MILLICENT	MILLICENT	**MI-01**	3	A5			1	

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SOUTH EAST	TANTANOOLA	TANTANOOLA	**MI-02**	2	F5			1	
SOUTH EAST	ROBE	ROBE	**MI-08**	15	G6			1	
SOUTH EAST	ROBE	LONG BEACH	**MI-13**	15	E8			1	
SOUTH EAST	BEACHPORT	BEACHPORT	**MI-14**	32	H8			1	
SOUTH EAST	SOUTH END	SOUTH END	**MI-16**	5	Q9			1	
SOUTH EAST	MILLICENT	MILLICENT NORTH	**MI-20**	50	P9			1	
SOUTH EAST	HATHERLEIGH	HATHERLEIGH	**MI-25**	105	D4			1	
SOUTH EAST	APCEL	APCEL	**MI-27**	47	B9			1	
SOUTH EAST	MILLICENT	MILLICENT EAST	**MI-32**	42	C2			1	
MID NORTH	MAITLAND	SOUTH MAITLAND	**MT-01**	60	L11	46	D11	2	
MID NORTH	MAITLAND	ARTHURTON	**MT-03**	8	C2			1	
MID NORTH	DOWLINGVILLE	DOWLINGVILLE	**MT-04**	10	G1			1	Single phase transformer
MID NORTH	CURRAMULKA	CURRAMULKA	**MT-05**	3	E6			1	
MID NORTH	ARDROSSAN	ARDROSSAN	**MT-06**	18	D3			1	
MID NORTH	PORT VINCENT	PORT VINCENT	**MT-08**	4	F9			1	
MID NORTH	BLACK POINT	BLACK POINT	**MT-13**	TC46415	B6			1	
MID NORTH	PORT CLINTON	PORT CLINTON	**MT-17**	8	A6			1	
MID NORTH	JAMES WELL	JAMES WELL	**MT-21**	6	D11			1	
MID NORTH	MAITLAND	MAITLAND	**MT-22**	18	E10			1	
MID NORTH	PORT JULIA	PORT JULIA	**MT-24**	5	A6			1	
EASTERN HILLS	MOUNT BARKER	MOUNT BARKER CENTRAL	**MTB-10**	39174	B10	100	K2	2	
EASTERN HILLS	MOUNT BARKER	WINDMILL	**MTB-11**	86	H4	170	HH11	2	
EASTERN HILLS	MOUNT BARKER	MOUNT BARKER	**MTB-12**	96	M1			1	
EASTERN HILLS	MOUNT BARKER	BUGLE RANGES	**MTB-13**	177	G11			1	

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EASTERN HILLS	MOUNT BARKER	FLAXLEY	**MTB-14**	40	C9			**1**	
EASTERN HILLS	MOUNT BARKER	MOUNT BARKER CBD	**MTB-15**	28501	B6			**1**	Urban feeder
EASTERN HILLS	HAHNDORF	HAHNDORF	**MTB-21**	73	C2			**1**	
EASTERN HILLS	HAHNDORF	BIGGS FLAT	**MTB-22**	10	Z10	111	D5	**2**	
EASTERN HILLS	MEADOWS	ECHUNGA	**MTB-32**	93	E1			**1**	
EASTERN HILLS	MOUNT BARKER	GREENHILLS	**MTB-33**	39	A9			**1**	
EASTERN HILLS	VERDUN	BALHANNAH	**MTB-41**	20	A3			**1**	
EASTERN HILLS	WOODSIDE	WOODSIDE	**MTB-51**	20	E2			**1**	
EASTERN HILLS	WOODSIDE	OAKBANK	**MTB-52**	39	Q5			**1**	
EASTERN HILLS	WOODSIDE	INVERBRACKIE	**MTB-53**	100	C2			**1**	
EASTERN HILLS	WOODSIDE	LENSWOOD	**MTB-54**	113	Y11			**1**	
EASTERN HILLS	NAIRNE	NAIRNE	**MTB-61**	20	A11			**1**	
EASTERN HILLS	NAIRNE	LITTLEHAMPTON	**MTB-62**	103	N8			**1**	
EASTERN HILLS	NAIRNE	HAY VALLEY	**MTB-63**	28	B3	90	P5	**2**	
EASTERN HILLS	BRUKUNGA	BRUKUNGA	**MTB-71**	21	M7			**1**	
EASTERN HILLS	KANMANTOO COPPER MINE	CALLINGTON	**MTB-81**	56	A7			**1**	
SOUTHERN SUBURBS	MCLAREN VALE	TATACHILLA	**MV-11**	42	O7			**1**	
SOUTHERN SUBURBS	CLARENDON	KANGARILLA	**MV-22**	94	C3			**1**	
FLEURIEU PENINSULA	MYPONGA	MYPONGA	**MV-31**	23	Q3	57	B9	**2**	Single phase transformer
FLEURIEU PENINSULA	MYPONGA	HINDMARSH TIERS	**MV-32**	49	D8			**1**	
FLEURIEU PENINSULA	MYPONGA	BLOCKERS ROAD	**MV-33**	90	O4			**1**	
FLEURIEU PENINSULA	MYPONGA	SELLICKS HILL	**MV-34**	120	D1			**1**	
FLEURIEU PENINSULA	SQUARE WATER HOLE	TOOPERANG	**MV-41**	25	A5			**1**	
FLEURIEU PENINSULA	SQUARE WATER HOLE	MOUNT COMPASS	**MV-42**	72	B6	181	Z3	**2**	

REGION	SUBSTATION	FEEDER NAME	FEEDER No	EOL TF NUMBER 1	FEEDER PLAN COORDINATES	EOL TF NUMBER 2	FEEDER PLAN COORDINATES	MONITORS REQD	COMMENTS
SOUTHERN SUBURBS	WILLUNGA	WILLUNGA NORTH	**MV-51**	16	D5			**1**	
SOUTHERN SUBURBS	WILLUNGA	WILLUNGA	**MV-52**	215	O4			**1**	
SOUTHERN SUBURBS	WILLUNGA	DINGABLEDINGA	**MV-53**	71	A7			**1**	
SOUTH EAST	NARACOORTE	NARACOORTE	**NA-01**	68	G8			**1**	Urban feeder
SOUTH EAST	NARACOORTE	MCINTOSH	**NA-02**	74	P1	82	E8	**2**	
SOUTH EAST	NARACOORTE EAST	CADGEE	**NA-03**	21	M1			**1**	
SOUTH EAST	NARACOORTE EAST	KYBYBOLITE	**NA-04**	112	L1			**1**	
SOUTH EAST	NARACOORTE EAST	CARTERS ROAD	**NA-05**	65	A8			**1**	
SOUTH EAST	NARACOORTE	HYNAM	**NA-06**	107	C11			**1**	
SOUTH EAST	NARACOORTE	KOPPAMURRA	**NA-07**	90	G3			**1**	
SOUTH EAST	PADTHAWAY	PADTHAWAY	**NA-12**	157	C10			**1**	
SOUTH EAST	LUCINDALE	LUCINDALE	**NA-13**	57	J12			**1**	
SOUTH EAST	LUCINDALE	BAKER RANGE	**NA-15**	40	H1			**1**	
SOUTH EAST	COONAWARRA	COONAWARRA	**NA-32**	58	N3			**1**	
SOUTH EAST	COONAWARRA	KATNOOK	**NA-33**	36	D11			**1**	
SOUTH EAST	COONAWARRA	KILLANOOLA	**NA-34**	68	Q9			**1**	
SOUTH EAST	INVERNESS	INVERNESS	**NA-35**	15	C6			**1**	
SOUTH EAST	KINGSTON SE	MARIA	**NA-51**	1	A2			**1**	
SOUTH EAST	KINGSTON SE	LACEPEDE BAY	**NA-52**	58	U10			**1**	
SOUTHERN SUBURBS	CLARENDON	CLARENDON NORTH	**NL-21**	37	Y5	135	A8	**2**	
BAROSSA	ANGASTON	DORRIEN	**NU-01**	24	H9			**1**	
BAROSSA	ANGASTON	ANGASTON	**NU-02**	28	D10			**1**	
BAROSSA	ANGASTON	PENRICE	**NU-04**	32	L1			**1**	
BAROSSA	ANGASTON	TANUNDA	**NU-05**	103	O10			**1**	
BAROSSA	KAPUNDA	KAPUNDA SOUTH	**NU-06**	17	P10			**1**	

REGION	SUBSTATION	FEEDER NAME	FEEDER No	EOL TF NUMBER 1	FEEDER PLAN COORDINATES	EOL TF NUMBER 2	FEEDER PLAN COORDINATES	MONITORS REQD	COMMENTS
BAROSSA	DORRIEN	SEPPELTSFIELD	**NU-13**	80	P1			**1**	
BAROSSA	STOCKWELL	TRURO	**NU-15**	33	Z8	64	B9	**2**	
BAROSSA	FREELING NORTH	NAIN	**NU-17**	7	B6			**1**	
BAROSSA	ANGASTON	FLAXMAN VALLEY	**NU-18**	20	G12			**1**	
BAROSSA	FREELING NORTH	FREELING	**NU-19**	29	J7			**1**	
BAROSSA	KAPUNDA	KAPUNDA NORTH	**NU-20**	28	C8			**1**	
BAROSSA	NURIOOTPA	NURIOOTPA EAST	**NU-21**	17	P5			**1**	
BAROSSA	LYNDOCH	PEWSEY VALE	**NU-22**	24	F5			**1**	
BAROSSA	NURIOOTPA	NURIOOTPA WEST	**NU-25**	45	B4			**1**	
BAROSSA	BAROSSA SOUTH	ROWLAND FLAT	**NU-26**	1	A10			**1**	
BAROSSA	ANGASTON	MENGLERS HILL	**NU-27**	11	H9			**1**	Single phase transformer
BAROSSA	STOCKWELL	WILLOWS	**NU-29**	14	F10			**1**	
BAROSSA	DORRIEN	TOLLEY	**NU-30**	13	D5			**1**	
BAROSSA	BAROSSA SOUTH	BAROSSA SOUTH	**NU-31**	131	C5			**1**	
BAROSSA	DORRIEN	STONEWELL	**NU-33**	3	O9			**1**	
BAROSSA	DORRIEN	LANGMEIL	**NU-34**	157	B9			**1**	
UPPER NORTH	PORT AUGUSTA	PORT AUGUSTA	**PA-01**	TC42213	P4			**1**	Urban feeder
UPPER NORTH	PORT AUGUSTA	CARLTON	**PA-02**	38	D10			**1**	
UPPER NORTH	PORT AUGUSTA	DAVENPORT	**PA-03**	25	E10			**1**	Urban feeder
UPPER NORTH	PORT AUGUSTA	WILLSDEN	**PA-04**	2	C7			**1**	
UPPER NORTH	PORT AUGUSTA WEST	STOKES	**PA-05**	109	O3	94	L12	**2**	
UPPER NORTH	PORT AUGUSTA WEST	MCSPORRAN CRESCENT	**PA-06**	16931	B11			**1**	Urban feeder
UPPER NORTH	PORT AUGUSTA WEST	DIGHTON STREET	**PA-07**	15984	H10			**1**	Urban feeder
UPPER NORTH	QUORN	QUORN	**PA-08**	21	E10			**1**	

REGION	SUBSTATION	FEEDER NAME	FEEDER No	EOL TF NUMBER 1	FEEDER PLAN COORDINATES	EOL TF NUMBER 2	FEEDER PLAN COORDINATES	MONITORS REQD	COMMENTS
UPPER NORTH	WILMINGTON	WILMINGTON	**PA-10**	2	G5			1	
UPPER NORTH	STIRLING NORTH	McCONNAL	**PA-13**	76	Q5			1	
UPPER NORTH	STIRLING NORTH	STIRLING NORTH	**PA-14**	65	C8			1	
UPPER NORTH	PORT AUGUSTA WEST	HAMILTON	**PA-26**	26	H9			1	
EYRE	PORT LINCOLN DOCKS	KIRTON	**PL-01**	32354	L7			1	Urban feeder
EYRE	PORT LINCOLN DOCKS	COMMERCIAL	**PL-03**	9	G7			1	Urban feeder
EYRE	PORT LINCOLN CITY	INDUSTRIAL	**PL-04**	19	N9			1	
EYRE	PORT LINCOLN CITY	LINCOLN BASIN	**PL-05**	13	A8			1	
EYRE	PORT LINCOLN CITY	CENTRAL	**PL-06**	36	A3			1	Urban feeder
EYRE	PORT LINCOLN CITY	NORTH	**PL-07**	50	X8			1	
EYRE	ULEY	WANILLA	**PL-10**	18	D1			1	
EYRE	LITTLE SWAMP	LITTLE SWAMP	**PL-11**	21	A9			1	
EYRE	COFFIN BAY	COFFIN BAY	**PL-12**	17	H5			1	
EYRE	PORT LINCOLN CITY	SHIELDS	**PL-14**	167	Y6	31	D6	2	
EYRE	POONINDIE	HAGE	**PL-15**	30	B6			1	
EYRE	POINT BOSTON	POINT BOSTON	**PL-754A**	98	B9			1	
UPPER NORTH	PORT PIRIE SOUTH	PIRIE TOWN	**PP-01**	26	E1			1	Urban feeder
UPPER NORTH	PORT PIRIE SOUTH	PIRIE WEST	**PP-02**	18	H9			1	Urban feeder
UPPER NORTH	PORT PIRIE SOUTH	RISDON PARK	**PP-03**	46	N10			1	
UPPER NORTH	PORT PIRIE SOUTH	PIRIE SOUTH	**PP-04**	112	X11	51	A8	2	
UPPER NORTH	BUNGAMA	WARNERTOWN	**PP-05**	16	C9			1	
UPPER NORTH	BUNGAMA	NAPPERBY	**PP-06**	19	A4			1	
UPPER NORTH	BAROOTA	BAROOTA	**PP-07**	21	E2			1	
MID NORTH	PORT GERMEIN	PORT GERMEIN	**PP-08**	19	Z4	149	F3	2	
UPPER NORTH	CRYSTAL BROOK	CRYSTAL BROOK	**PP-09**	32	H5			1	

REGION	SUBSTATION	FEEDER NAME	FEEDER No	EOL TF NUMBER 1	FEEDER PLAN COORDINATES	EOL TF NUMBER 2	FEEDER PLAN COORDINATES	MONITORS REQD	COMMENTS
UPPER NORTH	PORT PIRIE SOUTH	PIRIE NORTH	**PP-10**	2	D2			1	
MID NORTH	WATERLOO	MANOORA	**R-01**	18	C12			1	
MID NORTH	EUDUNDA	EUDUNDA	**R-02**	44	B6			1	
MID NORTH	MARRABEL	RIVERTON	**R-04**	84	L2			1	
MID NORTH	ROBERTSTOWN	ROBERTSTOWN	**R-09**	50	M11			1	
MID NORTH	MARRABEL	MARRABEL	**R-13**	24	D11			1	Single phase transformer
MID NORTH	EUDUNDA	HAMPDEN	**R-14**	47	D11			1	
MID NORTH	RIVERTON	RHYNIE	**R-18**	108	O6			1	
MID NORTH	BALAKLAVA	BALAKLAVA SOUTH	**R-20**	8	G11			1	
BAROSSA	HAMLEY BRIDGE	HAMLEY BRIDGE	**R-21**	30	A4			1	
BAROSSA	ALMA	ALMA	**R-22**	5	G7			1	
MID NORTH	BALAKLAVA	BALAKLAVA	**R-23**	4	G5			1	
EYRE	STREAKY BAY	STREAKY BAY	**SB-01**	77	Q5			1	
EYRE	STREAKY BAY	FLINDERS	**SB-02**	15	A12			1	
EYRE	TARLTON	WIRRULLA	**SB-03**	3	A3			1	
EASTERN HILLS	URAIDLA	PICCADILLY	**SG-01**	54	A10			1	
EASTERN HILLS	PICCADILLY	CRAFERS	**SG-02**	98	HH6			1	
EASTERN HILLS	ALDGATE	ALDGATE	**SG-03**	57	P12			1	
EASTERN HILLS	URAIDLA	CAREY GULLY	**SG-04**	84	A5			1	
EASTERN HILLS	PICCADILLY	MOUNT LOFTY	**SG-05**	7	E4			1	
EASTERN HILLS	ALDGATE	JIBILLA	**SG-06**	17	H6			1	
EASTERN HILLS	URAIDLA	SUMMERTOWN	**SG-07**	69	A4			1	
EASTERN HILLS	VERDUN	VERDUN	**SG-08**	30	F11			1	
EASTERN HILLS	MYLOR	MYLOR	**SG-09**	67	O12			1	
EASTERN HILLS	ALDGATE	BRIDGEWATER	**SG-10**	59	B9			1	

REGION	SUBSTATION	FEEDER NAME	FEEDER No	EOL TF NUMBER 1	FEEDER PLAN COORDINATES	EOL TF NUMBER 2	FEEDER PLAN COORDINATES	MONITORS REQD	COMMENTS
EASTERN HILLS	STIRLING EAST	STIRLING	**SG-11**	70	P3			**1**	
EASTERN HILLS	MYLOR	BRADBURY	**SG-12**	80	Q9			**1**	
EASTERN HILLS	STRATHALBYN	STRATHALBYN WEST	**ST-11**	76	V9			**1**	
EASTERN HILLS	STRATHALBYN	STRATHALBYN EAST	**ST-12**	34	X8			**1**	
EASTERN HILLS	STRATHALBYN	BELVIDERE	**ST-13**	53	G9			**1**	
EASTERN HILLS	MILANG	POINT STURT	**ST-21**	74	Q1			**1**	
EASTERN HILLS	MILANG	BAGLEY BRIDGE	**ST-22**	66	D2			**1**	
EASTERN HILLS	MILANG	MILANG	**ST-23**	60	D2			**1**	
EASTERN HILLS	MEADOWS	MACCLESFIELD	**ST-34**	74	D9			**1**	
EASTERN HILLS	MEADOWS	MEADOWS	**ST-35**	64	G10	77	Z4	**2**	
EASTERN HILLS	MEADOWS	BULL CREEK	**ST-36**	109	N12			**1**	
EASTERN HILLS	LANGHORNE CREEK	HARTLEY	**ST-41**	40	N9	87	L2	**2**	
EASTERN HILLS	LANGHORNE CREEK	ANGAS PLAINS	**ST-42**	42	A7			**1**	
EASTERN HILLS	LANGHORNE CREEK	LANGHORNE CREEK	**ST-43**	23	E8			**1**	
EASTERN HILLS	LANGHORNE CREEK	MULGUNDAWA	**ST-44**	40	A6			**1**	
EASTERN HILLS	SQUARE WATER HOLE	FINNISS	**ST-51**	132	F3			**1**	
FLEURIEU PENINSULA	VICTOR HARBOR	ENCOUNTER BAY	**VH-10**	28	P10			**1**	
FLEURIEU PENINSULA	VICTOR HARBOR	TOWN CENTRE	**VH-11**	6	H12			**1**	
FLEURIEU PENINSULA	VICTOR HARBOR	VICTOR HARBOR EAST	**VH-12**	30	F2			**1**	
FLEURIEU PENINSULA	VICTOR HARBOR	CUT HILL	**VH-13**	40	A6			**1**	Single phase transformer
FLEURIEU PENINSULA	VICTOR HARBOR	HINDMARSH VALLEY	**VH-14**	25	F2			**1**	
FLEURIEU PENINSULA	VICTOR HARBOR	URIMBIRRA	**VH-15**	87	A11			**1**	
FLEURIEU PENINSULA	VICTOR HARBOR	VICTOR HARBOR WEST	**VH-16**	36	V9			**1**	

REGION	SUBSTATION	FEEDER NAME	FEEDER No	EOL TF NUMBER 1	FEEDER PLAN COORDINATES	EOL TF NUMBER 2	FEEDER PLAN COORDINATES	MONITORS REQD	COMMENTS
FLEURIEU PENINSULA	VICTOR HARBOR	INMAN VALLEY	**VH-17**	111	Z9			1	
FLEURIEU PENINSULA	VICTOR HARBOR	WAITPINGA	**VH-18**	58	Z4			1	
FLEURIEU PENINSULA	GOOLWA	GOOLWA	**VH-21**	47	E10			1	
FLEURIEU PENINSULA	GOOLWA	HINDMARSH ISLAND	**VH-22**	69	M1			1	
FLEURIEU PENINSULA	GOOLWA	MIDDLETON	**VH-23**	73	Z9			1	
FLEURIEU PENINSULA	YANKALILLA	NORMANVILLE	**VH-31**	42	E1			1	
FLEURIEU PENINSULA	YANKALILLA	BALD HILLS	**VH-32**	70	H11			1	
FLEURIEU PENINSULA	YANKALILLA	PARAWA	**VH-33**	60	H11			1	
FLEURIEU PENINSULA	YANKALILLA	WATTLE FLAT	**VH-34**	57	C3			1	
FLEURIEU PENINSULA	SQUARE WATER HOLE	PAMBULA	**VH-43**	41	D11			1	
FLEURIEU PENINSULA	SQUARE WATER HOLE	FLAGSTAFF HILL	**VH-44**	140	B5			1	
FLEURIEU PENINSULA	GOOLWA	CURRENCY CREEK	**VH-45**	100	E3			1	
FLEURIEU	SECOND VALLEY	SECOND VALLEY - DELAMERE	**VH-51**	20	H10			1	
FLEURIEU PENINSULA	CAPE JERVIS	CAPE JERVIS	**VH-71**	49	Q5			1	
FLEURIEU	SALT CLIFFS	SALT CLIFFS	**VH-72**	57	A4			1	
EYRE	WUDINNA	WARRAMBOO	**W-01**	29	D12			1	
EYRE	WUDINNA	MINNIPA	**W-02**	26	Y9			1	
EYRE	LOCK	LOCK	**W-03**	7	A5			1	
EYRE	POLDA	ELLISTON	**W-04**	28	Y5			1	
EYRE	MOORKITABIE	VENUS BAY	**W-06**	17	P11			1	Short feeder - 3 transformers only
EYRE	MOORKITABIE	POOCHERA	**W-08**	17	K3			1	
EYRE	WHYALLA CITY	GEORGE AVENUE	**WHY-01**	25	Q5			1	Urban feeder
EYRE	WHYALLA CITY	HUMMOCK HILL	**WHY-02**	32	B11			1	Urban feeder
EYRE	WHYALLA CITY	BROADBENT TERRACE	**WHY-03**	24	A10			1	Urban feeder

REGION	SUBSTATION	FEEDER NAME	FEEDER No	EOL TF NUMBER 1	FEEDER PLAN COORDINATES	EOL TF NUMBER 2	FEEDER PLAN COORDINATES	MONITORS REQD	COMMENTS
EYRE	WHYALLA CITY	VISCOUNT SLIM	**WHY-04**	28	O4			1	Urban feeder
EYRE	WHYALLA CITY	JACOBS STREET	**WHY-05**	16	H11			1	Urban feeder
EYRE	WHYALLA CITY	HOSPITAL	**WHY-06**	21	C11			1	Urban feeder
EYRE	WHYALLA CITY	RUSSELL STREET	**WHY-07**	59	W7			1	
EYRE	WHYALLA STUART	OPIE ST	**WHY-08**	26	A6			1	
EYRE	WHYALLA STUART	WESTLAND	**WHY-09**	32	A6			1	Urban feeder
EYRE	WHYALLA STUART	FLINDERS AVE	**WHY-10**	36	A12			1	Urban feeder
EYRE	WHYALLA STUART	WHYALLA JENKINS	**WHY-12**	25	C11			1	
EYRE	WHYALLA STUART	MIDDLEBACK	**WHY-13**	TC48230	H6			1	Urban feeder
RIVERLAND	CADELL	CADELL	**WK-11**	51	Q6			1	
RIVERLAND	QUALCO	QUALCO	**WK-21**	27	D4			1	
RIVERLAND	QUALCO	HOGWASH	**WK-22**	8	G3			1	
RIVERLAND	RAMCO	GOLDEN HEIGHTS	**WK-31**	8	Q8	171	B6	2	
RIVERLAND	RAMCO	TOOLUNKA	**WK-32**	55	B7			1	
RIVERLAND	RAMCO	TAYLORVILLE	**WK-33**	30	E1			1	
RIVERLAND	WAIKERIE	WAIKERIE WEST	**WK-41**	46	Q10			1	
RIVERLAND	WAIKERIE	WAIKERIE SOUTH	**WK-42**	98	P10			1	
RIVERLAND	WAIKERIE	LOWBANK	**WK-43**	84	A4	48	A7	2	
RIVERLAND	WOOLPUNDA	WOOLPUNDA	**WK-51**	24	M5			1	
RIVERLAND	WOOLPUNDA	WOOLPUNDA EAST	**WK-52**	81	D7	57	A8	2	
RIVERLAND	MORGAN	MORGAN	**WK-61**	25	E11			1	
RIVERLAND	CORDOLA	CORDOLA	**WK-65**	48	D1			1	
RIVERLAND	ROONKA	HAYLANDS	**WK-71**	27	B1			1	
RIVERLAND	ROONKA	BLANCHETOWN	**WK-72**	23	C5			1	
RIVERLAND	PORTEE	PORTEE	**WK-81**	15	C1			1	

REGION	SUBSTATION	FEEDER NAME	FEEDER No	EOL TF NUMBER 1	FEEDER PLAN COORDINATES	EOL TF NUMBER 2	FEEDER PLAN COORDINATES	MONITORS REQD	COMMENTS
MID NORTH	STANSBURY	STANSBURY	**YK-02**	3	B5			**1**	
MID NORTH	EDITHBURGH	EDITHBURGH	**YK-03**	72	C12			**1**	
MID NORTH	PORT GILES	WOOL BAY SOUTH	**YK-04**	25	E1			**1**	
MID NORTH	MINLATON	MINLATON	**YK-07**	23	P4			**1**	
MID NORTH	WAROOKA	WAROOKA	**YK-09**	7	C6			**1**	
MID NORTH	WAROOKA	POINT TURTON	**YK-17**	40	Q5	23	H2	**2**	
MID NORTH	YORKETOWN	SUNBURY	**YK-18**	21	H6			**1**	
MID NORTH	MINLATON	KOOLYWURTIE	**YK-20**	35	H5			**1**	Single phase transformer
MID NORTH	STANSBURY	RAMSEY	**YK-22**	21	H8			**1**	
MID NORTH	YORKETOWN	YORKETOWN	**YK-23**	23	B5			**1**	

47. APPENDIX U

Transformer Monitoring - Country feeders EOL – 460 LV monitor locations

NUMBER	SUBSTATION	Feeder	Feeder ID	EOL transformer	Feeder plan coordinates
1	FULHAM GARDENS	West Lakes	AP-424A	24274	Q3
1	FULHAM GARDENS	Fulham	AP-424B	24	L2
1	FULHAM GARDENS	Marlborough	AP-424C	22621	D7
1	FULHAM GARDENS	Henley	AP-424D	81	E6
1	FULHAM GARDENS	Grange	AP-424E	68	P1
1	FULHAM GARDENS	Frederick	AP-424F	18550	BB5
2	SEAFORD	Pedlar	NL-544A	35914	E4
2	SEAFORD	Ochre	NL-544B	132	B1
2	SEAFORD	Seaford Rise	NL-544C	N/A	N/A
3	MORPHETT VALE EAST	Reynella	NL-115A	30745	J5
3	MORPHETT VALE EAST	Hackham	NL-115B	77	A8
3	MORPHETT VALE EAST	Bains Road	NL-115C	263	S9
3	MORPHETT VALE EAST	Morphett Vale	NL-115D	27924	P7
3	MORPHETT VALE EAST	Woodcroft	NL-115E	24312	OO9
3	MORPHETT VALE EAST	Emerson Drive	NL-115F	16505	D12
4	VICTOR HARBOR	Encounter Bay	VH-10	28976	E10
4	VICTOR HARBOR	Town Centre	VH-11	6	H12
4	VICTOR HARBOR	Victor Harbor East	VH-12	19	B6
4	VICTOR HARBOR	Urimbirra	VH-15	86	A11
4	VICTOR HARBOR	Victor Harbor West	VH-16	20	L10
4	VICTOR HARBOR	Inman Valley	VH-17	111	Z9
5	BLACKPOOL	North Haven	AP-125A	30163	P12
5	BLACKPOOL	Pelican Point	AP-125B	3	P3
5	BLACKPOOL	Osborne	AP-125C	27	D11
5	BLACKPOOL	Taperoo	AP-125D	57	P9
6	HAPPY VALLEY	Craigburn	NL-210A	79	A6
6	HAPPY VALLEY	Tapleys Hill	NL-210B	103	C8
6	HAPPY VALLEY	Aberfoyle	NL-210C	TC52551	A6
6	HAPPY VALLEY	Chandlers Hill	NL-210D	28949	B7
6	HAPPY VALLEY	Oakridge	NL-210E	TC39631	B11
6	HAPPY VALLEY	Flagstaff Road	**NL-210F**	**26072**	**Q10**
7	ALDINGA	Aldinga Beach	MV-61	51	C3
7	ALDINGA	Sellicks Beach	MV-62	106	D8
7	ALDINGA	Willunga West	MV-63	49	F10
7	ALDINGA	Maslins Beach	MV-64	20	O9
8	PARAFIELD GARDENS	Pines	SA-31	34569	Q6
8	PARAFIELD GARDENS	Downs	SA-32	35363	H8
8	PARAFIELD GARDENS	Gardens	SA-33	31881	C12
8	PARAFIELD GARDENS	Greenfields	SA-34	13	G2

NUMBER	SUBSTATION	Feeder	Feeder ID	EOL transformer	Feeder plan coordinates
8	PARAFIELD GARDENS	Salt Pans	SA-35	32732	F2
9	LARGS NORTH	Peterhead	AP-529A	67	F9
9	LARGS NORTH	Mildred	AP-529B	13472	C1
9	LARGS NORTH	Largs North	AP-529C	26	E5
9	LARGS NORTH	Birkenhead	AP-529D	59	W9
9	LARGS NORTH	Military Road	AP-529E	73	P12
10	SHEIDOW PARK	Karrara	NL-451A	7	W2
10	SHEIDOW PARK	Hallett Cove	NL-451B	26001	E1
10	SHEIDOW PARK	Trott Park	NL-451C	23730	D7
10	SHEIDOW PARK	Sheidow Park	NL-451D	23129	A10
10	SHEIDOW PARK	Patpa Drive	NL-451E	TC48167	P10
11	GOLDEN GROVE	Fairview Park	HH-496A	18597	Z7
11	GOLDEN GROVE	Yatala Vale	HH-496B	32	B6
11	GOLDEN GROVE	Wynn Vale South	HH-496C	255	FF7
11	GOLDEN GROVE	Wynn Vale West	HH-496D	25799	HH9
11	GOLDEN GROVE	Golden Grove North	HH-496E	TC52521	F4
11	GOLDEN GROVE	Greenwith	HH-496F	35111	A10
11	GOLDEN GROVE	Rifle Range	HH-496G	50	X3
11	GOLDEN GROVE	Golden Grove West	HH-496H	32761	P8
12	NORTHFIELD	Stockade	HH-403A	35099	Q4
12	NORTHFIELD	Valley View	HH-403B	TC40609	Q8
12	NORTHFIELD	Northfield	HH-403C	33241	B8
12	NORTHFIELD	Northgate	HH-403D	17	H7
13	BLACKWOOD	Glenalta	SM-126A	24	A4
13	BLACKWOOD	Sun Valley	SM-126B	55	A5
13	BLACKWOOD	Coromandel	SM-126C	27934	A10
13	BLACKWOOD	Eden	SM-126D	115	Q6
13	BLACKWOOD	Brighton Parade	SM-126E	TC40669	N12
14	PORT NOARLUNGA	Southport	NL-234A	31906	G1
14	PORT NOARLUNGA	Onkaparinga	NL-234B	31346	O11
14	PORT NOARLUNGA	Moana	NL-234C	15391	F12
14	PORT NOARLUNGA	Dyson Road	NL-234D	TC48141	B11
14	PORT NOARLUNGA	Seaford Meadows	NL-234E	TC1532	D12
15	GLANVILLE	Semaphore	AP-226A	TC1515	G6
15	GLANVILLE	Glanville	AP-226B	16886	B6
15	GLANVILLE	Ethelton	AP-226C	19450	M11
15	GLANVILLE	Swan Terrace	AP-226D	24043	D11
15	GLANVILLE	Mellor Park	AP-226E	55	G11
16	TEA TREE GULLY	Banksia Park	HH-145A	53	F8
16	TEA TREE GULLY	Surrey Downs	HH-145B	15998	X8
16	TEA TREE GULLY	Ridgehaven	HH-145C	93	T11
16	TEA TREE GULLY	Vista	HH-145D	214	D9

NUMBER	SUBSTATION	Feeder	Feeder ID	EOL transformer	Feeder plan coordinates
16	TEA TREE GULLY	Redwood Park	HH-145E	263	N6
17	EVANSTON	Gawler North	GA-01	23745	F6
17	EVANSTON	Gawler West	GA-02	11	Z1
17	EVANSTON	Dalkeith	GA-22	131	Y11
17	EVANSTON	Gawler East	GA-25	23	C12
17	EVANSTON	Evanston	GA-26	183	V12
17	EVANSTON	Willaston	GA-50	38105	D4
18	INGLE FARM	The Levels	HH-177A	12	J2
18	INGLE FARM	Para Hills	HH-177B	70	Q8
18	INGLE FARM	Rialto	HH-177C	279	U5
18	INGLE FARM	Ingle Farm	HH-177D	266	C11
18	INGLE FARM	Pooraka	HH-177E	230	P5
18	INGLE FARM	Montague	HH-177F	TC52017	X7
19	QUEENSTOWN	Queenstown	AP227A	53	D12
19	QUEENSTOWN	Royal Park	AP227B	34	M6
19	QUEENSTOWN	Carnegie Park	AP227C	24040	Q5
19	QUEENSTOWN	Hendon	AP227D	18168	L12
20	ELIZABETH HEIGHTS	Elizabeth East	EL-09	TC48201	N12
20	ELIZABETH HEIGHTS	Adams Road	EL-10	32975	A10
20	ELIZABETH HEIGHTS	'P' cable	EL-01	TC52987	H9
20	ELIZABETH HEIGHTS	'Q' cable	EL-01	TC52692	L11
20	ELIZABETH HEIGHTS	'R' cable	EL-01	TC54909	C11
21	GOOLWA	Goolwa	VH-21	16	J12
21	GOOLWA	Hindmarsh Island	VH-22	66	M1
21	GOOLWA	Middleton	VH-23	30	Y3
21	GOOLWA	Currency Creek	VH-45	100	D4

48. APPENDIX V

Transformer Monitoring - Metro pad-mount transformers – 635 LV monitors locations

GIS_ID	TF SIZES	ADD_STREET	ADD_SUBURB
NL760C 18054	150	CORINTH RD	HACKHAM WEST
NL451D 35377	150	BERRIMA RD/CORNISH NO 1	SHEIDOW PARK
HH121E 1216	150	RICHARD ST	ATHELSTONE
HH102D 62	100	FREDERICK ST	GILBERTON
HH341D 26544	200	MAGILL RD 407	ST MORRIS
NL115B 25821	150	BLUNDELL ST	MORPHETT VALE
HH102B 33024	150	SECOND AVE	KLEMZIG
HH428A 26089	150	DUTHIE ST	HILLCREST
GA26 TC43950	300		EVANSTON PARK
HH121C 1075	150	BILLS AVE	PARADISE
NL544A TC1550	150	BUCCANEER DRV	SEAFORD RISE
SM137A 25909	150	COHEN CRT	CLOVELLY PARK
NL451D TC1616	150	GREAT EASTERN AVE	SHEIDOW PARK
HH121F 1046	200	DE IONNO CRS	PARADISE
HH403B 36235	300		WALKLEY HEIGHTS
HH428B 30799	150	FEATURE CRT	GILLES PLAINS
HH428B 21757	200	SWANSON ST	GILLES PLAINS
NL451C 23729	150	LT54 HORNDALE DR(WEST)	WOODCROFT
NL210E 28037	150	LYN ST (WEST)	ABERFOYLE PARK
AP125D 23232	200	ORMISTON CRT	TAPEROO
NL115E 33479	150	PEGASUS DRV	WOODCROFT
HH403B 39128	150	DENE ST	WALKLEY HEIGHTS
NL760B 35056	150	OLDBOROUGH DRV	ONKAPARINGA HILLS
NL760B 28942	150	PENNYS/UPPER PENNYS HILL RD	ONKAPARINGA HILLS
NL115E TC1103	150	NORMANDY RD	WOODCROFT
NL511A 25831	150	HEPBURN RD	CHRISTIE DOWNS
NL511B 13948	150	LAMBERT ST	MORPHETT VALE
HH428A 30035	150	CHAPLIN AV	HILLCREST
NL234A 18053	150	GRUNDY RESERVE	CHRISTIES BEACH
SA13 16053	200	PORTER ST	ELIZABETH VALE
NL451C 23727	150	SUN CRES,	HAPPY VALLEY
MV15 18059	150	WEST PARK WAY	MCLAREN VALE
HH121F 1071	150	PEACEFUL CRT	CAMPBELLTOWN
NL760B 30918	150	FOXFIELD DRV	ONKAPARINGA HILLS
HH428E 31402	150	DUNHAM ST	OAKDEN
NL760A 24863	150	BAYTON RD 22	HUNTFIELD HEIGHTS
ME131B 23406	300	ANZAC HWY	PLYMPTON
GA50 15876	150	DUNDAS ST	GAWLER
NL760C 18580	150	WARSAW CRES	HACKHAM WEST
NL234C 29848	150	CEDAR AVE 3	SEAFORD

GIS_ID	TF SIZES	ADD_STREET	ADD_SUBURB
HH428A 33783	150	UPTON ST	OAKDEN
NL760B TC1422	150	OLD BOROUGH DVE	ONKAPARINGA HILLS
EL18 32341	150	JARRA LANE	CRAIGMORE
AP529E 23234	200	JETTY RD	LARGS BAY
EL01Q 3.3	200	STOCKTON ST / CODFORD ST	ELIZABETH
NL115A 32406	150	INVESTIGATOR DRV	WOODCROFT
NL544A 30752	150	LANTERN DRV	SEAFORD RISE
NL760C 25117	200	LORNE CRES	HUNTFIELD HEIGHTS
HH107C 30591	150	WILKINSON CRES	ENFIELD
SM137B 33075	150	MALDON AVE	MITCHELL PARK
SM137B 32351	150	MC INERNY AVE	MITCHELL PARK
NL115C TC834	150	WAVERLY WAY	MORPHETT VALE
HH121A 1055	150	O'LEARY CRT/CENTOFANTI AVE	NEWTON
NL111B 14979	150	CECELIA CRT/IMELDA ST	CHRISTIE DOWNS
NL210E 28955	150	THE PARKWAY	ABERFOYLE PARK
NL760B 30919	150	THE COMMON	ONKAPARINGA HILLS
NL451C 23730	150	MARANA DRV/MARS CRT	HAPPY VALLEY
NL210D 16603	150	TAYLORS RD 29	ABERFOYLE PARK
NL210E 23585	150	LYRIC ST	ABERFOYLE PARK
NL451C 32741	150	KINGSTON AV OP 10	HAPPY VALLEY
SA33 28293	150	SHEPHERDSON RD	PARAFIELD GARDENS
SA42 16413	150	CHARTWELL CRES	PARALOWIE
HH409D 26197	150	LANGMAN DRV	TERINGIE
NL451E 22213	200	WKY INGOMAR/GRAND CENTRAL	HALLETT COVE
HH121D 1213	150	ADELA CRS	ATHELSTONE
NL760B 30031	150	KINGS HILL CRT	ONKAPARINGA HILLS
NL451C 17513	150	TORRENS AVE	HAPPY VALLEY
NL760C 18462	150	AYLTON AV	HUNTFIELD HEIGHTS
NL234C 15680	150	CORVETTE RD NO1 NORTH 42	SEAFORD
HH496D 29824	150	MADELINE CRT	WYNN VALE
SA19 22343	150	KIMBER CRT	SALISBURY
AP529A 28209	300	TIM HUNT WAY	LARGS BAY
SA520A TC43879	300	METRO PDE	MAWSON LAKES
ME427F 33361	300	HENLEY BEACH RD 281	BROOKLYN PARK
NL451E TC40643	300	BROOKLYN DR	HALLETT COVE
MV15 23722	150	VALLEY VIEW DRV	MCLAREN VALE
SA20 17301	150	METALA RD	PARALOWIE
NL115F 16096	150	TRACY WAY	MORPHETT VALE
NL210E 17358	150	TOPAZ DRV	FLAGSTAFF HILL
SA20 23740	150	CLANCY CRT	PARALOWIE
AP125A 30646	200	FAILIE DRV NO1	NORTH HAVEN
SM137A 13505	200	WATERMAN TCE	MITCHELL PARK

GIS_ID	TF SIZES	ADD_STREET	ADD_SUBURB
HH428B 32759	150	OAKDALE DRV LOT 69	GILLES PLAINS
NL760B 31381	150	TUSMORE DRV	ONKAPARINGA HILLS
HH130F 33385	150	HUMBER ST	HOLDEN HILL
NL760B 31883	150	O'HALLORAN LANE	HACKHAM
NL511B 17519	150	HAGEN CRES	HACKHAM WEST
NL210C 16471	150	DOVE CRT	ABERFOYLE PARK
NL760C 16498	150	FIGTREE CRES	HUNTFIELD HEIGHTS
ME200G 22210	200	FARNHAM RD	ASHFORD
EL13 17986	150	WANBI CRT	MUNNO PARA
HH409D 35387	150	COACH HOUSE DR	TERTINGIE
HH496H 27535	150	HARRINGTON CRT:RESERVE	GREENWITH
NL234E 29873	150	RESERVE SEA EAGLE CRES	SEAFORD RISE
SA32 35249	150	HOWELL DR	PARAFIELD GARDENS
NL760B 30724	150	OLDE GUM TREE DRV	ONKAPARINGA HILLS
NL210D 24464	150	WINDEBANKS RD (NX77)	ABERFOYLE PARK
SA14 16188	150	MERALANG	SALISBURY PARK
NL760C 27228	150	CLARIDGE CRT	HUNTFIELD HEIGHTS
NL234A 19030	150	FOWEY ST NO 875	CHRISTIES BEACH
HH148B TC46238	750	STANLEY ST	LEABROOK
HH130D 21682	150	SOLANDRA AVE NORTH NO2	MODBURY NORTH
SA20 15835	150	WOODFIELD DRV	SALISBURY DOWNS
HH496A 13776	150	FLINDERS DRV	FAIRVIEW PARK
SA20 28969	150	PALM CRT	PARAFIELD GARDENS
HH121G 739	200	ACACIA AVE	CAMPBELLTOWN
NL115E 32727	200	EXCELSIOR GROVE	WOODCROFT
HH121C 1224	150	NAOMI WAY	ATHELSTONE
HH107C 30584	150	BRADFORD CRT NO2	ENFIELD
HH118B 28052	300	RUNDLE ST NO 5-9	KENT TOWN
HH522B 16802	150	TOOVIS RD VISTAS	ST AGNES
NL115E 16403	150	MATTHEWS ST	HAPPY VALLEY
HH428E 31893	150	BRAND ST	OAKDEN
GA02 30909	100	BARKLEY DRV	WILLASTON
SA18 21710	150	ETUNA ST	PARA HILLS WEST
SA18 23306	150	HAMPTON CRES	SALISBURY EAST
HH429B 17877	150	PROSPECT RD	KILBURN
NL451D 31108	150	ALIA DRV	SHEIDOW PARK
GA26 35203	150	GLEESON GR	EVANSTON PARK
HH522B 23478	150	SHELTON ST	ATHELSTONE
NL451C 35256	150	ALLWORTH DRV	HAPPY VALLEY
NL210C 17293	150	EMERALD ST	ABERFOYLE PARK
NL544B 32394	150	GOODRINGTON WAY	MOANA
NL210C 24132	150	EASDTFIELD CIRCUIT(OUTLOOK DR)	ABERFOYLE PARK

GIS_ID	TF SIZES	ADD_STREET	ADD_SUBURB
HH496C 25755	150	PEDARE CRT	WYNN VALE
HH496G 32958	150	LOCHEAL AVE	GREENWITH
HH177C 23626	150	EFFIE CRT	PARA VISTA
ME131E 25118	200	MARION RD	NORTH PLYMPTON
NL451A 24575	150	SPINNAKER CCT	SHEIDOW PARK
GA26 35127	150	ANGUS AVE	EVANSTON GARDENS
NL451D 33000	150	BERRIMA RD	SHEIDOW PARK
NL115C 26151	150	AUBURN CRT	MORPHETT VALE
NL210E 38177	150	COACHWOOD DRV "THE OAKS" LOT 1	ABERFOYLE PARK
NL451C 14923	150	LISA RD NO 5	HAPPY VALLEY
NL451C 35258	150	OAKFORD CRES	HAPPY VALLEY
HH428E 32348	150	WOODLAND DR	OAKDEN
NL115F 16138	150	BOWER CRT	MORPHETT VALE
HH496D 25432	150	TIMCRIS CRT : CNR CHERTSEY CRT	WYNN VALE
HH496F 30758	150	CROMER CRT	GREENWITH
NL451A 16495	150	KURRAMBIE CRES WALKWAY(NTH)	HALLETT COVE
HH496G 31744	150	HALCYON AVE	GREENWITH
HH496C 25071	150	PECOS CRT : 2	WYNN VALE
NL210B 32410	150	STIMSON ST NX 1	O'HALLORAN HILL
HH496H 29825	150	MOCKRIDGE ST	GREENWITH
HH121C 1236	150	HEATHER CRT	PARADISE
NL115F 16492	150	ELIZABETH ST	MORPHETT VALE
SA18 13147	150	MOSTYN CRES	SALISBURY EAST
NL451E 13160	150	COLUMBIA CR OP23	HALLETT COVE
SA31 22123	150	KINGS RD	SALISBURY DOWNS
HH145D 18643	150	KENNEDY ST	ST AGNES
HH118A 25828	200	FULLARTON RD	GLENSIDE
NL210C 28943	150	ESTATE DRIVE NOI	FLAGSTAFF HILL
NL210A 27454	150	LORIKEET GR 6	FLAGSTAFF HILL
GA26 35132	150	COPPERFIELD CRES	EVANSTON PARK
NL210A 17851	150	DUMPHRIES ST	FLAGSTAFF HILL
NL111A 14538	150	MEDWAY ST 10	HALLETT COVE
SM137B 37013	150	MC FARLANE AVE	MITCHELL PARK
HH496C 28353	150	DRUMOND ST	WYNN VALE
HH409A 24577	150	THE PARADE	ROSSLYN PARK
NL115B 25745	150	MATISON AVE	MORPHETT VALE
SM137B 30710	150	BURNLEY GROVE	MITCHELL PARK
HH496G 30725	150	BOWMORE CRT	GREENWITH
ME131B 20797	200	ANZAC HWY	PLYMPTON
EL14 5.10	300	RESERVE BIRDBUSH ST	ELIZABETH NORTH
ME200E 12638	200	EVERARD AVE	KESWICK
GA25 16100	150	MAY TCE	GAWLER EAST

GIS_ID	TF SIZES	ADD_STREET	ADD_SUBURB
SM349D 14126	150	ATTUNGA ST	SHEIDOW PARK
SM349D 15626	150	ELURA AVE	SHEIDOW PARK
NL210C 25085	150	GREENFIELD RISE	ABERFOYLE PARK
HH403B 37060	150	RIVER GUM CLOSE	WALKLEY HEIGHTS
HH145E 23260	150	BURFORD CRES	REDWOOD PARK
MV64 29985	150	MYERHOFF ST	ALDINGA BEACH
NL451E 14537	150	THERMOPYLAE CR 11	HALLETT COVE
HH130F 25939	150	ABBEY CLOSE	HOLDEN HILL
HH496D 25451	150	HERMITAGE PL : 17 : CNR MEDLAN	WYNN VALE
NL511B 16473	150	OSWIN CRT	CHRISTIE DOWNS
NL451B 26003	150	COORABIE CR NO13	HALLETT COVE
NL451C 16876	150	KENIHANS RD	HAPPY VALLEY
MV11 24950	150	VINE ST EAST	MCLAREN VALE
NL760B 28296	150	STATES RD/HEYLEN CRT	HACKHAM
NL544A 31832	150	BARBADOS DRV OPP 83	SEAFORD RISE
HH496A 24843	150	MARINERS DR	SURREY DOWNS
HH102C 20981	200	WALKERVILLE TCE	WALKERVILLE
HH102C 22022	300	STEPHEN TCE	WALKERVILLE
AP125B 16390	200	WALKWAY OFF KLINGBERG DRV	NORTH HAVEN
ME131A 21402	150	MARION RD	PLYMPTON
SM349D 14991	150	HEYSEN DRV	TROTT PARK
HH121F 25099	150	APHOS PL	PARADISE
NL760C 16974	150	LARRISA CRT	HACKHAM WEST
HH177F 31754	150	RESERVE-CASTON ST	MONTACUTE
NL234B 31346	150	ADMIRALTY CR NX30	SEAFORD
NL511B 17884	150	BRINDISI CRT	HACKHAM WEST
HH496A 14128	150	WALKWAY - OFF ALICANTE AVE	WYNN VALE
SA520A TC42186	300	GRENADA CRT	MAWSON LAKES
NL511B 16503	150	VALENTINE ST	CHRISTIE DOWNS
SA20 15986	150	ONKAPARINGA DRV	SALISBURY DOWNS
NL111B 15879	150	COE CRT	CHRISTIE DOWNS
SA20 15989	150	ONKAPARINGA DRV	SALISBURY DOWNS
HH130E 29006	150	RIDDELL RD	HOLDEN HILL
MV62 TC42098	300	LACEY CORAL AVE	ALDINGA
EL01C 1.3	300	MANNINGFORD RD / BAGOT RD	ELIZABETH SOUTH
HH409A 14539	150	WYFIELD AVE	WATTLE PARK
HH428B 30576	150	KEW DR	OAKDEN
NL210E 25762	150	GREENLEAF CRT	ABERFOYLE PARK
SA19 24379	150	RHYNE AVE	SALISBURY
SA42 32704	150	GENERAL DRV	PARALOWIE
SM410B TC1588	150	TAPLEYS HILL RD & ANZAC HWY	GLENELG NORTH
HH428E 33488	150	SALTRAM PDE	OAKDEN

GIS_ID	TF SIZES	ADD_STREET	ADD_SUBURB
HH496C 26163	150	GANNET PL : ADJ LOT 1	WYNN VALE
HH496G 31849	150	GLENEAGLES CCT	GREENWITH
ME131A 18256	150	BARODA AVE	NETLEY
SA42 25428	150	WINSTON AV/GRASSO ST	PARALOWIE
NL210E 25736	150	SUNNYMEADE DRV	ABERFOYLE PARK
NL115B 30020	150	BROOKLAND VALLEY DRV	WOODCROFT
NL760C 17003	150	FAIRVIEW GR	HACKHAM WEST
HH496D 25798	150	CRESTVIEW PL : LOT 23	WYNN VALE
SA14 16809	150	SANDY CRES	SALISBURY PARK
HH496G 30716	150	PT ELLEN CRT	GREENWITH
NL760A 16143	150	FLINDERS CRES	HACKHAM
HH107D 30029	150	MC DOUGALL CL	CLEARVIEW
HH496D 25720	150	STRATHISLA CRT LOT 58	WYNN VALE
HH496F 33642	150	LAKE MAURIE PLACE	GREENWITH
NL451B TC52059	150	CNR GOROKE ST & FORRESTERS RD	HALLETT COVE
HH121D 24203	150	PROSPERITY WAY	ATHELSTONE
AP125A 30774	200	MYTH DRV	NORTH HAVEN
HH102D 23376	200	MAIN NORTH EAST RD	COLLINSWOOD
GA01 27536	150	HUTCHINSON RD	GAWLER EAST
NL544A 34533	150	AUGUSTA DRV	SEAFORD RISE
SA20 31769	150	TOBIN WAY	PARALOWIE
NL210D 23833	150	MC HARGS RD (OP28)	HAPPY VALLEY
HH428B 32457	150	MONTACUTE DRV	OAKDEN
NL234D 756	150	GABRENOL CRT	NOARLUNGA DOWNS
NL115F 15916	150	GLENHELEN RD	MORPHETT VALE
NL210D 16415	150	ROBINSON RD	CHANDLERS HILL
NL544B 30762	150	MEADFOOT CLOSE	MOANA
HH496F 32437	150	CANDLEBARK GROVE	GREENWITH
ME131B 28345	150	BRENDAN CRT	GLANDORE
HH409F 21398	150	COMO ST	NEWTON
NL760C 25411	150	ARCTURUS RD	HUNTFIELD HEIGHTS
AP226C 23838	300	GOLDSWORTHY RD (SAHT)	ETHELTON
NL234D 29014	150	SELARU WAY	NOARLUNGA DOWNS
HH107D 25852	300	COLLINS ST	ENFIELD
GA26 32414	150	WILLIAMS RD	EVANSTON PARK
ME116D 35445	300	BOOTHBY CRT	UNLEY
NL234E TC43784	300		SEAFORD
AP529E 23225	200	MILITARY RD	LARGS BAY
SA520J TC45172	500	EUSTON WK	MAWSON LAKES
ME131C 38049	150	PATRICIA AVE	CAMDEN PARK
HH428B 30588	150	DORSET ST	HILLCREST
SM137B 24692	150	KARU CRES	MITCHELL PARK

GIS_ID	TF SIZES	ADD_STREET	ADD_SUBURB
NL760B 26200	150	GATEACRE BROW LOT 200	ONKAPARINGA HILLS
NL234B 32466	150	DRIFTWOOD CRES	SEAFORD RISE
SA35 32229	150	LOVELOCK RD	PARAFIELD GARDENS
MV64 35106	150	EVANS ST	ALDINGA
HH496D 27926	150	QUALITY CRT:LOT 20	WYNN VALE
SA20 15839	150	WOOLASTON RD	SALISBURY DOWNS
HH121D 35425	150	REIDGEFIELD AVE	PARADISE
HH496A 15690	150	CASSIA ST	SURREY DOWNS
NL760B 28958	150	RICHMOND GROVE	ONKAPARINGA HILLS
HH428B 32436	150	BROOKDALE CLOSE LOT	GILLES PLAINS
NL234B 31748	150	WINDLASS SQUARE	SEAFORD RISE
SA14 14989	150	FRANCIS CR	SALISBURY HEIGHTS
NL234C 18245	150	HALYARD CRES OPP 24	SEAFORD
NL210D 16412	150	HORN DR (OP59)	HAPPY VALLEY
SA42 16407	150	KENTWOOD DRV	PARALOWIE
HH386D 15875	150	JOHN CLELAND DRV	BEAUMONT
HH118D 21674	200	THOMAS PL	ROSE PARK
ME116C 35030	300	MARY ST	HYDE PARK
HH121C 1039	150	KYM ST	ATHELSTONE
NL210A 31775	150	SANDLEWOOD CRES	FLAGSTAFF HILL
HH121D 128	150	QUONDONG AVE	ATHELSTONE
NL451D 25944	150	HUGH JOHNSON BLVD 2	SHEIDOW PARK
HH121E 1053	150	STRADBROKE RD	ATHELSTONE
HH409A 17001	150	TRANIMER WAY	AULDANA
SA520A TC42220	300	PIKE AV	MAWSON LAKES
SM137B 30720	150	GENEVA CRT	MITCHELL PARK
SM349D 17579	150	KLIPPEL AVE 2	TROTT PARK
SM349D 17580	150	KLIPPEL AVE 1 SOUTH	TROTT PARK
NL451D 26152	150	MENZIES CRT	TROTT PARK
AP125A 18804	150	BROOKLYN TCE	NORTH HAVEN
HH496H 29856	150	PISANI CRT	GREENWITH
NL111B 17505	150	CLYDE ST	CHRISTIE DOWNS
NL210E 987	150	SUNNYMEADE DRV/SPRUCE AVE	ABERFOYLE PARK
NL451A 16478	150	CAPELLA DRV WALKWAY	HALLETT COVE
SA32 35054	150	RHODE ISLAND DRV	SALISBURY SOUTH
NL451E 14127	150	RESOLUTE CR 7	HALLETT COVE
HH496C 25750	150	GREENFINCH CRT : 9	WYNN VALE
NL115C 28917	150	KOOYONGA WAY	MORPHETT VALE
HH496F 31095	150	ORANGE AVE	GOLDEN GROVE
NL210C 16477	150	CARRICKALINGA BLVD	ABERFOYLE PARK
NL115D 15761	150	NASH CRES	MORPHETT VALE
NL511B 17518	150	FINLAND CRES	HACKHAM WEST

GIS_ID	TF SIZES	ADD_STREET	ADD_SUBURB
HH496G 32422	150	LOWE DRV	GREENWITH
ME347B 32502	300	VICTORIA ST	MILE END
NL234D 27129	150	NAPIER CT 1	NOARLUNGA DOWNS
SM126E TC47948	300	HIGHFIELD DVE	CRAIGBURN FARM
EL01N 4.10	300	GREEN ST & HAYLES RD	ELIZABETH PARK
SA11 35829	300	BAGSTER RD	SALISBURY NORTH
SM349D 14123	150	WESTALL WAY	SHEIDOW PARK
HH121D 1214	150	AURORA DRV	ATHELSTONE
HH121E 1231	150	GRAHAM DRV	ATHELSTONE
ME427F 16880	200	LOWE ST	THEBARTON
SM410B 117	200	DURHAM ST	GLENELG
HH432C 20937	200	NOBLE ST	OVINGHAM
HH177B 18615	150	CODD ST	PARA HILLS WEST
NL111A 17314	150	HESPERUS ST 13	HALLETT COVE
NL210E 32454	150	MT MALVERN RD	ABERFOYLE PARK
SA31 35208	150	WILLOWBROOK BLVD	PARALOWIE
NL115A 31871	150	MAWSON CT	WOODCROFT
SA32 35055	150	NEW HAMPSHIRE DRV	SALISBURY SOUTH
NL234D 35285	150	KANTILLA CRT	NOARLUNGA DOWNS
SA520D 39333	300	LAKEWOOD CRT	MAWSON LAKES
SA17 27128	150	OLDE DRV	SALISBURY EAST
SA32 17344	150	JUNE ST	PARAFIELD GARDENS
HH496F 35386	150	NAUGHTON CT	GREENWITH
HH428A 31763	150	OSTERLEY ST	NORTHFIELD
NL760C TC49587	300	LONG PL	HUNTFIELD HEIGHTS
SA18 22336	150	SHELTON DRV	SALISBURY EAST
SA14 16493	150	BRISTOL WAY	SALISBURY EAST
SA520D 39357	300	MAWSON LAKES BVLD	MAWSON LAKES
HH496D 31385	150	GOODWIN RESERVE	GOLDEN GROVE
NL234A 17666	150	CLEMENT TCE	CHRISTIES BEACH
HH496F 32738	150	PFITZNER PLACE	GREENWITH
ME131C 35084	150	BOSWARVA AVE	PLYMPTON
NL234D TC1021	150	MARLA CRES	NOARLUNGA DOWNS
NL234D 32450	150	GOULDING GROVE OP21	NOARLUNGA DOWNS
SA520D 39134	300	GREENGATE LANE RESERVE	MAWSON LAKES
NL760C 28030	150	BALLINA CRT	HUNTFIELD HEIGHTS
HH496C 24426	150	ISABELLA CRT : OPP 11	WYNN VALE
NL511B 25427	150	MARILYN AVE	CHRISTIE DOWNS
SA20 15915	150	MORRIS ST	PARALOWIE
HH428F 20707	150	WINDSOR GR	KLEMZIG
SA20 TC942	150	BURTON RD	PARALOWIE
AP125A TC1504	200	SEA SPRAY AVE NO1	NORTH HAVEN

GIS_ID	TF SIZES	ADD_STREET	ADD_SUBURB
EL13 16382	200	MALTARA RD	MUNNO PARA
HH409F 23530	300	THOMSON PLACE	ROSTREVOR
HH121E 1215	150	THEODORE AVE	ATHELSTONE
ME427D 23398	300	GEORGE ST	THEBARTON
NL111A 28350	150	ENDEAVOUR RD	HALLETT COVE
NL111A 33256	150	FREEBAIRN DR OP BRAMPTON CT	HALLETT COVE
NL234C 29730	150	PLOVER CRT LOT 401 END PLOVE	SEAFORD RISE
MV11 38015	150	ALDERSEY ST	MCLAREN VALE
NL115E 32740	150	EPSILON CLOSE	WOODCROFT
NL115E 36004	150	JIMMY WATSON DRV	WOODCROFT
NL451D 26128	150	CHIFLEY CRES	TROTT PARK
HH496D 27935	150	PRELATE CRT:LOT 16	WYNN VALE
SA42 24382	150	CAULFIELD CRES	PARALOWIE
HH496F 35111	150	HEDGEBROW CRT	GREENWITH
HH496F 34632	150	FEATHERSTONE CRT	GREENWITH
HH496H 27957	150	KENEALLY CRT	GREENWITH
SA42 24713	150	VIVEN DRV	PARALOWIE
SA42 24384	150	REDFORD ST	PARALOWIE NORTH
NL210C 23581	150	COLLEGE DRV	ABERFOYLE PARK
SA41 33898	150	LIBERATOR DRV	PARALOWIE
SA11 14437	150	ANTONAS AV	PARALOWIE
HH428E 35057	150	CONSERVATORY CCT	OAKDEN
HH496C 27956	150	SCHAFFER CRT	GOLDEN GROVE
NL234B 31773	150	ADMIRALTY CRES	SEAFORD RISE
HH496H 33650	150	GREEN PINE CRT	GREENWITH
NL111B 17352	150	SCOTTSGLADE RD	CHRISTIE DOWNS
HH496D 28941	150	REGENTS LAND - RESERVE	WYNN VALE
HH432C 16703	200	NOTTAGE TCE	MEDINDIE
SM349D 22011	200	EURELIA RD	SHEIDOW PARK
NL115A 31320	200	HARTOG ST	WOODCROFT
SA520J TC40676	300	GRASSWREN WAY RES	MAWSON LAKES
SA520D TC39391	300	SHEARWATER PLACE	MAWSON LAKES
SA520A TC48231	300	WENTWORTH ST	MAWSON LAKES
GA01 30604	300	BASSETT TOWN	GAWLER
HH496F 28028	150	MC CULLOUGH CRT RESERVE	GOLDEN GROVE
SA42 32705	150	GIRADOF ST	PARALOWIE
HH121C J9385	100	DONNIKA ST	PARADISE
NL115E 28978	150	BYARDS RD NO1	WOODCROFT
SA31 23767	150	ROXBY ST	PARAFIELD GARDENS
NL210D 24394	150	MINERVA GR 1	HAPPY VALLEY
HH496F 35368	150	LAKE MIRANDA CRT	GREENWITH
SA17 27451	150	COACHHOUSE DRV	SALISBURY EAST

GIS_ID	TF SIZES	ADD_STREET	ADD_SUBURB
SA20 15907	150	YOUNG BLVD	PARALOWIE
SA32 35363	150	SEABRIGHT AVE	PARAFIELD GARDENS
HH496G 31767	150	MC LEOD CT	GREENWITH
HH496F 30595	150	NELLA DAN CRT (RESERVE)	GREENWITH
NL210B 27797	200	WREN ST	O'HALLORAN HILL
HH177C 14748	150	MURRELL RD NO 2	PARA HILLS
HH130C 31850	150	ALMERTA ST	HOPE VALLEY
NL210D 16602	150	BROOK DR	ABERFOYLE PARK
ME131C 37081	150	WHELAN AVE	PLYMPTON
HH121C 1225	150	PATRICK ST	ATHELSTONE
HH522B 26127	150	STUDLEY DRV	ATHELSTONE
SA14 15186	150	HEATHERSETT CRES WALKWAY	SALISBURY PARK
HH428E 32439	150	BUCKINGHAM ST	OAKDEN
ME200E 19162	200	BARWELL AVE	KURRALTA PARK
NL760B 28361	150	LYNN/PETHICK WAY	HACKHAM
HH522B 23497	150	PANORAMA DRV	ATHELSTONE
HH428E 35204	150	HIDCOTE CCT	OAKDEN
MV62 TC43746	300	LOT 139 TURQUOISE CRT	ALDINGA BEACH
SA14 17585	150	JENKINS DRV	SALISBURY PARK
HH341G TC866	200	MAGILL RD 277	FIRLE
HH428B TC42452	300	KAPOOLA	GILLES PLAINS
HH121D 18880	200	GORGE RD	NEWTON
AP125B 15355	200	FRASER DRV NO2	NORTH HAVEN
AP125D 31185	200	ALISON CRT	TAPEROO
SA520A TC41402	300	SANCTUARY DR	MAWSON LAKES
SA520D 40022	300	MALLARD CRES	MAWSON LAKES
HH102D 19028	200	STEPHEN TCE	WALKERVILLE
SA520D 40024	150	ROSELLA ST	MAWSON LAKES
SM349D 17894	150	WALKWAY DRYSDALE DRV & STREETO	TROTT PARK
NL760B 30022	150	VINE CROSS CRES	ONKAPARINGA HILLS
HH102B 32220	150	SAMUEL PLACE	FELIXSTOW
HH121F 1076	150	PACKER CRES	PARADISE
NL111C 22032	150	TINGIRA DRV	CHRISTIES BEACH
HH496C 26195	150	O'LEARY PL 3	WYNN VALE
SA18 13454	150	DEBRA CRES	SALISBURY EAST
NL115A TC645	150	ALLMAN AVE	WOODCROFT
NL111C 15783	150	WALKWAY(OFF TINGIRA DR)	CHRISTIES BEACH
HH522A 13929	150	CURTIN AVE/AUSTRALIA AVE	HOPE VALLEY
NL234D 23509	150	GARLAND RD 21	NOARLUNGA DOWNS
HH496F 35250	150	BROOKLYN CHASE	GREENWITH
SA40 24198	150	ATKINSON DRV	BURTON
NL115C 33078	150	NASH LANE	MORPHETT VALE

GIS_ID	TF SIZES	ADD_STREET	ADD_SUBURB
HH148D TC831	150	WILLOWBRIDGE GR	STONYFELL
SA711C 15772	150	SHERWOOD CRES	PARALOWIE
HH107C 34629	150	MARKHAM ST	ENFIELD
HH145E 21811	150	WHITMORE ST	REDWOOD PARK
HH428E 32737	150	ACORN PDE	OAKDEN
SA20 15908	150	WEAVER BLVD	PARALOWIE
HH496G 31759	150	MARWICK CRT	GREENWITH
NL210E 17854	150	REDGUM PLACE	ABERFOYLE PARK
NL511B 17515	150	MILAN CR	HACKHAM WEST
MTB51 24138	150	GREVILLEA WAY	WOODSIDE
SA14 18657	150	DAMIAN DRV	SALISBURY HEIGHTS
MV15 31294	150	ABBOTT AVE	MCLAREN VALE
HH496G 31836	150	THORNTON DRV	GREENWITH
NL511B 17885	150	POZNAN CRES	HACKHAM WEST
HH496H 34614	150	CARRICK PLACE	GREENWITH
HH428B 32702	150	PARKVIEW AVE	OAKDEN
NL210D 23824	150	SERENADE CT 1	ABERFOYLE PARK
NL760C 16405	150	BIRCHENOUGH RD	HUNTFIELD HEIGHTS
NL511B 17516	150	MAXWELL RD (ITALIA CRT)	HACKHAM WEST
ME347A 32033	300	WILSON ST	HILTON
HH121D 1217	150	LORENZ ST	ATHELSTONE
NL451D TC45140	300	ISLINGTON ROAD	SHEIDOW PARK
HH121E 1050	150	KURRAJONG AVE	ATHELSTONE
SM410D 41	500	SALTRAM RD	GLENELG
HH177C 22012	200	MARY ALICE DRV	PARA HILLS
SA520A TC47996	300	AUGUSTINE ST	MAWSON LAKES
NL111B 16985	150	BLOCK 366 NADIA ST(EAST)	CHRISTIE DOWNS
SM349D 14376	150	DICKERSON CRES	TROTT PARK
NL115E 29819	150	LOT228 BYARDS RD/KNOX DRV	WOODCROFT
HH496E 33647	150	PERSIMMON GRV	GOLDEN GROVE
MV52 30812	150	KERNICK AVE	WILLUNGA
NL544B 29013	150	KARKO DRV	MOANA
MV15 16048	150	HEWITT DRV	MCLAREN VALE
NL451A 23113	150	KURRAMBIE CR	HALLETT COVE
NL115E 29017	150	DRESSAGE AVE	WOODCROFT
SA17 TC1083	150	PRIORY RD	SALISBURY EAST
NL210E 24462	150	PRIDHAM CRT	ABERFOYLE PARK
NL115E 35283	150	SHILLABEER CRS	WOODCROFT
NL210D 23825	150	IDLEWILD ST (NX47)	ABERFOYLE PARK
SA20 31340	150	DIGNAM DRV	PARALOWIE
SA13 24862	150	OSBORNE AVE	SALISBURY PLAIN
SA41 31114	150	PIAR ST	PARALOWIE

GIS_ID	TF SIZES	ADD_STREET	ADD_SUBURB
NL234D 23513	150	LYDIATE RD 7	NOARLUNGA DOWNS
NL210C 32953	150	SPRINGPARK CCT,OPP HUB SHOP	ABERFOYLE PARK
NL210E 17860	150	ABERFOYLE DRV (ON WOODLEA DRV)	ABERFOYLE PARK
HH403C 32441	150	FLORENCE ST	OAKDEN
GA745A 28919	150	LODGE CRT	WILLASTON
NL234C 35383	150	ALDER AVE	SEAFORD
NL511B 16470	150	GERMAINE ST	CHRISTIE DOWNS
NL234B 31348	150	BARBADOS DRV	SEAFORD RISE
ME131C 26093	150	BARKER ST	SOUTH PLYMPTON
HH496G 32331	150	TAMLYN CRT	GREENWITH
SM137B 30589	150	TROWBRIDGE AVE	MITCHELL PARK
SM126C 37033	150	MEADOW VALE RD	COROMANDEL VALLEY
SM126C 38178	150	KRISTEN CRT	COROMANDEL VALLEY
SM172C 23523	200	DAVID AVE	MITCHELL PARK
HH432F 21875	200	HARVEY ST	NAILSWORTH
HH341F 19314	200	QUEEN ST	NORWOOD
AP344E 14912	200	WELLINGTON RD	PORT ADELAIDE
HH121C 1226	150	TABITHA DRV	ATHELSTONE
SA520A TC46179	300	BIMINI CRES	MAWSON LAKES
MV64 TC42305	300	SEAHAVEN WAY	ALDINGA BEACH
AP132A 23134	200	ST VINCENT ST EAST	PORT ADELAIDE
EL02 17332	200	EDGECOMBE RD	DAVOREN PARK
NL111A 20708	150	GRETEL CR OP GENESA ST	HALLETT COVE
NL234E TC1394	150	CLEARWATER CRS RESERVE SEAFO	SEAFORD RISE
NL511B 18244	150	HAGEN ST	HACKHAM WEST
SA42 TC976	150	BOLIVIA CRES	PARALOWIE
SA31 32970	150	WILLOWBROOK BLVD	PARALOWIE
HH496G 31847	150	KINTYRE CRT	GREENWITH
HH496C 26079	150	SUMMERHILL CT ADJ 8	WYNN VALE
MV52 TC2366	150	RICHARDS	WILLUNGA
NL115F 14744	150	AVON AVE	MORPHETT VALE
HH121C 1237	150	CLARK CRS	PARADISE
NL111B 16988	150	GILES CRT WALKWAY	CHRISTIE DOWNS
MV64 TC46456	300	DOLPHIN BVD	ALDINGA BEACH
MV15 25937	150	VALLEY VIEW DRV	MCLAREN VALE
HH496H 28035	150	GILMORE CRT	GREENWITH
GA02 28053	150	CAUSBY CRES	WILLASTON
HH522A 14101	150	DEAKIN AVE	HOPE VALLEY
HH496D 30808	150	CHRISTIANA CRES	WYNN VALE
NL451E 16604	150	CAPRICE ST 15	HALLETT COVE
HH496D 28939	150	HAMPTON CRT:LOT 79	WYNN VALE
SA40 23561	150	HOPNER AVE NORTH	BURTON

GIS_ID	TF SIZES	ADD_STREET	ADD_SUBURB
HH496G 29016	150	CARDHA PL	GREENWITH
SA520D TC40037	300	LOMOND CCT	MAWSON LAKES
HH145B 18613	150	ZULEIKA ST	SURREY DOWNS
EL13 16189	150	MALTARA RD	MUNNO PARA
NL451A 23752	150	BARRAMUNDI DRV	HALLETT COVE
MV64 28067	150	ROWLEY RD	ALDINGA BEACH
NL544A 31878	150	WHITESTONE CRT OPP 4	SEAFORD RISE
SA18 14102	150	MARSHALL ST	SALISBURY EAST
NL544A 31392	150	BARBADOS DRV OP83	SEAFORD RISE
SA31 24711	150	FAIRBANKS DRV	PARALOWIE
SA41 30744	150	RODREGUEZ DRV	PARALOWIE
HH496D 36233	300	BELLEVUE CCT	PARA HILLS
NL451B 27925	150	LIGHTHOUSE DR OP24	HALLETT COVE
SA31 23323	150	MORDAUNT ST	PARAFIELD GARDENS
SM410C 27249	500	PATAWILYA GR	GLENELG SOUTH
NL210D 24839	150	JEANETTE CR 18	HAPPY VALLEY
HH121A 31749	150	OXFORD CCT	NEWTON
SM172F TC1502	300	MICHAEL DRV	SOUTH PLYMPTON
HH496D 31288	150	GOODWIN RESERVE	GREENWITH
HH341D TC42062	300	THIELE GROVE	KENSINGTON PARK
NL115B 27656	150	NATHAN CRT	MORPHETT VALE
HH107C 27286	150	PORTER CRES	ENFIELD
EL01M 6.10	300	ROW MC KENZIE RD & STAKES CR	ELIZABETH DOWNS
SM349D 23631	150	WESTALL WAY	SHEIDOW PARK
NL451D 28985	150	WORKMASTER AVE	SHEIDOW PARK
NL451D TC1263	150	SANDY GLASS CRT	SHEIDOW PARK
MV63 TC39430	300	QUINLIVEN RD	ALDINGA
HH102B 23156	300	WINDSOR GRV	WINDSOR GARDENS
SA520A TC41401	300	SANCTUARY DR	MAWSON LAKES
SA520E TC40030	300	POPLAR CRT	MAWSON LAKES
HH121A 1065	200	GLYNBURN RD	HECTORVILLE
NL760B 20792	200	BURKE ST	HACKHAM
AP125B 16063	200	FOTHERINGHAM DRV	NORTH HAVEN
NL234D 24601	200	KINGFISHER RD	NOARLUNGA DOWNS
HH121E 23479	150	ROCLIN AVE	NEWTON
NL210E TC39522	150	BUSHLAND DRV 4	ABERFOYLE PARK
SA11 14440	150	ALWYN ST	SALISBURY DOWNS
SA744D 15765	150	GERRARD AVE	PARALOWIE
HH403C 32760	150	ELMGLADE DRV	OAKDEN
NL760A 28075	150	FAILIE CRT	HUNTFIELD HEIGHTS
HH496C 26118	150	FOULIS CT 12	WYNN VALE
SA14 18143	150	CANTERBURY DR	SALISBURY HEIGHTS

GIS_ID	TF SIZES	ADD_STREET	ADD_SUBURB
NL115A 32337	150	MAWSON CT	WOODCROFT
HH496F 30598	150	DONOVAN ST	GREENWITH
SA18 34616	150	DAPHNE RD	SALISBURY EAST
HH428B 32766	150	ANNESLEY ST	OAKDEN
HH145A 16020	150	PELSAERT AVE	FAIRVIEW PARK
NL760C 17517	150	FLANDERS CRT	HACKHAM WEST
NL544A 31399	150	RESERVE SANTA CATALINA CRES SE	SEAFORD
NL451C 18492	150	LEE AVE	HAPPY VALLEY
GU42 34591	150	NOSKE CRT	LOBETHAL
HH496A 31030	150	BRUNSWICK TCE	WYNN VALE
NL544A 32462	150	PARKWOOD RISE	SEAFORD RISE
NL210E 23286	150	OPAL ST	ABERFOYLE PARK
NL544A 32464	150	PEBBLE BEACH GROVE	SEAFORD RISE
HH496F 31848	150	MC ARDLE PLACE	GREENWITH
NL115F 16097	150	BRODIE RD	MORPHETT VALE
NL115A TC646	150	HENDRIX DR	WOODCROFT
NL111P 28063	150	BRODIE RD/COMMODORE CRT	MORPHETT VALE
SA18 13228	150	MELVILLE RD	SALISBURY EAST
NL511B 17741	150	OSLO CRES	HACKHAM WEST
NL234A 30107	300	WARD ST	PORT NOARLUNGA
HH428E 35365	150	SALTRAM PDE	OAKDEN
GA22 TC41282	300	BRITHA AVE LOT 100	EVANSTON
NL511B 17744	150	BERGEN CRES/ HAMAR CRT	HACKHAM WEST
NL511B 23462	150	SELINA ST NO1 (EAST)	MORPHETT VALE
SA31 16976	150	SCHOLES AVE	PARAFIELD GARDENS
HH121A 30920	150	CROZIER AVE	NEWTON
SA11 14438	150	TANIA ST WALKWAY	SALISBURY NORTH
SA42 TC872	150	BOGART DRV	PARALOWIE
SA19 H46184	75	KARUNGA CRT	PARAFIELD GARDENS
SA744D 23311	150	DELAMERE DRV	PARALOWIE
SA42 24385	150	QUINN DRV	PARALOWIE
HH496C 28065	150	PANDORA CT	MODBURY HEIGHTS
HH428F 22031	150	YARALIN ST	KLEMZIG
EL13 16050	150	ALAWOONA RD	MUNNO PARA
SM126E 35390	150	WOOD LAKE DRV	CRAIGBURN FARM
EL09 TC1379	150	ASHWOOD BLVD	HILLBANK
HH386B 17594	300	DEVEREUX RD	BURNSIDE
53	200	RIDGE RD	PARA HILLS WEST 454
ME347B 31037	300	DARINGA ST	MILE END
HH428C 32522	300	CANDELL ST	WINDSOR GARDENS
HH145D 216	200	GRANDVIEW DR	TEA TREE GULLY
HH145A 15306	100	MOWBRAY CRES	FAIRVIEW PARK

GIS_ID	TF SIZES	ADD_STREET	ADD_SUBURB
HH496D 26159	100	FIRST FLEET CRT : OPP 6	WYNN VALE
ME200G 19939	200	HALMON AVE	EVERARD PARK
NL451D 32355	150	OAKBANK CRES & CURRANT CRT	SHEIDOW PARK
HH121C 1228	150	BRIDGET ST	ATHELSTONE
HH121C 1227	150	RIVER DRV	ATHELSTONE
EL01A 3.10	300	ROW NIMITZ RD & HORNET CR	ELIZABETH EAST
AP344A 21065	240	SHIP ST	PORT ADELAIDE
EL13 22781	150	MALTARRA RD	MUNNO PARA
GA50 24699	150	MULGA ST	GAWLER WEST
GA50 32765	150	ARGENT LANE	GAWLER WEST
HH522B 16975	150	MITTA ST	HIGHBURY
ME131B 18522	150	CLARK AVE	GLANDORE
NL234C 29736	150	AVOCET ST RESERVE	SEAFORD RISE
NL234E TC1532	150	CLEARWATER CRS RESERVE	SEAFORD RISE
SA18 31828	150	NORTHERN END KIEKEBUSCH RD	SALISBURY EAST
SA42 TC975	150	LIBERATOR DRV CNR NARINO	PARALOWIE
NL115E 29015	150	LOT 174 HORSESHOE DRV	WOODCROFT
NL21 33386	150	MAIN ST (OPP BAKERY)	CLARENDON
HH496G 28981	150	GOLDEN GROVE RD:LOT 22	GREENWITH
NL234D 33646	150	LIGURIA CRS	NOARLUNGA DOWNS
HH496D 27140	150	BENT CRT LOT 86	WYNN VALE
SA18 14997	150	BRABHAM CRES WALKWAY	SALISBURY EAST
NL234C 24434	150	CORVETTE RD OPP 65	MOANA
HH496F 32219	150	COBBLER DRV	GREENWITH
HH496D 28918	150	ST ANNES CRT	WYNN VALE
HH522C 27426	150	ADDOLORATA CRT	HIGHBURY
NL234B 32722	150	LYNTON TCE	SEAFORD
HH496C 25800	150	RAVEN CRT : OPP 20	WYNN VALE
SA14 30580	150	ST ALBANS DR	SALISBURY HEIGHTS
HH496F 30753	150	STILWELL CRT	GREENWITH
HH496A 15997	150	KURRAJONG ST	SURREY DOWNS
HH130E 15387	150	HEYSEN DRV	HOLDEN HILL
SA31 23280	150	SANDERSON RD	PARAFIELD GARDENS
NL115E TC1424	150	0	WOODCROFT
SA20 21812	150	WOODFIELD DRV	SALISBURY DOWNS
NL115A 28344	150	BANKS RD	WOODCROFT
NL451D 24656	150	BARTON DRV 1	TROTT PARK SOUTH
SA41 32330	150	ORINOCO ST	PARALOWIE
SA14 22448	150	MC EVOY DR	SALISBURY EAST
NL760C 16307	150	MELFORT RD	HUNTFIELD HEIGHTS
NL210D 23823	150	JULIE ST (OP6)	ABERFOYLE PARK
SA32 24388	150	BEGONIA CRT	PARAFIELD GARDENS

GIS_ID	TF SIZES	ADD_STREET	ADD_SUBURB
NL210E 17850	150	BANKSIA RD	ABERFOYLE PARK
HH496A 15996	150	KURRALI ST	SURREY DOWNS
SA32 24386	150	VERBENA DRV	PARAFIELD GARDENS
HH522A 16732	150	DOXIADIS ST	ST AGNES
HH496F 31386	150	PARKER CRT	GREENWITH
NL111P 24185	150	COODER CRES 2(NTH)	MORPHETT VALE
HH496G 29025	200	DEBENHAM CRT	GREENWITH
NL544A TC41226	300	KESTREL CCT	SEAFORD RISE

49. APPENDIX W

VOLTAGE REGULATION PROJECT ESTIMATED COSTS

Add remote voltage set point control

Set Up Costs (incl training, NOC)	20000
System design	24000
ADMS algorithm	10000
network total	54000
Testing	10000
ADMS mods	20000
AVR changes	33000
Recommissioning	10000
telecomm/SCADA link	35000
field services total	108000
Sub-Total	70000
network overhead	10800
field services overhead	27000
Total	**$ 199,800**

HV Substation Pole Top Voltage Regulator

network design	8000
network facilities	5000
network total	13000
3 can VR with CL6 controller install	47265
CL6 controller install	10000
stobie pole(s) install	15000
telecomm/SCADA link	35000
field services total	107265
network overhead	2600
field services overhead	26816
Total	**$ 149,681**

Retrofit SCADA to line HVR

network design	4000
network facilities	1000
network total	5000
telecomm/SCADA link	35000
field services total	35000
network overhead	1000
field services overhead	8750
Total	**$ 49,750**

50. APPENDIX X

TRANSFORMER MONITORING ESTIMATED COSTS

Transformer Monitoring Costs in $2013		Pole Top				Padmount	
		1 Circuit		SWER Isolating TF		1 Circuit	
Product/Service	**Unit Cost**	Qty	Cost	Qty	Cost	Qty	Cost
1ATiQ-P4							
1ATiQ-P4	$ 760.00						
Cellular Modem, GSM/GPRS class 10	$ 266.00	1	$ 266.00	1	$ 266.00	1	$ 266.00
MPA (Indicative costs only)							
1 Circuit 3G	$ 760.00	1	$ 760.00			1	$ 760.00
SWER	$ 760.00			1	$ 760.00		
Unit Labels	$ 5.00	1	$ 5.00	1	$ 5.00	1	$ 5.00
Mounting							
Banana Plug Fused Attachment	$ 195.00	1	$ 195.00	1	$ 195.00	1	$ 195.00
Magnetic Mounting, 75lb-pull, encapsulated	$ 30.00	1	$ 30.00	1	$ 30.00	1	$ 30.00
Temperature Sensor, 100 Ohm pt, 2 m lead, wtr prf conn	$ 90.00					1	$ 90.00
Rogowski Coils and hardware							
Flexible CT , 4 inch diam, 2m lead (no switching)	$ 210.00	3	$ 630.00	1	$ 210.00	3	$ 630.00
MONITORING EQUIPMENT SUBTOTAL			**$ 1,886.00**		**$ 1,466.00**		**$ 1,976.00**
Freight	$ 60.00	1	$ 60.00	1	$ 60.00	**1**	$ 60.00
ADDITIONAL EXPENSES			**$ 60.00**		**$ 60.00**		**$ 60.00**
Field Services							
Labour	$ 89.93						
Travel time (2 Man Crew + Vehicle)	$ 379.86	0.5	$ 189.93	2	$ 759.72	0.5	$ 189.93
Installation Time (2 Man Crew + Vehicle)	$ 289.93	1	$ 289.93	1	$ 289.93	1	$ 289.93
FIELD SERVICES INSTALLATION SUBTOTAL			**$ 479.86**		**$ 1,049.65**		**$ 479.86**
Network Management							
Labour	$ 88.00	0.5	$ 44.00	0.5	$ 44.00	0.5	$ 44.00
PROJECT MANAGEMENT SUBTOTAL			**$ 44.00**		**$ 44.00**		**$ 44.00**
Overheads							
Field Services	25%		$ 606.47		$ 643.91		$ 628.97
Network Management	20%		$ 8.80		$ 8.80		$ 8.80

Transformer Monitoring Costs in $2013		Pole Top				Padmount	
OVERHEADS SUBTOTAL			**$ 615.27**		**$ 652.71**		**$ 637.77**
Discount 10%	10%	1	-$ 188.60	1	-$ 146.60	**1**	-$ 197.60
Add Opex costs			302.9		302.9		302.9
	TOTAL		**$ 3,388.03**		**$ 3,575.26**		**$ 3,500.53**

51. APPENDIX Y

MINOR WORKS CAPEX - Install or upgrade road crossing and over/under service

labour	$ 89.93			
customer notifying	$ 179.86		1.5	$ 269.79
travelling	$ 179.86		3	$ 539.58
switching	$ 179.86		0.4	$ 71.94
install	$ 179.86		4	$ 719.44
material & vehicle	$ 2,200.00		1	$ 2,200.00
				$ 3,800.75
FS overhead		25%		$ 950.19
NM overhead		20%		$ 760.15
				$ 1,710.34
Total				$ 5,511.09
			Round up	**$5,520**

52. APPENDIX Z

Replace inline HVR with bi-directional HVR (with CL6 controller SCADA connected)

network design	500
network facilities	500
network total	1000
3 can VR with CL6 controller install	45000
telecomm/SCADA link	30000
field services total	75000
network overhead	200
field services overhead	18750
Total	**$94,950**
Total capex required for 15 units	**$1,424,250**

SWER HVR (single phase 19kV)

network design	500
network facilities	500
network total	1000
1 can VR with CL6 controller install	15500
telecomm/SCADA link	30000
field services total	45500
network overhead	200
field services overhead	11375
Total	**$58,075**
Total capex required for 10 units	**$580,750**

53. APPENDIX AA

SWER Isolating Transformer and Recloser Upgrades

ER Remediation	Feeder	Recloser	Cap (kVA)	Cap (A)	Peak Load (A)	Peak Load (%)	Peak Load Test Date	Solution	2015/16	2016/17	2017/18	2018/19	2019/20
								Funding Required	**$1,815,000**	**$1,482,200**	**$1,400,000**	**$1,400,000**	**$1,400,000**
WATTS GULLY 19kV SWER	GU16	R4756	100	5	7.8	156	12/07/2011	upgrade TF/recloser		100000			
LAKE ELIZA 19kV SWER	MI15	R4013	150	8	12	150	8/05/2014	upgrade TF/recloser		100000			
KULKAMI 19kV SWER	LM32	R4152	150	8	11.5	144	1/05/2014	upgrade TF/recloser		100000			
LAMEROO 19kV SWER	LM51	R4124	150	8	11.3	141	1/05/2014	upgrade TF/recloser		100000			
SPRINGTON 19kV SWER	GU34	R4363	150	8	11	138	19/03/2013	upgrade TF/recloser		100000			
BUTE NO 2 19kV SWER	KA17	R4225	150	8	10.7	134	29/03/2011	upgrade TF/recloser		100000			
HART 19kV SWER	CL12	R4241	150	8	10.6	133	30/03/2011	upgrade TF/recloser		100000			
HASLAM 19kV SWER	SB15	R4406	150	8	10.5	131	7/03/2012	upgrade TF/recloser		100000			
RIVERTON 19kV SWER	R05	R4188	150	8	10.5	130	30/03/2011	upgrade TF/recloser		100000			
BURGOYNE 19kV SWER	CD22	R5086	150	8	10.4	130	6/03/2012	upgrade TF/recloser		100000			
TAILEM BEND 19kV SWER	MB65	R4792	150	7	9	129	14/04/2014	upgrade TF/recloser		100000			
POINT LOWLY 19kV SWER	WHY14	R4620	150	8	10.1	126	9/03/2012	upgrade TF/recloser		100000			
WILD HORSE PLAINS 19kV	GA36	R4157	150	8	10	125	28/03/2013	upgrade TF/recloser			100000		
BENARA 19kV SWER	MG33	R4373	150	8	10	125	7/05/2014	upgrade TF/recloser			100000		
MOORLANDS 19kV SWER	MB01	R4608	150	8	10	125	10/04/2014	upgrade TF/recloser			100000		
SHERLOCK 19kV SWER	MB03	R4232	150	8	10	125	10/04/2014	upgrade TF/recloser			100000		
BELLUM 19kV SWER	MG31	R4026	150	8	10	125	7/05/2014	upgrade TF/recloser			100000		
MAYURRA 19kV SWER	MI03	R4311	150	8	10	125	7/05/2014	upgrade TF/recloser			100000		
DUNCAN 19kV SWER	KI53	R4148	150	8	10	125	21/05/2014	upgrade TF/recloser			100000		
NINNES 19kV SWER	KA21	R4226	150	8	9.9	124	29/03/2011	upgrade TF/recloser			100000		

ER Remediation	Feeder	Recloser	Cap (kVA)	Cap (A)	Peak Load (A)	Peak Load (%)	Peak Load Test Date	Solution	2015/16	2016/17	2017/18	2018/19	2019/20
LAKE ORMEROD SWER	NA22	R4037	150	8	9.3	116	29/02/2012	upgrade TF/recloser			100000		
PALLAMANA 19kV SWER	MB25	R4619	150	8	9.2	115	20/03/2012	upgrade TF/recloser			100000		
PIRIE 19kV SWER	PP16	R4257	150	8	9.2	115	26/03/2012	upgrade TF/recloser				100000	
MUNDOORA NO 2 SWER	KA20	R4231	150	8	9.1	114	29/03/2011	upgrade TF/recloser				100000	
CAPE JAFFA SWER	NA59	R4351	150	8	9.4	113	02/01/2012	upgrade TF/recloser				100000	
CRANEFORD 19kV SWER	GU35	R4228	150	8	9	113	19/03/2013	upgrade TF/recloser				100000	
SETTLERS ROAD 19kV SWER	MG49	R5073	150	8	9	113	19/12/2011	upgrade TF/recloser				100000	
LINWOOD 19kV SWER	GA35	R4628	150	8	9	113	20/03/2013	upgrade TF/recloser				100000	
PINERY 19kV SWER	R26	R4201	150	8	9	113	20/03/2013	upgrade TF/recloser				100000	
MIDDLE BEACH 19kV SWER	GA45	R4112	150	8	9	113	28/03/2013	upgrade TF/recloser				100000	
SHOAL BAY 19kV SWER	KI45	R4247	150	8	9	113	16/01/2014	upgrade TF/recloser				100000	
SETTLERS ROAD 19kV SWER	MG49	R5073	150	8	9	113	19/12/2013	upgrade TF/recloser				100000	
GERANIUM 19kV SWER	LM14	R4154	150	8	9	113	2/02/2014	upgrade TF/recloser				100000	
WYNARKA 19kV SWER	MB02	R4234	150	8	9	113	1/02/2014	upgrade TF/recloser				100000	
COLEBATCH 19kV SWER	CN74	R4127	150	8	8.9	111	29/02/2012	upgrade TF/recloser				100000	
MORTLOCK 19kV SWER	CM29	R4706	150	8	8.8	110	20/03/2012	upgrade TF/recloser				100000	
ELBOW HILL 19kV SWER	CV26	R4069	100	5	5.5	110	19/02/2009	upgrade TF/recloser					100000
WIRRULLA SOUTH SWER	SB18	R4488	100	5	5.5	110	6/03/2012	upgrade TF/recloser					100000

54. APPENDIX AB

SWER split and 11kV conversion (not listed in the above table)

SWER Remediation	Feeder	Recloser	Cap (kVA)	Cap (A)	Peak Load (A)	Peak Load (%)	Peak Load Test Date	Solution	2015/16	2016/17	2017/18	2018/19	2019/20
MAKIN 19kV SWER	BT23	R4025	150	8	12.3	154	11/01/2010	11kV extn/split SWER	1500000				
LAKE BONNEY 19kV SWER	MI17	R4301	150	8	10.3	129	23/01/2012	11kV extn/split SWER	315000				
GOODE 19kV SWER	CD17	R4438	150	8	9.4	120	24/02/2012	Split SWER		282200			
WEETULTA 19kV SWER	MT02	R4206	200	12	14	117	03/01/2013	Split SWER					400000
DUBLIN TOWNSHIP SWER	GA24	R5048	200	12	14	117	17/01/2013	11kV conversion			400000		
ELWOMPLE 19kV SWER	MB64	R4609	200	12	10.4	87	25/02/2012	Split SWER					400000
PORT PARHAM TOWNSHIP	GA17		150	8	6	75	18/02/2013	11kV conversion					400000

55. APPENDIX AC

Additional Projects in addition to the Remediation Program above

SWER Conversion to 11kV	Feeder	Recloser	Cap (kVA)	Cap (A)	Peak Load (A)	Peak Load (%)	Peak Load Test Date	Solution	2015/16	2016/17	2017/18	2018/19	2019/20
PORT NEILL TOWNSHIP	CM20		150	8	10	125	27/03/2013	11kV conversion	2000000	2000000	500000		

56. APPENDIX AC – STRATEGIC LV MONITORING BUSINESS CASE

Executive Summary

This business case recommends the proposal to install long term transformer power quality monitoring in strategic locations and parts of the electricity distribution network. It estimates the costs ($8M over 5 years) and states the important benefits to customers by enabling a bi-directional network.

The problem:

1. Lack of adequate LV network power quality monitoring (visibility) resulting in reactive, costly remediation and increasing dissatisfied customers installing new technologies, that do not adequately work under all network operating conditions.
2. Customers believe and expect that SA Power Networks operate a network fit for the purpose customers require and that they will receive the full benefits of their new technologies.
3. SA Power Networks must demonstrate compliance with Regulatory obligations.

Key discussion points:

- The LV network is important to customers (where they connect loads, such as air conditioners, electric vehicle chargers and the connection of distributed energy generation resources such as solar PV and energy storage).
- SA Power Networks have more solar embedded generation (solar PV) than any other State. It is expected that the penetration of solar PV will continue to impact the LV network. This is based on Energeia (consultant's report) and regulatory modelling (60 to 80MW per year added).
- Some of the benefits only benefit specific customer groups or future customer groups (such as solar PV customers) however SA Power Networks propose that all SA customers fund these benefits in line with the shared network available.
- 2013 stakeholder engagement workshops held to garner customer's views - customers regard a bi-directional network as essential for their new and future technologies.
- Network was historically designed for uni-directional power (central power station to customer)
- Network must be fit for purpose – the future network must be designed for bi-directional power flows and operated to enable new customer technologies (solar PV, energy storage, electric vehicle chargers).
- Customers make power quality complaints when their supply is not fit for purpose – leads to increased opex for short term testing and supply issue remediation.
- SA Power Networks obligated to comply with AS60038 – Voltage Levels.
- To resolve power quality issues there is a need to measure load and voltage levels in low voltage networks – measure at the supply transformer and individual customer.
- If you can measure something (load and voltage testing) you can manage it.
- Transformer load and voltage monitoring is in line with Australian Distribution Network Service Provider industry practice.
- Network investment must be based on actual measurements not inferred by calculation (assumed customer load profiles).

Customer Benefits:

- Transformer monitoring enables timely capex resulting in less customer outages from LV transformer fuse operations and transformer failures.
- Transformer monitoring enables improved, timely response to customer enquiries and efficient resolution of customer quality of supply issues.
- Transformer monitoring enables the provision of a bi-directional network to accommodate new customer technologies.
- Transformer monitoring enables improved customer service – less appliance damage claims, improved distributed energy resource operation.

Proposal and Costs (Table 1):

- It is proposed to purchase and install 1,985 monitors for long term transformer monitoring that are advanced distribution management system (ADMS) compatible with 3G telecommunications enabling remote data downloading.
- New LV monitors will be installed on metropolitan pad mounted transformers, some specific metro pole mounted transformers and some country, including SWER, transformers.
- The estimated total capital cost for the purchase of remote monitoring installations over the 5 year regulatory period 2015-2020 is $8M resulting in customer benefits of $14.96M in 2013 dollars in NPV terms. Capital expenditure evaluations over the asset's 10 year life for each proposal along with some explanatory notes are in the Attachments to this business case. The sites selected for the monitors are in the Attachments in the relevant Asset Management Plan.
- This Strategic Transformer Monitoring Business Case is in 5 distinct parts (Monitor Allocations). Table 1 below shows the breakdown of installed monitors numbers and total costs each year with average unit costs.

Monitor Allocation	2015/16	2016/17	2017/18	2018/19	2019/20	Ave unit cost ($)	Total Program ($M)
SWER (start & EOL) – 740 LV monitors	76	166	166	166	166	3,600	2.66
Country substations - non SCADA – 65 HV monitors	5	15	15	15	15	15,000	1.10
Country feeders EOL – 460 LV monitors	48	103	103	103	103	3,600	1.65
Metro feeders EOL – 85 LV monitors	9	19	19	19	19	3,600	0.31
Metro pad mount transformers – 635 LV monitors	63	143	143	143	143	3,600	2.30
Monitoring Capital Costs ($M)	**1.03**	**1.71**	**1.76**	**1.76**	**1.76**		**8.02**

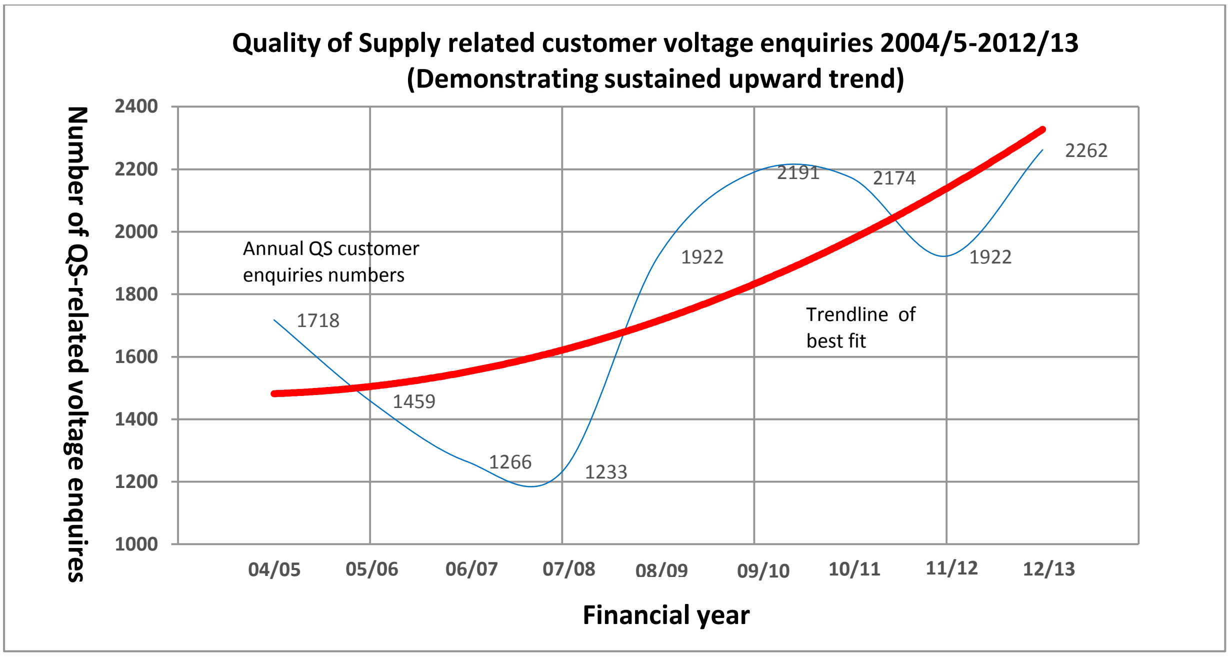
Table 1

Background

The SA Electricity Distribution Code (EDC) obligates SA Power Networks to comply with the voltage levels in AS60038. These are a nominal 230V phase to neutral and 400V phase to phase plus 10% (253V and 440V) and minus 6% (216V and 376V). There are several other Supply Standards SA Power Networks must comply with notably – voltage unbalance (LV - 2%, HV – 1%) and THD – total harmonic distortion (of the waveform). The most significant customer enquiry issue pertaining to the increase in customer solar installations is the rise in network voltages caused by solar energy exported from customer's solar PV installations into the LV network. When the rise in voltage exceeds the solar PV inverter set point the inverter disconnects and does not allow energy export. Customers lose the feed in tariff benefit of their potential exported energy.

Although we have a SCADA system to monitor a large proportion of our major HV assets, we have not historically monitored the LV network. Historically, SA Power Networks has relied on customers to enquire about unacceptable power quality before SA Power Networks undertake short term load and voltage tests to confirm customer's enquiries relating to power quality and these can number 150 per month on average to our Call Centre. A significant proportion of these enquiries are from country customers. Customer Stakeholder Workshops indicate that it is no longer generally acceptable that SA Power Networks reactively respond to customer supply quality enquiries. A greater pro-active approach is needed and to achieve this it is proposed to use strategic long term transformer monitoring to improve power quality visibility within the LV network. The more transformers with power quality monitors, the better the power quality will be. All expenditure must continue to be based on actual measured test results from either short term or long term monitoring of transformer and customer service point load and voltage.

Graph 1 below indicates the sustained increase in quality of supply related customer enquiries. It is expected that the installation of strategically continuous remotely downloadable long term load and voltage transformer monitoring will reduce the upward trend in customer enquiries. Customer enquiries will continue to rise due to the increasing continuing penetration of new customer technologies (eg solar PV, energy storage) requiring the provision of local two way networks. Where existing networks are not supporting two way power flows, some new customer technologies may not operate under all network conditions, resulting in customer enquiries eg PV related high voltage.



Graph 1

New low cost remotely downloadable monitoring devices are now available and their deployment across the LV network will significantly improve our Regulatory compliance and optimum pro-active LV network management with the benefit of improved customer quality of supply. These devices will monitor load and voltage levels in each phase, phase imbalance and capture any significant supply interference or variation. Without this monitoring we cannot determine general on-going compliance to the Electricity Distribution Code.

In addition, QS propose to enable the SCADA function, where it is fitted to existing HV voltage regulators (HVR) and to new HVR plant to assist QS monitoring and depot knowledge of voltage regulation – voltage regulator operational status on country feeders. Pro-actively remediating non-compliant voltage levels by LV monitoring and understanding/monitoring the status of HVR plant will significantly reduce the level of power quality customer enquiries made to our Call Centres.

SA Power Networks has an obligation to maintain supply voltage at customer premises within the range specified in AS60038. Historically, this has been achieved without any active monitoring of voltage in the LV network; in a one-way distribution network, voltage at the customer premises can normally be predicted to the required accuracy from known voltage at a major upstream network asset like a substation. We have so far employed a reactive approach to managing occasional customer power quality issues, in which we deploy temporary local monitoring in the LV network in areas where customers have raised complaints about power quality, and this has served us well.

Today, however, we operate a two-way grid, with more than 160,000 small-scale intermittent generators in the form of rooftop solar PV systems connected at the LV network. This is causing significant localised swings in voltage that cannot be detected at the substation. As the penetration of distributed energy resources continues to rise, there is the potential for voltage excursions outside of the allowed range across many parts of the network in the near future.

In this environment, a reactive approach is no longer prudent. If we are to continue to enable customers to connect solar PV and other embedded generation to the LV network and export energy to the grid while maintaining power quality standards, we need the capability to actively monitor power quality (PQ) in the LV network.

In order to assess the potential extent of this issue, SA Power Networks engaged consultant PSC in 2014 to model the impact of increasing penetration of solar PV and other distributed energy resources on quality of supply at the customer premises. The study modelled fifteen typical feeders representing a cross-section of categories of supply area including underground LV, overhead LV and SWER, and applied the findings to estimate the likelihood of future power quality issues across the whole network.

The PSC study found that across older areas of the LV network, existing network infrastructure and voltage regulation approaches limit acceptable solar PV penetration to around 25% of customers.

Currently, the penetration of solar PV is more than 22% of all households, and is forecast to rise further to 40% by 2020 and more than 50% by 2025. These forecasts are for penetration averaged across the network; penetration in a local feeder area can be significantly higher. PSC's findings indicate that many older feeders are already at tipping point in terms of acceptable solar PV penetration and, without improved voltage regulation; many parts of the network may be unable to accommodate forecast increases in solar PV during the 2015-20 period without triggering widespread customer power quality issues. These may include customer-visible fluctuations in voltage, increased failure rate of customer appliances, and customers' solar inverters tripping off the network due to overvoltage on mild sunny days, reducing the benefits they receive from feed-in tariffs.

PSC's study also examined mitigation strategies, concluding that:

"HV substation voltage regulation can be used, in most instances, to overcome voltage regulation issues provided that the voltage regulation range of the LV network is known. Changes to transformer tap settings (where available) or reconductoring feeder backbones may be sufficient to enable substantial increases in acceptable DER penetration levels.
Feeder load balancing and controllable load are also effective, provided that the HV voltage can be kept in the lower half of its usual range – that is, (i) the full LV network operates at a lower voltage, and (ii) the HV voltage is managed to avoid introducing voltage regulation violations under peak demand."

The modelling indicates that in many cases power quality issues can be mitigated by relatively simple means, eg voltage regulation at zone substations or tap changes at transformers, but the key element that is missing today is any visibility of actual power quality across the vast majority of the LV network. Although we may have the means to address issues, we are effectively blind to where those issues are emerging until such time as customers call in to complain. Moreover, without a way to monitor power quality at the premises we have no means to close the loop and measure the effect of any remedial action to confirm that it has been successful.

Strategic Transformer Monitoring Proposal

The benefit of HV and LV network transformer long term monitoring is to optimise the future quality of supply expenditure and ensure best value for money for our customers. At the end of the 5 year program the following specific installations are proposed. Listed in the Attachments are capital expenditure evaluations and explanatory notes for each proposal:

- SWER (start & end of line) – 740 LV monitors
  SWER systems are long single phase networks, with 3 strands/12 gauge steel or 3/10 alumoweld conductor, in rural locations generally supplied via SWER isolating transformers from 33kV or 11kV networks. There are 430 SWER systems in SA. SWERs are generally considered weak networks (max capacity 150/200kVA) with limitations for customer connections - up to 25kVA load per connection and up to 5kW of generation connection. These limitations are due to the voltage fluctuations expected. SA Power Networks has no knowledge of the real time HV and LV voltage levels on these rural and remote SWER networks. To ensure maintenance of compliance with Statutory voltage obligations (AS60038) we propose to install 740 long term LV monitors at selected SWER isolating transformers and at the end of the SWER line, this may be in more than one location. The benefit of these LV monitoring installations is greater visibility of voltage levels, Electricity Distribution Code compliance (AS60038), assist enabling a two way network with improved customer service.
- Country substations/feeders - non SCADA – 65 HV monitors
  Most of the SA Power Networks substations have SCADA for HV assets or will have SCADA in the next 5 to 10 years (refer SCADA roll out program and plan). However HV/HV transformers which do not have a substation switching diagram (typically transformers less than 1MVA) do not have SCADA. It is proposed to install HV monitors at substations not planned to be covered by SCADA. We have no knowledge of the real time HV voltage levels on these rural networks. The benefit of these HV monitoring installations is greater visibility of voltage levels, Electricity Distribution Code compliance (AS60038), assist enabling a two way network and improved customer service.
- Country feeders EOL – 460 LV monitors
  QS have no knowledge of the real time voltage levels on our rural feeders – worst case is at the end of the line (EOL). Many of our feeders have line voltage regulators however we have no visibility whether these are in service. This can sometimes cause field crews to suspect local issues and undertake voltage tests when in fact the voltage issues are caused by a line regulator that is out of service. As a consequence of this lack of voltage level visibility we cannot ensure maintenance of compliance with statutory voltage obligations (AS60038). QS propose to install long term LV monitors at selected end of line locations on feeders that may have quality of supply and two way network issues. The benefit of these LV monitoring installations is greater visibility of voltage levels, Electricity Distribution Code compliance (AS60038), assist enabling a two way network and improved customer service.
- Metro feeders EOL – 85 LV monitors
  It is proposed to install remote substation bus voltage set point control using SCADA at 20 selected metro substations with high solar PV penetrations. To determine voltage levels are compliant with Standards at the end of the feeders (worst case), connected to the selected substations with remote voltage set point control, QS propose to install LV monitors. These are check monitors to indicate the veracity of our remote substation bus voltage set point control substation selections. The benefit of these LV monitoring

installations is greater visibility of voltage levels, Electricity Distribution Code compliance (AS60038), assist enabling a two way network on high PV penetration feeders and improved customer service.

- Metro pad mount (ground level) transformers – 635 LV monitors
  Remediating pad mount transformers is costly and time consuming. The timing of this capital expenditure is critical – unplanned work is less cost efficient than planned work. QS have selected 635 pad mounted transformers out of the total of 7,270 pad mounts in the metro area, because they are greater than 100kVA capacity with multi customer connections and have solar PV and with a calculated peak loading of greater than 100% of the transformer nameplate normal rating in 2014. These transformers variously have one and up to four LV circuits.

By 2020 it is planned to have 1,985 permanently installed power quality data monitors that are ADMS compatible in a Transformer Monitoring Data Management system. The data from these will be polled by IP addresses and uploaded to an SA Power Networks owned secure virtual server. A program will be run over this data to identify planning threshold breaches eg loads over 130% and voltages over 253V or LV unbalance greater than 2% sustained for more than 1 minute. These can be shown on an office screen for general visibility and appear on responsible officer's (QS Analysts) desktop screens. The main users of this data are QS Analysts and Distribution Planning Engineers.

The data storage requirement is approximately 31GB per year or 155GB over 5 years.

	Number of monitors	Data per unit/month	Total Data per month	Total Data per year	Total Data 5 years
HV FEEDER	65	1.4MB	91.0MB	1.09GB	5.5GB
LV SWER	740	566kB	486.76MB	5.84GB	29.2GB
LV COUNTRY FEEDER EOL	460	1.7MB	783.7MB	9.4GB	47.0GB
LV METRO EOL	85	1.7MB	144.5MB	1.73GB	8.7GB
PAD MOUNT LV	635	1.7MB	1.08GB	12.95GB	64.7GB
TOTAL				**31GB**	**155GB**

Table 2

Considered Options:

Option 1 – Do nothing

The status quo at present is no visibility of voltage levels and the general quality of supply available to customers. This means SA Power Networks cannot adequately manage the LV network and ensure compliance with the Electricity Distribution Code (AS60038) requirements. SA Power Networks respond to customer power quality enquiries. Customers enquire about voltage levels, inoperable solar PV systems, plant and equipment damage allegedly from voltage variations outside of Standard voltages. The (reactive) response includes a short term load and voltage test and network remediation where required. Power quality enquiries are trending upwards (refer graph 1) and the continued uptake of customer technologies within a network not designed for two way power flows means customer enquiries will continue, and potentially, the upward trend will increase if nothing changes.

Option 2 – Short term testing

Currently SA Power Networks responds to customer power quality enquiries with a short term test. Similarly, where it is believed assets may be overloaded under peak loading conditions a short term test (survey) is conducted and the results factored up to simulate a test done during peak loading conditions, usually hot weather. Due to the low number of testing devices (253) and the number of supply transformers (73,500) it is not possible to adequately manage the LV network using a short term testing approach. This approach introduces inaccuracies in results, due to the factoring up approach and may lead to inappropriate or poor timing of capital expenditure.

Option 3 – Long term monitoring – recommended option

It is proposed to commence investment in long term transformer monitoring, initially installing 1,985 monitors at strategic supply transformer sites. The real time monitoring results will enable improved Distribution Code compliance, power quality level visibility, where there is none at present and assisting enabling a two way power flow network for the efficient operation of customer new technologies. Long term monitoring is consistent with the national approach to this issue and is supported by customers at recent Stakeholder Workshops.

Project Costs

The average unit installed costs for long term, remotely downloadable load and voltage recording monitors are assumed, for the financial analysis of this proposal, as generally $3,600 for LV monitors and $15,000 for HV monitors (also refer Attachment F). This is an overall installed cost that includes labour, materials, travel, vehicles and overheads on both Network and Field Services components.

Recurring operating costs – Telstra charge $10 per SIM card per month. It is assumed the annual costs will be $120 multiplied the number of monitoring units installed.

Projects Benefits

Generally the benefits include:

- more timely optimal capital expenditure – triggering upgrade solutions when actual measured demand exceeds planning criteria
- greater visibility of voltage levels for compliance with regulatory obligations eg Electricity Distribution Code (AS60038)
- assist enabling a two way network for customer's new technologies
- assist to provide an improved quality of supply and customer service with less voltage enquiries

<u>Avoided transformer testing (travel, vehicle, install)</u>

Long term transformer monitoring should obviate the need for short term transformer testing at specific supply transformers hence representing a potential opex saving. Short term tests require 2 site trips for a crew of 2 and a suitably equipped vehicle. It has been assumed that 10% of the long term monitoring installation costs represents the avoidable short term test costs to respond to customer enquiries or pro-active (survey) tests. Due to the likelihood of monitors installed coinciding with customer enquiries or survey tests being low, 10% was chosen as a possible credible co-incidence factor. We have also assumed zero in the first 2 years due to the small number of monitor installations. The opex savings accumulate with more installations each year until year 5 where they remain at year 5 levels for the evaluation period. The calculations (refer Attachment F) are:

- SWER (start & EOL) – 740 LV Monitors
  2 trips on/off for travel time (2 men + vehicle, average 2 hours @ $380) + install time (2 men + vehicle, average 1 hour @ $290) for 10% of 76 units installed in Yr3 = $0.09M. Each further year up to Yr5 adds 10% (assumed cost avoidance) of 166 units Yr2 to Yr5 to the potential savings.

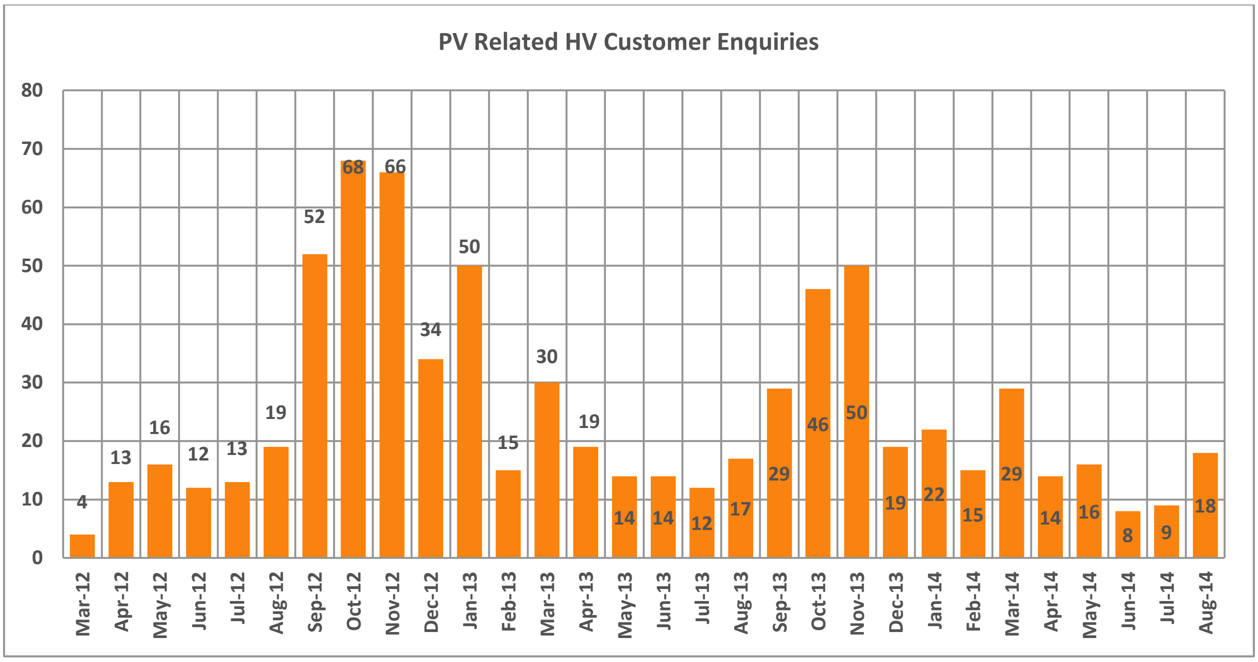
eg. (2trips*(10%*76monitors*(2 men + vehicle, average 2 hours @ $380) + install time (2 men + vehicle, average 1 hour @ $290))

- Country substations - non SCADA – 65 HV Monitors
  2 trips on/off for travel time (2 men + vehicle, average 2 hours @ $380) + install time (2 men + vehicle, average 1 hour @ $290) for 10% of 5 units installed in Yr3 = $0.007M. Each further year up to Yr5 adds 10% (assumed cost avoidance) of 15 units to the potential savings.
- Country feeders EOL – 460 LV Monitors
  2 trips on/off for travel time (2 men + vehicle, average 2 hours @ $380) + install time (2 men + vehicle, average 1 hour @ $290) for 10% of 48 units installed in Yr3 = $0.05M. Each further year up to Yr5 adds 10% (assumed cost avoidance) of 103 units to the potential savings.
- Metro feeders EOL – 85 LV Monitors
  2 trips on/off for travel time (2 men + vehicle, average 0.5 hours @ $190) + install time (2 men + vehicle, average 1 hour @ $290) for 10% of 9 units installed in Yr3 = $0.004M. Each further year up to Yr5 adds 10% (assumed cost avoidance) of 19 units to the potential savings.
- Metro pad mount transformers – 635 LV monitors
  2 trips on/off for travel time (2 men + vehicle, average 0.5 hours @ $190) + install time (2 men + vehicle, average 1 hour @ $290) for 10% of 63 units installed in Yr3 = $0.03M. Each further year up to Yr5 adds 10% (assumed cost avoidance) of 143 units to the potential savings.

<u>Reduced customer enquiries</u>

It is assumed that by assisting enabling a two way power flow network by monitoring and pro-actively remediating voltages outside of AS60038 voltage levels customer service levels will improve and customer power quality enquiries will be reduced. The annual cost of customer service, is assumed to be in these circumstances $10,000 and the improvement increases by one $10,000 potential saving per year over the transformer monitoring installation period (5 years) and is then maintained.

SA Power Networks received 150 customer enquiries per month on average. Between January 2013 and January 2014, 340 customer-enquiries concerning high voltage related to solar PV installations were referred to Network Quality of Supply for investigation and remediation (refer Graph 2 below). Voltages are confirmed by testing at the customer's service point, and where voltage levels are above 253V, without taking into account the additional voltage rise caused by PV, SA Power Networks is obligated to maintain the voltage level to within AS60038 levels. Transformer monitoring will assist to reduce customer enquiries in general and maintain a two way power flow network.



Graph 2

<u>Customer benefit - Improved PVI operation with standard voltages</u>

Greater visibility of the LV network voltage levels will assist enabling a two way power flow network and allow customer solar PV installations (inverters) to operate more often and under a greater number of network operating conditions. This improves with the annual increase in the number of transformer monitor installations and is maintained at the same level beyond year 5. The calculations are as follows:

- SWER (start & EOL) – 740 LV monitors
  It is assumed that each SWER transformer monitor has an average of 5 connected customers with 20% penetration of solar PV ie one in five customers have solar PV. By maintained standard network voltages to AS60038 voltage levels it has been assumed that each PV customer (average 5kW PVI) will save the loss of the FiT (feed in tariff) for 2 hours which is assumed at a minimum 10c/kWh (Retailer FiT) at least 10 times per annum. The Yr 3 calculation is as follows:

  (76+166+166units) x 5customers/transformer x 20% PV customers x 2 hours overvoltage x 5kW PVI x 10c/kWh x 10 times /year
- Country substations - non SCADA – 65 HV monitors
  It is assumed that each transformer monitor has an average of 50 connected customers with 20% penetration of solar PV ie one in five customers have solar PV. By maintained standard network voltages to AS60038 voltage levels it has been assumed that each PV customer (average 5kW PVI) will save the loss of the FiT (feed in tariff) for 2 hours which is assumed at a minimum 10c/kWh (Retailer FiT) at least 10 times per annum. The Yr 3 calculation is as follows:

  (5+15+15units) x 50customers/substation transformer x 20% PV customers x 2 hours overvoltage x 5kW PVI x 10c/kWh x 10 times /year

- Country feeders EOL – 460 LV monitors
  It is assumed that each transformer monitor has an average of 25 connected customers with 20% penetration of solar PV ie one in five customers have solar PV. By maintained standard network voltages to AS60038 voltage levels it has been assumed that each PV customer (average 5kW PVI) will save the loss of the FiT (feed in tariff) for 2 hours which is assumed at a minimum 10c/kWh (Retailer FiT) at least 10 times per annum. The Yr 3 calculation is as follows:

  (48+103+103units) x 50customers/transformer x 20% PV customers x 2 hours overvoltage x 5kW PVI x 10c/kWh x 10 times /year
- Metro feeders EOL – 85 LV monitors
  It is assumed that each transformer monitor has an average of 50 connected customers with 20% penetration of solar PV ie one in five customers have solar PV. By maintained standard network voltages to AS60038 voltage levels it has been assumed that each PV customer (average 5kW PVI) will save the loss of the FiT (feed in tariff) for 2 hours which is assumed at a minimum 10c/kWh (Retailer FiT) at least 10 times per annum. The Yr 3 calculation is as follows:

  (9+19+19units) x 50customers/transformer x 20% PV customers x 2 hours overvoltage x 5kW PVI x 10c/kWh x 10 times /year
- Metro pad mount transformers – 635 LV monitors
  It is assumed that each transformer monitor has an average of 50 connected customers with 20% penetration of solar PV ie one in five customers have solar PV. By maintained standard network voltages to AS60038 voltage levels it has been assumed that each PV customer (average 5kW PVI) will save the loss of the FiT (feed in tariff) for 2 hours which is assumed at a minimum 10c/kWh (Retailer FiT) at least 10 times per annum. The Yr 3 calculation is as follows:

  (63+143+143units) x 50customers/transformer x 20% PV customers x 2 hours overvoltage x 5kW PVI x 10c/kWh x 10 times /year

Customer benefit - Customer VoCR - value of improved customer reliability

The value of improved customer reliability is taken to be the industry standard of $50,000/MWh or $50/kWh. The VoCR calculations are as follows:

- SWER (start & EOL) – 740 LV monitors
  It is assumed that 10% of the monitor installations per year represent the improvement value if each event (outage) has a 6 hour duration and each customer, on average 5 customers per SWER transformer, has an average maximum demand of 3kW. The year 3 calculation is:

  ((6.3+14.3+14.3)units*5customers/transformer*50$/kWh*6h*3kW)
- Country substations - non SCADA – 65 HV monitors
  It is assumed that 10% of the monitor installations per year represent the improvement value if each event (outage) has a 3 hour duration and each customer, on average 50 customers per transformer, has an average maximum demand of 3kW.
- Country feeders EOL – 460 LV monitors
  It is assumed that 10% of the monitor installations per year represent the improvement value if each event (outage) has a 3 hour duration and each customer, on average 25 customers per transformer, has an average maximum demand of 3kW.

- Metro feeders EOL – 85 LV monitors
  It is assumed that 10% of the monitor installations per year represent the improvement value if each event (outage) has a 2 hour duration and each customer, on average 50 customers per transformer, has an average maximum demand of 3kW.
- Metro pad mount transformers – 635 LV monitors
  It is assumed that 10% of the monitor installations per year represent the improvement value if each event (outage) has a 2 hour duration and each customer, on average 50 customers per transformer, has an average maximum demand of 3kW.

SA Power Networks benefit - Reduced customer equipment damage claims

By maintained standard network voltages to AS60038 voltage levels it has been assumed that all customers will avoid combined equipment damage costs totalling on average $10,000 per year (all SA Power Networks customers' voltage related claims). The rate of claims is low so the incremental increase in claims is also low and is assumed to be $10,000 per year over the 5 year transformer monitoring installation period in line with more monitors in service and is then maintained at this year 5 level.

Project Evaluation - Net Present Value Analysis

The project has a positive NPV and has positive cash flows after 5 years based on a 10 year useful life of both HV and LV monitors. At 50% sensitivity levels the project remains positive in NPV terms.

The project is funded by SA Power Networks capital budget allocated to Network Quality of Supply. Total NPV cost is $8M and total NPV benefits to customers of $14.96M over 10 years commencing 2016 – based on the important assumption that the monitors are installed in the right locations to achieve the benefits.

The Net Present Value (benefits – costs) and Profitability Index (benefits/costs) is shown in Table 3 below.

The summary analysis is shown in Table 3 below:

	NPV Costs ($M2013)	NPV Benefits ($M2013)	NPV ($M2013)	PI
SWER (start & EOL) – 740 LV monitors	2.66	3.16	0.48	1.18
Country substations - non SCADA – 65 HV monitors	1.10	1.55	0.70	1.83
Country feeders EOL – 460 LV monitors	1.65	3.66	1.99	2.19
Metro feeders EOL – 85 LV monitors	0.31	0.96	0.64	2.33
Metro pad mount transformers – 635 LV monitors	2.30	5.63	3.38	2.50
Totals (Full 10 year program)	$8.02	$14.96	$7.19	1.90

Table 3

Transformer Monitor Costs

SA Power Networks has recently purchased 200 Current load and voltage monitors and successfully trialled them in the LV network. Attachment F are some recent costs included in the various Monitor installations and the costs (refer Table 1 above) are supported by invoices.

The HV monitor average unit cost ($15,000 per installation) is based on a recent 2013 installations at Hindmarsh Island, Mylor and Piccadilly Substations.

The costs must be taken as indicative for this proposal because it is proposed to undertake a Request for Tender process in order to get the best purchase value for money and assess the latest products available in the Australian market for HV and LV power quality monitoring devices. The technical specifications will be similar to the units trialled.

Project Resourcing

The monitor installations are achievable using existing Quality of Supply Investigation Field Services resources and the management and analysis is possible with existing Quality of Supply Network resources.

Project Timing

This project commences when AER regulatory funding is approved, expected by 31 October 2015.

Recommendation

It is recommended that this project, entitled Strategic LV Transformer Monitoring, be approved to commence after AER funding approval in October 2015. The total NPV cost of implementing this project is $8M (capex and opex) with benefits to customers of $14.96M over a 10 year financial evaluation period to 2025. The project shows a profitability index of 1.90.

Paul Driver

Network Manager Quality of Supply

Attachment A

CAPITAL EVALUATION - GENERAL FORMAT											
Purchase, Installation and Data Management System for LV Transformer Monitors - SWER network (start & EOL)											
Evaluation Factors											
Discount Rate (Real Pre-Tax)	8.98%	Policy rate for investment in core business assets									
Base Year Ending 31 Dec	2016										
Asset Depreciation Life (years)											
LV Transformer Monitor	10	This evaluation has been done over 10 years									
Financial Analysis	0	1	2	3	4	5	6	7	8	9	10
Year ended 31/12:	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Costs:											
LV monitors	0.27	0.60	0.60	0.60	0.60						
Total Capital	0.27	0.60	0.60	0.60	0.60	0	0	0	0	0	0
Telstra (capitalised) opex charges	0.01	0.03	0.05	0.07	0.09	0.09	0.09	0.09	0.09	0.09	0.09
Total Costs	**0.28**	**0.63**	**0.65**	**0.67**	**0.69**	**0.09**	**0.09**	**0.09**	**0.09**	**0.09**	**0.09**
Benefits:											
Avoided TF testing (travel, vehicle, install)			0.09	0.12	0.16	0.16	0.16	0.16	0.16	0.16	0.16
Avoided TF damage/failures											
Reduced customer enquiries			0.03	0.04	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Improved PVI operation with standard voltages			0.000	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001
Reduced customer eqpt damage claims			0.030	0.040	0.050	0.050	0.050	0.050	0.050	0.050	0.050
Customer VoCR - value of improved customer reliability			0.209	0.295	0.381	0.381	0.381	0.381	0.381	0.381	0.381
Total Benefits	**0.00**	**0.00**	**0.36**	**0.50**	**0.64**	**0.64**	**0.64**	**0.64**	**0.64**	**0.64**	**0.64**
Net Cash Flow	**-0.28**	**-0.63**	**-0.29**	**-0.17**	**-0.05**	**0.55**	**0.55**	**0.55**	**0.55**	**0.55**	**0.55**
Pre Tax:	**$M**										
Net Present Value 100%	**$0.48**										
Net Present Value 50%	**$0.24**										

Notes:

1. LV power quality monitors generally have a serviceable life of 10 years. The NPV evaluation is done over 10 years at the business policy discount rate 8.98% commencing in 2016.
2. The installed capital cost of SWER LV monitors is estimated to be $3,600 (average unit cost).
3. The annual installation rate follows Table 1 above.
4. Telstra 3G annual operating costs per unit are $120 paid monthly as part of a plan. These costs are capitalised.
5. By installing long term transformer monitors short term tests are avoided. Short term tests require 2 site trips for a crew of 2 and a suitably equipped vehicle. It has been assumed that 10% of the proposed annual long term monitoring installations represents the avoidable short term tests to respond to customer enquiries or pro-active (survey) tests.
6. It is assumed that by assisting enabling a two way power flow network by monitoring and pro-actively remediating voltages outside of AS60038 voltage levels customer service levels will improve and customer power quality enquiries will be reduced. The annual cost of customer service, in these circumstances, is $10,000 and the improvement increases by one $10,000 cost per year over the installation period (5 years) and is maintained.
7. Assisting enabling a two way network will allow customer solar PV installations to operate more often and under a greater number of network operating conditions. This improves with the annual increase in the number of monitor installations and is maintained. It is assumed that each SWER transformer monitor has an average of 5 connected customers with 20% penetration of solar PV ie one in five customers have solar PV. By maintained standard network voltages to AS60038 voltage levels it has been assumed that each 1kW PV customer will save 10c/kWh over 1 hour 10 times per annum.
8. By maintained standard network voltages to AS60038 voltage levels it has been assumed that total customers will avoid equipment damage on average of $10,000 per annum. The rate of claims is low so the incremental benefit from long term voltage monitoring could increase by $10,000 per annum in line with the increase in the number of monitors installed over the 5 year installation period and is then maintained at this year 5 level.
9. The value of improved customer reliability is taken to be the industry standard of $50,000/MWh or $50/kWh. It is assumed that 10% of the monitor installations per year represent the improvement value if each event has a 8 hour duration and each customer, on average 5 customers per SWER transformer, has an average maximum demand of 3kW.

Attachment B

Purchase, Installation and Data Management System for LV Transformer Monitors - Country Non-SCADA HV monitors											
Evaluation Factors											
Discount Rate (Real Pre-Tax)	8.98%	Policy rate for investment in core business assets									
Base Year Ending 31 Dec	2016										
Asset Depreciation Life (years) LV Transformer Monitor	10	This evaluation has been done over 10 years									
Financial Analysis	0	1	2	3	4	5	6	7	8	9	10
Year ended 31/12:	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Costs:											
HV monitors	0.075	0.225	0.225	0.225	0.225	0	0	0	0	0	0
Total Capital	0.075	0.225	0.225	0.225	0.225	0	0	0	0	0	0
Telstra (capitalised) opex charges	0.001	0.002	0.004	0.006	0.008	0.008	0.008	0.008	0.008	0.008	0.008
Total Costs	**0.08**	**0.23**	**0.23**	**0.23**	**0.23**	**0.01**	**0.01**	**0.01**	**0.01**	**0.01**	**0.01**
Benefits:											
Avoided TF testing (travel, vehicle, install)			0.007	0.011	0.014	0.014	0.014	0.014	0.014	0.014	0.014
Avoided TF damage/failures											
Reduced customer enquiries			0.06	0.08	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Improved PVI operation with standard voltages			0.000	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001
Reduced customer eqpt damage claims			0.030	0.040	0.050	0.050	0.050	0.050	0.050	0.050	0.050
Customer VoCR - value of improved customer reliability			0.079	0.113	0.146	0.146	0.146	0.146	0.146	0.146	0.146
Total Benefits	**0.00**	**0.00**	**0.18**	**0.24**	**0.31**	**0.31**	**0.31**	**0.31**	**0.31**	**0.31**	**0.31**
Net Cash Flow	**-0.08**	**-0.23**	**-0.05**	**0.01**	**0.08**	**0.30**	**0.30**	**0.30**	**0.30**	**0.30**	**0.30**
Pre Tax:	**$M**										
Net Present Value 100%	**$0.70**										
Net Present Value 50%	**$0.35**										

Notes:

1. HV power quality monitors generally have a serviceable life of 10 years. The NPV evaluation is done over 10 years at the business policy discount rate 8.98% commencing in 2016.
2. The installed capital cost of HV monitors is estimated to be $15,000 (average unit cost).
3. The annual installation rate follows Table 1 above.
4. Telstra 3G annual operating costs per unit are $120 paid monthly as part of a plan. These costs are capitalised.
5. By installing long term transformer monitors short term tests are avoided. Short term tests require 2 site trips for a crew of 2 and a suitably equipped vehicle. It has been assumed that 10% of the proposed annual long term monitoring installations represents the avoidable short term tests to respond to customer enquiries or pro-active (survey) tests.
6. It is assumed that by assisting enabling a two way power flow network by monitoring and pro-actively remediating voltages outside of AS60038 voltage levels customer service levels will improve and customer power quality enquiries will be reduced. The annual cost of customer service, in these circumstances, is $10,000 and the improvement increases by one $10,000 cost per year over the installation period (5 years) and is maintained.
7. Assisting enabling a two way network will allow customer solar PV installations to operate more often and under a greater number of network operating conditions. This improves with the annual increase in the number of monitor installations and is maintained. It is assumed that each transformer monitor has an average of 100 connected customers with 20% penetration of solar PV ie one in five customers have solar PV. By maintained standard network voltages to AS60038 voltage levels it has been assumed that each PV customer will save $100 per annum.
8. By maintained standard network voltages to AS60038 voltage levels it has been assumed that total customers will avoid equipment damage on average of $10,000 per annum. The rate of claims is low so the incremental benefit from long term voltage monitoring could increase by $10,000 per annum in line with the increase in the number of monitors installed over the 5 year installation period and is then maintained at this year 5 level.
9. The value of improved customer reliability is taken to be the industry standard of $50,000/MWh or $50/kWh. It is assumed that 10% of the monitor installations per year represent the improvement value if each event (outage) has a 3 hour duration and each customer, on average 100 customers per transformer, has an average maximum demand of 3kW.

Attachment C

FINANCIAL EVALUATION											
Purchase, Installation and Data Management System for LV Transformer Monitors - Country Feeders (EOL)											
Evaluation Factors											
Discount Rate (Real Pre-Tax)	8.98%	Policy rate for investment in core business assets									
Base Year Ending 31 Dec	2016	Specify Date									
Asset Depreciation Life (years) LV Transformer Monitor	10	This evaluation has been done over 10 years									
Financial Analysis	0	1	2	3	4	5	6	7	8	9	10
Year ended 31/12:	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Costs:											
LV monitors	0.17	0.37	0.37	0.37	0.37						
Total Capital	0.17	0.37	0.37	0.37	0.37	0	0	0	0	0	0
Telstra (capitalised) opex charges	0.01	0.02	0.03	0.04	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Total Costs	**0.18**	**0.39**	**0.40**	**0.41**	**0.43**	**0.06**	**0.06**	**0.06**	**0.06**	**0.06**	**0.06**
Benefits:											
Avoided TF testing (travel, vehicle, install)			0.05	0.07	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Avoided TF damage/failures											
Reduced customer enquiries			0.03	0.04	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Improved PVI operation with standard voltages			0.013	0.018	0.023	0.023	0.023	0.023	0.023	0.023	0.023
Reduced customer eqpt damage claims			0.030	0.040	0.050	0.050	0.050	0.050	0.050	0.050	0.050
Customer VoCR - value of improved customer reliability			0.286	0.402	0.518	0.518	0.518	0.518	0.518	0.518	0.518
Total Benefits	**0.00**	**0.00**	**0.41**	**0.57**	**0.74**	**0.74**	**0.74**	**0.74**	**0.74**	**0.74**	**0.74**
Net Cash Flow	**-0.18**	**-0.39**	**0.01**	**0.16**	**0.31**	**0.68**	**0.68**	**0.68**	**0.68**	**0.68**	**0.68**

Pre Tax:	**$M**
Net Present Value 100%	**$1.99**
Net Present Value 50%	**$0.99**

Notes:

1. LV power quality monitors generally have a serviceable life of 10 years. The NPV evaluation is done over 10 years at the business policy discount rate 8.98% commencing in 2016.
2. The installed capital cost of LV monitors is estimated to be $3,600 (average unit cost).
3. The annual installation rate follows Table 1 above.
4. Telstra 3G annual operating costs per unit are $120 paid monthly as part of a plan. These costs are capitalised.
5. By installing long term transformer monitors short term tests are avoided. Short term tests require 2 site trips for a crew of 2 and a suitably equipped vehicle. It has been assumed that 10% of the proposed annual long term monitoring installations represents the avoidable short term tests to respond to customer enquiries or pro-active (survey) tests.
6. It is assumed that by assisting enabling a two way power flow network by monitoring and pro-actively remediating voltages outside of AS60038 voltage levels customer service levels will improve and customer power quality enquiries will be reduced. The annual cost of customer service, in these circumstances, is $10,000 and the improvement increases by one $10,000 cost per year over the installation period (5 years) and is maintained.
7. Assisting enabling a two way network will allow customer solar PV installations to operate more often and under a greater number of network operating conditions. This improves with the annual increase in the number of monitor installations and is maintained. It is assumed that each transformer monitor has an average of 50 connected customers with 20% penetration of solar PV ie one in five customers have solar PV. By maintained standard network voltages to AS60038 voltage levels it has been assumed that each PV customer will save $100 per annum.
8. By maintained standard network voltages to AS60038 voltage levels it has been assumed that total customers will avoid equipment damage on average of $10,000 per annum. The rate of claims is low so the incremental benefit from long term voltage monitoring could increase by $10,000 per annum in line with the increase in the number of monitors installed over the 5 year installation period and is then maintained at this year 5 level.
9. The value of improved customer reliability is taken to be the industry standard of $50,000/MWh or $50/kWh. It is assumed that 10% of the monitor installations per year represent the improvement value if each event (outage) has a 3 hour duration and each customer, on average 50 customers per transformer, has an average maximum demand of 3kW.

Attachment D

FINANCIAL EVALUATION											
Purchase, Installation and Data Management System for LV Transformer Monitors - Remote Voltage Control Project Metro Feeders EOL check LV monitors											
Evaluation Factors											
Discount Rate (Real Pre-Tax)	8.98%	Policy rate for investment in core business assets									
Base Year Ending 31 Dec	2016	Specify Date									
Asset Depreciation Life (years) LV Transformer Monitor	10	This evaluation has been done over 10 years									
Financial Analysis	0	1	2	3	4	5	6	7	8	9	10
Year ended 31/12:	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Costs:											
LV monitors	0.032	0.067	0.067	0.067	0.067	0	0	0	0	0	0
Total Capital	0.032	0.067	0.067	0.067	0.067	0	0	0	0	0	0
Telstra (capitalised) opex charges	0.001	0.003	0.030	0.008	0.010	0.010	0.010	0.010	0.010	0.010	0.010
Total Costs	**0.03**	**0.07**	**0.10**	**0.07**	**0.08**	**0.01**	**0.01**	**0.01**	**0.01**	**0.01**	**0.01**
Benefits:											
Avoided TF testing (travel, vehicle, install)			0.004	0.006	0.008	0.008	0.008	0.008	0.008	0.008	0.008
Avoided TF damage/failures											
Reduced customer enquiries			0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Improved PVI operation with standard voltages			0.005	0.007	0.009	0.009	0.009	0.009	0.009	0.009	0.009
Reduced customer eqpt damage claims			0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010
Customer VoCR - value of improved customer reliability			0.068	0.095	0.122	0.122	0.122	0.122	0.122	0.122	0.122
Total Benefits	**0.00**	**0.00**	**0.13**	**0.16**	**0.19**	**0.19**	**0.19**	**0.19**	**0.19**	**0.19**	**0.19**
Net Cash Flow	**-0.03**	**-0.07**	**0.03**	**0.08**	**0.11**	**0.18**	**0.18**	**0.18**	**0.18**	**0.18**	**0.18**
Pre Tax:	**$M**										
Net Present Value 100%	**$0.64**										
Net Present Value 50%	**$0.32**										

Notes:

1. LV power quality monitors generally have a serviceable life of 10 years. The NPV evaluation is done over 10 years at the business policy discount rate 8.98% commencing in 2016.
2. The installed capital cost of LV monitors is estimated to be $3,600 (average unit cost).
3. The annual installation rate follows Table 1 above.
4. Telstra 3G annual operating costs per unit are $120 paid monthly as part of a plan. These costs are capitalised.
5. By installing long term transformer monitors short term tests are avoided. Short term tests require 2 site trips for a crew of 2 and a suitably equipped vehicle. It has been assumed that 10% of the proposed annual long term monitoring installations represents the avoidable short term tests to respond to customer enquiries or pro-active (survey) tests.
6. It is assumed that by assisting enabling a two way power flow network by monitoring and pro-actively remediating voltages outside of AS60038 voltage levels customer service levels will improve and customer power quality enquiries will be reduced. The annual cost of customer service, in these circumstances, is $10,000 and the improvement increases by one $10,000 cost per year over the installation period (5 years) and is maintained.
7. Assisting enabling a two way network will allow customer solar PV installations to operate more often and under a greater number of network operating conditions. This improves with the annual increase in the number of monitor installations and is maintained. It is assumed that each transformer monitor has an average of 50 connected customers with 20% penetration of solar PV ie one in five customers have solar PV. By maintained standard network voltages to AS60038 voltage levels it has been assumed that each PV customer will save $100 per annum.
8. By maintained standard network voltages to AS60038 voltage levels it has been assumed that total customers will avoid equipment damage on average of $10,000 per annum. The rate of claims is low so the incremental benefit from long term voltage monitoring could increase by $10,000 per annum in line with the increase in the number of monitors installed over the 5 year installation period and is then maintained at this year 5 level.
9. The value of improved customer reliability is taken to be the industry standard of $50,000/MWh or $50/kWh. It is assumed that 10% of the monitor installations per year represent the improvement value if each event (outage) has a 2 hour duration and each customer, on average 50 customers per transformer, has an average maximum demand of 3kW.

Attachment E

FINANCIAL EVALUATION											
Purchase, Installation and Data Management System for LV Transformer Monitors - Metro Padmounts											
Evaluation Factors											
Discount Rate (Real Pre-Tax)	8.98%	Policy rate for investment in core business assets									
Base Year Ending 31 Dec	2016										
Asset Depreciation Life (years) LV Transformer Monitor	10	This evaluation has been done over 10 years									
Financial Analysis	0	1	2	3	4	5	6	7	8	9	10
Year ended 31/12:	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Costs:											
LV monitors	0.22	0.50	0.50	0.50	0.50						
Total Capital	0.22	0.50	0.50	0.50	0.50	0	0	0	0	0	0
Telstra (capitalised) opex charges	0.01	0.02	0.04	0.06	0.08	0.08	0.08	0.08	0.08	0.08	0.08
Total Costs	**0.23**	**0.53**	**0.54**	**0.56**	**0.58**	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**
Benefits:											
Avoided TF testing (travel, vehicle, install)			0.03	0.04	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Avoided TF damage/failures											
Reduced customer enquiries			0.03	0.04	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Improved PVI operation with standard voltages			0.035	0.049	0.064	0.064	0.064	0.064	0.064	0.064	0.064
Reduced customer eqpt damage claims			0.020	0.020	0.020	0.020	0.020	0.020	0.020	0.020	0.020
Customer VoCR - value of improved customer reliability			0.524	0.738	0.953	0.953	0.953	0.953	0.953	0.953	0.953
Total Benefits	**0.00**	**0.00**	**0.64**	**0.89**	**1.13**	**1.13**	**1.13**	**1.13**	**1.13**	**1.13**	**1.13**
Net Cash Flow	**-0.23**	**-0.53**	**0.09**	**0.33**	**0.56**	**1.06**	**1.06**	**1.06**	**1.06**	**1.06**	**1.06**
Pre Tax:	**$M**										
Net Present Value 100%	**$3.38**										
Net Present Value 50%	**$1.69**										

Notes:

1. LV power quality monitors generally have a serviceable life of 10 years. The NPV evaluation is done over 10 years at the business policy discount rate 8.98% commencing in 2016.
2. The installed capital cost of LV monitors is estimated to be $3,600 (average unit cost).
3. The annual installation rate follows Table 1 above.
4. Telstra 3G annual operating costs per unit are $120 paid monthly as part of a plan. These costs are capitalised.
5. By installing long term transformer monitors short term tests are avoided. Short term tests require 2 site trips for a crew of 2 and a suitably equipped vehicle. It has been assumed that 10% of the proposed annual long term monitoring installations represents the avoidable short term tests to respond to customer enquiries or pro-active (survey) tests.
6. It is assumed that by assisting enabling a two way power flow network by monitoring and pro-actively remediating voltages outside of AS60038 voltage levels customer service levels will improve and customer power quality enquiries will be reduced. The annual cost of customer service, in these circumstances, is $10,000 and the improvement increases by one $10,000 cost per year over the installation period (5 years) and is maintained.
7. Assisting enabling a two way network will allow customer solar PV installations to operate more often and under a greater number of network operating conditions. This improves with the annual increase in the number of monitor installations and is maintained. It is assumed that each transformer monitor has an average of 50 connected customers with 20% penetration of solar PV ie one in five customers have solar PV. By maintained standard network voltages to AS60038 voltage levels it has been assumed that each PV customer will save $100 per annum.
8. By maintained standard network voltages to AS60038 voltage levels it has been assumed that total customers will avoid equipment damage on average of $10,000 per annum. The rate of claims is low so the incremental benefit from long term voltage monitoring could increase by $10,000 per annum in line with the increase in the number of monitors installed over the 5 year installation period and is then maintained at this year 5 level.
9. The value of improved customer reliability is taken to be the industry standard of $50,000/MWh or $50/kWh. It is assumed that 10% of the monitor installations per year represent the improvement value if each event (outage) has a 2 hour duration and each customer, on average 50 customers per transformer, has an average maximum demand of 3kW.

Attachment F

Transformer LV Monitoring Costs in $2013		Pole Top				Padmount	
		1 Circuit		SWER Isolating TF		1 Circuit	
Product/Service	Unit Cost	Qty	Cost	Qty	Cost	Qty	Cost
1ATiQ-P4	$ 760.00						
Cellular Modem, GSM/GPRS class 10	$ 266.00	1	$ 266.00	1	$ 266.00	1	$ 266.00
MPA (Indicative costs only)							
1 Circuit 3G	$ 760.00	1	$ 760.00			1	$ 760.00
SWER	$ 760.00			1	$ 760.00		
Unit Labels	$ 5.00	1	$ 5.00	1	$ 5.00	1	$ 5.00
Mounting							
Banana Plug Fused Attachment	$ 195.00	1	$ 195.00	1	$ 195.00	1	$ 195.00
Magnetic Mounting, 75lb-pull, encapsulated	$ 30.00	1	$ 30.00	1	$ 30.00	1	$ 30.00
Temperature Sensor, 100 Ohm pt, 2 m lead, water proof connector	$ 90.00					1	$ 90.00
Rogowski Coils and hardware							
Flexible CT , 4 inch diam, 2m lead (no switching)	$ 210.00	3	$ 630.00	1	$ 210.00	3	$ 630.00
MONITORING EQUIPMENT SUBTOTAL			$ 1,886.00		$ 1,466.00		$ 1,976.00
Freight	$ 60.00	1	$ 60.00	1	$ 60.00	1	$ 60.00
ADDITIONAL EXPENSES			$ 60.00		$ 60.00		$ 60.00
Field Services							
Labour	$ 89.93						
Travel time (2 Man Crew + Vehicle)	$ 379.86	0.5	$ 189.93	2	$ 759.72	0.5	$ 189.93
Installation Time (2 Man Crew + Vehicle)	$ 289.93	1	$ 289.93	1	$ 289.93	1	$ 289.93
FIELD SERVICES INSTALLATION SUBTOTAL			$ 479.86		$ 1,049.65		$ 479.86
Network Management							
Labour	$ 88.00	0.5	$ 44.00	0.5	$ 44.00	0.5	$ 44.00
PROJECT MANAGEMENT SUBTOTAL			$ 44.00		$ 44.00		$ 44.00
Overheads							
Field Services	25%		$ 606.47		$ 643.91		$ 628.97
Network Management	20%		$ 8.80		$ 8.80		$ 8.80
OVERHEADS SUBTOTAL			$ 615.27		$ 652.71		$ 637.77
Discount 10% for volume purchases	10%	1	-$ 188.60	1	-$ 146.60	1	-$ 197.60
Add Opex costs			302.9		302.9		302.9
	TOTAL		$ 3,388.03		$ 3,575.26		$ 3,500.53

57. APPENDIX AD – STRATEGIC VOLTAGE REGULATION BUSINESS CASE

Executive Summary

New customer technologies, such as solar PV, now require improved voltage regulation to facilitate a two way power flow network. If a two way network is not facilitated, customers will be denied the opportunity, under many network operating conditions, to realise the full benefits of their new technologies. Customer power quality enquiries will continue to increase from dissatisfied customers. SA Power Networks costs (opex) will continue to increase if no pro-active action is taken to ensure substation and feeder voltage levels are compliant and meet customer expectations.

This business case supports two credible, technically feasible, HV regulation projects and both will utilise the ADMS (Advanced Distribution Management) system when it becomes available/operational in 2016 as currently planned. The capital cost of this proposal is $4.40M over 5 years.

<u>Remote Voltage Regulation at Country Substations</u>

Most of the SA Power Networks substations have SCADA for HV assets, or will have SCADA in the next 5 to 10 years (refer SCADA roll out program and plan). However there are at least ten (10) HV/HV country substations (nine 33/11kV and one 33/7.6kV) with transformers (typically transformers less than 1MVA) that do not have SCADA. It is proposed to add a SCADA-enabled pole top voltage regulator at each of these sites to provide remote monitoring and control of substation voltage and load levels. The proposed sites are listed in Attachment D.

It is estimated that this project will have an NPV cost of $1.31M (capex and opex) over 35 years (asset life) and has an estimated NPV benefit of $1.81M over 35 years. The Profitability Index is 1.39. This project will facilitate a two way power flow network to enable these customer benefits.

<u>Remote Voltage Regulation on Country Feeders</u>

To increase power quality voltage level visibility and set point control it is proposed to retrofit SCADA to 63 existing high voltage line regulators (total of 309 HV line voltage regulators in service on country feeders), selected because they have suitable CL5/6 controllers to enable a SCADA retrofit. The proposed sites are listed in Attachment E.

It is estimated that this project will have a NPV cost of $3.40M (capex and opex) over 35 years (asset life) and has an estimated NPV benefit of $3.74M over 35 years. The Profitability Index is 1.10. This project will facilitate a two way power flow network to enable these customer benefits.

The combined projects' NPV costs total $4.71M and result in NPV benefits to customers totalling $5.55M over a 35 year financial evaluation period.

Background

It is essential to maintain AS60038 voltage levels to both comply with the SA Distribution Code and to importantly meet customer expectations of a two way network capability to allow new customer technologies to operate adequately now and into the future. Recent 2013 customer Stakeholder Workshops (Stage 2 – Stakeholder & Consumer Workshop Report, December 2013, Deloitte, p15) confirmed that it is customers' expectations that SA Power Networks has knowledge of voltage levels on its network and that it will maintain power quality in the network so that it is capable of accepting new technologies, such as solar PV, energy storage and electric vehicle charging. A key component to maintaining feeder voltage levels within acceptable limits is an automatic high voltage regulator (HVR). The pole-top regulators will be deployed at locations that have multiple voltage enquiries from customers, as a priority.

Remote Voltage Regulation at Country Substations

SA Power Networks currently has 10 country substations, listed in Attachment D, where it is not cost effective to install full substation SCADA – not part of the proposed ADMS/SCADA roll-out program. Presently there is no visibility of the load and voltage levels at these substations. Installing SCADA enabled voltage regulators at those 10 country substations will enable visibility of their operational status, and will provide essential knowledge when analysing customer voltage enquiries. In addition, to have the ability to remotely change the voltage set points of those HVRs via SCADA would be a very useful and cost efficient benefit (creating opex savings).

Remote Voltage Regulation on Country Feeders

SA Power Networks currently has 309 existing country line voltage regulators with 63 of them equipped with suitable controllers that can be retrofitted with SCADA. The locations are listed in Attachment E. Installing SCADA enabled to mid-line voltage regulators on those 63 country feeders will enable visibility of their operational status, and will provide essential knowledge when analysing customer voltage enquiries. In addition, to have the ability to remotely change the voltage set points of those HVRs via SCADA would be a very useful and cost efficient benefit (creating opex savings).

To improve voltage visibility and voltage set point control it is proposed to enable SCADA to 63 of the existing 309 line HVRs because they have suitable controllers that will accept SCADA connection.

Considered Options

In order to facilitate feasible and credible solutions to improve voltage regulation for country customers the following options have been considered:

Option 1 – Do nothing

The status quo at present is no visibility of voltage levels and the general quality of supply available to customers. This means SA Power Networks cannot adequately manage the LV network and ensure compliance with the Electricity Distribution Code (AS60038) voltage level requirements. SA Power Networks responds to customer power quality enquiries. The (reactive) response includes a short term load and voltage test and network remediation where required. Power quality enquiries are trending upwards and the continued uptake of customer technologies within a network not designed for two way power flows means customer enquiries will continue and potentially the upward trend will increase if nothing changes.

Option 2 – Supply transformer tap changes

Currently SA Power Networks responds to customer power quality enquiries with a short term test, analysis and a remediation solution where required. Similarly, where it is believed assets may be overloaded under peak loading conditions, a short term test (survey) is conducted and the results factored up to simulate a test done during peak loading conditions. Once the customer enquiry has been confirmed by a short term test, the remediation solution to voltage levels outside of Standard levels is often to tap up or down the off load taps of the supply transformer. If the transformer doesn't have taps then it is sometimes appropriate to change the transformer with one with off-load taps. This is a seasonal short term remediation solution that is not cost efficient considering the volume of transformers in the LV network (73,500).

Option 3 – Voltage regulation – recommended option

The most cost effective solution to varying voltage levels is automatic voltage regulation by a high voltage regulator (HVR). If this HVR is SCADA-enabled it can provide both voltage level measurement visibility and set point control. This can either be done at the start of the feeder at the substation or along the line at a suitable HVR. Suitable HVR's have CL5 or CL6 controllers which can be SCADA enabled. SA Power Networks has 10 non SCADA country substations that will require new SCADA enabled voltage regulators. SA Power Networks also has 309 line HVR's in service and at least 63 of these 309 have suitable HVR with CL5/6 controllers.

If the high voltage is regulated it is more likely that the low voltage levels can be better controlled within Standard voltage levels. Installing new voltage regulation at 10 substations and retro-fitting 63 existing line voltage regulators is a more prudent and efficient use of capex to achieve more wide spread customer benefits than tap changes at individual customer supply transformers.

Project Costs

The project costs are based on the unit costs outlined in Attachment C. These costs are derived from recent HVR purchases and installations on the SA Power Networks network.

Total purchase and installation capex for the 10 SCADA-enabled pole-top regulators for country substations over 5 years is $1.5M. The on-going opex SCADA (telecommunications) costs are assumed to be 1% of the capex, $0.003M per annum over the 35 year evaluation period (asset life). Total costs (capex and opex) are $1.608M over 35 years.

Total purchase and installation costs for retrofitting SCADA-enable to the 63 high-voltage line regulators in country locations over 5 years is $3.00M. The ongoing capex SCADA (telecommunications) costs are assumed to be 1% of the capex; $0.065M per annum over the 35 year evaluation period (asset life). Total costs (capex and opex) are $5.48M over 35 years.

Project Benefits

The combined projects; that is, installing 10 new HVR at country non-SCADA substations at the rate of 2 per year and enabling SCADA to 63 line HVR has at least 4 benefits:

<u>Avoided transformer testing</u>

A routine transformer load test is undertaken each year at the substation to measure load and voltage. The travelling (to put the test equipment on and take it off), vehicle and installation costs of this test per substation are $0.0042M. The year 1 calculation is:

2 trips*(2 substations * (Travel time 2 man crew + vehicle $760)+(Installation time 2 man crew + vehicle $290)). Because the 2 trips will do both substations, 50% of the costs are assumed.

<u>Reduced customer enquiries</u>

It is assumed that by assisting enabling a two way power flow network by monitoring and pro-actively remediating voltages outside of AS60038 voltage levels, customer service levels will improve and customer power quality enquiries will be reduced. The annual cost of customer service, in these circumstances, is conservatively assumed to be $10,000, and the improvement increases by one $10,000 cost per year over the installation period (5 years), and is then maintained at this level over the evaluation period. The average number of customer enquiries referred to Quality of Supply is 2000 per year. The calls are logged at a Call Centre, information downloaded, and where needed, a load and voltage test is undertaken (2 trips, travelling and installation). The test results are analysed and remedial action, often requiring a line design (scope, on-site visit, design) is undertaken when necessary. Voltage regulation will reduce the likelihood that the customers will need to make voltage related enquiries, resulting in capex and opex savings.

Reduced customer equipment damage claims

By maintaining standard network voltages to AS60038 voltage levels it has been assumed that all customers will avoid combined equipment damage costs conservatively totalling on average $10,000 per year (all SA Power Networks customers' voltage related claims). Claims can be for electronic appliances sensitive to voltage variations, burnt out motors, and various control systems and relays. The rate of claims is low so the incremental increase in claims is also low, and is assumed to be $10,000 per year over the 5 year transformer monitoring installation period, in line with more monitors in service, and is then maintained at this year 5 level.

Customer VoCR - value of improved customer reliability

The value of improved customer reliability is taken to be the industry standard of $50,000/MWh or $50/kWh. This is the value to customers of having a reliable, continuous electricity supply. The VoCR calculation for each installation is based on the assumption that, of 50 connected customers, 10% will receive this benefit each year. The VoCR calculation for each line HVR is similarly based on the assumption that, of 50 connected customers, 10% will receive this benefit each year, however because the line HVR is assumed to be half way along the feeder, 50% of the benefit has been assumed.

Strategic Voltage Regulation Proposal

Remote Voltage Regulation at Country Substations

To improve voltage level visibility, where there is none at present, and to maintain compliance with AS60038 voltage levels, it is proposed to install SCADA-enabled pole top voltage regulators at 10 non-SCADA country substations, in order to provide voltage level visibility and set point control. (This proposal must be read in conjunction with the SCADA submission.) Those substations with SCADA will be implemented via ADMS, while for those without, it is proposed to add SCADA controlled pole top regulators.

Remote Voltage Regulation on Country Feeders

To increase power quality voltage level visibility and set point control it is proposed to retrofit SCADA to 63 existing high voltage line regulators (309 HV line voltage regulators in service on country feeders), selected because they have suitable CL5/6 controllers to enable a SCADA retrofit. Improved line voltage visibility and regulator operation status will greatly assist customer service and the provision of a two way network for customers' new technologies.

Table 1 below shows the two proposed Voltage Regulation proposal expenditures:

VOLTAGE REGULATION	2015/16 (units)	2016/17 (units)	2017/18 (units)	2018/19 (units)	2019/20 (units)	Ave unit cost ($M)	Total program cost ($M)
Country substations - non SCADA – SCADA enabled voltage regulators	2	2	2	2	2	$0.14	$1.40
Existing line HVR - with retrofit SCADA enabled	13	13	13	12	12	$0.05	$3.00
Total Capital Costs ($M 2013)							**$4.40**

Table 1

Project Evaluation - Net Present Value Analysis
Both projects have positive NPV and positive cash flows after 5 years based on a 35 year useful life of high voltage regulators. At 50% sensitivity levels the project remains positive in NPV terms.

The combined projects' NPV costs are $4.71M and are funded by SA Power Networks' capital budget allocated to Network Quality of Supply. The combined projects' NPV benefits are $5.55M over the 35 year evaluation period, based on the important assumption that the voltage regulators are installed in the right locations to achieve the benefits.

	Total Costs ($M2013) 35 yrs	Total Benefits ($M2013) 35 yrs	NET PRESENT VALUE ($M2013) 35 years	PI
Country substations – SCADA enabled voltage regulators	1.31	1.81	0.51	1.39
Country line HVR – retrofit SCADA enabled	3.40	3.74	0.33	1.10
	$4.71M	$5.55M		

Table 2

Project Estimated Costs
Attachment C details our best estimates of likely project costs based on recent 3 can HVR and SCADA installations. The costs are provided for Networks costs and for Field Services (installation costs). Network overheads (20%) and Field Services overheads (25%) are also added.

Project Resourcing
SA Power Networks SCADA and telecommunications resources will implement SCADA to the HVR. The data will be received by the ADMS and downloaded by various Departments including Network Planning, Customer Solutions and Depot operational personnel. The HVR data will be used by current Quality of Supply Analysts to ensure compliance with the SA Distribution Code and ensure voltages are adequate for the customer's expectations. It is not expected that an increase in the existing Quality of Supply Network resources will be required over the 5 year program.

Project Timing
This project commences when AER regulatory funding is approved, expected by 31 October 2015. Expenditure cash flows include purchase and installation costs over the first 5 years and operating (telecommunications ADMS/SCADA) costs every year over 35 years to 2051.

Recommendation
It is recommended that this project, entitled Strategic Voltage Regulation, be approved to commence after AER funding approval in October 2015. The project NPV costs total $4.40M and results in benefits to customers totalling $5.55M over a 35 year financial evaluation period.

Paul Driver

Network Manager Quality of Supply

Attachment A

FINANCIAL EVALUATION											
Purchase, Installation and Data Management System for RVCP at Country Non-SCADA Substations (Pole Top HVR)											
Evaluation Factors											
Discount Rate (Real Pre-Tax)	8.98%	Policy rate for investment in core business assets									
Base Year Ending 31 Dec	2016										
Asset Depreciation Life (years) HVR	35	This evaluation has been done over 10 years									
Financial Analysis	0	1	2	3	4	5	6	7	8	9	10
Year ended 31/12:	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Costs:											
Capital - Installed HVR with SCADA	0.300	0.300	0.300	0.300	0.300	0	0	0	0	0	0
Operating - SCADA telecom	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003
Total Costs	**0.303**	**0.303**	**0.303**	**0.303**	**0.303**	**0.003**	**0.003**	**0.003**	**0.003**	**0.003**	**0.003**
Benefits - OPERATIONAL											
Avoided TF testing (travel, vehicle, install)	0.0042	0.0084	0.0126	0.0168	0.0210	0.0210	0.0210	0.0210	0.0210	0.0210	0.0210
Reduced customer enquiries	0.01	0.02	0.03	0.04	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Customer VoCR - value of improved customer reliability	0.0030	0.0060	0.0090	0.0120	0.0150	0.0150	0.0150	0.0150	0.0150	0.0150	0.0150
Total Operational Benefits ($M)	0.0172	0.0344	0.0516	0.0688	0.0860	0.0860	0.0860	0.0860	0.0860	0.0860	0.0860
Benefits - CAPITAL											
Reduced customer eqpt damage claims	0.020	0.040	0.060	0.080	0.100	0.100	0.100	0.100	0.100	0.100	0.100
Total Capital Benefits ($M)	0.0200	0.0400	0.0600	0.0800	0.1000	0.1000	0.1000	0.1000	0.1000	0.1000	0.1000
Total Benefits	**0.04**	**0.07**	**0.11**	**0.15**	**0.19**	**0.19**	**0.19**	**0.19**	**0.19**	**0.19**	**0.19**
Net Cash Flow	**-0.27**	**-0.23**	**-0.19**	**-0.15**	**-0.12**	**0.18**	**0.18**	**0.18**	**0.18**	**0.18**	**0.18**
Pre Tax:											
Net Present Value	$0.51	million									
Net Present BENEFIT	$1.81	million	and PI =	1.39							
Net Present COST	$1.31	million									

Notes:

1. It is estimated an HVR installation with SCADA will cost $0.15M. The NPV evaluation is done over 35 years at the business policy discount rate 8.98% commencing in 2016.
2. The annual installation rate follows Table 1 above.
3. By installing SCADA on pole top regulators at 10 substations we avoid the annual substation short term transformer load and voltage testing tests. Short term tests require 2 site trips for a crew of 2 and a suitably equipped vehicle to 2 substations. We assume a ramp up each year of another 2 substations up to year 5 and maintain this year 5 benefit until year 35.
4. It is assumed that by assisting enabling a two way power flow network by monitoring and pro-actively remediating voltages outside of AS60038 voltage levels customer service levels will improve and customer power quality enquiries will be reduced. The annual cost of customer service, in these circumstances, is assumed to be $10,000 and the improvement increases by one $10,000 cost per year over the installation period (5 years) and is then maintained to year 35 (2051).
5. By maintained standard network voltages to AS60038 voltage levels it has been assumed that customers will avoid equipment damage on average of $10,000 for all claims. The rate of claims is low so the benefit from improved voltage regulation is $10,000 saved per year increasing by $10,000 per year as the number of HVR installed increases over the 5 year installation period and is then maintained at this year 5 level.
6. The value of improved customer reliability is taken to be the industry standard of $50,000/MWh or $50/kWh. It is assumed that each event (outage) has a 2 hour duration and each customer has an average maximum demand of 3kW. It is assumed 10% of 50 connected customers will get the benefit.

Attachment B

FINANCIAL EVALUATION											
Purchase, Installation and Data Management System for RVCP at Country Feeders with Existing Pole Top HVR - Retrofit SCADA											
Evaluation Factors											
Discount Rate (Real Pre-Tax)	8.98%	Policy rate for investment in core business assets									
Base Year Ending 31 Dec	2016										
Asset Depreciation Life (years) HVR	35	This evaluation has been done over 10 years									
Financial Analysis	0	1	2	3	4	5	6	7	8	9	10
Year ended 31/12:	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Costs:											
Capital - Installed HVR with SCADA	0.650	0.650	0.650	0.600	0.600	0	0	0	0	0	0
Operating - SCADA telecom	0.065	0.065	0.065	0.060	0.060	0.060	0.060	0.060	0.060	0.060	0.060
Total Costs	**0.715**	**0.715**	**0.715**	**0.660**	**0.660**	**0.060**	**0.060**	**0.060**	**0.060**	**0.060**	**0.060**
Benefits - OPERATIONAL											
Avoided TF testing (travel, vehicle, install)	0.0021	0.0042	0.0063	0.0084	0.0105	0.0105	0.0105	0.0105	0.0105	0.0105	0.0105
Reduced customer enquiries	0.01	0.02	0.03	0.04	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Customer VoCR - value of improved customer reliability	0.002	0.004	0.006	0.008	0.009	0.009	0.009	0.009	0.009	0.009	0.009
Total Operational Benefits ($M)	0.0139	0.0278	0.0419	0.0559	0.0700	0.0700	0.0700	0.0700	0.0700	0.0700	0.0700
Benefits - CAPITAL											
Reduced customer eqpt damage claims	0.060	0.120	0.185	0.250	0.315	0.315	0.315	0.315	0.315	0.315	0.315
Total Capital Benefits ($M)	0.0600	0.1200	0.1850	0.2500	0.3150	0.3150	0.3150	0.3150	0.3150	0.3150	0.3150
Total Benefits	**0.07**	**0.15**	**0.23**	**0.31**	**0.38**	**0.38**	**0.38**	**0.38**	**0.38**	**0.38**	**0.38**
Net Cash Flow	**-0.64**	**-0.57**	**-0.49**	**-0.35**	**-0.28**	**0.32**	**0.32**	**0.32**	**0.32**	**0.32**	**0.32**
Pre Tax:											
Net Present Value	$0.35	million									
Net Present BENEFIT	$3.74	million	and PI =	1.10							
Net Present COST	$3.39	million									

Notes:

1. It is estimated an existing HVR installation with retro-fit SCADA will cost $0. 05M. The NPV evaluation is done over 35 years at the business policy discount rate 8.98% commencing in 2016.
2. The annual installation rate follows Table 1 above.
3. By installing SCADA on existing line regulators at 63 sites we avoid some down line short term transformer load (customer or survey) tests. It is assumed 50% of tests are avoided in line with the number of retro fit installations completed. Short term tests require 2 site trips for a crew of 2 and a suitably equipped vehicle to 2 substations. We assume a ramp up each year of another 2 substations up to year 4 and maintain this year 4 benefit until year 35.
4. It is assumed that by assisting enabling a two way power flow network by monitoring and pro-actively remediating voltages outside of AS60038 voltage levels customer service levels will improve and customer power quality enquiries will be reduced. The annual cost of customer service, in these circumstances, is $10,000 and the improvement increases by one $10,000 cost per year over the installation period (5 years) and is maintained. Because the line regulators are roughly mid way down the feeder we have assumed 50% of this benefit is applicable.
5. The value of improved customer reliability is taken to be the industry standard of $50,000/MWh or $50/kWh. It is assumed that each event has a 2 hour duration and 10% of 50 connected customers has an average maximum demand of 3kW. Because the line regulators are roughly mid way down the feeder we have assumed 50% of this benefit is applicable.

Attachment C

VOLTAGE REGULATION PROJECT ESTIMATED COSTS

HV Substation Pole Top Voltage Regulator

network design	8000
network facilities	5000
network total	*13000*
3 can VR with CL6 controller install	47265
stobie pole(s) install	15000
telecomm/SCADA link	35000
field services total	*107265*
network overhead	2600
field services overhead	26816
Total	**$ 139,681**

Retrofit SCADA to line HVR

network design	4000
network facilities	1000
network total	*5000*
telecomm/SCADA link	35000
field services total	*35000*
network overhead	1000
field services overhead	8750
Total	**$ 49,750**

Attachment D

Substation Name	SSD/Feeder ID	Region	Pole top/Ground level?	Number of Feeders	Recloser	Regulator ?	KV IN	KV OUT	Number & Size of tfrs	Monitor required?	Routine Load & Voltage Tests	Comments
Sandy Creek	SSD755	Barossa	G	2	Y	N	33	11	1x1.0	**2**	Yes	Sub at end of SD375. 132/33kv OLTC at Templers. Regulation required on GA23 at feeder exit
Lyndoch South	SSD362	Barossa	PT	1	R2082	N	33	7.6		**1**	Yes	7.6kV feeder towards end of SD523. Regulation at VR584 15km upstream on SD523
Kersbrook	GU14	Eastern Hills	PT	1	N	N	33	11	1x0.3	**1**	Yes	Most heavily loaded feeder on SD383. Fed via SD382. No regulation on either. OLTC at Angas Creek
Second Valley	VH51	Fleurieu	PT	1	N	N	33	11		**1**	Yes	No voltage regulation for township - 33kV regulator at Yankalilla
Wasleys	SSD185	Mid North	G	3	Y	N	33	11	2x1.0	**3**	Yes	3 feeders from Wasleys Sub with no regulation
Booleroo Centre	SSD726	Mid North	G	1	R1411	N	33	11	1x1.0	**1**	Yes	No voltage regulation for township - 33kV regulator at Murraytown - other towns on 33kV line regulated at their substations
Karoonda	SSD472	Murraylands	G	1	Y	N	33	11	2x0.5	**1**	Yes	Sub at end of SD405. Regulation at Sherlock 33kV sub 27km upstream
Beachport	SSD274	South East	G	1	R1040	N	33	11	1x1.0	**1**	Yes	Substation at end of long tee off on SD492. Hatherleigh 33kV reg 17km upstream
Hawker	SSD716	Upper North	G	1	R1746	N	33	11		**1**	Yes	2 regulators on Wilpena SWER(HK02) No regulation on HK01 or HK03, or at Neuroodla 132/33kV
Verdun	SSD719	Eastern Hills	G	2	Y	N	33	11	1x1.0	**2**	Yes	2 feeders with no regulation and close to Verdun Substation

Attachment E

VOLTAGE REGULATION – Retrofit SCADA to 63 line regulators with suitable controllers (CL5/6)

Region	Substation name	Feeder	Feeder ID	Feeder Coordinates	VR
Eastern Hills	Houghton	Houghton	GU13	N5	VR125
Eastern Hills	Mt. Pleasant	Mt. Pleasant	GU32	P11	VR200
Eastern Hills	Mt. Pleasant	Springton	GU34	G3	VR468
Eastern Hills	Mt. Pleasant	Cookes Hill	GU37	G8	VR127
Eastern Hills	Mount Barker	Mt. Barker	MTB11	M3	VR199
Eastern Hills	Mount Barker	Bugle Ranges	MTB13	E12	VR129
Eastern Hills	Woodside	Lenswood	MTB54	T10	VR360
Eyre	Ceduna	Smoky Bay	CD4	B8	VR084
Eyre	Ceduna	Penong	CD5	C7	VR062
Eyre	Caralue	Kimba	CV08	M7	VR376
Eyre	Caralue	Kimba	CV08	F10	VR375
Eyre	Cowell	Cowell T/ship	CV753A	Y5	VR085
Eyre	Cowell	Cowell T/ship	CV753A	F6	VR510
Eyre	Cowell	Cowell T/ship	CV753A	C7	VR511
Eyre	Arno Bay	Arno Bay	CV757A	F5	VR423
Eyre	Streaky Bay	Streaky Bay	SB01	F7	VR507
Eyre	Streaky Bay	Streaky Bay	SB01	N4	VR503
Eyre	Streaky Bay	Haslam	SB15	E7	VR411
Eyre	Streaky Bay	Calca	SB17	B8	VR006
Eyre	Streaky Bay	Calca	SB17	D8	VR007
Eyre	Polda	Elliston	W04	P9	VR384
Eyre	Polda	Elliston	W04	E5	VR514
Eyre	Moorkitabie	Venus Bay	W06	M5	VR381
Fleurieu	Kingscote	Kingscote	KI31	O3	VR159
Fleurieu	Parndana	Parndana	KI42	D7	VR421
Fleurieu	Parndana	Parndana	KI42	H7	VR160
Fleurieu	Parndana	Parndana	KI42	Q10	VR204
Fleurieu	Langhorne Creek	Hartley	ST41	M9	VR355
Fleurieu	Langhorne Creek	Hartley	ST41	E6	VR443
Mid North	Jamestown	Jamestown	G02	O9	VR064
Murraylands	Meningie	Coorong 19Kv SWER	CN25	N5	VR172
Murraylands	Coomandook	KiKi 19kV SWER	CN53	N5	VR202
Riverland	Paringa	Murtho 33kV	LX21	M6	VR434
Riverland	Pyap	Pata	LX52	D9	VR148
South East	Kongorong	Carpenter Rocks	MG32	E8	VR363
South East	Robe	Robe 7.6kV	MI08	C8	VR431
South East	Millicent	Southend	MI16	C7	VR366
South East	Naracoorte	McIntosh	NA2	K8	VR378
South East	Naracoorte East	Cadgee	NA3	N12	VR527

Attachment E (continued)
VOLTAGE REGULATION – Retrofit SCADA to 63 line regulators with suitable controllers (CL5/6)

Region	Substation name	Feeder	Feeder ID	Feeder Coordinates	VR
South East	Naracoorte East	Kybylite	NA4	H11	VR076
South East	Naracoorte	Joanna	NA8	Q4	VR077
South East	Padthaway	Padthaway	NA12	N8	VR347
Upper North	Orroroo	Orroroo	G17	Q9	VR104
Upper North	Hawker	Wilpena 19kV SWER	HK02	C3	VR542
Upper North	Port Augusta West	Stokes	PA5	N7	VR213
Upper North	Port Augusta West	Stokes	PA5	L12	VR374
Yorke	Warooka	Point Turton	YK17	D7	VR438
Yorke	Maitland	South Maitland	MT01	E7	VR442
Yorke	Maitland	South Maitland	MT01	D3	VR441
Yorke	Maitland	Weetulta 19kV	MT02	C5	VR111
Yorke	Maitland	Weetulta 19kV	MT02	H7	VR467
South East	Keith	Keith	BT06	L3	VR163
South East	Keith	Keith	BT06	G5	VR164
South East	Keith	Keith	BT06	F7	VR165
South East	Keith	Keith	BT06	E2	VR418
South East	Bordertown	Mundulla	BT03	J3	VR162
South East	Bordertown	Teatrick	BT04	M8	VR428
South East	Bordertown	Teatrick	BT04	L1	VR427
Yorke	Moonta	Moonta	KA03	J8	VR440
Yorke	Port Broughton	Port Broughton	KA22	G9	VR345
Upper North	Gladstone	Laura	G05	F2	VR100
Upper North	Bungama	Warnertown	PP05	E2	VR453
Upper North	Bungama	Napperby	PP06	C9	VR105

58. APPENDIX AE – REMOTE VOLTAGE CONTROL BUSINESS CASE

Executive Summary

This Business Case recommends the installation of remote voltage control, via ADMS/SCADA, to selected metropolitan substation transformer on-load tap changers (OLTC) to enable a bi-directional network for customer's new technologies (eg solar PV) to operate under various network operating conditions. The capital cost of this proposal is $4M over 5 years.

The problem:

1. In 'weak' networks (consisting of long, high-impedance conductors and consumer mains) and at low demand periods, residential solar PV inverters must elevate voltages above the network voltage to enable export of solar generated energy into the Network.
2. Managing elevated voltages, as caused by customer's solar PV generation export to the network, on a customer by customer enquiry basis, is not prudent nor cost efficient.
3. The lack of a global network feeder solution utilising SCADA at zone substations to achieve a pro-active approach that would enable bi-directional power flows.

Key discussion points:

- The larger the PV installation (kW), the greater the voltage rise will be in weak networks.
- If a customer's solar inverter set-point is exceeded, the inverter will disconnect, causing the customer to lose the benefit of the feed-in tariff and generated renewable energy until voltages reduce and the customer's inverter reconnects to the network.
- SA Power Networks is obligated to supply a maximum voltage of 253V at the customer's service point in accordance with AS60038.
- Part of the remedy for future solar PV installations is to restrict the voltage rise between the inverter and customer's service point to 1% of the network voltage (nominally a maximum voltage rise of 2.3V), in accordance with the requirements of the revised AS4777. This may be further backed up by amendments to AS3000 – Wiring Rules.
- There are numerous solutions to this issue (Network and customer funded). One Network solution has been to tap down the low voltage distribution transformer supplying the customer to reduce output voltage, but this is only possible where the transformer has off-load voltage taps. This is a seasonal short term remedial solution.

Customer Benefits:

- Maintenance of Standard voltage levels will improve customer supply quality by reducing outages caused by transformer LV fuse operations and transformer failures.
- Customers will achieve the full benefits (e.g. the feed in tariff) of their new technologies.
- Customers will have a reduced need to lodge domestic appliance damage claims.
- Voltage-related customer enquiries that can result in individual costly solutions will reduce.

Proposal and Costs/Benefits

- It is proposed that as the penetration of residential solar PV increases from current levels of 20% to 30% (based on current installations), it is increasingly more cost-efficient to pro-actively reduce the substation bus output voltage by remotely altering the substation transformer(s) OLTC voltage relay (AVR) set point control, thus affecting all low voltage distribution transformers and customers on the feeders supplied by the substation – rather than reducing the output voltage at individual low voltage transformers. This approach forms the basis of this RVCP (Remote Voltage Control Project) business case.
- The NPV cost is $3.53M resulting in NPV customer benefits of $11.17M over 35 year financial evaluation period. This Business Case demonstrates a positive net present value of $7.64M over 35 years for feeders with high solar PV penetration. The profitability Index is 3.16.

Background

It is possible to utilise the control function within the SCADA system to send a signal to the bus voltage set point controller (AVR relay) of suitably equipped substation transformers and effectively reduce the substation's bus voltage level, as determined by the transformer's on-load tap changer movement.

The operating regime would preferably need to consider the weather effect on voltage rise from solar PV installations. On a typical summer's day and after the sun rises, feeder voltage levels will increase and reach a maximum during the day, co-incident with peak generation, and later in the day voltage levels will reduce. An operating regime that accounts for weather conditions; for example, a blue-sky day compared with a cloudy day; is ultimately necessary. The change of voltage level signal could either be automatically generated from the Network Control Centre, or could be manually set.

This Business Case considers 20 substations (refer Attachment B) whose feeders have high PV penetration (>20%) for installation of such a scheme over the Regulatory period 2015 to 2020, with two of those substations (with the highest PV penetration of the twenty) to be selected to trial the method and develop the process during the 2014/15 and 2015/16 spring/summer periods.

Discussion

The project evaluation period is 35 years, equating to the normal Business asset (substation asset life) depreciation life for Regulatory purposes.

Project Costs

The once-off costs over the Regulatory period 2015-2020 are the connection of the 20 SCADA installations between the remote monitors and the 40 relays in the substation control buildings. Installation costs are estimated at $0.2M per substation (refer Attachment C).

The on-going costs are for the 3G telecommunications, estimated to be 1% of the $0.2M capex pa for each installation. It is intended that one trial installation will be enabled in each of the first two years of the Regulatory period, with six installations added in each of the following three years. Telecommunication and ADMS[41]/SCADA[42] costs will increase cumulatively over the 5 year installation period, and there-after remain at year 5 levels.

[41] ADMS = Automatic Distribution Management System
[42] SCADA = Supervisory Control and Data Acquisition

Project Benefits

This project will offer the following benefits:

- Improved customer-service levels by reducing PV-related high voltage enquiries;
- Avoided tap-down requests – assume 340 enquiries per year, with 50% of those enquires in the metropolitan area, and only 20% of those metropolitan enquiries able to be remediated by tapping down the transformer; that is, 340 x 50% x 20% = 34 tap down requests per annum, at a cost of $1,190 to tap down a single low voltage transformer. Note that those of the low voltage transformers that are in fact equipped with tapping capability have off-load taps, requiring low voltage switching and communication with the NOC[43] in order to change tap positions on the transformers. Note also that not all low voltage transformers are equipped with taps;
- Avoided testing of typical customer PV-related high voltage complaints – assume 340 enquiries per year x 50% of those enquiries, or 170, located in the metropolitan area, and 80% (136) of those metropolitan enquiries requiring short-term metering to provide data for analysts to affect appropriate solutions;
- Avoided cost of installing replacement low voltage transformers with ones with taps, as recommended by analysis, with 20% of the 136 tested (27) requiring replacement, at a total cost of $540k per year ($20,000 per changeover);
- Avoided cost of installing an infill transformer with tapping ability adjacent the customer's premises, as recommended by analysis, with 30% of the 136 tested (41 customers) requiring an infill transformer, at a total cost of $1.428M per year ($35,000 per infill transformer installation); and
- Avoided cost of restringing low voltage circuits with larger conductor, as recommended by analysis, with 5% of the 136 tested (7) requiring restringing, and an average distance of 100 metres, at a total cost of $18k per annum ($2,580 per restring).

Remote EOL Monitor Voltage Feed-back

To check the end-of-line voltage levels on the feeders affected by this proposal, low-voltage monitors will be installed at appropriate locations having high concentrations of PV. Ultimately, if feasible and cost effective, a feed-back control system will be designed and retrofitted to enable communication between the end-of-line voltage monitor output of each low-voltage feeder and the substation relay voltage set point controller (via appropriate logic that takes account of the remote monitor input from *each* of the substation's feeders) to enable bus voltage levels to adjust appropriately to maintain end-of-line voltages within AS60038 limits throughout the day. The installation of end-of-line low-voltage monitors is the subject (in part) of a separate Business Case, A3: Strategic Transformer Monitoring.

[43] NOC = Network Operations Centre

PV-related voltage rise containment options

The following options have been considered as measures to contain voltage levels on the low voltage network at times of high PV generation and low local load. They are:

1. *Do nothing (business as usual)*
2. *Demand Management*
3. *Local generation*
4. *Remote voltage control (Stage 1))*

Manually lower the substation voltage set-point an appropriate amount early in the daylight hours of an expected high PV generation, low load day, and return the voltage set-point to its initial setting at sunset of that same day.

5. *Remote voltage control (Stage 2))*

Install monitoring devices, capable of remote communication, at the most distant customer connection point on the low-voltage network of each of the substation's 11kV (or 7.6kV) feeders that has high PV penetration, and use the voltage levels recorded on each of those feeders to jointly provide feedback to the AVRs of the supplying substation's OLTC transformers in order to maintain voltages at the outskirts of the low voltage network within AS60038 standards.

The five options will now be examined more closely.

58.1 Option 1 – Do nothing (business as usual)

This is not a recommended option in the context of the requirements of the proposal.

Advantages:

This option requires no additional capital expenditure, and requires no additional skills or training.

Disadvantages:

This course of action will not decrease the likelihood that a PV customer connected to a high PV penetration part of the network will have their inverter trip during periods of high solar PV generation. This will not assist the sustained rise in customer complaints concerning HV related to PV generation.

58.2 Option 2 – Demand Management

This is not a plausible option in the context and timeframe of the proposal.

Advantages:

For this option to be effective, Demand Management would have to be in the form of a switchable load-bank (for instance, battery storage), rather than load reduction, in order to absorb the PV-generated power, rather than have the inverter raise output voltage to enable export of that power. However, the network presently has a low penetration of energy storage batteries due to their cost.

Disadvantages:

This option forfeits the opportunity for the PV customer to export excess power and receive credits for that exported power.

58.3 Option 3 – Local generation

This is not a plausible option.

Advantages:

This option offers no advantage in the context of the proposal.

Disadvantages:

This option would result in any local household load being supplied by the 'local generation', with any excess generation effectively becoming 'negative load', which would itself be exported to the wider network. PV generation would exacerbate that situation, and the PV inverter would have still *more* likelihood of being disconnected from the low voltage network due to high inverter output voltages.

58.4 Option 4 – Remote Voltage Control (Stage 1)

This option is recommended.

This option will demonstrate the effectiveness of controlling the substation voltage set-point to counter the PV-related voltage rise on the low voltage network, and will eventually lead to the future project of completely automating the control of substation bus voltages with those at the remote ends of the substation's low voltage feeders in order to maintain remote voltages within standard on an ongoing basis.

Advantages:

This option will reduce the overall substation voltage, and therefore low-voltage feeder volts, in anticipation of high-PV, low-load days. The success of this approach will however be dependent on accurate temperature/weather forecasts as obtained from such sources as the Bureau of Meteorology.

Disadvantages:

This option will not be able to respond to changing weather conditions during any one particular day, but will be restricted to the substation transformer set-point setting decided prior to, or at the outset, of that day. This method will require daily human interpretation and intervention (via the joint effort of QS Analysts and the NOC). This option will also require NOC operator acceptance.

58.5 Option 5 – Remote Voltage Control (Future stage)

This option is not recommended at this stage, but will form the scope of future voltage control advances that will build on the outcomes of the recommended Option 4.

Advantages:

This option is intended to offer a universal, cost-effective solution that will ensure that far fewer PV customers would be disconnected at times of low load, high PV generation, while non-PV customers would in the main notice no discernable difference in the quality of their electricity supply; some customers may however be subject to low volts, but this would be permanently rectified on a case-by-case basis.

Disadvantages:

This option may result in increased wear to the OLTC mechanisms of the substation transformers, depending on the sensitivity/bandwidth of the remote monitors, and consequently the frequency/number of tap-changing operations per day. It will also require far more analysis and development than is the scope of this project, and will not be further pursued at this stage of development.

Project Evaluation - Technical

Only Options 4 and 5 offer technically viable means of providing remote control of low-voltage feeder voltages under conditions of high PV penetration, with Option 5 being the natural progression from Option 4. Option 4 is the technically preferred option for the purposes of this project.

Project Evaluation - Economic
The total project implementation cost is $4M in 2014 dollars ($200k in each of 2016 and 2017, followed by (6 x $200k) = $1.2M in each of the following three years). The net present cost of the project is $3.53M over 35 years.

This is offset by net present benefits of $11.17M over those 35 years (the life of the asset), based on the assumption that the remote voltage control schemes are installed in the 20 substations that currently have the highest PV penetration, in order to achieve maximum benefit from the avoided costs of manual intervention in the event of PV-related high-voltage incidents.

This project will represent a positive economic benefit for customers, with an NPV of $7.64M, and will produce a positive cash flow (annual benefits compared with annual costs) after 2 years (refer Attachment A). The profitability index for the preferred solution is 3.16.

Project Funding
The project is funded by SA Power Networks' capital budget allocated to Network Quality of Supply. Total CAPEX is $4.00M (2014 dollars) over 5 years, commencing 2016.

Project Resourcing
SA Power Networks Field Services personnel will install remote monitors as guided by Network QS, and SCADA and Telecommunications personnel will establish SCADA links between those remote monitors and both QS Analysts and the NOC, as well as between the specific substations' transformer OLTC automatic voltage regulators (AVRs) and the NOC. The data will initially be analysed by Quality of Supply Analysts, in liaison with the NOC, and a protocol determined to initiate substation voltage set-point changes in anticipation of the following day's forecast weather and loading conditions. The first two sites have been selected as *trial* sites, with the intention of using those sites to develop and refine the process of remote voltage set-point control for high PV penetration substations.

It is not expected that an increase in existing Quality of Supply Network resources will be required over the 5-year duration of this programme.

Project Costs Estimate
Attachment C indicates a cost estimation of Network and Field Services costs with overheads added. This indicative estimate is based on experience gained from recently estimated projects. The design and installation work, including SCADA work, will all be done in-house.

Project Timing
This project will commence when AER regulatory funding is approved, expected by 31 October 2015. Expenditure cash flows are expected to be $0.4M for the first two years (the two trial sites), followed by $1.2M for each of the following three years to 2020.

Recommendation
It is recommended that this project be approved as part of the SA Power Networks 2015-2020 submission, with implementation scheduled to commence after AER funding approval in October 2015. The total project cost is estimated to be $4M, and will represent a positive net present value to SA Power Networks of $7.64M over the nominal 35-year life of the assets.

Paul Driver

Network Manager Quality of Supply

Attachment A: Financial Analysis

CAPITAL EVALUATION

NPA Details

Substation bus volts remote setpoint control

Evaluation Factors

Discount Rate (Real Pre-Tax)	8.98%	Policy rate for investment in core business assets
Base Year Ending 31 Dec	2016	
Asset Depreciation Life	35	Default regulatory value - general network assets

Other assumptions made in this case:

Based on 2012-13 avoided costs as benefits
25% Field Services O/H and 20% Network
Management O/H (incl 11% corp) included in material
and labour costs and benefits

PV-related QSI tests per year (logger installation, removal)	136		340*50%*20%
PV-related QSI tapping down of LV transformers as per QS direc	34		Average of 2 to 3 per week during summer months
Cost of QSI installation and then removal of one logger	$960		2x(2 x (0.5h travel + 1h installation))
Cost of QSI tapping of LV transformer	$1,190		1x(two linespersons+one line truck)x one hour plus LV switching and NOC
Cost of unsupplied energy	$50	/kWh	Cost reflecting financial disadvantage to PV customers
Duration of inverter disconnection	1	hours	Period during which voltage reduces with increasing inverter disconnections
Percentage of PV customers affected by PV-related HV outage	20	%	Proportion of customers located farthest from LV transformer

Financial Analysis	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Year ended 31/12:	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
Costs:																					
Installation of SCADA connection (including remote metering and OLTC relay)	0.200	0.200	1.200	1.200	1.200																
Total Capital	0.200	0.200	1.200	1.200	1.200	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Telecommunications (3G)		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total operating	0.002	0.004	0.016	0.028	0.040	0.040	0.040	0.040	0.040	0.040	0.040	0.040	0.040	0.040	0.040	0.040	0.040	0.040	0.040	0.040	0.040
Total Costs ($M)	0.202	0.204	1.216	1.228	1.240	0.040	0.040	0.040	0.040	0.040	0.040	0.040	0.040	0.040	0.040	0.040	0.040	0.040	0.040	0.040	0.040
Benefits - OPERATIONAL																					
Avoided QSI testing ($M)	0.000	0.000	0.131	0.118	0.106	0.095	0.086	0.077	0.069	0.062	0.056	0.051	0.046	0.041	0.037	0.033	0.030	0.027	0.024	0.022	0.020
Avoided cost of corrective manual LV transformer tapping	0.000	0.000	0.042	0.043	0.044	0.044	0.044	0.044	0.044	0.044	0.044	0.044	0.044	0.044	0.044	0.044	0.044	0.044	0.044	0.044	0.044
Customer benefit - connection access ($M)	0.000	0.004	0.015	0.017	0.018	0.020	0.022	0.024	0.027	0.030	0.033	0.036	0.039	0.043	0.048	0.052	0.058	0.063	0.070	0.077	0.084
Total Operational Benefits ($M)	$0.000	$0.004	$0.187	$0.177	$0.168	$0.159	$0.152	$0.146	$0.140	$0.136	$0.133	$0.130	$0.129	$0.128	$0.129	$0.130	$0.132	$0.134	$0.138	$0.143	$0.148
Benefits - CAPITAL																					
Avoided cost of installing an LV tfr adjacent the customer	0.000	0.000	1.428	1.285	1.157	1.041	0.937	0.843	0.759	0.683	0.615	0.553	0.498	0.448	0.403	0.363	0.327	0.294	0.265	0.238	0.214
Avoided cost of replacing an LV tfr with one with taps	0.000	0.000	0.544	0.490	0.441	0.397	0.357	0.321	0.289	0.260	0.234	0.211	0.190	0.171	0.154	0.138	0.124	0.112	0.101	0.091	0.082
Avoided cost of restringing LV	0.000	0.000	0.018	0.016	0.014	0.013	0.012	0.010	0.009	0.008	0.008	0.007	0.006	0.006	0.005	0.004	0.004	0.004	0.003	0.003	0.003
Total Capital Benefits ($M)	0.000	0.000	1.990	1.791	1.612	1.450	1.305	1.175	1.057	0.952	0.856	0.771	0.694	0.624	0.562	0.506	0.455	0.410	0.369	0.332	0.299
Total Benefits ($M)	$0.00	$0.00	$2.18	$1.97	$1.78	$1.61	$1.46	$1.32	$1.20	$1.09	$0.99	$0.90	$0.82	$0.75	$0.69	$0.64	$0.59	$0.54	$0.51	$0.47	$0.45
Net Cash Flow ($M)	-$0.20	-$0.20	$0.96	$0.74	$0.54	$1.57	$1.42	$1.28	$1.16	$1.05	$0.95	$0.86	$0.78	$0.71	$0.65	$0.60	$0.55	$0.50	$0.47	$0.43	$0.41

Pre Tax:				
Net Present Value	$7.64	million		
Net Present BENEFIT	$11.17	million	and PI =	3.16
Net Present COST	$3.53	million		

Attachment B: High PV Penetration Substations Intended for Remote Voltage Control Installation

Trial Number	ZONE SUBSTATION	Number of Transformers	Number of Customers	AVR	Combined Normal Cyclic Rating (MVA)	Forecast Max Demand in 2013/14 (MW) - source DAPR 10% POE forecast	Minimum spring load (MW)	Date and Time of minimum	Total PV penetration (MW)	% Penetration (PV cf transformer capacity) 2013/14	PV % pa= 2020/21	15.0%
Trial 1	HACKHAM	1	5,959	DRMCC	30	16.6	0.04	14/11/2013 2:30	3.95	13%	10.51	35%
Trial 2	FULHAM GARDENS	2	12,254	AVE4	51	36.1	4.09	19/09/2013 13:00	11.23	22%	29.87	59%
3	HOPE VALLEY	1	6,759	DRMCC	30	18.6	-0.66	1/11/2013 13:30	4.27	14%	11.36	38%
4	SEAFORD	1	3,099	2V162	15	8.5	-2.41	15/10/2013 13:30	2.29	15%	6.09	41%
5	MORPHETT VALE EAST	2	13,588	AVE3	61	32.9	0.09	14/11/2013 13:30	9.34	15%	24.84	41%
6	VICTOR HARBOR	2	11,670	DRMCC	69.8	25.7	0.00	1/09/2013 1:30	7.09	10%	18.86	27%
7	BLACKPOOL	2	5,738	MK20	21	14.2	1.02	12/11/2013 13:30	3.7	18%	9.84	47%
8	HAPPY VALLEY	2	10,511	2V164	61	33	0.74	14/11/2013 14:30	8.5	14%	22.61	37%
9	ALDINGA	2	6,835	MK20	32.6	17.9	0.80	15/10/2013 13:30	4.44	14%	11.81	36%
10	PARAFIELD GARDENS	2	9,399	DRMCC	24.6	18.8	0.00	1/09/2013 6:00	4.63	19%	12.32	50%
11	LARGS NORTH	2	5,424	MK20	27.2	14.2	1.42	24/11/2013 13:00	3.47	13%	9.23	34%
12	SHEIDOW PARK	2	8,182	MK20	32.8	26.8	0.72	12/11/2013 13:00	6.41	20%	17.05	52%
13	GOLDEN GROVE	3	14,644	MK20	91	45.6	2.29	7/10/2013 14:00	10.27	11%	27.32	30%
14	NORTHFIELD	2	5,396	AVE3	28.7	18.4	1.29	10/11/2013 13:30	3.97	14%	10.56	37%
15	BLACKWOOD	2	9,159	AVE3	61	26.9	2.02	30/10/2013 13:30	5.7	9%	15.16	25%
16	PORT NOARLUNGA	2	9,503	DRMCC	60	26.3	3.34	8/10/2013 0:00	5.51	9%	14.66	24%
17	GLANVILLE	2	5,210	AVE3	17.2	13.4	1.38	8/11/2013 14:30	2.75	16%	7.32	43%
18	TEA TREE GULLY	2	11,228	AVE3	49.6	32.9	3.26	7/10/2013 13:30	6.63	13%	17.64	36%
19	EVANSTON	2	10,570	AVE	61	34.4	4.70	13/10/2013 14:00	6.79	11%	18.06	30%
20	INGLE FARM	2	13,014	AVE3	55	35.1	4.87	7/10/2013 13:00	6.92	13%	18.41	33%

Note: the last 2 columns are a 2020/21 forecast of PV penetration (MW) with 15% pa increase in PV from 2013/14.

Attachment C: Remote Voltage Set Point Control Project Estimated Costs per Substation

Set Up Costs (incl training, NOC)	20000
System design	24000
ADMS algorithm	10000
network total	**54000**
Testing	10000
ADMS mods	20000
AVR changes	33000
Recommissioning	10000
telecomm/SCADA link	35000
field services total	**108000**
network overhead	**10800**
field services overhead	**27000**
Total	**$199,800**