

# NETWORK CONTROL - PROJECTS REVIEW 2021-25

SA Power Networks Limited

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## 1 EXECUTIVE SUMMARY

SA Power Networks has been operating with the ADMS since 2015 and this has delivered network and customer benefits. Whilst the ADMS is now an integrated part of SA Power Networks' control system environment there is a need for continued investment to ensure these benefits are maintained and maximised for SA Power Networks and its customers. The investments break down into 3 areas:

- Extending Network Data – Expansion of SCADA to the remaining Zone Substations
- Maintaining a Current ADMS – Upgrade ADMS and operating systems that are out of support as well as accessing newer functionality required to manage a changing environment
- Risk Mitigation for Obsolescence - Two projects to replace RTUs and Data Concentrators and ensure data is reliably received by the ADMS

A review of each project is summarised in the table below.

Project	Description	Capex Cost (2021-2025)	Key Benefits
ZSS SCADA Expansion	Completion of an on-going program to install SCADA at 61 remaining ZSS	\$9.29m	Improved information, visibility and control at the ZSS results in \$14.8m of customer and SA Power Networks benefits with a project NPV of \$5.7m
ADMS Upgrade	Upgrade the combined ADMS/OMS and operating system	\$7.39m	Improved system security as well as facilitation and control of increased Distributed Generation
Data Concentrator Replacement	Replacement of 5 Data Concentrators that are 20 years old at the start of the regulatory period and beyond their design life	\$0.76m	Reduced likelihood of Data Concentrators failing and mitigation of the risk of not being able to see the many devices that rely on them
RTU Replacement	Replacement of the oldest RTUs on SA Power Networks system that will all be more than 20 years old and beyond their design life	\$4.88m	Reduced risk of RTUs failing through a co-ordinated replacement program as limited spares and age increases the probability of failure and an inability to view and control equipment at the ZSS

Table 1 Proposed Projects and Capex Requirements in the 2021-2025 Regulatory Period

The investment in the SCADA Expansion at ZSS has a positive business case with the quantified societal benefits outweighing the costs. The replacement of DC/RTU assets that are over 20 years old and the upgrade of the ADMS will assist in maintaining reliability, quality and security of supply as it reduces the risk of operating without full visibility and control of the network.

The combination of projects will also provide better planning data and more reliable control of load/distributed generation on the network. This will facilitate network connection and management without unnecessary network augmentation and therefore meets the prudence and efficiency requirements of the AER.

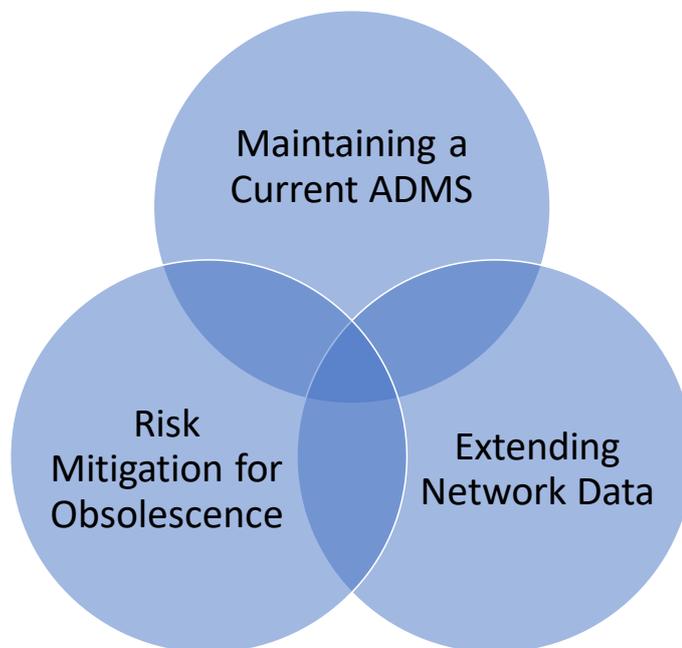
## 2 INTRODUCTION

### 2.1 Background

SA Power Networks have been operating the network with the ADMS since 2015, which has created many network and customer benefits including:

- Improved control and monitoring of the network highlighting potential issues including damage to network or customer equipment from operating outside normal operating parameters
- More detailed warnings and the ability to predict potential problems and respond to actual issues
- Enhanced information to assist with augmentation requirements and avoid unnecessary capacity expansion
- Real time and historic data to assist with asset management and maintenance decisions
- Improved fault detection and faster restoration times
- Automated responses to certain types of issue such as faults that have triggered an outage

Whilst the ADMS is now an integrated part of the control system environment there is a need for continued investment to ensure these benefits are maintained and maximised for SA Power Networks and its customers. This breaks down into 3 complementary investment areas shown in the chart below:



*Figure 1 Investments Needed to Maintain and Optimise the Benefits of the ADMS*

These investments can be summarised as:

- Extending Network Data – Expanding SCADA coverage and the visibility and control network operators have over the network.
- Maintaining a Current ADMS – As with all systems, there is a need for regular upgrades to the ADMS/OMS and Operating Systems to enhance the functionality (such as DER functions) and overcome security risks.
- Risk Mitigation for Obsolescence – Two project to replace older RTUs and DCs that are already well outside the design life.

## **2.2 Structure of the Report**

This document summarises the four proposed network control projects, which are:

**1) Extending Network Data – Expansion SCADA to remaining Zone Substations (ZSS)**

SA Power Networks has identified several benefits of continuing to roll out SCADA to the remaining ZSS. The continuation of this program should result in all ZSSs having SCADA by the end of the next regulatory period.

**2) Maintaining a Current ADMS – ADMS Upgrade Project**

A key concern for SA Power Networks is that the operating system for ADMS will be out of extended support during the next regulatory period, which will increase the risk of potential cyber attack. An ADMS upgrade will mitigate this risk and provide several additional benefits from the functionality of the latest version of the system. This upgrade will complement planning which is underway to replace the ADMS hardware as it reaches end-of-life and needs upgrading to include the integrated OMS.

**3) Risk Mitigation for Obsolescence – Data Concentrator Replacement**

Seven of SA Power Networks Nine Critical Data Concentrators are, or will be, beyond their designed life expectancy and are beginning to experience regular failures. SA Power Networks is proposing to replace the oldest five devices.

**4) Risk Mitigation for Obsolescence – RTU Replacement**

As with the Data Concentrators, SA Power Networks is proposing to replace the oldest of the ZSS RTUs which are, or will be, beyond their designed life expectancy, and are becoming less reliable.

The remainder of this document provides a description of each of the projects including costs as well as quantitative and qualitative benefits.

## 3 SCADA TO REMAINING ZSS

### 3.1 Project Scope and Background

SA Power Networks has been undertaking a program over the current regulatory period to deploy SCADA devices to rural ZSS that currently aren't monitored. The intention is to complete this project over the 2021-2025 regulatory period to ensure that all ZSS have visibility and control through SCADA. The business case approach is based on the cost and benefits identified in the 2014 review<sup>1</sup>.

The SCADA solution is based on replacement of the current hydraulic recloser at the ZSS with a modern electronic recloser that has integrated SCADA supporting monitoring and control via the ADMS. The recloser is fitted on the exit side of the feeder with most of the remaining substations requiring just a single recloser. However, for the larger ZSS with two feeders it will be necessary to deploy two reclosers with monitoring and control capability.

As at December 2018 there were 81 ZSS without SCADA. This is forecast to reduce to 61 sites by the start of the next regulatory period. The 61 ZSSs include 12 sites that will require monitoring and control to be applied to two feeders rather than one.

The original business case had considered converting the shared sites (shared with ElectraNet) to a SCADA solution that was fully controlled and owned by SA Power Networks. However, given the incremental benefits of this separation are likely to be low the project has not planned to modify these sites.

The completion of this project will result in all substations having SCADA by the end of the next regulatory period.

### 3.2 Projects Costs

The NPV of the Project Costs is shown in the table below assuming a 5-year linear roll out of SCADA to the remaining ZSS. A real discount rate of 3.5% has been applied in the modelling with a 15-year project assessment period.

Description	NPV
Capital Cost of SCADA Expansion (Reclosers and associated equipment)	\$8.5m
Opex Cost for Expanded SCADA	\$0.6m
<b>Total</b>	<b>\$9.1m</b>

*Table 2 Cost of ZSS SCADA Expansion*

The capital costs are based on the Substation SCADA Feeder recloser priority list for 2018. This has a cost per project of \$132k for the ZSS with a single feeder requiring an electronic recloser. The priority list had included a cost of \$235k where two feeders needed to be monitored and controlled. This cost includes the capital cost of the communications infrastructure required for the SCADA solution. The undiscounted capital cost of the SCADA Expansion is \$9.288m with 49 single feeder installations and 12 two feeders installs.

The modelling has assumed some incremental Opex costs for maintaining SCADA at the ZSS. It is based on the 2014 estimated cost of maintaining SCADA at existing ZSS of around \$1k per ZSS per year. This is an average figure as most years will have very little maintenance, but this is offset by the occasional repair.

### 3.3 Quantitative Project Benefits

A table of the quantified project benefits is shown below along with a fuller description in the following sections.

<sup>1</sup> DNV GL, ADMS Roadmap and Project investigation, Oct 2014

Benefit	SA Power Networks	Customers
Avoiding Major Equipment Problems at ZSS	\$0.9m	\$1.3m
Faster Fault Entry on OMS		\$6.7m
Reduced ZSS Visits	\$1.6m	
Avoided Augmentation	\$1.9m	
Defer Repex	\$2.4m	
<b>Total</b>	<b>\$6.9m</b>	<b>\$7.9m</b>

*Table 3 Benefits of ZSS SCADA Expansion*

Only one benefit (the avoided major equipment problems) will result in SAIDI improvements and consequently STPIS incentives for SA Power Networks. Given this relatively small impact the STPIS incentive has not been considered in this analysis.

### 3.3.1 Avoiding Major Equipment Problems from Better Monitoring

This benefit arises from monitoring of the load at the ZSS and taking action where it indicates that major equipment (such as power transformers) is being damaged. In the previous review of 75 ZSSs it was estimated that 1 event per year of major damage could occur and this has been pro-rated down to 0.8 events per year for the 61 ZSSs that won't have SCADA at the start of the regulatory period. The modelling assumes that only 50% of these could be avoided with monitoring and control as no actions may be possible with some of the incidents. These ZSS are relatively small with an estimate residual value for each transformer of \$250k.

The customer benefit of avoiding damaged equipment is the reduction in outages and consequently unserved energy that would result from the damage. The benefit assumes that any outage could last for 8 hours as it would require a transformer to be replaced.

### 3.3.2 Improvements from Faster Identification of Faults and Entry into OMS

When ZSS have SCADA, any faults detected can be automatically transferred to the OMS allowing the dispatch team to start the restoration activity. The current process requires customers to ring up to report the fault and the fault restoration process (at ZSS level) will only commence once a fault has registered sufficient calls. The time saving with SCADA is composed of 2 elements - firstly, the detection by SCADA, and secondly the 'automatic' link from the ADMS to the OMS so that these outages can be actioned almost immediately.

The modelling assumes that this automatic transfer will save 10 minutes for each SCADA detected fault. This reflects the rural nature of these ZSS and the fact that these outages could occur at any time of the day/night.

There are 230,000 annual customer outages due to HV faults on the Rural Long network with some customers impacted multiple times. The 61 ZSSs gaining SCADA represent 44% of the rural long customers and this has been used to pro-rata the 10 minutes savings from each incident. This time saving is multiplied by the average rural long customer load to calculate the energy that is now supplied. This is valued at customer reliability value for SA rural customers.

**It should be noted that this is a customer benefit and would not be captured in SA Power Networks' SAIDI calculations, which commences when the fault is recognised and recorded in the OMS.**

### 3.3.3 Reduced Visits to ZSS to change settings

A significant efficiency benefit from installation of SCADA at ZSS was the avoided cost of reduced visits to ZSS to change settings. Once SCADA monitoring and control is installed at the ZSS these settings can be done remotely. The following assumptions were made in these calculations;

- Average number of visits per year was 6 – this includes planned switching visits, unplanned switching events and changes due to bushfire. These activities can often involve two separate trips to initially change the settings and then revert back to the previous settings once the activity has been completed.
- Hours per visit was 2 – many of these ZSS are rural and could involve considerable travel time from the depot, so this figure is considered conservative.
- Crew size was 2 – this reflects SA Power Networks typical crew size for these types of activities.
- Hourly cost of Field Crew – this included the cost of the vehicle and was set at \$120 per hour.

### 3.3.4 Deferred Augmentation through Enhanced Information for Planners

This is the benefit of Planners having more accurate information on the status of the network. This information can be used to allow Network Planners to be less conservative in their decisions on when to upgrade the network for growth reasons. This could include growth of Distributed Generation (DG) and the level of reverse power flows as well as more conventional demand limits. This less conservative approach would also be assisted by the ability of the control room to have direct control and be able to intervene at a ZSS. This would give the Planner increased confidence that they can operate the network closer to its limits and defer augmentation.

The modelling has assumed that this more accurate information is equivalent to a 0.5% increase in network capacity. A review of the 81 ZSS that currently don't have SCADA suggested a mean normal operating rating of 3 MVA. However, there are several larger rural ZSS that may install SCADA before this regulatory period and therefore a more conservative average size of 1.5 MVA has been assumed per ZSS. This results in a forecast of 92 MVA for the normal operating rating for the 61 ZSS. The 0.5% saving of this network capacity represents 0.45MVA. This has been multiplied by the Long Run Marginal Cost of capacity at the rural substation level (\$438/kVA/year).

### 3.3.5 Defer Repex

The proposed project will provide for an early replacement of the hydraulic reclosers by electronic reclosers. This should result in a modern stock of reclosers on this part of the network, which should therefore avoid the need to replace assets due to age and condition of the asset.

Without this ZSS SCADA project there would be a need to replace the existing reclosers as they will fail due to age and asset conditions. The modelling has assumed a 4% failure rate with an installed cost per replaced hydraulic recloser of \$70k. The benefit is assumed to apply to all the remaining ZSSs from the start of the regulatory period as any failures would see this substation prioritised for the recloser replacement, rather than making a temporary straight replacement with a hydraulic recloser without SCADA.

## 3.4 Qualitative Project Benefits

These benefits are a mixture of customer and SA Power Networks benefits and are described in the table below. Some of these benefits could increase in importance over time as the level of distributed generation grows.

Benefit	Description
Future ability to monitor and manage increasing levels of DER	The expansion of the SCADA network provides more granular information on the loading of the network and the need/ability to manage DER levels and constraints.

Benefit	Description
	This may become more important as the market moves to a DSO model and there is a need to dispatch and manage DER sources such as VPPs and aggregators
Reduced Complaints and PV Impacts from Improved Voltage at ZSSs	This is a combination of small benefits that emerge from the control room being able to improve the voltage profile at the ZSS due to improved information on the network. It includes four separate elements: <ul style="list-style-type: none"> <li>• Reduced incidence of damage to customer equipment due to voltage issues;</li> <li>• Reduced SA Power Networks cost of dealing with complaints about voltage;</li> <li>• Increased PV generation (less inverters tripping off due to voltage problems); and</li> <li>• Reduced claims against SA Power Networks for damage to equipment</li> </ul>
Reduced Cost of Manual Voltage Checking from ZSS measurements	The expansion of SCADA will avoid the need to regularly check voltage levels at each ZSS. Currently, on average, the ZSS has its voltage checked using a data logger every 5 years with additional checks where customers report a voltage issue that may be a HV issue.
Improved Quality of Load Flow Solution	The additional input data from more ZSS with SCADA/ADMS will improve the quality of the load flow solution and make for better operational and planning decisions.
Bushfire Benefits	Under extreme fire danger conditions, where there is a danger of SA Power Networks assets starting a bushfire, it may be necessary to disconnect some customers. To ensure that customers are not unnecessarily disconnected, SA Power Networks strategy is to provide remote control of switches. Operating these switches remotely minimises the timing of interruptions as only those sections of lines that present a significant fire risk would be disconnected for the minimum time necessary with no waiting for crews to arrive to reconnect.
Improved Use of the State Estimator	Increased information makes the ADMS State Estimator more accurate and therefore more useful to the Planners.
Avoided Outages through better Load Management	In overload situations there may be an option to transfer load across feeders and avoid outages. It is not clear how often this will be an option, so this has not been explicitly captured in the calculations.

Table 4 Qualitative Project Benefits from ZSS SCADA Expansion

### 3.5 Business Case Summary

#### 3.5.1 Comparison of Costs and benefits

The Societal NPV of the costs and benefits of ZSS Expansion are summarised in the table below covering customer and SA Power Networks benefits. This is compared to a base case of continuing with hydraulic reclosers with no SCADA providing data back to the ADMS.

Category	NPV (\$m)
Costs	\$9.1m
Benefits	\$14.8m
Net NPV	\$5.7m

Table 5 Summary Table of Costs and Benefits from ZSS SCADA Expansion

3.5.2 Cash Flow Analysis

The picture below illustrates the cash flows associate with the project. The first 5 years show significant investment as the remainder of the ZSS are equipped with SCADA. However, once all ZSS have SCADA there is a consistent annual benefit that results in a positive NPV by year 10 of the project. The increase in costs in year 2 is due to the assumption of 3 complex sites being completed this year, rather than the two sites completed in year 1.

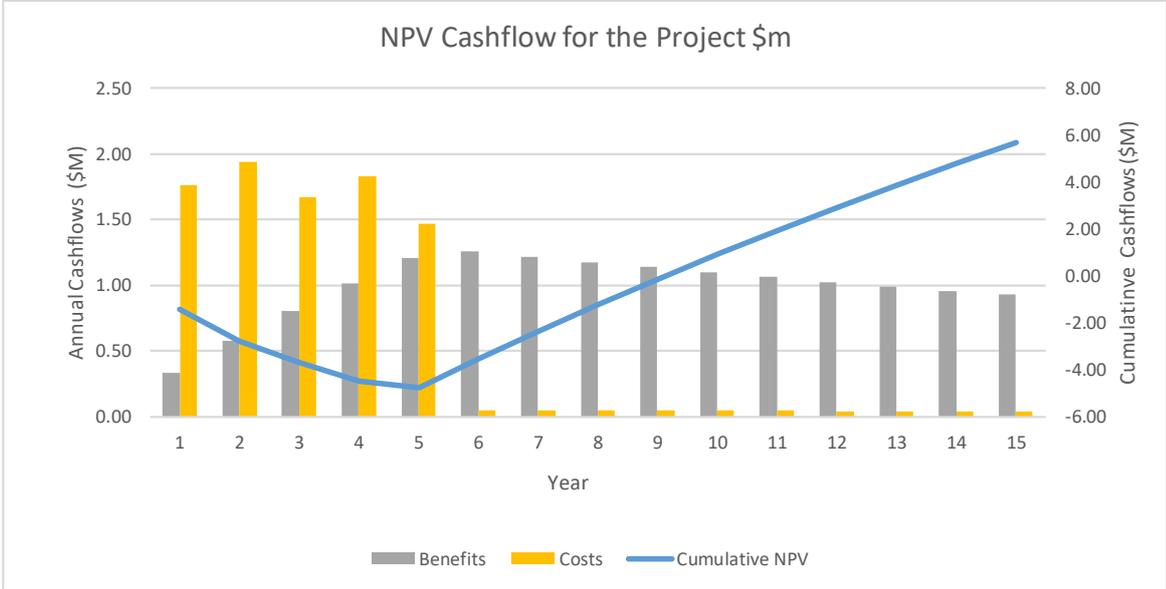


Figure 2 NPV Cashflow for the ZSS SCADA Expansion Project

3.5.3 Sensitivity Analysis

Whilst the central estimate of the NPV to society is forecast at \$5.7m this is sensitive to a number of key parameters. The figure below indicates the impact on the NPV of moving a single parameter from its expected value to the high or low values that were considered feasible. This shows the significance of the project assessment period for the project.

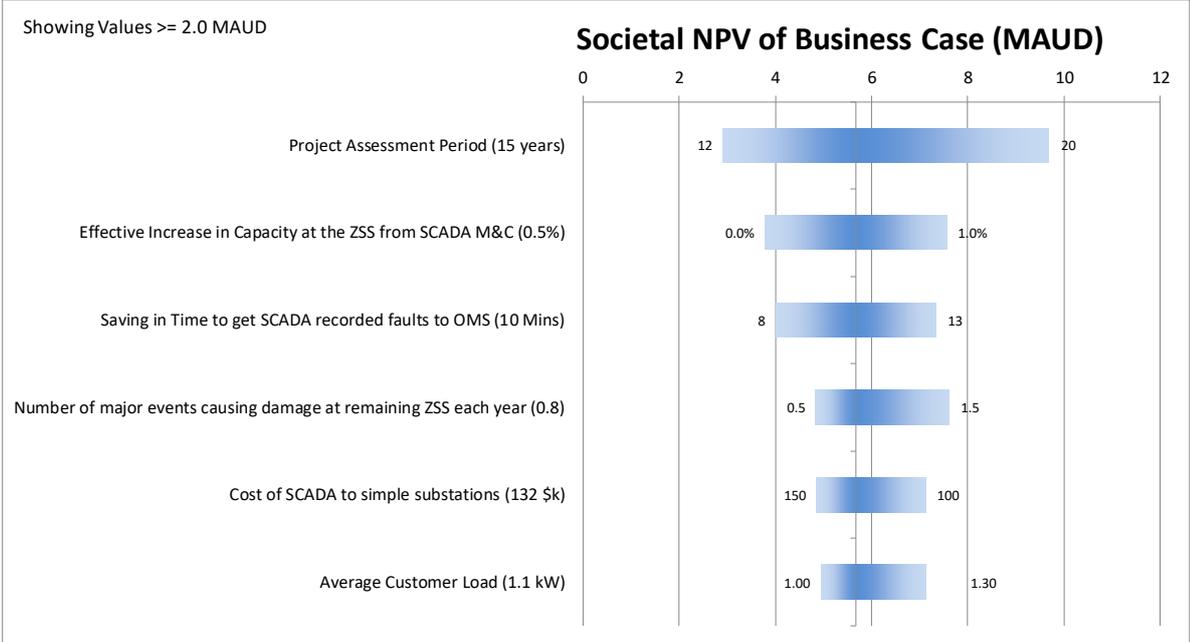


Figure 3 Societal NPV of ZSS SCADA Expansion

The three most sensitive parameters were:

- Project Assessment Period (range \$6.8m)
- Effective Increase in Capacity at the ZSS from SCADA M&C (range \$3.8m)
- Saving in Time to Get SCADA recorded faults to OMS (range \$3.3m)

### 3.5.4 Monte Carlo Analysis

The Monte-Carlo simulation randomly varies all of the key parameters within their defined probability distribution to predict a range of potential outcomes and the probability of a specific outcome. The chart below shows the NPV forecast chart for a simulation of 10,000 trials with a triangular distribution applied to all parameters. The key observation from this Monte Carlo simulation is that the mean NPV using this approach (\$7m) is slightly higher than the value using the most likely value. The simulations showed almost all outcomes with a positive NPV and over 99% of simulations with an NPV above \$2m.

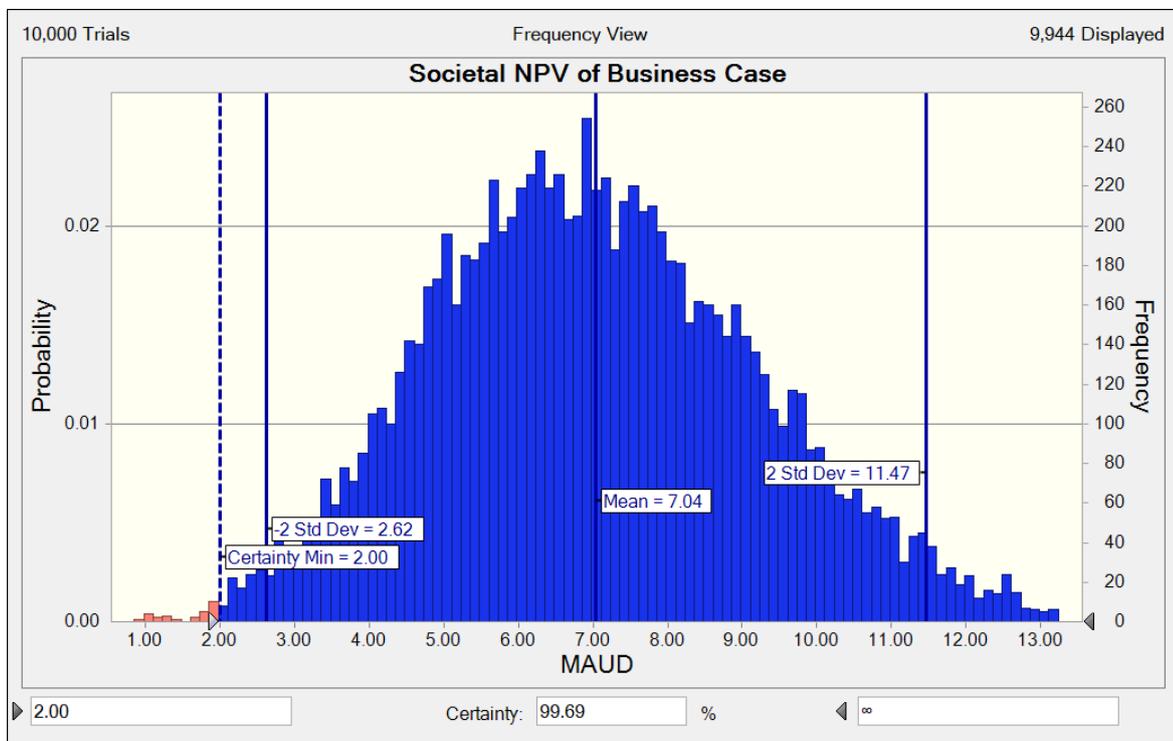


Figure 4 Monte Carlo Simulation for ZSS SCADA Expansion

## 4 ADMS UPGRADE

### 4.1 Project Background and Scope

The Schneider Electric ADMS has been in live operation at SA Power Networks since April 2015. The functionality of the system is currently being extended to include an integrated OMS along with the ADMS. This provides many benefits but does increase the complexity of any upgrades which has impacted the upgrade schedule now proposed by SA Power Networks.

The system is scheduled to have a hardware refresh in FY 2020 as the hardware has reached end-of-life. The hardware refresh will also ensure sufficient performance to run the integrated OMS within the ADMS. Given this upgrade, SA Power Networks plans to operate on this hardware throughout the next regulatory period. This may require extended support after the first 5 years has expired, but this is believed to present a manageable risk to the organisation.

Whilst the hardware is being replaced in FY 2020 the intention is to continue operating on the same version of the ADMS software (v3.6) due partly to the complexity of the change with the integration of the OMS. This delay will allow more time for the latest version of the product (v3.8) to be widely deployed and for development and testing of the DERMS module within the newer ADMS software versions. This DERMS module will be critical to the management and control of the increasing levels of distributed generation connecting to SA Power Networks system over the next regulatory period. SA Power Networks is therefore planning to upgrade to version 3.8 or later of the software, which will include the DERMS module in FY2024 and FY2025 with a 2 year project planned by the ADMS Project Team.

Further details on the drivers for the upgrade are provided in Project Benefits below.

### 4.2 Project Costs

The upgrade costs have been produced by the ADMS project team and includes both internal and external costs as shown in the table below. These costs include overhead.

Cost/Financial Year	2024	2025	Total
Total Costs	\$3,696,000	\$3,696,000	\$7,392,000

Table 6 Capex Costs for ADMS/OMS Upgrade

### 4.3 Project Benefits

#### 4.3.1 Maintain Cyber Security Protections

The version of the ADMS installed at SA Power Networks uses the Windows 7 operating system for the user workstations and the Windows Server 2012 operating system. Extended Support for the operating system will end in 2023. The end of support will mean security patches will no longer be provided by Microsoft, making these devices more vulnerable to cyber-attacks. The latest version of the ADMS (v3.8) upgrades these operating systems to Microsoft's currently supported operating systems – Windows 10 and Windows Server 2016.

The energy sector has received considerable attention in regard to cyber security by government agencies within Australia and overseas, primarily due to the high risk associated with a cyber security incident in this sector. The Australian Cyber Security Centre (ACSC) and AEMO have both provided guidelines for management of cyber security in the energy sector. It is likely that AEMO's Australian Energy Sector Cyber Security Framework (AESCSF) will be the basis of new rules relating to cyber security management for NEM participants in 2019.

The intention of SA Power Networks is to be a prudent network operator and as such is currently meeting the "Essential Eight" measures as defined by the ACSC and utilised by the AESCSF. However, over the next regulatory period, the operating systems used by the ADMS will become unsupported. SA Power Networks will then fail the "Essential Eight"

recommendation that all operating systems be patched and that unsupported operating systems should not be used. In addition, the unsupported operating systems will negatively impact SA Power Networks comparatively high maturity level<sup>2</sup> as assessed against AEMO's AESCSF.

### **4.3.2 Real-time Control of Embedded Generation**

With the rapid growth in distributed generation on SA Power Networks' system there are times of the day, on an increasing number of parts of the network, where the network can be overloaded. Currently, SA Power Networks needs to manually reduce the available controllable generation to manage the state of the network. The response time for this intervention is often too slow to adequately protect the network from overload conditions.

The DERMS module in the newer versions of the ADMS will allow SA Power Networks to automate the regulation of generation to quickly detect and manage any overload situations.

### **4.3.3 Tools to Facilitate DER Connection**

As distributed generation on SA Power Networks system continues to grow, the potential already exists for customers to be unable to generate into the LV network due to high voltages on the network. This inability to generate from residential DER will only continue to grow with the growth of DER penetration.

The ADMS DERMS module will allow SA Power Networks to more accurately model the LV network. The accurate modelling will provide both real-time monitoring to identify and manage voltage issues as they arise and assist in the identification of parts of the network that would need augmentation to facilitate the investment in DER by SA Power Networks customers.

### **4.3.4 Improved Management of DER**

SA Power Networks anticipates that virtual power plants (VPPs) are likely to be allowed by NEM rule changes in this regulatory period. VPPs are then likely to expand quickly in the network, spurred on by government incentives that will encourage the uptake of residential batteries. VPPs have the potential of creating a significant impact on SA Power Networks' system, and the ability to forecast their generation levels will be essential to adequately manage the network state.

As the current version of the ADMS does not have a DERMS module, it will not be until v3.8 or later that the ADMS can be used in this forecast requirement. The DERMS module will also allow control or generation target information to be passed to the VPPs.

### **4.3.5 Improved Network Modelling**

The later versions of the ADMS software (v3.8 was released in 2018) provide a sandbox environment whereby the testing of potential network operational scenarios can be modelled. Currently this modelling is performed using specialised modelling systems which are labour-intensive to maintain, particularly the maintenance of the network model. The sandbox uses the same network model as the ADMS, so maintenance effort is minimised, and due to its isolation from the real-time system, it can be utilised to test the various scenarios that may eventuate. The ADMS can provide:

- Improved power flow modelling tools

<sup>2</sup> A recent benchmarking assessment undertaken by a major consulting firm showed SA Power Networks as one of the most mature companies against this framework.

As the ADMS has an up-to-date network model that is consistently maintained and incorporates powerful tools for evaluating power flow in the sandbox, Network Planners can use these tools to assist them to better manage the state of the network. These tools can be utilised to determine if augmentation may be required for DER access, or whether augmentation can be deferred as the network can be operated more efficiently.

- Network Planning for Small Scale Generator Connections (direct connections to the network)

The sandbox environment can be used to test the potential scenarios related to generator connections and identify where issues may arise and/or augmentation is required.

## 5 DATA CONCENTRATOR REPLACEMENT PROJECT

### 5.1 Project Background and Scope

SA Power Networks uses varying types of equipment to provide the required SCADA functionality to its field devices. The primary method to communicate with the RTUs is using a Data Concentrator (DC). This is a device that is used as a protocol gateway to convert legacy propriety protocols to the standardised protocol used by the Network Operating Centre (NOC). It also aggregates field data to the NOC via a high-speed fibre/radio network using the DNP3-over-IP protocol.

SA Power Networks' SCADA system is designed around a distributed Data Concentrator topology providing telemetry to the NOC. Nine (9) Data concentrators (in a redundant configuration) are connected in a dual redundant WAN (via fibre and radio) providing telemetry to the ADMS SCADA Masters (Primary and Backup). Each Data Concentrator polls a subset of substation RTUs via either a serial link (predominant connection) or an Ethernet connection. The Data Concentrator currently also acts as a media converter that converts standard serial DNP3 to the DNP3-over-IP protocol used for communications with the NOC. Details of the data acquisition network are given in the diagram below.

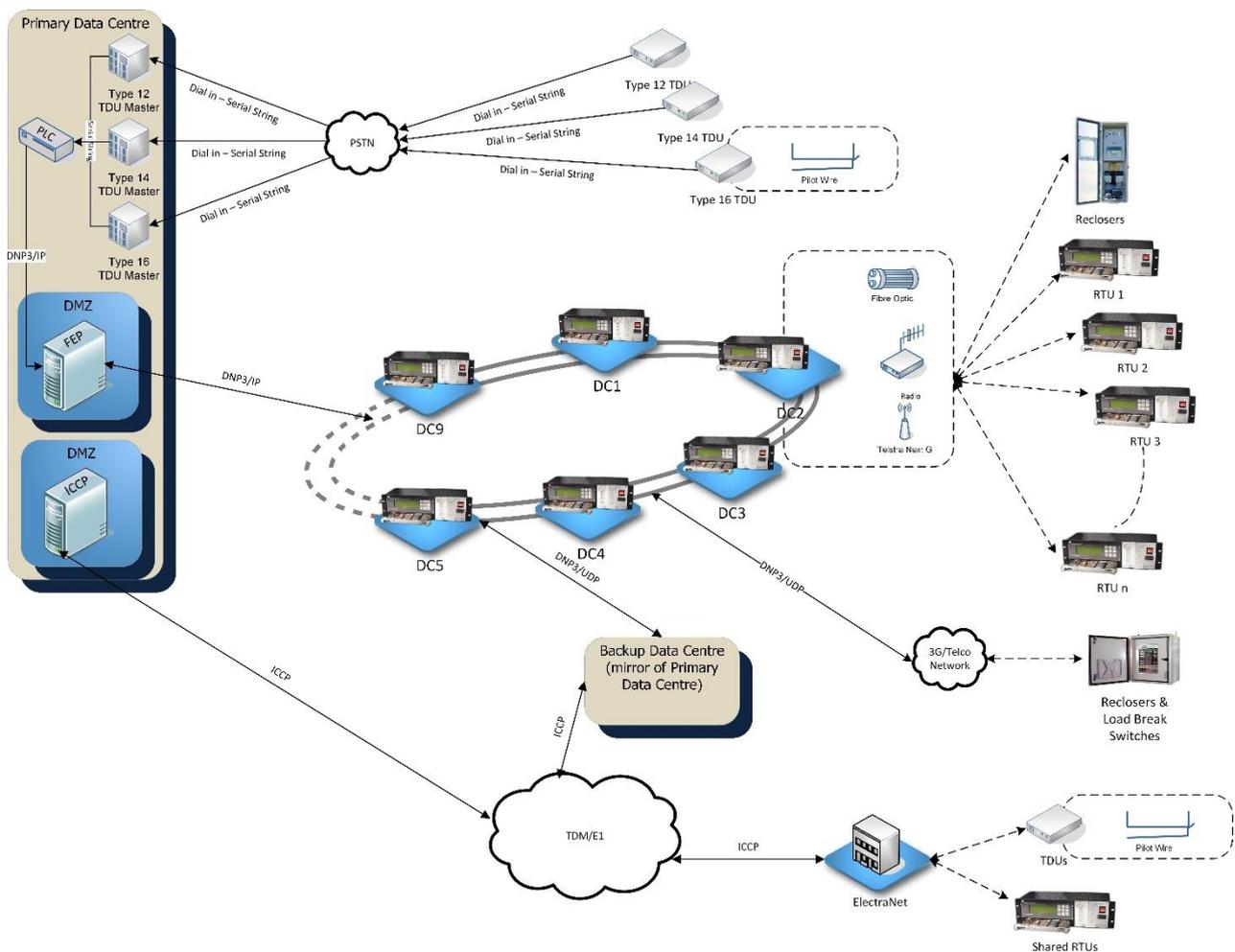


Figure 5: SCADA Communication Paths and Protocols

## 5.2 Approach to Replacement Needs

### 5.2.1 Asset Age and Condition

The Data Concentrators are based on the same technology as the GE Harris RTUs. The life expectancy for these assets is 15 years. However, by the start of the regulatory period 5 units will be more than 20 years old and if no action is taken will be over 25 years old before the period ends.

Year	98	99	00	01	02	03	04	05	06	07	08	09	10	11	12	13	14	15	16	17	18
Data Concentrators			5			1	1									2					

Table 7 Age Profile of Data Concentrators

All the DCs are GE D200 RTUs with 4 D20ME processors per shelf. There are 2 shelves per DC with 8 processors in total as there is a redundant arrangement within the DC.

### 5.2.2 Operational Issues

SA Power Networks has a current contract agreement for supply and service of GE products, however, the current DCs utilise the D20ME processors, which along with other modules, are no longer available from the vendor.

### 5.2.3 Failure Rates

It is not possible to predict the failure mode for this category of asset. Typically, a failure may occur in a hardware component resulting in partial or complete failure. Failure rates would be expected to increase with age, particularly once the Data Concentrator is outside its design life.

On average SA Power Networks has recently had around 2 failures on D20ME processors in Data Concentrators each year. These processors are also used for larger/metro substation RTUs, which have failures of about 4 per year. SA Power Networks currently only have a stock of around 18 Spare D20E processors, which are quickly being used up by the DC and large RTU failures.

### 5.2.4 Recommended Replacement Strategy

The Data Concentrators are a critical component of SA Power Networks' SCADA system and collectively on average collect information from over 200 substations. As a result, failures of the Data Concentrators have a significant impact on the NOCs ability to manage the distribution network. It is therefore recommended that in addition to a fix-on-failure strategy, the Data Concentrators be replaced at the end of their operational life.

Given the recent failure rates and age of the assets it is suggested a replacement strategy is implemented to gradually replace all Data Concentrators that will be significantly over 20 years old by the end of the next regulatory period. This covers the 5 Data Concentrators that were installed in 2000 and will be 20 years old at the start of the period. Whilst, the Data Concentrators installed in 2003/2004 will be 20 years old during the period it is planned for these to be retained until the following regulatory period to restrict the workload to an achievable level.

This gives a total of 5 Data Concentrators suggested for replacement implying a replacement rate of 1 per year. It is suggested a complete replacement of Chassis and processors is undertaken with a linear profile used to replace the assets.

A condition assessment could be undertaken for the 2 DCs that are past their expected operating life during the regulatory period. A decision could then be taken on whether these should be replaced during the 2026-2030 regulatory period.

## 5.3 Costing Approach

### 5.3.1 Cost per Data Concentrator

The average costs for each Data Concentrator replacement was estimated by SCADA Engineering. This was based on a D20MX with chassis, power supply, 14 Com ports and rear fibre ethernet ports with 2 of these required for each Data Concentrator and some smaller costs for additional items.

- Material Cost of DC = \$80,000
- Labour Cost of DC = \$71,000
- Total Average Cost for Installed Data Concentrator = \$151,000

These costs have been used in calculation of the budget for the next regulatory period. The labour costs include overhead, which is assumed to cover the vehicle costs required for the installation.

### 5.3.2 Budget for Next Regulatory Period

The intention is to replace all the Data Concentrators that will be over 20 years old by the start of the next regulatory period. This would be done at a rate of one per year with the replaced parts being used as spares for the remaining equipment. The project budget for each year is outlined below.

Financial Year	2021	2022	2023	2024	2025	Total
Planned DC Expenditure (\$K)	151	151	151	151	151	755

Table 8 Forecast Capital Expenditure for Data Concentrator Replacement

## 6 RTU REPLACEMENT PROJECT

### 6.1 Project Background and Scope

The SCADA system is an industry standard tool that SA Power Networks uses to manage its high voltage distribution network. Specifically, the SCADA system is used by the Network Operations Centre to gather, process and display information about the status of the network as well as to change the operating state of devices remotely.

Remote Terminal Units (RTUs) form a large overall component of SA Power Networks SCADA system. RTUs are typically located within the relay room of a substation and provide control outputs, process alarms and status indications, and collect metering data from the corresponding substation via hard-wired or serial communications channels.

Information from substation RTUs is typically transmitted over dedicated telecommunications channels to one of nine data concentrating RTUs. The Data Concentrators serve two purposes; to act as a protocol converter between the substation RTUs and the NOC; and to concentrate data onto limited communications channels into the NOC.

### 6.2 Approach to Replacement Needs

#### 6.2.1 Asset Age and Condition of RTUs

The age of SA Power Networks SCADA assets are detailed in the table below. The Telephone Dialling Units (TDU) are already in the process of being replaced and will not be operational at the start of the next regulatory period with the RTUs and Data Concentrators the oldest SCADA assets on the network.

Year/ Type	98	99	00	01	02	03	04	05	06	07	08	09	10	11	12	13	14	15	16	17	18
GE RTUs	1			11	26	27	18	22	22	17	26	21	21	22	23	1	8	4	5	5	
TDUs	1	6	35																		
Data Quality RTUs								1													

Table 9: Age Profile of SCADA Assets

This gives a total of 280 RTUs at the end of 2018. In addition to these GE RTUs, there are other assets that can provide SCADA data to the ADMS including protection relays and Reclosers, some of which are being used for the roll out of SCADA to the remaining ZSS.

SA Power Networks in the Network Security and Control Asset Plan (2.1.02) have a designed life expectancy for the field SCADA devices as follows:

- RTU 10-15 years
- TDU 10-15 years
- Data Concentrator 15 years

This is consistent with industry standards. It suggests that based on the age of SA Power Networks' field SCADA devices, a significant capital expenditure will be required over the following years in order to maintain the required standard of services in terms of quality, safety and reliability.

#### 6.2.2 Operational Issues

Historically the GE RTUs have proven to be very reliable, and only in recent years have some RTUs started failing. However, there are currently different hardware variations of GE RTUs in service, creating maintenance and spares holding

concerns, exacerbated by the inability to source spare parts for the older RTUs. Old processor models also require different firmware versions, further complicating the management of these assets.

### **6.2.3 Failure Rates**

It is not possible to predict the failure pattern of field SCADA units and as a result the management strategy is largely one of fix-on-failure. However, over the last 5 years the failure rate of the RTUs has averaged 18 failures per year, with the bulk of the failures due to RTU module failure, many being processor module failures. The module failures have significantly reduced SA Power Networks spares holdings, which cannot be replenished as the modules are no longer provided by GE.

### **6.2.4 Recommended Replacement Strategy**

Due to the unpredictability of the failure mode for GE RTUs the overall strategy is to fix-on-failure. As these assets have an unpredictable failure mode, there is no routine or preventative maintenance recommended for this asset category.

Given the recent failure rates and age of the assets it is suggested a replacement strategy is implemented to gradually replace all RTUs that will be significantly over 20 years old by the end of the next regulatory period. In the first instance this covers:

- 1 RTU installed in 1998
- 11 RTU installed in 2001
- 26 RTUs installed in 2002
- 27 RTUs installed in 2003

This gives a total of 65 RTUs suggested for replacement implying a replacement rate of 13 per year.

Whilst those installed in 2004 and 2005 (an additional 40 RTUs) will also be over 20 years it is not recommended that a planned replacement of these is undertaken at this time. This should restrict the workload to an achievable level given current SA Power Networks resources. This planned rollout also provides some flexibility should those from 2004/2005 etc fail these could be replaced and those installed in 2002/2003 installations continued for a short timespan beyond the end of the regulatory period.

It is suggested a complete replacement of chassis and RTU processors is undertaken with a linear profile used to replace the assets.

## **6.3 Costing**

### **6.3.1 Cost per RTU**

The average costs for each RTU replacement was estimated by SA Power Networks' SCADA Engineering. This was based on a D20 MX with chassis, power supply, 7 Com ports and rear fibre ethernet ports as well as some smaller costs for additional items.

- Material Cost of RTU = \$37,000
- Labour Cost of RTU = \$38,000
- Total Average Cost for Installed RTU = \$75,000

These costs have been used in calculation of the budget for the next regulatory period. The costs include overhead, which is assumed to cover the vehicle costs required for the installation.

**6.3.2 Budget for Next Regulatory Period**

The intention is to only replace the oldest RTUs that will be over 20 years old by the end of the next regulatory period. This would be done at a rate of 13 per year with the replaced parts being used as spares for the remaining equipment. The project budget for each year is outlined below.

<b>Financial Year</b>	<b>2021</b>	<b>2022</b>	<b>2023</b>	<b>2024</b>	<b>2025</b>	<b>Total</b>
Number of RTU Replacements	13	13	13	13	13	<b>65</b>
Planned RTU Expenditure (\$K)	\$975	\$975	\$975	\$975	\$975	<b>\$4,875</b>

*Table 10 Planned Capex Expenditure for RTU Replacement*

## APPENDIX A MODEL DATA REFERENCES

### List of Key Parameters

Parameter	Central	High	Low	Reason
Real Discount Percentage (%)	3.5%	4.5%	3%	Real Discount Rate agreed with SA Power Networks – 19 <sup>th</sup> December 2018. Reflects latest AER position on rate of return
Total Project Duration (years)	15	20	12	Conservative estimate previously applied of life of 15 years.
Number of Substations without SCADA in July 2020	61	65	50	Based on reduction from 89 outstanding at start of 2018 and 81 in December 2018
Number of Complex Sites without SCADA in July 2020	12	14	10	Based on reduction from 17 complex sites outstanding at start of 2018
Cost of SCADA to Simple Substations (\$k)	132	150	100	Based on Substation SCADA 11 kV 7.6 kV feeder Recloser Priority List Nov 17 - Discussed at Meeting 13th November 2017
Cost of SCADA to Complex Substations (\$k)	235	250	220	Based on Substation SCADA 11 kV 7.6 kV feeder Recloser Priority List Nov 17 – Peterborough example- Discussed at Meeting 21 <sup>st</sup> March 2018
Sensitivity Applied to Upgrade Costs (%)	0%	10%	-10%	Testing sensitivity to price increase
Value of a damaged Transformer at ZSS (\$k)	250k	500k	150k	Unchanged since previous submissions - Estimate confirmed with SA Power (e-mail of 8 <sup>th</sup> May 2014) – This should reflect the depreciated installed cost of the transformers as early replacement for failure avoids a cost that would have been incurred in the future. Suggest cost should reflect half the installed cost of the transformer assuming damage occurs half way through the asset life.
Number of Customers Impacted by a whole Substation Outage	1000	1250	750	The variable now only applies to the situation where there is a major incident at the substation that would result in all customers being off-supply at that ZSS. This is calculated by dividing the number of customers connected to rural long ZSS by the number of rural long ZSS.
Hourly vehicle cost per field crew (\$/hour)	0	0	0	Included in field services crew costs
Number of major events causing damage at ZSS each year	0.8	2	0.5	Previous analysis suggested 1 outage for 75 ZSS, which was based on discussion with SA Power of number of events each year. This has been scaled down to reflect 61 ZSS rather than 75 proposed for previous response.

Parameter	Central	High	Low	Reason
Saving in Time to get SCADA recorded faults to OMS (Mins)	10	15	5	Unchanged - This saving was agreed with SA Power Networks on the meeting of the 20 <sup>th</sup> May 2015 and reflects their experience with rural customers. This saving covers 2 elements, the detection by SCADA and secondly the 'automatic' link from the ADMS to the OMS so that these outages get responded on almost immediately.
Number of ZSS visits per year that could be avoided	6	8	4	Unchanged - estimate discussed with SA Power includes planned switching, bushfires changes and unplanned switching that may require changes in settings
Average Customer Load (kW)	1.10	1.30	1.00	This has been reduced from the previous value to reflect the average load for rural long customers. It is calculated by dividing 1376 GWhs by 142,000 customers and converted to hourly load. Information provided by Network Performance and Regulatory Manager on 21/3/2018
SPS Rate per Customer per Minute (\$)	0.42	0.5	0.35	Based on e-mail from Network Performance and Regulatory Manager on 20/3/2018 that gave SPS rate of \$0.42 per customer on a rural long service. This is not currently used in the modelling results presented.
Value of Customer Reliability (\$)	38,566	40,000	35,000	Based on revised regional figures published by AEMO provided by Network Performance and Regulatory Manager on 20/3/2018.
SPS Rate Customer Interruption	\$70.6	\$80	\$55	Derived from e-mail from Network Performance and Regulatory Manager on 20/3/2018 that gave SPS rate of \$70.6 per customer interruption on a rural long service. This is not currently used in the modelling results presented.
Hourly cost of SA Power Networks Field Crew (Aud)	120	140	100	Number includes an allowance for vehicle costs and consistent with previous business cases. Agreed with SA Power Networks Jan 2019
Number of Rural Long Customers Impacted by HV Outage	230000	250000	200000	Average Total Customers impacted by HV outages on Rural Long Network – E-mail from Network Performance and Regulatory Manager on 20/3/2018
Field Crew size	2	3	1	Estimate discussed with SA Power Networks on 20 <sup>th</sup> May 2015 - Normally at least 2 people in each crew
LRMC of Capacity gained at ZSS (\$/kVA)	438	500	350	Unchanged LRMC of capacity at rural ZSS. This was provided by SA Power Networks on the 28 <sup>th</sup> May 2015.
Effective increase in Capacity at the ZSS from SCADA M&C (%)	0.5%	1%	0%	Unchanged Estimate in 2015 assessment – will help planners but unclear exactly how much so this is a conservative figure agreed with SA Power Networks at the meeting of the 15 <sup>th</sup> May 2015
Cost of Replacement of Hydraulic Reclosers (Aud)	70000	100000	50000	Estimate discussed with SA Power Networks in December 2018. Just over half the cost of the electronic recloser with SCADA

Parameter	Central	High	Low	Reason
Failure Rate of Existing Hydraulic Reclosers (%)	4%	5%	2.5%	Estimate discussed with SA Power Networks in December 2018. Would see existing stock of reclosers fail over a 25 year period.

**Single Value Key Parameter**

Parameter	Value	Reason
Years for Deployment of SCADA to ZSS	5	Agreed timeframe to roll out remaining ZSS
Total Number of Rural Long ZSS	140	Figure from Network Performance and Regulatory Manager – 20/3/2018

## Individual Key Parameters for Included Costs/Benefits

### Cost Parameters

#### Opex Costs

Parameter	Value	Reason
Average annual cost to maintain each ZSS (AUD)	\$1000	Unchanged estimate based on discussion with SA Power Networks that current annual maintenance costs was around \$1000 per ZSS

### Benefits Parameters

#### Avoiding Major Equipment Problems from Better Monitoring

Parameter	Value	Reason
Percentage of major events that can be avoided with increased ZSS monitoring and control	50%	Unchanged estimate discussed with SA Power Networks – only some of the damage could be avoided – agreed 20 <sup>th</sup> May 2015
Time off Supply	8 hours	Unchanged estimate of time to restore after major outages – Agreed with SA Power Networks 20 <sup>th</sup> May 2015

#### Reduced visits to ZSS to change settings

Parameter	Value	Reason
Hours per visit	2	Unchanged estimate discussed with SA Power Networks on 20 <sup>th</sup> May 2015– some sites may have long travel time

### Defer Augmentation

Parameter	Value	Reason
Network Capacity of ZSS Gaining SCADA with Monitoring	91.5 MVA	Nominal Rating without SCADA of 81 sites without SCADA is 242 MVA (At 12 <sup>th</sup> Dec 2018) implying 3 MVA per site. However, a figure of 1.5 MVA has been applied recognising that some of the larger site may gain SCADA before the next regulatory period and that the Median figure was only 1.2 MVA.

### Defer Repex

Parameter	Value	Reason
Number of Reclosers for a Simple Site	1	Based on solution proposed and described in scope
Number of Reclosers for a Complex Site	2	Based on solution proposed and described in scope