REVENUE PROPOSAL 2019 - 2023

Attachment 11

Service Target Performance Incentive Scheme

28 March 2017

ElectraNet

Company Information

ElectraNet Pty Ltd (ElectraNet) is the principal electricity transmission network service provider (TNSP) in South Australia.

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Note

This attachment forms part of our Revenue Proposal for the 2018-19 to 2022-23 regulatory control period. It should be read in conjunction with the other parts of the Revenue Proposal.

Our Revenue Proposal comprises the overview and attachments listed below, and the supporting documents that are listed in Attachment 15:

Revenue Proposal Overview

Attachment 1 – Maximum allowed revenue

Attachment 2 – Regulatory asset base

Attachment 3 – Rate of return

Attachment 4 – Value of imputation credits

Attachment 5 – Regulatory depreciation

Attachment 6 – Capital expenditure

Attachment 7 – Operating expenditure

Attachment 8 – Corporate income tax

Attachment 9 – Efficiency benefit sharing scheme

Attachment 10 – Capital expenditure sharing scheme

Attachment 11 – Service target performance incentive scheme (this document)

Attachment 12 – Pricing methodology

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Attachment 14 – Negotiated services

Attachment 15 – List of supporting documents

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11. Service Target Performance Incentive Scheme

11.1 Key points

- We have proposed parameter values for the Service Target Performance Incentive Scheme (STPIS) in accordance with version 5 of the scheme.
- Our proposal complies with all aspects of the STPIS.

11.2 Introduction

This attachment sets out our proposed application of the STPIS for the forthcoming regulatory period. The STPIS plays an important role in counter-balancing the incentives to minimise operating and capital expenditure that are provided by other aspects of the regulatory framework. In broad terms, the STPIS provides incentives to improve network reliability and performance.

The STPIS consists of three components:

1. A service component, which has four main parameters and various sub-parameters which act as key indicators of network reliability.
2. A market impact component, which provides incentives to minimise the impact of network outages on the dispatch of generation.
3. A network capability component, which provides incentives to undertake low cost projects to enhance network capability for the benefit of customers.

Each year, our Maximum Allowed Revenue (MAR) is adjusted based on our performance against the STPIS parameters in the previous calendar year. The Rules require that the STPIS may result in a maximum revenue increment or decrement between one and five per cent of the annual MAR.

In its framework and approach paper, the AER explained that STPIS version 5, which was published in October 2015, will apply for our forthcoming regulatory period. In accordance with this scheme, we are required to:

- Submit proposed values for the service component parameters.
- Submit data for the market impact component for the preceding seven regulatory years, and propose values for the performance target; the unplanned outage event limit; and dollar per dispatch interval incentive rate.
- Submit a Network Capability Incentive Parameter Action Plan (NCIPAP).

As explained in this attachment, our proposed parameter values for the service, market impact and network capability components comply with the requirements of STPIS clauses 3.2, 4.2 and 5.2 respectively.

The remainder of this attachment is structured as follows:

- Section 11.3 sets out our proposed parameter values in relation to the service component.
- Section 11.4 sets out our proposed parameter values for the market impact component.
- Section 11.5 summarises our priority projects which form the network capability component of the STPIS. Our NCIPAP is provided as a supporting document.

11.3 Service component

In accordance with the STPIS, our performance will be assessed against the following measures:

1. Unplanned outage circuit event rate (fault and forced).
2. Loss of supply event frequency.
3. Average outage duration.
4. The proper operation of equipment.

These performance measures differ from those under the scheme currently applying to us (Version 3). The coverage of the service component has been updated so that it now only focuses on unplanned outages. It also includes an additional measure - proper operation of equipment - which is 'report only' and not subject to incentive payments.

Each of these Sub Parameters is explained below.

11.3.1 Unplanned outage circuit event rate – fault

A fault outage is any element outage that occurred because of unexpected automatic operation of switching devices (such as circuit breakers). That is, the element outage did not occur because of intentional manual operation of switching devices.

The fault outage circuit event rate parameter measures network reliability by using an aggregate number of fault outages per annum for each of the transmission element types, namely, lines, transformers and reactive plant.

11.3.2 Unplanned outage circuit event rate – forced

A forced outage is any element outage that occurred because of intentional manual operation of switching devices based on the requirement to undertake urgent and unplanned corrective activity, where less than 24 hours' notice was given to the affected customer(s) and/or AEMO.

Similar to the fault outage rate, the forced outage circuit event rate parameter measures network reliability by using an aggregate number of forced outages per annum for lines, transformers and reactive plant.

11.3.3 Loss of supply event frequency

The loss of supply event frequency parameter includes and counts both small (x) and large (y) loss of supply events.

The parameter is measured in system minutes, which is calculated using energy not supplied for each supply interruption divided by peak network demand. The number of events where system minutes exceed x and y thresholds are summed each year, where x is 0.05 and y is 0.2 under the current scheme. We propose to maintain these performance measures for the forthcoming period.

11.3.4 Average outage duration

The average outage duration parameter measures the average time to restore loss of supply events and is calculated by dividing the annual summation of the loss of supply event duration time by the number of loss of supply events. The performance measure of the average outage duration parameters will be calculated on a rolling average basis.

11.3.5 Proper operation of equipment

This performance measure has three components, recording the number of events of each type:

1. Failure of protection system.
2. Material failure of the Supervisory Control and Data Acquisition (SCADA) system.
3. Incorrect operational isolation of primary or secondary equipment.

This parameter is report only, with zero weighting.

11.3.6 Historical performance

Historical performance against the service performance sub parameters is summarised in Table 11.1.

Table 11.1: Reliability data 2012-2016

Sub Parameter	2012	2013	2014	2015	2016
Lines outage rate – fault	39.09%	22.52%	22.12%	19.30%	32.09%
Transformers outage rate – fault	40.00%	28.47%	35.56%	15.44%	35.29%
Reactive plant outage rate – fault	22.58%	26.47%	20.59%	17.65%	51.35%
Lines outage rate - forced outage	9.09%	14.41%	11.50%	14.04%	8.02%
Transformers outage rate - forced outage	24.44%	16.06%	16.30%	16.91%	3.68%
Reactive plant outage rate - forced outage	12.90%	32.35%	11.76%	11.76%	18.92%
No. of events >0.05 system minutes	6	5	4	1	5
No. of events >0.2 system minutes	5	4	1	0	2
Average outage duration (minutes)	122.0	154.2	130.7	147.0	250.6
Failure of protection system (No. events)	23	28	28	24	10
Material failure of Supervisory Control and Data Acquisition (SCADA) system (No. events)	2	2	0	0	2
Incorrect operational isolation of primary or secondary equipment (No. events)	8	5	9	7	10

Clause 3.2(f) of the STPIS requires (subject to certain exceptions) that our proposed target for each performance measure must be our average actual performance over the most recent five year period. The data used to calculate the performance target must also be consistently recorded, in accordance with the scheme's parameter definitions.

Consistent with these requirements, for target setting purposes we propose to use our performance data for the period 2012 to 2016, being the most recent 5 year period for which data is currently available. We are not proposing any adjustments to the historical data. The data is consistent with the parameter definitions set out in the STPIS.

Clause 3.2(e) of the STPIS states that the proposed floors and caps for each performance measure must be calculated using a sound methodology. In accordance with this requirement, we have calculated floors and caps that reflect the 5^{th} and 95^{th} percentiles using the statistical distributions set out in Table 11.2 on page 11 of this attachment.

11.3.7 Statistical approach

ElectraNet retained Parsons Brinckerhoff to review the performance data for 2012-2016 and recommend appropriate distributions, targets, caps and floors in accordance with version 5 of the scheme.

The @RISK product, a risk analysis and simulation add-in tool for Microsoft Excel, was used to determine the types of probability distribution that best fit the reliability data. The AER's principles for selecting a distribution to calculate caps and floors (listed below) were taken into account:

- The chosen distribution should reflect any inherent skewness of the performance data.
- The distribution should not imply that impossible values are reasonably likely. For example, the distribution for an average circuit outage rate sub-parameter should not imply that values below zero per cent are reasonably likely.
- Discrete distributions should be used to represent discrete data. For example, a discrete distribution such as the Poisson distribution should be used when calculating caps and floors for loss of supply sub-parameters. Continuous distributions should not be used.

In view of these principles, the following distribution parameters were chosen for this exercise:

- Average circuit outage rates are fitted with continuous probability distributions bounded at a lower limit of zero.
- Loss of supply event frequency and improper operation of equipment are fitted with discrete probability distributions.
- Average outage duration data are fitted using continuous probability distributions bounded at a lower limit of zero.

To align with the methodology applied by the AER and remain consistent across all distribution types, the caps and floors were calculated using the 5th and 95th percentiles, respectively.

Three key fit statistics were used to measure how well the probability distribution functions fit the input data. For discrete probability distributions, the Akaike Information Criterion (AIC) was used. For non-discrete distributions, the Kolmogorov-Smirnov (K-S) and the Anderson-Darling (A-D) fit statistics were used, based on the following rationale:

1. Discrete Data
    - For discrete probability distributions, tests relied on are the chi-square, the AIC and the Bayesian Information Criterion (BIC).
    - For the chi-square approximation to be valid the expected frequency in each interval bin should be at least 5. As this is not possible with only 5 values in the dataset (one value for each year from 2012 to 2016), some uncertainty in the fitted distribution will occur. Therefore, the chi-square approximation is not used for model selection.
    - AIC is a measure of the relative quality of a statistical model for a given set of data. AIC deals with the trade-off between the goodness of fit of the model and the complexity of the model. It is founded on information entropy: it

offers a relative estimate of the information lost when a given model is used to represent the process that generates the data. As such, AIC provides a means for model selection.

- BIC is closely related to the AIC, with a greater penalty for the number of parameters in the model. It is only valid for sample sizes much larger than the number of parameters in the model and is therefore likely to be inaccurate for small sample sizes. Therefore, BIC is not used for model selection.
- In view of the points noted above, AIC is considered to provide a more appropriate methodology for determining the curve of best fit to small datasets than the chi-square or BIC.

2. Continuous Data
   - For non-discrete distributions, tests relied on are the chi-square, the K-S, the A-D, the AIC and BIC.
   - The chi-square test, as discussed above, will have some uncertainty in the fitted distribution for small sample sizes and is therefore not used for model selection in this instance.
   - The K-S fit statistic focuses on the differences between the middle of the fitted distribution and the input data. The A-D fit statistic focuses on the difference between the tails of the fitted distribution and input data. Historically the AER has applied the K-S fit statistic in its regulatory determinations to calculate the caps and floors, stating that it considers the K-S fit statistic to be preferred due to its simplicity, especially when there is no evidence to suggest the A-D fit statistic is more appropriate in this particular case. Further, with only 5 data points being available, the AER considers placing more weight at the tail end by using the A-D statistical fit to be unsound[1].
   - The AIC test, as discussed above, is a valid test and is preferred over the BIC for small sample sizes.
   - Given the simplicity of the K-S fit statistic, we have used this in preference to the A-D or AIC tests.

Because a probability distribution is being fitted to a dataset of only five values for each parameter, the fit statistics are typically low in value and the curve of best fit is sensitive to small changes in any of the five values. We have examined the curve of second best fit to see if similar values occur at the 5th and 95th percentile, as these values are used to set the cap and floor values.

Where the curve of best fit and the curve of second best fit do not align, they are further examined to test for any large variations in the calculated values that might indicate that the curve of best fit should not have been used. Where parameters suggest that the curve of best fit should not be used, a number of other approaches may be examined such as:

- A different distribution may be chosen that best reflects the shape and spread of the underlying data.
- Other fit statistics – the results of other fit statistics may indicate the use of another curve.

[1] AER, Final – Service Target Performance Incentive Scheme, October 2015, cl. 3.2(e).

- Longer run data may be used to assist in improving the fit statistic.

11.3.8 Summary of findings

Table 11.2 summarises the probability distribution functions that have been chosen to best fit the parameter data (Table 11.1). This approach appears to be robust and does not seem to be sensitive to the choice of distribution function, because the results were either close for the next best fit distributions or confirmed through analysis of the data. The approach is also consistent with the AER's previous regulatory decisions to use a curve of best fit approach.

Table 11.2: Summary of best fit distributions

Sub Parameter	Best Fit Distribution	5% POE	95% POE
Lines outage rate - fault	LogLogistic	15.8%	41.1%
Transformers outage rate - fault	Weibull	18.0%	43.0%
Reactive plant outage rate – fault	LogLogistic	13.3%	43.8%
Lines outage rate - forced outage	Pearson5	7.7%	16.6%
Transformers outage rate - forced outage	Uniform	1.5%	29.0%
Reactive plant outage rate - forced outage	LogLogistic	7.8%	29.5%
No. of events >0.05 system minutes	Poisson	1	8
No. of events >0.2 system minutes	Poisson	0	5
Average outage duration (minutes)	Pearson5	106	236
Failure of protection system (No. events)	Poisson	15	31
Material failure of supervisory control and data acquisition (SCADA) system (No. events)	Geometric	0	4
Incorrect operational isolation of primary or secondary equipment (No. events)	Poisson	4	13

Table 11.3 on the following page summarises the proposed floor, targets and caps for each performance measure. The table also shows the weightings, which are consistent with those specified in Table 3.1 of the STPIS.

Table 11.3: Proposed performance targets, caps, floors and weightings

Sub Parameter	Floor	Target	Cap	Weighting (% of MAR)
Unplanned outage circuit event rate				**0.75**
Lines event rate – fault	41.10%	27.00%	15.80%	0.20
Transformer event rate – fault	43.00%	31.00%	18.00%	0.20
Reactive plant event rate – fault	43.80%	27.70%	13.30%	0.10
Lines event rate – forced	16.60%	11.40%	7.70%	0.10
Transformer event rate – forced	29.00%	15.50%	1.50%	0.10
Reactive plant event rate – forced	29.50%	17.50%	7.80%	0.05
Loss of Supply Event Frequency				**0.30**
Events > 0.05 System Minutes	8	4	1	0.15
Events > 0.2 System Minutes	5	2	0	0.15
Average Outage Duration				**0.20**
(minutes)	236	161	106	0.20
Proper operation of equipment				**0.00**
Failure of protection system (No. events)	31.00	22.60	15.00	0.00
Material failure of SCADA (No. events)	4.00	1.20	0.00	0.00
Incorrect operational isolation of primary or secondary equipment (No. events)	13.00	7.80	4.00	0.00

It should be noted that the performance measures for the ‘unplanned outage circuit event rate’ and the ‘average outage duration’ will be calculated on a rolling average basis, in accordance with Appendix E of the STPIS. This approach reduces the impact of annual variations in performance outcomes, which may not reflect underlying performance.

11.4 Market impact component

The market impact component provides an incentive for us to minimise the impact of transmission outages that can affect NEM market outcomes. To give effect to this component of the STPIS, we are required to propose:

1. A performance target.
2. An unplanned outage event limit.
3. A dollar per dispatch interval incentive.

The STPIS also states that the first time a TNSP commences version 5 of the scheme, the performance target for the first regulatory control period must be calculated in accordance with Appendix F of the scheme. Under this methodology, the performance target is determined by:

- Calculating the raw performance target which is equal to our average annual performance history against the market impact parameter for the median five out of seven preceding calendar years.
- Calculating 17 per cent of the raw performance target.
- Adjusting our annual performance history for the seven preceding calendar years by limiting the impact of market impact parameter counts associated with unplanned outages to 17 per cent of the raw performance target.
- Using the adjusted performance history to calculate the performance target, which is the average adjusted annual performance history of the median five out of seven preceding calendar years.

Table 11.4 below shows our performance history in relation to the market impact parameter.

Table 11.4: Historical performance in relation to the market impact parameter

	2010	2011	2012	2013	2014	2015	2016
Planned outages	1611	1319	4078	2362	87	17,237	13,862
Unplanned outages	179	43	177	103	9	871	820
Total dispatch interval count	1790	1362	4255	2465	96	18,108	14,682

In accordance with Appendix C and Appendix F of the scheme, the above historic data produces:

1. A raw performance target (M) of 4910.8 dispatch intervals.
2. An unplanned outage event limit of (17% of M) of 834.8 dispatch intervals.
3. An adjusted performance count of 4910.8.

In accordance with the scheme, we have calculated the dollar per dispatch interval by taking one per cent of the MAR of the first year of the regulatory control period and dividing it by the performance target. This calculation results in a dollar per dispatch interval of $636.

11.5 Network capability component

The network capability component of the STPIS provides us with an incentive to fund low cost works to increase network capacity to benefit customers.

In accordance with this component of the STPIS, we have developed a range of projects to improve network capability. The Australian Energy Market Operator (AEMO) must independently assess the projects and identify those it considers will deliver the most efficient outcomes for customers.

Table 11.5 summarises our priority projects from our NCIPAP. A copy of our NCIPAP is provided as Appendix A. It has been prepared in accordance with the requirements of clause 5.2 of the STPIS.

Table 11.5: Network capability improvement program

Proposed project	Timing	Expenditure ($m nom)	Payback period (years)	Benefit
South East dynamic line ratings	2018-19	0.1	0.1	Increased capability of the Heywood Interconnector to import power from Victoria.
Robertstown - Davenport Plant ratings	2018-19	1.3	0.2	Alleviating mid-north congestion on renewable generation, lowering generation costs.
Robertstown transformer management relay uprating program	2021-22	0.5	1.2	Increased inter-regional power flows and reduced network congestion.
Constraint formulation investigation	2022-23	0.3	1.2	Increased capability of the transmission network including the Heywood Interconnector.
South East Capacitor bank	2020-21	3.6	3.3	Increased capability of the Heywood Interconnector to import power from Victoria.
Smart Wires Powerline Guardian trial (Waterloo - Templers)	2019-20	5.9	4.3	Reduced congestion on the mid-north network to improve power transfers to Adelaide and the Heywood Interconnector, though trial technology that can be rapidly deployed to other circuits.
Tailem Bend to Cherry Gardens line tie in	2019-20	5.3	6.5	Improved interstate transfers through more consistent operation of the Heywood Interconnector to the nominal 650 MW capability.
Total		**17.0**		

Appendix A Network Capability Incentive Parameter Action Plan (NCIPAP)

REVENUE PROPOSAL 2019 - 2023

Attachment 11 - Appendix A

Network Capability Incentive Parameter Action Plan

28 March 2017

ElectraNet

Contents

Glossary of Terms

Term	Description
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
CT	Current Transformer
kV	kiloVolts
MMS	Market Management System
MVA	MegaVolt-Ampere
MW	MegaWatt
MWh	MegaWatt hour
NCIPAP	Network Capability Incentive Parameter Action Plan
NEFR	National Electricity Forecasting Report
NEM	National Electricity Market
NER	National Electricity Rules
NGFR	National Gas Forecasting Report
NPV	Net Present Value
NTNDP	National Transmission Network Development Plan
PACR	Project Assessment Conclusions Report
SRMC	Short-run marginal cost
STPIS	Service Target Performance Incentive Scheme
RIT-T	Regulatory Investment Test for Transmission
TNSP	Transmission Network Service Provider

1. Introduction

This document presents ElectraNet's proposed Network Capability Incentive Parameter Action Plan (NCIPAP or Plan) for the 2018-19 to 2022-23 regulatory period.

The Plan operates under the Network Capability Component of the Australian Energy Regulator's (AER's) electricity transmission Service Target Performance Incentive Scheme (STPIS). The Network Capability Component (NCC) was introduced to the STPIS in December 2012. The STPIS including the NCC was amended in September 2015 to version 5.

This Plan addresses the requirements of the NCIPAP component of version 5 of the STPIS.

1.1 Overview of the Network Capability Component

The Network Capability Component is set out in Section 5 of the STPIS guideline[1].This Component measures the improvements in the capability of transmission assets through operating expenditure and minor capital expenditure on a transmission network that results in:

- improved capability of those elements of the transmission system most important to determining spot prices, or
- improved capability of the transmission system at times when Transmission Network Users place greatest value on the reliability of the transmission system.

The Network Capability Component has been designed to improve the capability of the transmission network to the benefit of consumers. It seeks to incentivise TNSPs to review the capability of the transmission network and to identify low cost network capability improvements that would provide greatest value.

As a result of such improvements, generation is less likely to be constrained by network limits, leading to more efficient dispatch and downward pressure on wholesale energy costs. Customers benefit from the resulting lower wholesale costs and efficient improvements in network capability.

This is the second Plan developed by ElectraNet. The first Plan is in the process of being delivered with a number of completed projects that have demonstrated reduced incidence of congestion, in particular across the Heywood interconnector. The current Plan will alleviate further network congestion across the Murraylink interconnector and for wind generators in the mid-north before the end of the current regulatory period.

This plan for the following regulatory period proposes seven projects that will contribute to improving the capability of South Australia's transmission network in terms of both the elements most important to determining spot prices and the times when users place the greatest value on the reliability of the system.

[1] AER, Final Electricity Transmission Network Service Providers Service Target Performance Incentive Scheme, December 2012, pp11-16.

The elements most important to determining spot prices tend to be interconnector limits and major intra-regional constraints. The projects in the plan have been targeted directly at these elements.

1.2 Period of the Plan

The Plan is proposed to cover the five year period from 1 July 2018 to 30 June 2023.

1.3 South Australia's energy transformation

South Australia remains at the forefront of global change in the energy sector. AEMO is forecasting further significant growth in renewable generation connected to the South Australian network.

Across its suite of planning documents AEMO has demonstrated or is forecasting major changes in the way South Australia produces energy and utilises the grid, including:

- an additional 1,430 MW of transmission connected wind generation in South Australia by 2020-21 – the third year of the next regulatory period[2];
- distributed PV is forecast to increase by almost 500 MW by 2022-23 to a total of around 1,200 MW;
- distributed PV is leading to minimum grid demand declining during the day. By 2027, all domestic consumption in South Australia is forecast to be met at times by local distributed PV i.e. grid demand for electricity in South Australia will be zero[3]. All energy from grid connected renewables under these conditions will be exported to the east coast;
- maximum grid demand across the state declining to around 2,700 MW over the next ten years;
- Gas Powered Generation (GPG) in South Australia has reduced by 60 per cent between 2012 and 2016. GPG demand for gas will increase by 0.8 per cent per annum from 2016 to 2026. Since these forecasts there have been a number of changes that might influence the demand for gas for gas powered generators. AEMO has recently introduced a requirement for at least two sufficiently large synchronous generators to be online in South Australia and the retirement of Hazelwood power station in Victoria from March 2017; and

The decline in operation of synchronous generation in South Australia has resulted in system security concerns. The South Australian Government has responded to these concerns by introducing a Rate of Change of Frequency (RoCoF) standard, which manages imports and exports across the Heywood interconnector to limit the RoCoF in South Australia to 3Hz/s for the non-credible loss of the Heywood interconnector from a secure operational state.

On 14 March 2017, the South Australian Government also announced a six-point Energy Plan including both energy security and power system security measures.

2 AEMO, National Transmission Development Plan Neutral Scenario based network development, 2016
3 AEMO, National Electricity Forecasting Report, 2016

All of these changes will result in a general reversal of flows across the Heywood interconnector over the next regulatory period. However, South Australia will remain reliant on interconnection and gas power generation for firm supply.

Within the context of these changes, the selection of optimal projects for our Plan is influenced by:

- the outcomes from the South Australia Energy Transformation (SAET) RIT-T which is seeking to identify the best long term solution to the challenges discussed above;
- the precise location of congestion in the mid-north, which will depend on the generation projects that proceed and the technology of the projects; and
- congestion on the Heywood Interconnector, which will depend on a range of factors such as the capability of the interconnector following the completion of the recent upgrade and the influence of new operational requirements such as the RoCoF standard, the minimum operation of synchronous generators and any further measures that may be taken.

ElectraNet has developed a proposed Plan that reflects the current and expected future state of the network based on committed and known developments, based on the available information at this time.

Ensuring that the best projects are selected and delivered in this environment requires flexibility. ElectraNet proposes to ensure maximum flexibility by proposing a Plan in its Revenue Proposal that assumes the SAET RIT-T (which is separately addressed as a contingent project) does not materially change the design and operation of the current transmission network.

By the time of a Revised Revenue Proposal, the SAET RIT-T will have substantially progressed and the role of these projects can be reassessed in the light of any new information available at that time. The proposed Plan as it stands therefore remains subject to review and update, as required, for the outcomes of the SAET RIT-T or any other outcomes or new information prior to a final decision by the AER.

Secondly, the Plan will be required to demonstrate that it is delivering improvements that it was intended to deliver. Before undertaking each project, ElectraNet will be reviewing each project to ensure the project remains a prudent investment, and can be expected to deliver the benefits anticipated. Where conditions have changed, the projects can also be substituted, with the approval of the AER, for new priorities that may emerge that would deliver greater benefits for customers.

2. Approach

This chapter outlines the approach ElectraNet has used to identify and rank projects for the purposes of this proposed Plan and the engagement it has undertaken with key stakeholders including AEMO and customers.

2.1 Requirements of the Scheme

The STPIS requires this Plan to:

- Identify for every transmission circuit or injection point on its network, the reason for the limit for each transmission circuit or injection point.
- Propose the priority projects to be undertaken in the regulatory control period to reduce the limits on the transmission circuits and injection points listed above through operational and/or minor capital expenditure projects. This proposal must include:
  - (i) the total operational and capital cost of each priority project;
  - (ii) the proposed value of the priority project improvement target in the limit for each priority project;
  - (iii) the current value of the limit for the transmission circuits and/or injection points which the priority project improvement target is seeking to improve; and
  - (iv) the ranking of the priority projects in descending order based on the likely benefit of the priority project on customers or wholesale market outcomes.[4]

These requirements are addressed below.

2.2 Approach to Identifying Projects

ElectraNet has systematically reviewed limits, operating conditions and constraints on its network to identify projects for inclusion in the proposed Plan. The reviews that have been undertaken to identify projects involved:

- Review of the limits for each transmission line, connection point and transformer, including identification of all limiting factors less than the conductor thermal rating;
- Identification of credible contingencies where increased capability would improve wholesale market outcomes;
- Studies on interconnectors;
- Review of binding transmission constraints to identify capability improvements that would improve wholesale market outcomes;
- Discussions with ElectraNet's system operators to identify operating conditions where capability improvements could provide benefits;

[4] AER, *Final Electricity Transmission Network Service Providers Service Target Performance Incentive Scheme*, October 2015, p12

- Discussions with planning staff at AEMO to identify operating conditions where capability improvements could provide benefits; and
- Discussions with asset management and design staff at ElectraNet to identify innovations that could provide capability improvements.

This work has been undertaken in collaboration with AEMO in its role as national transmission planner and market operator, and in accordance with its South Australian advisory functions under the National Electricity Law

Development of this plan is consistent with observations made in recent National Transmission Network Development Plans (NTNDP) published by AEMO including the 2016 NTNDP.[5]

2.3 Approach to Ranking Projects

The STPIS requires proposed projects to be ranked in descending order based on the likely benefit of the project to customers or wholesale market outcomes.

ElectraNet and AEMO have taken the following approach to ranking the projects:

- Estimated annual benefits of each project has been calculated;
- Payback periods have been calculated based on the amount of time required to recover the investment;
- Project priority rankings have been determined based on duration of the payback period, shorter durations being given priority over longer periods; and
- The timings of the projects have been determined with regards to ElectraNet's capabilities to deliver, the likelihood that conditions that give rise to congestion will be realised and the operational flexibility that the project provides.

2.3.1 Project Considered but not Proposed

A number of projects were identified but not considered for inclusion in the final Plan as priority projects. These projects included:

- Automated reclosing projects designed to reduce congestion following network faults;
- Voltage support at Tailem Bend to support additional imports across the Heywood interconnector;
- Improvements to Cultana substation to improve reliability and dispatch outcomes in the region;
- Voltage support in the Riverland to support additional exports to Victoria under high demand conditions;
- Increasing the ratings of critical or emerging constraints on lines in the mid-north.
- Various solutions to congestion across Tailem Bend to Mobilong impacting on Heywood flows.

5 AEMO, *2016 National Transmission Network Development Plan*, December 2016.

2.4 Consultation with AEMO

The STPIS requires ElectraNet to consult with AEMO prior to submitting the Plan as to:

1. Whether there is potential for co-ordinated projects with other TNSPs;
2. Whether the proposed priority project improvement targets for its projects will result in a material benefit;
3. Which projects should be classified as priority projects based on their likely benefit to consumers or wholesale market outcomes, and
4. The ranking of the priority projects.[6]

ElectraNet has worked collaboratively with AEMO in the development of this plan, including consultation on these four factors.

ElectraNet has also provided AEMO with a copy of its capital expenditure program for the relevant regulatory control period as required under the STPIS, and consistent with its South Australian advisory functions under the National Electricity Law, as discussed further below.

2.5 Consultation with Customers

ElectraNet has consulted with customers and wider stakeholders through the release of a draft NCIPAP in its Preliminary Revenue Proposal, issued for comment on 9 September 2016. ElectraNet invited submissions from customers, representatives and other stakeholders, and held metropolitan and regional forums with stakeholders to discuss these proposals.

The feedback received on ElectraNet's Preliminary Revenue Proposal confirmed that the level of electricity prices in South Australia remains of concern to customers. Accordingly, ElectraNet has been encouraged to continue to focus on driving its costs down, while pursuing broader measures to reduce the delivered cost of energy.

Consistent with this feedback, ElectraNet has finalised its proposed NCIPAP by focusing on those projects expected to produce the greatest net benefit to customers, in the form of improved power flows across the network and reduced constraints on generation dispatch. This delivers benefits by placing downward pressure on wholesale energy costs, and in turn on delivered energy costs for customers.

This involved a shift in our focus from projects designed to improve network operability under outage conditions, to projects designed to improve network capabilities during normal system operation, including improved power flows between regions, thereby delivering benefits for a greater proportion of the time.

2.6 Relationship with Capital and Operating Expenditure

The costs associated with the projects proposed in this plan are not included in the capital or operating expenditure forecasts in respect of the forthcoming regulatory control period.

[6] AER, *Electricity Transmission Network Service Providers Service Target Performance Incentive Scheme*, October 2015, p13

As part of its South Australian Advisory Functions AEMO reviews ElectraNet's proposed capital expenditure allowances[7]. AEMO also reviews ElectraNet's Transmission Annual Planning Reports on an annual basis for consistency with the capital expenditure program approved by the AER[8].

AEMO therefore has copies of and is closely familiar with ElectraNet's approved capital expenditure program for the current regulatory control period, and proposed capital expenditure program for the forthcoming regulatory control period, focusing in particular on projects relating to the capacity of the transmission network.

2.7 Annual reporting

ElectraNet will continue to report on outcomes from the Network Capability Component on an annual basis, as required under the Scheme.

Should circumstances change, which would result in a priority project no longer likely to result in a material benefit, ElectraNet would propose to the AER to remove the project and may propose a replacement project, consistent with the objectives of the Scheme.

ElectraNet must consult with AEMO prior to making such a proposal. This allows for changes to the plan to be made should conditions unexpectedly change, in order to ensure maximum benefits are delivered for customers.

3. Network Action Plan

ElectraNet proposes seven projects to improve the capability of South Australia's transmission network for the benefit of customers. The proposed timing and benefits to be delivered by these projects are summarised in Table 3-1 and Table 3-2 below, and detailed in the following sections.

The total value of the proposed projects identified is $17.0 million. One per cent of ElectraNet's average forecast Maximum Allowed Revenue for the forthcoming regulatory control period is $17.04 million. Therefore, the total value of the proposed projects identified does not exceed the maximum allowed threshold for the forthcoming period.

[7] AEMO, *Independent Planning Review – ElectraNet Capital Expenditure Projects, March* 2017

Table 3-1: Proposed Network Capability Incentive Projects ($m nominal)

Project	2018-19	2019-20	2020-21	2021-22	2022-23	Total
1. South East-Tungkillo dynamic line ratings	0.1					0.1
2. Robertstown - Davenport Plant ratings upgrade	1.3					1.3
3. Robertstown transformer management relay uprating program				0.5		0.5
4. Constraint formulation investigation					0.3	0.3
5. South East Capacitor bank		3.6				3.6
6. Smart Wires Powerline Guardian trial (Waterloo – Templers line)		5.9				5.9
7. Tailem Bend to Cherry Gardens line tie in			5.3			5.3
Total	**$1.4**	**$9.5**	**$5.3**	**$0.5**	**$0.3**	**17.0**

Table 3-2: Estimated benefits from Network Capability Incentive Projects ($m nominal)

Project and Rank	Completion date	Estimated Capital Expenditure ($m nom)	Estimated Operating Expenditure ($m nom)	Payback period (Years)
1. South East-Tungkillo dynamic line ratings	2018-19		0.1	<1
2. Robertstown - Davenport Plant ratings upgrade	2018-19	1.3		<1
3. Robertstown transformer management relay uprating program	2021-22	0.5		<2
4. Constraint formulation investigation	2022-23	0.2	0.1	<2
5. South East Capacitor bank	2020-21	3.6		3.3
6. Smart Wires Powerline Guardian trial (Waterloo – Templers line)	2019-20	5.9		4.3
7. Tailem Bend to Cherry Gardens line tie in	2019-20	5.3		6.5

4. Proposed Priority Projects

4.1.1 Priority Project 1 – South East – Tungkillo 275 kV dynamic line ratings

Figure 4-1 is a geographical diagram of the South East region transmission network.

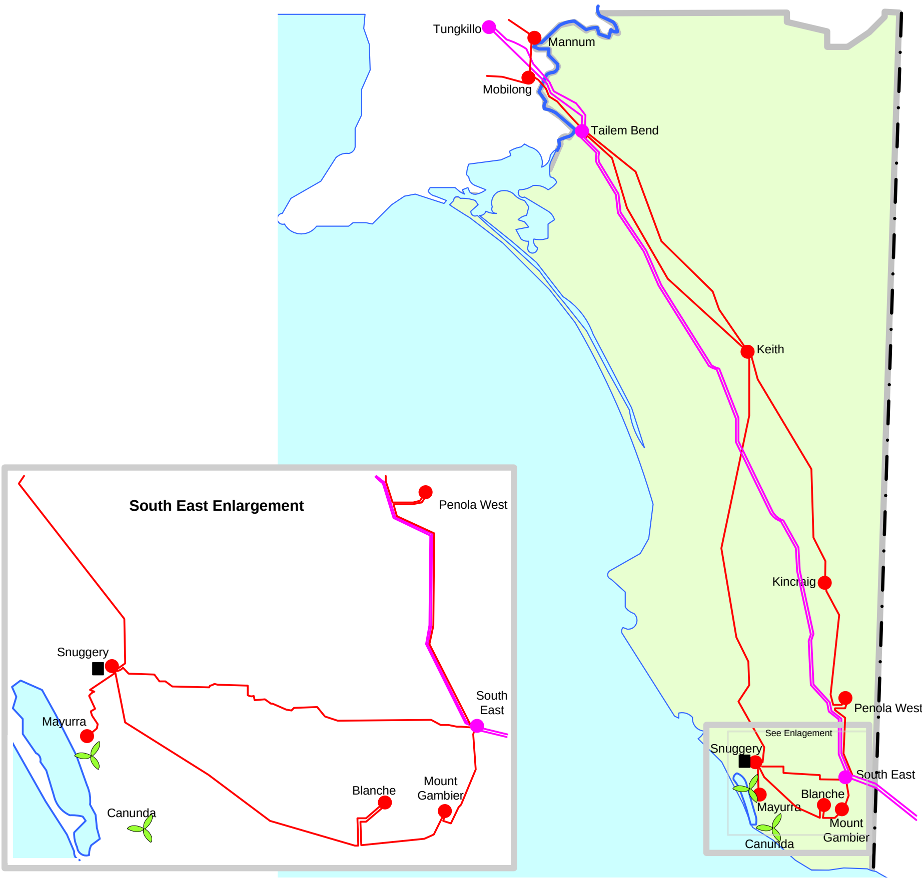

Figure 4-1: Geographical diagram of the South East transmission region

Transmission Circuit/ Injection Point	Tailem Bend – Mobilong 132 kV Tailem Bend – Tungkillo 275 kV Tailem Bend – Cherry Gardens 275 kV South East – Tailem Bend #1 275 kV South East – Tailem Bend #2 275 kV
Limit and Reason for the Limit	Thermal design capability of the lines.
Project	South East – Tungkillo 275 kV dynamic line ratings
Project Description	Apply dynamic ratings to the key circuits that make up the Heywood interconnector in South Australia to better account for favourable weather conditions and release further transfer capacity.

Present Limit	Transmission circuit / Present limit (Summer rating - MVA) Tailem Bend – Mobilong 132 kV: 183 Tailem Bend – Tungkillo 275 kV: 603 Tailem Bend – Cherry Gardens 275 kV: 597 South East – Tailem Bend #1 275 kV: 701 South East – Tailem Bend #2 275 kV: 701
Target Limit	Transmission circuit / Target limit (Winter rating - MVA) Tailem Bend – Mobilong 132 kV: 207 Tailem Bend – Tungkillo 275 kV: 684 Tailem Bend – Cherry Gardens 275 kV: 675 South East – Tailem Bend #1 275 kV: 766 South East – Tailem Bend #2 275 kV: 766
Capital cost ($ nominal)	$0
Operating Cost	$0.1 million
Priority project improvement target	Transmission circuit / Improvement (MVA) Tailem Bend – Mobilong 132 kV: 24 Tailem Bend – Tungkillo 275 kV: 81 Tailem Bend – Cherry Gardens 275 kV: 78 South East – Tailem Bend #1 275 kV: 65 South East – Tailem Bend #2 275 kV: 65

Reasons to undertake the project:

The Heywood interconnector is the primary connection between South Australia and Victoria. The 2013 Heywood interconnector upgrade RIT-T estimated that the value of increasing capability across the corridor is$1.8 million per MW[9].

The current notional limit of the Heywood interconnector is 650 MW.

ElectraNet expects that thermal congestion across the Heywood interconnector will occur between Tailem Bend and Tungkillo and between Tailem Bend and Mobilong when the interconnector is limited below 650 MW. This project will also allow for ratings above 650 MW.

9 ElectraNet and AEMO, *South Australia – Victoria (Heywood) Interconnector Upgrade, RIT-T Project Assessment Conclusions Report*, January 2013, available at https://www.electranet.com.au/wp-content/uploads/resource/2016/06/20130130-Report-HeywoodInterconnectorPACR.pdf.

The summer ratings of these circuits are 597 MVA and 183 MVA respectively. AEMO had identified that economic dispatch limitations occur between Tailem Bend and Tungkillo in the 2015 and 2016 NTNDP[10]. Congestion is likely to occur in both directions by the end of the next regulatory period.
Benefit/s: The majority of the benefits will be realised through increasing the capability of the Heywood interconnector to import power from Victoria. AEMO is forecasting an increase in the price of gas in South Australia before the end of ElectraNet's current regulatory period. This project will also facilitate increased exports of wind from South Australia. These benefits have not been valued. The value of congestion across this corridor is estimated at around $50/MWh. This value is a high level estimate of the historical substitution of gas for brown coal. The Heywood interconnector is forecast to be constrained due to summer and autumn ratings for around 500 hours per year. An improvement target of 31 MW has been used in the estimation of benefits. This is the average improvement expected from improving the ratings of Tailem Bend – Tungkillo summer ratings by 47 MW and the spring/autumn ratings by 15 MW up to the 650 MW Heywood interconnector limit. The Tailem Bend – Tungkillo circuits expected to lead to most of the thermal congestion across the interconnector. A utilisation factor of 100 per cent has been assumed. This reflects that due to the relatively small improvement in the capability the full improvement will be realised whenever the constraint is binding, before further constraints bind. Annual benefits have been estimated as: Duration (Hours) * Target (MW) * [Value ($/MWh) * Utilisation Factor] = 500 * 32 * [50 * 1] = $800,000 This results in annual import benefits of $800,000 for a payback period of 2 months. Two value sensitivities have also been considered. A higher sensitivity value has been derived from the difference in estimated Short-Run Marginal Cost (SRMC) between Latrobe Valley coal generators and metropolitan Adelaide gas generators as estimated for the year 2017 in the 2015 NTNDP. This value is estimated at $75/MWh and when applied results in an annual import benefit of $1.2m. This results in a payback period of around 1 month.. A lower sensitivity of $25/MWh has also been tested resulting in an annual benefit of $400,000 with a payback period of around 3 months.

[10] Available at http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NTNDP/2016/Dec/2016-NATIONAL-TRANSMISSION-NETWORK-DEVELOPMENT-PLAN.

4.1.2 Priority Project 2 – Removal of plant limits on Robertstown to Davenport lines

Figure 4-2 is a geographical diagram of the Mid North transmission network.

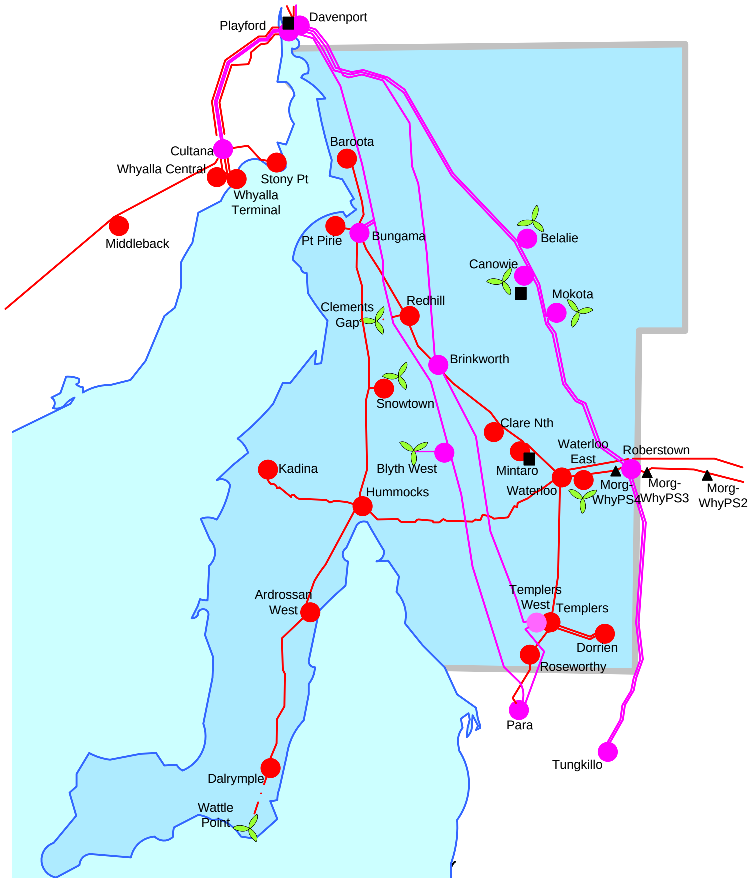

Figure 4-2: Geographical diagram of the mid north transmission region

Transmission Circuit/ Injection Point	Davenport – Belalie – Mokota – Robertstown 275 kV Davenport – Mt Lock - Canowie – Robertstown 275 kV
Limit and Reason for the Limit	Thermal design capability of the lines.
Project	Removal of plant limits on Davenport to Robertstown lines
Project Description	Remove and replace plant that are rated lower than the design capability of the conductors to release further transfer capacity
Present Limit	<u>Transmission circuit</u> / <u>Summer rating (MVA)</u> / <u>Winter rating (MVA)</u> Mokota – Robertstown 275 kV: 429 / 429 Davenport – Mt Lock 275 kV: 476 / 476 Mt Lock – Canowie 275 kV: 476 / 476 Canowie – Robertstown 275 kV: 429 / 429

<table>
<tr><td>Target Limit</td><td>

Transmission circuit	Summer rating (MVA)	Winter rating (MVA)
Mokota – Robertstown 275 kV	591	675
Davenport – Mt Lock 275 kV	591	675
Mt Lock – Canowie 275 kV	591	675
Canowie – Robertstown 275 kV	591	675

</td></tr>
<tr><td>Capital cost
($ nominal)</td><td>$1.3 million</td></tr>
<tr><td>Operating Cost</td><td>$0</td></tr>
<tr><td>Priority project improvement target</td><td>

Transmission circuit	Summer rating (MVA)	Winter rating (MVA)
Mokota – Robertstown 275 kV	162	246
Davenport – Mt Lock 275 kV	115	200
Mt Lock – Canowie 275 kV	115	200
Canowie – Robertstown 275 kV	162	246

</td></tr>
</table>

Reasons to undertake the project:

The Mid North region comprisesboth a 132 kV sub-transmission system and the Main Grid 275 kV system. The region is bound to the west by the Spencer Gulf, the Riverland region to the east, the Metro region to the south and the Upper North region to the North.

The mid-north region of South Australia currently has the following wind farm connections:

1. 4 wind farms totalling 358 MW connected to the 132 kV network;
2. 1 wind farm totalling 273 MW connected at Blythe West between Davenport and Brinkworth;
3. 5 wind farms totalling 450 MW connected between Davenport and Robertstown; and
4. a further 200 MW committed to connect between Davenport and Robertstown

In the last 12 months ElectraNet has received connection enquiries for nearly 2,000 MW of wind and 1,000 MW of grid scale solar generation that could be online in the next five years. AEMO has visibility of a potential 2,950 MW of proposed renewable projects in South Australia and has forecast that 1,400 MW of additional wind generation will connect in South Australia by 2020-21.

AEMO has identified in the 2016 NTNDP that economic dispatch limitations occur between Northern South Australia and the Adelaide demand centre.

Most interest in new connections has centred on the Mid North, Riverland and Eyre Peninsula regions. This is expected to result in higher flows along the Davenport – Robertstown circuits. These circuits have significant thermal capability but are limited to due secondary plant limits.

This project is required to improve the transfer capabilities of the Davenport to Robertstown 275 kV lines by removing various plant limits at Robertstown, Canowie, Davenport and Mokota substations.

Benefit/s:

This project will increase the summer capability of the Davenport to Robertstown 275 kV lines by at least 115 MVA. Improvements beyond 115 MVA will occur under winter and spring/autumn ratings.

The value of congestion has been estimated at $75/MWh, which is an indicative estimate for the substitution of renewables for thermal gas generation in South Australia. A lower value of $25/MWh has also been tested.

ElectraNet's economic network models have estimated future congestion as a result of further renewable generation across this flow path will rise to 1,430 hours per annum (or 16 per cent of the year) over the course of the next regulatory period. This expectation assumes a generator expansion forecast which is consistent with AEMO's 2015 NTNDP and includes around 1,600 MW additional wind in South Australia and 180 MW of solar. The 2016 NTNDP has broadly reconfirmed these forecasts. Benefits have been estimated as: Duration (Hours) * Value ($/MWh) * [Target (MW) * Utilisation (%)] = 1430 * 75 * 115 * 0.5 = $6.2 million. This equates to a payback period of well under 1 year. The target improvement of 115 MVA has been adjusted by a utilisation factor of 50 per cent due to the significant increase in capability. Whilst the 115 MVA improvement will be available whenever congestion is forecast, it is not expected that the full 115 MVA will always be required by the market. The lower value sensitivity has demonstrated a payback period of one year.

4.1.3 Priority Project 3 – Transformer management relay uprating program

Transmission Circuit/ Injection Point	Robertstown 275/132 kV transformers
Limit and Reason for the Limit	Thermal design rating of the transformers
Project	Transformer management relay uprating program
Limit Addressed	Thermal capability of the transformers will be increased, releasing further transfer capacity.
Project Description	Install DR-E3 transformer management relays and bushing monitoring add-on equipment to the two 275/132 kV transformers at Robertstown
Present Limit	<u>Transformer rating</u> — <u>Rating (MVA)</u> Robertstown 275/132 kV #1 — 160 Robertstown 275/132 kV #2 — 160
Target Limit	<u>Transformer rating</u> — <u>Rating (MVA)</u> Robertstown 275/132 kV #1 — 208 Robertstown 275/132 kV #2 — 208
Capital cost ($ nominal)	$0.5 million
Operating Cost	0
Priority Project Improvement Target	<u>Transformer rating</u> — <u>Rating (MVA)</u> Robertstown 275/132 kV #1 — 48 Robertstown 275/132 kV #1 — 48
Reasons to undertake the project: The Mid North region comprises both a 132 kV sub-transmission system and the Main Grid 275 kV system. The region is bound to the west by the Spencer Gulf, the Riverland region to the east, the Metro region to the south and the Upper North region to the North.	

The Mid North region of South Australia currently has the following wind farm connections: • 4 wind farms totalling 358 MW connected to the 132 kV network; • 1 wind farm totalling 273 MW connected at Blythe West between Davenport and Brinkworth; • 5 wind farms totalling 450 MW connected between Davenport and Robertstown; and • a further 200 MW committed to connect between Davenport and Robertstown In the last 12 months ElectraNet has received connection enquiries for nearly 2,000 MW of wind and 600 MW of grid scale solar that could be online in the next five years. AEMO has visibility of a potential 2,950 MW of proposed renewable projects in South Australia. AEMO is forecasting an additional 1,400 MW of wind generation in South Australia by 2021. Most interest has been centred on the Mid North, Eyre Peninsula and Riverland regions. Interconnection flows for both import and export are increasing in importance as South Australia's generation fleet continues to transition from a primarily fossil fuel dominated system to one high in renewable energy, during a period of extreme gas price volatility. The transformers at Robertstown are forecast to affect interconnector flows across the Murraylink interconnector.
Benefit/s: Congestion through the Riverland has been increasing. This is despite increases in the capability of the Riverland network over the last couple of years. Further increases are to be delivered in the current financial year. Following these works, constraints are still expected on exports below 220 MW due to voltage stability limits and the Robertstown transformers. Constraint S>V_NIL_NIL_RBNW in the market systems, which is the thermal limit on exports via the Riverland 132 kV network has increased from 242 hours in 2014 to 452 hours in 2015 and 587 hours in 2016. This has increased export congestion despite the reduction in conventional generators in South Australia. This constraint is a reasonable upper limit on the congestion that will occur on the transformers following the completion of a number of committed projects this period. An estimate of 200 hours congestion per annum has been assumed in the base case or 2.3 per cent of the year. Reducing this constraint allows SA wind generation to replace east coast thermal generation – in particular New South Wales black coal generators. An estimated fuel cost saving of $25/MWh have been used. Forecast congestion through this corridor has assumed wind farm development consistent with AEMO's 2015 NTNDP and results from the 2016 NTNDP. Export benefits have been estimated as: Duration (Hours) * Value ($/MWh) * [Target (MW) * Utilisation (%)] This project will result in a 48 MVA increase in the ratings of the Robertstown transformers. This has been assumed to result in 48 MW of additional export capability through Murraylink. A utilisation factor of 50 per cent has been assumed, reflecting that although the improvement is available all of the time, the market will not always utilize this capability improvement. The above approach results in this benefit being estimated at $120,000 per annum. For sensitivity analysis a lower value of hours has been assumed at 100 hours. Likewise, a higher value sensitivity of $75/MWh fuel cost saving has also been tested. Additional benefits would also accrue on the Robertstown transformer via online monitoring. The CIGRE developed Economics of Transformer Management[11] demonstrates that the benefits of effective on-line monitoring can also deliver major lifetime extensions. This benefit is estimated as an additional $120,000 per annum.

[11] Guide 248 on Economics of Transformer Management, CIGRE Working Group A2-20, 2004

The additional export benefits on the Robertstown transformers increase the benefits on to $240,000 per annum, resulting in a payback period of less than two years. Under lower value export benefit sensitivities, the benefits result in payback periods of less than 2 years. Under high value export benefit sensitivities, the payback period is 1 year.

Benefits would also accrue on the importing direction. Both transmission and distributed connected generators are progressing through the Riverland region. These will tend to increase congestion across the transformers. The timing and magnitude of these additional potential benefits have not been estimated

4.1.4 Priority Project 4 – Constraint formulation improvement investigation

Operational Software package	PSS/E AULimit search program
Network limit	Transient and Voltage Stability limits
Project	Network Limit Derivation Improvement Opportunity
Project Description	To review the existing AULimit search program to support other power system analysis software packages currently available in the market such as Power Factory, its limit search criteria, appropriate programing language and any improvement that can potentially be achieved in improving the accuracy of the limit derivation methodology, thereby improving the accuracy of network constraints and releasing further capacity on the network.
Present limit	Present network limit is calculated based on the following software tools • PSS/E and AULimit search software • Existing limit search criteria • Python programming language • Excel linear regression curve fitting Other than minor works, ElectraNet's network limit calculation tools have been largely unchanged since its initial development in 2007.
Capital cost **($ nominal)**	$0.2m
Operating Cost	$0.1m
Priority Project Improvement Target	Updated major "system normal" constraint equations. It is anticipated that the increase confidence in the solutions to each study iteration, together with the regression methodology improvement will directly reduce the statistical spread and hence the margin deducted to ensure stable operation under all conditions. This improvement is expected to achieve a nominal 10MW target, with the outcome verified through the delivery of a report demonstrating the conclusions of the assessment.

Reasons to undertake the project:

ElectraNet develops constraints for AEMO's dispatch engine using the custom software package AULimit.

This program was developed by The University of Adelaide based on the limit search criteria provided by ElectraNet in 2007 designed, developed and operated using Python programing language to interact with PSSE software owned by Siemens PTI.

The AULimit search program is currently being used to perform large numbers of PSSE network study cases required to develop constraint equations for the South Australian (SA) transmission network under system normal (N) and prior outage (N-1) operating conditions.

The AULimit search program interacts with PSSE functions to perform network studies in PSSE to derive transmission network limits for both steady state and dynamic conditions based on the user defined limit search criteria. It calls PSSE commands to perform network study in PSSE and flags the network limit when the limit search criteria has been met. Other than minor works, the program has been largely unchanged since its initial development in 2007.

Review of the AULimit search programme will review the following:

1. Power system analysis software currently available in the market.
2. Existing network limit search criteria.
3. Any improvements possible in the existing AULimit search program.
4. Operational mitigation strategies.

To maximise the utilisation of the existing SA transmission network and its interconnectors, it is necessary to have a high level of accuracy in the network limits determined using existing power system analysis software. Therefore, it is important to examine the existing power analysis software package, the methodology, the limit search criteria, and any potential operational strategy currently used to derive the network limits. As network limit accuracy improves, and the operating envelope of the network is increased, it will translate into market benefits for all network users.

Benefit/s:

The majority of the benefits will be realised through increasing the capability of the transmission network along the Heywood corridor.

Higher utilisation of the network will drive greater value from existing transmission assets and reduce future capital investment requirements of the network.

Any improvement in SA network transfer limits will benefit to all network users and this market benefit will be calculated based on the following formula:

Duration (Hours) * Target (MW) * Value ($/MWh)

Table 1 shows how often voltage and transient stability constraints have bound since 2014. ElectraNet have assumed 500 hours of constraint action in the calculation of the benefits.

Constraint type	2014	2015
Transient Stability		556
Voltage Stability	214	45
Total	**214**	**601**

Table 2 shows the estimated value of improving these constraints by 10 MW.

Constraint type	2014	2015
Transient Stability	0	$278,000
Voltage Stability	$107,000	$22,500
Total	**$107,000**	**$300,500**

This indicates a possible payback period of around 1 year. Using congestion from 2014, the payback period is around 3 years.

4.1.5 Priority Project 5 – South East 275 kV capacitor bank

Substations	South East 275 kV substation
Limit and Reason for the Limit	Voltage Stability
Project	South East 275 kV capacitor bank
Project Description	Install an additional 100 Mvar capacitor at South East substation to support increased inter-regional power flows
Present Limit	V^^S_NIL_MAXG V::S_NIL_MAXG V^^S_NIL_TBSE V::S_NIL_TBSE
Target Limit	V^^S_NIL_MAXG **+ 30 MW** V::S_NIL_MAXG **+ 30 MW** V^^S_NIL_TBSE **+ 30 MW** V::S_NIL_TBSE **+ 30 MW**
Capital cost ($ nominal)	$3.6 million
Operating Cost	0
Priority project improvement target	30 MW improvement to the constraints listed above

Reasons to undertake the project:

Following the completion of the Heywood interconnector upgrade project, SA import and export is nominally limited to 650 MW. This is based on the winter capability of the South East to Tailem Bend lines with 100 degree ratings. Under some operating conditions lower transfer capability would result. The Heywood interconnector upgrade RIT-T identified that each additional MW of capability along the Heywood interconnector would deliver around $1.8 million of net market benefit over the lifetime of the investment[12].

ElectraNet, as part of its current 2015-2018 NCIPAP has improved the thermal ratings along the Heywood corridor to 120 degree ratings. This has the effect of increasing the firmness of the interconnector – allowing 650 MW operation more often.

Lower limits – below 650 MW - on the interconnector will still result due to voltage limits along the corridor. Additional reactive power support along this route will alleviate these constraints. South East 275 kV substation has been identified as an optimal location to install additional reactive power support. With an additional 100 Mvar capacitor bank at South East, total reactive power reserve at South East 275 kV node will increase.

Examples of the impact of voltage limits can be seen with congestion on the Heywood interconnector on Tuesday 3 January where constraint: V::S_NIL_MAXG_1 limited Heywood to around 530 MW import capability.

This increased reactive power reserve will improve the firmness of the Heywood interconnector also allowing for more frequent operation with a 650 MW limit.

12 ElectraNet and AEMO, *South Australia – Victoria (Heywood) Interconnector Upgrade, RIT-T Project Assessment Conclusions Report*, January 2013, available at https://www.electranet.com.au/wp-content/uploads/resource/2016/06/20130130-Report-HeywoodInterconnectorPACR.pdf.

Benefits: The majority of the benefits will be realised through increasing the capability of the Heywood interconnector to import power from Victoria. Following the completion of the Heywood Interconnector Upgrade project, SA import and export capability is being increased to 650 MW nominal transfer level. To maximise the utilisation of the new capability of the Heywood interconnector, it is necessary to add more reactive power support plants along this path of the network. Preliminary network studies indicated potential improvement of the South East – Heywood I/C by approximately 30MW by adding 100Mvar capacitor bank to the existing South East 275 kV substation. Annual benefits have been estimated as: Duration (Hours) * Target (MW) * Value ($/MWh) * Utilisation factor For average demand, the value of congestion across Heywood is assumed to be $50/MWh. A lower value of $25/MWh and a higher value of $75/MWh has also been tested. ElectraNet estimates that voltage limitations will restrict the interconnector below its nominal 650 MW capability for significant periods. ElectraNet's economic models, derived from the NTNDP, expect high imports across Heywood for around 15 per cent of the time irrespective of additional wind and solar generation in SA. Congestion at this time is expected to be split between: the notional 650 MW limit; thermal limits at less than 650 and constraints related to voltage stability. The voltage stability constraint is projected to occur for a duration of approximately 675 hours per year. The estimated target increase will be 30 MW. A utilisation factor of 100 per cent has been assumed. This reflects that due to the relatively small improvement in the capability the full improvement will be realised whenever the constraint is binding, before further constraints bind. The estimated benefit will be 675 * 30 * 50 * 100% = $1 million per annum and a payback period of around 3 years. Under a low value sensitivity, the annual benefits are around $500,000 per annum. The payback period is around 7 years. The high value sensitivity shows benefits of around $1.5 million per annum with a payback period of around 2 years.

4.1.6 Priority Project 6 –Smart Wires PowerLine Guardian trial

Transmission Circuit/ Injection Point	Templers – Waterloo 132 kV Robertstown – Tungkillo 275 kV Robertstown – Para 275 kV
Limit and Reason for the Limit	Design thermal limit of Templers – Waterloo 132 kV
Project	Smart Wires PowerLine Guardian trial
Project Description	Install 90 Smart Wires Powerline Guardian SD4-1200 and 3 Power Guardian 390-800 devices on Waterloo – Templers 132 kV. These devices will "push" power flows from the congested line to parallel circuits such as Robertstown – Tungkillo 275 kV with surplus capability by increasing the impedance of the congested Waterloo – Templers 132 kV circuit, thereby improving transfer capacity. Undertake appropriate tests to ensure suitability of Guardian devices on the ElectraNet network such as vibration analysis and testing on target circuits. Uprate the parallel 275 kV circuits between Robertstown – Tungkillo and Robertstown – Para and on the 132 kV Roseworthy – Templers line as necessary to achieve higher limits flows on Waterloo – Templers 132 kV.

Present Limit	S>>NIL_BRTW_WTTP S>>NIL_BRTX_WTTP S>>NIL_BWMP_WTTP S>>NIL_RBTU_WTTP
Target Limit	S>>NIL_BRTW_WTTP + 17 MW S>>NIL_BRTX_WTTP + 17 MW S>>NIL_BWMP_WTTP + 17 MW S>>NIL_RBTU_WTTP + 17 MW
Capital cost ($ nominal)	$5.9 million
Operating Cost	$0
Priority project improvement target	S>>NIL_BRTW_WTTP + 17 MW S>>NIL_BRTX_WTTP + 17 MW S>>NIL_BWMP_WTTP + 17 MW S>>NIL_RBTU_WTTP + 17 MW

Reasons to undertake the project:

South Australia has world class wind and solar renewable resources in close proximity to the existing grid. There is currently around 1,600 MW of wind commissioned or undergoing commission and around 700 MW of distributed PV. By the end of 2017, these figures are expected to rise to 1,800 MW of wind (committed) and over 750 MW of distributed PV (likely).

In the last 12 months ElectraNet has received connection enquiries for nearly 2,000 MW of wind and 600 MW of grid scale solar that could be online in the next five years. AEMO has visibility of a potential 2,950 MW of proposed renewable projects in South Australia.

The 2016 NTNDP forecasts an additional 1,400 MW of wind connections by 2020-21 and a further 500 MW of distributed PV by 2022-23 – the last year of the next regulatory period.

The addition of this much generation will fundamentally change power flows across the South Australian transmission network. Notably, South Australia is forecast to go from being a net importer of energy to a net exporter over the next seven years.

AEMO has identified the following emerging economic limitations within South Australia:

- 132 kV network in the Eyre Peninsula
- 132 kV network in the Mid-North region
- 132 kV network in the Riverland region
- 275 kV network between northern South Australia and Adelaide
- Limitations between Tailem Bend and Tungkillo on both the 132 kV and 275 kV network.

This project seeks to alleviate constraints on the 132 kV Mid-north region of South Australia. Congestion will be centred on Waterloo – Templers 132 kV network.

By nature, traditional AC networks are controlled by managing the output of specific generation facilities. As South Australia becomes increasingly powered by abundant renewable energy sources and the proportion of electricity generated by gas plants decreases, the ability to control power flow will be reduced and reliance on interconnectors with New South Wales and Victoria will increase.

ElectraNet has identified a commercialized modular power flow control technology (developed by (Smart Wires Inc.). Smart Wires technology offers the opportunity to develop additional dynamic-control ability on the network to manage the increasingly complex power flows brought about by the changing generation mix. In the near term these solutions allow network operators to improve the utilisation of existing network infrastructure by redistributing power between individual transmission lines and to thereby reduce dispatching generators out of merit order.

In the longer term, these solutions can be deployed on key network paths to obviate the need for new construction or conductor replacement and to give operators more precise control over power flows resulting from changing system conditions.

Further, these solutions are re-deployable, eliminating the risks associated with making long-lived, capital-intensive infrastructure investments amidst considerable uncertainty and giving network operators the ability to address temporary, but impactful network constraints.

Benefits:

The majority of the benefits of this project have been estimated via increasing the transfer capability between northern South Australia and into Adelaide and Victoria via the Heywood interconnector.

This is achieved by installing Smart Wires PowerLine Guardian technology on the thermally-limited Templers – Waterloo 132 kV circuit to increase its impedance and redirect power to the parallel 275 kV network circuit with spare capacity.

Under some circumstances, where flows along the 132 kV are high relative to the 275 kV network, the Smart Wires PowerLine Guardians are expected to alleviate more than 17 MW of network constraint.

The PowerLine Guardian technology proposed for this project is modular. Each device injects a fixed amount of reactance and the fleet of devices can be controlled in real time or operate based on pre-programmable current set points. Devices are installed in series to provide the required level of power flow compensation, and devices can be added or removed, to scale the fleet up or down based on evolving need. Because the devices are installed on existing assets, implementation of the technology benefits from reduced permitting requirements and can be achieved faster and with fewer labour and resources than conventional network augmentations. Thus, benefits of congestion relief accrue to consumers on the timescale of months as opposed to years.

An advantage of this solution is its inherent flexibility; devices can be deployed quickly and also relocated on the network if required at a future date. For example if new congestion patterns emerge, devices could be transferred to other lines such as:

- Penola West – Keith – Tailem Bend 132 kV;
- Robertstown – Waterloo 132 kV;
- Robertstown - NWB 132 kV; and
- Davenport – Brinkworth 275 kV.

All of these lines are expected to experience growing congestion over the next reset period. And all are examples of congestion in parallel with network which has surplus capability at the time. For some of these, the magnitude of the congestion will depend on generation developments if they are to warrant a solution. Given the quantity of generator developments under consideration, some or all of these may justify market benefits projects subject to the costs of the solutions.

ElectraNet expects congestion to rise to around 1,000 hours over the next reset period as a result of additional wind and solar connecting to the mid-north and far-north of South Australia.

The value of additional wind generation is estimated at $75/MWh. The benefits have been estimated (for a 17 MW improvement) at $1.3 million p.a. resulting in a payback period of 4.7 years.

For deployment on the Waterloo – Templers circuit, payback periods range from 3.1 years to 9.3 years subject to the level of congestion along Waterloo – Templers which has been tested at 500 hours and 1,500 hours p.a.

4.1.7 Priority Project 7 – Tailem Bend to Cherry Gardens tie in

Substations	Tungkillo 275 kV substation
Limit and Reason for the Limit	Transient (rotor angle) and Voltage Stability
Project	11002 Tailem Bend to Cherry Gardens 275 kV Tungkillo tie-in
Project Description	Populate one additional diameter at Tungkillo by tie-in of Tailem Bend – Cherry Gardens 275 kV to improve inter-regional transfer capacity.
Present Limit	V^^S_NIL_MAXG V::S_NIL_MAXG V^^S_NIL_TBSE V::S_NIL_TBSE
Target Limit	V^^S_NIL_MAXG **+ 10 MW** V::S_NIL_MAXG **+ 10 MW** V^^S_NIL_TBSE **+ 10 MW** V::S_NIL_TBSE **+ 10 MW**
Capital cost **($ nominal)**	$5.3 m
Operating Cost	0
Priority project improvement target	+ 10 MW across four constraints identified above

Reasons to undertake the project:

Following the completion of the Heywood interconnector upgrade project, SA import and export is notionally limited to 650 MW.

The Heywood interconnector RIT-T identified that each additional MW of capability along the Heywood interconnector would deliver around $1.8 million of net market benefit over the lifetime of the investment[13].

The current 2015-2018 NCIPAP has improved the thermal ratings along the Heywood corridor to 120 degree ratings. This has the effect of increasing the firmness of the interconnector – allowing 650 MW operation more often.

Lower limits – below 650 MW - on the interconnector will still result due to voltage limits along the corridor. Turning-in the Tailem Bend to Cherry Gardens line at the Tungkillo switching station will impact on the "meshing" of the network and result in improved transient (rotor angle) and voltage stability along the Heywood corridor.

Examples of the impact of voltage limits can be seen with congestion on the Heywood interconnector on Tuesday 3 January where constraint: V::S_NIL_MAXG_1 limited Heywood to around 530 MW import capability

This increased reactive power reserve will improve the firmness of the Heywood interconnector also allowing for more frequent operation with a 650 MW limit.

13 ElectraNet and AEMO, *South Australia – Victoria (Heywood) Interconnector Upgrade, RIT-T Project Assessment Conclusions Report*, January 2013, available at https://www.electranet.com.au/wp-content/uploads/resource/2016/06/20130130-Report-HeywoodInterconnectorPACR.pdf.

In addition, transmission losses can be expected to be reduced and an incremental improvement to reliability to South Australia during planned and unplanned outages around Cherry Gardens due to this substation effectively being removed from the Heywood corridor.
Benefits: The majority of the benefits will be realised through increasing the capability of the Heywood interconnector to import power from Victoria. Following the completion of the Heywood Interconnector Upgrade project, SA import and export capability is being increased to 650 MW nominal transfer level. Utilisation of the new capability of the Heywood interconnector can be increased by 10 MW. Annual benefits have been estimated as: Duration (Hours) * Target (MW) * Value ($/MWh) * Utilisation factor For typical average demand, the value of congestion across Heywood is assumed to be $50/MWh. A high value of $75/MWh has also been tested. ElectraNet estimates that voltage limitations will restrict the interconnector below its nominal 650 MW capability for significant periods. This is expected to occur for a duration of approximately 675 hours per year. A lower value of 310 hours has also been estimated. A utilisation factor of 100 per cent has been assumed. This reflects that due to the relatively small improvement in the capability the full improvement will be realised whenever the constraint is binding, before further constraints bind. The benefits have been estimated at ranging from $200,000 to $500,000 pa. Additional benefits due to reduced losses and reliability improvements across the Heywood interconnector during planned and unplanned outages around Cherry Gardens by effectively removing Cherry Gardens from the Heywood corridor would also be realised. This has an estimated value of $420,000 pa. The payback period is estimated at between 5.3 and 8.5 years.

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