REVENUE PROPOSAL 2019 - 2023

Attachment 6

Capital Expenditure

28 March 2017

ElectraNet

Company Information

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

For information about ElectraNet visit www.electranet.com.au.

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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 (this document)

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

Attachment 12 – Pricing methodology

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6. Capital Expenditure

6.1 Key points

- We are forecasting total capital expenditure of $458m ($2017-18) for the forthcoming regulatory period. This is 39% lower than our expected actual expenditure for the current period, as shown in Figure 6.1 below.
- We are investing to maintain South Australia's transmission network to support the safe, secure and reliable supply of electricity into the future. Our expenditure plans reflect feedback we received through our early engagement on our Preliminary Revenue Proposal.

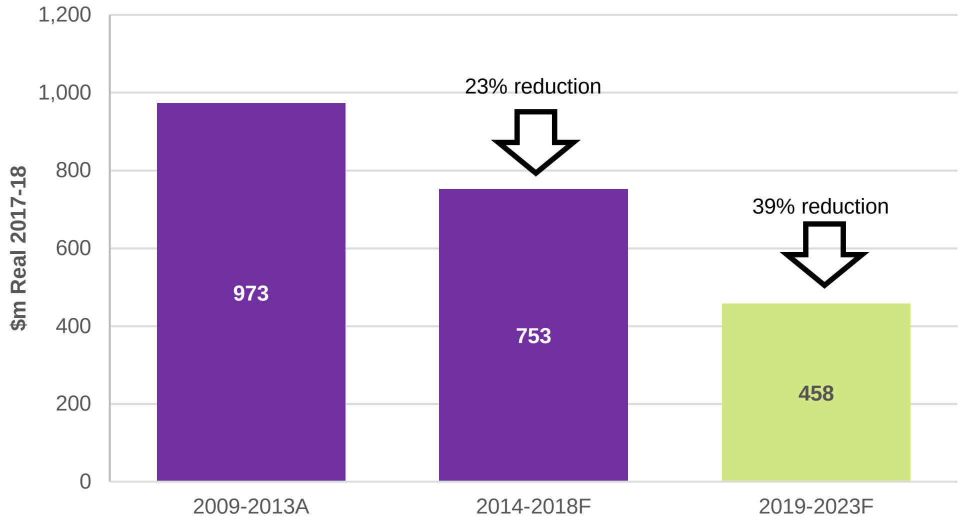

Figure 6.1: Actual and forecast capital expenditure ($ million real 2017–18)[1]

- A key driver of our lower forecast capital expenditure is the decline in demand growth in South Australia, which means that only a very small amount of load-related capital expenditure is required during the forthcoming regulatory period.
- We also expect to deliver the capital program in the current period for approximately 6% (or $48m) less that the capital expenditure allowance. This will deliver further ongoing savings to customers through avoided investment.
- The increasing penetration of solar photovoltaic (PV) generation and the changing mix of generation on the South Australian network is raising important challenges in relation to the resilience of the network, with implications for the security and reliability of supply.

[1] Excludes NCIPAP expenditure.

- We have included a small number of targeted projects in our capital program to improve the security and resilience of the network to extreme weather events. This has resulted in a modest increase (around 13%) to the indicative capital expenditure forecasts contained in our Preliminary Revenue Proposal.

- Our preliminary advice is that additional expenditure on larger scale projects to improve the resilience of the network to extreme wind events is not economically justified considering the low frequency of such events, although our internal investigations remain ongoing.

- A number of inquiries are currently underway following the impact of severe storms on 28 September 2016 resulting in a state-wide blackout. The forecasts presented in this attachment assume that no new obligations are imposed on us following the conclusion of those inquiries. If, however, new obligations are introduced these may have implications for our future capital (or operating) expenditure requirements. We will discuss any new or emerging expenditure requirements with the Australian Energy Regulator (AER) at the earliest opportunity.

- South Australia has among the oldest assets of the transmission networks in the National Electricity Market (NEM). The bulk of our capital expenditure plans are focused on refurbishing and replacing assets that are approaching their end of life. This expenditure is essential in order to maintain safe, secure and reliable supply in accordance with the Rules, our compliance obligations, and to meet customer expectations.

- In addition to these forecasts, we have identified five separate contingent projects where there is a possibility that additional capital expenditure may be required. These are subject to separate approval by the AER if and when required based on economic cost-benefit assessment. They include our South Australian Energy Transformation investigations into potential interconnection options to the eastern states and non-network alternatives, and supply upgrade options for the Eyre Peninsula.

- Our approach is consistent with the Expenditure Forecast Methodology previously lodged with the AER[2] and reflects best practice. Our input assumptions are reasonable and soundly based.

- The AER's latest annual benchmarking report indicates that our capital expenditure is efficient. In addition, we have introduced a number of measures to drive further efficiencies over time which are built into our capital cost estimates.

- Our forecast capital expenditure complies with the Rules requirements and will deliver outcomes consistent with the National Electricity Objective.

6.2 Introduction

This attachment presents our capital expenditure forecasts for the forthcoming regulatory period in accordance with the Rules requirements. In particular, clauses 6A.6.7(a) and (c) specify *capital expenditure objectives* and *capital expenditure criteria* that we must satisfy in order for the AER to approve our forecast capital expenditure. To summarise,

[2] ElectraNet, *Expenditure Forecast Methodology: Regulatory Control Period 2018-19 to 2022-23*, June 2016, available at https://www.electranet.com.au/wp-content/uploads/report/2016/09/20160630-Report-ElectraNetExpenditureForecastMethodology.pdf.

these provisions require us to submit a forecast total capital expenditure that we consider is required to meet the following objectives:

- meet or manage the expected demand for prescribed transmission services over the forthcoming regulatory period;
- comply with all applicable regulatory obligations or requirements associated with the provision of prescribed transmission services[3]; and
- maintain the safety of the transmission system through the supply of prescribed transmission services.

The Rules require the AER to determine whether our total forecast capital expenditure reasonably reflects the efficient and prudent costs of meeting these objectives.

Our forecasting methodology, which is described in Section 6.7, is designed to produce capital expenditure forecasts that satisfy these Rules requirements. The information presented in this attachment explains how we have applied our forecasting methodology and why the forecasts should therefore be accepted by the AER.

The remainder of this attachment is structured as follows:

- Section 6.3 describes our current environment and key challenges facing South Australia's electricity transmission network, and how we are responding to these challenges in light of customer feedback;
- Section 6.4 provides an overview of our historical and forecast capital expenditure;
- Section 6.5 describes our key obligations relating to capital expenditure;
- Section 6.6 describes the capital expenditure categories we have used in presenting our capital expenditure forecasts;
- Section 6.7 sets out our capital expenditure forecasting methodology;
- Section 6.8 describes the key inputs and assumptions underlying the capital expenditure forecasts and provides substantiation for these inputs and assumptions;
- Section 6.9 provides an overview of the efficiency initiatives we have put in place in the current period, and our benchmarking performance against industry peers;
- Section 6.10 provides further detailed information on our capital expenditure forecasts;
- Section 6.11 presents information relating to proposed contingent projects; and
- Section 6.12 concludes by outlining the benefits and risks to customers that arise from our proposed capital expenditure program.

In accordance with the Rules requirements, we confirm that our capital expenditure forecasts only includes expenditure that has been properly allocated to prescribed

[3] In our case, the Electricity Transmission Code and schedule 5.1 of the Rules specify the applicable obligations in relation to quality, reliability and security of supply. Therefore, clause 6A.6.7(a)(3) is not applicable.

transmission services in accordance with our approved Cost Allocation Methodology[4]. We also confirm that there has not been any change in our capitalisation policy.

6.3 Current environment and key challenges

6.3.1 South Australia remains at the forefront of change

South Australia's transmission network plays a major role in the State's electricity supply, at a time when the forces of change are greater than ever before.

Network security is a challenge being tackled across the National Electricity Market (NEM), and around the world. South Australia is at the forefront of energy transformation with world-leading levels of renewable energy penetration through large-scale wind generation developments and rooftop solar photovoltaic (PV) installation.

Approximately 45% of South Australia's electricity comes from these renewable energy sources with the combined installed capacity of wind and solar generation (around 2200 MW) far exceeding average demand levels (around 1500 MW). South Australia also has limited interconnection to the rest of the NEM, and so has greater exposure to the system challenges posed by high levels of renewable generation, unlike other parts of the world such as Denmark which have greater interconnection to other networks.

On 28 September 2016, shortly after our Preliminary Revenue Proposal was published, electricity supply in South Australia was lost following an extreme weather event resulting in a state-wide blackout. The detailed circumstances of this event remain the subject of ongoing investigations and inquiries.

The experience of a major loss of supply – while in exceptional circumstances – is a reminder of the importance of system security and the challenges arising from the changing generation mix and unprecedented extreme weather events.

For these reasons, the challenges of energy transformation are nowhere more evident or pressing than in South Australia today.

A strong, reliable and more interconnected electricity transmission network is now more important than ever, to provide access to a diversity of supply sources and to support a secure, reliable, resilient and competitive supply of electricity into the future.

More broadly, the longer-term implications of climate change for Australia's electricity networks are potentially significant, including the potential for increased frequency and severity of extreme weather events and related risks, such as drought, heatwaves, bushfires and extreme rainfall.

Against this backdrop, a number of reviews and inquiries are currently under way by state and national bodies into the implications of the recent extreme weather event of 28 September 2016, and wider system security issues facing the NEM. Most relevantly to our expenditure program, these include:

- The Independent Review into the Future Security of the NEM chaired by Dr Alan Finkel, tasked with developing a national reform 'blueprint' for the NEM;

[4] Available at www.electranet.com.au/wp-content/uploads/resource/2016/06/20081508-Report-Cost-Allocation-Methodology.pdf.

- The AEMC is reviewing various Rule changes and conducting its System Security Market Frameworks Review, which is considering the regulatory frameworks that affect system security in the NEM;
- The Australian Energy Market Commission's (AEMC's) Review of the System Black Event in South Australia on 28 September 2016, which will be considering the need for any changes to the regulatory frameworks to address any systemic issues that contributed to the system black event;
- The Australian Energy Market Operator's (AEMO's) Future Power System Security program, which is examining operational challenges arising from the generation mix, and technical options to address these challenges;
- The Essential Services Commission of South Australia (ESCOSA) is investigating how electricity companies can improve power reliability on the Eyre Peninsula[5]; and
- ElectraNet's South Australian Energy Transformation RIT-T process (discussed further below).

On 12 October 2016, the South Australian Government introduced measures[6] to improve the security and reliability of the power system and reduce the risks of a 'system black' event (as discussed further in Section 6.3.3). On 14 March 2017, it announced further reforms to the operation of the NEM in South Australia to address the immediate electricity supply and security challenges facing the State.

Against this backdrop, our expenditure forecasts and planning assumptions contained in this Revenue Proposal reflect our current service requirements, standards and obligations for a safe, secure and reliable network and is based on the best information available to us at the time of submission.

However, we are mindful that the various inquiries underway may conclude that more should be done to improve network security. For example, our role may change to include additional responsibilities. Equally, more information may come to hand through the outcomes of ongoing internal analysis and investigations on the risks facing the network and the most cost effective actions available to improve network security.

The revenue determination process, therefore, needs to be flexible enough to respond to any updated information, requirements or obligations that impact on our expenditure programs for the transmission network, and to take into account the funding required for any increased investment needs that may emerge.

ElectraNet will share with stakeholders and the AER any new or updated information that becomes available as a result of these developments during the course of the revenue determination process that may impact on our expenditure forecasts, so that these can be taken into account in the AER's draft and final decisions.

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5 ESCOSA has been asked to investigate how electricity companies can improve power reliability on the Eyre Peninsula. ESCOSA will investigate and make recommendations on what measures can be taken to incentivise ElectraNet and SA Power Networks to upgrade current infrastructure and reconnect supply quicker after damaging storm events. The Office of the Technical Regulator will provide advice on the technical aspects of the investigation. ESCOSA will also investigate and report on the costs associated with each potential reliability measure they recommend. Hon. Tom Koutsantonis News Release, 24 January 2017, available at www.premier.sa.gov.au/index.php/tom-koutsantonis-news-releases/1707-energy-minister-meets-mayors-over-eyre-peninsula-power-issues.

6 Electricity (General) (Provision of Limit Advice) Variation Regulations 2016, available at www.governmentgazette.sa.gov.au/sites/default/files/documentstore/2016/October/2016_064.pdf.

6.3.2 How we are responding to customer feedback

The challenges emerging from higher levels of intermittent renewable energy and the resulting closure or mothballing of conventional thermal generation include additional volatility in wholesale market prices and risks to system security and reliability. These challenges are expected to require new solutions from a transmission network and broader power system security perspective. Specific examples include:

- ensuring satisfactory South Australian frequency control, particularly in relation to potential separation events;
- investigating whether lower fault currents (reduced system strength) due to the operation of less conventional generators will adversely impact customers, generators or the operation of the network, and exploring ways to address any adverse impacts; and
- managing high system voltages resulting from declining minimum demand in South Australia as the growth in solar PV connections continues.

In addition to the challenges of a changing generation mix and declining demand, there are also unique factors that lead to higher supply costs in South Australia compared to other states of Australia. Most notably, South Australia has highly ‘peaky’ electricity demand, leading to more supply capacity being required, and generation sources that are more expensive. In addition, customers are geographically spread across the state, resulting in the need for many thousands of kilometres of network to reach and service our customers.

Recent events and increasing system security challenges have caused us to revisit our expenditure plans and review some of the assumptions that underpinned our Preliminary Revenue Proposal. Our thinking has also been informed by our customer engagement. Table 6.1 provides a summary of some of the key insights from this engagement, and how this has helped to shape our capital expenditure forecast.

Table 6-1: How we are responding to customer feedback

What we heard	Our Response
South Australia's blackout on 28 September 2016 crystallised the importance of reliability of electricity supply to business and once the exact causes and their relative contributions to the system failure are determined by relevant inquiries, it will be important for ElectraNet to take reasonable steps at appropriate costs to mitigate future impacts of similar events.	We have carefully examined these risks and adopted measured and targeted proposals to address these risks on a cost effective basis, based on the best information available at this point in time, as outlined in Section 6.3.3 and Section 6.10. We are continuing to monitor the multiple ongoing investigations into this event and will continue to assess whether any further expenditure is required.
The blackout events on 28 September 2016 highlighted the vulnerability of Pt Lincoln customers.	We are actively investigating cost effective solutions to improve the reliability of supply to the Eyre Peninsula, as outlined in Section 6.3.3. The blackout event is the subject of multiple investigations which are ongoing.
After labour, electricity costs are the most significant concern for small business.	We will continue to focus on driving costs down while maintaining the reliable network expected in a modern society, and pursue broader measures to reduce the delivered cost of energy, such as interconnection options, as outlined in Section 6.3.3.
There is limited reference in the Preliminary Revenue Proposal to any projects that focus on maintaining frequency reliability in the transmission system.	We have adopted a number of targeted measures in the short and medium-term to address the security and reliability of the transmission network, including the implications from the recent extreme weather event of 28 September 2016 and the management of system frequency, and continue to investigate such measures, as outlined in Sections 6.3.3 and 6.10.
It's welcoming that ElectraNet is exploring solutions that provide for greater interconnection and should consider including non-network options.	We will continue to investigate the feasibility of new interconnection options and non-network solutions through our SA Energy Transformation RIT-T process, which is now underway, as outlined in Section 6.3.3.
General support for the two contingent projects proposed in the Preliminary Revenue Proposal, however, if approved, this may significantly increase the capital expenditure on the transmission network.	The potential price impacts of these two projects - a full Eyre Peninsula line replacement and new interconnect project - are detailed in Attachment 1. These projects can only be approved by the AER if sufficient net benefits to customers can be demonstrated. Details of the contingent projects we propose are set out in further in Section 6.11.
There is mention of two contingent projects in the Preliminary Revenue Proposal – but there is no mention of other major projects for other regions, such as the Upper North Region.	The Revenue Proposal details five contingent projects being proposed to cater for potential capital expenditure requirements across the network in the coming period, including two projects in the Upper North Region which are contingent on potential mining developments, as set out in Section 6.11.
Support ElectraNet's options to improve reliability on the Eyre Peninsula, not only to Port Lincoln but also to the surrounding region.	We will continue to investigate the most cost effective solutions to support supply reliability to customers on the Eyre Peninsula, as set out in in Section 6.3.3.

What we heard	Our Response
The PRP does not respond to the current and future limitations and weaknesses of the Upper North region or consider potential plans for mining growth.	The Revenue Proposal details five contingent projects being proposed to cater for potential capital expenditure requirements across the network in the coming period, including two projects in the Upper North Region which are contingent on potential mining developments, as set out in Section 6.11. We have also undertaken an investigation into the scope for larger scale works to improve the resilience of the network at its most vulnerable points, focusing on the mid-North, as set out in in Section 6.3.3.
There is a large amount of assets nearing, or at, the end of their intended life. Have some concerns around the reliability of supply and there is limited detail in the PRP.	We will maintain our focus on minimising capital expenditure while maintaining network security and reliability. A risk based approach is being applied to efficiently manage the challenge of ageing assets, with a focus on replacing individual network assets to maintain safety and reliability rather than replacing whole substations or transmission lines, and cost effective measures to efficiently extend the life of our network assets, such as the transmission line refurbishment program. This is detailed in Section 6.4 and Section 6.10.
ElectraNet's proposed 46% reduction in capital expenditure will relieve pressure on a growing RAB and is welcomed as an important first step to addressing concerns with South Australia's high electricity prices.	We will maintain our focus on minimising capital expenditure while maintaining network security and reliability, as outlined in this Attachment. Our regulated asset base (RAB) is projected to decline in real terms over the forthcoming regulatory period, as detailed in Attachment 2.

Further information on the outcomes of our early engagement program are contained in the Customer Engagement Outcomes Report[7].

6.3.3 Key initiatives

A small number of prudent and targeted investments designed to improve the security of the transmission network and increase the ability to withstand or recover more quickly from the impact of extreme weather events, such as occurred on 28 September 2016, have been added to our capital expenditure forecast. While this means a smaller reduction in our capital program than indicated in our Preliminary Revenue Proposal, this investment is more than offset by the benefits of improved network security. At this time, the detailed investigations into the event and its future implications remain ongoing.

We are also examining additional measures to strengthen the network, including stronger interconnection, special protection schemes, synchronous condensers, energy storage and upgraded supply for the Eyre Peninsula in order to respond to security and reliability challenges facing the power system and deliver the reliability outcomes our customers expect.

[7] ElectraNet, Customer Engagement Outcomes Report. March 2017 (ENET049)

Network Resilience

Transmission lines throughout the world are not designed to withstand the most extreme weather conditions they may possibly experience. This is largely due to the prohibitive cost of building infrastructure to withstand extreme, but very low probability events, within an economic regulatory framework focused on efficient outcomes.

Rather, it is recognised that infrastructure may be damaged and customer supply interrupted under the most extreme and unlikely events, and emergency response measures are put in place to minimise the extent and duration of this resulting disruption.

Unprecedented extreme weather events such as occurred in South Australia on 28 September 2016 provide an opportunity for everyone to take stock of the security and reliability of the NEM. In this regard, we are looking at whether there are any prudent actions that should be taken to improve network resilience to extreme weather events and / or to improve emergency response capabilities. As a result, a small number of prudent and targeted investments designed to improve the security of the transmission network and increase its ability to withstand or recover more quickly from the impact of extreme weather events have been added to our capital expenditure forecast, as discussed further in Section 6.10.

In addition to these new projects, we have also examined the scope for further targeted and cost effective options aimed at further improving the resilience of the network to withstand the impacts of extreme weather events. Such measures could include for example larger scale works to strengthen, reinforce or ‘harden’ existing transmission line structures at the most vulnerable and critical points of the network to reduce the risk of multiple tower failures leading to potential widespread and extended loss of customer supply during extreme wind events.

We engaged an independent expert to assist in identifying such options with a focus on mitigating the risk of loss of supply to customers in the north of South Australia, that would result from extreme wind damage to all three 275 kV transmission lines between Adelaide and Davenport (near Port Augusta) .

The independent expert developed models for predicting failures of one or more of the 275 kV transmission lines in a single weather event.

The models showed that the highest likelihood of failure of three lines in one storm event arises in the 22.5 km zone immediately south east of Davenport substation, where the three lines are close together, and thus where a tornado could impact all three lines.

These studies also included cost/benefit analysis consistent with the established regulatory frameworks for networks, which assess potential benefits in the context of both the predicted economic impacts on customers of network outages and the (very low) likelihood of occurrence of extreme weather events, balanced against the cost of mitigating options.

Specifically, the estimated economic cost to customers of a high impact network outage is multiplied by the statistical likelihood of occurrence of the causal extreme weather event to give annual economic loss predictions. The analysis included a range of assumptions regarding likelihood of transmission line failure, the expected statistical frequency of future storm events, the expected time to restore supply, and the locational value of customer reliability.

More than twenty project options were identified that could potentially reduce either the probabilities of failure of the transmission lines or the impact of these failures. The costs of these options were estimated by the expert using standard cost estimation techniques and knowledge of transmission project costs in Australia.

These costs were then compared with the estimated potential economic benefits arising from each project through the reduction of outage risk.

The cost-benefit assessment included identifying the sensitivity to variations of the key input variables or assumptions over a reasonable range, applying probabilities to these variations, calculating the weighted potential benefits for each project and comparing these with the estimated capital cost of the project options.

The analysis undertaken concluded that the weighted outcome over all reasonable sensitivities did not show an economic case for investment within the current economic regulatory framework for any of the identified project options. An economic case could possibly only be made for some highly improbable sensitivity cases; e.g. by assuming a significantly higher frequency of extreme wind events in the future than the historically-derived frequency.

ElectraNet also sought advice from independent experts specialising in fields of wind engineering, aerodynamics, structural dynamics and risk analysis, on the likely impact of climate change on the future frequency of extreme wind events. The independent experts concluded that, based on both past observational data and modelling of the forward-looking impacts of climate change, there is presently no evidentiary basis for assuming a higher than historical frequency of extreme wind events in South Australia.

Based on these analyses and conclusions, and given the regulatory framework for assessment of proposed capital expenditures, we have not included any of these larger scale project options in our proposed capital expenditure forecast.

Investigations remain ongoing, and cost effective options for improving the resilience of the network to withstand the impacts of extreme wind events may emerge in the light of new or updated information, or analysis that becomes available after our Revenue Proposal has been submitted. In these circumstances, we will provide any such updated information to stakeholders and the AER at the earliest opportunity.

In order to respond to security and reliability challenges facing the power system, we are separately examining additional measures to accelerate proof-of-concept projects, such as the application of battery storage technology at a grid scale and the potential for investment in synchronous condensers. These initiatives are discussed further below.

South Australian Government and AEMO system security measures

Managing system frequency is vital to the security and stability of an interconnected power system, and is increasingly challenging in the face of growing levels of renewable generation that is generally ‘asynchronous’, or unable to control frequency.

On 12 October 2016, the South Australian Government introduced frequency control measures to improve the security of the power system and reduce the risks of a ‘system black’ event. These measures took the form of a new obligation in the Electricity (General) Regulations (SA) 2012 requiring us to provide advice to AEMO on the limitations of the Heywood Interconnector for the purposes of AEMO’s power system security responsibilities so as to maintain the expected rate of change of frequency

(RoCoF) to not exceed 3 Hz/s in relation to the potential non-credible loss of the interconnector[8]. Separately, AEMO has introduced a requirement for the capacity of two generators to be available in South Australia at all times to provide sufficient system strength to support the stability of the system. The Government announced further measures on 14 March 2017 to address the immediate electricity supply and security challenges facing the State, including the provision of grid scale storage, emergency generation and an energy security target.

These immediate measures were introduced pending longer-term solutions expected to flow from current reviews, such as the System Security Market Frameworks Review and associated Rule changes being progressed by the AEMC. Options being considered include new technical standards for generators, provision of new services by network businesses such as ElectraNet, the procurement of additional control services by AEMO, and the establishment of new markets for services such as inertia.

Any implications that subsequently arise out of these unfolding developments for our expenditure programs will also need to be taken into account by the AER in its revenue determination.

Energy Storage Project

Consistent with the State Government's recent commitment to provide South Australia with large scale battery storage we have for some time been pursuing a proof-of-concept project to trial a grid scale battery storage solution as an option to improve the security of the power system.

This initiative, known as the Energy Storage for Renewable Integration South Australia (ESCRI-SA) Project, is being undertaken by a consortium of ElectraNet, AGL and Advisian (WorleyParsons). Subject to successful part funding from the Australian Renewable Energy Agency (ARENA) this project involves installing a 30 MW, 8 MWh energy storage device to provide fast frequency response that can address RoCoF concerns as well as provide other benefits to the power system.

The need for such projects has also been identified in reviews such as the Finkel Review, AEMO's Future Power System Security work program, and by the COAG Energy Council. Successful deployment of this facility would establish battery storage as a viable technical solution to assist in meeting the system security challenges facing South Australia, consistent with the State Government's energy plan[9].

Capital expenditure of about $6m [10] has been included in our forecasts for the forthcoming regulatory period to part fund the delivery of this project.

8 Available at www.governmentgazette.sa.gov.au/sites/default/files/documentstore/2016/October/2016_064.pdf

9 A formal grant application for gap funding for the project was lodged with ARENA on 22 February 2016. The review and assessment process continues at this time.

10 This equates to the expected value of the prescribed network services to be delivered by this project, with the balance of the asset to be funded by ARENA and AGL as a non-regulated service.

Increased Interconnection

A more decentralised power system must be a more interconnected power system.

In December 2016, AEMO published its latest National Transmission Network Development Plan (NTNDP) [11] which included the following important observations regarding the future direction for transmission networks:

- The NEM is moving into a new era for transmission planning:
  - Transmission networks designed for transporting energy from coal generation centres will need to transform to support large-scale renewable generation development in new areas.
  - Transmission networks will increasingly be needed for system support services, such as frequency and voltage support, to maintain a reliable and secure supply.
- Preliminary modelling suggests positive net benefits for potential interconnection developments… including a new interconnector linking South Australia with either New South Wales or Victoria from 2021.

AEMO also observed that local network and non-network options, such as synchronous condensers or similar technologies, are also needed as part of the solution to maintain a reliable and secure supply by providing local system strength and resilience to frequency changes.

Clearly, a strong, secure electricity transmission network is now more important than ever.

Increased interconnection within the NEM is vital to achieving affordable and reliable electricity supplies, while enabling the increasing choice and long-term sustainability valued and desired by electricity customers. Increased interconnection will deliver system security benefits by reducing the likelihood of a system disturbance leading to a major disruption to electricity supply. It will also facilitate greater competition between sources of generation and thus deliver better prices for customers, by allowing increased access to a range of power sources, as well as opening up access to the market for more renewable generation developments.

We are therefore exploring potential solutions to these challenges and investigating options that include new transmission lines between South Australia and the Eastern States, as well as non-network options that provide benefits to the market and system security. This involves applying the established Regulatory Investment Test for Transmission (RIT-T) as the cost benefit test applied to major network investments under the Rules, overseen by the AER. This process formally commenced with the release of an initial consultation report in November 2016.[12]

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11 Available at www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NTNDP/2016/Dec/2016-NATIONAL-TRANSMISSION-NETWORK-DEVELOPMENT-PLAN.pdf.

12 Available on our website at www.electranet.com.au/projects/south-australian-energy-transformation/

The work undertaken to date has identified four credible network options, all of which involve constructing a new interconnector between South Australia and the eastern states, together with a range of potential non-network solutions. These options and others will be analysed further in the first stage of the RIT-T process. The RIT-T process is currently scheduled to conclude in late 2017. If ultimately approved, a solution including a new interconnector and alternative or accompanying non-network solutions could be operational as early as 2022.[13]

A new interconnector project or non-network alternatives would only proceed if sufficient benefits to customers can be demonstrated. If this proves to be the case, then the outcomes would be subject to separate AER approval as a 'contingent project' at that time. Due to the uncertainty around if and when this contingent project might proceed, the costs are excluded from our expenditure forecasts.

For illustration, as discussed in Section 6.3.3, a new interconnector to New South Wales for example at an indicative cost in each State of $250m would add approximately $8 per annum to a typical residential customer bill in South Australia at the time of completion, which would be expected to be towards the end of the forthcoming 2019-2023 regulatory period.

Our proposed contingent projects are discussed further in Section 6.11.

Eyre Peninsula Upgrade Options

We are investigating the most cost effective ways to improve supply reliability to the Eyre Peninsula.

ElectraNet understands the importance of a reliable electricity transmission supply to the regional areas of South Australia such as the Eyre Peninsula, and the contribution it makes to the ongoing economic development of the wider South Australian economy. The extreme weather event of 28 September 2016 and other recent storm events have highlighted the importance of supply reliability to these areas and the impacts of extended outages on these communities.

Eyre Peninsula is served by a radial 132 kV transmission line which runs from Cultana to Yadnarie to Port Lincoln. A radial 132 kV line also extends to Wudinna to supply the West Coast. The original line to Port Lincoln was established in 1967. We have in recent years been reinforcing and rebuilding the Cultana and Whyalla substations.

Supply to Port Lincoln is supported by a network support agreement between ElectraNet and Engie which expires on 31 December 2018. Under this agreement, ElectraNet is able to call upon the services of three diesel-fired gas turbines connected at Port Lincoln when needed. The reliability standards require that ElectraNet provide "N-1" equivalent line capacity to the Port Lincoln exit point, so that back-up supply is available for Port Lincoln when supply from the 132 kV line is interrupted.

ElectraNet has been actively exploring options to replace or upgrade the transmission lines serving the Eyre Peninsula. Our most recent assessment of the condition of the line assets indicates that components of the line are nearing the end of their functional life (with a standard line life of 55 years) and will require replacement in the next few years.

[13] To allow for the possibility of future investment in non-traditional network assets such as synchronous condensers, if found to be economic, ElectraNet is introducing a new asset class to cater for these types of assets.

To enable this work, we have included in our plans an allowance for the replacement of major transmission line components on the Eyre Peninsula. This is the largest single project included in our capital expenditure forecast, at a cost of approximately $80m, and involves replacing the line conductor in high priority sections of the lines.

Alternatively, the full replacement of the line (for example as a double circuit line) may be more cost effective and deliver greater benefits to Eyre Peninsula customers through potentially improving supply reliability and avoiding the ongoing costs of generation support at Port Lincoln. The cost of fully replacing the line as a separate project is currently estimated at approximately $200m, being $120m more than the approximate cost of the replacement of major line components mentioned above.

The additional $120m has been excluded from our capital expenditure forecast, as the case for this investment has not yet been established. However, we are proposing a contingent project for the full replacement of the line, which would be subject to separate approval by the AER if a full replacement was demonstrated to deliver greater net benefits to customers.

To take this forward, we are currently exploring the economic case for a full line replacement and alternative options in more detail. This involves undertaking the RIT-T, which will assess the costs and benefits of alternative network and non-network solutions[14].

We will continue to actively monitor and maintain the condition of our lines on the Eyre Peninsula through our ongoing maintenance program, to ensure the security and reliability of transmission supply while the RIT-T process is undertaken.

We will also continue working closely with ESCOSA as the body responsible for setting reliability standards for South Australia’s transmission network, as it reviews the reliability standard for the Eyre Peninsula following a recent request by the South Australian Treasurer and Minister for Energy, as discussed in Section 6.3.1.

Our proposed contingent projects are discussed further in Section 6.11.

6.4 Overview of historical and forecast capital expenditure

Despite the significant challenges described above, our total capital expenditure is forecast to reduce by 39% to $458 million in the 2019-2023 regulatory period (with an annual range of $60–110 million) compared with an estimate of $753 million for the current period (and historical annual levels of $150–200 million), as shown in Figure 6.2[15].

[14] An Eyre Peninsula Electricity Supply Reinforcement Project Specification Consultation Report (PSCR) is expected to be published in April 2017, as the initial consultation report under the RIT-T, to be available on our website at www.electranet.com.au.

[15] A full breakdown by project category is provided in the capital expenditure model which accompanies this Revenue Proposal.

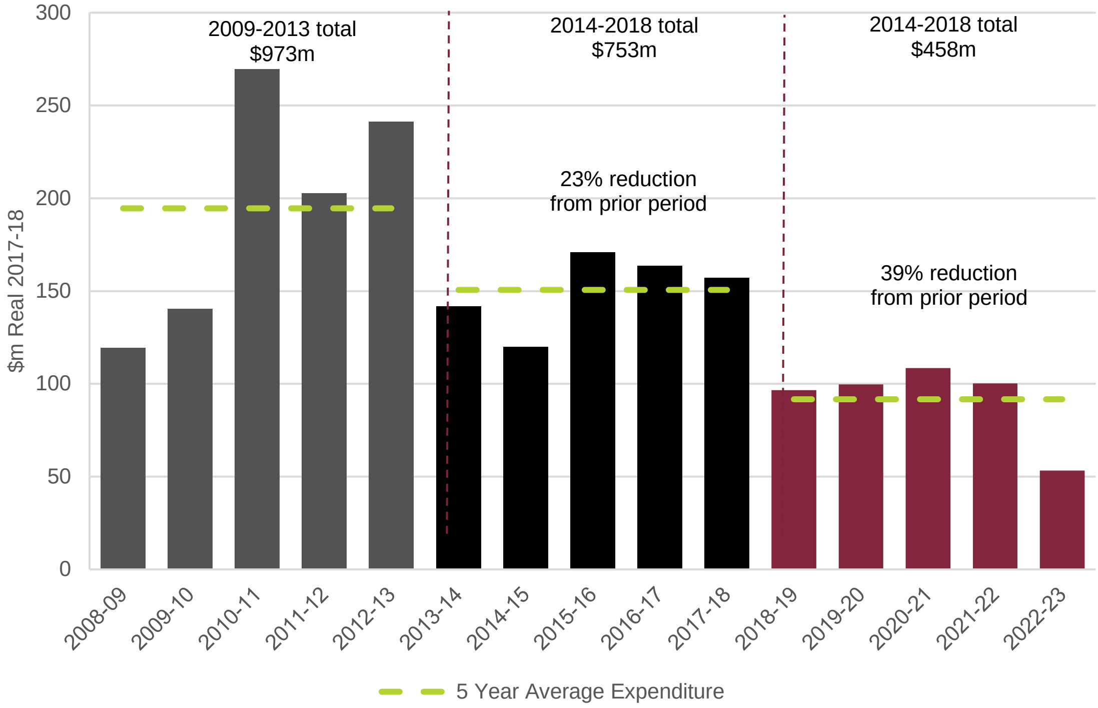


Figure 6.2: ElectraNet's actual and indicative forecast capital expenditure ($m 2017–18)

As growth in electricity demand has decreased and is projected to fall further, there is minimal load-related investment required over the forthcoming regulatory period. However, we must continue to invest to ensure that the condition, risk and performance of our assets enables us to continue to provide a safe, reliable and secure network, in accordance with our customers' needs and our regulatory obligations. As noted in AEMO's assessment of our capital investment program:

> The driver for investment in South Australia's transmission network has shifted from meeting peak demand, to enabling a secure and reliable transformation to a low carbon future[16].

Accordingly, our investment program for the forthcoming regulatory period is focused on:

- pursuing targeted measures to improve the ability of the network to withstand extreme weather events and improve network security;
- replacing individual network assets whose condition signals that they are at the end of their useful lives; and
- refurbishing other assets in order to drive the network harder and longer.

South Australia has among the oldest assets of the transmission networks in the NEM. While significant investment has been made in recent years in replacing aged substation assets, a key focus of the next regulatory period is to address transmission line condition and risk to ensure reliability of the network for South Australian households and businesses.

16 AEMO is expected to publish this assessment report by early April 2017.

Between 30% and 45% of our major line assets will have exceeded their standard economic lives by the end of the next regulatory period, as shown in Figure 6.3 below.

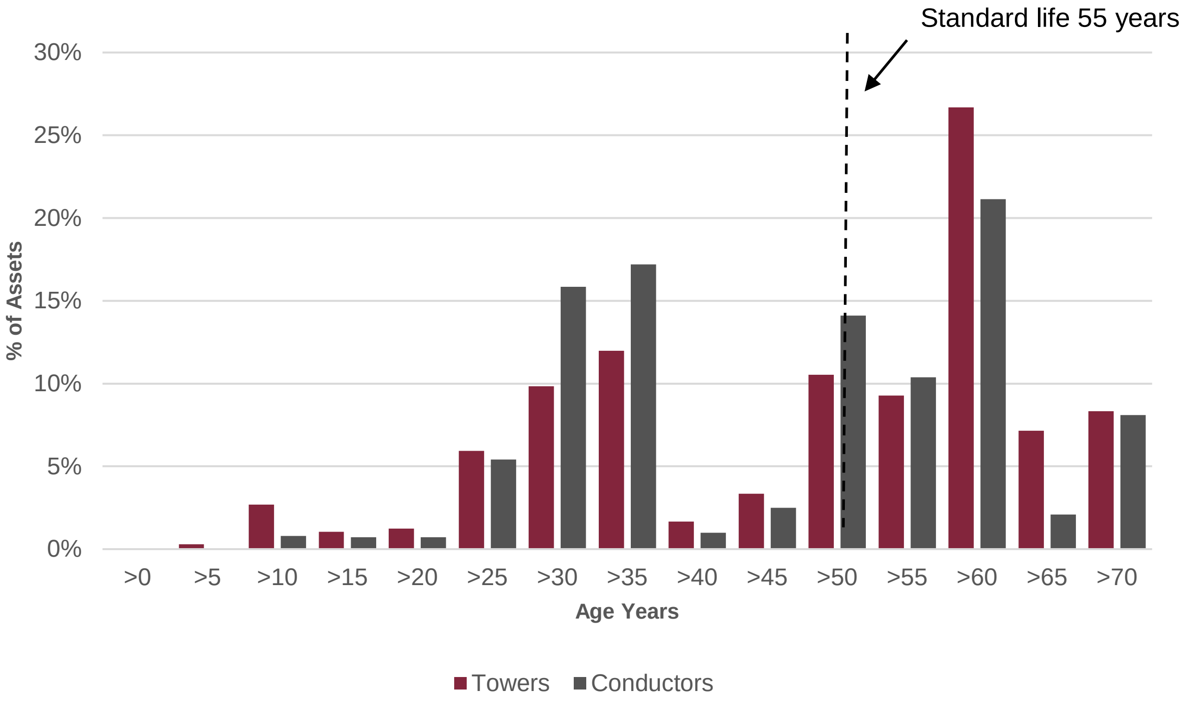


Figure 6.3: ElectraNet's transmission line predicted asset age profile in 2023

While age is a useful indicator of future replacement requirements, we do not replace assets based on age, but based on condition and risk. We carefully monitor the condition of our assets and apply a risk based approach to ensure that assets are replaced only when it is cost effective to do so. Our plans are consistent with maintaining safety and reliability in accordance with the Rules requirements.

The majority of our investment program relates to risk based asset replacement and line refurbishment and targeted network security measures, with the remainder relating to recurrent and other capital expenditure required to maintain the systems and facilities needed to efficiently run the network.

We are forecasting a significant decrease in all categories of capital expenditure, with the exception of refurbishment. We also expect to deliver the capital program in the current period for approximately 6% (or $48m) less that the capital expenditure allowance. This will deliver further ongoing savings to customers through avoided investment.

Table 6.2 provides a summary of the forecast capital program, including a breakdown by type and investment driver, compared to the current regulatory period, with greater detail on the refurbishment and replacement elements outlined in Table 6.3.

Table 6-2: Actual and forecast capital expenditure ($ million real 2017–18)

Category	Forecast Expenditure 2014–2018	Forecast Expenditure 2019–2023	Change	Drivers
Augmentation	102	16	-86	Minimal new load driven capital investment requirements in the declining demand environment
Connection	39	6	-33	
Easement/land	26	0	-26	
Replacement	349	167	-182	Focus on component asset replacements with reduced need for large scale rebuilds – key expenditure drivers are to manage network safety, security and reliability risk and contain escalating maintenance costs
Refurbishment	75	159	84	Key expenditure drivers are to extend the useful life of ageing transmission lines and manage network safety, security, reliability and fire start risk
Security / Compliance	74	46	-28	Reduced requirements based on work undertaken in the current period, with a focus on targeted measures to address network security risks
Inventory/ spares	14	12	-2	Ongoing stock replenishment program
Information technology	58	47	-11	Reduced program largely focused on ongoing replacement requirements
Facilities	14	6	-8	Ongoing minor asset replacement
Total*	**753**	**458**	**-295**	**Reduction of 39%**

** Totals may not add due to rounding*

Table 6-3: Replacement and refurbishment forecast for 2019-2023 ($ million real 2017–18)

Type	Program	$m	Drivers
Network replacements	Telecommunications	24	Manage reliability and contain escalating maintenance costs
	Operational IT	12	
	Other	43	
Unit asset replacements	Protection Systems	29	Manage reliability and safety risks and contain escalating maintenance costs
	Isolators	11	
	Circuit Breakers	5	
	Transformer Bushings	7	
	Transformers	8	
	Other	28	
Subtotal		**167**	
Line refurbishment	Conductors	92	Extend line life and manage safety, reliability and fire start risk
	Insulators	59	
	Support Systems	9	
Subtotal		**159**	

The largest single project in ElectraNet's ex-ante capital expenditure forecast is the replacement of major components of the radial 132 kV transmission line supplying the Eyre Peninsula (comprising the conductor and earth wire refurbishment of the Cultana-Yadnarie 132kV line, and Yadnarie-Pt Lincoln 132kV line). As discussed in Section 6.3.3, the alternative option of full replacement of the line would only proceed if the benefits to customers can be shown to exceed the costs.

We are committed to delivering a safe and reliable network and to meeting our compliance obligations at an efficient cost. Table 6.4 (on the following page) summarises how we ensure that our capital expenditure forecasts are efficient and prudent. Further detailed information is provided in the later sections of this attachment and supporting documents.

Table 6-4: Development of prudent and efficient capital expenditure forecasts

Inputs and Analysis	Our Approach
Demand forecasts and reliability	Forecast demand is an important driver of reliability capital expenditure. We have adopted the AEMO's latest demand forecasts[17] and estimates of the Value of Customer Reliability (VCR)[18]. Adopting these independent values provides confidence in these inputs.
Project cost estimates and efficiencies	An efficient capital expenditure forecast relies on accurate project cost estimates. To ensure that our project cost estimates are accurate, we have updated our estimates for the latest actual project costs and market rates. We have also incorporated efficiencies expected to arise as we combine the delivery of related projects. We also obtained check estimates of project costs from independent experts to verify the efficiency and prudency of our estimates. This ensures that our project cost estimates are accurate and reasonable.
Economic assessments	We conduct an economic assessment to determine whether the benefits of undertaking the project exceed the costs, and we review all available options. We examine the optimal timing of the project, so that customers obtain the maximum net benefit from the expenditure, and projects are deferred when this is more economic. Our economic assessments have been reviewed by economic experts Houston Kemp[19] to ensure they are robust and reasonable. AEMO has also conducted an independent technical assessment of the network capacity related investments underpinning this program. For each project identified, AEMO has assessed that the need exists; the timing is appropriate; and the solution being proposed appears reasonable[20].
Risk and reliability analysis	Our decision to replace an asset is driven by asset condition, risk and reliability considerations, not asset age, balanced against cost. Our risk analysis considers the: • probability of an asset failure; • likelihood of adverse consequence(s); and • likely cost(s) of the consequence(s). This is based on a systematic process for collecting, recording and analysing detailed information on the condition of network assets, and balances the expected risk reduction against the costs of the proposed expenditure to ensure safety and reliability requirements are met at lowest cost. This framework has been developed with input from asset management experts AMCL[21].

17 AEMO, National Electricity Forecasting Report – For The National Electricity Market, June 2016, available at www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Electricity-Forecasting-Report.

18 AEMO, Value of Customer Reliability Review Final Report, September 2014, available at available at www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Value-of-Customer-Reliability-review.

19 Houston Kemp – Review of ElectraNet Economic Assessment Framework March 2017 (ENET029)

20 AEMO is expected to publish its conclusions by early April

21 Asset Risk Cost Modelling Guideline March 2017 (ENET058)

6.5 Obligations relating to capital expenditure

In developing our capital expenditure plans, an important objective is to satisfy all of our compliance obligations, including those arising from:

- our transmission licence and the Electricity Transmission Code (ETC);
- the National Electricity Rules; and
- our Safety, Reliability, Maintenance and Technical Management Plan (SRMTMP), which is required by our transmission licence.

6.5.1 Transmission licence and ETC obligations

Under section 15 of the *Electricity Act 1996 (SA),* we are required to be licensed in order to operate a transmission network in South Australia. The transmission licence authorises us to carry on the operation of the transmission network in accordance with the terms and conditions of the licence.

Our transmission licence sets out obligations in relation to network performance, which have implications for our capital expenditure requirements. These obligations require us to:

- maintain connection point reliability standards;
- maintain regulated voltage levels and reactive margins;
- manage fault levels;
- manage equipment ratings;
- manage system stability and security; and
- manage quality of supply (frequency, harmonics and flicker).

The transmission licence is issued by ESCOSA[22].

A central part of ESCOSA's licensing function is to set standards of service under the terms of each licence. ESCOSA undertakes this task through the provisions of the ETC, made pursuant to Part 4 of the *Essential Services Commission Act 2002* (ESC Act). Compliance with the ETC is a mandatory licence condition for ElectraNet as well as a regulatory obligation in accordance with clause 6A.6.7 of the Rules.

Section 1.6.1 of the ETC makes it clear that any obligations imposed under the ETC are in addition to those imposed under the Rules and the *Electricity Act 1996 (SA)* (and regulations). We must therefore comply with both the ETC and the Rules.

The ETC forms part of a broader regulatory scheme for transmission in the NEM, with regulation of the system occurring at two levels:

- the Rules establish technical standards dealing with matters such as frequency, system stability, voltage and fault clearance[23]; and

[22] Our transmission licence as currently in force (last varied 1 July 2008) is available at www.escosa.sa.gov.au/ArticleDocuments/531/080703-ElectricityTransmissionLicenceVaried-ElectraNet.pdf.aspx?Embed=Y.
[23] National Electricity Rules, Schedule 5.1

- jurisdictional standards, such as those set out under the ETC, provide for security and reliability standards which align with technical standards set out under the Rules.

In particular, the ETC contains provisions relating to:

- service standards;
- interruptions;
- design requirements;
- technical requirements;
- general requirements;
- access to sites;
- telecommunications access; and
- emergencies.

Clause 2 of the ETC mandates specific reliability standards at each transmission exit point (a customer connection point) or group of exit points, and supply restoration standards[24].

6.5.2 Rules requirements

ElectraNet is the principal TNSP and the Jurisdictional Planning Body for South Australia under clause 11.28.2 of the Rules. As such, we have specific obligations under Chapter 5 of the Rules with regard to network connection, network planning and establishing or modifying a connection point, including technical obligations that apply to all registered participants.

As part of our planning and development responsibilities, we must:

- consider public and worker safety paramount when planning, designing, constructing, operating and maintaining the network;
- operate the network with sufficient capability to provide the minimum level of transmission network services required by customers;
- comply with the technical and reliability standards contained in the Rules and jurisdictional instruments such as the ETC;
- plan, develop and operate the network such that there is no need to shed load under normal and foreseeable operating conditions to achieve the quality and reliability standards within the Rules;
- conduct joint planning with distribution network service providers (DNSPs) and other TNSPs whose networks can impact the South Australian transmission network;

[24] The version of the Electricity Transmission Code currently scheduled to apply from 1 July 2018 (version TC/09) is available at www.escosa.sa.gov.au/ArticleDocuments/1020/20160922-Electricity-TransmissionCode-TC09.pdf.aspx?Embed=Y.

- provide information to registered participants and interested parties on projected network limitations and the required timeframes for action; and
- develop recommendations to address projected network limitations through joint planning with DNSPs and consultation with registered participants and interested parties.

The planning process considers network and non-network options, such as local generation and demand side management initiatives, on an equal footing. We select the solution (which may include 'do nothing') that maximises net benefits.

6.5.3 Safety, Reliability, Maintenance and Technical Management Plan

In accordance with clause 7 of our transmission licence, we are required to:

- prepare and submit to ESCOSA for approval a SRMTMP dealing with the matters prescribed by regulation;
- annually review, and if necessary update, the plan to ensure its efficient operation, and submit the updated plan to ESCOSA for approval;
- not amend the plan without the approval of ESCOSA;
- comply with the plan (as updated from time to time) as approved by ESCOSA; and
- undertake annual audits of our compliance with our obligations under the plan and report the results of those audits to the Office of the Technical Regulator (OTR), in a manner approved by the OTR.

The SRMTMP must address, amongst other things, the safe design, installation, commissioning, operation, maintenance and decommissioning of electricity infrastructure owned or operated by a licensed person. As such, the SRMTMP, in addition to the obligations described in Sections 6.5.1 and 6.5.2, is an important driver of our future capital expenditure requirements.

6.6 Capital expenditure categories

We have retained the same capital expenditure categories as the current regulatory period, as set out in Figure 6.4 on the following page. These categories accord with the Rules requirements.

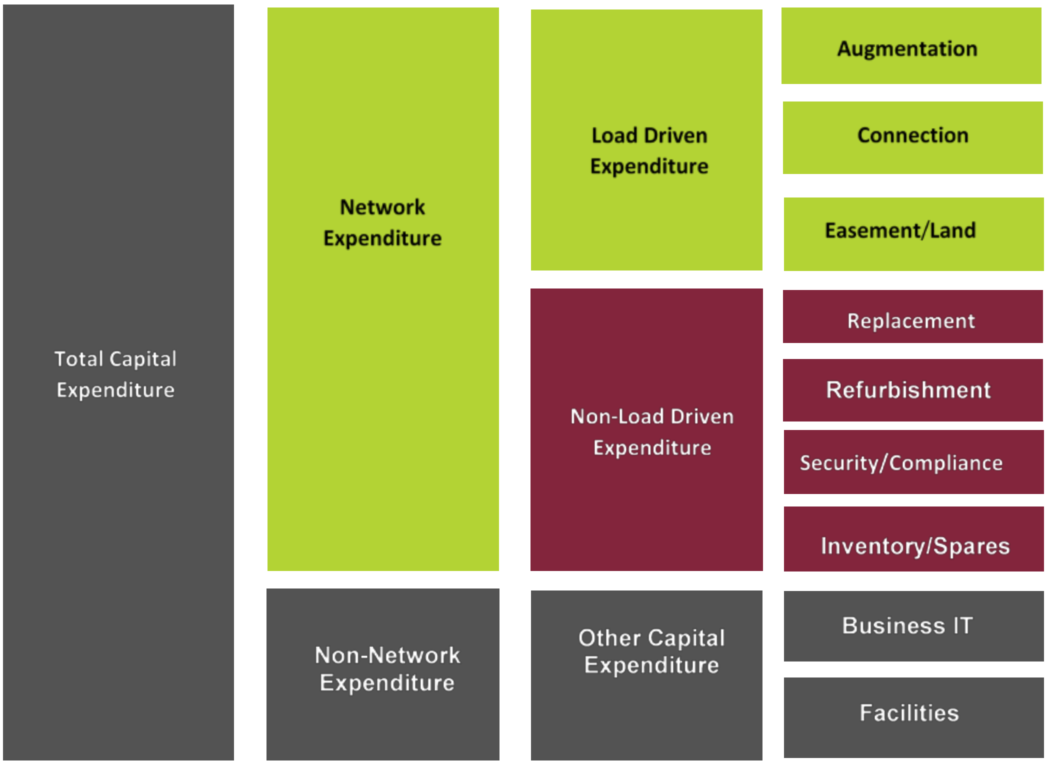


Figure 6.4: Our capital expenditure categories

The table below describes each of the 9 expenditure categories presented in the right hand column of Figure 6.3. For each category, we also identify the associated transmission services.

Table 6-5: Description of capital expenditure categories

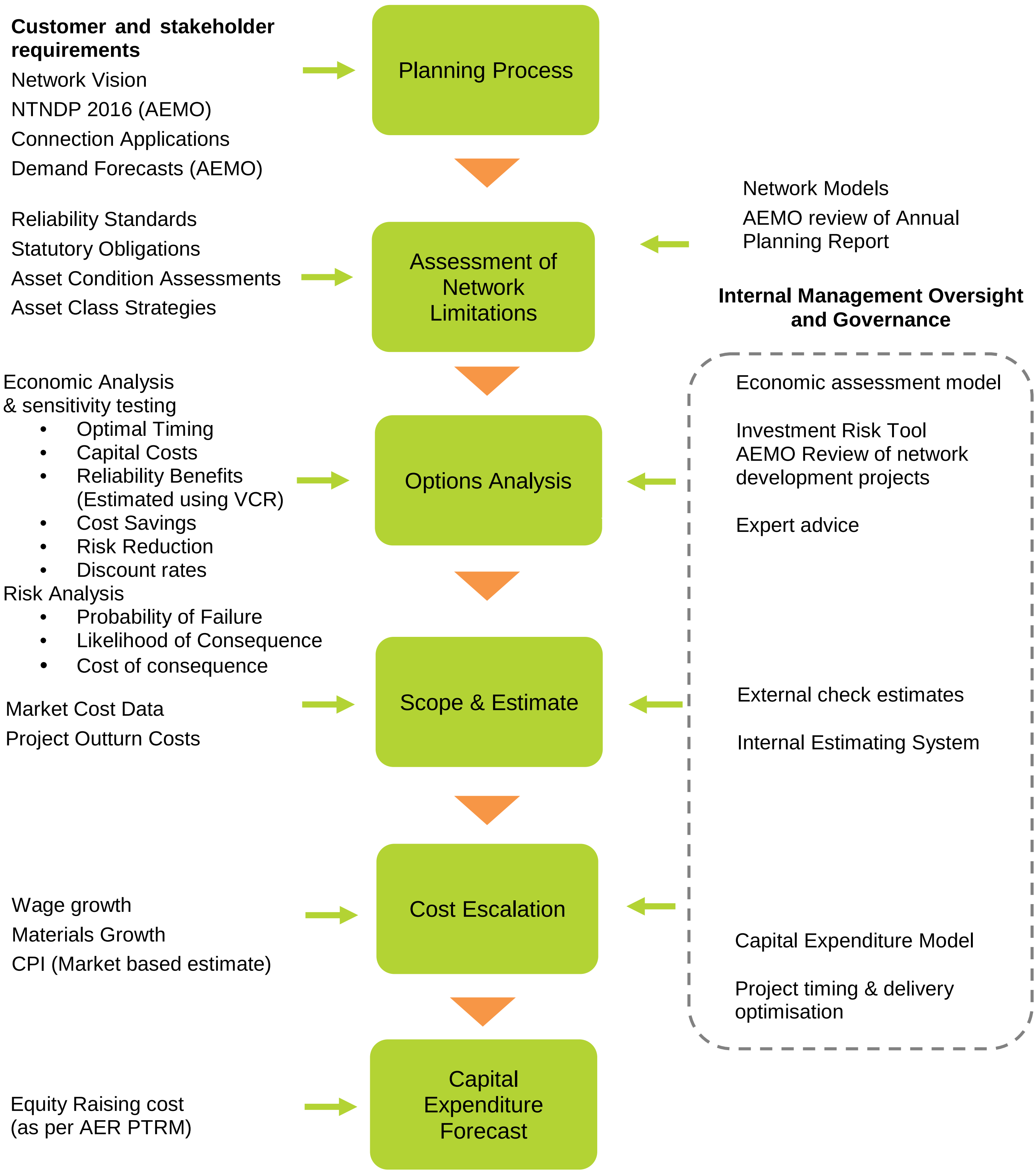
Expenditure Category	Definition	Service Category
Network – Load Driven		
Augmentation	Works to enlarge the system or to increase its capacity to transmit electricity. This includes projects to which the RIT-T applies and involves the construction of new transmission lines or substations, reinforcement or extension of the existing shared network. The projects may be driven by reliability or market benefits requirements, and are inclusive of any supporting communications infrastructure, land and IT systems.	Transmission Use of System Services (TUOS)
Connection	Works to either establish new prescribed customer connections or to increase the capacity of existing prescribed customer connections based on specific customer requirements. Includes projects driven by the Electricity Transmission Code (ETC) reliability standards. In accordance with the Rules, new connection works between regulated networks are treated as prescribed services. Other new connections are treated as negotiated or contestable transmission services.	Exit Services

Expenditure Category	Definition	Service Category
Easement / Land	Strategic land and easement acquisitions for projected augmentation, connection and replacement requirements. Typically, these are long term requirements guided by Government strategic plans or to address risks relating to the future availability of land.	Common Services
Network Non-Load Driven		
Replacement	Works to replace transmission lines, substation primary plant, secondary systems, communications equipment and other transmission system assets in order to maintain reliability of supply. Replacement projects are generally undertaken due to the increased risk of plant failure as a result of asset age, asset condition, obsolescence or safety issues.	Exit Services and TUOS
Refurbishment	For some assets, refurbishment is an alternative to asset replacement. Refurbishment works are generally undertaken based on the asset condition, performance and asset risk to efficiently extend asset life as a more economic alternative to wholesale asset replacement.	TUOS
Security / Compliance	Projects that address network compliance requirements set out in legislation and regulations, and industry standards. Projects required to ensure the physical and system security of critical infrastructure assets.	Entry Services, Exit Services, TUOS, Common Services
Inventory / Spares	Spares holdings to enable us to respond to asset failures in accordance with the restoration times specified in the ETC and good electricity industry practice.	Common Services
Non Network		
Business IT	Projects to develop and maintain IT capacity and to improve the functionality of business systems to support business operation.	Common Services
Facilities	Projects to replace and upgrade office accommodation and services to meet business needs.	Common Services

6.7 Expenditure forecasting methodology

Our capital expenditure forecasting methodology is illustrated in Figure 6.5 on the following page. The methodology is consistent with the approach notified to the AER in June 2016 in accordance with the Rules requirements, as discussed further in the following sections.

Figure 6.5: Capital expenditure forecasting methodology



Our capital expenditure forecasting process is integrated with our business as usual budgetary, planning and governance processes. In addition to the internal controls governing these 'business-as-usual' processes, the input assumptions are subject to rigorous review and sign off.

These quality assurance steps provide confidence that the inputs to our forecasting model are soundly based and consistent with efficient expenditure.

In the remainder of this section, we explain each step of our methodology in turn. This is followed by a detailed description of the key inputs and assumptions to our capital expenditure forecast in Section 6.10.

6.7.1 Customer and stakeholder requirements

The starting point for our capital expenditure forecasting methodology is understanding our customers' requirements through effective engagement. As noted in Section 6.3.2, our expenditure priorities have been shaped by the feedback we have received through our customer engagement process.

Further information on our customer engagement process is provided in the Revenue Proposal Overview.

6.7.2 Planning process

As explained in Section 6.6 we follow a systematic process to develop plans and initiate projects to deliver a safe, reliable and sustainable transmission network to meet our customers' requirements in the most cost effective manner.[25]

The planning process operates within a strategic framework informed by our Network Vision, and industry planning documents prepared by AEMO such as the National Transmission Network Development Plan (NTNDP). The planning process also relies on inputs such as demand forecasts and connection applications, as discussed further in Section 6.8. We confirm that our forecast capital expenditure presented in this Revenue Proposal is consistent with the most recent NTNDP, which was published in December 2016[26].

Our network planning and investment analysis process ensures that we optimise our capital and operating expenditure. As indicated in Section 6.9, the AER's benchmarking indicates that our current mix is optimal. From a forecasting perspective, we do not expect our capital expenditure plans to have a material impact on our operating expenditure forecasts. The interaction between operating and capital expenditure forecasts is discussed further in Section 7.7 of Attachment 7.

6.7.3 Assessment of network limitations

In developing our forecast capital expenditure, we consider projected network limitations, the condition and performance of the existing assets and the associated supporting facilities and business systems required to efficiently operate the network over the

25 For reference, a map of South Australia's transmission network is included in our response to the Regulatory Information Notice which accompanies this Revenue Proposal (ENET088).

26 Available at www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NTNDP/2016/Dec/2016-NATIONAL-TRANSMISSION-NETWORK-DEVELOPMENT-PLAN.pdf.

forecast period. The application of this approach differs by expenditure category, as follows:

- Load-driven network investment requirements are identified through modelling of future power system capability and analysis of network constraints.
- Non-load driven network investment requirements are primarily determined in accordance with our asset management framework, which takes a risk-based approach to the replacement or refurbishment of assets based on assessed risk, condition and performance.
- Non-network investment requirements are largely determined in accordance with the strategic priorities for information technology, which provides for the efficient development and operation of the business systems and supporting facilities required to efficiently manage the network and supporting business functions.

6.7.4 Options analysis

As explained in Section 6.7.3, a range of solutions (including both network and non-network options) are considered in order to address identified network limitations, and to efficiently defer the need for major capital investments for as long as possible, while maintaining safety, security, reliability and resilience, following a risk-based approach.

Economic analysis and risk assessment techniques are applied to investigate the potential options. The preferred solution must be technically and economically feasible, be deliverable in the timeframe required and minimise long-run total costs.

6.7.5 Scope and estimate

All network solutions are designed to comply with legislated safety, environmental and technical obligations. These solutions are based on scopes of work which identify the inputs required to deliver each project. Project cost estimates are developed for each solution based on a detailed database of materials and transmission construction costs, and recent outturn cost information from delivered projects.

The projects included in the capital expenditure forecast are at different stages of development. Approved projects that are currently in progress have been subject to a more detailed cost assessment than those in the concept phase, which have yet to commence. We also obtain independent check estimates from external experts to verify the accuracy of our network project cost estimates.

We exclude from our capital expenditure forecast any significant network projects that are not considered sufficiently certain in terms of timing, scope or cost. Where the requirement for such a project is considered probable during the regulatory period, that project will be classified as a Contingent Project.

For non-network projects, cost estimates are generally developed based on independent expert advice and market cost information.

6.7.6 Cost escalation

Cost escalation involves escalating or de-escalating cost estimates for expected changes in input costs, being wages, contractor rates and materials. Forecasts of cost escalation rates are derived from independent expert sources. Where efficient to do so, projects are also combined for delivery purposes to ensure that efficiencies are captured through combining related works and coordinating timing of implementation.

6.7.7 Equity raising cost

As outlined in Attachment 1, an allowance for these costs is determined by applying the benchmark methodology approved by the AER and calculated in its Post Tax Revenue Model (PTRM). This cost has been calculated at $0 based on this methodology, indicating there is no equity raising requirement in the forthcoming regulatory period.

6.8 Key inputs and assumptions

This section describes the key inputs and assumptions underlying the capital expenditure forecast and provides substantiation for these inputs and assumptions, which comprise:

- demand forecasts;
- asset condition assessments;
- planning and design standards;
- network model;
- economic assessments;
- risk assessments;
- project cost estimation;
- cost escalation;
- project timing and delivery; and
- efficiency improvements.

These are discussed in turn below.

6.8.1 Demand forecasts

Growth in customer peak demand has historically been the principal driver of transmission system augmentation and connection point reinforcement. Increasingly, falling minimum demand levels on the network are also revealing network limitations that need to be addressed.

In determining our capital expenditure forecast, we have adopted the state-wide 10-year medium case 10% Probability of Exceedance maximum demand forecast and 90% Probability of Exceedance minimum demand forecasts independently published by AEMO[27]. The connection point level demand forecasts are obtained from SA Power

[27] AEMO, National Electricity Forecasting Report: For The National Electricity Market, June 2016 available at www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Electricity-Forecasting-Report.

Networks, while forecasts for large directly connected transmission customers are obtained from AEMO.[28]

AEMO's latest demand forecasting report explains that for South Australia[29]:

> "In the medium term (2015–16 to 2025–26), operational consumption in South Australia is forecast to decline, continuing the trend that started in 2010–11. This decline is attributed to projected lower residential consumption and flat business consumption, as a result of forecast high uptake in rooftop photovoltaic (PV) and ongoing energy efficiency improvements.
>
> In the short term (2015–16 to 2018–19), AEMO forecasts flat operational consumption in South Australia, driven by a projected recovery in industrial consumption from assumed stabilising economic conditions in the neutral scenario, offset by rooftop PV uptake, energy efficiency savings, and the exit of the automotive industry.
>
> Maximum demand is expected to continue to decline, driven by rooftop PV, energy storage, and energy efficiency improvements.
>
> AEMO has again forecast minimum demand to investigate the impact of rooftop PV on the daily load profile. This provides useful information on network usage, which can inform further studies to evaluate operational implications. By the end of 2026–27, continued uptake of PV is projected to result in negative minimum demand under certain conditions. This leads to net exports from the distribution network to the transmission grid in aggregate, and ultimately from the region during those periods."

AEMO's maximum demand forecasts are reproduced in the table below.

Table 6-6: Summer operational maximum demand forecasts for South Australia MW[30]

Summer	Actual	10% POE	50% POE	90% POE
2015–16	2,895	3,158	2,823	2,534
2016–17		3,081	2,753	2,489
2017–18		3,038	2,714	2,427
2018–19		3,034	2,656	2,421
2019–20		2,928	2,599	2,370
2020–21		2,878	2,569	2,360
2021–22		2,805	2,487	2,294
2022–23		2,756	2,460	2,279
2023–24		2,734	2,435	2,254
2024–25		2,693	2,421	2,202
2025–26		2,639	2,396	2,202

28 This demand forecast information is contained in ElectraNet's response to the AER's Revenue Reset Regulatory Information Notice which forms part of this Revenue Proposal. A summary of these forecasts is also issued annually in ElectraNet's South Australian Connection Point Forecasts, due to be published by April 2017.

29 AEMO, South Australian Demand Forecasts, South Australian Advisory Function, June 2016, page 4.

30 AEMO, National Electricity Forecasting Report: for the National Electricity Market, June 2016, Table 2, page 8, available at www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Electricity-Forecasting-Report.

Figure 6.6 below shows the South Australian maximum demand forecasts prepared by AEMO in 2015 and 2016. Recent actual demand is also shown. It is noted that an actual maximum demand level of 3,105MW[31] was recently experienced on 8 February 2017.

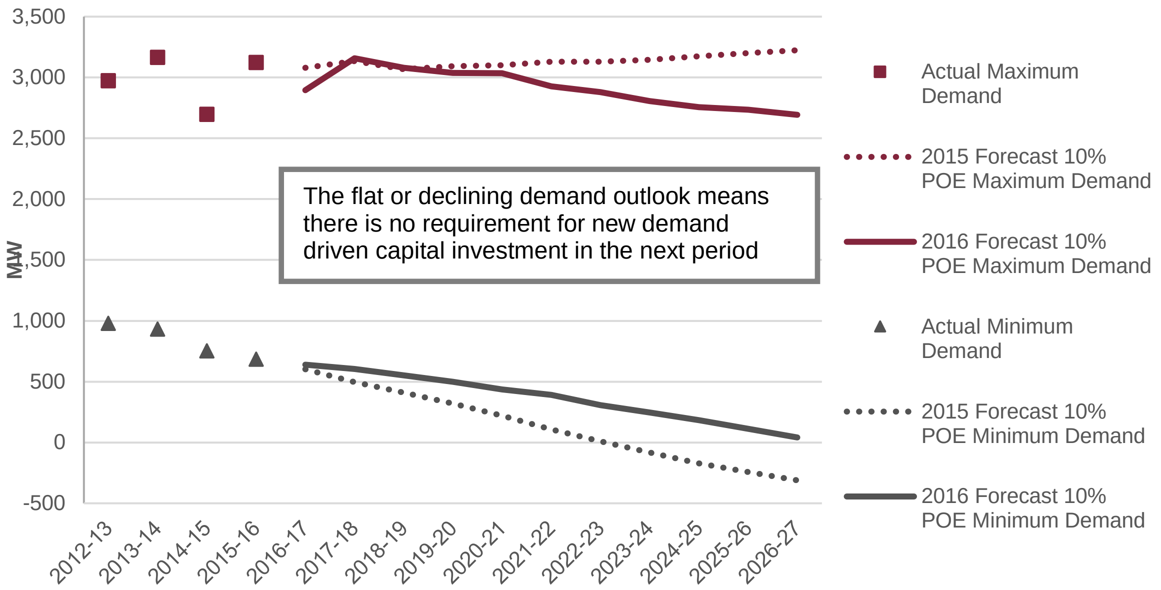


Figure 6.6: Actual and forecast demand on the South Australian transmission network[32]

It is evident from the above figure that AEMO has reduced its maximum demand forecasts for South Australia compared to the forecasts it prepared in 2015. The significant reduction in demand forecasts has practically eliminated the need for augmentation capital expenditure in the forthcoming regulatory period.

It is also important to note that the changing pattern of generation and demand on our network – including the declining minimum demands noted by AEMO – raises important issues regarding the resilience of the network. Increasingly, we expect issues associated with South Australia's growing penetration of intermittent renewable energy to be an important driver of our future capital expenditure requirements, for example voltage control requirements on the network driven by more complex power flows.

6.8.2 Asset condition assessments

We apply a systematic process for collecting, recording and analysing detailed information on the condition of our network assets, and we apply a risk-based approach in our asset management decision making. The information produced by this process is continuously updated as on-going condition assessments and risk analysis are undertaken.

Our Transmission Asset Life Cycle (TALC) assessment framework employs a range of factors to determine where an asset is in its life cycle. The framework assists in optimising our asset management decisions. Our assessment considers both the

[31] 30 min average SA demand
[32] Ibid, Figure 3, page 9

technical health of the asset and its strategic importance in the network (related to the level of risk).

These condition assessments and the ongoing improvement in our understanding of asset condition are key inputs to the asset management planning process and the development of asset replacement and refurbishment programs.

6.8.3 Planning and design standards

Our planning standards are derived from the Rules and the ETC and are presented in more detail in our Annual Planning Report[33]. The ETC establishes the specific reliability standards that apply to each exit point on the transmission network. Connection point power factor requirements are reflected in customer connection agreements.

ESCOSA is currently conducting a review of the reliability standard for transmission supply to Port Lincoln. The capital expenditure forecasts presented in this Revenue Proposal are based on the current standards. A change in these planning standards may require us to revise our forecasts.

We have developed and maintain a comprehensive set of design and construction standards in order to comply with the requirements of our SRMTMP. This plan is required by section 15 of the *Electricity Act 1996 (SA)* to demonstrate that our infrastructure complies with good electricity industry practice and the standards referred to in the Act.

6.8.4 Network model

We use the Siemens Power Technologies International PSS/E suite of power system analysis programs as the platform for identifying both operational and future network limitations, as is the case for most other Australian TNSPs, DNSPs and AEMO. Our network model is provided to AEMO and is, therefore, subject to regular scrutiny by independent power industry experts.

Plant data is based on primary sources such as transmission line impedance tests, generator commissioning and compliance tests, power transformer test certificates and on secondary sources such as line impedances calculated from first principles.

6.8.5 Economic assessments

We conduct an economic assessment to review the available options, costs, benefits, and optimal timing for all large projects to ensure that any investment we make maximises the net benefit to customers. The outcomes of these assessments reflect current information, and are updated as further information and analysis becomes available.

The options generally considered include ‘do nothing’, deferred investment, non-network alternatives and network solutions. Only if a network investment is clearly shown to be the least cost solution do we include such a project in our capital expenditure forecast.

[33] ElectraNet, South Australian Transmission Annual Planning Report, June 2016, section A3, Appendix A, pages 86 and 87. Available at www.electranet.com.au/what-we-do/network/regulated-network-reports-and-studies/

Inputs considered in these assessments include:

- Capital and operating costs of alternative options
- Reliability Benefits - where unserved energy is measured by the Value of Customer Reliability (VCR) estimates published by AEMO[34]
- Cost savings - for example avoided maintenance costs;
- Risk reduction - as measured by the quantified value of the risk reduced or avoided through the project (for example avoided environmental contamination);
- Standard discount rate assumptions – based on a range of estimates including commercial rates and the prevailing regulated rate of return; and
- Optimal timing – including the potential for deferral of an investment to a subsequent regulatory period.

Sensitivity testing is also conducted to determine the robustness and level of confidence in the outcomes of these economic assessments.

These economic assessments have been externally reviewed by economic experts Houston Kemp to ensure they are robust and reasonable[35].

AEMO also conducts a detailed independent technical assessment of a portion of the network capital program relating to large network development projects and its findings are available in a separate published report[36].

6.8.6 Non-network alternatives

We consider the scope for non-network alternatives when we address identified needs on the network.

Potential opportunities for efficient non-network alternatives have been considered during the application of an integrated planning assessment for significant replacement and refurbishment projects, specifically at Leigh Creek South, Leigh Creek Coalfield, Mount Gambier, and Mount Barker connection points. Options considered included network support and micro grid (i.e. off grid) solutions. In each of these specific cases, a transmission network investment was found to be the most efficient solution. These assessments were independently reviewed by AEMO.

Overall, given the flat demand outlook, there are minimal load driven projects in our capital expenditure forecast, with a focus on individual component asset replacement, life extension works, and targeted network security measures. The nature of these requirements limits the scope for efficient non-network alternatives to provide a technically and economically viable solution.

A number of our proposed contingent projects will also provide an opportunity for efficient non-network solutions to be considered as efficient alternatives to, or in combination

[34] AEMO, Value of Customer Reliability Review Final Report, September 2014, available at www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Value-of-Customer-Reliability-review.

[35] Further information is available in Houston Kemp- Review of ElectraNet Economic Assessment Framework March 2017 (ENET029)

[36] AEMO – Confirmation of ElectraNet's Network Incentive Parameter Action Plan (NCIPAP) March 2017 (ENET050)

with, transmission network solutions, including two active RIT-T processes, as discussed in Section 6.3.3.

6.8.7 Risk assessments

For projects driven primarily by risk mitigation (including, for example, safety, reliability and environmental risks) a detailed risk assessment is undertaken to estimate and quantify the risk involved, as a key input to the economic analysis of available options to address the risk.

This risk analysis considers:

- probability of an asset failure
- likelihood of adverse consequence(s)
- likely cost(s) of the consequence(s)

This is based on a systematic process for collecting, recording and analysing detailed information on the condition of network assets, and balances the expected risk reduction against the costs of the proposed expenditure to ensure safety and reliability requirements are met at lowest cost.

We have relied on detailed asset condition and risk information to develop specific plans for capital replacement and refurbishment projects for different asset categories and key risk areas, such as asset operational integrity, and safety and environmental issues. A decision to replace an asset is thereby driven by detailed asset condition assessment, risk and reliability considerations, balanced against cost.

The key input assumptions to our asset risk cost evaluation framework include, amongst other factors:

- the adoption of an upper estimate of the Value of Statistical Life (VSL) for modelling purposes based on the Australian Government's Best Practice Guidance Note for using the VSL approach (December 2014)[37] together with appropriate sensitivity assumptions and disproportionate factors to reflect our very low tolerance of, and appetite for, safety risk; and
- other key cost inputs with respect to the value of customer reliability, such as the potential for bushfire related property damage and environmental costs.

This framework has been developed with input from asset management experts AMCL, and represents a best practice approach.[38]

6.8.8 Project cost estimation

Project cost estimates are derived from our internal estimating system, based on a range of information from internal and external sources. These estimates are subject to ongoing change and review as new information becomes available.

[37] Australian Government, Department of the Prime Minister and Cabinet, Office of Best Practice Regulation, Best Practice Regulation Guidance Note Value of statistical life, December 2014 available at www.dpmc.gov.au/sites/default/files/publications/Value_of_Statistical_Life_guidance_note.pdf.

[38] Further information on the asset risk cost evaluation framework and key input assumptions is contained in the supporting document Asset Risk Cost Modelling Guideline - March 2017 (ENET058)

As our capital program is delivered entirely through external contracting arrangements, for those projects in their delivery phase, cost estimates reflect commercially determined rates.

For projects at earlier stages or yet to commence, cost estimates are derived from a range of sources, including estimates from contractors and suppliers, outturn costs for similar projects, and unit rates provided by independent sources. No contingency amount for risk has been included in the base estimates. Further information is provided in the capital expenditure model which accompanies this Revenue Proposal.

We have also obtained independent check estimates of a representative sample of projects from external experts including Aquenta, PSC and Think 180 to verify the accuracy of our network project cost estimates. This analysis shows that the variations in the individual check estimates are generally within the range of accuracy expected of our cost estimates[39].

6.8.9 Cost escalation

The primary cost components of the capital expenditure forecasts are:

- internal and external labour costs; and
- materials (i.e. plant and equipment) which generally include various commodity inputs such as copper, aluminium and steel.

Our capital expenditure forecasts adopt the following cost escalation inputs:

- A real average increase of 0.9% per annum for labour, which reflects the average of Deloitte Access Economics' (DAE) forecasts in the AER's May 2016 Final Determination for Australian Gas Networks in South Australia and BIS Shrapnel's latest South Australian Utilities Wage Price Index growth forecasts[40].
- No real increases in the costs of materials over the forthcoming regulatory period.

The labour cost escalation assumptions are as shown in the table below.

Table 6-7: Real labour cost forecast (%)

Labour escalation estimates	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22	2022-23	Average 2019-2023
Deloitte Access Economics' May 2016	0.20	0.50	0.60	0.70	0.70	0.70	0.70	0.70
BIS Shrapnel January 2017	1.00	0.80	0.70	0.80	1.10	1.50	1.60	1.10
Average	**0.60**	**0.65**	**0.65**	**0.75**	**0.90**	**1.10**	**1.15**	**0.91**

39 The expected accuracy range is within 30 percent for a project in the initial 'concept' phase.
40 BIS Shrapnel – Report on Expected Wage Changes to 2022/23 February 2017 (ENET057).

These labour escalation assumptions have also been applied in relation to our operating expenditure forecasts, as explained in Attachment 7.

6.8.10 Project timing and delivery

We prioritise the delivery of our capital program to ensure that the capital expenditure objectives are met as efficiently as possible. Our capital expenditure forecasts reflect the latest information on the timing of current projects, which is continually updated as projects proceed. The deliverability of our reduced capital program in the forthcoming regulatory period relies on the realistic timeframes we have adopted and contractual arrangements we have in place which give us access to the required resources.

6.8.11 Directors' responsibility statement

Clause S6A.1.2(6) of the National Electricity Rules requires our Revenue Proposal to contain a certification of the reasonableness of the key assumptions that underlie the operating expenditure forecast by the Directors of ElectraNet.

A Directors' Responsibility Statement has been provided addressing this requirement.[41]

6.9 Efficiency initiatives and benchmarking

In line with our continuous improvement approach, we have implemented a number of initiatives to improve the efficiency of our capital expenditure program. Over the current and previous regulatory periods, we have:

- deferred augmentation and connection works in response to lower demand forecasts;
- advocated a reduction in the required connection point standard to successfully remove the need for an uneconomic upgrade to the Baroota substation[42];
- achieved savings through targeted scope improvements and more efficient procurement and delivery of capital works;
- implemented a comprehensive competitive tendering process to pre-qualify and engage construction contractors;
- implemented a new organisational structure to better align our internal functions with core responsibilities, to improve capital project delivery performance; and
- enhanced our internal capability to produce more robust capital project cost estimates.

These improvement initiatives are reflected in our benchmark performance, as set out in the AER's 2016 annual benchmarking report[43]. Figure 6.7 below, which is reproduced from the AER's report, shows the AER's Multilateral Total Factor Productivity (MTFP) index for each TNSP.

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41 ElectraNet Directors' Responsibility Statement dated 16 March 2017 (ENET051).

42 Essential Services Commission of South Australia, Variation to clause 2.4.1 of the Electricity Transmission Code, Final Decision, 26 October 2015, available at www.escosa.sa.gov.au/ArticleDocuments/309/20151029-Electricity-VariationtoClause2_4_1TransmissionCode-FinalDecision.pdf.aspx?Embed=Y.

43 AER, Annual Benchmarking Report - Electricity transmission network service providers, November 2016, available at www.aer.gov.au/system/files/Final%20TNSP%20annual%20benchmarking%20report%202016%20-%20for%20release_1.pdf.

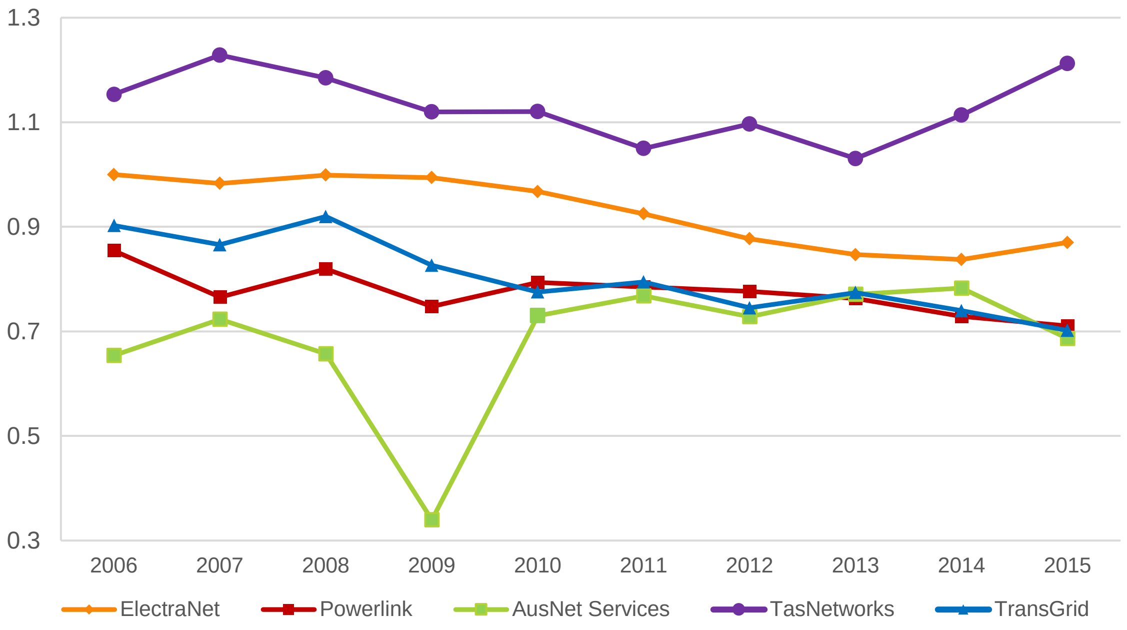

Figure 6.7: Multilateral total factor productivity index by TNSP, 2006 to 2015

The MTFP measures both the level of productivity, and productivity trends over time by calculating the ratio of outputs to inputs. While noting that limited reliance can be meaningfully placed on transmission benchmarks, particularly in relation to capital expenditure, we continue to perform well in overall productivity terms, ranking second amongst the five TNSPs.

In addition to analysing MTFP, the AER's benchmarking report also assesses Multilateral Partial Factor Productivity (MPFP). The MPFP techniques use the same output specification as the MTFP technique, but they focus only on the productivity of either operating expenditure or capital expenditure in isolation.

Figure 6.8 on the following page is also reproduced from the AER's 2016 annual benchmarking report. It shows capital MPFP for all TNSPs from 2006 to 2015.

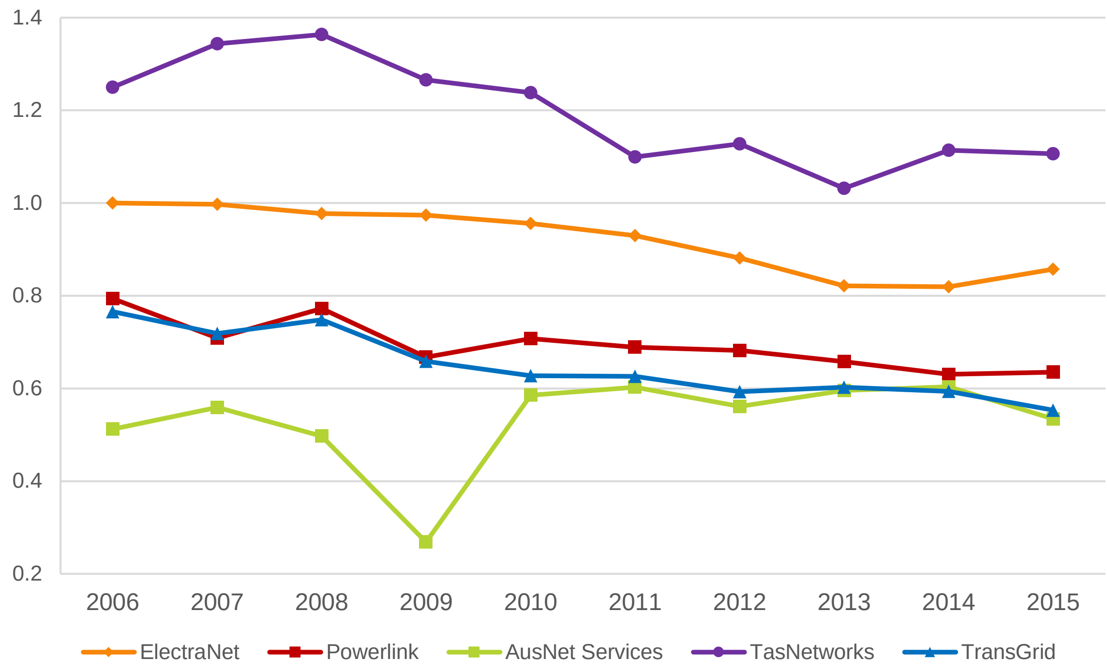

Figure 6.8: Capital partial factor productivity index, 2006 to 2015

The AER's analysis shows that we are also ranked second in terms of our capital expenditure efficiency. While benchmarking transmission performance is inherently difficult and should be treated with caution - particularly in relation to capital expenditure – the AER's analysis provides further evidence that our capital expenditure is prudent and efficient.

6.10 Forecast capital expenditure

This section provides further detailed information on our forecast capital expenditure for the forthcoming regulatory period. The forecast is the result of applying our forecasting methodology described in Section 6.7, and the key inputs and assumptions described in Section 6.8.

A summary of the capital expenditure forecast by category is shown in the table on the following page.[44]

[44] The capital expenditure categories are explained in Section 6.7 of this Revenue Proposal

Table 6-8: Capital expenditure forecast by category ($m 2017-18)

	2018-19	2019-20	2020-21	2021-22	2022-23	Total
Augmentation	13.8	1.6	0.1	0.0	0.0	15.5
Connection	0.1	1.2	5.0	0.0	0.0	6.3
Easement / Land	0.0	0.0	0.0	0.0	0.0	0.0
Subtotal: Load driven capital	**13.9**	**2.8**	**5.1**	**0.0**	**0.0**	**21.9**
Replacement	32.0	34.8	37.7	43.1	19.0	166.7
Refurbishment	10.0	38.2	48.0	40.9	21.8	158.8
Security/Compliance	22.4	12.5	4.9	3.5	3.0	46.2
Inventory/Spares	2.3	2.3	2.3	2.3	2.3	11.5
Subtotal: Non-load driven capital	**66.7**	**87.8**	**92.9**	**89.8**	**46.0**	**383.2**
Business IT	14.6	8.0	9.0	9.4	6.5	47.5
Facilities	1.5	1.2	1.5	1.1	0.7	5.9
Subtotal: Non-network capital	**16.0**	**9.1**	**10.5**	**10.5**	**7.2**	**53.4**
Total Capital expenditure	**96.6**	**99.8**	**108.5**	**100.2**	**53.2**	**458.4**

As already noted, growth in electricity demand in South Australia has decreased and is projected to fall further. The transmission network now has sufficient capacity to meet projected demand over the forthcoming regulatory period, so minimal load-related investment is required. Our forecasts reflect this, with load driven capital expenditure comprising less than 5% of our forecast over the forthcoming regulatory period.

Replacement, refurbishment and security/ compliance projects make up the majority (approximately 80%) of our total forecast capital expenditure. This expenditure will enable us to maintain a safe, secure and reliable network, in accordance with our customers' needs and our regulatory obligations.

The remainder of our forecast non-load driven network capital expenditure comprises only 2.5% of our forecast and relates to inventory purchases required to maintain an efficient level of spares holdings to enable us to respond to asset failures in accordance with the restoration times specified in the ETC and good electricity industry practice.

Our non-network capital expenditure forecast comprises 12% of the total. It includes prudent and efficient allowances for capital expenditure to develop and maintain our IT capacity and to improve the functionality of business systems. It also includes investment on office accommodation and services to meet business needs.

Table 6.9 summarises the capital projects in our capital expenditure forecast with a value exceeding $5m in the forthcoming regulatory period, other than works in progress, describing their estimated cost and location in accordance with clause S6A.1.1(1) of the Rules.

Table 6-9: Forecast capital projects greater than $5 million ($m 2017-18)

Project	Description	Category	Cost ($m)
Line Insulator Systems Refurbishment	Replace line insulator systems based on condition and risk to extend overall asset life.	Refurbishment	58.7
Yadnarie – Pt Lincoln F1811 132 kV Line Conductor and Earth wire Refurbishment	Refurbish line conductor and earth wire to extend the overall asset life.	Refurbishment	38.2
Cultana – Yadnarie F1810 132 kV Line Conductor and Earth wire Refurbishment	Refurbish line conductor and earth wire to extend the overall asset life.	Refurbishment	35.5
Protection Systems Unit Asset Replacement	Replace identified protection scheme relay assets that have reached the end of their technical and economic lives.	Replacement	29.3
Line Conductor and Earthwire Refurbishment	Refurbish line conductor and earth wire to extend the overall asset life.	Refurbishment	17.7
Brinkworth – Waterloo Bearer Replacement	Replacing six existing radio links that are end of life with OPGW.	Replacement	11.1
Isolator Unit Asset Replacement	Replace individual substation isolators that are at the end of life.	Replacement	11.0
AC Board Unit Asset Replacement	Replace substation AC Auxiliary Supply Systems that are at the end of life.	Replacement	9.6
Line Support Systems Refurbishment	Refurbish tower structures on selected lines to achieve a life extension of the overall asset.	Refurbishment	8.8
Substation Improvements for System Black Conditions	Improve substation AC auxiliary supplies by providing back-up diesel generation or diesel generator ready connections to critical substations.	Security / Compliance	7.5
Transformer Bushing Unit Asset Replacement	Replace a number of specified transformer bushings that are at end of life.	Replacement	6.9
Telecommunications Unit Asset Replacement	Replace telecommunication assets that are classified as high risk of failure.	Replacement	6.8
Robertstown Circuit Breaker Arrangement	Reduce constraints and improve network security through installation of additional equipment	Security / Compliance	6.6
Dalrymple ESCRI Energy Storage	Proof-of-concept project to help trial grid scale battery storage options to improve the security of South Australia's transmission network.	Augmentation	6.4

Project	Description	Category	Cost ($m)
Gawler East Connection Point	Create a new substation to address distribution network limitations that arise from the forecast demand growth in the Gawler region.	Connection	6.3
One IP Substation Network – Stage 2	Replace equipment that is at end of life and no longer supported by the manufacturer.	Replacement	5.0

** Does not include projects substantially in progress at the start of the regulatory period*

Further details for these projects are provided in Appendix A, including a description of the project need, solution options considered, and identification of the most economical solution that has been included in the capital expenditure forecast.

As noted in Section 6.3.3, a number of targeted and prudent measures have been identified in the forthcoming regulatory period to improve the ability of the transmission network to withstand the impact of extreme weather events, and improve the security of the network, in the most cost effective manner. These investments are summarised in Table 6-10 below.

Table 6-10: Projects in the next period to address network security risks ($m real 2017-18)

Project	Driver	Cost ($m)
Special Protection Scheme	Improved network security through developing, validating and implementing a Special Protection Scheme to maintain system security and protect against the islanding of the South Australian power system during non-credible events (completion of project commencing in current regulatory period)	3
Substation Improvements for System Black Conditions	Provide alternative diesel generator supplies to critical substations (where not already provided) and connection points for mobile generators to non-critical substations, to enable quicker restoration of the network for both short term and prolonged outages	8
Transmission Line Access Track Upgrade	Improved outage restoration times through better access tracks at vulnerable tower locations across the network (e.g. swamp locations) and improved readiness to replace damaged towers in adverse conditions (e.g. for use of heavy vehicles in inclement conditions)	4
Line Design Manual	In light of recent events, the review and update of the transmission line design manual to ensure it remains appropriate to address the future security of the network to extreme weather risks	2
South East SVC Computer Control System Replacement	Improved network security and management of interconnector flows through replacement of control systems for voltage control equipment, nearing end of life	5
Para Reactor	Improved network security through installation of additional equipment to maintain voltages under more complex power flows	4

Project	Driver	Cost ($m)
Blyth West Reactor	Improved network security through installation of additional equipment to maintain voltages under more complex power flows	4
Torrens Island North Substation Tie Bus	Improved network security through installation of additional equipment to facilitate a faster and more reliable black start	2

We have developed our network capital expenditure plans in consultation with AEMO, which has reviewed the load-driven and network development projects underpinning this program. For each project identified, AEMO has assessed that the need exists, that the timing is appropriate and that the solution being proposed appears reasonable. AEMO has also confirmed the consistency of the forecast with the NTNDP and concluded that the network will remain compliant with the reliability requirements of the ETC at the end of the regulatory period[45].

6.11 Proposed contingent capital expenditure projects

This section presents our proposed contingent projects.

A contingent project must be reasonably required in order to achieve the capital expenditure objectives specified in the Rules. However, unlike other proposed capital expenditure projects, there is much greater uncertainty as to whether the contingent project will be required during the regulatory period. As such, the expenditure for contingent projects does not form part of the total forecast capital expenditure approved by the AER.

The Rules provide for contingent projects to be defined with reference to a project-specific 'trigger event'. The occurrence of the trigger event must be probable during the relevant regulatory control period. If the trigger event for an approved contingent project occurs, the TNSP makes an application to the AER for a cost allowance to be included in an amended revenue determination.

Contingent projects are also required to exceed a threshold of the greater of $30m or 5% of the maximum allowed revenue for the first year of the regulatory control period (which equates to $15.6m). The applicable threshold is therefore $30m.

Our proposed contingent projects are summarised below. Appendix B provides further information on each proposed contingent project, together with an explanation of how each project satisfies the requirements of clause 6A.8.1 of the Rules.

[45] AEMO – Confirmation of ElectraNet's Network Incentive Parameter Action Plan (NCIPAP) March 2017 (AEMO050)

Table 6-11: Proposed contingent projects

Project Name	Trigger Events	Indicative Cost ($m Nom)
Eyre Peninsula Reinforcement	1. Successful completion of the RIT-T including an assessment of credible options identifying the duplication or replacement of the existing Cultana-Yadnarie and/or Yadnarie-Port Lincoln transmission lines as the preferred option. 2. Determination (if applicable) by the AER under clause 5.16.6 of the NER that the proposed investment satisfies the RIT-T. 3. ElectraNet board commitment to proceed with the project subject to the AER amending the revenue determination pursuant to the Rules.	200*
South Australian Energy Transformation	1. Successful completion of the RIT-T for the South Australian Energy Transformation with the identification of a preferred option or options: – demonstrating positive net market benefits; and/or – addressing a reliability corrective action. 2. Determination (if applicable) by the AER under clause 5.16.6 of the NER that the proposed investment satisfies the RIT-T. 3. ElectraNet Board commitment to proceed with the project subject to the AER amending the revenue determination pursuant to the Rules.	200-500*
Upper North West Region Line Reinforcement	1. Customer commitment for additional load to connect to the transmission network causing the Davenport to Pimba 132kV line to exceed its thermal limit of 76 MVA. 2. Successful completion of the RIT-T including an assessment of credible options showing a transmission investment is justified. 3. Determination by the AER under clause 5.16.6 of the NER that the proposed investment satisfies the RIT-T. 4. ElectraNet board commitment to proceed with the project subject to the AER amending the revenue determination pursuant to the Rules.	110
Upper North East Region Line Reinforcement	1. Customer commitment for additional load to connect to the transmission network causing the Davenport to Leigh Creek 132kV line to exceed its thermal limit of 10 MVA. 2. Successful completion of the RIT-T including an assessment of credible options showing a new connection point and line upgrade is justified. 3. Determination by the AER under clause 5.16.6 of the NER that the proposed investment satisfies the RIT-T. 4. ElectraNet board commitment to proceed with the project subject to the AER amending the revenue determination pursuant to the Rules.	60

Project Name	Trigger Events	Indicative Cost ($m Nom)
Main Grid System Strength Support	1. Confirmation by AEMO of the existence of a Network Support and Control Ancillary Services (NSCAS) gap relating to system strength, or other requirement for ElectraNet to address a system strength requirement, in the South Australian region. 2. Successful completion of the RIT-T (or equivalent economic evaluation) including an assessment of credible options showing a transmission investment is justified. 3. Determination (if applicable) by the AER under clause 5.16.6 of the NER that the proposed investment satisfies the RIT-T. 4. ElectraNet board commitment to proceed with the project subject to the AER amending the revenue determination pursuant to the Rules.	60-80

* Noting that the differential cost over the alternative partial replacement option included in the ex-ante forecast at approximately $80m would be around $120m, for which funding would be sought should the contingent project be triggered.

** This represents an estimate of the SA portion of total cost of a new interconnector.

6.12 Benefits and risks for customers

Our capital expenditure program will provide the following benefits for customers:

- Safety – Our capital expenditure plans aim to deliver services that are safe for the communities we serve and the environment.
- Network security and reliability – Our capital program is aimed at delivering a secure and reliable network. We have also expanded our proposed program from the indicative forecast presented in our Preliminary Revenue Proposal to include additional measures to improve network security and maintain reliability of supply.
- Efficiency – We will continue to drive improvements in our capital cost performance, building on the significant achievements achieved to date.
- Affordability – We are proposing a significant reduction in our capital program, which will feed through to lower prices for our customers.
- Choice – Our capital plans to manage the challenges of an increasingly complex power system support the differing choices being made by customers over the way energy will be produced and consumed in the future.
- Long term sustainability – We are planning and investing in the transmission network to accommodate the changing nature of generation and demand as we move to a low carbon economy, and to deliver the outcomes sought by customers into the future.

We are aiming to efficiently manage the following risks to customers in relation to our capital expenditure program:

- Additional investment requirements – we are managing the potential cost impact to customers of uncertain events that may trigger the need for additional capital expenditure through identified contingent projects. If and when further investment is required, our revenue requirement and transmission prices would be higher than set out in our proposal, but only if the benefits to customers can be shown to exceed the costs.
- New obligations – following the conclusion of the current reviews, new security obligations may be imposed on us to further improve network security. While such obligations would provide customer benefits, they could also require increases in our capital program.
- While our plans are based on the best available information at the time of submission in relation to the capital expenditure requirements for the next period, including the issues and implications raised by the 28 September 2016 extreme weather event, there remains a possibility that new information may come to light following further internal analysis and external reviews and investigations that results in a need for additional unforeseen capital expenditure requirements.

REVENUE PROPOSAL 2019 - 2023

Attachment 6 - Appendix A

Forecast Network Capital Projects

28 March 2017

ElectraNet

Contents

Forecast Network Capital Projects

A1 Introduction

ElectraNet's capital expenditure forecast for the 1 July 2018 to 30 June 2023 regulatory period is presented in Chapter 7 of the Revenue Proposal Overview and Attachment 6, which also includes a description of the methodology and key inputs and assumptions used to develop the capital expenditure forecast.

ElectraNet's Capital Expenditure Forecast Model accompanying the Revenue Proposal includes a full list of the capital projects included in the capital expenditure forecast.

This Appendix includes project summaries for all capital projects, other than work in progress projects, involving expenditure of greater than $5 million in the forthcoming regulatory period – these projects are summarised in Attachment 6, Table 6.9.

The project summaries include:

- Details of the project requirement and timing including the Rules capital expenditure objective(s) that the capital project is required to meet;
- The alternative options considered to address the limitation; and
- A brief description of the project.

Capital costs in this Appendix are expressed in $2017-18 unless otherwise indicated.

A2 Line Insulator Systems Refurbishment

Project Number: EC.14081

Category: Refurbishment

Estimated Cost: $58.7m

Required Completion Date: 2023

A2.1 Project Requirement and Timing

The identified need for this project is to replace transmission line porcelain disc insulator systems that are at risk of failing and dropping a conductor to ground with consequential risks to public safety, including from bushfires, and customer reliability.

Porcelain discs are susceptible to puncture due to voltage stress. A puncture is an internal defect that compromises the capability of the insulator to withstand the system voltage level. This defect cannot be detected by visual inspection and requires voltage drop testing.

Punctured porcelain insulators have an unknown probability of failure interval due to the random and internal nature of the puncture failure mode. This represents a bushfire start risk due to the increased likelihood that after the disc has experienced this failure mode, and is exposed to further voltage stress, it may be unable to mechanically support the conductor resulting in the conductor dropping to ground.

The results of nearly 4,000 Voltage Drop tests conducted across the network indicates that porcelain insulators over the age of 30 years have a higher than acceptable proportion of defective discs due to puncturing. The proportion of defective discs continues to increase as the insulators age.

If nothing is done, operating and maintenance costs will increase over time as the result of an increasing failure rate. Risk cost will also increase as the result of the increased likelihood of safety, environmental and bushfire risks being realised.

This project is required to meet the Rules capital expenditure objectives to comply with all applicable regulatory obligations associated with the provision of prescribed transmission services and to maintain the quality, reliability and security of supply of prescribed transmission services.

While the need for the line refurbishments that form this project have been scoped and evaluated individually, these have been combined and costed jointly, to be undertaken over the 2019-2023 regulatory period as a staged program of works.

Coordinated delivery allows for greater cost efficiencies to be realised through mobilisation and coordination of the relevant resources, compared with delivery as individual line projects. The efficiencies expected to arise as we combine the delivery of these related projects have been incorporated into the overall cost estimate.

This project is scheduled to be completed by 2023.

A2.2 Option Analysis

Option	Description	Estimated NPV[1] ($m 2017-18)	Ranking of Options
Base case	Maintain the status quo and accept the increased risk of insulator failure and resulting consequences	-	3
Option 1	Replacement of the insulators in 2019 – 2023 regulatory control period.	479.4	1
Option 2	Replacement in the following regulatory control period 2024 – 2028	307.0	2

Option 1 has been identified as the most economical solution to meet the identified need.

The Net Present Value (NPV) benefits shown are in comparison to the base case, which assumes no replacement capital investment and increasing operating and maintenance, and risk costs. Benefits have been justified individually per line project and then aggregated for presentation purposes.

The benefits shown are based on central input assumptions to the analysis. Sensitivity analysis over a reasonably wide range of input assumptions has been undertaken to validate the robustness of the option ranking outcomes.

For comparison, were the relevant line sections to be replaced in their entirety rather than the component asset replacement program proposed, the estimated cost would be approximately $300m, rather than the $58.8m cost of the proposed line insulator systems refurbishment project.

Non-network options were also considered. However, these solutions can not address the issues associated with the condition of the network assets, and full replacement of the lines in question through non-network alternatives (such as generation support or demand side options) would not be viable.

A2.3 Project Scope

This project includes the replacement of the insulator systems of the following 18 transmission lines.

Line	Scope
F1714 TIPS - NEW OSBORNE No3 66 kV Line	25 structures, 96 insulator strings
F1715 TIPS - NEW OSBORNE No4 66 kV Line	25 structures, 93 insulator strings
F1805 WATERLOO – MINTARO 132 kV Line	64 structures, 231 insulator strings
F1813 DAVENPORT-LEIGH CREEK 132 kV Line	29 structures, 114 insulator strings
F1820 NORTH WEST BEND - MONASH No1 132 kV Line	315 structures, 1000 insulator strings

1 The NPV analysed is based on the sum of the individual NPVs for the replacement of the insulator systems on each of the 18 transmission lines.

Line	Scope
F1828 KEITH - KINCRAIG 132 kV Line	256 structures, 803 insulator strings
F1829 SOUTH EAST - MOUNT GAMBIER 132 kV Line	40 structures, 155 insulator strings
F1831 KINCRAIG - PENOLA WEST 132 kV Line	148 structures, 431 insulator strings
F1850 MURRAY BRIDGE HAHNDORF PS3-KANMANTOO-BACK CALLINGTON 132 kV Line	16 structures, 64 insulator strings
F1901 PELICAN POINT – PARAFIELD GARDENS WEST 275 kV Line	25 structures, 238 insulator strings
F1902 TIPS - PARA (No4) 275 kV Line	76 structures, 559 insulator strings
F1903 TIPS - CHERRY GARDENS 275 kV Line	171 structures, 939 insulator strings
F1906 CHERRY GARDENS - HAPPY VALLEY 275 kV Line	24 structures, 132 insulator strings
F1912 TIPS - MAGILL 275 kV Line	130 structures, 853 insulator strings
F1921 PARA - TUNGKILLO 275 kV Line	95 structures, 507 insulator strings
F1940 PARAFIELD GARDENS WEST - PARA 275 kV Line	54 structures, 405 insulator strings
F1945 PARA – ROBERTSTOWN 275 kV Line	9 structures, 72 insulator strings
F1956 PARA – MUNNO PARA 275 kV Line	9 structures, 55 insulator strings

A3 Yadnarie – Pt Lincoln 132 kV Line Conductor and Earth Wire Refurbishment

Project Number: EC.14145 **Category:** Refurbishment

Estimated Cost: $38.2m **Required Completion Date:** 2023

A3.1 Project Requirement and Timing

The identified need for this project is to replace sections of transmission line conductor and earth wire that are in poor condition and at risk of failing and dropping a conductor to ground with consequential risks to public safety, including from bushfires, and customer reliability.

This project is required to refurbish the sections of line conductors and earth wire in poor condition, and in so doing achieve a life extension of the overall asset.

The failure modes of the conductors and earth wires have been identified. Corrosion of aged conductors and earth wires is the dominant failure mode. The loss of cross section or mechanical integrity of the conductor / earth wire can result in a conductor breaking and falling to ground with consequential risks to public safety, including from bushfires, and customer reliability.

A detailed conductor/ earth wire visual inspection and non-destructive testing program has been conducted for lines exhibiting signs of worsening condition and has identified a statistically valid failure rate, via prioritised sample based testing, that poses unacceptable risk of failure. A full cyclic testing and corrective repair / replacement program is considered cost prohibitive and does not materially reduce the risk of failure.

This project is required to meet the Rules capital expenditure objectives to comply with all applicable regulatory obligations or requirements associated with the provision of prescribed transmission services and to maintain the quality, reliability and security of supply of prescribed transmission services.

The project is required to be completed by 2023.

A3.2 Option Analysis

Option	Description	Estimated NPV[2] ($m 2017-18)	Ranking of Options
Base case	Maintain the existing line and continue the grid support contract at Pt Lincoln	-	3
Option 1	Live line reconductoring of the existing single circuit 132 kV line in 2019 – 2023 regulatory control period.	45.7	1
Option 2	Option 1 but undertaken in the next regulatory control period 2024-2028	43.2	2

[2] The NPV has been analysed based on EC.14145 and EC.14137 being completed as one program of work. The NPV represented is proportionate to the cost of completing only EC. 14145 Yadnarie – Pt Lincoln 132 kV Line Conductor and Earth Wire Refurbishment.

Option 1 has been identified as the most economical solution to meet the identified need (subject to the RIT-T discussed below).

The NPV benefits shown are in comparison to the base case, which assumes no replacement capital investment and increasing operating and maintenance, and risk costs.

The benefits are based on central input assumptions to the analysis. Sensitivity analysis over a reasonably wide range of input assumptions has been undertaken to validate the robustness of the option ranking outcomes.

Non-network options were also considered as part of the option analysis. However, non-network solutions are unable to address the condition of the conductors, and a full non-network solution through the complete removal of the line (i.e. off grid supply) was not found to be economically viable.

While the selected option represents the minimum scope of works that need to be undertaken on the Yadnarie – Pt Lincoln line in the forthcoming regulatory period, the alternative of fully replacing the line may deliver greater benefits to Eyre Peninsula customers through improving supply reliability and avoiding the ongoing costs of generation support at Port Lincoln.

We are currently exploring the economic case for a full line replacement in more detail. This involves undertaking the RIT-T, which will assess the costs and benefits of alternative network and non-network solutions through a comprehensive assessment and consultation process. If found to be the most economical solution, this would be pursued instead as a separate contingent project for the differential cost.

A3.3 Project Scope

The proposed scope of works includes the replacement of 66 km of conductor and earth wire on the Yadnarie – Port Lincoln line, together with associated generation support during construction to maintain supply to southern Eyre Peninsula.

A4 Cultana – Yadnarie 132 kV Line Conductor and Earth Wire Refurbishment

Project Number: EC.14137 **Category:** Refurbishment

Estimated Cost: $35.5m **Required Completion Date:** 2023

A4.1 Project Requirement and Timing

The identified need for this project is to replace sections of transmission line conductor and earth wire that are in poor condition and at risk of failing and dropping a conductor to ground with consequential risks to public safety, including from bushfires, and customer reliability.

This project is required to refurbish the sections of line conductors and earth wire in poor condition, and in so doing achieve a life extension of the overall asset.

The failure modes of the conductors and earth wires have been identified. Corrosion of aged conductors and earth wires is the dominant failure mode. The loss of cross section or mechanical integrity of the conductor/ earth wire can result in a conductor breaking and falling to ground with consequential risks to public safety, including from bushfires, and customer reliability.

A conductor/ earth wire visual inspection and non-destructive testing program has been conducted for lines exhibiting signs of worsening condition and has identified a statistically valid failure rate, via prioritised sample based testing, that poses unacceptable risk of failure. A full cyclic testing and corrective repair / replacement program is considered cost prohibitive and does not materially reduce the risk of failure.

This project is required to meet the Rules capital expenditure objectives to comply with all applicable regulatory obligations or requirements associated with the provision of prescribed transmission services and to maintain the quality, reliability and security of supply of prescribed transmission services.

The project is required to be completed by 2023.

A4.2 Option Analysis

Option	Description	Estimated NPV[3] ($m 2017-18)	Ranking of Options
Base case	Maintain the existing line and continue the grid support contract at Pt Lincoln	-	3
Option 1	Live line reconductoring of the existing single circuit 132 kV line in 2019 – 2023 regulatory control period.	42.4	1
Option 2	Option 1 but undertaken in the next regulatory control period 2024-2028	40.0	2

[3] The NPV has been analysed based on EC.14145 and EC.14137 being completed as one program of work. The NPV represented is proportionate to the cost of completing only EC. 14137 Cultana – Yadnarie 132 kV Line Conductor and Earth Wire Refurbishment.

Option 1 has been identified as the most economical solution to meet the identified need (subject to the RIT-T discussed below).

The NPV benefits shown are in comparison to the base case, which assumes no replacement capital investment and increasing operating and maintenance, and risk costs.

The benefits are based on central input assumptions to the analysis. Sensitivity analysis over a reasonably wide range of input assumptions has been undertaken to validate the robustness of the option ranking outcomes.

Non-network options were also considered as part of the option analysis. However, non-network solutions are unable to address the condition of the conductors, and a full non-network solution through the complete removal of the line (i.e. off grid supply) was not found to be economically viable.

While the selected option represents the minimum scope of works that need to be undertaken on the Cultana - Yadnarie line in the forthcoming regulatory period, the alternative of fully replacing the line may deliver greater benefits to Eyre Peninsula customers through improving supply reliability and avoiding the ongoing costs of generation support at Port Lincoln.

We are currently exploring the economic case for a full line replacement in more detail. This involves undertaking the RIT-T, which will assess the costs and benefits of alternative network and non-network solutions through a comprehensive assessment and consultation process. If found to be the most economical solution, this would be pursued instead as a separate contingent project for the differential cost.

A4.3 Project Scope

The scope of works for this project includes the replacement of 52 km of conductor and earth wire on the Cultana – Yadnarie line together with associated generation support during construction to maintain supply to the Eyre Peninsula.

A5 Protection Systems Unit Asset Replacement

Project Number: EC.14031 **Category:** Replacement

Estimated Cost: $29.3m **Required Completion Date:** 2023

A5.1 Project Requirement and Timing

The identified need for this project is to replace individual substation protection systems that have been assessed to be at the end of their technical and/or economic lives. Unreliable protection schemes result in increasing corrective maintenance costs and the increasing likelihood and duration of connection point outages and consequential loss of customer supply.

This project is required to meet the Rules capital expenditure objectives to comply with all applicable regulatory obligations or requirements associated with the provision of prescribed transmission services and to maintain the quality, reliability and security of supply of prescribed transmission services.

The project represents a series of individual asset replacements to be undertaken progressively across the network by 2023.

A5.2 Option Analysis

Option	Description	Estimated NPV ($m 2017-18)	Ranking of Options
Base case	Replacement of relays via emergency corrective maintenance	-	3
Option 1	Replacement of relays before failure is undertaken over the 2019 – 2023 regulatory period	11.1	1
Option 2	Replacement of relays not already replaced through corrective maintenance during the 2024 – 2028 regulatory period	8.6	2

Option 1 has been identified as the most economical solution to meet the identified need.

The NPV benefits shown are in comparison to the base case, which assumes no replacement capital investment and increasing operating and maintenance, and risk costs.

The benefits are based on central input assumptions to the analysis. Sensitivity analysis over a reasonably wide range of input assumptions has been undertaken to validate the robustness of the option ranking outcomes.

Non-network solutions are not a viable alternative to address the condition of the protection systems.

A5.3 Project Scope

A total of 416 Protection Relays have been identified for replacement, aged between 27 and 63 years, as their safe and reliable performance can no longer be adequately managed. The scope has been limited to replacement of only those components identified as being unable to reliably meet their intended function.

A6 Line Conductor and Earth Wire Refurbishment

Project Number: EC.14084 **Category:** Refurbishment

Estimated Cost: $17.7m **Required Completion Date:** 2023

A6.1 Project Requirement and Timing

The identified need for this project is to replace sections of transmission line conductor and earth wire that are in poor condition and at risk of failing and dropping a conductor to ground with consequential risks to public safety, including from bushfires, and customer reliability.

It has been identified that the conductor and earth wire sections on a number of transmission lines have reached end of life. This project is required to refurbish the line conductor and earth wire on the identified lines, and in so doing achieve a life extension of the overall asset.

The failure modes of conductors and earth wires have been identified and corrosion of aged conductors and earth wires is the dominant failure mode. The loss of cross section or mechanical integrity of the conductor/ earth wire can result in a conductor breaking, and consequently dropping to the ground.

A conductor/ earth wire visual inspection and non-destructive testing program has been conducted for lines exhibiting signs of worsening condition and has identified a statistically valid failure rate, via prioritised sample based testing, that poses unacceptable risk of failure. Such a failure would result in dropping a conductor to ground which is a safety risk event together with a potential fire-start event. A full cyclic testing and corrective repair/ replacement program is cost prohibitive and does not materially reduce the risk of failure.

This project is required to meet the Rules capital expenditure objectives to comply with all applicable regulatory obligations or requirements associated with the provision of prescribed transmission services and to maintain the quality, reliability and security of supply of prescribed transmission services.

While the need for the line refurbishments that form this project have been scoped and evaluated individually, these have been combined and costed jointly, to be undertaken over the 2019-2023 regulatory period as a staged program of works.

Coordinated delivery allows for greater cost efficiencies to be realised through mobilisation and coordination of the relevant resources, compared with delivery as individual line projects. The efficiencies expected to arise as we combine the delivery of these related projects have been incorporated into the overall cost estimate.

The project is required to be completed by 2023.

A6.2 Option Analysis

Option	Description	Estimated NPV[4] ($m 2017-18)	Ranking of Options
Base case	Maintain the status quo and accept the increased risk of conductor failure and resulting consequences	-	3
Option 1	Replacement during 2019-2023 regulatory period	234.1	1
Option 2	Replacement in the next regulatory period in 2024-2028	196.2	2

Option 1 has been identified as the most economical solution to meet the identified need.

The NPV benefits shown are in comparison to the base case, which assumes no replacement capital investment and increasing operating and maintenance, and risk costs. Benefits have been justified individually per line project and then aggregated for presentation purposes.

The benefits are based on central input assumptions to the analysis. Sensitivity analysis over a reasonably wide range of input assumptions has been undertaken to validate the robustness of the option ranking outcomes.

Other options that have been considered include:

- Replacement of individual identified conductor corrosion sections, which has higher cost and introduces other modes of asset failure.
- Full line replacement, which has higher cost and is not economically justified.
- Non-network options. However, these solutions can not address the issues associated with the condition of the network assets, and full replacement of the lines in question through non-network alternatives (such as generation support or demand side options) would not be viable.

A6.3 Project Scope

The proposed scope of works for this project includes the replacement of conductors for the following sections across 7 lines:

Line	Scope
F1806: WATERLOO – WATERLOO EAST 132 kV	3 km
F1888 WATERLOO EAST - MORGAN WHYALLA PS4 132 kV	14 km
F1855 MORGAN WHYALLA PS4 – ROBERTSTOWN 132 kV	8 km
F1847: ROBERTSTOWN – MORGAN WHYALLA PS3 132 kV	6 km
F1849: MORGAN WHYALLA PS3 – MORGAN WHYALLA PS2 132 kV	22 km
F1853: MORGAN WHYALLA PS2 – MORGAN WHYALLA PS1 132 kV	25 km
F1854: MORGAN WHYALLA PS1 – NORTH WEST BEND 132 kV	6 km

[4] The NPV analysed is based on the sum of the individual NPVs for the replacement of the conductors on each of the 7 transmission lines.

A7 Brinkworth – Waterloo Telecommunications Bearer Replacement

Project Number: EC.14105

Category: Replacement

Estimated Cost: $11.1m

Required Completion Date: 2023

A7.1 Project Requirement and Timing

The identified need for this project is to address telecommunications capacity constraints on sections of the Brinkworth – Robertstown 132 kV transmission line, specifically on the radio links between Brinkworth – Bungaree Hill, Bungaree Hill – Clare North, Clare North – Quarry Hill and Quarry Hill – Waterloo East. These radio links will also be at end of life and need replacement by 2023.

In addition, the substation of Mintaro is currently serviced by a radio site at Mt Horrocks (and two radio links, Mintaro – Mt Horrocks and Mt Horrocks – Quarry Hill) that will be at end of life and need replacement by 2023.

Replacing the six existing radio links with high capacity radio will also provide more adequate communications capacity to serve the needs of this region of the network.

This project is required to meet the Rules capital expenditure objectives to comply with all applicable regulatory obligations or requirements associated with the provision of prescribed transmission services and to maintain the quality, reliability and security of supply of prescribed transmission services.

This project is scheduled to be completed by 2023.

A7.2 Option Analysis

Option	Description	Estimated NPV ($m 2017-18)	Ranking of Options
Base case	Units are run to failure with emergency replacement of telecommunications assets as required	-	4
Option 1	Install OPGW (optical ground wire) on the line between Brinkworth and Waterloo via Clare North and Mintaro during the 2019-2023 regulatory period	1.1	1
Option 2	Install buried fibre on the line between Brinkworth and Waterloo via Clare North and Mintaro during the 2019-2023 regulatory period	0.9	2
Option 3	Delay the planned replacement for installing the OPGW until 2029-2034 as prior to this units are run to failure with emergency replacement of telecommunications asset as required	0.3	3

Option 1 involving the replacement of radio links with OPGW has been identified as the most economical solution to meet the identified need. In addition to the benefits that have been quantified in the NPV analysis, this option also increases the overall life of the line and allows for future line uprating without the need for a line replacement.

The NPV benefits shown are in comparison to the base case, which assumes reactive capital investment and increasing operating and maintenance, and risk costs.

The benefits are based on central input assumptions to the analysis. Sensitivity analysis over a reasonably wide range of input assumptions has been undertaken to validate the robustness of the option ranking outcomes.

Non-network solutions are not a viable alternative to provide the ongoing telecommunication capability required.

A7.3 Project Scope

Install OPGW on the line from Brinkworth to Waterloo (via Mintaro and Clare North) decommission 6 radio links, vacate the sites of Mt Horrocks and Quarry Hill.

Replace 56 pole structures to support the OPGW.

A8 Isolator Unit Asset Replacement

Project Number: EC.14034 **Category:** Replacement

Estimated Cost: $11.0m **Required Completion Date:** 2023

A8.1 Project Requirement and Timing

The identified need for this project is to replace individual substation isolators that have been assessed to be at the end of their technical and/or economic lives, to address increasing corrective maintenance costs and safety risks, and reliability issues.

This project is required to meet the Rules capital expenditure objective to comply with all applicable regulatory obligations or requirements associated with the provision of prescribed transmission services.

The project represents a series of individual asset replacements to be undertaken progressively across the network by 2023.

A8.2 Option Analysis

Option	Description	Estimated NPV ($m 2017-18)	Ranking of Options
Base case	Maintain the status quo, and accept the increased safety risks and reliability issues	-	3
Option 1	Replacement during 2019 – 2023 regulatory period	2.5	1
Option 2	Replacement during 2024 – 2028 regulatory period	1.9	2

Option 1 has been identified as the most economical solution to meet the identified need.

The NPV benefits shown are in comparison to the base case, which assumes no replacement capital investment and increasing operating and maintenance, and risk costs.

The benefits are based on central input assumptions to the analysis. Sensitivity analysis over a reasonably wide range of input assumptions has been undertaken to validate the robustness of the option ranking outcomes.

Non-network solutions are not a viable alternative to address the condition of the identified isolators.

A8.3 Project Scope

A total of 101 isolators have been identified for replacement across 5 separate substations on the network, aged between 46 and 62 years. Of these a number are located on line exits and require the integral earth switch to also be replaced.

The scope of works for this project includes replacement of the isolators where no other network projects are scheduled to undertake replacement of the identified isolators in the 2018 – 2023 regulatory period.

A9 AC Board Unit Asset Replacement

Project Number: EC.14046 **Category:** Replacement

Estimated Cost: $9.6m **Required Completion Date:** 2022

A9.1 Project Requirement and Timing

The identified need for this project is to replace substation AC Auxiliary Supply Systems that no longer comply with safe systems of work and the associated Australian Standards. As an interim measure safety barriers and administrative controls have been put in place until the assets can be replaced.

This project involves replacing the relevant substation AC Auxiliary Supply Systems at locations where the asset is not already scheduled to be replaced as part of a network project during the 2019 – 2023 regulatory control period.

This project is required to meet the Rules capital expenditure objectives to comply with all applicable regulatory obligations associated with the provision of prescribed transmission services and to maintain the safety of the transmission system through the supply of prescribed transmission services.

This project is scheduled to be completed by 2022.

A9.2 Option Analysis

Substation condition assessments have shown that a number of Workplace Health and Safety issues exist with the condition of substation 415 V main switchboards and sub circuits. There are also operational problems associated with security of supply and essential equipment being fed from general purpose outlets.

In general, the installations do not comply with the relevant Australian Standard (AS3000), including exposed live terminals and supply arrangements that are not secure.

This project is to address all potential and existing hazards by replacing non-compliant equipment with new switchboards and associated equipment with AS3000 compliant installations.

An assessment of potential solutions confirmed there is no feasible alternative to the replacement of this equipment. As this project is essentially addressing a safety compliance requirement, the least cost solution has been identified.

Non-network options cannot technically or economically meet the requirement.

A9.3 Project Scope

AC Auxiliary Supply Systems at 17 sites have been identified for replacement.

The work to be performed for each site is limited to those non-compliant assets requiring replacement and includes the design, supply, installation and commissioning of new:

- Incomer 415 V power supply cables,
- Station TF CB cubicles,
- AC switchboards (including automatic supply changeover systems),

- LV distribution boards,
- Cabling to external plant and equipment,
- Streamline filter power supply boxes and cabling,
- Switchyard power boxes,
- Building power boxes,

The scope of works for this project includes replacement of AC Auxiliary Supply Systems, where no other network projects are scheduled to undertake the replacement of the assets in the 2019-23 regulatory period.

A10 Line Support Systems Refurbishment

Project Number: EC.14076

Category: Refurbishment

Estimated Cost: $8.8m

Required Completion Date: 2023

A10.1 Project Requirement and Timing

The identified need for this project is to replace transmission line support system components that have been assessed to have a high likelihood of failure with consequential risks to public safety, including from bushfires, and customer reliability.

This refurbishment is expected to achieve a life extension of the overall asset. The project is to be undertaken in the 2019 – 2023 regulatory period.

This project is required to meet the Rules capital expenditure objectives to comply with all applicable regulatory obligations or requirements associated with the provision of prescribed transmission services and maintain the quality, reliability and security of supply of prescribed transmission services.

The project is to be undertaken in the 2019 – 2023 regulatory period as a staged program of works. This allows for greater efficiencies to be realised through mobilisation and coordination of the relevant resources compared with delivery as individual projects. The efficiencies expected to arise as we combine the delivery of these related projects have been incorporated into the overall cost estimate.

This project is scheduled to be completed by 2023.

A10.2 Option Analysis

Option	Description	Estimated NPV ($m 2017-18)	Ranking of Options
Base case	Maintain the status quo and accept the increased risk of tower failure and resulting consequences	-	3
Option 1	Replacement in the 2019 – 2023 regulatory period	77.4	1
Option 2	Replacement in the 2024 – 2028 regulatory period	45.3	2

Option 1 has been identified as the most economical solution to meet the identified need.

The NPV benefits shown are in comparison to the base case, which assumes no replacement capital investment and increasing operating and maintenance, and risk costs.

The benefits are based on central input assumptions to the analysis. Sensitivity analysis over a reasonably wide range of input assumptions has been undertaken to validate the robustness of the option ranking outcomes.

Non-network options were also considered. However, these solutions can not address the issues associated with the condition of the network assets, and full replacement of the lines in question through non-network alternatives (such as generation support or demand side options) would not be viable.

A10.3 Project Scope

The works scoped for this project include the wholesale replacement of all nuts and bolts on approximately 140 ElectraNet steel lattice towers.

The lines identified for refurbishment are:

- F1838: SNUGGERY – BLANCHE – 106 towers (and 1 Stobie pole)
- F1839: BLANCHE – MOUNT GAMBIER – 33 towers

This project is to be completed where no other network projects are scheduled to undertake the replacement of any of the identified assets in the 2019 – 2023 regulatory period.

A11 Substation Improvements for System Black Conditions

Project Number: EC.14209 **Category:** Security/Compliance

Estimated Cost: $7.5m **Required Completion Date:** 2023

A11.1 Project Requirement and Timing

The identified need for this project is to reduce restoration times following events such as a system black or other abnormal conditions, by improving the availability of auxiliary power supplies at critical sites to allow substation equipment to be switched remotely. This reduces time to restore supply by avoiding the time taken to undertake manual switching.

This project improves substation AC auxiliary supplies by providing alternative diesel generator supplies (DGS) at critical substations and connection points for mobile generators at less critical substations.

This project is required to meet the Rules capital expenditure objectives to comply with all applicable regulatory obligations associated with the provision of prescribed transmission services and maintain the quality, reliability and security of supply of prescribed transmission services.

This project is scheduled to be completed across the relevant sites by 2023.

A11.2 Option Analysis

Option	Description	Estimated NPV ($m 2017-18)	Ranking of Options
Base case	Maintain the status quo and accept the delays in restoration associated with manual switching in some locations	-	3
Option 1	During the 2019 – 2023 regulatory period installation of DGS units at critical substations to provide AC supply to the substation and allow all functions to be remotely operated during a system black event	4.5	1
Option 2	Option 1 undertaken in the 2024 – 2028 regulatory period	2.6	2

Option 1 involving the installation of diesel generator supplies and other measures by 2023 has been identified as the most economical solution to meet the identified need.

The Net Present Value (NPV) benefits shown are in comparison to the base case, which assumes no capital investment and increasing operating and maintenance, and risk costs.

The benefits are based on central input assumptions to the analysis. Sensitivity analysis over a reasonably wide range of input assumptions has been undertaken to validate the robustness of the option ranking outcomes.

No non-network options can technically or economically meet the project requirement.

A11.3 Project Scope

The works scoped for this project include:

- Install additional diesel generators (at critical sites where not already provided for);
- Install new AC Switchboards (auto changeover circuits to support the integration of fixed or mobile diesel generators at critical sites);
- Install external diesel generator “plug in” connection points (at lower criticality sites);
- Procure mobile diesel generators (a pool of generators located centrally between Port Augusta, Adelaide and the South East); and
- Provide remote battery voltage and current monitoring to all substation DC systems where this is not available.

A12 Transformer Bushing Unit Asset Replacement

Project Number: EC.14047

Category: Replacement

Estimated Cost: $6.9m

Required Completion Date: 2022

A12.1 Project Requirement and Timing

The identified need for this project is to replace individual transformer bushings that have been assessed to be at end of life with an increased risk of failure and consequential safety and reliability impacts, including from explosive failure.

A total of 98 transformer bushings have been identified for replacement on 19 transformers across 11 substation sites. The bushings are aged between 36 and 54 years.

There is an increasing probability of failure resulting in increased safety risk, higher corrective maintenance costs and unplanned outages, and potential loss of customer supply.

This project is required to meet the Rules capital expenditure objectives to comply with all applicable regulatory obligations associated with the provision of prescribed transmission services and maintain the quality, reliability and security of supply of prescribed transmission services.

The project represents a series of individual asset replacements to be undertaken progressively across the network by 2022.

A12.2 Option Analysis

Option	Description	Estimated NPV ($m 2017-18)	Ranking of Options
Base case	Maintain the status quo and accept the increased risk of failure which may result in safety and reliability issues, or in the worst case, explosive failure of the transformer	-	3
Option 1	Bushings are replaced in the 2019 – 2023 regulatory period before end of technical life is reached. Testing of new bushings is not required.	43.7	1
Option 2	Scope of work as for Option 1 however, the capital expenditure will not occur until the 2024 – 2028 regulatory period	26.6	2

Option 1 has been identified as the most economical solution to meet the identified need.

The Net Present Value (NPV) benefits shown are in comparison to the base case, which assumes no replacement capital investment and increasing operating and maintenance, and risk costs.

The benefits are based on central input assumptions to the analysis. Sensitivity analysis over a reasonably wide range of input assumptions has been undertaken to validate the robustness of the option ranking outcomes.

Non-network solutions are not a viable alternative to address the condition of the identified bushings.

A12.3 Project Scope

The proposed scope of works involves:

- Replacement of 98 Transformer Bushings at 19 ElectraNet Transformers across 11 substation sites; and
- Associated fittings and site works.

A13 Telecommunications Unit Asset Replacement

Project Number: EC.12115 **Category:** Replacement

Estimated Cost: $6.8m **Required Completion Date:** 2023

A13.1 Project Requirement and Timing

The identified need for this project is to replace high risk telecommunication assets that have been assessed to be at end of life.

This project is required to meet the Rules capital expenditure objectives to comply with all applicable regulatory obligations or requirements associated with the provision of prescribed transmission services and maintain the quality, reliability and security of supply of prescribed transmission services.

The project represents a series of individual asset replacements to be undertaken progressively across the network by 2023.

A13.2 Option Analysis

Option	Description	Estimated NPV ($m 2017-18)	Ranking of Options
Base case	Units are run to failure with emergency replacement of telecommunications assets as required.	-	3
Option 1	Replacement of high risk assets in the 2019 – 2023 regulatory period	1.4	1
Option 2	Replacement of assets not already replaced through emergency maintenance during the 2024 – 2028 regulatory period	0.4	2

Option 1 involving the replacement of selected telecommunication assets has been identified as the most economical solution to meet the identified need.

The Net Present Value (NPV) benefits shown are in comparison to the base case, which assumes reactive replacement capital investment and increasing operating and maintenance, and risk costs.

The benefits are based on central input assumptions to the analysis. Sensitivity analysis over a reasonably wide range of input assumptions has been undertaken to validate the robustness of the option ranking outcomes.

No non-network options can technically or economically meet the requirement for telecommunications capability.

A13.3 Project Scope

The project will replace all end of life telecommunication assets identified as high risk including:

- Communication line drivers;
- Microwave radios;
- Multiplexers;
- Power Line Carriers;
- Protection Signalling equipment and interfaces; and
- 48V DC Power Systems.

A14 Robertstown Circuit Breaker Arrangement

Project Number: EC.14071

Category: Security/Compliance

Estimated Cost: $6.6m

Required Completion Date: 2020

A14.1 Project Requirement and Timing

The identified need for this project is to deliver net market benefits by reducing network constraints during maintenance outages of equipment at the Robertstown substation.

The present layout of Robertstown Substation poses a number of operational issues; the main issue is that when maintenance is scheduled for any of the centre breakers (or their associated disconnectors, CTs etc.), in addition to line exit disconnectors, a line fault on one of the Davenport to Robertstown to Para to Tungkillo lines will split the 275 kV buses.

This results in power flows travelling from the 275 kV yard to the 132 kV yard through one transformer and then from the 132 kV yard back to the 275 kV yard through the other transformer via the 132 kV bus. Therefore during any of these scheduled maintenance times the Murraylink interconnection must be significantly constrained or forced to import and generation north of Robertstown may need to be constrained to manage the post contingent flows.

This project reduces the costs to end-use customers under outage conditions, by reducing the constraints that are currently unavoidable due to the existing 275 kV circuit breaker arrangement at Robertstown.

This project is required to meet the Rules capital expenditure objectives to comply with all applicable regulatory obligations associated with the provision of prescribed transmission services and maintain the quality, reliability and security of supply of prescribed transmission services.

This project is scheduled to be completed by 2020.

A14.2 Option Analysis

Option	Description	Estimated NPV ($m 2017-18)	Ranking of Options
Base case	Retain current substation arrangements and maintenance practices	-	3
Option 1	Install an additional 275 kV circuit breaker and associated equipment at Robertstown Substation by 2020	4.0	1
Option 2	Install an additional 275 kV circuit breaker and associated equipment at Robertstown Substation by 2020 in a different location that does not require the expansion of the site but would constrain future development	3.3	2

Option 1 involving the installation of an additional 275 kV diameter has been identified as the most economical solution to meet the identified need.

The Net Present Value (NPV) benefits shown are in comparison to the base case, which assumes no capital investment and increasing constraint costs.

The benefits are based on central input assumptions to the analysis. Sensitivity analysis over a reasonably wide range of input assumptions has been undertaken to validate the robustness of the option ranking outcomes.

No non-network options can technically or economically meet the project requirement to reduce the network constraints resulting from the layout of the Robertstown substation.

A14.3 Project Scope

Install a single 275 kV circuit breaker and associated equipment (i.e. isolators, CT and protection) between the 275 kV buses at Robertstown.

A15 Dalrymple ESCRI-SA Energy Storage

Project Number: EC.14133

Category: Augmentation

Estimated Cost: $6.4m

Required Completion Date: 2019

A15.1 Project Requirement and Timing

The identified need for this project is a proof of concept demonstration that utility scale battery storage can support the integration of renewable energy by helping to address the system security challenges that result from a high penetration of intermittent renewable energy on an interconnected power system.

South Australia has world leading penetration levels of intermittent renewable energy generation sources. The intermittent nature of the renewable generation, combined with a decreased reliance on conventional generation poses unique challenges for the secure and stable operation of the power system. Combined with the impact of extreme weather events, these system security challenges have in recent months seen a number of significant and well-publicised interruptions to electricity supply.

The ESCRI-SA project will capture both regulated and non-regulated benefits. The estimated cost of $6.4m above is the portion of the total project cost to be allocated to the provision of prescribed transmission services.

The purpose of this regulated component is to:

- Demonstrate the application of fast acting battery storage to providing essential system security services such as Fast Frequency Response that can address system security risks associated with a high Rate of Change of Frequency.
- Demonstrate islanded operation during contingency periods, with local demand around Dalrymple supplied by the Wattle Point wind farm and local rooftop solar alone, balanced by the battery storage. This will improve local supply reliability and result in learnings applicable to other systems with 100% intermittent renewable generation.

The regulated cost component is outweighed by customer benefits associated with these purposes (see below).

The project will also deliver substantial knowledge sharing benefits and a detailed Knowledge Sharing Plan is being developed with the Australian Renewable Energy Agency (ARENA).

This project is consistent with the Rules' capital expenditure objectives to comply with all applicable regulatory obligations associated with the provision of prescribed transmission services and maintain the quality, reliability and security of supply of prescribed transmission services – both now and into the future through the proof of concept for grid scale storage.

A15.2 Option Analysis

Because the identified need is a proof of concept demonstration of utility scale battery storage, no alternative options have been considered.

As stated earlier, only a component of the project cost will be allocated to the provision of prescribed transmission services (using ElectraNet's Cost Allocation Methodology). The remainder of the project costs are being recovered via:

- Unregulated revenue, by way of a lease contract with AGL (consistent with ElectraNet's Cost Allocation Methodology); and
- ARENA grant funding contribution.

Prescribed service benefits to customers exceed the cost to be allocated to the provision of prescribed transmission services as shown below.

Estimated costs and benefits to regulated customers	Estimated NPV ($m 2017-18)
Regulated costs of the project	6.3
Benefits of reduced unserved energy around Dalrymple	2.8
Benefits of reduced Heywood interconnector constraints	4.7
Net benefits to customers of the Dalrymple ESCRI-SA Energy Storage project	**1.2**

All values above are shown in Net Present Value (NPV) terms and are relative to a 'business as usual' base case, which assumes the project does not go ahead.

The costs and benefits are based on central input assumptions to the analysis. Sensitivity analysis over a reasonably wide range of input assumptions has been undertaken to validate the robustness of this conclusion.

The net benefits shown above are considered to be conservative with actual benefits realised likely to be materially higher.

Further, the knowledge sharing benefits to be delivered by the project are additional to the quantified benefits shown in the analysis above.

A15.3 Project Scope

The scope of the project involves:

- Installation and commissioning of a nominal 30 MW, 8 MWh Energy Storage Device (ESD) with design and construction of the ESD performed by the manufacturer; and
- Associated site establishment, high voltage switchgear, secondary systems and telecommunications equipment.

A16 Gawler East Connection Point

Project Number: EC.14085 **Category:** Connection

Estimated Cost: $6.3m **Required Completion Date:** 2022

A16.1 Project Requirement and Timing

The identified need for this project is to establish a new transmission connection point at Gawler East to supply increased demand in the distribution network.

SA Power Networks is proposing to establish a new substation at Gawler East to supply new residential developments in the area. SA Power Networks identified a solution which supplies its 11 kV distribution network directly from ElectraNet's 132 kV transmission network between Para and Roseworthy Substations, as a potential alternative to a more expensive 66 kV sub-transmission network solution. A RIT-D for this project will be carried out by SA Power Networks.

This project is required to meet the Rules capital expenditure objectives to meet or manage the expected demand for prescribed transmission services over the period.

This project is scheduled to be completed by 2022.

A16.2 Option Analysis

Option	Description	Estimated NPV[5] ($m 2017-18)	Ranking of Options
Base case	Do nothing	-	4
Option 1	Construct a new 132/11 kV Connection Point Substation by 2022.	33.0	1
Option 2	SA Power Networks extends 66 kV network from Evanston to supply a 66/11 kV substation by 2022	30.8	2
Option 3	SA Power Networks extends 33 kV network from Gawler Belt Tee to supply a 33/11 kV substation by 2022	19.4	3

Option 1 involving the construction of a new 132/11 kV connection point substation by 2022 has been identified as the most economical solution to meet the identified need.

The Net Present Value (NPV) benefits shown are in comparison to the base case, which assumes no capital investment increasing unserved energy costs.

The benefits are based on central input assumptions to the analysis. Sensitivity analysis over a reasonably wide range of input assumptions has been undertaken to validate the robustness of the option ranking outcomes.

Non-network options were considered. However, given that this is a new load development there is minimal opportunity for demand side management to reduce or

[5] The NPV analysed is based on the total project cost which includes a distribution component of capital expenditure for work to be undertaken by SA Power Networks.

defer the need for network augmentation. Generation support can potentially help to defer the need but is not considered to be economic in this instance. A comprehensive options analysis will be undertaken as part of the RIT-D process.

A16.3 Project Scope

The project involves constructing a new 132/11 kV Connection Point Zone Substation to tee off the Para – Roseworthy 132 kV transmission line and establish a 132 kV connection point.

A17 One IP Substation Network – Stage 2

Project Number: EC.12330 **Category:** Replacement

Estimated Cost: $5.0m **Required Completion Date:** 2023

A17.1 Project Requirement and Timing

The identified need for this project is to replace obsolete telecommunications technology to ensure the required performance levels for reliability of operational data can be maintained.

Plesiochronous digital hierarchy (PDH) is an obsolete technology used in telecommunications networks to transport large quantities of data over digital equipment. Existing PDH equipment is now at end of life and the last major manufacturer of PDH equipment has ceased production and support as of December 2014.

In order to lower the risk profile of PDH assets and maintain asset performance and service level standards, services should progressively be migrated over to a Multiprotocol Label Switching (MPLS) based network.

Project 11816 One IP Substation Network – Stage 1 is presently building and migrating some services onto an IP/MPLS network. The recovered PDH equipment is currently being used to support the performance of the equipment that is left is place to carry the remaining services.

This project will continue the migration of all services (except protection services), returning further spares to the network to manage the performance of the protection services until such time it is ready to be operated on an IP/MPLS network.

This project is required to meet the Rules capital expenditure objective to maintain the quality, reliability and security of supply of prescribed transmission services.

The project represents a staged rollout to be undertaken progressively across the network by 2023.

A17.2 Option Analysis

Option	Description	Estimated NPV[6] ($m 2013-2014)	Ranking of Options
Base case	Continue to run critical services on an aging and deteriorating PDH network, with no support from vendors and manufacturers. Replacement to be done on a piecemeal and ad hoc basis.	-	2
Option 1	Build a Native IP Network; this option involves a complete replacement of the existing PDH network, at a significant upfront cost, and would also require significant asset write-offs, and significant risk to the network.	(15.6)	3

[6] The NPV analysed includes total project costs from stage 1 of the project which has been undertaken in the regulatory control period 2014-2018.

Option	Description	Estimated NPV[6] ($m 2013-2014)	Ranking of Options
Option 2	Continue to build an overlay IP network, and migrate services in a staged manner. Allow for the continued use of the legacy PDH equipment until the end of its useful life (required for protection signalling), whilst moving services onto the IP network from other networks (such as OPSWAN).	1.7	1

Option 2 involving the continued rollout of the one IP substation network has been identified as the most economical solution to meet the identified need.

The Net Present Value (NPV) benefits shown are in comparison to the base case, which assumes reactive replacement capital investment and increasing operating and maintenance, and risk costs.

The benefits are based on central input assumptions to the analysis. Sensitivity analysis over a reasonably wide range of input assumptions has been undertaken to validate the robustness of the option ranking outcomes.

No non-network options can technically or economically meet the project requirement.

A17.3 Project Scope

This project involves transferring all remaining services onto the MPLS network except protection services.

This will require completion of the roll out of the One IP network to the remaining 20 substations not included in the scope of an existing rollout project (EC.11816). This includes:

- Installation of 2 x routers per substation;
- Installation of 2 x switches per control/telecoms room per substation;
- Infrastructure upgrades to support the above, as required; and
- Migration of relevant services to the One IP Network.

REVENUE PROPOSAL 2019 - 2023

Attachment 6 - Appendix B

Contingent Projects 2018-23

28 March 2017

ElectraNet

Contents

B1 Eyre Peninsula Reinforcement

B1.1 Background

The customer load in the Eyre Peninsula region is primarily related to small scale mining, residential and commercial activities, with seasonal primary industry activity (grain handling). Previous State Government mineral resources forecasts have indicated the prospect of increasing large scale mining activities, such as iron ore extraction.

The Eyre Peninsula is supplied by a radial 132 kV line that extends from Cultana to Yadnarie, and from Yadnarie to Port Lincoln. A radial line also extends west to Wudinna to supply the West Coast. Mount Millar wind farm is connected at Yadnarie, and Cathedral Rocks wind farm is connected at Port Lincoln.

The underlying distribution network consists of a mixture of 66 kV and 33 kV sub-transmission lines that take power from the Whyalla, Stony Point, Yadnarie, Wundinna and Port Lincoln 132 kV substations.

Supply to Port Lincoln is supported by a network support agreement between ElectraNet and Engie which expires on 31 December 2018. Under this agreement, ElectraNet is able to call upon the services of three diesel-fired gas turbines connected at Port Lincoln when needed. The reliability standards require that ElectraNet provide "N-1" equivalent line capacity to the Port Lincoln exit point, so that back-up supply is available for Port Lincoln when supply from the 132 kV line is interrupted. The current cost of this network support arrangement to customers is approximately $9 million per year.

ElectraNet has identified a requirement to replace components of the Cultana to Yadnarie and Yadnarie to Port Lincoln transmission lines based on assessed asset condition, and the estimated cost of these replacement works are included in the capital expenditure forecast (further details available in B1.4).

Expiry of the network support agreement and the replacement works required on the existing transmission lines provides a valuable opportunity to investigate alternatives for providing reliable and affordable supply to the Eyre Peninsula.

ElectraNet is commencing a RIT-T process to conduct this investigation.

B1.2 Project Description

The project involves replacing the existing single-circuit radial 132 kV transmission lines from Cultana to Yadnarie and from Yadnarie to Port Lincoln (for example with new double-circuit 132 kV or 275 kV lines).

An indicative scope involves the construction of a double circuit line (initially operating at 132kV) from Cultana to Port Lincoln, associated substation works and the decommissioning of the existing line.

The project is based on the potential for new transmission lines to provide a more cost effective solution for the Eyre Peninsula than entering into a new network support agreement and undertaking major replacement works on the existing transmission lines.

ElectraNet considers that the project should be accepted as a contingent project because of uncertainty about the relevant trigger events occurring and the size and cost of the project.

B1.3 Trigger Events

The following trigger events are proposed for this contingent project:

1. Successful completion of the RIT-T including an assessment of credible options identifying the duplication or replacement of the existing Cultana-Yadnarie and/or Yadnarie-Port Lincoln transmission lines as the preferred option.
2. Determination (if applicable) by the AER under clause 5.16.6 of the NER that the proposed investment satisfies the RIT-T.
3. ElectraNet Board commitment to proceed with the project subject to the AER amending the revenue determination pursuant to the Rules.

These trigger events are specific and capable of objective verification, relate to a specific location, are sufficient for the revenue determination to be amended, and are probable but too uncertain to include the proposed contingent project in the capital expenditure forecast.

B1.4 Project Requirement

Detailed condition assessment indicates that significant lengths of conductor on the Cultana to Yadnarie and Yadnarie to Port Lincoln 132 kV lines are in poor condition, and are likely to experience a significantly increased rate of failure in future years. Potential consequences of failure of these conductors include increasing rates of customer outages, an increasing risk of bushfire starts with a consequential risk to public safety, and escalating maintenance effort involving increased inspection, monitoring and associated costs to address deteriorating sections and repair and restore conductor sections after failure.

Analysis of available options has identified that replacement of the sections of conductor in poor condition on each of these lines is more cost effective from a customer perspective than incurring the increasing operating and maintenance costs associated with the deteriorating line sections.

ElectraNet has therefore included the costs of replacing the sections of conductor that are in poor condition on the Cultana to Yadnarie and Yadnarie to Port Lincoln 132 kV lines in its ex ante capital expenditure forecast for the 2019-2023 regulatory control period (refer projects EC.14137 and EC.14145 respectively).

However, as indicated earlier, it is possible that the full replacement of the overall line may deliver sufficient benefits to customers to outweigh the additional costs by improving supply reliability to customers in the region, avoiding the ongoing annual costs of network support at Port Lincoln and reducing network losses.

This would involve replacing the existing radial Cultana to Yadnarie and Yadnarie to Port Lincoln 132 kV lines (for example with new double-circuit 132 kV or 275 kV lines). This alternative project has therefore been identified as a contingent project, which would be subject to the outcomes of detailed economic assessment and consultation through the RIT-T[1].

[1] An *Eyre Peninsula Electricity Supply Reinforcement Project Specification Consultation Report* (PSCR) is expected to be published in April 2017, as the initial consultation report under the RIT-T, to be available on our website at https://www.electranet.com.au.

ElectraNet will also continue to work with the Essential Services Commission of South Australia (ESCOSA) as the responsible body for setting transmission reliability standards in South Australia is it undertakes a review of the applicable reliability standard for the Eyre Peninsula for the South Australian Treasurer and Minister for Energy[2].

Both the timing and scope of this project and therefore the potential expenditure requirements are uncertain at this point in time.

If the trigger events occur the proposed contingent project would be reasonably required to meet the Rules capital expenditure objectives to efficiently meet expected demand for prescribed transmission services and to comply with all applicable regulatory obligations associated with the provision of prescribed transmission services.

B1.5 Contingent Capital Expenditure

The proposed contingent project cost is estimated at $200m.

This estimate is based on an indicative 132 kV double circuit line option. If required, this project would also consider any associated works that may be justified to reinforce or improve the resilience of the network from the nearest nodal substation at Davenport.

If this contingent project were to be triggered, ElectraNet would seek the differential capital expenditure (currently estimated at $120m) that would be required to undertake full line replacement as an alternative to the partial line replacement projects (EC.14137 and EC.14145).

The methodology used for developing the forecast cost estimate is described in Section 6.7 of this Attachment.

By definition it is generally not possible to accurately define the scope of a proposed contingent project at this early stage. Therefore, the estimated cost of the project is indicative only.

The actual cost of a fully scoped solution would depend on the construction voltage (132 kV or 275 kV) and final configuration, subject to the outcomes of the RIT-T. A detailed project scope and cost estimate will be required before any amendment to the revenue determination is considered by the AER should the specified trigger event occur during the regulatory period.

The proposed contingent capital expenditure exceeds the applicable threshold of $30m (see section 6.11 of this Attachment).

2 ESCOSA is to investigate how electricity companies can improve power reliability on the Eyre Peninsula. ESCOSA will investigate and make recommendations on what measures can be taken to incentivise ElectraNet and SA Power Networks to upgrade current infrastructure and reconnect supply quicker after damaging storm events. The Office of the Technical Regulator will provide advice on the technical aspects of the investigation. ESCOSA will also investigate and report on the costs associated with each potential reliability measure they recommend. Hon. Tom Koutsantonis News Release, 24 January 2017, available at http://www.premier.sa.gov.au/index.php/tom-koutsantonis-news-releases/1707-energy-minister-meets-mayors-over-eyre-peninsula-power-issues.

B1.6 Demonstration of Rules Compliance

ElectraNet considers that this project should be accepted as a contingent project for the forthcoming regulatory control period as it complies with the provisions set down in clause 6A.8.1(b) of the Rules as:

1. the proposed contingent project is reasonably required to be undertaken in order to achieve the capital expenditure objectives;
2. the proposed contingent capital expenditure:
   i. is not otherwise provided for (either in part or in whole) in the forecast capital expenditure for the relevant regulatory control period;
   ii. reasonably reflects the capital expenditure criteria, taking into account the capital expenditure factors; and
   iii. exceeds the applicable threshold.
3. the proposed contingent project and the proposed contingent capital expenditure, and the related information provided meets the requirements of the Revenue Reset Regulatory Information Notice; and
4. the trigger events in relation to the proposed contingent project are appropriate.

B2 South Australian Energy Transformation

B2.1 Background

South Australia has world leading levels of intermittent renewable energy, with around 45% of the State's power generation now coming from renewable energy sources. There are 18 wind farms in operation with total capacity of around 1,500 MW with more commitments underway, and more than a quarter of the State's homes have installed solar power with total installed capacity of around 700 MW.

New challenges are emerging from these higher levels of intermittent renewable energy and the resulting closure or mothballing of conventional generation. These challenges, which include more volatile wholesale market prices and ensuring system security and reliability expectations continue to be met, are expected to require a range of new solutions. Stronger interconnection is one of these solutions.

While interconnector import capacity is only around 30% of South Australia's peak demand, a nation such as Denmark, which has a similar level of intermittent electricity output of over 40%, can meet more than 80% of its peak demand from interconnection with neighbouring countries.

We are therefore exploring potential solutions to help address these increasing challenges and investigating options that include a new interconnector between South Australia and the Eastern States, as well as non-network options that provide benefits to the market and system security.

B2.2 Project Description

The project involves increased interconnection to the Eastern states via a new interconnector with a notional capacity of 650 MW, together with associated works required (e.g. synchronous condensers, special protection schemes, dynamic reactive support) combined with non-network solutions.

The project is based on the potential for the South Australian Energy Transformation RIT-T process result in a new interconnector as the preferred option that is the most cost effective solution for customers.

Further details are available in the South Australian Energy Transformation Project Specification Consultation Report.[3]

ElectraNet considers that the project should be accepted as a contingent project for the regulatory period because of uncertainty about the relevant trigger events occurring and the size and cost of the project.

B2.3 Trigger Events

The following trigger events are proposed for this contingent project:

1. Successful completion of the South Australian Energy Transformation RIT-T with the identification of a preferred option or options:
   - demonstrating positive net market benefits; and/or
   - addressing a reliability corrective action.

[3] Available at https://www.electranet.com.au/projects/south-australian-energy-transformation/.

2. Determination (if applicable) by the AER under clause 5.16.6 of the NER that the proposed investment satisfies the RIT-T.

3. ElectraNet Board commitment to proceed with the project subject to the AER amending the revenue determination pursuant to the Rules.

The triggers are specific and capable of objective verification, relate to a specific location or locations, are sufficient for the revenue determination to be amended, and are probable but too uncertain to include the proposed contingent project in the capital expenditure forecast.

B2.4 Project Requirement

On 7 November 2016, ElectraNet commenced the South Australian Energy Transformation (SAET) Regulatory Investment Test for Transmission (RIT-T) by publishing a Project Specification Consultation Report (PSCR).

As required by the National Electricity Rules (NER), the RIT-T is directed at meeting an identified need[4], which ElectraNet has identified as:

- facilitating greater competition in the wholesale electricity market, to lower dispatch costs and consequently wholesale electricity prices, particularly in South Australia ('market need');
- providing appropriate security of supply, including inertia, frequency response and system strength services in South Australia ('security need'); and
- facilitating the transition to lower carbon emissions and the adoption of new technologies ('emissions need').

Options that were highlighted in the PSCR include new interconnectors between South Australia and neighbouring eastern states and alternative solutions that do not involve an interconnector, such as demand response, generation options, battery storage and other solutions (a non-interconnector solution).

To support this work, the South Australian Government announced in the 2016-17 state budget[5] a $500,000 contribution towards the costs of ElectraNet pursuing a feasibility study into increased interconnection between South Australia and the Eastern states.

Both the timing and scope of this project and therefore the potential expenditure requirements are uncertain at this point in time.

If the trigger events occur the proposed contingent project would be reasonably required to meet the Rules capital expenditure objectives to efficiently meet expected demand for prescribed transmission services and/ or to comply with all applicable regulatory obligations associated with the provision of prescribed transmission services.

B2.5 Contingent Capital Expenditure

The South Australian component of the proposed contingent project has an indicative cost estimate in the order of $200m to $500m. This estimate is based on the construction of a new double circuit 275 kV transmission line from Robertstown in South Australia to

[4] NER cl 5.16.4(b)(2).

[5] News releases – Premier Jay Weatherill, State Budget 2016/17: Study into new interconnector, available at http://www.premier.sa.gov.au/index.php/tom-koutsantonis-news-releases/697-state-budget-2016-17-study-into-new-interconnector.

Buronga in New South Wales, including associated works such as SVCs, synchronous condensers, and a Special Protection Scheme.

The methodology used for developing the forecast cost estimate is described in Section 6 .7 of this Attachment.

By definition it is generally not possible to accurately define the scope of a proposed contingent project at this early stage. Therefore, the estimated cost of the project is indicative only. Subject to the outcomes of the RIT-T, estimates of credible network options range from $500m to $2,500m.

It is also possible that a combination of supporting network investments (e.g. synchronous condensers, special protection schemes, and dynamic reactive support) combined with non-network options is found to be part of the most economical solution identified through the RIT-T.

A detailed project scope and cost estimate will be required before any amendment to the revenue determination is considered by the AER should the specified trigger event occur during the regulatory period.

The proposed contingent capital expenditure exceeds the applicable threshold of $30m (see section 6.11 of this Attachment).

B2.6 Demonstration of Rules Compliance

ElectraNet considers that this project should be accepted as a contingent project for the forthcoming regulatory control period as it complies with the provisions set down in clause 6A.8.1(b) of the Rules as:

ElectraNet considers that this project should be accepted as a contingent project for the forthcoming regulatory control period as it complies with the provisions set down in clause 6A.8.1(b) of the Rules as:

1. the proposed contingent project is reasonably required to be undertaken in order to achieve the capital expenditure objectives;
2. the proposed contingent capital expenditure:
   i. is not otherwise provided for (either in part or in whole) in the forecast capital expenditure for the relevant regulatory control period;
   ii. reasonably reflects the capital expenditure criteria, taking into account the capital expenditure factors; and
   iii. exceeds the applicable threshold.
3. the proposed contingent project and the proposed contingent capital expenditure, and the related information provided meets the requirements of the Revenue Reset Regulatory Information Notice; and
4. the trigger events in relation to the proposed contingent project are appropriate.

B3 Upper North-East Line Reinforcement

B3.1 Background

The ElectraNet transmission system north east of Port Augusta currently consists of a relatively low capacity 132 kV line constructed in 1961. The transmission line supplies distribution connection points at Neuroodla (supplying Hawker and environs), and at Leigh Creek South (supplying the Leigh Creek township, Copley, Lyndhurst and environs).

This line also supplies the connection point at Leigh Creek Coalfield. This coalfield connection point has effectively reduced to a minimal Agreed Maximum Demand (AMD) while Alinta Energy undertakes rehabilitation works at the mine site following the closure of its coal-fired generation facilities.

ElectraNet has received a number of recent medium to large load connection enquiries along the line due to interest in mineral exploration and resource development in the area.[6]

To support any material additional loads, a major up-rating or rebuilding of the line would be required from Davenport to the point where the new load connected.

B3.2 Project Description

The project involves uprating of the Leigh Creek 132 kV line and establishment of associated substation assets (including reactive support).

In the event that an uprating of the Leigh Creek line was proven technically or economically impractical, requiring for example the insertion of new structures in between every low span, then a full line rebuild would be required.

ElectraNet considers that the project should be accepted as a contingent project for the regulatory period because of uncertainty about the relevant trigger events occurring and the size and cost of the project.

B3.3 Trigger Events

The following trigger events are proposed for this contingent project:

1. Customer commitment for additional load to connect to the transmission network causing the Davenport to Leigh Creek 132kV line to exceed its thermal limit of 10 MVA.
2. Successful completion of the RIT-T including an assessment of credible options showing a new connection point and line upgrade is justified.
3. Determination by the AER under clause 5.16.6 of the NER that the proposed investment satisfies the RIT-T.
4. ElectraNet Board commitment to proceed with the project subject to the AER amending the revenue determination pursuant to the Rules.

[6] An example in the public domain is Leigh Creek Coalfield (Post Alinta load for in-situ gasification) at http://www.lcke.com.au/Our-Business/Leigh-Creek-Energy-Project.

The triggers are specific and capable of objective verification, relate to a specific location or locations, are sufficient for the revenue determination to be amended, and are probable but too uncertain to include the proposed contingent project in the capital expenditure forecast.

B3.4 Project Requirement

The existing Davenport to Leigh Creek transmission line was designed with a thermal rating of 49 °C (120 °F), which has been shown to be inadequate for Australian summer conditions. Most circuits designed and built to this standard have been uprated or replaced. However, the Davenport to Leigh Creek line continues to have an adequate rating for the magnitude of the load it supplies at Neuroodla, the Leigh Creek coal mine and Leigh Creek township, and consequently uprating or replacement has not been necessary to date.

Aerial laser survey data has revealed that, assuming the structures are mechanically capable, the connection of a 35 MW load at Leigh Creek, would require the uplifting of some 300 of the total 600 spans in the existing line over its 240 km length to meet minimum ground clearance requirements.

Any step load increase causing the line to exceed its thermal limit of 10 MVA would require either a significant uprating or the rebuild of the line.

Both the timing and scope of this project and therefore the potential expenditure requirements are uncertain at this point in time.

If the trigger events occur the proposed contingent project would be reasonably required to meet the Rules capital expenditure objectives to efficiently meet expected demand for prescribed transmission services and to comply with all applicable regulatory obligations associated with the provision of prescribed transmission services.

B3.5 Contingent Capital Expenditure

The proposed contingent project is estimated to cost $60m.

This estimate is based on the uprating of some 300 spans of the Davenport to Leigh Creek 132kV line, establishment of a 132/33 kV substation and plant and protection systems at both remote ends of the lines. The scope includes associated integration, telecommunication SCADA and metering works.

The methodology used for developing the forecast cost estimate is described in Section 6.7 of this Attachment.

By definition it is generally not possible to accurately define the scope of a proposed contingent project at this early stage. Therefore, the estimated cost of the project is indicative only. A detailed project scope and cost estimate will be required before any amendment to the revenue determination is considered by the AER should the specified trigger event occur during the regulatory period.

The proposed contingent capital expenditure exceeds the applicable threshold of $30m (see section 6.11 of this Attachment).

B3.6 Demonstration of Rules Compliance

ElectraNet considers that this project should be accepted as a contingent project for the forthcoming regulatory control period as it complies with the provisions set down in clause 6A.8.1(b) of the Rules as:

1. the proposed contingent project is reasonably required to be undertaken in order to achieve the capital expenditure objectives;
2. the proposed contingent capital expenditure:
   i. is not otherwise provided for (either in part or in whole) in the forecast capital expenditure for the relevant regulatory control period;
   ii. reasonably reflects the capital expenditure criteria, taking into account the capital expenditure factors; and
   iii. exceeds the applicable threshold.
3. the proposed contingent project and the proposed contingent capital expenditure, and the related information provided meets the requirements of the Revenue Reset Regulatory Information Notice; and
4. the trigger events in relation to the proposed contingent project are appropriate.

B4 Upper North-West Line Reinforcement

B4.1 Background

The ElectraNet transmission system North West of Port Augusta currently consists of a relatively low capacity 132 kV line constructed in 1961. The transmission line supplies a distribution connection point at Mount Gunson, together with connection points with the Department of Defence at Woomera and with BHPB at Pimba.

This line normally only supplies Mount Gunson and Woomera. Load is only taken from the Pimba connection point during planned outages or in an emergency, when either BHP Billiton's 275 kV transmission line is out of service, or to restore power to Roxby Downs and to part of BHP Billiton's Olympic Dam operations after a wide scale outage.

ElectraNet has received a number of recent medium to large load connection enquiries along this line due to interest in mineral exploration and resource development in the area.[7]

To support any material additional loads, rebuilding of the line would be required from Davenport to the point where the new load connected.

B4.2 Project Description

The project involves rebuilding of the Pimba 132 kV line and establishment of associated substation assets (including reactive support).

ElectraNet considers that the project should be accepted as a contingent project for the regulatory period because of uncertainty about the trigger event occurring and the size and cost of the project.

B4.3 Trigger Events

The following trigger events are proposed for this contingent project:

1. Customer commitment for additional load to connect to the transmission network causing the Davenport to Pimba 132kV line to exceed its thermal limit of 76 MVA.
2. Successful completion of the RIT-T including an assessment of credible options showing a transmission investment is justified.
3. Determination by the AER under clause 5.16.6 of the NER that the proposed investment satisfies the RIT-T.
4. ElectraNet Board commitment to proceed with the project subject to the AER amending the revenue determination pursuant to the Rules.

The triggers are specific and capable of objective verification, relate to a specific location or locations, are sufficient for the revenue determination to be amended, and are probable but too uncertain to include the proposed contingent project in the capital expenditure forecast.

[7] Examples in the public domain include:

- Woomera airfield upgrade installing two new 20MVA transformers http://www.news.com.au/national/breaking-news/pm-launches-woomera-test-range-upgrade/news-story/9fd23019ac2488a72cc6fb6459d77b28.
- Mt Gunson 50 MW Mine load enquiry (Carrapateena) http://www.ozminerals.com/operations/carrapateena-project/.

B4.4 Project Requirement

The existing Davenport to Pimba 132 kV transmission line was designed with a thermal rating of 49 °C (120 °F), which has been shown to be inadequate for Australian summer conditions. This transmission line has a rating of 76 MVA. The line was uprated to allow this level of loading during the 1980s to support the initial development of Olympic Dam. This uprating involved lifting the lowest spans using insulated cross-arms. ElectraNet considers that this uprating represents the mechanical limit for the structures involved.

Any step load increase causing the line to exceed its thermal limit of 76 MVA would therefore require a rebuild of the circuit.

Both the timing and scope of this project, and therefore the potential expenditure requirements, are uncertain at this point in time.

If the trigger events occur the proposed contingent project would be reasonably required to meet the Rules capital expenditure objectives to efficiently meet expected demand for prescribed transmission services and to comply with all applicable regulatory obligations associated with the provision of prescribed transmission services.

B4.5 Contingent Capital Expenditure

The proposed contingent project cost estimate is $110m.

This estimate is based on the rebuilding of the Davenport to Pimba 132kV line to Mt Gunson, the establishment of a 132/33 kV substation and associated works.

The methodology used for developing the forecast cost estimate is described in Section 6 .7 of this Attachment.

By definition it is generally not possible to accurately define the scope of a proposed contingent project at this early stage. Therefore, the estimated cost of the project is indicative only. A detailed project scope and cost estimate will be required before any amendment to the revenue determination is considered by the AER should the specified trigger event occur during the regulatory period.

The proposed contingent capital expenditure exceeds the applicable threshold of $30m (see section 6.11 of this Attachment).

B4.6 Demonstration of Rules Compliance

ElectraNet considers that this project should be accepted as a contingent project for the forthcoming regulatory control period as it complies with the provisions set down in clause 6A.8.1(b) of the Rules as:

1. the proposed contingent project is reasonably required to be undertaken in order to achieve the capital expenditure objectives;
2. the proposed contingent capital expenditure:
   i. is not otherwise provided for (either in part or in whole) in the forecast capital expenditure for the relevant regulatory control period;
   ii. reasonably reflects the capital expenditure criteria, taking into account the capital expenditure factors; and
   iii. exceeds the applicable threshold.

3. the proposed contingent project and the proposed contingent capital expenditure, and the related information provided meets the requirements of the Revenue Reset Regulatory Information Notice; and
4. the trigger events in relation to the proposed contingent project are appropriate.

B5 Main Grid System Strength Support

B5.1 Background

Synchronous generators (i.e. those that help stabilise system frequency) are the predominant source of fault levels, which are important for system strength on the network. Existing intermittent renewable generators are generally asynchronous and do not contribute significant fault levels.

With increasing levels of asynchronous renewable generation, decreasing system demand and the progressive withdrawal or mothballing of conventional synchronous generation, there is an increasing risk that without intervention insufficient or no synchronous generators will participate in the market at times when renewable generation exceeds the demand. This was seen on 13 November 2016, when for a time only one synchronous generator was dispatched.

Fault levels are a more local characteristic of the power system. For example, the Heywood Interconnector provides a portion of the fault level required for power electronic interfaced devices but this diminishes with distance.

B5.2 Project Description

The indicative scope of the project involves upgrading existing protection devices and installing six synchronous condensers at selected locations across the 275 kV transmission network.

Further studies will be required to confirm the optimal locations and required numbers of synchronous condensers.

ElectraNet considers that the project should be accepted as a contingent project for the regulatory period because of uncertainty about the relevant trigger events occurring and the size and cost of the project.

B5.3 Trigger Events

The following trigger events are proposed for this contingent project:

1. Confirmation by AEMO of the existence of a Network Support and Control Ancillary Services (NSCAS) gap relating to system strength, or other requirement for ElectraNet to address a system strength requirement, in the South Australian region.
2. Successful completion of the RIT-T (or equivalent economic evaluation) including an assessment of credible options showing a transmission investment is justified.
3. Successful Determination (if applicable) by the AER under clause 5.16.6 of the NER that the proposed investment satisfies the RIT-T.
4. ElectraNet Board commitment to proceed with the project subject to the AER amending the revenue determination pursuant to the Rules.

The triggers are specific and capable of objective verification, relate to a specific location or locations, are sufficient for the revenue determination to be amended, and are probable but too uncertain to include the proposed contingent project in the capital expenditure forecast.

B5.4 Project Requirement

AEMO has identified that the operation of large high voltage power systems such as South Australia at low fault levels can result in the conditions of the power system being unstable due to factors such as[8]:

- Manufacturers' design limits on power electronic interfaced devices such as wind turbines and static Var compensators. Operation of these devices outside their minimum design limits could give rise to generating systems' instability and consequent disconnection from the grid.
- Protections systems which rely on measurement of current (excluding differential protection) or current and voltage during a fault to achieve two basic requirements – selectivity (that is, to operate only for conditions for which the system has been installed) and sensitivity (that is, to be sufficiently sensitive to faults on the equipment it is protecting).
- Inability to control voltage during normal system and market operations such as switching of transmission lines or transformers, switching reactive plant (capacitors and reactors), transformer tap changing, and routine variations in load or generation.

AEMO's preliminary analysis of 13 November 2016 concluded that two large synchronous generating units, or combinations of smaller generating units, are required to be online in South Australia to ensure a secure operating state as defined in clause 4.2.2 of the Rules. AEMO also concluded that this may demonstrate the existence of an NSCAS gap.

AEMO plans to further investigate this issue and publish a report in early 2017 in relation to this requirement, and will collaborate with ElectraNet to confirm the existence, size, and trigger date of the NSCAS gap[9].

The requirement for the project is to maintain minimum fault levels in South Australia for foreseeable operating conditions above a level that is sufficient to ensure that:

- Power electronic interfaced devices such as wind turbines and static Var compensators can remain stable.
- Protection systems can adequately function.
- Voltage can be maintained during normal system and market operations including switching transformers, transmission lines and reactive plant, transformer tap changing, and routine variations in load or generation.

Both the timing and the scope of this project and therefore the transmission requirements are uncertain at this point in time.

Confirmation of the existence, size, and trigger date of a potential NSCAS gap, or other requirement for ElectraNet to address a system strength requirement in the South Australian region, will determine the need and timing for this project.

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8 AEMO, SA System Strength, available at www.aemo.com.au/~/media/Files/Media_Centre/2016/SA-System-Strength.pdf.

9 AEMO, 2016 NTNDP, p 98, available at www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NTNDP/2016/Dec/2016-NATIONAL-TRANSMISSION-NETWORK-DEVELOPMENT-PLAN.pdf.

If the trigger events occur the proposed contingent project would be reasonably required to meet the Rules capital expenditure objectives to efficiently meet expected demand for prescribed transmission services and to comply with all applicable regulatory obligations associated with the provision of prescribed transmission services.

B5.5 Contingent Capital Expenditure

The proposed contingent project cost estimate is $60-80 million.

This indicative estimate is based on installing six synchronous condensers on the 275 kV transmission network at various locations, and includes associated substation works.

The methodology used for developing the forecast cost estimate is described in Section 6.7 of this Attachment.

By definition it is generally not possible to accurately define the scope of a proposed contingent project at this early stage. Therefore, the estimated cost of the project is indicative only. A detailed project scope and cost estimate will be required before any amendment to the revenue determination is considered by the AER should the specified trigger event occur during the regulatory period.

The proposed contingent capital expenditure exceeds the applicable threshold of $30m (see section 6.11 of this Attachment).

B5.6 Demonstration of Rules Compliance

ElectraNet considers that this project should be accepted as a contingent project for the forthcoming regulatory control period as it complies with the provisions set down in clause 6A.8.1(b) of the Rules as:

1. the proposed contingent project is reasonably required to be undertaken in order to achieve the capital expenditure objectives;
2. the proposed contingent capital expenditure:
   i. is not otherwise provided for (either in part or in whole) in the forecast capital expenditure for the relevant regulatory control period;
   ii. reasonably reflects the capital expenditure criteria, taking into account the capital expenditure factors; and
   iii. exceeds the applicable threshold.
3. the proposed contingent project and the proposed contingent capital expenditure, and the related information provided meets the requirements of the Revenue Reset Regulatory Information Notice; and
4. the trigger events in relation to the proposed contingent project are appropriate.

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