SOUTH AUSTRALIAN TRANSMISSION ANNUAL PLANNING REPORT

29 JUNE 2018

ElectraNet

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Purpose of the Transmission Annual Planning Report

Each year, ElectraNet reviews the capability of its transmission network and regulated connection points to meet ongoing electricity demand, forecast under a variety of operating scenarios. ElectraNet works with SA Power Networks, which is responsible for distributing electricity throughout South Australia, to complete the review. We also take into account outcomes of joint planning with Powerlink in Queensland, TransGrid in New South Wales, AusNet Services in Victoria, and the Australian Energy Market Operator (AEMO) in its roles as Victorian Transmission Planner and National Transmission Planner (Appendix A).

ElectraNet's asset management, planning and forecasting processes align with the applicable regulatory requirements (Appendix B).

This report meets the requirements of the National Electricity Rules, and in doing so presents the outcomes of the annual planning review and forecasting to help you understand the network's current capacity and how we think this may change in the future (Appendix C). The report covers a 10-year planning period (1 July 2018 to 30 June 2028) and identifies potential network capability limitations and possible solution options.

The report provides information on:

- the changing energy system (Chapter 1)
- national transmission planning (Chapter 2)
- demand forecast for the next 10-year period (Chapter 3)
- constraints that impact South Australia (Chapter 4)
- demand management and connection opportunities (Chapter 5)
- recently completed, committed, and planned projects (Chapter 6)
- transmission network development plans (Chapter 7)
- control schemes (Chapter 8).

The report does not define a single specific future development plan for the South Australian transmission system, rather it is intended to form part of a consultation process to ensure efficient and economical development of the transmission network to meet forecast electricity demand over the planning period. Decisions by ElectraNet to invest in the South Australian transmission system will only be made at the time they become needed.

We are committed to ongoing improvement of the Transmission Annual Planning Report and its value to our customers and industry stakeholders.

We invite feedback on any aspect of this report, from our demand projections and emerging network limitations to proposed solutions, the planning scenarios considered and the presentation of information in this report. Your feedback will help us to serve you better and ensure we can provide a reliable and high quality electricity supply to customers at the lowest long-run cost.

Comments and suggestions can be directed to:

Hugo Klingenberg, Senior Manager Network Development, consultation@electranet.com.au.

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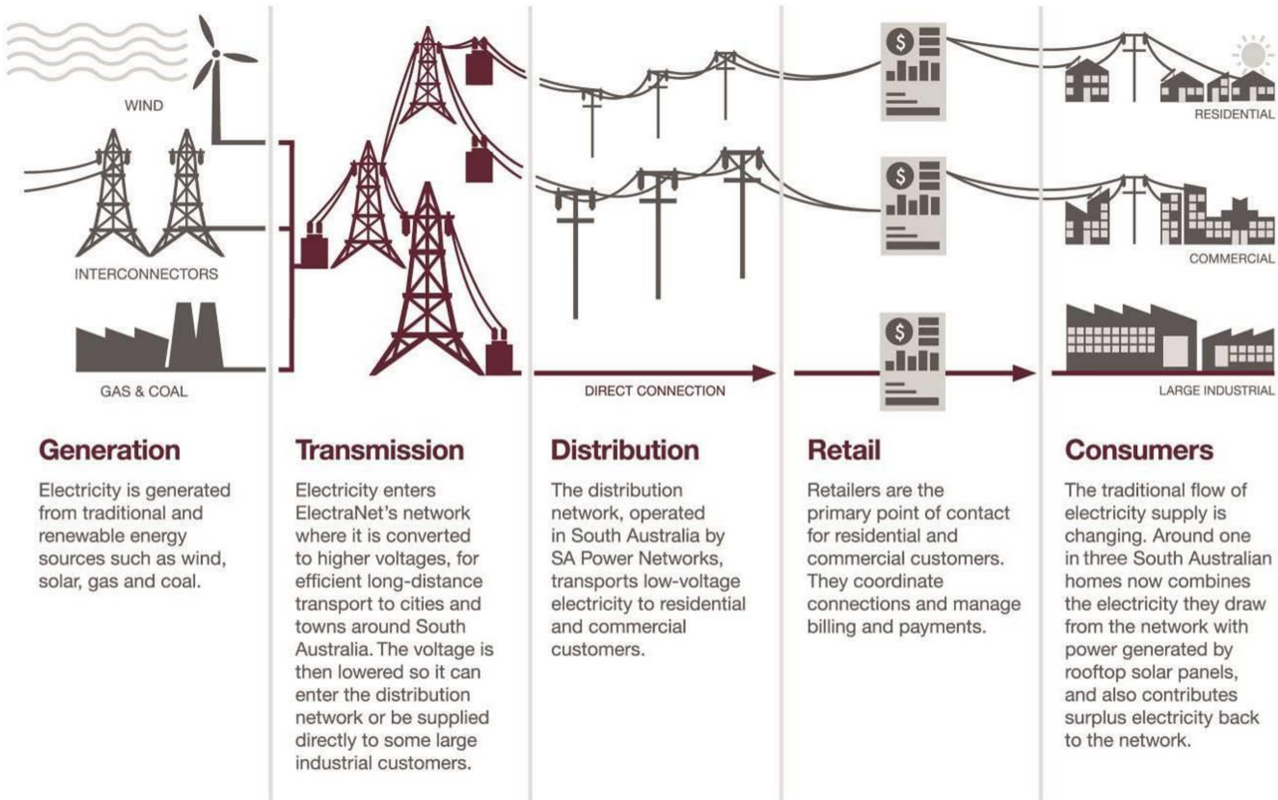
About ElectraNet

ElectraNet powers people's lives by delivering safe, affordable and reliable solutions to power homes, businesses and the economy.

As South Australia's principal Transmission Network Service Provider, we are a critical part of the electricity supply chain. We build, own, operate and maintain high-voltage electricity assets, which move energy from traditional and renewable energy generators in South Australia and interstate to large load customers and the lower voltage distribution network.

We also provide consultancy and other services to third parties involved with our high voltage electricity assets and our one stop-shop service means our clients can entrust us with the end-to-end delivery and management of electricity infrastructure assets.

ElectraNet is part of the National Electricity Market and maintains close working relationships with electricity market bodies including the Australian Energy Market Commission, Australian Energy Regulator, Australian Energy Market Operator and the Essential Services Commission of South Australia.



Role of ElectraNet in the electricity supply chain

Our customers, community and environment

We are committed to genuine engagement with electricity customers to provide meaningful opportunities to improve the value of electricity transmission services in South Australia.

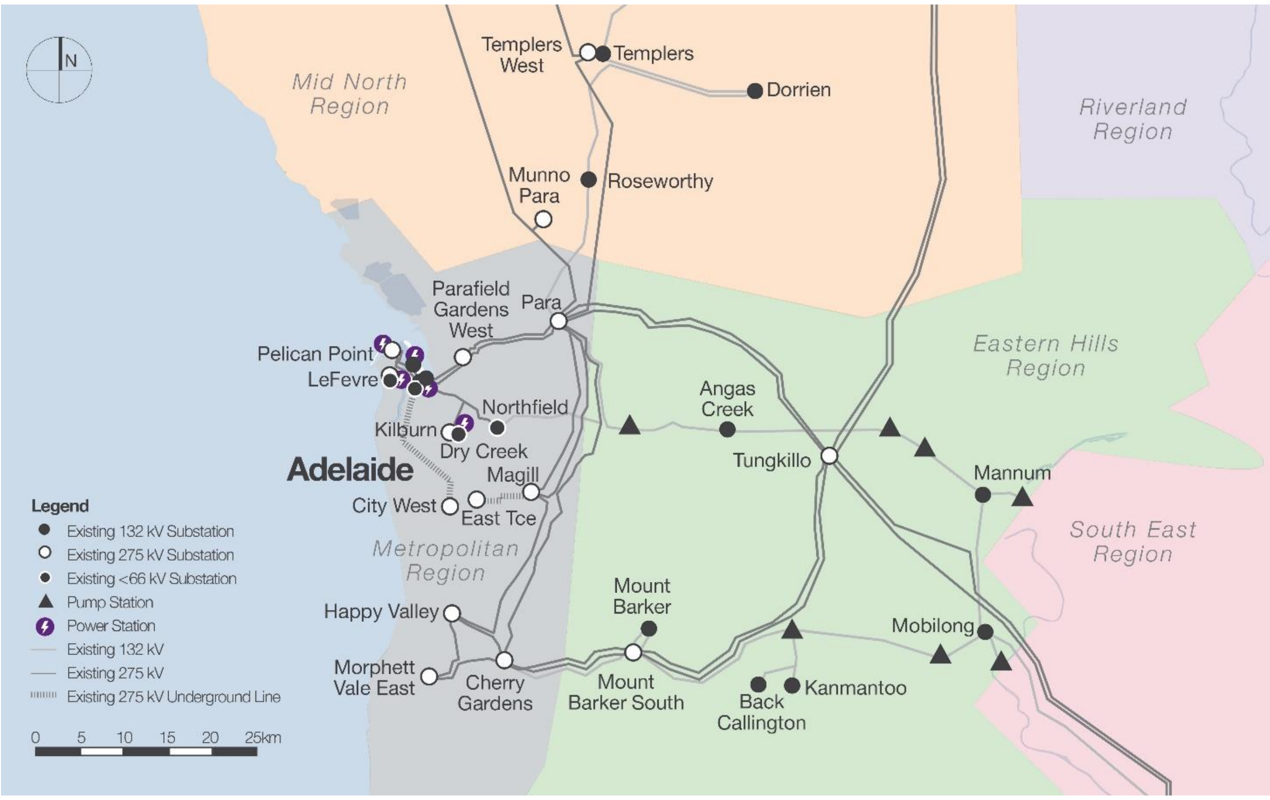
As ElectraNet develops new assets, we engage with local communities and strive to build productive and lasting relationships.

We recognise the importance of effectively engaging with community stakeholders to minimise the impact of our infrastructure when we plan, build and operate the electricity transmission assets that power homes, businesses and the economy.

Our network

South Australia's electricity transmission network (over page) covers an area of more than 200,000 square kilometres.

This network consists of 5,600 circuit kilometres of transmission lines and underground cables, together with 91 substations and switchyards, predominantly operating at 132 kV and 275 kV. An underlying telecommunications network, utilising mainly radio and optical fibre, supports the operation of the network.



South Australian electricity transmission network map - metropolitan area


Prominent Hill
Olympic Dam North
Olympic Dam West
Roxby Downs
Leigh Creek
Leigh Creek Coalfield
Leigh Creek South
Upper North Region
Woomera
Pimba
Carrapateena Mine
Pernatty (future)
Mount Gunson
Mount Gunson South (future)
SOUTH AUSTRALIA
Neuroodla
NEW SOUTH WALES
Port Augusta
Emeroo
Davenport
Corraberra
Mid North Region
Eyre Region
Cultana
Whyalla Central
Stony Point
Baroota
Wudinna
Mount Lock
Middleback
Port Pirie
Bungama
Belalie
Canowie
Willalo
Mokota
Redhill
Riverland Region
Brinkworth
Mount Millar
Snowtown
Yadnarie
Blyth West
Clare North
Mintaro
Robertstown
North West Bend
Kadina East
Waterloo
Hummocks
Monash
Murraylink
Berri
ENLARGEMENT AREA
Ardrossan West
Templers
Roseworthy
Dorrien
Munno Para
Port Lincoln
Para
Pelican Point
Tungkillo
Sleaford
Dalrymple North
Dalrymple
Adelaide
Magill
Mannum
Mobilong
Morphett Vale East
Mount Barker
Cherry Gardens
Tailem Bend
Metropolitan Region
South East Region
Legend
Existing 132 kV Substation
Existing 275 kV Substation
Existing <66 kV Substation
Wind Farm
Solar Farm
Battery Power Reserve
Power Station
Existing 132 kV
Existing 275 kV
Existing 132 kV (owned by others)
Existing 275 kV (owned by others)
Eastern Hills Region
Keith
Black Range
VICTORIA
Kincraig
Penola West
Snuggery
Mayurra
South East
Blanche
Mount Gambier
Haywood
N
0 25 50 75 100 125km

South Australian electricity transmission network map

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Executive Summary

South Australia's transmission network plays a major role in the State's electricity supply, in an environment of unprecedented change.

With world-leading levels of intermittent renewable energy compared to demand, South Australia is at the forefront of energy transformation.

ElectraNet understands the critical importance of system security and reliability as Australia's energy supply transitions to a lower carbon emissions future. Our annual planning process has focussed on ensuring system security and reliability during this time of transition and sought to pre-empt network obstacles or opportunities, and ensure efficient plans are in place to accommodate them.

This South Australian Transmission Annual Planning Report summarises the outcomes of this planning process, including information on the current capacity, connection opportunities, and emerging limitations of South Australia's electricity transmission network. It covers a ten-year planning period and describes the current network, demand projections, emerging network limitations or constraints, and information on completed, committed, pending and proposed transmission network developments.

We also look further ahead, as we consider AEMO's Integrated System Plan (ISP) and National Transmission Network Development Plans, and assess potential major developments over a twenty-year period.

This report includes ElectraNet's response to the challenges that face South Australia's changing electricity system. This includes:

- continuation of a Regulatory Investment Test for Transmission (RIT-T) to investigate the feasibility of a new electricity transmission interconnector between South Australia and the Eastern States
- work that we are doing with the Australian Energy Market Operator (AEMO) to address the changing requirements for system strength, inertia, and frequency control to manage system security,
- continuation of a RIT-T to investigate electricity supply options for the Eyre Peninsula, and
- commissioning of a grid-scale battery energy storage project to support higher levels of intermittent renewable energy.

Our network planning considers a wide range of potential future scenarios and developments.

This report is designed to inform stakeholders and help potential users of electricity and generators to identify and assess opportunities in the SA region of the National Electricity Market (NEM).

The key planning outcomes in this report are summarised in the table over the page.

High level summary of key planning outcomes

Planning focus	Key outcomes
National transmission planning	We have published a draft report for the South Australian Energy Transformation RIT-T, which shows that a new 330 kV interconnector between South Australia and New South Wales, with a transfer capacity of about 800 MW, is expected to deliver net market benefits from the early 2020s, with associated reductions in electricity prices. This work has been closely coordinated with the development of AEMO's ISP.
Existing interconnector capacity	The full 650 MW nominal transfer capacity of Heywood Interconnector is expected to be released in 2018. At times, transfers over the Heywood interconnector will be limited by other network constraints. Our Network Capability Incentive Parameter Action Plan includes the planned implementation of dynamic line ratings, and the planned installation of an additional 100 Mvar 275 kV capacitor bank at the South East substation to alleviate forecast congestion on the Heywood interconnector due to voltage stability limits, providing increased availability of the full capacity.
System strength and system inertia	AEMO has identified a system strength gap (i.e. a fault level shortfall) in South Australia. We are working with AEMO to develop an appropriate scope for the installation of a number of synchronous condensers on the transmission network by 2020, to meet South Australian system security needs now and into the future. AEMO plans to publish a NEM-wide assessment of system inertia adequacy in June 2018. We will work to incorporate any minimum requirements for South Australian inertia in the synchronous condensers that are needed to meet the identified system strength needs.
Connection points	The existing network support arrangement at Port Lincoln expires in December 2018. ElectraNet will soon complete a RIT-T which is investigating the most cost effective long-term way of continuing to meet the required reliability level at Port Lincoln, while considering the possibility of future mining or renewable generation development in the region. A new connection point has been forecast by SA Power Networks to be required at Gawler East in about 2023. Development of this new connection point will occur subject to the successful completion of a Regulatory Investment Test for Distribution and receipt of a formal connection request from SA Power Networks. All other connection points are forecast to remain within design and equipment limits for the duration of the planning period, unless new large customer connections occur.
Market benefit opportunities	A range of market benefit driven projects is proposed to reduce the impact of existing and forecast constraints and increase the capability of the transmission network, providing net market benefits. This includes a range of projects to increase the usable rating of lines and transformers, increase voltage stability limits, and improve power flows to alleviate congestion that form ElectraNet's 2018-19 to 2022-23 Network Capability Incentive Parameter Action Plan. We also plan to improve the circuit breaker arrangement at Robertstown, to reduce significant operational constraints and costs during outages of plant and equipment.
Maximum demand	Further network capacity in the Upper North region is needed to supply OZ Minerals' new and existing mines in the area. We are considering options that would also provide capacity for potential future developments in the Upper North, for example additional mine developments or solar farms. Increased transmission network capacity may also be needed on the Eyre Peninsula if potential significant load connections occur there in the future. Elsewhere, maximum demands are forecast to remain at about their present level. The remaining areas of South Australia's transmission network are projected to remain adequate to supply forecast maximum demand for the duration of the planning period.

Planning focus	Key outcomes
Minimum demand	The minimum demand supplied by the transmission network is forecast to continue to decrease. A 50 Mvar, 275 kV reactor is being installed at Templers West during 2018 to prevent voltage levels from exceeding equipment ratings if an unplanned contingency event was to occur at times of low demand. Beyond this, the synchronous condensers that are planned to meet the identified system strength and potential inertia needs are expected to also enable improved system voltage control. A further 50 Mvar, 275 kV reactor may need to be installed between 2023 to 2028, to again prevent voltage levels from exceeding equipment ratings if an unplanned contingency event was to occur at times of low demand.
Maximum fault levels	Fault levels are forecast to remain within design and equipment limits for the duration of the planning period.
Emergency control schemes	A new System Integrity Protection Scheme (SIPS) has been implemented to reduce the likelihood that an outage of multiple generation units in South Australia will result in an outage of the Heywood interconnector between South Australian and Victoria. AEMO's Power System Frequency Review (PSFRR)[1] identified a need for upgrading the existing SIPS. We are working with AEMO on the scope of works to upgrade the SIPS to a Wide Area Protection Scheme (WAPS).
Network asset retirements and de-ratings	We plan to address the condition of a range of assets on South Australia's electricity transmission network. Significant programs are based on an assessment of asset condition, risk, cost and performance, and include the replacement of substation lighting and infrastructure, protection systems, transformer bushings and isolators, and the refurbishment of motorised isolators, transmission line support systems, insulators, and conductors.

1 Available from https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Power-System-Frequency-Risk-Review.

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1. A changing electricity system

1.1 Renewable generation development is continuing in South Australia

Driven by renewable energy policies, rapidly evolving technology and changing customer needs, South Australia has reached world-leading levels of renewable energy penetration as a percentage of peak demand, through large scale wind generation developments and rooftop solar photovoltaic (PV) installation.

Renewable energy generation continues to grow, with approximately 51% of energy generated in South Australia now coming from renewable energy sources, with more renewable energy generation under construction. Federal and state government policies are expected to continue to drive further uptake of renewable energy. Overall, the generation mix in South Australia has changed substantially in recent years (Figure 1-1 and Figure 1-2).

South Australia has limited interconnection to the rest of the National Electricity Market (NEM) and so has greater exposure to the system security challenges posed by high levels of renewable generation, compared other parts of the world such as Denmark, which have strong interconnection to other large power systems.

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

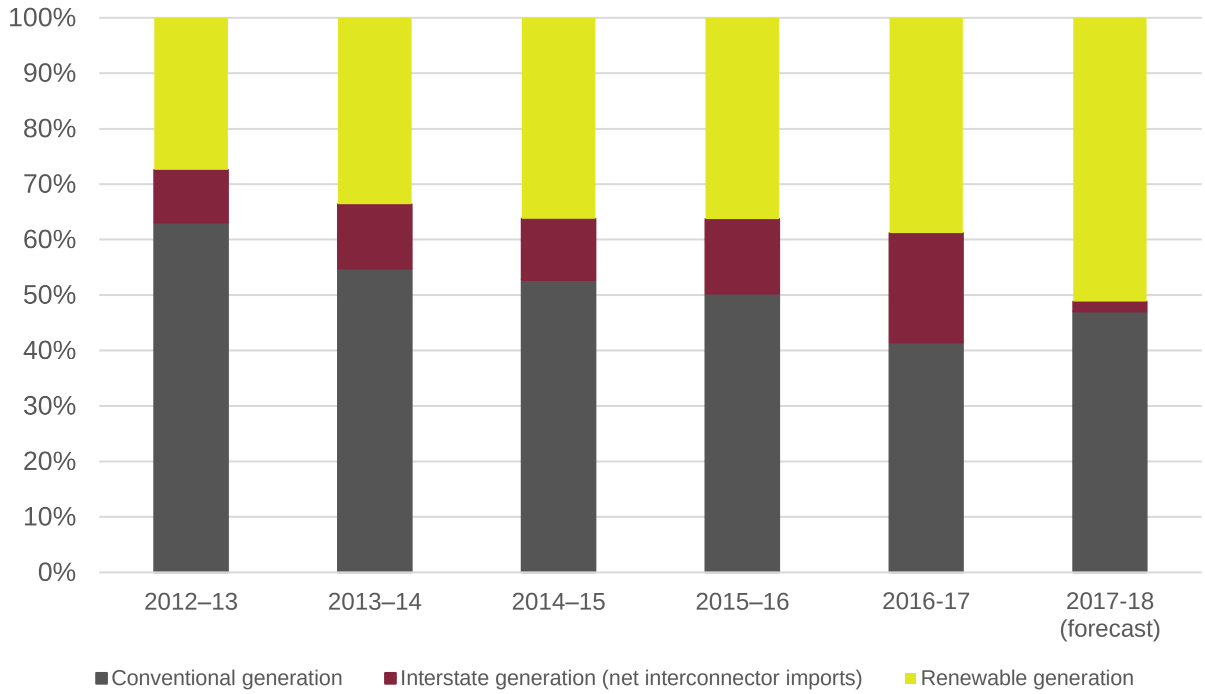

Figure 1-1: Energy generation patterns have changed significantly in recent years

Source: The Australian Energy Market Operator's (AEMO's) 2017 South Australian Historical Market Information Report, and AEMO's 2017 South Australian Generation Forecasts report

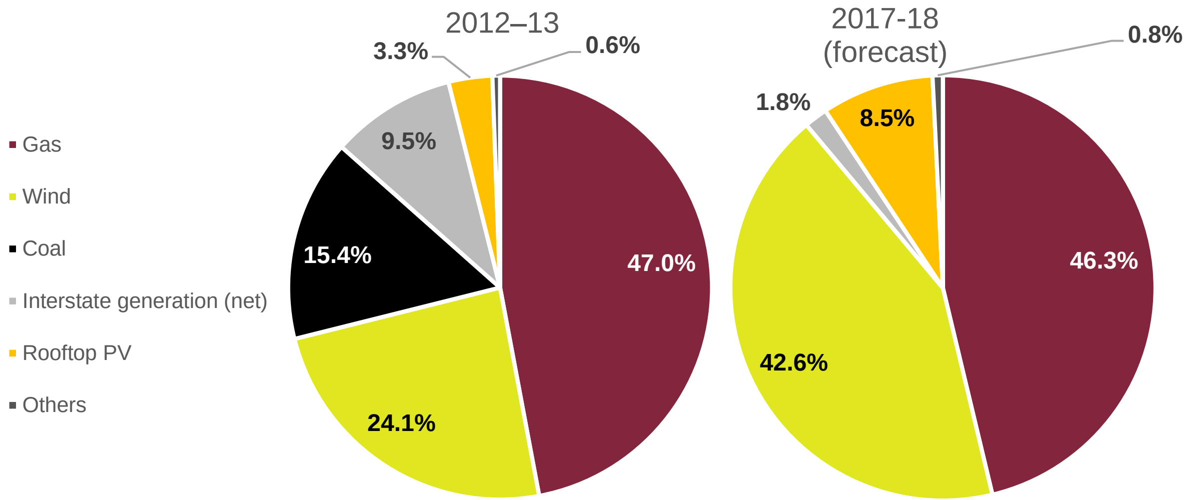

Figure 1-2: Renewable energy generation from wind and solar rooftop PV has increased significantly over the last five years

Source: AEMO's 2017 South Australian Historical Market Information Report, and AEMO's 2017 South Australian Generation Forecasts report

1.2 Future directions and key priorities

It is vital that we continue to engage with customer representatives and other stakeholders to ensure we understand their experiences, priorities and points of view. This enhances our ability to plan and evolve the transmission network so it delivers the greatest possible value.

We continue to monitor emerging industry trends and developments and undertake scenario based planning, and shorter term assessment of emerging system security issues, to inform our ongoing decision making.

The following directions and priorities are intended to provide guidance on the practical ways we plan for the future of the network.

1.2.1 The transmission network will continue to play an important role into the future to support safe, reliable and affordable electricity supply

Directions

Customers are seeking material electricity price reductions

Customers and stakeholders want ongoing and genuine engagement

Grid maximum demand remains steady

Grid minimum demand is reducing

Grid supplied energy demand remains flat or declining

The grid needs to be maintained to deliver services, efficiently, safely and reliably

The grid needs to support economic growth and the transition to a low-carbon future

Priorities

Create a sustainable network for the long term by seeking to deliver the most cost effective solutions for customers

Show leadership in favourably influencing the delivered price of energy

Build trust by undertaking ongoing, genuine engagement with customers, consumer representatives and other stakeholders

Focus on efficiently prolonging asset life wherever possible and deferring major replacement while maintaining reliability

Maintain network reliability as safely and efficiently as possible through a risk-based

Directions	Priorities
Maximum demand driven investment is expected to be minimal Network utilisation will continue to fall, placing ongoing pressure on unit costs The age and condition of the network will be an increasing challenge to manage	approach Retire assets unlikely to be needed in the future only where economic to do so Apply accelerated depreciation on a targeted basis where a clear case exists (e.g. assets no longer required due to generation closures) Explore more efficient and transparent pricing arrangements to promote clarity and stability Manage any major uncertain network developments (e.g. to support mining loads) as contingent projects within the regulatory framework where appropriate to do so

1.2.2 The ongoing uptake of distributed energy resources by customers is changing the role of the grid

Directions	Priorities
Further significant installation of rooftop solar PV capacity and distribution-connected solar PV farms is expected, with periods of net zero grid level demand expected within a decade The impact of energy storage at a customer level is likely to be driven initially by government policies. The emergence of virtual power plants, which aggregate distributed energy resources, may have a significant impact on the grid over the planning horizon The uptake and impact of electric vehicles by customers is expected to be modest over the planning horizon Distributed energy growth rates are uncertain and will be driven by customer preferences, technology costs and policy support Forecasting technology uptake is challenging and scenario planning is important to consider a range of possible futures	Actively monitor and respond to trends, developments and expectations to ensure the grid is ready to meet the needs of customers as distributed energy technology is adopted Plan for emerging technologies in order to maintain safe, reliable and secure supply under reasonably foreseeable demand and supply conditions

1.2.3 The generation mix is changing, creating new challenges for the secure and reliable operation of the grid

Directions	Priorities
The withdrawal of conventional generators is placing a greater reliance on wind generators, other renewable energy technologies, and interconnectors The operation of the network is becoming more complex and challenging The potential consequences of state-wide outages after rare interconnector separation events is severe The transmission network needs to support the integration of high levels of renewable generation while maintaining secure and reliable electricity	Develop efficient solutions to maintain a secure and reliable system with less conventional generation Investigate further interconnection opportunities which enhance benefits to customers by facilitating market competition, and supporting competitive, secure and stable power supplies, and renewable generation exports

supply

1.2.4 New technologies are changing the way some network services can be delivered

Directions	Priorities
Storage technology is likely to become economic in the medium term at a grid scale, offering a new potential option to efficiently deliver network and ancillary services	Continue to investigate the application of grid scale energy storage and gain experience in the deployment and operation of this emerging technology
In a flat demand environment, non-network solutions and new technologies such as storage can offer more economic alternatives to traditional network options	Actively pursue cost effective demand side solutions and innovations in the deployment of non-network solutions and new technology
Ongoing advances in information technology and network control systems provide access to a wealth of 'big data' to inform network decision making	Adopt best practice data analytics to improve decision making in asset management and network operation

1.3 Strategic South Australian transmission developments

ElectraNet is pursuing a number of strategic initiatives to support the energy transformation that is occurring in South Australia.

1.3.1 Increase interconnection with the rest of the NEM

Increased interconnection within the NEM is vital to achieving affordable and reliable electricity supplies by harnessing the diversity of available supply across different regions, while enabling the increasing choice and long-term sustainability valued and desired by electricity customers.

ElectraNet is progressing the South Australian Energy Transformation Regulated Investment Test for Transmission (RIT-T) to consider interconnector and network support options aimed at reducing the cost of providing secure and reliable electricity in the near term, while facilitating the longer-term transition of the energy sector across the NEM as a whole to low emission energy sources.

ElectraNet has now published the Project Assessment Draft Report (PADR) for this RIT-T.[2]

Our investigation has been undertaken in consultation with, and with the support of AEMO as the national planning body, and Jurisdictional Planning Bodies AEMO (Victoria), Powerlink (Queensland) and TransGrid (New South Wales).

A key development since the publication of the Project Specification Consultation Report (PSCR) in November 2016 has been the development by AEMO of the Integrated System Plan (ISP) that provides a 'roadmap' for the transition of the energy sector, in response to a recommendation of the *Independent Review into the Future Security of the National Electricity Market* (Finkel Review). Finkel highlighted that additional interconnection within the NEM was likely to form a key feature of the transition, and would help to unlock low emission generation Renewable Energy Zones (REZs).

2 Available from electranet.com.au.

ElectraNet considers it essential that the outcomes of the SA Energy Transformation RIT-T are fully coordinated with the ISP to deliver outcomes that are best for the NEM as a whole, and in the interests of electricity customers. We have been working closely with AEMO to achieve the required coordination.

A new interconnector between South Australia and New South Wales has been confirmed by AEMO in the ISP as an important element of the 'roadmap' for the NEM, and as one of its immediate priorities that would deliver positive net market benefits as soon as it can be built.

The SA Energy Transformation RIT-T is the process through which a more detailed economic cost-benefit assessment is undertaken to identify the most appropriate option that delivers the greatest net market benefits.

In assessing options under the RIT-T, we reflected the assumptions adopted by AEMO in the ISP in all material respects. We also took into account the complementary investments identified by AEMO as part of the ISP, in particular the investments being considered by AEMO's Western Victoria Renewable Integration RIT-T and the identification of priority REZs in the Riverland and Murray River areas of South Australia and New South Wales.

In addition to the development of the ISP, there has been a continual stream of other important changes to regulations and policies since publication of the SA Energy Transformation PSCR, affecting both the NEM as a whole, and South Australia specifically (Figure 1-3). These changes have a material impact on both the identified need for the investment being considered in the RIT-T, as well as the assessment of the costs and benefits of different options to meet this need.

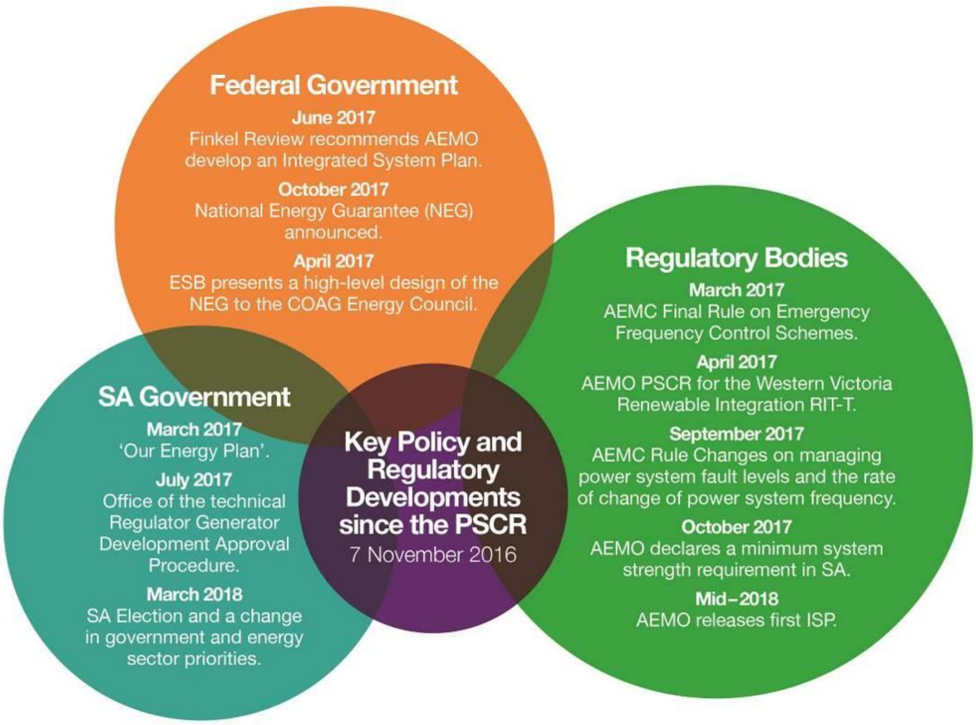

Figure 1-3: Key policy and regulatory developments since release of the SA Energy Transformation PSCR

Given the substantive and at times uncertain nature of these changes, we delayed publication of the PADR to ensure that the changes were properly understood and reflected in our analysis and to ensure our work is fully coordinated with national planning processes.

We have now published the PADR to release the draft results of our assessment, which take into account the above changes, in conjunction with publication by AEMO of the inaugural ISP.

The identified need for the SA Energy Transformation RIT-T is to create a net benefit to consumers and producers of electricity and support energy market transition through:

- lowering dispatch costs, initially in South Australia, through increasing supply options across regions
- facilitating the transition to lower carbon emissions and the adoption of new technologies through improving access to high quality renewable resources
- enhancing security of electricity supply, including management of inertia, frequency response and system strength in South Australia.

Overall, this identified need remains consistent with that stated in the SA Energy Transformation PSCR, with the exception being a refinement in how system security is considered, consistent with the development of new policies and near term responses to manage system security.

In particular, the declaration by AEMO on 13 October 2017 of a system strength gap in South Australia is leading to the fast-track implementation of a synchronous condenser solution that is expected to be in operation by 2020 (sections 1.3.2 and 7.4.1). This solution is built into the base case for consideration of interconnector and 'non-interconnector' options in the SA Energy Transformation PADR.

Given the new policies and requirements, and the commitments they have led to, the system security component of the identified need for the SA Energy Transformation RIT-T has evolved from avoiding unserved energy in South Australia due to risks posed by insufficient system security, to instead further enhancing system security, over and above these requirements.

ElectraNet has investigated variants of four credible options to address the identified need, comprising both a local South Australian 'non-interconnector' option as well as options involving new interconnectors to the three neighbouring states.

Both the interconnector and non-interconnector options contribute to improving system security. These improvements are captured in the RIT-T assessment through their impact in alleviating two existing network constraints: the RoCoF constraint on the operation of the existing Heywood interconnector and the cap on non-synchronous generation output in South Australia (see section 4.1 for a summary of the impact these constraints had during 2017).

The benefit of relieving these constraints is captured in the cost benefit analysis as part of the fuel cost savings in South Australia, as alleviating these constraints reduces the need to dispatch higher cost gas generation in South Australia.

Our RIT-T assessment shows that of all options considered a new 330 kV interconnector between mid-north South Australia and Wagga Wagga in New South Wales, via Buronga

(Figure 1-4), is expected to deliver the highest net market benefits. This finding is robust across a wide range of future scenarios and sensitivity tests.

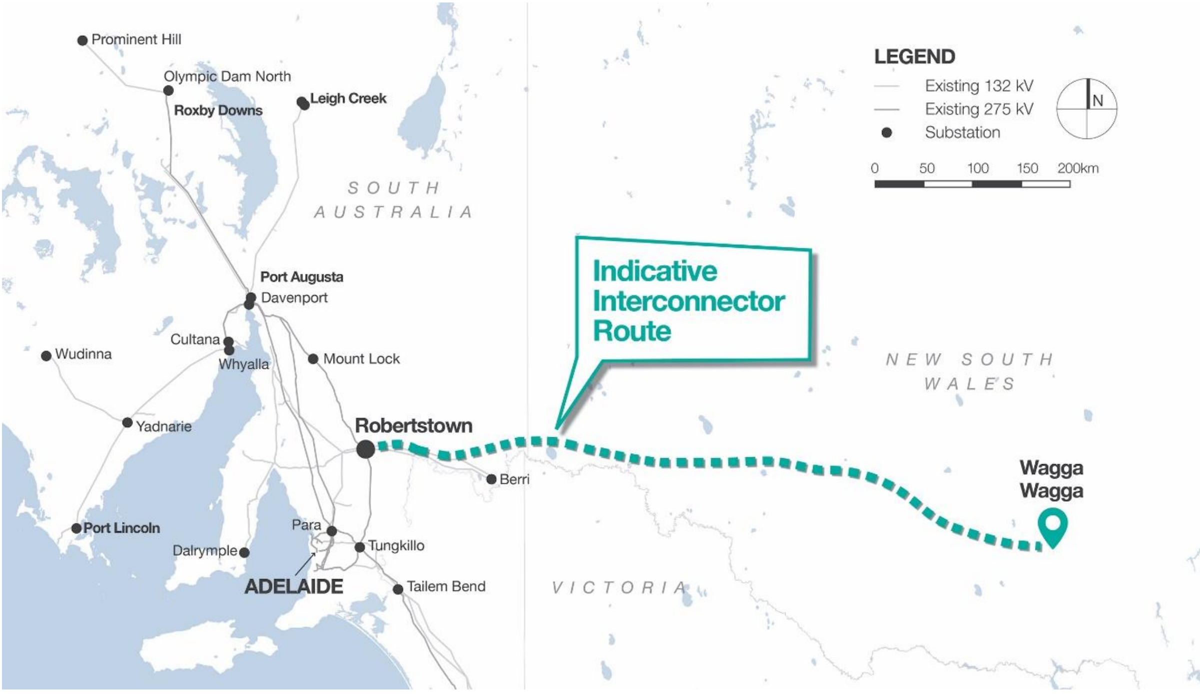

Figure 1-4: Draft preferred option for the SA Energy Transformation RIT-T

This preferred option[3] is estimated to deliver net market benefits of around $1 billion over 21 years (in present value terms)[4], including wholesale market fuel cost savings of around $100 million per annum putting downward pressure on wholesale electricity prices with flow on benefits to customer pricing. Independent modelling by ACIL Allen estimates an overall reduction in the average annual residential customer bill of up to about $30 in South Australia and $20 in New South Wales.

The new interconnector is estimated to cost $1.5 billion across both South Australia and New South Wales and could be delivered by 2022 to 2024. Section 7.3.1 provides more detail regarding the identification of the preferred option.

1.3.2 Maintain the strength of the South Australian electricity system

South Australia has become a world leader in intermittent renewable energy generation. This means that traditional synchronous generation sources, such as gas-fired units, now operate less often.

A secure power system needs adequate levels of system strength and inertia, which to date have been provided by traditional synchronous generators.

System strength relates to the ability of a power system to manage fluctuations in supply or demand while maintaining stable voltage levels. Inertia relates to the ability of a power

3 The preferred option is defined as the option that maximises net market benefits under the RIT-T framework.

4 Broader benefits to the wider economic are additional to and beyond the scope of this RIT-T assessment, which is required to focus on the direct benefits to consumers and producers of electricity.

system to manage fluctuations in supply or demand while maintaining stable system frequency.

Both are important to ensure secure supply for customers. If there is not enough of these services within the power system, there is an increased risk of generator or system instability and supply interruptions.

In October 2017, the Australian Energy Market Operator (AEMO) declared a gap in system strength (i.e. a fault level shortfall) in South Australia. ElectraNet is required to use its reasonable endeavours to address this gap on an ongoing basis.

To maintain and manage the security of the power system, the system strength that has until now been supplied by traditional synchronous generation sources now needs to be provided by other means.

ElectraNet has been investigating options to address this gap to ensure we can provide customers with a reliable and secure power system, while also keeping costs down. Options include entering into contracts with existing conventional generators or installing synchronous condensers.

Following an analysis of these options through a generator tendering process and advice from independent energy market experts, the installation of synchronous condensers on the network has been determined to be the most efficient and least cost option.

A synchronous condenser operates in a similar way to large synchronous electric motors and generators. It contains a synchronous motor whose shaft is not directly connected to anything, but spins freely and is able to adjust technical conditions on the power system. Synchronous condensers are an important source of system strength and other services such inertia.

The implementation of a fast track approach to deliver a synchronous condenser solution has the support of AEMO, the Australian Energy Regulator (AER) and the South Australian Government. It is expected to be operational within 18-24 months.

Importantly, the solution is also anticipated to deliver customers a net saving equivalent to $18 to $20 per year on a typical South Australian residential electricity bill from the time of commissioning, as it avoids the increasing costs being incurred by AEMO in directing and compensating existing gas fired generators to manage the gap.

Detailed technical analysis is being undertaken in consultation with AEMO and manufacturers to determine the required number, size, specification, design, and location of the synchronous condensers to meet the system strength gap.

Section 7.4.1 provides further details.

1.3.3 Upgrade the Eyre Peninsula transmission system

We are exploring options for providing reliable electricity supply to the Eyre Peninsula most efficiently in the future, including 'future proofing' to accommodate potential developments in mining and renewable energy investment on the Eyre Peninsula.

The existing single-circuit 132 kV line serving the Eyre Peninsula has been in service since 1967 and several sections now require replacement works. In April 2018, the AER accepted our revenue proposal that included capital expenditure of about $80 million for these replacement works, and ongoing network support to provide backup supply to Port Lincoln.[5]

However, we will soon complete a RIT-T that is investigating whether there are more efficient supply options, including building new transmission lines. It is also considering the benefits of 'future proofing' the new transmission line options to provide flexibility for upgrading the network to operate at a higher capacity when needed at a later date.

We are investigating five broad options for supplying the Eyre Peninsula, including variants of these options. These range from maintaining equivalent capacity on the Eyre Peninsula as currently (ie, a single-circuit 132 kV line coupled with network support at Port Lincoln), through to upgrading the entire network to 275 kV, with two completely divergent network paths (including one going via Wudinna).

The RIT-T assessment published in the Eyre Peninsula Electricity Supply Options PADR in November 2017 showed that options that involve building a new double-circuit transmission line from Cultana to Port Lincoln, via Yadnarie, are expected to deliver the greatest net market benefits.

We are currently finalising our options assessment in accordance with the requirements of the RIT-T, and plan to publish a Project Assessment Conclusions Report (PACR) in July 2018.

Section 7.5.1 provides further details, including the options that are being considered.

1.3.4 Provide connection to the Upper North

The Upper North region in South Australia is characterised by long radial 132 kV and 275 kV transmission circuits.

The use of radial transmission circuits reduces the upfront costs to connect customers. However, while many loads or generators may tolerate a lower level of network reliability as an individual installation, when a number of loads or generation facilities are aggregated together, network reliability becomes of greater importance along with the ability to appropriately manage transmission system security.

AEMO's identification of two potential REZs in the upper north region (section 2.1.4) recognises that the region represents a significant renewable generation resource.

We are working to develop a high level strategy for network development in the Upper North region that will consider the potential to connect renewable generation, coupled with the on-going development of mining interests in the region.

5 AER, *ElectraNet Transmission Determination 2018 to 2023*, Final Decision, Attachment 6 – Capital Expenditure, April 2018, pp, 11-15.

1.3.5 Develop large-scale energy storage

Integrating battery storage into the electricity supply chain is an important step to capitalise on the uptake of environmentally sustainable renewable generation, at both customer and grid levels.

Being able to store large quantities of energy generated by intermittent wind and solar generators may provide commercial benefits by allowing this cheap energy to be used at times when the wind isn't blowing or the sun isn't shining. It may also help manage system security by enabling a fast and controlled release of energy in the event of an unexpected network disturbance.

ElectraNet's 30 MW 8 MWh ESCRI-SA battery energy storage system at Dalrymple substation will demonstrate how energy storage can strengthen the grid and improve reliability for the lower Yorke Peninsula (section 6.2.1).

The battery energy storage system has been built next to, and connected to, ElectraNet's Dalrymple substation, seven kilometres south-west of Stansbury. It achieved registration in the National Electricity Market in June 2018, with commissioning and the commencement of full operation planned for July 2018.

The battery system will work with AGL's existing 90 MW Wattle Point windfarm or local rooftop solar PV to provide back-up power in the event of an interruption to supply from the grid.

The battery will provide both regulated network services and competitive market services (Figure 1-5).

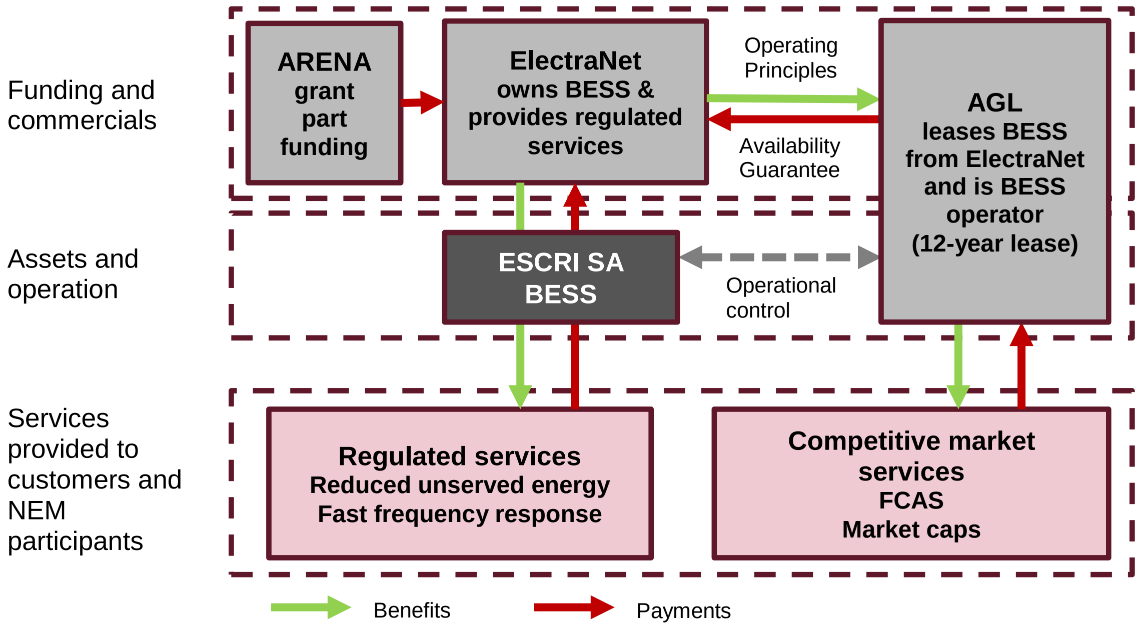

Figure 1-5: The ESCRI-SA battery energy storage system at Dalrymple will provide regulated and unregulated benefits

The regulated network service benefits will include:

- improved reliability for the lower Yorke Peninsula region by supplying power for approximately 2 hours following the loss of transmission supply, or longer if there is sufficient renewable generation from Wattle Point windfarm or local rooftop solar PV
- fast frequency response to reduce Heywood interconnector constraints and improve power system security by quickly injecting power into the grid following a disturbance

ElectraNet has leased the battery to AGL, who will operate it as a generator to provide competitive market services.

The competitive market services include the ability to participate in the cap trading[6] and Frequency Control Ancillary Services (FCAS) markets.

The project is part funded by the Australian Renewable Energy Agency (ARENA).

6 Cap trading is a market derivative/insurance product.

2. National Transmission Planning

2.1 Integrated System Plan

The Independent Review into the Future Security of the National Electricity Market (Finkel Review) recommended:

> By mid-2018, the Australian Energy Market Operator, supported by transmission network service providers and relevant stakeholders, should develop an integrated grid plan to facilitate the efficient development and connection of renewable energy zones across the National Electricity Market.[7]

ElectraNet has worked closely with AEMO to support the development of the 2018 Integrated System Plan (ISP). The ISP has clear observations and recommendations for the short-term development of the transmission network, which form the basis of an over-arching long-term strategy.

The 2018 ISP is not the end of the process, but rather the first of many steps, with updates in future years to reflect the dynamically changing nature of the power system and the need to continually innovate and evolve strategies for the future.

ElectraNet provided a range of network planning inputs to AEMO's ISP modelling process[8], supporting the development of the ISP through regular engagement and review of the long-term network development strategy and findings.

Throughout its development, AEMO conducted workshops and regular coordination meetings to incorporate input from the industry, and received a range of public submissions.[9]

The primary outcome of the ISP that relates to ElectraNet's network planning is the ISP network development plan. This plan sets out a long-term strategy for the efficient development of the NEM transmission network, and the connection of Renewable Energy Zones over the coming 20 years. This plan will be available on AEMO's website.[10] ElectraNet has reviewed, and supports, the ISP network development plan.

The following sections provide a short description of the specific outcomes that relate to the South Australian electricity transmission network.

2.1.1 System strength

The gap in system strength in SA that was formally identified by AEMO in October 2017 needs to be addressed.

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7 Finkel et al., 2017. *Independent Review into the future security of the National Electricity Market* – recommendation 5.1, available at http://www.environment.gov.au/energy/national-electricity-market-review.

8 AEMO. Integrated System Plan Assumptions Workbook. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan.

9 AEMO. Integrated System Plan Stakeholder Submissions. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan.

10 AEMO. Integrated System Plan. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan.

Refer to sections 1.3.2 and 7.4 for information regarding our current activity through which we are working with AEMO in this area.

2.1.2 Distributed energy resources orchestration

AEMO has identified a need to coordinate South Australian distributed energy resources from about 2024, to manage times of minimum demand on mild sunny days which are caused by the forecast increasing penetration of rooftop solar PV.

We will work with AEMO to explore how ElectraNet can contribute to achieving the required coordination of distributed energy resources.

2.1.3 South Australia to New South Wales interconnector

Interconnection between South Australia and New South Wales has been identified by AEMO in the ISP as having an overall net market benefit from the early 2020s.

The SA Energy Transformation RIT-T (sections 1.3.1 and 7.3.1) is the process through which additional interconnection from South Australia would be developed.

In assessing options under the SA Energy Transformation RIT-T, ElectraNet has sought to reflect the assumptions adopted by AEMO in the ISP as far as possible. ElectraNet has also taken into account the complementary investments identified by AEMO as part of the ISP, in particular the investments being considered by the Western Victoria Renewable Integration RIT-T and the identification of priority REZs in the Murray River and Riverland areas of South Australia and New South Wales.

2.1.4 South Australian Renewable Energy Zones

AEMO has identified 9 potential REZs in South Australia:

- South East South Australia
- Riverland (South Australia and New South Wales)
- Mid North South Australia
- Yorke Peninsula
- Northern South Australia
- Leigh Creek
- Roxby Downs
- Eastern Eyre Peninsula
- Western Eyre Peninsula.

Figure 2-1 shows a number of conceptual transmission network investments that would support the development of the identified REZs.

Figure 2-1: Potential long-term transmission system developments that would unlock identified potential South Australian Renewable Energy Zones

AEMO's ISP modelling indicates that until the end of the 2020s, new renewable generation will mostly utilise existing network capacity across the NEM. In South Australia, the ISP indicates that from now until 2030, new solar PV generation may choose to utilise existing network capacity in the Roxby Downs REZ.

Between 2030 and 2040, the ISP modelling indicates the further connection of new solar PV generation in the Roxby Downs, Eastern Eyre Peninsula, and Northern South Australia REZs, and the connection of new wind generation in the Mid North South Australia and South East South Australia REZs.

2.2 National Transmission Network Development Plan

Each year, AEMO publishes a National Transmission Network Development Plan (NTNDP) as part of its role as the national transmission planner. The NTNDP provides an independent, strategic view of the efficient development of the NEM transmission grid over a 20-year planning horizon.

As the Integrated System Plan's purpose and scope encompass those which would normally be covered in the NTNDP, the AER permitted AEMO to defer the release of the 2017 NTNDP and integrate it into the Integrated System Plan.

3. Demand forecast

Forecasting electricity demand and network loading conditions is important because transmission system projects take significant time to implement.

Each registered participant connected to ElectraNet's network is required to provide demand forecast information on an annual basis according to Schedule 5.7 of the Rules. ElectraNet uses this information and observed data (section 5.1) to forecast electricity demand (section 5.2).

3.1 Range of South Australian demands

The South Australian load profile is very 'peaky' in nature with relatively low energy content (Figure 3-1). This means that even though demand can exceed 3000 MW on hot summer days, demands between 1000 and 2000 MW are most common throughout the year. It is important to consider the peaky nature of demand if network augmentation to meet high demand is being considered. Given that very high demands only occur for a small fraction of the year, network augmentations can often be deferred or avoided by implementing non-network solutions, such as demand-side management and local generation support.

ElectraNet actively considers these non-network solutions together with transmission and distribution network augmentation options. In this way, we can deliver the overall least cost solution to customers.

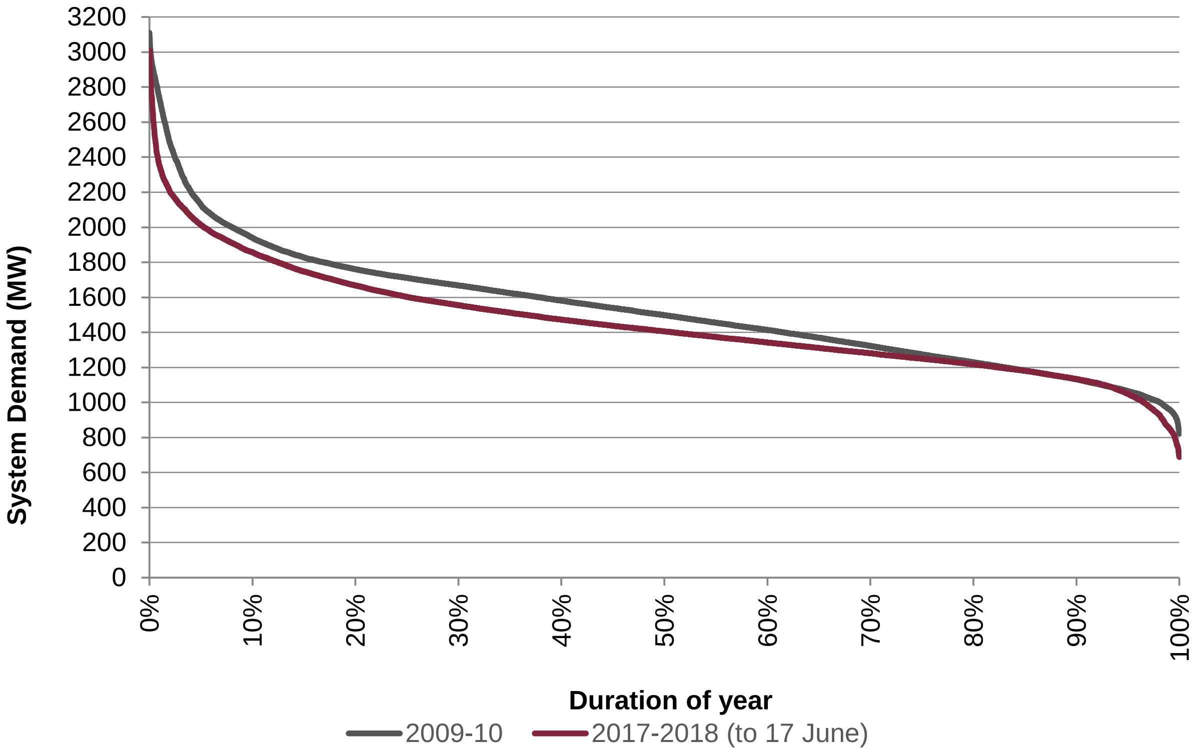

Figure 3-1: South Australian system wide load duration curves for 2009-10 and 2017-18 (to 17 June)

Note the very small percentage of time that demands above 2,500 MW are present on the South Australian transmission network. Maximum demands have remained at a similar level, whereas average and minimum demands have reduced from 2009-10 to 2017-18.

3.2 Demand forecasting methodology

ElectraNet considers that our customers are best placed to understand their needs. Given this, and in accordance with Rules clause 5.11.1, ElectraNet annually receives 10-year demand forecasts from SA Power Networks, and collaborates with AEMO to receive forecasts from direct connect customers. ElectraNet and SA Power Networks work together to determine and agree on any adjustments required to account for embedded generators and major customer loads connected directly to the distribution network.

Transmission network development plans are revised as connection point demand forecasts are updated. The development plans presented in this report are based on the connection point demand forecasts that were provided by SA Power Networks in October 2017. Details of the forecast can be found in ElectraNet's *2018 South Australian Connection Point Forecasts Report*.[11]

In June 2017, AEMO published maximum and minimum demand forecasts for South Australia as part of the 2017 *Electricity Forecasting Insights* (EFI).[12] These forecasts have been updated periodically by AEMO, most recently in March 2018. ElectraNet has used those forecasts to determine future needs for improved voltage control on the 275 kV Main Grid at times of maximum and minimum demand in South Australia.

AEMO also publishes connection point forecasts for South Australia. These forecasts, along with information on AEMO's methodology for connection point forecasting can be found on AEMO's website.[13]

ElectraNet compares its forecasts (as published in the *2018 Connection Point Forecasts Report*)[14] against AEMO's forecasts. At an aggregate level, AEMO's and ElectraNet's connection point forecasts are both reconciled to AEMO's State-level forecast from the 2017 *Electricity Forecasting Insights* during their development. Thus the connection point forecasts inherently reconcile to one another.

When individual connection point forecasts are considered there are some differences between the two forecasts, but neither forecast is consistently higher or lower than the other. The difference between the ElectraNet and AEMO connection point forecasts has no impact on network limitations or development plans within the next ten years. ElectraNet uses both the AEMO State-wide forecasts and its own connection point forecasts depending on the needs of a particular planning study.

3.3 2017-18 demand forecast

In most cases there is very little change in the projections of future demand for connection points compared to the demand forecast which was used as the basis for the augmentation plans presented in the 2017 Transmission Annual Planning Report. Our plans for individual connection points have not needed to be updated.

AEMO publishes annual state-wide demand forecasts for South Australia. Until 2016, this was published as part of a National Electricity Forecasting Report (NEFR). From 2017, the forecasts have been published as part of AEMO's Electricity Forecasting Insights.

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[11] Available from electranet.com.au.
[12] Available from aemo.com.au.
[13] Available from aemo.com.au.
[14] Available from electranet.com.au.

The most recent update to AEMO's EFI was published in March 2018. In it, AEMO found that:

- State-wide overall electricity demand is forecast to remain relatively flat, declining at an average forecast rate of 0.1% per annum across the forecast period, due to growth in energy efficiency measures and rooftop solar PV
- In contrast, driven by the forecast increasing penetration of embedded solar PV generation, minimum demand on the South Australian transmission network is forecast to continue to reduce rapidly, indicating that demand centres could actually provide net injection of generation into the South Australian transmission system during the middle of the day on mild, sunny weekends or public holidays, from about 2025-26.

AEMO's March 2018 EFI neutral growth forecasts for South Australian maximum and minimum demand are compared to the 2016 NEFR forecasts (that formed the basis of the plans presented in the 2017 Transmission Annual Planning Report) in Figure 3-2, along with the previous four or five years and current year of estimated actual maximum, average and minimum demands. Forecast average demands have been derived from AEMO's central forecast of energy consumption.

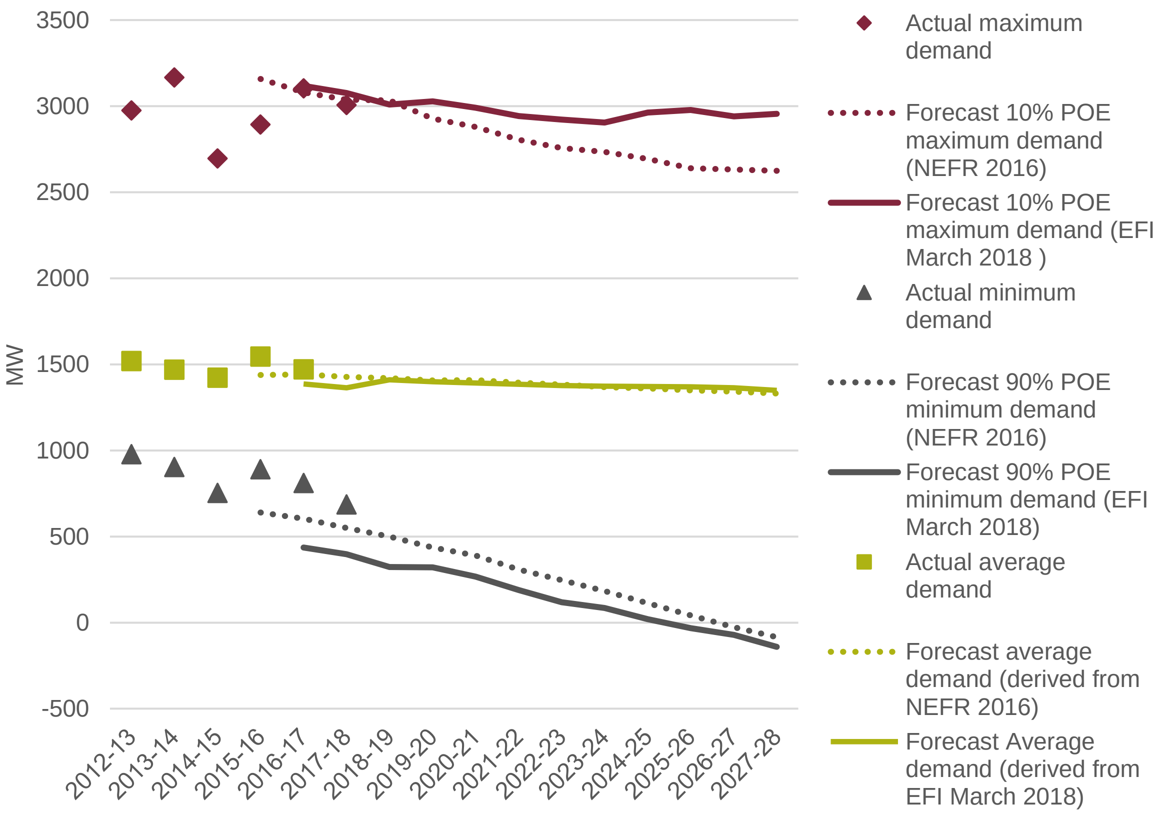

Figure 3-2: AEMO's 2016 NEFR and March 2018 EFI neutral growth forecasts

Source: AEMO 2016 NEFR, and AEMO March 2018 Electricity Forecasting Insights

3.4 Performance of 2017-18 demand forecasts for summer 2017-18

Temperatures over the summer are a key driver of maximum demand for electricity in South Australia. Consecutive days of high temperatures, such as those that make up a typical summer heat wave, can drive state-wide demands to levels of more than double the average.

The holiday period that begins at Christmas time and extends until Australia Day reduces the impact of high temperatures on demand, as do weekends and public holidays. For state-wide electricity demand to reach high levels, metropolitan Adelaide needs to experience high temperatures during summer, generally on weekdays outside of the holiday period.

Individual connection points, however, may experience isolated heat events, driving high localised demands independent of state-wide demand levels. This is especially possible in holiday regions, or in regions where local industry has a seasonal demand (for example, vintage time in wine regions).

According to the Bureau of Meteorology, average maximum Adelaide temperatures during the 2017-18 summer exceeded their long term summer average (Table 3-1). Highlights include:

- many Adelaide suburbs recorded temperatures over 40 °C on Sunday 28 January, the hottest day of the summer for the Adelaide region, with warmer than average temperatures recorded across most of the rest of South Australia
- state-wide demand reached a maximum of 3,008 MW on Thursday 18 January 2018: Adelaide recorded a maximum temperature of 42.8 °C on this day
- demand exceeded 2,700 MW on 6 occasions during the 2017-18 summer (Table 3-2).

Table 3-1: 2017-18 summer temperature data compared with long term trends

	December		January		February		March	
	Long term trend	2017-18	Long term trend	2017-18	Long term trend	2017-18	Long term trend	2017-18
Max temp (°C)	43.4	38.8	45.7	44.1	44.7	40.8	41.9	36.4
Date of max temp	19 Dec 2013	13 Dec 2017	28 Jan 2009	28 Jan 2018	2 Feb 2014	9 Feb 2018	6 Mar 1986	10 Mar 2018
Average max temp	27.3	27.9	29.5	32.6	29.5	30.6	26.5	27.5
Days* >30°C	9.8	9	13.5	18	12.6	15	8.3	10
Days* >35°C	3.7	6	6.4	11	5.5	8	2.6	2
Days* >40°C	0.7	0	1.8	4	1	3	0.1	0
Difference between 2017-18 average max and long term trend	0.6		3.1		1.1		1.0	

*Mean days for long term trend data, actual days for 2017-18 data

Source: Bureau of Meteorology

Table 3-2: Highest demand periods in summer 2017-18

Date	Maximum demand (MW)[15]	Maximum temperature (°C)	Temperature demand index (°C)
Thursday 18 January	3,008	42.8	37.2
Friday 19 January	2,858	43.7	38.2
Sunday 28 January	2,747	44.1	38.8
Wednesday 7 February	2,934	40.7	35.5
Thursday 8 February	2,913	40.5	36.2
Friday 9 February	2,852	40.8	36.9

A key high-level indicator of demand is the temperature demand index. It identifies temperature patterns that have the potential to deliver a 10% POE demand level.

SA Power Networks has previously determined that a threshold value of 38 (comprised of a 67% weighting to the day's maximum temperature, 18% weighting to the overnight minimum and a 15% weighting to the previous day's average temperature[16]) occurring on a weekday after Australia Day provides the necessary temperature conditions to achieve 10% POE at a state level.[17]

The temperature index exceeded 38 °C on two occasions during the summer. The highest value of the temperature demand index was 38.8 °C, on Sunday 28 January. The second highest value was 38.2 °C, on Friday 19 January.

Given that the days on which the temperature index exceeded 38 °C were each either on the weekend or in the holiday period, ElectraNet expects that the maximum State demand recorded during the 2017-18 summer is likely to be below the 10% POE maximum demand level.

The day of maximum demand was Thursday 18 January, which had a temperature index of 37.2 °C.

3.4.1 Connection point review

As the need for transmission reinforcement is often localised, ElectraNet and SA Power Networks review each connection point on the transmission system. During summer 2017-18, most connection points recorded maximum demands that were between 85% and 100% of their forecast 10% POE maximum demand.

15 These values include demand supplied by non-scheduled generation and embedded generation connected to the distribution network, but exclude demand provided by rooftop solar PV generation.

16 For calculation of the temperature demand index, ElectraNet has calculated the previous day's average temperature using the average of the 24 hourly temperature readings.

17 Analysis of data from over 100 years found that this threshold was exceeded 19 times over a ten-week period from 20 December to the end of February. Half of this period includes the summer holiday period and weekends. Hence, over the last 100 years, it can be assumed there have been 9–10 weather events above this threshold at times that are expected to result in 10% POE demand conditions. As high demand is primarily driven by extreme temperature conditions during non-holiday periods, a temperature index above 38 on a working day is considered an appropriate indicator of 10% POE demand conditions.

Seven bulk connection points met or exceeded 100% of ElectraNet's 10% POE connection point demand forecasts (Table 3-3), but all were still within the network capability. Five connection points failed to reach 85% of their 10% POE forecast (Table 3-4). The performance of measured connection point maximum demands compared with forecasts is generally in line with expectations.

ElectraNet and SA Power Networks' 2018 review of connection point forecasts will consider the impact of measured maximum demands from summer 2017-18.

Table 3-3: Recorded maximum demands more than 100% of 10% POE demand forecast in summer 2017-18

Connection point	ElectraNet 10% POE demand forecast (MW)	AEMO 10% POE forecast (MW)	Actual Maximum (MW)	Date and time of maximum demand (Market time)
Angas Creek	16.9	17.9	17.9	07/02/2018 19:00
Blanche	34.5	35.2	36.1	28/01/2018 17:30
Brinkworth	4.6	4.7	4.7	28/01/2018 17:30
Hummocks	14.1	15.0	14.1	07/02/2018 18:30
Leigh Creek South	0.8	1.1	1.0	18/12/2017 18:30
North West Bend	26.8	28.0	27.2	21/01/2018 18:00
Snuggery Industrial[18]	7.0	25.2	19.0	10/01/2018 19:00

Table 3-4: Recorded maximum demands less than 85% of 10% POE demand forecast in summer 2017-18

Connection point	ElectraNet 10% POE demand forecast (MW)	AEMO 10% POE forecast (MW)	Actual Maximum (MW)	Date and time of maximum demand (Market time)
Adelaide Central	212.0	214.0	174.0	19/01/2018 14:00
Southern Suburbs	652.5	668.1	543.2	19/01/2018 16:30
Dalrymple	8.0	7.3	6.2	18/01/2018 19:00
Davenport West	34.5	34.7	28.9	08/02/2018 18:30
Stony Point	0.2	0.2	0.1[19]	05/01/2018 21:30

18 Actual demands for this connection point are highly dependent on the output of embedded generation. The AMD of 7 MW is able to be temporarily breached and so the observed higher demand is not necessarily representative of a deficiency in the forecast. The observed actual maximum is well below the available capacity of the connection point transformers.

19 Actual maximum is within the margin of error of the 10% POE demand forecast

4. Forecast network and system constraints

4.1 Transmission network constraints in 2017

AEMO uses constraint equations to manage system security and market pricing. A constraint binds on dispatch when it alters the level of power from either a generator or an interconnector from what it would have been if there was no constraint. Generators (and interconnectors) can be either constrained on (above the level that would otherwise be set by the market) or constrained down (below the level that would otherwise be set by the market).

AEMO publishes the marginal value of a constraint when it binds. The marginal value indicates its impact on market prices, but this measure is only an approximation and can be misleading in some instances. At times, constraints that have a relatively small impact can report large marginal values due to interactions between the network limitation, price at the time and the bids of generators affected by the constraint.

ElectraNet has assessed the top binding network constraints that impacted transmission network and interconnector flows during the 2017 calendar year (Table 4-1). Constraints selected for assessment were in the top ten by impact on marginal value or by binding duration in 2017. Some constraints have been grouped as they manage the same network limit or operating condition. For example, two constraints might both manage the overload of the same network element for different contingency events.

Table 4-1: Constraint equations, descriptions and ranking

Where constraints are closely related to one another, they have been grouped together. Note that constraints used to manage frequency control ancillary services have not been included.

Constraint equation and description	2017 marginal value[20] (2016)	Rank by 2017 marginal value	2017 hours[21] binding (2016)	Rank by 2017 hours binding	Commentary
S_WIND_1200_AUTO Upper limit for South Australian wind farms of 1,200 MW at times of minimum South Australian conventional generation	4746491 (0)	1	397 (0)	3	Since 2017, AEMO has refined the requirements for minimum South Australian conventional generation and increased the upper limit for South Australian wind generation at such times to 1,295 MW This constraint could be alleviated by running more high inertia generators in SA, or by installing synchronous condensers (sections 1.3.2 and 7.4.1)
S_PLN_ISL2 Run Port Lincoln generators in accordance with Network Support Agreement	4278378 (988797)	2	26 (7)	44	ElectraNet dispatches this generation under a network support arrangement to supply the Port Lincoln demand when supply from the transmission network is unavailable We will soon complete a RIT-T investigating the most economical way of continuing to meet ETC reliability standards on the Eyre Peninsula after the existing network support arrangement expires in December 2018 (sections 1.3.3 and 7.5.1)
S_PLN_ISL32 Run Port Lincoln generators in accordance with Network Support Agreement	4152742 (239609)	3	26 (6)	45	
#OSB-AG_P_E Discretionary limit applied to New Osborne Power Station	2603885 (0)	4	205 (0)	7	AEMO invokes this constraint when needed to satisfactorily manage the transmission system
S>NIL_HUWT_STBG Avoid overloading the Snowtown to Bungama 132 kV line if an outage of the Hummocks to Waterloo 132 kV line was to occur	1227468 (968995)	5	97 (79)	15	ElectraNet improved the application of dynamic line ratings on the Snowtown to Bungama 132 kV line in May 2017, which has alleviated this constraint

20 Cost of constraint in any interval is limited to market price cap
21 Rounded to the nearest hour

Constraint equation and description	2017 marginal value[20] (2016)	Rank by 2017 marginal value	2017 hours[21] binding (2016)	Rank by 2017 hours binding	Commentary
N^^V_NIL_1 Limit transfers from New South Wales to Victoria to avoid voltage collapse if an outage of the largest Victorian generator or Basslink was to occur	736588 (42416)	6	1808 (82)	1	This constraint can limit the ability to transfer power from Victoria to South Australia on the Heywood interconnector AEMO monitors the performance of this constraint in its role as Victorian transmission planner
#TORRB2_P_E Discretionary limit applied to Torrens Island B Power Station	700900 (0)	7	167 (0)	10	AEMO invokes this constraint when needed to satisfactorily manage the transmission system
#NBHWF1_E Discretionary limit applied to North Brown Hill Wind Farm	691501 (524471)	8	54 (50)	21	AEMO invokes this constraint when needed to satisfactorily manage the transmission system
S_HALWF_0 Discretionary upper limit for Hallett Wind Farm generation of 0 MW	660008 (2675)	9	52 (1)	23	AEMO invokes this constraint when needed to satisfactorily manage the transmission system
S-SNWWF_0 Discretionary upper limit for Snowtown Wind Farm generation of 0 MW	608566 (31322)	10	46 (28)	27	AEMO invokes this constraint when needed to satisfactorily manage the transmission system
V::N_NIL_V2 Avoid transient instability if a trip of a Hazelwood to South Morang 500 kV line was to occur	127120 (71764)	36	433 (326)	2	This constraint can limit the ability to transfer power from South Australia to Victoria on the Heywood interconnector AEMO monitors the performance of this constraint in its role as Victorian transmission planner
V>>V_NIL_2A_R Avoid overload of the South Morang F2 500/330 kV transformer	137485 (136123)	34	290 (966)	4	This constraint can limit the ability to transfer power from South Australia to Victoria on the Heywood interconnector AEMO monitors the performance of this constraint in its role as Victorian transmission planner

Constraint equation and description	2017 marginal value[20] (2016)	Rank by 2017 marginal value	2017 hours[21] binding (2016)	Rank by 2017 hours binding	Commentary
V:S_600_HY_TEST_DYN Import from Victoria to South Australia on Heywood interconnector upper transfer limit of 600 MW	582677 (76535)	11	289 (182)	5	ElectraNet is working to incorporate the South Australian grid connected batteries into the System Integrity Protection Scheme (SIPS), after which AEMO plans to raise the import transfer limit on the Heywood interconnector to 650 MW
S>V_NIL_NIL_RBNW Avoid overload of the Robertstown to North West Bend No. 1 or No. 2 line during system normal conditions	112551 (127120)	39	283 (587)	6	This constraint limits the ability to export power from South Australia across Murraylink interconnector The uprate of the Robertstown to North West Bend No. 1 132 kV line in 2015 and the committed uprate of the Robertstown to North West Bend No. 2 and North West Bend to Monash No. 2 132 kV lines in 2018 (see section 6.2.3) will alleviate this constraint
S:V_500_HY_TEST_DYN Export from South Australia to Victoria on Heywood interconnector upper transfer limit	63489 (73402)	47	190 (1)	8	ElectraNet is working with South Australian wind farms to fully implement the Over Frequency Generator Shedding (OFGS) scheme that has been agreed with AEMO (section 8.1.2), after which AEMO plans to raise the export transfer limit on the Heywood interconnector to 650 MW
V::N_SMF2_V2 Avoid transient instability if a fault and trip of a Hazelwood to South Morang 500 kv line was to occur while the South Morang F2 500/330 kV transformer is out of service	52624 (436)	48	173 (2)	9	This constraint can limit the ability to transfer power from South Australia to Victoria on the Heywood interconnectorAEMO monitors the performance of this constraint in its role as Victorian transmission planner

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4.2 Emerging and future network constraints and performance limitations

Following recent increases in capability across the Heywood and Murraylink interconnectors (installation of series capacitors at Black Range and uprating of lines), the generally higher flows across both interconnector corridors are at times expected to remain constrained by network import and export limitations (Table 4-2).

The potential development of a new interconnector between South Australia and New South Wales, changing dispatch patterns of existing conventional generators, and further significant development of renewable energy generation in South Australia, could lead to significant changes in congestion patterns on the transmission network.

This will depend on future generator connection locations. The limitations that could bind as a result of such additional renewable generation connections are highlighted in Table 4-2. Where possible, references to other sections of this report are provided that contain information regarding projects or initiatives that would resolve or mitigate the forecast limitations.

Table 4-2: Forecast South Australian transmission network congestion

Limitation	Status/Timing indication	Affected Interconnector	Reference to potential mitigating project(s)
System strength limits SA wind farm generation to 1295 MW at times of SA minimum conventional generation	Existing	Intra-regional	Install synchronous condensers to increase South Australian system strength (section 1.3.2 and 7.3.1)
Lower South East Region: thermal ratings of 275 kV lines between Tailem Bend and Heywood	Forecast to occur after the full upgraded Heywood capacity is released	Heywood (import and export)	Apply dynamic line ratings to transmission lines between South East and Tungkillo (section 7.6.2)
Mid North Region: thermal ratings of 275 kV lines between Davenport and Para	Depends on future generation connections	Intra-regional	No project currently proposed. Consider removing plant limits and applying dynamic line ratings on the 275 kV lines between Davenport and Para
Mid North Region: thermal ratings of 275 kV lines between Davenport and Robertstown	Depends on future generation connections	Intra-regional	Remove plant rating limits from the Robertstown to Davenport 275 kV lines (section 7.6.3)
Mid North Region: thermal ratings of 275 kV lines between Robertstown and Tungkillo and between Robertstown and Para	Depends on future generation connections; could be exacerbated by a new SA to NSW interconnector	Intra-regional, new SA-NSW interconnector (import)	No project currently proposed. Consider tying Robertstown to Para 275 kV line in at Tungkillo, and applying dynamic line ratings to Robertstown to Tungkillo and Robertstown to Para 275 kV lines

Limitation	Status/Timing indication	Affected Interconnector	Reference to potential mitigating project(s)
Mid North Region: thermal ratings of 132 kV lines between Robertstown and North West Bend	Existing	Murraylink (export)	Establish a new interconnector between South Australia and the rest of the NEM (section 7.3.1)
Mid North Region: thermal ratings of 132 kV lines between Waterloo and Templers	Existing; could be exacerbated by future generation connections or by a new SA to NSW interconnector	Intra-regional	Trial modular power flow control elements on the Waterloo to Templers 132 kV line to relieve congestion (section 7.6.1)
Mid North Region: thermal ratings of 132 kV lines between Waterloo East and Robertstown	Existing; could be exacerbated by a new SA to NSW interconnector	Murraylink (export)	No project currently proposed. Consider implementation of a control scheme to open line if overloaded following a contingency event (see entry in Table 4-4)
North West Bend, Berri and Monash: voltage limitations	Existing	Murraylink (export)	No project currently proposed. Consider installing additional 132 kV switched capacitors at Monash to improve voltage levels at times of high transfer
Robertstown 275/132 kV transformers: thermal ratings	Depends on future generation connections; could be exacerbated by a new SA to NSW interconnector	Intra-regional and Murraylink (export)	Apply short term overload ratings to the Robertstown 275/132 kV transformers (section 7.6.7)
South East Region: thermal ratings of 275 kV lines between Tailem Bend and Tungkillo	Forecast to occur after the full upgraded Heywood capacity is released	Heywood (import and export)	Connect the Tailem Bend to Cherry Gardens 275 kV line at Tungkillo (section 7.6.5). Consider stringing vacant circuit to create third Tailem Bend to Tungkillo 275 kV line)
South East Region: voltage stability limitations	Existing, and forecast to occur after the full upgraded Heywood capacity is released	Heywood (import and export)	Install an additional 100 Mvar switched capacitor bank at South East (section 7.6.5)
Transient instability between South Australia and the rest of the NEM	Existing, and forecast to occur after the full upgraded Heywood capacity is released	Heywood and Murraylink (import and export)	Establish a new interconnector between South Australia and the rest of the NEM (section 7.3.1)

4.3 Potential projects to address constraints

A range of factors can impact on the efficient development and operation of the transmission network, such as the connection of significant new loads, a change in the nature of the generation fleet, or higher gas prices. Such developments may lead to network constraints that are efficient to address with network augmentation projects (or non-network alternatives) that provide a net market benefit.

ElectraNet has identified a range of potential future inter-regional and intra-regional market benefit projects (Table 4-3 and Table 4-4 respectively). Some of these projects would be required if new generation develops along the lines envisaged in the 2018 Integrated System Plan.

Other projects may be warranted if either the least-cost generator expansion changes or actual generator investment decisions do not follow the Integrated System Plan generator expansion forecasts. The specific projects that will provide net market benefits are often uncertain until actual generator investment decisions are made or there is sufficient information available to proceed with a RIT-T. Project timings have not been proposed or presented because of this uncertainty.

The potential projects (Table 4-3 and Table 4-4), whilst high level, have been identified through constraint and planning analysis. ElectraNet expects that these projects would reduce network congestion in the future and hence may deliver sufficient benefits to customers to warrant development. These projects may also lead to minor improvements in network reliability.

Table 4-3: Potential inter-regional market benefit projects

Project name	Drivers/value of potential project	Description of potential project	Capacity/benefit provided	Lead time	Cost ($M)
New AC Interconnector between South Australia (Robertstown) and New South Wales (Buronga – Wagga Wagga)	Increased wholesale market competition to put downward pressure on electricity prices in South Australia, improve system security, support development of renewable generation and reduce transmission losses	This is one of the interconnector options proposed in the South Australian Energy Transformation PSCR that was published in November 2016 The PADR and AEMO's Integrated System Plan, both being published in mid-2018, have identified that this is the preferred option for implementation in the early to mid-2020s	800 MW capacity increase on new interconnector, plus a 100 MW transfer capability increase on the existing Heywood interconnector	RIT-T in-progress 3-5 years detailed design and delivery	Around 1,500
New AC Interconnector between South Australia (Tungkillo) and Victoria (Horsham)	Increased wholesale market competition to put downward pressure on electricity prices in South Australia, improve system security, support development of renewable generation and reduce transmission losses	This is one of the interconnector options proposed in the South Australian Energy Transformation PSCR that was published in November 2016 Even though the PADR has not identified this to be the preferred option, it could still deliver market benefits in the longer term	650 MW capacity increase on new interconnector, plus a 100 MW transfer capability increase on the existing Heywood interconnector	2-3 years RIT-T 3-5 years detailed design and delivery	1,000 to 1,500
Upper South East network augmentation	Increased generation injection at Tailem Bend or Tepko, or market driven requirement for increased interconnector capacity in either direction	String vacant 275 kV circuit between Tailem Bend and Tungkillo and install dynamic reactive support at Tailem Bend	400-600 MW increase in line section capacity	1-2 years RIT-T 2 years delivery	40 to 60

Table 4-4: Potential intra-regional market benefit projects

Project name	Drivers/value of potential project	Description of potential project	Capacity/benefit provided	Lead time	Cost ($M)
New Davenport–Para High Capacity 275 kV Lines	Increased generation and/or loads through the Mid North, Eyre Peninsula, or Upper North	Replace one or both of the Davenport–Brinkworth–Para and the Davenport–Bungama–Blyth West–Munno Para–Para 275 kV lines with high capacity AC double circuit lines with twin conductors, possibly via Robertstown	1200+ MW capacity increase	1-2 years RIT-T 5 years easement acquisition, detailed design and delivery	300–600
Tie Robertstown to Para 275 kV line in to Tungkillo Substation	Increased generation through the Mid North, Eyre Peninsula, or Upper North or a new SA to NSW interconnector	Tie Robertstown to Para 275 kV line in at Tungkillo	Capacity increase depending on location of new generation	1-2 years detailed design and delivery	3-6
Increase Mid North 275 kV network transfer capacity	Increased generation in the Mid North, Upper North, or Eyre Peninsula	Various line uprating and application of dynamic line ratings depending on generator developments.	Capacity increase depending on location of generation and local network capability	1-2 years detailed design and delivery	<5 (total)
Reconfigure Mid North 132 kV network	Increased generation on the Mid North network	Various potential reconfiguration options depending on generator and load developments[22]	Capacity increase depending on location of generation and load	Dependent on location of generation and load	Dependent on location of generation and load

[22] A potential example is to investigate whether automatically taking out of service either the Waterloo to Waterloo East or the Waterloo East to Robertstown 132 kV line after a contingency event that causes one of them to be overloaded

5. Demand management and connection opportunities

Electricity supply in the South Australian region comes from local generation as well as the Heywood and Murraylink interconnectors.

AEMO's September 2017 Electricity Statement of Opportunities (ESOO) projected a tight supply-demand balance in parts of the NEM.[23] AEMO's modelling showed that generation reserves have reduced to the extent that there is a heightened risk of significant unserved energy over the next 10 years, compared with recent levels.

The ESOO projected that the highest risk of unserved energy due to inadequate generation reserves was for South Australia, along with Victoria, in 2017-18. In future years, AEMO projects reducing levels of potential unserved energy due to the forecast continued connection of renewable generation.

We encourage potential new generators or customers to contact our Corporate Development Team (connection@electranet.com.au) to discuss their needs.

In this section we outline connection opportunities for generators (section 5.1) and customers (section 5.2) and discuss the factors that influence them, followed by a summary of the opportunities (section 5.3). We also identify proposed new connection points (section 5.4), and information relating to projects for which network support solutions are being sought or considered (section 5.5).

5.1 Connection opportunities for generators

ElectraNet has conducted a high level assessment of the ability of existing transmission network nodes and connection points to accommodate new generator connections. We considered a range of demand, generation, and interconnector operating conditions to determine an indicative maximum generation capacity that could be connected without breaching existing line and transformer thermal ratings, under system normal and single credible contingency conditions.

However, this assessment is limited to a few operating conditions and does not attempt to define the amount and value of constraints that could be experienced in terms of energy lost by connecting generation at any particular location. We recommend that parties seeking connection to the network should carry out a detailed network access and market impact assessment.

Almost any point in the proximity of the Main Grid 275 kV transmission system should be suitable for a new generator to connect. In particular, several 275 kV substations in the Mid North represent strategic locations close to fuel resources, including wind. However, proponents should be mindful of the risk of clustering and resulting potential issues with system security and dispatch constraints.

Sites that are electrically favourable for connecting generation are located along the 275 kV backbone from Port Augusta (near Davenport and Cultana) to South East (near Penola and Mount Gambier). However, connection of generation anywhere from Tungkillo through to Tailem Bend and South East will directly impact the ability to import real power from Victoria and the rest of the NEM.

23 Available from www.aemo.com.au.

In the metropolitan region, population density limits the ability to economically extend the network. Also existing fault levels (Appendix E) are approaching the plant capability limits of both ElectraNet's and SA Power Networks' assets, particularly in the vicinity of Torrens Island, LeFevre, Kilburn, Northfield, Magill and within the Adelaide central business district (CBD). Therefore, while the existing Metropolitan 275/66 kV system otherwise has capacity to accept new generation connections, this could accelerate the need for major augmentation and/or replacement of existing transmission and distribution assets to address fault level issues.

We have assessed the ability to accommodate additional generation for eight different system conditions (next page).

At each location, the output of a new generator was gradually increased, while we considered the impact of maintaining the supply-demand balance by either adjusting interconnector flows, or displacing conventional generation in the metropolitan area. The impact of existing run back schemes was considered in the assessment (where practicable).

System conditions three to eight have been assessed with minimum conventional generator units in service. This has been modelled as two Torrens Island Power Station B units, one Pelican Point gas turbine and one Pelican Point steam turbine, both New Osborne power station units, and the largest Quarantine Power Station unit.

At each location, and for each considered system condition, simulations stopped when a voltage limitation or a thermal overload was observed on a line or transformer, with single credible contingencies considered.

There are several factors that may impact the ability of ElectraNet's transmission network to accommodate significant amounts of new generation in the future:

- the main works for the Heywood interconnector upgrade were completed in July 2016, and 600 MW in available transfer capacity has been released so far.[24] The full future 650 MW capacity is included in the calculation of indicative generator connection capability

- the incremental upgrades along key transmission corridors that are included in ElectraNet's Network Capability Incentive Parameter Action Plan (NCIPAP) for the 2018-19 to 2022-23 period (section 7.6), would further alleviate forecast thermal constraints. This would enable the further deployment of generation in South Australia

- opportunities to minimise intra-regional transmission constraints by implementing projects that deliver positive net market benefits are assessed by ElectraNet on an ongoing basis. These projects would generally increase the amount of generation that could be connected not considering transient/dynamic issues

- an increase in the generation dispatched at one connection point would directly reduce the additional generation dispatch that could be accommodated at other connection points, particularly for connection points in close electrical proximity, e.g. dispatch of a new generator connected to Yadnarie may limit the dispatch of generation at Wudinna or Port Lincoln, and

[24] The full 650 MW capacity will be released when approved by AEMO, following integration of SA grid-connected batteries into the System Integrity Protection Scheme (SIPS, section 8.1.3).

- the changing dispatch behaviour of existing conventional generation has the potential to change the pattern of power flows on the transmission system. This may alter the capacity of the South Australian transmission network to accommodate increased generation.

The indicative ability of the existing South Australian transmission network and connection points to accommodate new generation (in addition to any existing and committed generation) is summarised in section 5.3.

In some cases, it may be feasible to connect larger generators if low cost upgrades can increase the network's transfer capacity; for example, by replacing low-cost plant that may limit the available rating of a transmission line.

We have incorporated the impact of committed projects that are planned for completion in 2018 (section 6.2).

5.1.1 Implications of South Australian system strength requirements for generator connection projects

Recent amendments to the Rules regarding system strength obligations require new connecting generators to 'do no harm' to existing plant and TNSPs to maintain minimum levels of system strength. Operation of these rules commences on 1 July 2018.

Since 17 November 2017, transitional arrangements have been in place for new connection projects to 'do no harm', as described in the Interim System Strength Impact Assessment Guidelines published by AEMO.[25] From 1 July 2018, these interim guidelines will be superseded by the publication of Final Guidelines by AEMO.

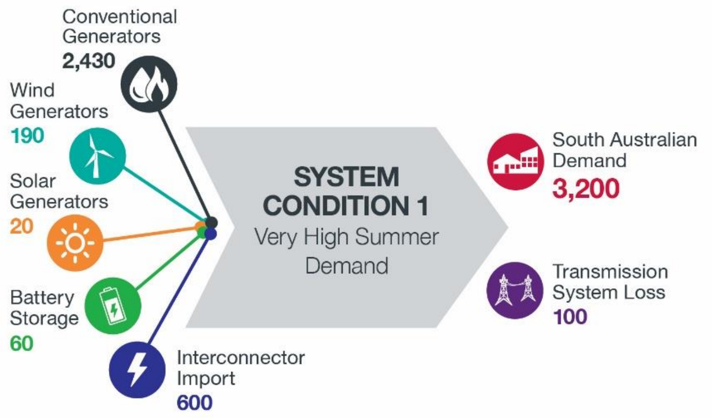
The Rules and Guidelines describe a two stage process for assessing the impact of a new connection – preliminary and full impact assessments. If a preliminary assessment identifies a risk of system strength related interactions for a proposed project then the NSP is required to conduct a Full Impact Assessment.

New connecting generators are required to fund the cost associated with providing system strength services necessary to address any adverse impact on system strength that they may cause.

We anticipate that the majority of new generation project proposals will result in a requirement to conduct Full Impact Assessments, which will impact on the time required to agree TCAs.

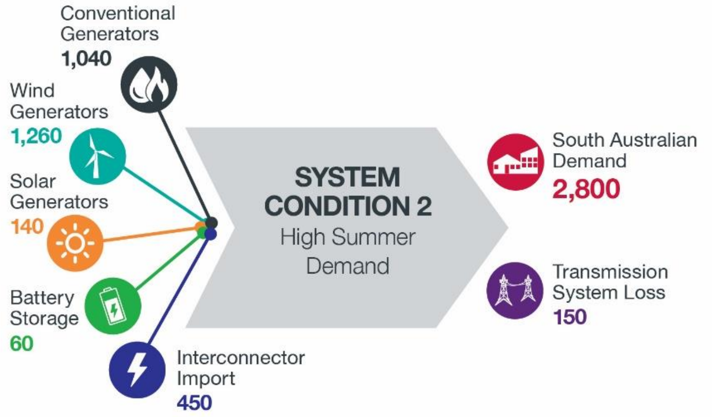
Given the impact of the Main Grid System Strength project on the system strength of the South Australian system, ElectraNet advises that the completion of Full Impact Assessments will be delayed until after the scope of the synchronous condenser solution is finalised (section 7.4.1). We are taking this approach as it will avoid significant rework that would be necessary if the assumptions made in conducting Full Impact Assessments later shift following the finalisation of the synchronous condenser specifications.

[25] Available at http://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Interim-System-Strength-Impact-Assessment-Guidelines-PUBLISHED.pdf.

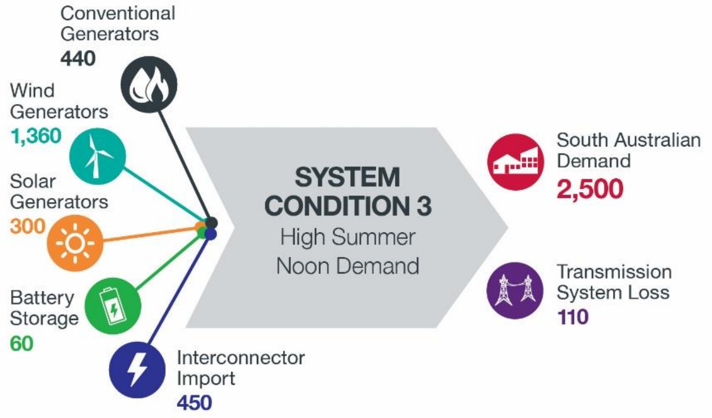


This condition represents 10% POE conditions on the South Australian transmission system

As the system peak typically occurs late in the day, output from solar generators is low

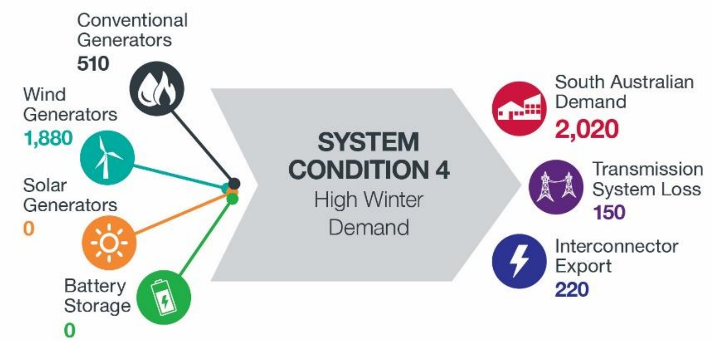


This condition models high demand on a hot summer's day, with a moderately high level of wind and solar generation



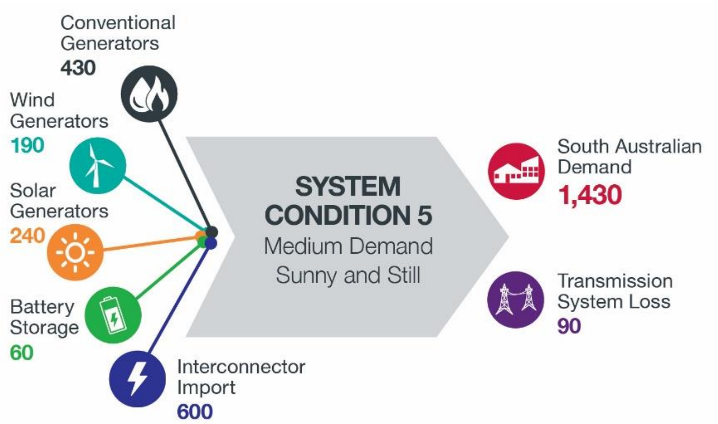
This condition models a moderately high level of wind generation and a very high level of solar generation, such as would occur at noon on a hot summer day

Unless SA system strength is increased, the level of wind generation in a situation like this would actually be capped at 1,295 MW

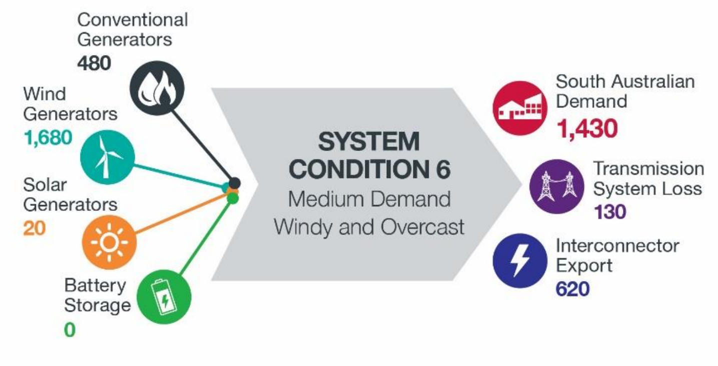


This condition represents high demand on a windy winter day

Unless SA system strength is increased, the level of wind generation in a situation like this would actually be capped at 1,295 MW



This condition represents a sunny and still day, with a high level of solar generation and a low level of wind generation

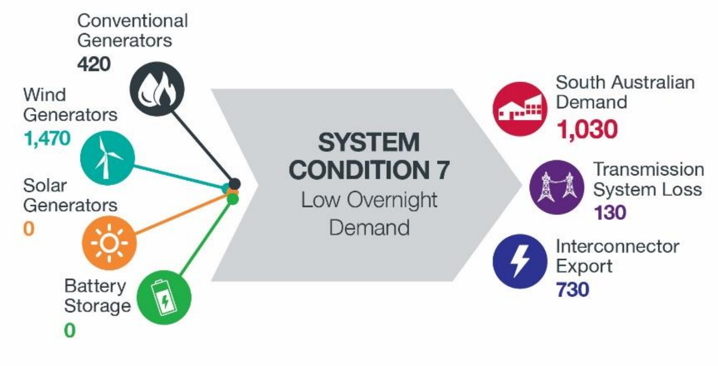


This condition represents a sunny and still day, with a high level of wind generation and a low level of solar generation

Unless SA system strength is increased, the level of wind generation in a situation like this would actually be capped at 1,295 MW

Under this system condition, new generation would be limited to a maximum of about 150 MW due to existing limits on export capability

This limit on total exports would be alleviated by a new interconnector

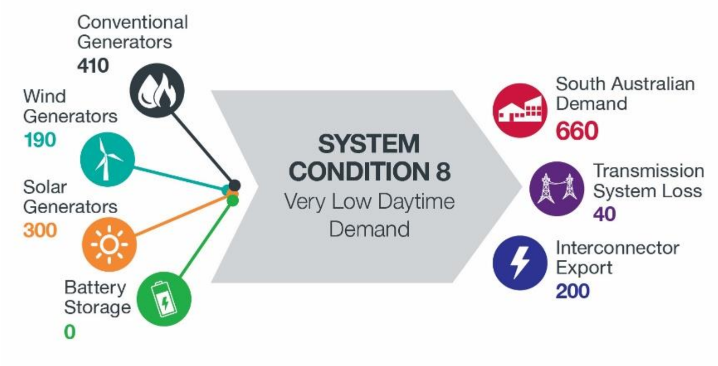


This condition represents an overnight low demand condition, with no solar generation and a moderately high level of wind generation

Unless SA system strength is increased, the level of wind generation in a situation like this would actually be capped at 1,295 MW

Under this system condition, new generation would be limited to a maximum of about 60 MW due to existing limits on export capability

This limit on total exports would be alleviated by a new interconnector



This condition represents a very low demand condition, as can occur on a mild, sunny weekend or public holiday

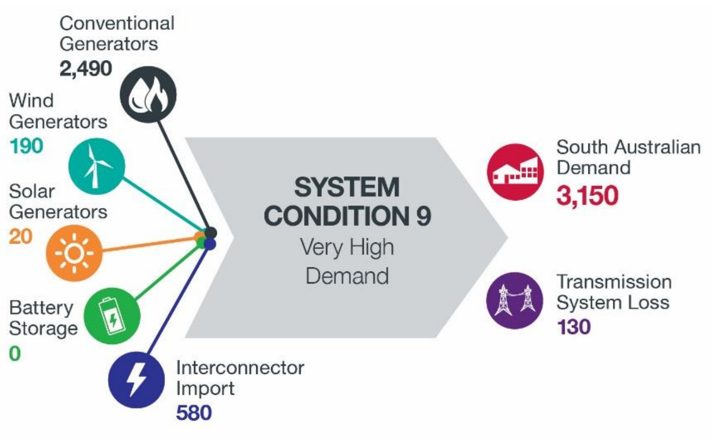
5.2 Connection opportunities for customers

Almost any point in the proximity of the Main Grid 275 kV transmission system should be suitable for a new large load to connect. However, any substantial load connections may require deep network augmentation to provide a reliable supply arrangement.

There is an under-voltage load shedding scheme applied to major loads that are connected at or near Davenport (at the northern end of the transmission system) to allow for secure operation under outage conditions. Any further load connections in this area would be incorporated into this scheme to ensure that potential under-voltage issues continue to be adequately managed.

Metropolitan electricity demand has grown steadily until recently as a result of residential, commercial and industrial development in the Adelaide metropolitan area. SA Power Networks' distribution network supplies individual electricity customers and the existing Metropolitan 275/66 kV network can accommodate new load connections. However, recently the loads have either generally remained flat or begun to slowly reduce. Depending on their size and location, connecting new load may create a need to substantially augment or replace existing assets.

In other regions, we have assessed the ability of existing connection points to accommodate the connection of new large loads (section 5.3). The values listed represent the additional load that could be connected to the connection point's high voltage bus, in addition to the forecast 2018-19 10% POE load (system condition 9, below).



This condition has been used to assess the ability of the South Australian transmission system to accommodate new customer connections

It differs from system condition 1 in the assumption that generators within regional networks could be out of service

The maximum amount of increased demand that a given connection point could accommodate under the most onerous system conditions (including consideration of system normal and credible single contingencies) has been determined by comparing network voltage levels to the relevant voltage criteria, for example:

- 275 kV and 132 kV voltage levels to remain above 95% of nominal voltage levels during system normal conditions
- 275 kV and 132 kV voltage levels to remain above 90% and below 110% of nominal after a single credible contingency event

- the total load at the connection point must remain at least 5% below the level at which voltage collapse occurs (identified as the 'knee point' on the relevant curve of voltage versus power transfer).

The thermal capacity of the transmission network was also applied as a limit to the amount of additional demand that could be supplied at each connection point.

The assessment has the following limitations:

- any additional load at each existing connection point has been assumed to require the same ETC reliability standard as the connection point. If a less-onerous reliability standard is acceptable for the new load, it may allow a larger demand increase to be accommodated without augmentation

- an increase in the load connected at one connection point would directly reduce the additional load that could be accommodated at other connection points, particularly for connection points in close electrical proximity, e.g. a significant new load connection at Berri may reduce the amount of new load that could connect to North West Bend or Monash

- the ability of potential low-cost projects to release additional thermal transmission network capacity (for example, by replacing low-cost plant that may limit the available rating of a transmission line) has not been considered in the study. In some cases, it may be feasible to connect larger loads if low cost upgrades can increase the available capacity of upstream assets; however, a large proportion of the transmission system is now limited by line and transformer thermal ratings instead of by smaller plant and equipment limits.

5.3 Summary of connection opportunities

An indicative summary of the ability of the South Australian transmission network to accept generator or load connections is given in Table 5-1, which should be read with the limitations described in sections 5.1 and 5.2 in mind.

We emphasise that these values only provide a high level indication, as the actual generation or load that can be accommodated often depends on the technical characteristics, operating profile and needs of equipment a customer wishes to connect. If a customer needs to discuss further regarding specific generation or load connections, it is suggested that they contact ElectraNet.

The loads and generation represent the capability of the existing transmission network only, and do not account for any additional transformer capacity that may be required to facilitate connection at voltage levels below 275 kV or 132 kV (as applicable).

For each system condition we have indicated the amount of additional generation dispatch that could be accommodated at each connection point without exceeding voltage or capacity limits, should the most onerous single credible contingency occur.

Note that we have not considered constraints that AEMO would apply to restore system security after a contingency has occurred.

Connection points where generator dispatch is expected to be subject to co-optimisation with the existing Heywood or Murraylink interconnectors are marked with an asterisk.

Two of the system conditions considered are significantly constrained by existing limits on the ability to export from South Australia to Victoria. Specifically, limits on South Australian exports are expected to limit the amount of new generation that could be accommodated at any connection point to no more than 150 MW for system condition 6, and no more than 60 MW for system condition 7. We have therefore not listed more granular results for those system conditions in Table 5-1.

Table 5-1: Indication of available capacity to connect generation and load in 2018-19

Connection point	Additional generation that could be connected (MW)						Additional load that could be connected (MW)
	System Condition (see Table 5-1 for description)						
	1	2	3	4	5	8	9
Main Grid							
Belalie (275 kV)	350	200	200	100	250	200	250
Blyth West (275 kV)	400	300	300	150	400	350	240
Brinkworth (275 kV)	400	300	150	250	100	250	180
Bungama (275 kV)	300	400	250	250	300	250	200
Canowie (275 kV)	250	200	200	100	150	150	260
Cherry Gardens (275 kV)*[26]	600	600	600	550	600	450	510
Cultana (275 kV)	450	400	250	250	450	250	100
Davenport (275 kV)	450	500	300	250	450	250	120
Mokota (275 kV)	400	200	200	100	250	200	260
Mount Lock (275 kV)	50	200	200	100	200	150	260
Robertstown (275 kV)	300	150	400	300	350	150	260
South East (275 kV)*	600	600	600	550	600	400	510
Tailem Bend (275 kV)*	600	600	600	550	600	400	510
Templers West (275 kV)	350	200	100	150	50	350	140
Tungkillo (275 kV)*	600	600	600	600	600	450	510

[26] * This node is on an interconnector flow path - subject to co-optimization and constraints.

Connection point	Additional generation that could be connected (MW)						Additional load that could be connected (MW)
	System Condition (see Table 5-1 for description)						
	1	2	3	4	5	8	9
Eastern Hills							
Angas Creek (132 kV)*	150	150	100	100	100	100	70
Cherry Gardens (132 kV)*	100	150	100	150	150	150	110
Kanmantoo (132 kV)*	50	50	50	50	50	50	70
Mannum (132 kV)*	150	150	150	150	100	155	60
Mobilong (132 kV)*	100	200	200	300	200	250	140
Mount Barker (132 kV)*	250	150	100	200	200	200	150
Mount Barker South (275 kV)*	600	600	600	600	600	450	510
Eyre Peninsula							
Cultana (132 kV)	300	250	250	200	50	250	50
Port Lincoln, Wudinna, Yadnarie (132 kV)	50	50	50	25	75	75	30
Stony Point (132 kV)	25	25	25	25	25	25	40
Whyalla Central (132 kV)	150	150	150	200	75	150	50
Mid North							
Ardrossan West (132 kV)	75	0	0	0	75	75	30
Baroota (132 kV)	<10	<10	<10	<10	<10	<10	20
Brinkworth (132 kV)	250	250	200	100	150	200	180
Bungama	25	25	150	100	75	200	110
Clare North (132 kV)	150	150	150	50	50	150	100
Dalrymple (132 kV)	0	0	0	25	50	50	30
Dorrien (132 kV)	150	150	0	100	150	100	80
Hummocks, Kadina East (132 kV)	100	0	0	50	75	75	40
Robertstown (132 kV)*	300	250	100	200	150	250	40
Templers West (132 kV)	100	25	0	100	100	100	80
Waterloo (132 kV)*	250	100	150	25	25	250	70
Monash, North West Bend, Berri (132 kV)*	200	200	200	150	150	150	20

Connection point	Additional generation that could be connected (MW)						Additional load that could be connected (MW)
	System Condition (see Table 5-1 for description)						
	1	2	3	4	5	8	9
South East							
Blanche, Mt Gambier, Snuggery, South East (132 kV)	75	0	0	0	50	100	60
Keith*, Kincraig (132 kV)*	50	25	25	25	25	150	90
Penola West (132 kV)*	75	50	50	0	50	150	60
Tailem Bend (132 kV)*	100	100	100	200	100	200	100
Upper North							
Davenport (132 kV)	200	150	25	200	50	25	40
Leigh Creek South, Neuroodla (132 kV)	<10	<10	<10	<10	<10	<10	20
Mt Gunson, Pimba (132 kV)	50	50	50	50	50	25	20

5.4 Proposed and committed new connection points

Several new connection points have recently been energised or committed, to enable the connection of new generators, each of which was committed after our 2017 Transmission Annual Planning Report was published. In addition, a new connection point is proposed by SA Power Networks at Gawler East in the Mid North to meet localised growing demand (Table 5-2).

Note that based on latest information from SA Power Networks, the planned date for Gawler East has been changed from 2022 to 2023, and may be able to be moved to a still later date if a technically and economically feasible demand management solution can be implemented.

Table 5-2: Proposed and committed new connection points for generators and customers

Connection point	Planning region	Project year	Connection voltage	Scope of work
Emeroo	Upper North	2018 – energised April 2018	132 kV	Construct a new 132 kV line from Davenport to Emeroo Establish a 132 kV bus and a 132/33 kV connection point substation at Emeroo Bungala solar farm connected at 33 kV
Willalo	Mid North	2018 – energised March 2018	275 kV	Turn the Mokota to Belalie 275 kV line in/out at Willalo and establish a 275 kV bus Willogoleche wind farm connected at 275 kV

Connection point	Planning region	Project year	Connection voltage	Scope of work
Corraberra Hill	Eyre Peninsula	2018	275 kV	Turn one of the Davenport to Cultana 275 kV lines in/out at Corraberra Hill and establish a 275 kV bus Lincoln Gap wind farm to connect at 275 kV
Mount Gunson South	Upper North	2018	132 kV	Turn in the Davenport to Mt Gunson 132 kV line at Mount Gunson South to establish a 132 kV bus and 132 kV connection point Carrapateena mine to be connected at 132 kV
		2020	upgrade to 275 kV	In 2019-20, construct a new Saltbush Hill to Mount Gunson South 275 kV line and upgrade to a 275/132 kV connection point at Mount Gunson South Prominent Hill mine to be connected at 132 kV
Saltbush Hill	Upper North	2020	275 kV	Turn one of the Davenport to Cultana 275 kV lines in/out at Saltbush Hill and establish a 275 kV bus Construct a new 275 kV line from Saltbush Hill to provide a 275 kV connection to Mount Gunson South connection point
Gawler East	Mid North	2023 (subject to request from SA Power Networks)	132 kV	Turn the Para to Roseworthy 132 kV line in/out at Gawler East and establish a 132 kV bus SA Power Networks to establish a single-transformer 132/11 kV distribution substation Refer to section 0 for more details

5.5 Projects for which network support solutions are being sought or considered

ElectraNet considers potential network support solution options on an equal basis with network options for addressing network limitations or constraints.

5.5.1 Network support solutions framework

ElectraNet seeks proposals from non-network solution providers for potentially viable non network options, and considers the merits of all proposals received. This includes detailed assessment of technical feasibility, expected timeframes, and efficiency. If a network support solution option is shown to be the most cost effective technically viable solution and can be implemented in an appropriate timeframe, then a network support agreement is negotiated with the proponent.

Network support options are assessed according to their ability to:

- provide a level of net demand reduction that will resolve the identified limitation
- operate to reduce the level of net demand on the limited asset(s) at appropriate times (for example, above 90% of the asset's 10% POE demand level)
- be provided at the lowest net present value (NPV) cost
- provide reliable demand reduction.

For a market benefit-driven project, the option must also yield a positive net market benefit.

For projects that require application of the RIT-T, the option must satisfy the RIT-T as the preferred option.

5.5.2 Recent, current, and upcoming consultations

Recently completed, in-progress, and planned consultations for forecast limitations on which we have sought or seek proposals for network support solutions are outlined in Table 5-3.

Dates are indicative only. Reports will be published on ElectraNet's website[27], with a summary on AEMO's website[28]. We also liaise with AEMO to notify interested parties when we publish new RIT-T reports through the "AEMO Communications" email notifications.[29]

Table 5-3: Recently completed, in-progress, and planned consultations for which ElectraNet has sought or seeks proposals for network support solutions

Project	Expected project commitment date	Consultation status
Managing Main Grid High Voltage Levels	Already committed in early 2018	Our 2017 Transmission Annual Planning Report had indicated that a PSCR was planned to be published in the second half of 2017 The proposed installation of synchronous condensers in 2020 to address system strength needs (section 7.4.1) will also enable adequate Main Grid voltage control at times of low system demand. As the installation of a single 275 kV reactor in the 2018 to 2023 period to enable adequate voltage levels is below the RIT-T threshold, a RIT-T will not be undertaken for this identified need

27 www.electranet.com.au
28 www.aemo.com.au
29 To sign up to the AEMO Communications newsletter, use this link: https://aemo.us10.list-manage.com/track/click?u=eae433173c2b1acb87c5b07d1&id=3a670fe4f3&e=f482090852.

Project	Expected project commitment date	Consultation status
Eyre Peninsula Electricity Supply Options Refer to sections 1.3.3 and 7.5.1 of this report	By the end of 2018, for completion in 2021	The current network support arrangement that enables ElectraNet to meet the ETC category 3 reliability standard at Port Lincoln expires in December 2018, and significant portions of the conductor on the Eyre Peninsula 132 kV lines are in poor condition We plan to publish a PACR in July 2018, which will describe the preferred option to meet the identified need (sections 1.3.3 and 7.5.1)[30]
South Australian Energy Transformation Refer to section 7.3.1 of this report	2019, for completion in about 2022 to 2024	ElectraNet is investigating the feasibility of an additional interconnector between South Australia and the Eastern States, as outlined in the PSCR published in November 2016[31] We have now published a PADR, which indicates the draft preferred option to meet the identified need, and which will remain open for consultation until mid-August 2018[32]
Protection Systems Unit Asset Replacement 2018-23 Refer to section 7.12.1 of this report	2019, for completion by 2023	Application of the RIT-T is planned to be commenced with publication of a PSCR in about October 2018 The replacement of these assets is not expected to have any credible non-network alternatives
Transformer Bushing Unit Asset Replacement 2018-23 Refer to section 7.12.2 of this report	2019, for completion by 2020	Application of the RIT-T is planned to be commenced with publication of a PSCR in July 2018 The replacement of these assets is not expected to have any credible non-network alternatives
AC Board Unit Asset Replacement 2018-23 Refer to section 6.2.9 of this report	2019, for completion by 2022	Application of the RIT-T is planned to be commenced with publication of a PSCR by the end of 2018 The replacement of these assets is not expected to have any credible non-network alternatives
Robertstown Circuit Breaker Arrangement Upgrade Refer to section 7.6.4 of this report	To be reviewed subject to outcome of SA Energy Transformation RIT-T	Subject to SA Energy Transformation RIT-T outcome, application of the RIT-T is planned to be commenced with publication of a PSCR in the second half of 2019 The rearrangement of these assets is not expected to have any credible non-network alternatives

30 Available from electranet.com.au.
31 Available from electranet.com.au.
32 Available from electranet.com.au.

Project	Expected project commitment date	Consultation status
Isolator Unit Asset Replacement 2018-23 Refer to section 0 of this report	2019, for completion by 2023	Application of the RIT-T is planned to be commenced with publication of a PSCR in about October 2018 The replacement of these assets is not expected to have any credible non-network alternatives
Gawler East New Connection Point Refer to section 7.5.2 of this report	2022, for completion in 2023	Application of the RIT-D[33] is planned to begin with publication by SA Power Networks of a NNOR[34] for this project before project commitment Proponents of potential network support solutions will be encouraged to make a submission in response to the NNOR

33 Regulatory Investment Test for Distribution.
34 Non Network Options Report, representing the first formal step in the RIT-D process.

6. Completed, committed and pending projects

This chapter summarises the significant projects to remove network limitations and address asset condition that we have completed, committed to and which have become pending over the last year.

Estimated project costs quoted in this chapter are presented in 2018 dollar values. Cost estimates are provided as a range to reflect the variability of expected project costs.

6.1 Recently completed projects

ElectraNet has completed several significant projects to remove network limitations and address asset condition (Table 6-1 and Figure 6-1).

Table 6-1: Projects completed between 1 June 2017 and 31 May 2018

Project description	Region	Project Category	Asset in service
Weather Stations 2013-18 Install modern weather stations at various monitoring locations to facilitate the implementation of dynamic line ratings on critical circuits and thereby reduce constraints	Various	Augmentation	July 2017
SA Water Mannum-Adelaide Pump Station #2 Rebuild the Mannum to Adelaide pumping station #2 supply site to modern-day standards and replace the 132/3.3 kV transformers. Employ a standardised approach across all pumping station sites to realise design and operational efficiencies	Eastern Hills	Replacement	October 2017
SA Water Morgan-Whyalla Pump Station #4 Rebuild the Morgan to Whyalla pumping station #4 supply site to current day standards and replace the 132/3.3 kV transformers. Employ a standardised approach across all pumping station sites to realise design and operational efficiencies	Mid North	Replacement	October 2017
SA Water Mannum-Adelaide Pump Station #3 Rebuild the Mannum to Adelaide pumping station #3 supply site to modern-day standards and replace the 132/3.3 kV transformers. Employ a standardised approach across all pumping station sites to realise design and operational efficiencies	Eastern Hills	Replacement	November 2017
SA Water Mannum-Adelaide Pump Station #1 Rebuild the Mannum to Adelaide pumping station #1 supply site to modern-day standards and replace the 132/3.3 kV transformers. Employ a standardised approach across all pumping station sites to realise design and operational efficiencies. Replace associated line assets that are in poor condition	Eastern Hills	Replacement	November 2017

Project description	Region	Project Category	Asset in service
Brinkworth – Mintaro 132 kV line remediation and insulator replacement Porcelain disc insulator assemblies that have reached end-of-life will be replaced along with defective poles and cross arms on the Brinkworth to Mintaro 132 kV transmission line. This will extend the life of the transmission line by at least 15 years	Mid North	Refurbishment	November 2017
SA Water Millbrook Pumping station Rebuild the Millbrook pumping station supply site to modern-day standards and replace the 132/3.3 kV transformers. Employ a standardised approach across all pumping station sites to realise design and operational efficiencies. Replace associated line assets that are in poor condition	Eastern Hills	Replacement	May 2018
Waterloo to Robertstown 132kV Line Uprating Uprate the Waterloo to Robertstown 132 kV line from 80°C design clearances to 100°C design clearances	Mid North	Augmentation	May 2018

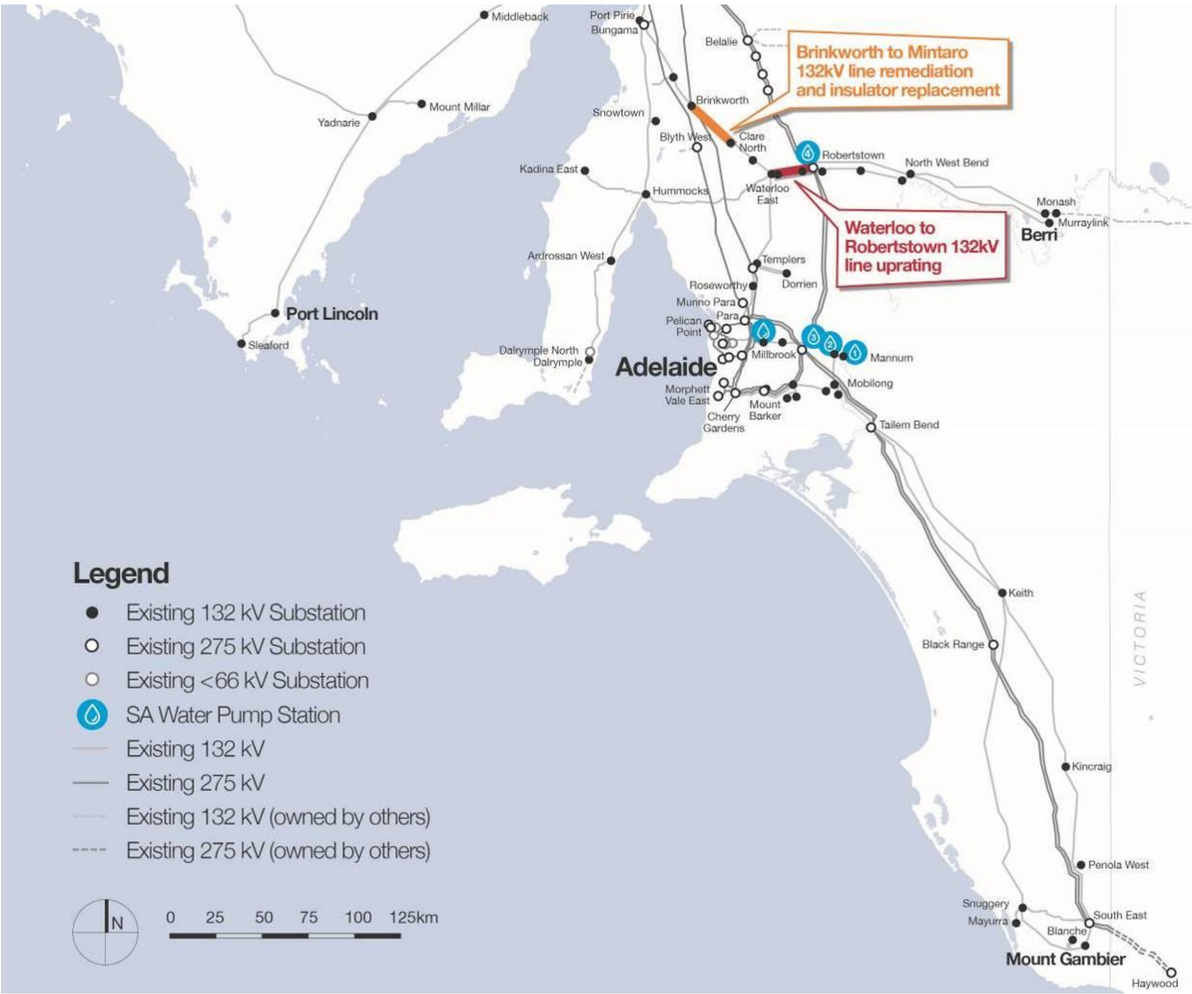


Figure 6-1: Recently completed projects

6.2 Committed projects

Committed projects are projects where the RIT-T has been completed (where required), and the ElectraNet Board has given approval. ElectraNet is currently undertaking several committed projects which are expected to be completed in the near future (Table 6-2 and Figure 6-2).

Table 6-2: Committed projects as of 31 May 2018

Project description	Region	Project Category	Asset in service[35]
Baroota substation replacement Maintain the reliability of Baroota substation by replacing assets that are at end of life	Mid North	Replacement	June 2018

35 Dates are indicative and subject to change.

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Project description	Region	Project Category	Asset in service[35]
Dalrymple ESCRI Energy Storage Design and build a grid-connected, utility scale battery energy storage system at Dalrymple that will help to manage frequency related system security issues, as well as improve the reliability of supply for customers at Dalrymple connection point and provide other market benefits	Mid North	Augmentation	July 2018
Tailem Bend Substation Upgrade Extend the Tailem Bend substation to accommodate an additional 275 kV diameter with two circuit breakers, associated plant and secondary systems, and rearrange 275 kV line exits	Main Grid	Security/ Compliance	August 2018
Templers West 50 Mvar 275 kV reactor Install a 50 Mvar 275 kV switched reactor at Templers West	Main Grid	Security/ Compliance	August 2018
Uprate Riverland 132 kV lines Uprate the Robertstown to North West Bend No. 2 132 kV line and the North West Bend to Monash 132 kV line from 80°C design clearances to 100°C design clearances	Riverland	NCIPAP	August 2018
Online asset condition monitoring equipment replacement Replace or upgrade the majority of primary plant online condition monitoring equipment, which is at the end of its usable life and experiencing high failure rates	Various	Replacement	August 2018
Back Up Control and Data Centre Construct a new Backup Control and Data Centre to meet current physical and electronic security requirements	Metropolitan	Security/ Compliance	October 2018
Substation Lighting and Infrastructure Replacement Replace substation lighting and associated infrastructure at sites where safety hazards exist	Various	Replacement	October 2018
Para-Brinkworth-Davenport Hazard Mitigation Replace load-releasing cross arms and all porcelain disc insulators on Para-Brinkworth-Davenport 275 kV line to achieve a 15-year life extension	Main Grid	Refurbishment	December 2018
Davenport-Pimba 132 kV Line Low Span Uprating Treat low spans to achieve the designed nominal T65 rating for the Davenport – Mt Gunson section of the Davenport-Pimba 132 kV transmission line	Upper North	Refurbishment	December 2018

Project description	Region	Project Category	Asset in service[35]
AC Board Replacement 2013-18 Replace and improve AC auxiliary supply equipment, switchboards and cabling at 11 substations	Various	Replacement	April 2019
Various unit asset replacements Individual unit assets, such as circuit breakers, voltage transformers, current transformers or protection relay sets that have reached end of life will be replaced at 36 substations	Various	Replacement	May 2019
Monash and Berri relay replacements Replace protection relays and a communications gateway at Monash and Berri substations to enable remote control and monitoring, to improve network reliability, maintainability and response following system events	Riverland	Replacement	August 2019
Line Support Systems Refurbishment 2018-23 Refurbish transmission line support systems and extend the life of the Snuggery – Blanche – Mt Gambier 132 kV line by renewing line asset components	South East	Refurbishment	December 2019
Motorised Isolator LOPA Improvement Replace or refurbish mechanical and electrical isolation lock-off points on all motorised air insulated isolators identified as safety hazards by a Layer of Protection Analysis (LOPA)	Various	Security/ Compliance	March 2021
Line Insulator Systems Refurbishment 2018-23 Program to refurbish transmission line support systems and extend the life of 18 transmission lines by renewing line asset components.	Various	Refurbishment	July 2023

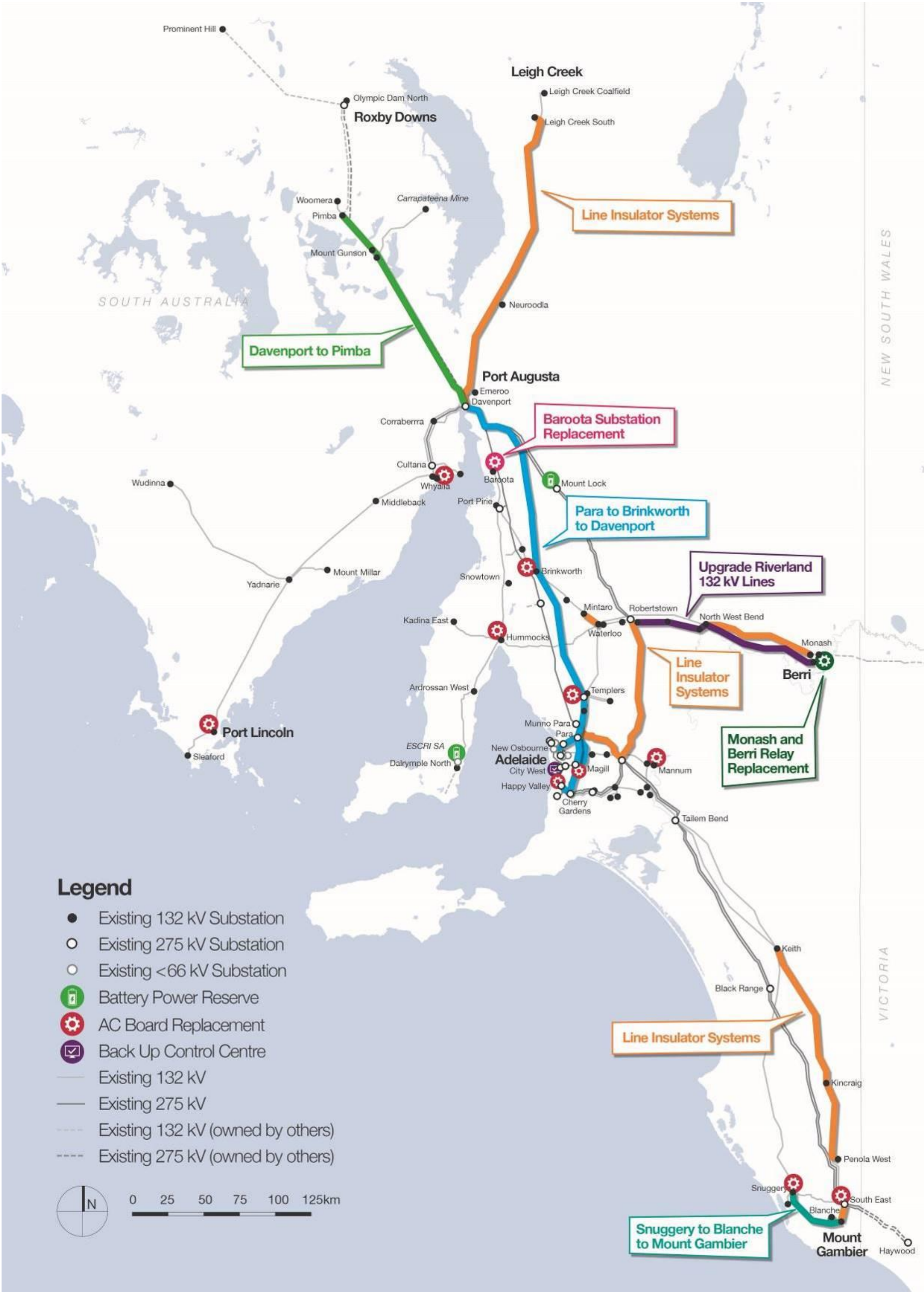

Figure 6-2: Committed projects

Note that this figure does not show the large number of sites impacted by the Substation Lighting and Infrastructure Replacement project, the Motorised Isolator LOPA improvement project, or the Online Asset Condition Monitoring Equipment Replacement project.

The following sections provide additional details for our current major committed projects (increases network capacity, or greater than $5 million expenditure at a single site).

6.2.1 Baroota Substation Replacement

Scope of work: Replace assets that are at end of life

Estimated cost: $5-$8 million

Project category: Replacement

Timing: June 2018

Project status: Committed

Project need:

The majority of the primary equipment at Baroota is at end of life and requires replacement.

This project will replace the necessary plant, and implement flood mitigation measures at the site.

The existing 10 MVA 132/33 kV transformer will be retained.

We did not conduct the RIT-T for this project, as it was committed before 30 January 2018.

6.2.2 Dalrymple ESCRI-SA Battery Project

Scope of work: Construct a 30 MW 8MWh large scale battery energy storage system adjacent to and connected to the network via 33 kV bus at Dalrymple substation. The battery control system will be integrated with the main grid, local network and Wattle Point Wind Farm to enable the BESS to provide a range of regulated and competitive market services.

Estimated cost: About $30 million total (regulated component less than $6 million)

Project category: Augmentation

Timing: July 2018

Project status: Committed, commissioning in progress

Project need:

The Dalrymple ESCRI-SA project will demonstrate how a large scale energy storage system can strengthen the grid and improve reliability for the lower Yorke Peninsula. The sizing of the battery capacity has been optimised to be able to provide the following range of primary services, both regulated network services and competitive market services.

The regulated network service include:

- Supply of Fast Frequency Response (FFR) to reduce constraints on the Heywood interconnector, resulting in increased flows on the interconnector;
- Reduction of expected unserved energy to Dalrymple following loss of supply, involving islanding of the BESS with the local load, the Wattle Point Wind Farm intended to remain in service at reduced output, and local rooftop PV, until grid supply is restored.

The competitive market services include:

- Market trading of electricity in the National Electricity Market through the provision of market caps (a market derivative/ insurance product), and
- Frequency Control Ancillary Services (FCAS) services.

Once completed, ElectraNet will lease the battery to AGL who will operate it to provide competitive market services.

The project is partly funded by the Australian Renewable Energy Agency (ARENA).

6.2.3 Uprate Riverland 132 kV lines

Scope of work:	Uprate the Robertstown to North West Bend No. 2 132 kV line and the North West Bend to Monash No. 2 132 kV line from 80 °C design clearances to 100 °C design clearances
Estimated cost:	<$5 million
Project category:	NCIPAP
Timing:	August 2018
Project status:	Committed

Project need:

This project was in ElectraNet's NCIPAP for the 2014-15 to 2017-18 period. It will increase the transfer capacity of selected Riverland 132 kV lines that connect to the Murraylink interconnector, enabling increased power export to Victoria under high Riverland demand by about 24 MW. It will also increase the capability of South Australian wind farms to export power under high wind generation conditions at all times of the year. This will be achieved by increasing the design operating temperatures of the selected lines, from 80 °C design clearances to 100 °C design clearances.

ElectraNet envisages that this project will impact inter-regional transfer.

6.2.4 Tailem Bend substation upgrade

Scope of Work:	Extend Tailem Bend substation to accommodate an additional 275 kV diameter with two circuit breakers, associated plant and secondary systems, and rearrange 275 kV line exits
Estimated Cost:	$9-10 million
Project Category:	Security/Compliance
Timing:	August 2018
Project Status:	Committed, construction in progress

Project Need:

The upgrade of the Heywood interconnector has resulted in a greater reliance on the performance of the substations that connect South Australia to the National Electricity Market via the Heywood Interconnector.

Tailem Bend substation has a 275 kV section that is not laid out in a 'circuit breaker and a half' topology as is required by ElectraNet's current day policies and standards. The existing topology significantly constrains the interconnector under certain conditions.

The planned layout will minimise the impact of these constraints on NEM participants and improve the quality, reliability and security of supply of prescribed transmission services. A similar upgrade was completed at South East substation in December 2015.

We did not conduct the RIT-T for this project, as it was committed before 30 January 2018.

6.2.5 Back Up Control and Data Centre

Scope of work:	Construct a new Backup Control and Data Centre (BUCC) to meet current physical and electronic security requirements.
Estimated cost:	$7-$9 million
Project category:	Security and compliance
Timing:	October 2018
Project status:	Committed

Project need and option analysis:

The current BUCC facility is not considered secure against natural disasters or physical attack, does not enable quick and secure access from ElectraNet's System Monitoring and Switching Centre and is not suitable for extended operations.

The 2015 Sampson Flat bushfire, near the Para substation where the existing BUCC is currently located, prompted a review and proposal to relocate the BUCC to a more easily accessible location.

The system black event on 28 September 2016 and subsequent investigations have reinforced the need for a more robust BUCC that is easily and quickly accessible by ElectraNet operational personnel during a state of emergency, and that is suitable for prolonged use in case of complete loss of the main control room at Pirie Street.

The options considered include:

1. Build a new facility at Keswick in 2018; and
2. Maintain the existing facility at Para and build a new facility at Keswick in 2023.

Option 1, building a new facility at Keswick is in the best interests of customers by reducing the risk costs associated with a potential extended network outage if the current BUCC was unavailable, or not easily accessible, during a state of emergency.

We did not conduct the RIT-T for this project, as it was committed before 30 January 2018.

6.2.6 Substation lighting and infrastructure replacement

Scope of work: Replace substation lighting and associated infrastructure at sites where the safety hazards that exist as a result of poor lighting.

Estimated cost: $10-$12 million

Project category: Replacement (grouped)

Timing: October 2018

Project status: Committed

Project need

The project will replace lighting in existing buildings at 75 substations and 40 telecommunication sites, including LED illuminated exit signs, emergency lighting, internal lighting and exterior entry door lighting. New floodlighting controls will be installed at 42 critical sites and new floodlighting will be installed at 12 substation yards where lighting levels have been identified as insufficient.

Due to the safety implications of this project no other option was considered.

We did not conduct the RIT-T for this project, as it was committed before 30 January 2018.

6.2.7 Install a 50 Mvar 275 kV switched reactor at Templers West

Scope of work: Install a switched 50 Mvar 275 kV reactor at Templers West

Estimated cost: $4-6 million

Project category: Security/Compliance

Timing: August 2018

Project status: Committed

Project need and option analysis:

Studies have shown that steady-state voltage levels on the South Australian transmission system may breach 110% at times of low demand from 2018-19, following a single contingency event of an in-service generator or significant item of reactive control plant. This can be addressed by installing an additional 50 Mvar 275 kV reactor in 2018 to limit high voltage levels on the transmission network at times of low system demand.

Studies indicate that installing this reactor at Templers West will optimise the benefit.

ElectraNet does not envisage that this project will have any material impact on inter-regional transfer.

6.2.8 Davenport to Pimba 132 kV line low span uprating

Scope of work:	Treat low spans to achieve the designed nominal 65 °C design temperature rating for the Davenport to Mount Gunson section of the Davenport to Pimba 132 kV line
Estimated cost:	$12-$15 million
Project category:	Refurbishment
Timing:	November 2018
Project status:	Committed

Project need and option analysis:

Condition assessment reports have identified that there are a significant number of low spans that limit the line from achieving its summer rating of 76 MVA. These reports also indicate that the condition of the line is acceptable to last a further 20 years with appropriate maintenance.

ElectraNet is required address the low spans, to return the line to its T65 rating to maintain safe clearances during peak load.

The options considered include:

1. Address only medium and high risk sections only, and
2. Address all sections that are below minimum clearance

Option 2, to address all sections that are below minimum clearance was selected as the preferred option as the load on this line is forecasted to increase to maximum summer rating of the line, which could result in sag below minimum clearance during times of high load, high temperature and low wind speed.

We did not conduct the RIT-T for this project, as it was committed before 30 January 2018.

6.2.9 AC Board Replacement 2013-18

Scope of work:	Replace and improve AC auxiliary supply equipment, switchboards and cabling at 11 substations
Estimated cost:	\$12-\$14 million
Project category:	Replacement
Timing:	April 2019
Project status:	Committed

Project need and option analysis:

A review undertaken prior to the 2008-09 to 2012-13 regulatory control period identified 35 sites requiring replacement of AC boards and associated equipment to address safety and operational security risks. The seven highest risk sites were addressed during 2009-2013 period. This project is addressing the eleven sites that have been assessed to be exposed to the next highest risk.

These sites are:

Brinkworth	Magill	Hummocks
Happy Valley	Snuggery	Mannum
South East	Whyalla Terminal	Port Lincoln Terminal
Northfield	Templers	

Replacing sub-standard and hazardous equipment is considered to be the only viable option.

We did not conduct the RIT-T for this project, as it was committed before 30 January 2018.

6.2.10 Line support systems refurbishment 2018-23

Scope of work:	Refurbish transmission line support systems to achieve an overall life extension of the Snuggery – Blanche and Blanche – Mt Gambier 132 kV lines by replacing every fastener on every transmission tower on these two transmission lines.
Estimated cost:	\$9-\$10 million
Project category:	Refurbishment
Timing:	July 2023
Project status:	Committed

Project need and option analysis:

Detailed inspection has identified that the fasteners used to secure the tower lattice work on the Snuggery – Blanche and Blanche – Mount Gambier 132 kV transmission lines are corroded and near end of life, requiring replacement by 2023. The remaining transmission tower components are expected, with appropriate maintenance, to last for a further 20 years of operation.

The options considered include:

1. Planned replace all components identified at risk.
2. Replace individual components or sections on failure, and
3. Full line replacement

Option 1, to replace all fasteners used to secure the tower lattice work on the Snuggery – Blanche and Blanche – Mount Gambier 132 kV transmission lines has been selected as the preferred option, as this reduces the likelihood of failure and extends the life of the two transmission lines.

We did not conduct the RIT-T for this project, as it was committed before 30 January 2018.

6.2.11 Motorised isolator LOPA Improvement 2018-19 to 2022-23

Scope of work: Replace or refurbish mechanical and electrical isolation lock-off points on all motorised air insulated isolators identified as safety hazards by a Layer of Protection Analysis (LOPA)

Estimated cost: $10-$15 million

Project category: Security/Compliance

Timing: March 2021

Project status: Committed

Project need and option analysis:

ElectraNet under took a Layer of Protection Analysis (LOPA) to review possible integrity issues with motorised isolator lock-off systems. The analysis identified the risk of each isolator model closing as a result of a lock-off failure while functioning as a point of isolation.

The LOPA review made recommendations to reduce this risk to a lower level considered to be So Far As Is Reasonably Practical (SFAIRP), as required by the South Australia Work Health and Safety Act 2012.

The options considered include:

1. fit mechanical lock-off points and electrical lock-off switches to approximately 840 motorised isolators at 77 substations, and replace 15 motorised isolators at 7 substations
2. Replace all air insulated switchgear motorised isolators with new compliant isolators.

Option 1, to fit mechanical lock-off points and electrical lock-off switches to approximately 840 motorised isolators at 77 substations, and replace 15 motorised isolators at 7 substations was assessed as the lowest cost compliant option and has been selected as the preferred option.

We did not conduct the RIT-T for this project, as it was committed before 30 January 2018.

6.2.12 Line Insulator Systems Refurbishment 2018-23 program

Scope of work: Program to refurbish transmission line support systems and extend the life of 18 transmission lines by renewing line asset components.

Estimated cost: $45-$60 million

Project category: Replacement

Timing: June 2023

Project status: Committed

Project need and option analysis:

This project is required to address to high levels of porcelain disc faults on insulator assemblies that have been in service for greater than 30 years and have been assessed as having reached end-of-life. A porcelain disc condition assessment program has been conducted across the network and has identified a statistically valid failure rate, via sample based testing, that poses unacceptable risk of failure resulting in dropping a conductor to ground and a potential fire-start event, a catastrophic failure.

The options considered include:

1. Replace all porcelain insulators on selected transmission lines during the 2019-2023 regulatory period;
2. Replacement of individual components or sections on failure: and.
3. Full transmission line replacement.

Option 1 is the preferred option, to replace all 6,700 insulator strings, together with associated line hardware including vibration dampers on 18 transmission lines during the 2018-2023 period. This reduces risk including the probability of failure, the likelihood of personal injury consequences and the extent of customer supply interruption from failed porcelain insulators. This program of planned insulator system replacement projects will increase the asset life of the 18 transmission lines (Table 6-3).

Table 6-3: Lines included in the Line Insulator Systems Refurbishment 2018-23 program

Lines	Voltage	Number of Structures/ Insulators	Year
North West Bend – Monash No. 1	132kV	315 / 1000	2019
South East – Mount Gambier	132kV	40 / 155	2019
Kincraig – Penola West	132kV	148 / 431	2019
Torrens Island Power Station – Cherry Gardens	275kV	171 / 939	2020

Lines	Voltage	Number of Structures/ Insulators	Year
Cherry Gardens – Happy Valley	275kV	24 / 132	2019
Torrens Island Power Station – Magill	275kV	130 / 853	2020
Para – Tungkillo	275kV	95 / 507	2019
Parafield Gardens West – Para	275kV	54 /405	2019
Keith – Kincraig	132kV	256 / 803	2019
Torrens Island Power Station – Para No. 4	275kV	76 / 559	2020
Torrens Island Power Station – New Osborne No. 3	66kV	25 / 96	2020
Torrens Island Power Station – New Osborne No. 4	66kV	25 / 93	2020
Waterloo – Mintaro	132kV	64 / 231	2020
Davenport – Leigh Creek	132kV	29 / 114	2021–2023
Murray Bridge Hahndorf Pump Station No. 3 – Kanmantoo – Back Callington	132kV	16 / 64	2021–2023
Pelican Point – Parafield Gardens West	275kV	25 / 238	2021–2023
Para – Robertstown	275kV	9 / 72	2021–2023
Para – Munno Para	275kV	9 / 55	2021 – 2023

Five of the projects exceed the RIT-T threshold, namely:

- North West Bend to Monash No. 1 132 kV line
- Torrens Island Power Station to Cherry Gardens 275 kV line
- Torrens Island Power Station to Magill 275 kV line
- Para to Tungkillo 275 kV line, and
- Keith to Kincraig 132 kV line.

We did not conduct a RIT-T for these individual projects, as they were committed before 30 January 2018.

6.3 Pending projects

ElectraNet does not currently have any pending projects, meaning projects which have passed the RIT-T but are not yet fully committed.

7. Network development plan

ElectraNet and SA Power Networks analyse the expected future operation of the South Australian network, taking into account forecast loads, future generation, market network services, demand side participation and transmission developments, according to Rule requirements. The analyses and resulting development plan (presented in this chapter) are designed to address projected limitations on the South Australian transmission network over a 10-year period. These developments include projects to meet various needs, such as to:

- augment capacity to meet increasing connection point demand (if relevant)
- maintain compliance with Rules obligations
- improve system security and operational flexibility
- maintain adequate asset condition
- provide net market benefits by minimising transmission network constraints.

Estimated project costs quoted in this chapter are presented in 2018 dollar values. Cost estimates are provided as a range to reflect the variability of expected project costs. The estimated range for proposed projects is typically wider than for committed and pending projects, due to uncertainties about project scope, contingencies and risk and the early stages of a project.

A central planning scenario has been developed and evaluated as part of ElectraNet's planning process. We have also considered a range of different assumptions about the future development of demand and generation in South Australia. The scenario together with the range of assumptions is intended to represent a range of credible potential futures.

The planning scenario and assumptions have been characterised (Table 7-1) and a range of potential new loads and generation connections over the next ten years (generic, but based on received enquiries) are graphically represented in Figure 7-1.

Table 7-1: Characteristics and assumptions of ElectraNet's planning scenario and sensitivities

Characteristic	Planning scenario
Connection point demand forecasts	ElectraNet's 2018 Connection Point Forecasts Report[36] SA light load scenario projected by scaling embedded rooftop solar PV at each connection point to achieve AEMO's March 2018 EFI 90% POE minimum demand forecast
SA transmission system coincident maximum demand forecast	AEMO's March 2018 EFI 10% POE maximum demand forecast
New load connections	As shown in Figure 7-1.
New conventional generators	
New renewable generators	

36 Available from electranet.com.au.

Figure 7-1: Assumptions considered in ElectraNet's planning process, including potential future step load increases, generator retirements, renewable generator and battery connections

7.1 Summary of planning outcomes

Analysis of the planning scenario and sensitivities led to a range of high level outcomes or project recommendations (Table 7-2). Detailed outcomes, or potential projects required to support the sensitivities, are covered in sections 7.2 to 7.12.

Table 7-2: Summary of planning outcomes

Planning focus	Key outcomes
National transmission planning	We have published a draft report for the South Australian Energy Transformation RIT-T, which shows that a new 330 kV interconnector between South Australia and New South Wales, with a transfer capacity of about 800 MW, is expected to deliver net market benefits from the early 2020s, with associated reductions in electricity prices. This work has been closely coordinated with the development of AEMO's ISP.
Existing interconnector capacity	The full 650 MW nominal transfer capacity of Heywood Interconnector is expected to be released in 2018. At times, transfers over the Heywood interconnector will be limited by other network constraints. Our NCIPAP includes the planned installation of an additional 100 Mvar 275 kV capacitor bank at South East substation to alleviate forecast congestion on the Heywood interconnector due to voltage stability limits, providing increased availability of the interconnector's full capacity.
System strength and system inertia	AEMO has identified a system strength gap (i.e. fault level shortfall) in South Australia. We are working with AEMO to develop an appropriate scope for the installation of a number of synchronous condensers on the transmission network by 2020, to meet South Australian system security needs now and into the future. AEMO plans to publish a NEM-wide assessment of system inertia adequacy in June 2018. We will work to incorporate any minimum requirements for South Australian inertia in the synchronous condensers that are needed to meet the identified system strength needs.
Connection points	The existing network support arrangement at Port Lincoln expires in December 2018. ElectraNet will soon complete a RIT-T investigating the most cost effective long-term way of continuing to meet the required reliability for Port Lincoln, while considering the possibility of future mining or renewable generation development in the region. A new connection point has been forecast by SA Power Networks to be required at Gawler East in about 2023. Development of this new connection point will occur subject to the successful completion of a RIT-D and receipt of a formal connection request from SA Power Networks. All other connection points are forecast to remain within design and equipment limits for the duration of the planning period, unless new large customer connections occur.
Market benefit opportunities	A range of market benefit driven projects is proposed to reduce the impact of existing and forecast constraints and increase the capability of the transmission network, providing net market benefits. This includes a range of projects to increase the usable rating of lines and transformers, increase voltage stability limits, and improve power flows to alleviate congestion that form ElectraNet's 2018-19 to 2022-23 NCIPAP. We also plan to improve the circuit breaker arrangement at Robertstown, to reduce significant operational constraints and costs during outages of plant and equipment.

Planning focus	Key outcomes
Maximum demand	Further network capacity in the Upper North region is needed to supply OZ Minerals' new and existing mines in the area. We are considering options that would also provide capacity for potential future developments in the Upper North, for example additional mine developments or solar farms. Increased transmission network capacity may also be needed on the Eyre Peninsula if potential significant load connections occur there in the future. Elsewhere, maximum demands are forecast to remain at about their present level. The remaining areas of South Australia's transmission network are projected to remain adequate to supply forecast maximum demand for the duration of the planning period.
Minimum demand	The minimum demand supplied by the transmission network is forecast to continue to decrease. A 50 Mvar, 275 kV reactor is being installed at Templers West during 2018 to prevent voltage levels from exceeding equipment ratings if an unplanned contingency event was to occur at times of low demand. Beyond this, the synchronous condensers that are planned to meet the identified system strength and potential inertia needs are expected to also enable improved system voltage control. A further 50 Mvar, 275 kV reactor may need to be installed between 2023 to 2028, to again prevent voltage levels from exceeding equipment ratings if an unplanned contingency event was to occur at times of low demand.
Maximum fault levels	Fault levels are forecast to remain within design and equipment limits for the duration of the planning period.
Emergency control schemes	A new System Integrity Protection Scheme (SIPS) has been implemented to reduce the likelihood that an outage of multiple generation units in South Australia will result in an outage of the Heywood interconnector between South Australian and Victoria. AEMO's Power System Frequency Review (PSFRR)[37] identified a need for upgrading the existing SIPS. We are working with AEMO on the scope of works for the upgrade (SIPS Stage 2).
Network asset retirements and de-ratings	We plan to address the condition of a range of assets on South Australia's electricity transmission network. Significant programs are based on an assessment of asset condition risk, cost and performance, and include the replacement of substation lighting and infrastructure, protection systems, transformer bushings and isolators, and the refurbishment of motorised isolators, transmission line support systems, insulators, and conductors.

7.2 Committed urgent and unforeseen investments

ElectraNet is required to report any investments that have been made since the publication of the last Transmission Annual Planning Report that would have been subjected to the RIT-T had they not been required to address an urgent and unforeseen network issue.

ElectraNet has not made any such investments.

[37] Available from https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Power-System-Frequency-Risk-Review.

7.3 National transmission planning

Consistent with the results of AEMO's mid 2018 ISP, we have developed one proposed project to that will increase electrical transmission interconnection between South Australia and the rest of the NEM.

ElectraNet's modelling indicates that this project will have a material impact on inter-regional transfer.

7.3.1 New high capacity interconnector

Scope of work:	Construct a new 330 kV, 800 MW interconnector from Robertstown in South Australia to Wagga Wagga in New South Wales, via Buronga
Estimated cost:	$1.5 billion
Project category:	Augmentation
Timing:	Between 2022 and 2024
Project status:	Contingent (refer to Appendix F section F4 for trigger)

Project need and option analysis:

On 7 November 2016, ElectraNet commenced the South Australian Energy Transformation RIT-T by publishing a PSCR.

We have now published the PADR for this RIT-T.[38]

As required by the Rules, the RIT-T is directed at meeting an identified need, which in this case is to create a net benefit to consumers and producers of electricity and support energy market transition through:

- lowering dispatch costs, particularly in South Australia, through increasing supply options across regions.
- facilitating the transition to lower carbon emissions and the adoption of new technologies through improving access to high quality renewable resources.
- enhancing security of electricity supply, including management of inertia, frequency response and system strength in South Australia.

ElectraNet has investigated variants of four credible options to address the identified need, comprising both a local South Australian 'non-interconnector' option as well as options involving new interconnectors to neighbouring states (Table 7-3).

All network options also include a Wide Area Protection Scheme (WAPS) to prevent cascaded tripping of the new interconnector and the Heywood interconnector following non-credible loss of either one.

[38] Available from www.electranet.com.au

Table 7-3: Summary of the four credible interconnector options assessed in the SA Energy Transformation RIT-T

Overview	Distance (km)[39]	Capital cost ($ billion)[40]	Annual contract cost ($ million)	Notional Maximum Capability (MW)	
				Heywood	New interconnector
'Non-interconnector' option					
Option A – Least cost non-interconnector option in SA	NA	–	130	650	–
An interconnector to Queensland					
Option B – HVDC from north SA to Qld	1,450	1.8	–	750	700
New South Wales interconnector options					
Option C.1 – New DC link from Riverland SA to NSW ('Murraylink 2')	370	0.8	–	750	300
Option C.2 – 275 kV line from mid-north SA to Wagga Wagga NSW, via Buronga	920	1.0	–	750	600
Option C.3 – 330 kV line from mid-north SA to Wagga Wagga NSW, via Buronga	920	1.4	–	750	800
Option C.3i – 330 kV line from mid-north SA to Wagga Wagga NSW, via Buronga, plus series compensation (or similar)	920	1.5	–	750	800
Option C.4 – 330 kV line mid-north SA to Wagga Wagga NSW, via Darlington Point	910	1,3	–	750	800
Option C.5 – 500 kV line Northern SA to east NSW	1,200	2.9	–	750	1,000
A new interconnector to Victoria					
Option D – 275 kV line from central SA to Victoria	420	1.2	–	750	650
Option Di – 275 kV line from central SA to Victoria plus series compensation (or similar)	420	1.2	–	750	650

ElectraNet received 18 submissions on the PSCR from network support proponents. Submissions to the PSCR helped us shape and include the standalone non-interconnector option in the RIT-T assessment.

39 All distances are approximate.
40 All options are based on a preliminary design have been designed and costed, to be consistent with the relevant Australian Standards.

ElectraNet engaged engineering consultants Entura to provide technical insight into how network support technologies could assist, particularly in relation to providing system security, and in identifying an optimal standalone non-network option.

For the interconnector options, both HVAC and HVDC options have been considered, with line lengths varying from 370 km to 1,450 km (Figure 7-2). These potential interconnectors have additional capacity varying from 300 MW to 1,000 MW, with indicative costs of $800 million to $2.900 billion. Potential energisation could occur from 2022 to 2024.

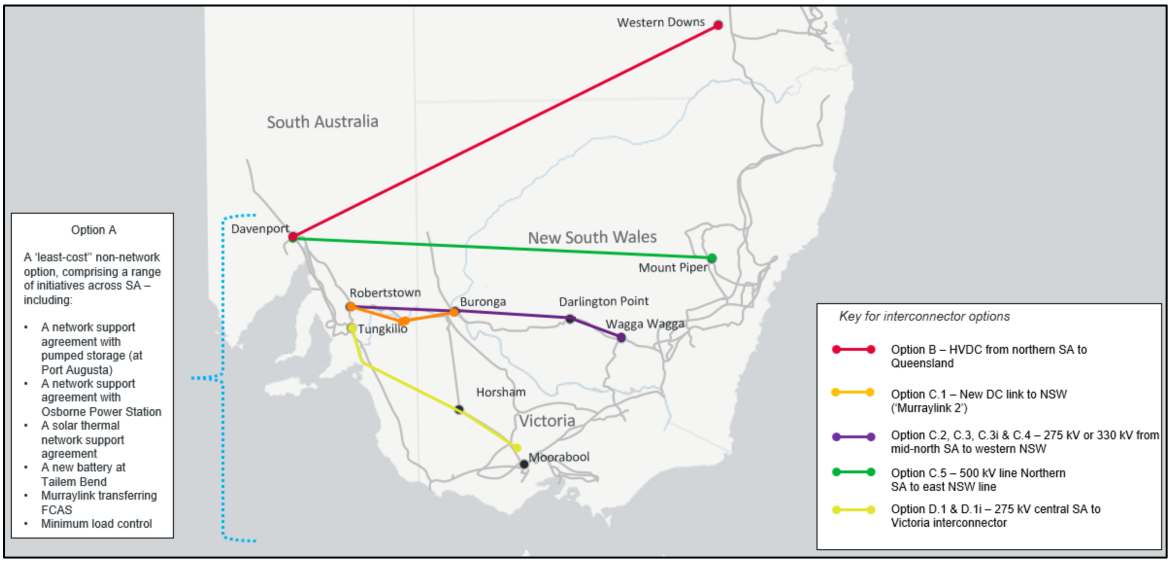

Figure 7-2: Overview of the options and variants assessed in the SA Energy Transformation RIT-T PADR

These interconnector options predominantly remain the same as set out in the PSCR, although ElectraNet has identified further variants of both the 330 kV interconnection option from mid-North South Australia to central and western NSW (Option C3i), and the 275 kV central South Australia to Victoria option (Option D1i) that include series compensation or equivalent investments to reduce constraints that would otherwise arise on the combined capacity of the existing Heywood interconnector and the new interconnector.

The RIT-T assessment presented in the PADR shows that overall additional interconnection at 330 kV between mid-north South Australia and western NSW is expected to deliver the highest net market benefit and to therefore satisfy the RIT-T.

The preferred option in the majority of scenarios and sensitivity tests, as well as under the weighted assessment, is Option C.3i. This option includes a tie-in to the existing network at Buronga and complementary investments in series capacitors (or similar technologies) to address constraint issues.

The key drivers of market benefit for option C.3i under the central scenario primarily arise from avoided gas generation dispatch costs, with a lesser contribution from the benefits arising from avoided generator fixed costs (with the forecast retirement of gas generation in South Australia), and the greater integration of renewables.

We have considered the interaction between this RIT-T and AEMO's concurrent Western Victoria RIT-T. The identification of Option C.3i as the preferred option is not affected by the outcome of the Victorian RIT-T.

Although some options identified within the Victorian RIT-T reduce the cost of new interconnection with Victoria in the SAET RIT-T, this reduction in cost is not sufficient to displace Option C.3i as the preferred option.

Option C.3i is estimated to deliver net market benefits of around $1 billion over 21 years (in present value terms)[41], including wholesale market fuel cost savings of around $100 million per annum putting downward pressure on wholesale electricity prices with flow on benefits to customer pricing. Independent modelling by ACIL Allen estimates an overall reduction in the average annual residential customer bill of up to about $30 in South Australia and $20 in New South Wales.

The new interconnector is estimated to cost $1.5 billion across both South Australia and New South Wales and could be delivered by 2022 to 2024.

ElectraNet envisages that this project will impact inter-regional transfer.

7.4 System strength and inertia

A secure power system needs adequate levels of both system strength and inertia, which to date have been provided by synchronous power generation.

System strength relates to the ability of a power system to manage fluctuations in supply or demand while maintaining stable voltage levels. Inertia relates to the ability of a power system to manage fluctuations in supply or demand while maintaining stable system frequency.

Both are important to ensure secure supply for customers. If there is not enough of these services within the power system, there is an increased risk of system instability and supply interruptions.

AEMO currently applies two constraints to wind farm outputs in South Australia to manage system strength and security:

1. AEMO applies a 1295 MW constraint to the total output of South Australian non-synchronous generation if only a minimum level of conventional plant is online (“low” combination of conventional generators). AEMO currently directs generation to maintain at least a minimum set of conventional plant online.
2. If sufficient conventional generators are online to meet a “high” combination of conventional generators, AEMO invokes a dynamic South Australian non-synchronous generation constraint that is linked to interconnector flows. For example, if the interconnector was exporting 400 MW during high wind and lighter demand conditions, the wind generation limit would by 2270 MW. Moving to the high combination of generators substantially increases the amount of wind generation that can be dispatched.

In October 2017, the Australian Energy Market Operator (AEMO) declared a gap in system strength in South Australia. This gap relates to the provision of sufficient system strength to enable AEMO to apply the first constraint described above, without the need to direct a minimum level of conventional generation to remain online.

41 Broader benefits to the wider economic are additional to and beyond the scope of this RIT-T assessment, which is required to focus on the direct benefits to consumers and producers of electricity.

ElectraNet is required to use its reasonable endeavours to address this gap on an ongoing basis.

We have proposed one project to meet this need; however, the scope of this project is subject to the outcome of detailed studies (section 7.4.1).

7.4.1 Maintain required minimum levels of South Australian system strength

Scope of work:	Upgrade existing protection devices and install synchronous condensers at selected locations across the 275 kV transmission network
Estimated cost:	\$80-\$140 million
Project category:	Security/Compliance
Timing:	2020
Project status:	Planned

Project need and option analysis:

On 13 October 2017, AEMO declared a gap in system strength in South Australia,[42] which ElectraNet has opted to treat as a fault level shortfall under the new system strength framework described in clause 5.20C.3 of the Rules. ElectraNet is required to use its reasonable endeavours to address this gap on an ongoing basis.

To address the gap in the short-term, AEMO has identified various combinations of South Australian synchronous generators which must be operating. AEMO currently directs these generators to operate when required under its powers of market direction. However, this is a costly process considering the compensation that directed generators are entitled to and the associated impacts on the wholesale electricity market. Directing generators is an interim operational solution only, and is unlikely to remain a viable option in the longer term.

ElectraNet has evaluated the potential options to meet the system strength requirement, including the option of entering into contracts with the relevant generators. This involved a generator tendering process and advice from independent energy market experts.

Our analysis identified that in the interests of customers:

- Contracts with generators would not be economic based on generator costs obtained from the available synchronous generators
- Installing synchronous condensers on the network is the least cost solution, and that staged options should also be considered where feasible and economic
- The cost and risks of the current generator direction process requires a fast track alternative solution
- No other realistic options are available to meet the need in the required timeframe

[42] AEMO, Second Update to the 2016 National Transmission Network Development Plan tor the National Electricity Market, October 2017, available at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Transmission-Network-Development-Plan.

- Installing network synchronous condensers is a no regrets measure to meet an immediate need. Any future sources of system strength available will help address wider constraints on the power system.

Table 7-4: Options considered to maintain required minimum levels of South Australian system strength

Option	Description
Base Case	AEMO continues to operate under the generator directions framework. Ongoing direction compensation costs per annum are currently estimated to be in the order of approximately $50 million to $70 million per annum[43] based on annualised historical costs.[44] There is also considerable risk and uncertainty as to how long this operational solution will remain viable from a practical perspective.
Option 1	ElectraNet sources system strength services from existing synchronous generators in South Australia (AGL Energy, Engie and/or Origin Energy). Annual generator contract costs are estimated to be $85 million per annum based on tender pricing.[45]
Option 2	ElectraNet installs a number of synchronous condenser units at suitable network sites at an indicative capital cost of $80 million to $140 million. Commissioning within 24 months (by 1 July 2020).

We are working with specialist consultants to develop the scope of the synchronous condenser solution that will alleviate the requirement to run any synchronous generators in meeting AEMO's 1,295 MW constraint. In preparation of this engagement appropriate PSCAD models have been sourced from existing wind farms and the scope of the studies has been agreed with AEMO. This work is being progressed as a very high priority and is expected to take several months to complete.

ElectraNet is engaging with a number of suppliers of synchronous machines to competitively source the required units for contract award before the end of 2018 and subsequent installation as soon as possible, including any prudent staged options which may enable earlier delivery. Commissioning is expected to occur by mid 2020.

We are expecting AEMO to publish a minimum inertia requirement for South Australia (during periods when separation is credible) by the end of June 2018. This requirement will be included in the scoping studies and potentially lead to the synchronous condensers being fitted with flywheels.

The most likely sites being considered are on the 275 kV network at Davenport, Robertstown and an Adelaide metropolitan site yet to be determined (Figure 7-3).

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43 Reflects updated advice provided by AEMO on market directions issued up to 18 May 2018.

44 This excludes the broader impact of intervention pricing on the wholesale market through the generator direction process, estimated at $24m over the 4 months to December 2017 based on information from AEMO.

45 Under this option, there would also remain a potential need for generator direction with its associated costs once the volumes and unit combinations offered by tenderers had been exhausted, and a potential for negative pool price exposure, both of which would add further costs to this option. These additional costs have not been included in this assessment.

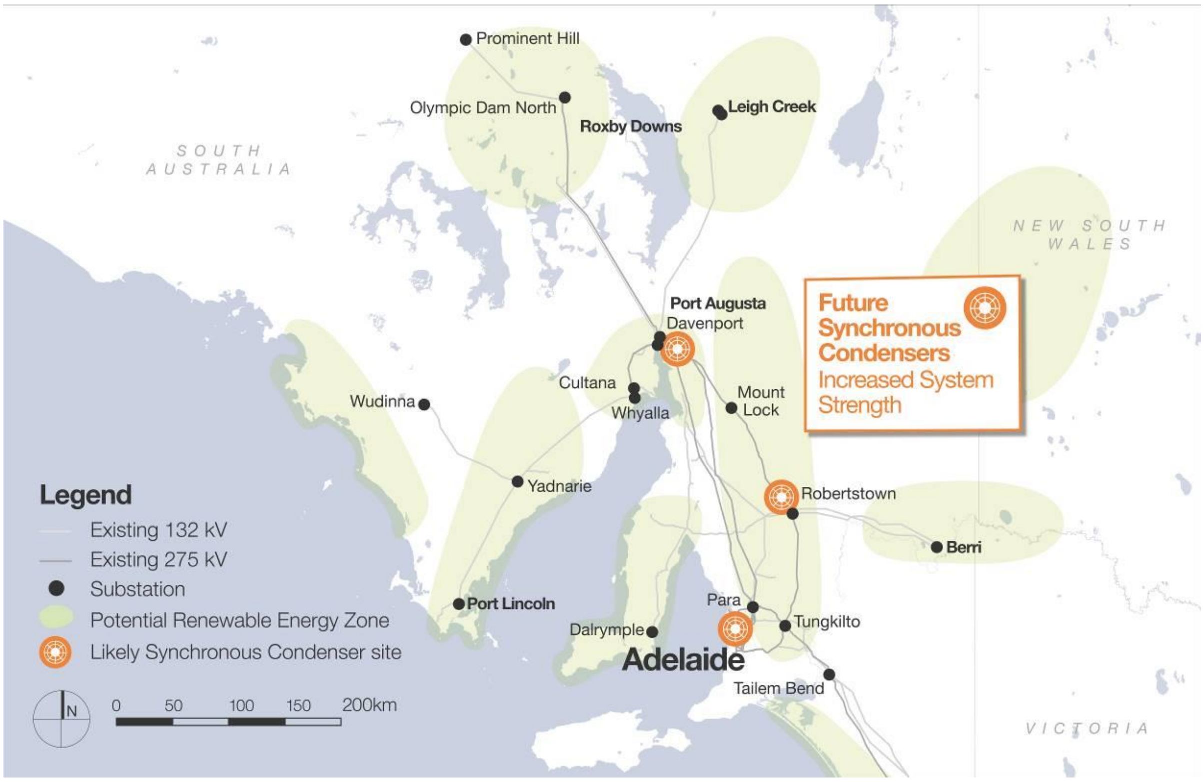


Figure 7-3: Likely sites to install synchronous condensers

While helping to maintain a stable power system, installing synchronous condensers will also avoid the need for costly generator direction by AEMO which is expected to result in a net cost saving equivalent to $18 to $20 per year on a typical South Australian residential electricity bill.

Next steps include:

- Develop detailed specification and design of a full synchronous condenser solution in consultation with AEMO and manufacturers
- Approval by AEMO of the technical specifications, performance standards and operational arrangements
- Competitive sourcing of synchronous condensers and associated equipment direct from the relevant suppliers
- Obtain land & approvals for the relevant sites
- Assessment and approval of the required capital and operating expenditure by the Australian Energy Regulator (AER)
- Construction & commissioning by mid 2020.

AEMO, the AER and the South Australian Government have expressed their support for this fast track approach to meet the system strength shortfall. We will continue to work closely with these bodies, customers and wider stakeholders to deliver a solution that is in the best interests of electricity customers.

ElectraNet envisages that this project will impact inter-regional transfer in a manner that is expected to place downward pressure on electricity market prices in South Australia.

7.5 Connection points

ElectraNet annually compares connection capability against forecast connection point demand, considering the redundancy requirements specified for each connection point in the ETC (Appendix C section C2.1) with SA Power Networks, in which connection point projects are considered, proposed, and planned.

Over the 10-year planning period, only one connection point – Port Lincoln Terminal – requires action to ensure that its Category 3 reliability standard continues to be met (section 7.5.1). This action is not driven by an increase in demand, but rather by the expiry of the existing network support arrangement.

In addition, one new connection point is proposed, at Gawler East (section 0), subject to local land development activity and advice from SA Power Networks regarding required timing. The locations of these projects are shown in Figure 7-4.

ElectraNet does not envisage that these projects will have any material impact on inter-regional transfer.

7.5.1 Replace Eyre Peninsula 132 kV transmission lines

Scope of work: Reconductor sections of the Cultana to Yadnarie and Yadnarie to Port Lincoln 132 kV lines, or replace the lines with new 132 kV or 275 kV lines

Estimated cost: $80 to $560 million (based on the range of options being considered)

Project category: Contingent – refer to Appendix F (section F4) for trigger

Timing: December 2021

Project status: Contingent

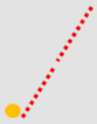
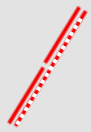
Project need and option analysis:

ElectraNet is exploring options for providing reliable electricity supply to the Eyre Peninsula most efficiently in the future, including ‘future proofing’ to accommodate potential developments in mining and renewable energy investment on the Eyre Peninsula.

We are investigating five broad options for supplying the Eyre Peninsula, including variants of these options (Table 7-5). These range from maintaining equivalent capacity on the Eyre Peninsula as currently (that is, a single-circuit 132 kV line coupled with network support at Port Lincoln), through to upgrading the entire network to 275 kV, with two completely divergent network paths (including one going via Wudinna).

Figure 7-4: Planned connection point projects

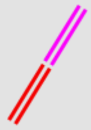
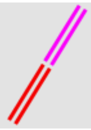
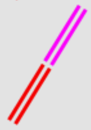
Table 7-5: Options considered for Eyre Peninsula 132 kV line replacement

Option Overview	Capital cost ($ million)	Affected/new network[46]
Option 1 ('base case') Continue network support at Port Lincoln and reconductor the existing 132 kV single-circuit line	80[47]	
Reconductor remaining sections of 132 kV single-circuit line in about 2033	90[48]	
Option 2 A double circuit 132 kV line following a Cultana to Yadnarie and Yadnarie to Port Lincoln route, each circuit rated to about 240 MVA	225	
Option 2B A single-circuit (about 240 MVA) 132 kV line along a parallel route to the existing Cultana to Yadnarie and Yadnarie to Port Lincoln 132 kV single-circuit line, and reconductor the existing 132 kV single-circuit line	210	
Reconductor remaining sections of 132 kV single-circuit line in about 2033	25	
Option 3 Two single circuit 132 kV lines routes between Cultana and Port Lincoln (one going via Wudinna), each circuit rated to about 240 MVA	405	
Option 3B A single-circuit (about 240 MVA) 132 kV line following a Cultana to Wudinna and Wudinna to Port Lincoln route, and reconductor the existing Cultana to Yadnarie and Yadnarie to Port Lincoln 132 kV line	285	
Reconductor remaining sections of 132 kV single-circuit line in about 2033	25	
Option 4A Double circuit 275 kV following a Cultana to Yadnarie and Yadnarie to Port Lincoln route, each circuit rated to about 600 MVA	330	

46 These schematics illustrate the affected/new network under each option. Under all options, the existing 132 kV line from Wudinna to Yadnarie remains unchanged and so is not shown in these high-level network diagrams.

47 Capital cost includes network support costs incurred during construction.

48 Capital cost includes network support costs incurred during construction.

Option Overview	Capital cost ($ million)	Affected/new network[46]
Option 4B Double circuit 275 kV between Cultana and Yadnarie, each circuit rated to about 600 MVA, and double circuit 132 kV between Yadnarie and Port Lincoln, each circuit rated to about 240 MVA	275	
Option 4C Double circuit 132 kV line following a Cultana to Yadnarie and Yadnarie to Port Lincoln route, each circuit initially rated to about 300 MVA – with the ability to be upgraded to 275 kV at a later date, if required, for a new rating of about 600 MVA for each circuit	240	
	55	
	95	
Option 4D Double circuit 132 kV line following a Cultana to Yadnarie route, each circuit initially rated to about 300 MVA, and following a Yadnarie to Port Lincoln route, each circuit initially rated to about 240 MVA – with the ability to upgrade the Cultana to Yadnarie section to 275 kV at a later date, if required, for a new rating of about 600 MVA for each circuit	230	
	55	
Option 5A Two single circuit 275 kV lines following separated routes between Cultana and Port Lincoln (one going via Wudinna), each circuit rated to about 600 MVA	560	
Option 5B Two single circuit lines between Cultana and Port Lincoln (one going via Wudinna), with the Cultana to Wudinna line built and operated at 275 kV and rated to about 600 MVA, and the rest only ever operated at 132 kV with each circuit rated to about 240 MVA	450	

Option Overview	Capital cost ($ million)	Affected/new network[46]
Option 5C Two single circuit 132 kV lines following separated routes between Cultana and Port Lincoln (one going via Wudinna), each circuit rated to about 300 MVA – with the ability to be upgraded to 275 kV at a later date, if required, for a new rating of about 600 MVA for each circuit	455	
	25	
	60	
	110	

Key:			&	&
	Reconductored 132 kV	*Network support at Port Lincoln*	*132 kV single-circuit & 132 kV double-circuit*	*275 kV single-circuit & 275 kV double-circuit*

We are currently finalising the RIT-T and intend to publish a PACR in July 2018, which will include a full analysis of the options considered.

7.5.2 Establish a new connection point at Gawler East

Scope of work: Cut into the Para to Roseworthy 132 kV line and create a 132 kV connection point for a new 132/66/11 1x25 MVA transformer substation

Estimated cost: <$5 million (transmission component comprising 132 kV bus and connection point)

Project category: Connection

Timing: November 2023

Project status: Proposed

Project need and option analysis:

The new Gawler East 132 kV connection point is planned to support “greenfields” residential development in the area. The development site allows for up to 2,450 allotments and a commercial centre with an ultimate residential demand estimated at 22 MVA and 2.5 MVA of commercial load. There are also future plans to develop the adjacent greenfields region (Concordia), with more than double the potential ultimate demand increase. Residential development commenced at Gawler East in 2014, with an anticipated requirement for the new 132/11 kV zone substation by the end of 2022.

SA Power Networks has advised that it plans to work with ElectraNet to commence a Regulatory Investment Test for Distribution (RIT-D) assessment by issuing a Non-Network Options Report (NNOR) at a future date.

A suitable ElectraNet 132 kV transmission line traverses the planned greenfields residential development region. Compared to the alternative of extending SA Power Networks' 66 kV network, a new connection point is better placed both environmentally (as the 132 kV line already exists), and in terms of total cost to South Australian distribution customers (as the total cost is lower), to supply SA Power Networks' proposed 25 MVA 11 kV substation.

The preferred option will be determined by the outcome of the RIT-D assessment (Table 7-6).

ElectraNet does not envisage that this project will impact inter-regional transfer.

Table 7-6: Options considered for a new Gawler East connection point

Option	Description	Comment	Estimated cost ($ Million)
1	Build 132 kV bus to provide supply to a 132/11 kV substation	ElectraNet to provide 132 kV bus and connection point; SA Power Networks to own 1x25 MVA 132/11 kV transformer	11-14 (ElectraNet and SA Power Networks)
2	Build a 132/11 kV substation with a single 25 MVA transformer	ElectraNet to own 1x25 MVA 132/11 kV transformer and provide an 11 kV connection point	11-14 (ElectraNet and SA Power Networks)
3	Distribution solution: SA Power Networks to construct a new 66 kV line and 66/11 kV zone substation	This option is expensive and is excluded from further consideration	16-34 (SA Power Networks)
4	Non-network solution:		

7.6 Market benefit opportunities

ElectraNet monitors congestion on the South Australian transmission network. We also consider information regarding future likely generator and load connections, along with AEMO's most recent NTNDP or ISP (as available), to predict new constraints that may develop in future years.

Over the next five years, we plan to complete projects that form part of our 2018-19 to 2022-23 Network Capability Incentive Parameter Action Plan (NCIPAP, sections 7.6.1 to 7.6.3 and 7.6.5 to 7.6.7). We have also proposed one further market benefit project for the 2018-19 to 2022-23 regulatory control period (section 7.6.4).

The locations of these projects are illustrated in Figure 7-5.

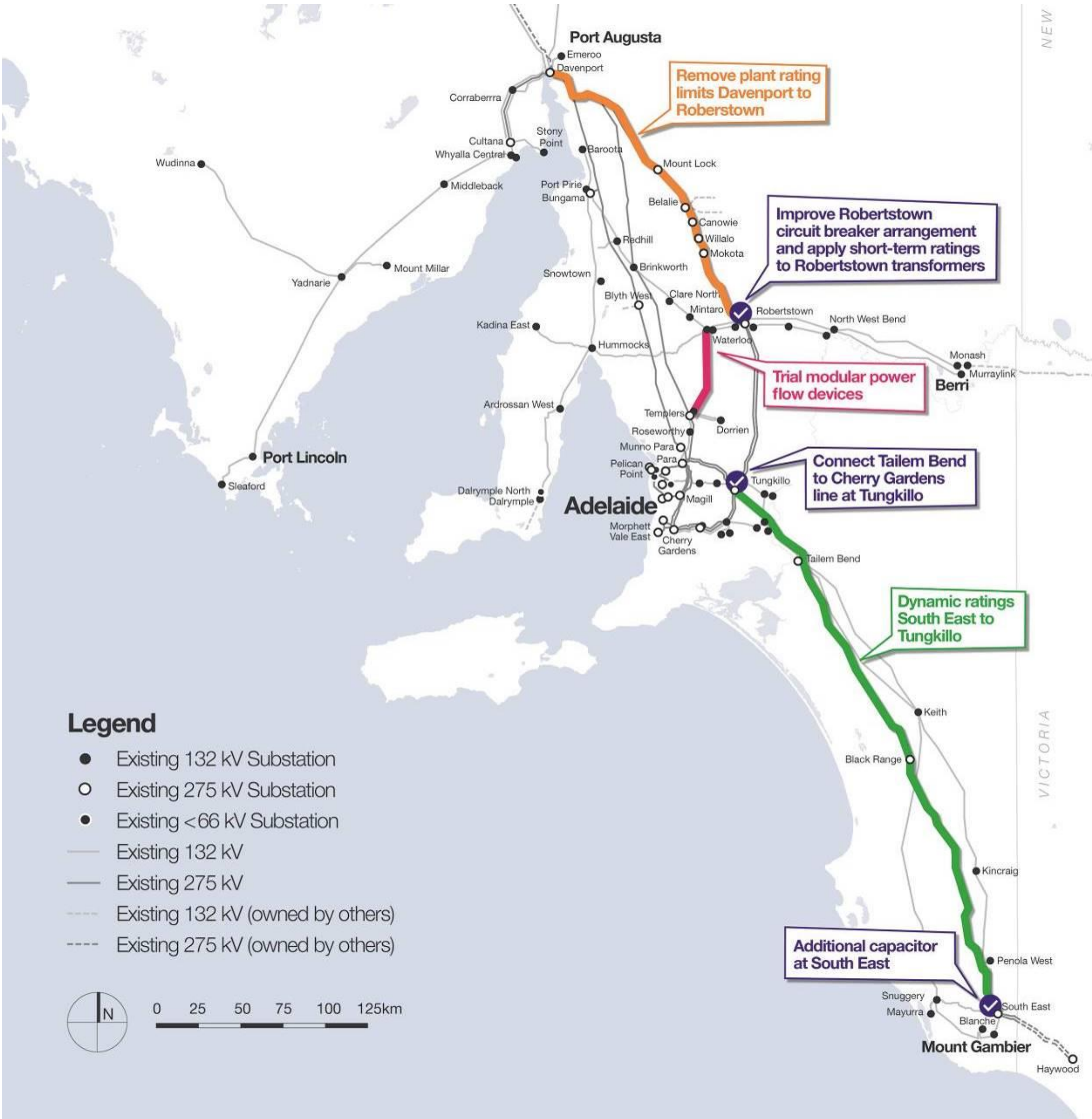


Figure 7-5: Planned and proposed market benefits projects

7.6.1 Trial modular power flow control elements to relieve congestion

Scope of work:	Install modular power flow control elements to relieve congestion on the Waterloo to Templers 132 kV line, and uprate the parallel Robertstown to Tungkillo and Robertstown to Para 275 kV lines as well as the Templers to Roseworthy 132 kV line
Estimated cost:	$3-6 million
Project category:	2018-19 to 2022-23 NCIPAP
Timing:	March 2019 for installation of modular power flow control elements, December 2019 for completion of transmission line works

Project status: Planned

Project need and option analysis:

This project is in ElectraNet's NCIPAP for the 2018-19 to 2022-23 period. Uprating the relevant 275 kV and 132 kV lines and installing the modular power flow control elements on the Waterloo to Templers 132 kV line will reduce forecast congestion between the Adelaide metropolitan region and the northern region of SA, where AEMO's 2016 NTNDP identified that 1,400 MW of renewable generation may connect by 2020-21.[49]

This will increase the transfer capacity between the northern region of SA and the Adelaide metropolitan region by about 17 MW. During network conditions that have high flows on the 132 kV lines relative to the 275 kV lines, the dynamic line impedance devices are expected to alleviate constraints by more than 17 MW.

ElectraNet envisages that this project will impact intra-regional transfer, but not inter-regional transfer.

7.6.2 Apply dynamic ratings to transmission lines between South East and Tungkillo

Scope of work: Apply dynamic ratings to the Tailem Bend to Tungkillo, Tailem Bend to Cherry Gardens, South East to Tailem Bend No. 1, and South East to Tailem Bend No. 2 275 kV lines and to the Tailem Bend to Mobilong 132 kV line

Estimated cost: <$5 million

Project category: 2018-19 to 2022-23 NCIPAP

Timing: June 2019

Project status: Planned

Project need and option analysis:

This project is in ElectraNet's NCIPAP for the 2018-19 to 2022-23 period. Increasing the dynamic rating of these lines will reduce congestion on the Heywood interconnector, enabling increased power transfers to and from Victoria by about 31 MW. This is the average improvement expected from improving the ratings of the Tailem Bend to Tungkillo 275 kV line summer ratings by 47 MW and the spring/autumn ratings by 15 MW, up to the 650 MW Heywood interconnector limit.

ElectraNet envisages that this project will impact inter-regional transfer, by increasing the thermal transfer capacity across the Heywood interconnector.

[49] Since December 2016, ElectraNet has connected 209 MW of new renewable generation in this region, and a further 549 MW of new renewable generation has committed to connect. ElectraNet is also aware of substantial further interest in connecting new renewable generation in this region.

7.6.3 Remove plant rating limits from the Robertstown to Davenport 275 kV lines

Scope of work: Remove and replace plant that are rated lower than the design capability of the conductors on the 275 kV lines between Robertstown and Davenport, to release further transfer capacity

Estimated cost: <$5 million

Project category: 2018-19 to 2022-23 NCIPAP

Timing: June 2019

Project status: Planned

Project need and option analysis:

This project is in ElectraNet's NCIPAP for the 2018-19 to 2022-23 period. Increasing the rating of this line will alleviate forecast congestion between the northern region of SA, where AEMO's 2016 NTNDP identified that 1,400 MW of renewable generation may connect by 2020-21[50], and the Adelaide metropolitan region.

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

ElectraNet envisages that this project will impact intra-regional transfer, but not inter-regional transfer.

7.6.4 Improve Robertstown circuit breaker arrangement

Scope of work: Install a single 275 kV circuit breaker and associated equipment (including isolators, current transformer and protection) between the 275 kV buses at Robertstown

Estimated cost: $5-8 million

Project category: Security/Compliance

Timing: June 2020

Project status: Proposed - to be reviewed following completion of the South Australian Energy Transformation RIT-T

Project need and option analysis:

The present layout of Robertstown substation poses operational challenges. During planned outages of certain items of plant, it is possible for an unplanned 275 kV line outage to electrically separate the 275 kV buses. This would result in large power flows travelling from one 275 kV bus, through one Robertstown 275/132 kV transformer, and back up the other Robertstown 275/132 kV transformer to the other 275 kV bus. To guard against the risk of

50 Since December 2016, ElectraNet has connected 209 MW of new renewable generation in this region, and a further 549 MW of new renewable generation has committed to connect. ElectraNet is also aware of substantial further interest in connecting new renewable generation in this region.

transformer overload during such times, the Murraylink interconnector needs to be significantly constrained and generation north of Robertstown may need to be constrained to limit potential post-contingency flows.

This project will reduce 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.

ElectraNet envisages that this project will impact inter-regional transfer, by alleviating constraints on Murraylink interconnector during planned outages at Robertstown substation.

The need for this project may be addressed by the outcome of the South Australian Energy Transformation RIT-T. The need for this project will be reviewed following the completion of the South Australian Energy Transformation RIT-T process, after which ElectraNet will initiate a new RIT-T if this project continues to be required.

7.6.5 Install an additional 100 Mvar 275 kV capacitor bank at South East

Scope of work: Install an additional 100 Mvar 275 kV switched capacitor at South East substation

Estimated cost: <$5 million

Project category: 2018-19 to 2022-23 NCIPAP

Timing: June 2020

Project status: Planned

Project need and option analysis:

This project is in ElectraNet's NCIPAP for the 2018-19 to 2022-23 period. Installing this capacitor will alleviate forecast congestion on the Heywood interconnector due to voltage stability limits.

This will increase the 'firmness' of Heywood interconnector's notional 650 MW capability, providing increased availability of the full capability.

ElectraNet envisages that this project will impact inter-regional transfer, by enabling voltage stability to be maintained at increased transfer levels across the Heywood interconnector.

7.6.6 Connect the Tailem Bend to Cherry Gardens 275 kV line at Tungkillo

Scope of work: Populate one additional diameter at Tungkillo to connect the Tailem Bend to Cherry Gardens 275 kV line, to improve inter-regional transfer capacity

Estimated cost: $3-6 million

Project category: 2018-19 to 2022-23 NCIPAP

Timing: June 2021

Project status: Planned

Project need and option analysis:

This project is in ElectraNet's NCIPAP for the 2018-19 to 2022-23 period. Tying in the Tailem Bend to Cherry Gardens 275 kV line is expected to alleviate voltage limitations on the Heywood interconnector, allowing the 650 MW operational limit to be available more often.

At times when voltage limits restrict flows on the Heywood interconnector, this project will increase the interconnector's transfer capability by 10 MW.

ElectraNet envisages that this project will impact inter-regional transfer.

7.6.7 Apply short term overload ratings to the Robertstown 275/132 kV transformers

Scope of work: Install transformer management relays and bushing monitoring equipment to enable the application of short term ratings to the Robertstown 275/132 kV transformers

Estimated cost: <$5 million

Project category: 2018-19 to 2022-23 NCIPAP

Timing: June 2022

Project status: Planned

Project need and option analysis:

This project is in ElectraNet's NCIPAP for the 2018-19 to 2022-23 period. Uprating the Robertstown 275/132 kV transformers will reduce forecast congestion between the Riverland and the northern region of SA, where further renewable generation is forecast to connect.

This project will increase the ratings of the Robertstown transformers by 48 MVA, alleviating forecast constraints on Murraylink interconnector.

ElectraNet envisages that this project will impact inter regional transfer, by improving the export capability of Murraylink interconnector.

7.7 Maximum demand

Maximum demands on South Australia's electricity transmission network typically occur during heatwave conditions in summer (section 3.1).

We have assessed the ability of the network to deliver maximum demand without overload with all system elements in service, and allowing for any one item of plant to be out of service.

As a result, we are projecting that the transmission network is adequate to supply forecast maximum demand for the duration of the 10-year planning period. However, two projects to reinforce 132 kV transmission lines may be needed if potential significant spot loads connect in certain locations (Figure 7-5, with details in sections 7.7.1 and 7.7.2).

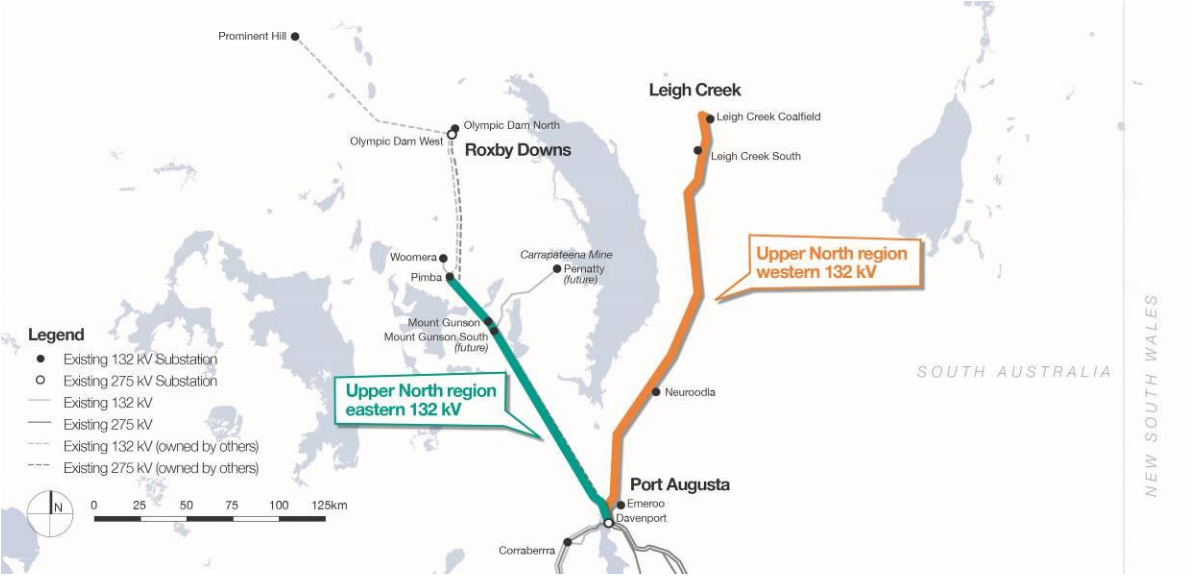


Figure 7-6: Contingent projects to meet possible localised increases in maximum demand

7.7.1 Upper North region eastern 132 kV line reinforcement

Scope of work: Uprate or rebuild the Davenport to Leigh Creek 132 kV line and establish associated substation assets (including reactive support).

Estimated cost: $60 million

Project category: Augmentation

Timing: Uncertain

Project status: Contingent – refer to Appendix F (section F4) for trigger

Project need and option analysis:

The existing Davenport to Leigh Creek 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. Most circuits designed and built to this standard have been uprated or replaced. However, the Davenport to Leigh Creek 132 kV line continues to have an adequate rating for the small load it currently supplies at Neuroodla, the Leigh Creek coal mine and Leigh Creek Township, so uprating or replacement has not yet been necessary.

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 some 300 of the total 600 spans in the existing 240 km line to be uprated to meet minimum ground clearance requirements.

Any step load increase causing the line to exceed its thermal limit of 10 MVA would require the line to be significantly uprated or rebuilt.

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

ElectraNet does not envisage that this project will impact inter-regional transfer.

7.7.2 Upper North region western 132 kV line reinforcement

Scope of work: Rebuild the Davenport to Pimba 132 kV line and establish associated substation assets (including reactive support).

Estimated cost: $110 million

Project category: Augmentation

Timing: Uncertain

Project status: Contingent – refer to Appendix F (section F4) for trigger

Project need and option analysis:

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. The line has a rating of 76 MVA, as it was uprated to allow this level of loading during the 1980s to support the initial development of Olympic Dam. That uprate work involved lifting the lowest spans using insulated cross-arms. 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 require the line to be rebuilt.

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

ElectraNet does not envisage that this project will impact inter-regional transfer.

7.8 Minimum demand

For many years, minimum demands on South Australia's electricity transmission network typically occurred at roughly 4 AM in the morning during periods of mild weather, such as during April and Spring. More recently, the increasing penetration of rooftop solar PV has seen periods in the middle of the day record even lower demand levels, typically on mild, sunny weekends or public holidays. AEMO forecasts the level of minimum demand in South Australia to continue to decrease over the forecast period (section 3.3).

Low demands drawn from the transmission level can correlate closely with a decreased dispatch of large synchronous generators (section 1.3.2).

Our analysis has shown that high main grid voltage levels are expected to occur at such times of extremely low demand. Investment is needed to prevent voltage levels from exceeding equipment ratings during system normal conditions or after an unplanned outage of any single line, transformer, or other network element.

As a result, we have determined that one project is expected to be needed over the 10-year planning period to manage the impact of declining minimum demand (Figure 7.6, details in section 7.8.1).

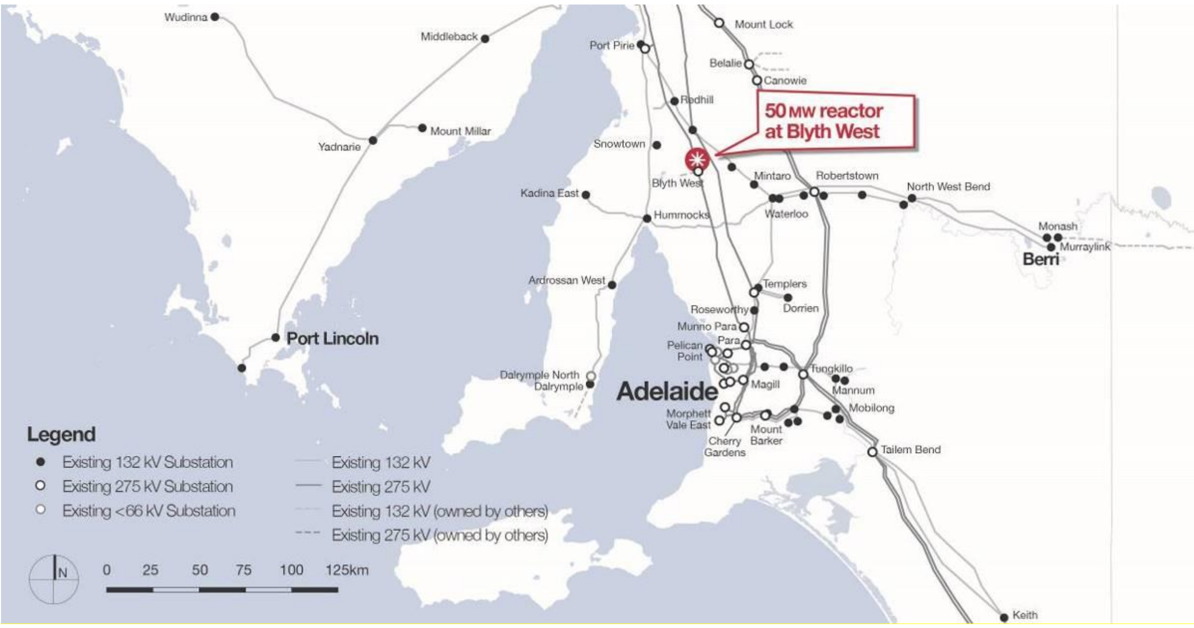


Figure 7-7: Planned project to address declining minimum system demand

7.8.1 Install a 50 Mvar 275 kV switched reactor at Blyth West

Scope of work: Install a switched 50 Mvar 275 kV reactor at Blyth West

Estimated cost: <$5 million

Project category: Security/Compliance

Timing: About 2025

Project status: Proposed

Project need and option analysis:

AEMO's March 2018 EFI forecast that minimum demand supplied by SA's transmission network may drop to below zero from summer 2025-26 (that is, continued rooftop solar PV installations would reach a level that will more than offset consumer demand). ElectraNet's studies show that steady-state voltage levels on the South Australian transmission system may again breach 110% at such times of low demand, following a single contingency event of an in-service generator or significant item of reactive control plant. This can be addressed by installing an additional 50 Mvar 275 kV reactor before September 2025, to limit high voltage levels on the transmission network at times of low system demand.

Initial studies indicate that installing this reactor at Blyth West may optimise the benefit. Further studies will provide further clarity for scope and timing after the scope for the expected future installation of synchronous condensers in South Australia has been determined (section 7.4.1).

ElectraNet does not envisage that this project will have any material impact on inter-regional transfer.

7.9 Maximum fault levels

For safety reasons, transmission system maximum fault levels should not exceed the fault rating of the bus or any equipment in that part of the system at any time for any plausible network configuration. It is also important that the fault level at a substation does not exceed the fault rating of the earth grid to prevent excessive earth potential rise.

Based on the outcomes of AEMO's ISP, the total conventional generation in South Australia is expected to reduce over the next ten years. Substation fault levels were assessed (Appendix E) to ensure they will remain within design and equipment limits.

7.10 Network asset retirements and replacements

ElectraNet has a number of projects that are planned to address needs that arise from planned retirements of assets (e.g. due to condition).

Projects have been selected for presentation in this section if they are subject to the RIT-T, or if they would be been subject to the RIT-T if they had not already been committed by 30 January 2018.

A full list of projects to address asset retirement needs is included in section F3 of Appendix F.

7.10.1 Line Conductor and Earthwire Refurbishment 2018-23 Program

Scope of work: Program to replace transmission line conductors and earthwire to extend the life of 7 transmission lines.

Estimated cost: $15-$20 million

Project category: Replacement

Timing: 2019 to 2022

Project status: Planned

Project need and option analysis:

It has been identified that 7 conductor and earthwire sections have been assessed at end life. This program is required to replace the line conductor and earthwire on the 7 lines sections to achieve an overall life extension of transmission lines.

Significant consequences exist in the event of conductor failure along these lines, if they are not replaced. Primarily, the consequences relate to dropping a conductor to ground which affects network availability, safety and fire start risk.

The options considered include:

1. Replace transmission line conductors and earthwire on selected transmission lines during the 2018-19 to 2022-23 regulatory period;
2. Replacement of individual components or sections on failure: and.
3. Full transmission line replacement.

Option 1, to replace to replace transmission line conductors and earthwires together with associated line hardware on 7 transmission lines during the 2018-2023 period, is the preferred option. This reduces risk including the probability of failure, the likelihood of personal injury consequences and the extent of customer supply interruption from transmission line conductors and earthwire failure. These planned transmission line conductors and earthwire replacement will increase the asset life of the 7 transmission lines (Table 7-7, Figure 7-8).

Table 7-7: Transmission lines included in the line conductor and earthwire refurbishment 2018-23 program

Lines	Line length (km)	Year
Waterloo – Waterloo East 132 kV line	3	2019 – 2022
Waterloo East – Morgan Whyalla Pump Station #4 132 kV line	14	2019 – 2022
Morgan Whyalla Pump Station #4 – Robertstown 132 kV line	8	2019 – 2022
Morgan Whyalla Pump Station #3 – Morgan Whyalla 132 kV line	8	2019 – 2022
Morgan Whyalla Pump Station #3 – Morgan Whyalla Pump Station #2 132 kV line	22	2019 – 2022
Morgan Whyalla Pump Station #2 – Morgan Whyalla Pump Station #1 132 kV line	25	2019 – 2022
Morgan Whyalla Pump Station #1 – North West Bend 132 kV line	6	2019 – 2022

The replacement of conductors and earthwires lines sections are targeted to meet needs on individual lines, and so have been conceived as individual projects. To improve delivery efficiency, ElectraNet plans to deliver these projects as a single program of work.

ElectraNet does not envisage that these projects will impact inter-regional transfer.

As none of the individual projects exceeds $6 million in estimated cost, ElectraNet does not plan to apply the RIT-T to these planned investments.

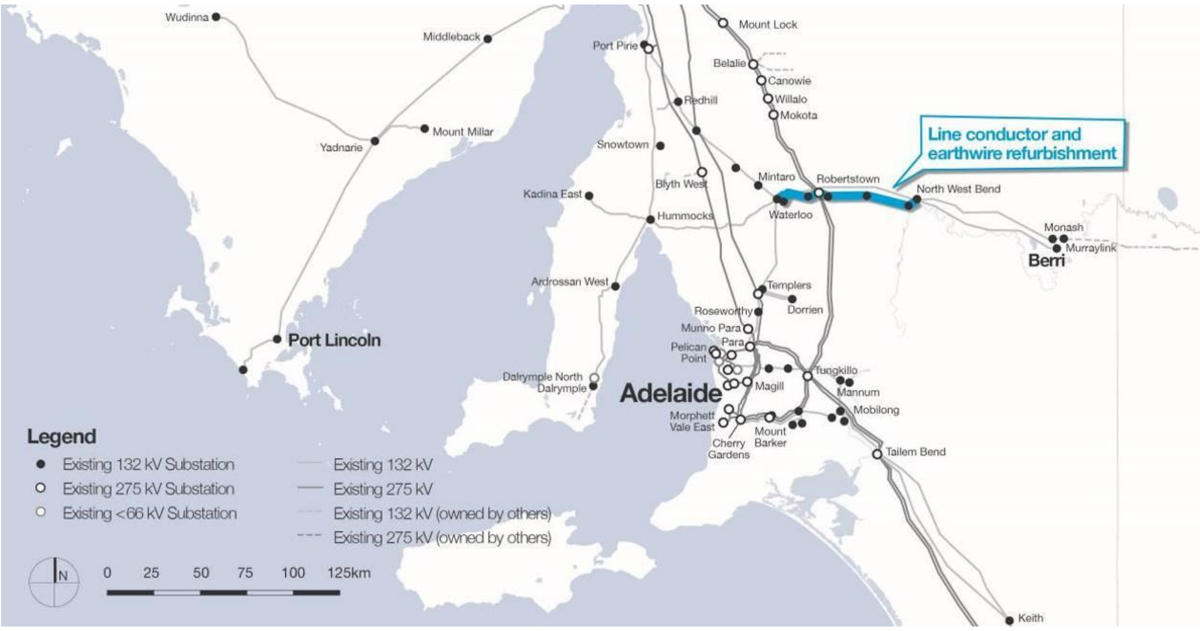


Figure 7-8: Transmission lines included in the line conductor and earthwire refurbishment 2018-23 program

7.10.2 AC Board Replacement 2018-23

Scope of work: Replace and improve AC auxiliary supply equipment, switchboards and cabling at 17 substations

Estimated cost: $8-$12 million

Project category: Replacement

Timing: 2022

Project status: Planned

Project need and option analysis:

A review undertaken in previous years had identified 35 sites requiring replacement of AC boards and associated equipment to address safety and operational security risks. The highest risk sites have been addressed during 2009-10 to 2012-13 period, with a further eleven sites addressed during the 2013-13 to 2017-18 period.

This project is to address the seventeen sites that have been assessed to be exposed to the next highest risk (Figure 7-9).

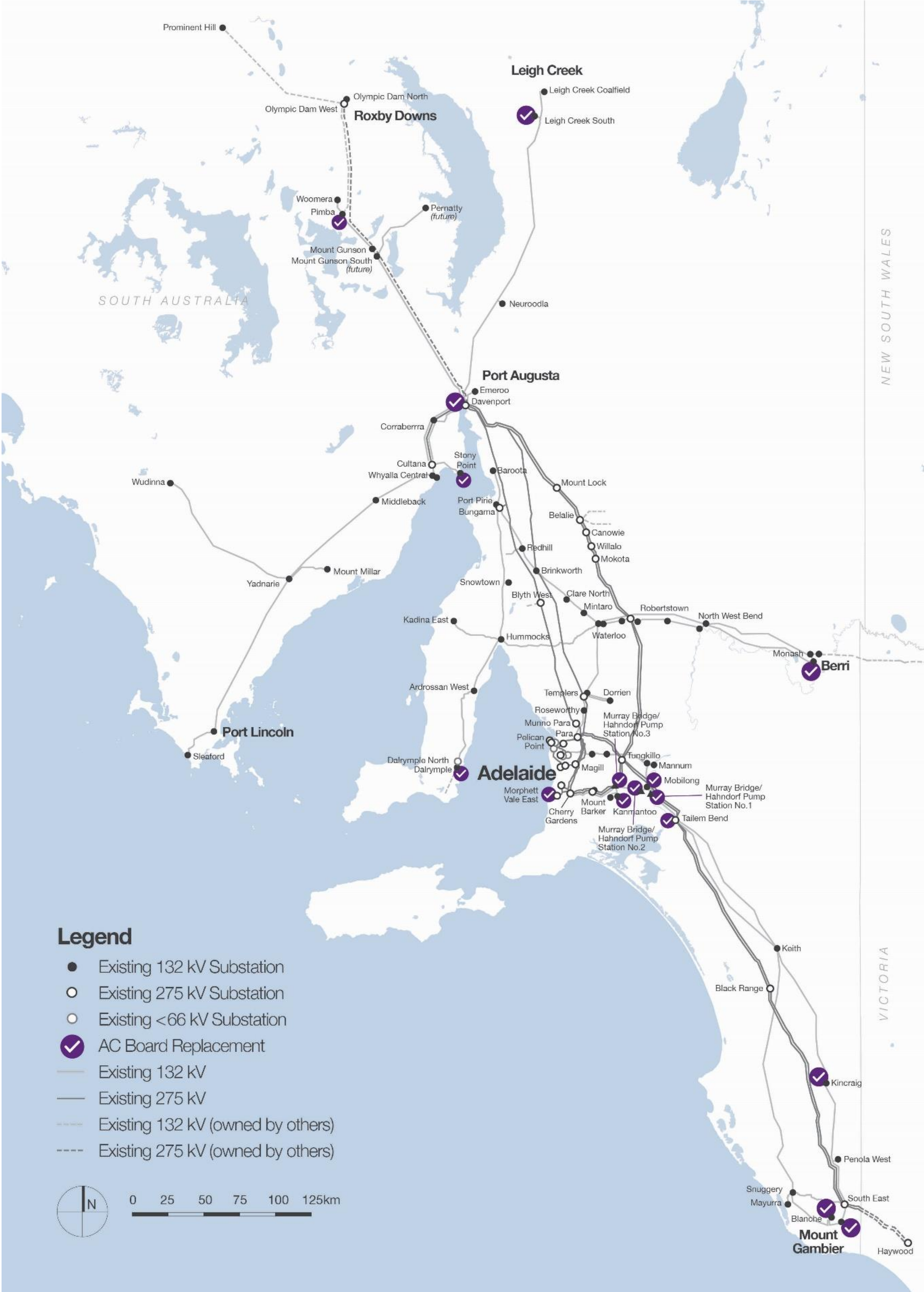


Figure 7-9: Transmission lines included in the AC Board Replacement 2018-23 program

These sites are:

- Berri
- Blanche
- Dalrymple
- Davenport
- Tailem Bend
- Kanmantoo
- Kincraig
- Leigh Creek South
- Mobilong
- Morphett Vale East
- Mount Gambier
- Murray Bridge/Hahndorf Pump Station No. 1
- Murray Bridge/Hahndorf Pump Station No. 2
- Murray Bridge/Hahndorf Pump Station No. 3
- Pimba
- Stony Point

Replacing sub-standard and hazardous equipment is considered to be the only viable option.

ElectraNet does not envisage that this project will impact inter-regional transfer.

As none of the individual projects exceeds $6 million in estimated cost, ElectraNet does not plan to apply the RIT-T to these planned investments.

7.11 Network asset de-ratings

ElectraNet continually reviews the conditions of its network assets to ensure that these assets are suitable to support the forecast load. Where condition assessment indicate that an asset's condition is beginning to decline, a planned refurbishment or replacement program is put in place.

We are currently reviewing our approach to rating transmission lines to incorporate improved information regarding prevailing wind speed and direction.

ElectraNet currently has no plans to de-rate any of its assets.

7.12 Grouped network asset retirements, de-ratings and replacements

7.12.1 Protection Systems Unit Asset Replacement 2018-19 to 2022-23

Scope of work: Replace protection scheme relays that have reached the end of their technical or economic lives

Estimated cost: $25-$35 million

Project category: Replacement

Timing: 2018 to 2023

Project status: Planned

Project need and option analysis:

This program is required to replace individual substation protection systems that have been assessed to be at the end of their technical and/or economic lives, at locations where the asset won't be replaced as part of an augmentation or substation rebuild during the 2018-19 to 2022-23 regulatory control period.

We anticipate that between 400 and 500 relays will require replacing during the 2018-19 to 2022-23 regulatory control period. It is likely that if these assets are not replaced, a number will fail within the next five to ten years, resulting in corrective operational expenditure and the unplanned unavailability of parts of the network.

This program includes the replacement of assets at the following sites (Figure 7-10, Figure 7-11):

Angas Creek	Kincraig	Pimba
Berri	Leigh Creek South	Port Lincoln Terminal
Brinkworth	Morphett Vale East	Robertstown
Davenport	Mount Barker	Snuggery
East Terrace	Mount Gambier	South East
Happy Valley	Murray Bridge / Hahndorf No.1 Pump Station	Stony Point
Hummocks	North West Bend	Tailem Bend
Kanmantoo	Northfield	Templers
Keith	Parafield Gardens West	Yadnarie
Kilburn		

Figure 7-10: Sites where some protection system assets are planned to be replaced from 2018-19 to 2022-23 (metropolitan area)

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Figure 7-11: Sites where some protection system assets are planned to be replaced from 2018-19 to 2022-23

The options considered include:

1. Run to failure; and
2. Planned replacement in the 2018-19 to 2022-23 period;

Option 2, planned replacement in the 2018-19 to 2022-23 period is selected as the preferred option as this minimises the risk of unplanned unavailability of parts of the network.

ElectraNet does not envisage that this project will impact inter-regional transfer.

This investment is subject to the RIT-T. We intend to issue a PSCR for this identified need in 2018.

7.12.2 Transformer bushing unit asset replacement 2018-19 to 2022-23

Scope of work:	Replace individual transformer bushings that have been assessed to be at the end of the technical or economic lives
Estimated cost:	\$5-\$8 million
Project category:	Replacement
Timing:	2018 to 2022
Project status:	Planned

Project need and option analysis:

101 Transformer Bushings have been identified for replacement on eighteen ElectraNet transformers across ten substation sites. The bushings are aged between 36 and 55 years.

These assets are at the end of their technical life, as they have been identified to have an increased risk of failure which may result in increased safety and reliability issues, or in the worst case, catastrophic failure of the transformer and the resultant loss and damage associated with this.

It is likely that if these assets are not replaced, a number will fail during the regulatory period or the next period, resulting in corrective operational expenditure cost and the unplanned unavailability of parts of the network.

This program includes the replacement of transformer bushings at the following sites (Figure 7-12):

- Para
- LeFevre
- Cherry Gardens
- Robertstown
- Snuggery
- Yadnarie
- Murray Bridge / Hahndorf Pump Station #1
- Murray Bridge / Hahndorf Pump Station #3
- Berri
- North West Bend

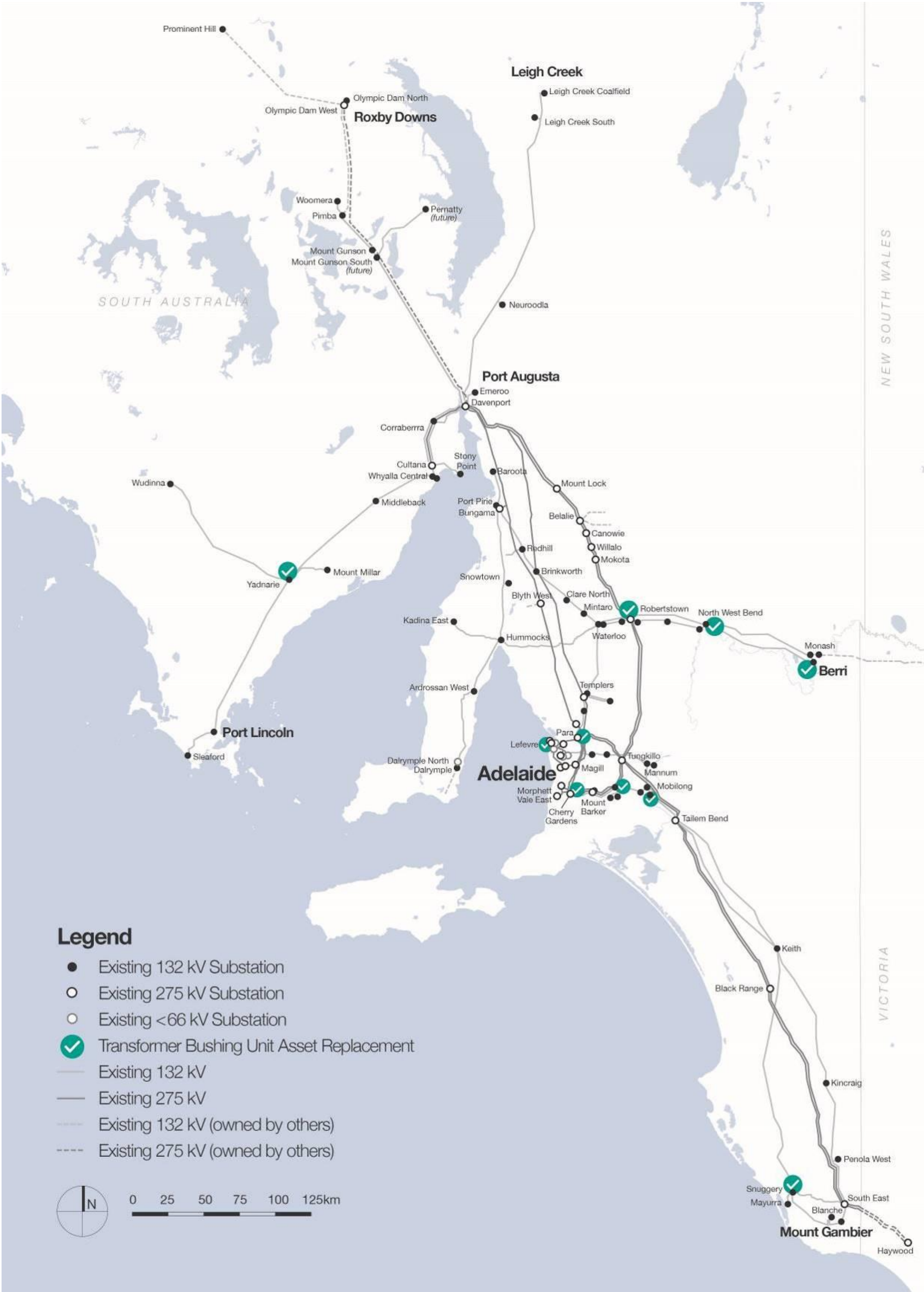

Figure 7-12: Sites where transformer bushing replacement is planned on at least some transformers between 2018-19 and 2022-23

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The options considered were:

1. Full replacement of transformer; and
2. Replacement of transformer bushings.

Option 2, Replacement of transformer bushings in the 2018-19 to 2022-23 period is selected as the preferred option as this minimises the risk transformer failure due to bushing failure and will extend the operational life of the selected transformers.

ElectraNet does not envisage that this project will impact inter-regional transfer.

This investment is subject to the RIT-T. We intend to issue a PSCR for this identified need in 2018.

7.12.3 Isolator unit asset replacement 2018-2023

Scope of work: Replace individual substation isolators that have been assessed to be at the end of their technical or economic lives, or that no longer have manufacturer support

Estimated cost: $8-$12 million

Project category: Replacement

Timing: 2018 to 2023

Project status: Planned

Project need and option analysis:

This project is to replace individual substation isolators that have been assessed to be at the end of their technical and/or economic lives or that no longer have manufacturer support, at locations where the asset won't be replaced as part of an augmentation or substation rebuild during the 2018-23 regulatory period. In addition the replacement is targeted at selected isolators that can be refurbished and utilised as spares for isolators that remain in service and are no longer supported by the original equipment manufacturer

This program includes the replacement of isolators at the following sites (Figure 7-13):

Berri Cultana Dorrien LeFevre Magill Middleback	Monash Mount Gambier Para Penola West Robertstown	Snuggery Tailem Bend Torrens Island A Torrens Island B Yadnarie

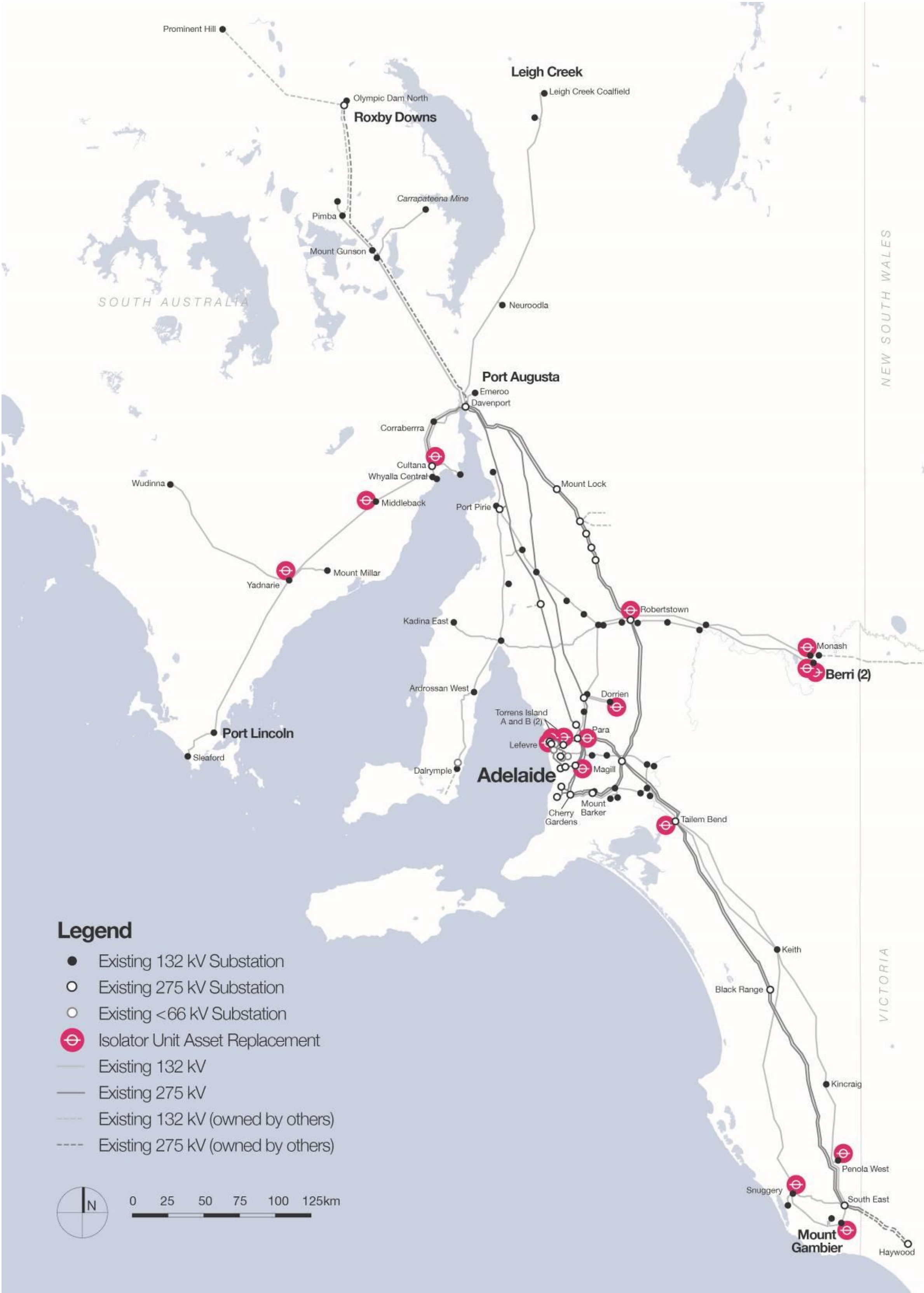

Figure 7-13: Sites where some isolators are planned for replacement between 2018-19 and 2022-23

The options considered were:

1. Replacement of 56 identified isolators and/or parts of isolators that have been assessed at end life;
2. Run to Failure; and
3. Full asset Make/Model population replacement

Option 1 Replacement of 56 identified isolators and/or parts of isolators that have been assessed at end life has been selected as the preferred option as minimises the risk of unplanned failure and unplanned unavailability of parts of the network.

ElectraNet does not envisage that this project will impact inter-regional transfer.

This investment is subject to the RIT-T. We intend to issue a PSCR for this identified need in 2018.

8. Frequency Control schemes

8.1 Frequency control schemes

There are presently three control schemes implemented in South Australia that are designed to contribute to system frequency control. These are:

- an automatic under-frequency load shedding scheme (section 8.1.1)
- an automatic over-frequency generator shedding scheme (section 8.1.2)
- a System Integrity Protection Scheme (section 8.1.3).

8.1.1 Automatic under-frequency load shedding

There is an existing UFLS scheme in South Australia, designed to return system frequency to normal following an event that leads to South Australia separating from the rest of the NEM.

AEMO has reviewed the design of the UFLS scheme for South Australia, taking into account:

- The reduction in inertia in the region and the resulting higher RoCoF
- The larger potential contingency size due to the upgrade of the Heywood Interconnector
- The increasing penetration of rooftop PV generation.

The basic design premise of the UFLS scheme is that, in response to a separation event or a multiple contingency event[51], the frequency fall should be limited to 47 Hz by the controlled disconnection of load.

AEMO assessed the performance of the UFLS in South Australia using a single mass model representation of the network, and also using detailed electromagnetic transient (EMT) studies. These studies assumed a worst-case islanding of South Australia due to separation of the Heywood Interconnector at its thermal limit. AEMO's studies indicated that the existing UFLS scheme is sufficient to manage this contingency when RoCoF within South Australia is limited to 3 Hz/s during this event[52].

AEMO's assessment indicates the present South Australia UFLS settings are adequate. AEMO has not identified any need to modify the South Australia UFLS scheme.

8.1.2 Automatic over-frequency generator shedding

The purpose of OFGS is to manage the frequency performance during islanding events resulting from non-credible or multiple contingencies during high export to Victoria. The South Australia OFGS operates in the frequency range of 51 to 52 Hz.

51 As defined in the Frequency Operating Standards.

52 A constraint equation is used to ensure that RoCoF within South Australia does not exceed 3 Hz/s for a non-credible loss of the Heywood Interconnector.

On 23 November 2016, AEMO requested that ElectraNet implement an OFGS scheme. After initial implementation, some wind farms were incorrectly tripped due to over-frequency relay maloperation during fault transients. Further work was performed in consultation with wind farms to determine appropriate OFGS delay times to avoid maloperation. At present, most of the required generators have implemented over-frequency trip settings, and others are in the process of implementing their trip settings.

AEMO, with ElectraNet, designed the South Australia OFGS to limit frequency rise in South Australia to 52 Hz in line with the frequency operating standards. The objective of the scheme is to coordinate the tripping of generation in a pre-determined manner, tripping low inertia generators first, to maximise the inertia online. This seeks to minimise the impacts of exacerbated RoCoF that would result from disconnecting synchronous generators that provide system inertia during extreme frequency events. Actual operation of the scheme is expected to be rare.

The scheme is designed to only operate for frequency excursions above the upper limit of the “operational frequency tolerance band” of 51 Hz. Generation to be tripped is split into eight blocks, each with around 150 MW of wind generation, set to trip between 51 Hz and 52 Hz.

AEMO’s review of the South Australian OFGS scheme found that:

- The OFGS scheme will help to arrest frequency rise for a separation event when South Australia is exporting to Victoria
- During island conditions, the OFGS will help to arrest frequency rise in the event of a non-credible contingency.

System inertia is the most predominant factor for effective operation of the OFGS, and is provided by synchronous generation. As the proportion of non-synchronous generation increases, the system inertia declines, leading to increased RoCoF for large contingency events, causing loss of discrimination between OFGS groups. This leads to increased risk of over-tripping, causing frequency decline and subsequent UFLS occurring.

When interconnected to Victoria, this OFGS limitation is currently mitigated through a constraint equation that limits RoCoF within South Australia to 3 Hz/s for a non-credible loss of the Heywood Interconnector. Any change to this constraint equation would necessitate a review of the OFGS scheme.

AEMO’s assessment indicates the present South Australia OFGS settings are adequate. AEMO has not identified any need to modify the South Australia OFGS scheme.

8.1.3 System Integrity Protection Scheme

The non-credible loss of multiple generating units in South Australia, at times of high import into South Australia, can lead to extreme flows on the Heywood Interconnector, causing it to trip. This loss of multiple generators and import across the Heywood interconnector would result in rapid frequency decline, and would pose a high risk of a state-wide blackout.

The SIPS was designed to rapidly identify conditions that could otherwise result in a loss of synchronism between South Australia and Victoria. The SIPS is designed to correct these conditions by rapidly injecting power from batteries or shedding some load to assist in rebalancing supply and demand in South Australia, to prevent a loss of the Heywood Interconnector.

The SIPS incorporates three discrete progressive stages. The three stages are intended to operate in an escalating manner, in that the outcome from the preceding stage is intended to defer or prevent the onset of the next stage. The three stages are:

a) Stage 1 – Fast response from battery energy storage systems

   Activation of this stage enables battery energy storage systems to provide additional active power to the system. The activation signal will be initiated if imported power across the Heywood Interconnector either:

   (i) increases at a rate of change which is faster than a rate which could occur through any reasonably foreseeable load increase, or

   (ii) increases beyond a defined threshold.

b) Stage 2 – Load shedding trigger to shed approximately 200 MW of South Australian load

   The unstable power swing load shedding trigger is initiated from a pair of redundant distance protection relays located at Tailem Bend substation. In the event of an unstable power swing, relays issue a load shedding signal to selected transmission substations.

   Additionally, a load shedding trigger is initiated if imported power across the Heywood interconnector increases beyond a defined threshold. Relays issue a load shedding signal to the same transmission substations as for the unstable power swing trigger.

c) Stage 3 – Out-of-step trip scheme (islanding South Australia).

   If required, the third component of SIPS opens the Heywood Interconnector, which forms a synchronous South Australian island. The out-of-step trigger is initiated from an existing pair of redundant distance protection relays located at South East Substation. The out-of-step signal initiates tripping of 275 kV circuit breakers at South East substation to open the Heywood Interconnector, islanding the South Australia power system.

AEMO developed an EMT model of the South Australian power system in PSCAD to test the SIPS for a range of conditions. The objectives of AEMO's analysis were to:

- Determine the ability of Stage 1 (fast response from BESS) in avoiding the trigger of Stage 2 (fast load shedding in South Australia).
- Assess the impact of potential over voltages that could arise from rapid load shedding.
- Assess the effectiveness of the Tailem Bend relay in detecting unstable power swings (loss of synchronism) under various operating conditions.

The study concluded that:

- Under all scenarios, activation of Stage 1 has not shown any detrimental effect on South Australia power system stability. The studies carried out confirm the ability of Stage 1 in avoiding activation of Stage 2 for some dispatch scenarios.

- The outcome of Stage 2 depends on the amount of load being shed. Customer load being a variable, it is likely (and studies have confirmed) that under some circumstances activation of Stage 2 disconnects more load than required, resulting in additional generation tripping on over voltages. For some scenarios a reduction in the amount of load shed does not avoid activation of Stage 3.
- There were instances where the Tailem Bend loss of synchronism relay failed to detect unstable power swings, thereby being unsuccessful in activating Stage 2.
- The Tailem Bend loss of synchronism relay failed to detect unstable power swing during high demand and high import conditions.

AEMO recommended an investigation of technologies and solutions to upgrade the existing SIPS, considering:

- Alternative mechanisms to detect onset of loss of synchronism between South Australia and the rest of the NEM, because the impedance-based Tailem Bend and South East loss of synchronism relays failed to detect unstable power swings under some conditions
- Dynamic arming of load blocks, batteries, and potentially the Murraylink interconnector, based on real-time measurement and pre-processing of information for a number of different generation loss events ("Stage 2"). This is required because the current fixed load shed blocks may cause under or over-tripping and over-voltages, leading to trip of additional generation under some conditions. Detailed investigation of technologies and design is required due to the countless number of generation tripping events that could conceivably occur in the South Australia power system
- The scheme will still apply to South Australia. AEMO estimated that the modification can be completed within two years. However, a number of uncertainties, stemming from the potential complexity of this protection scheme and the importance of performance monitoring and design accuracy before implementation, could delay its implementation beyond two years
- This SIPS upgrade should be progressed as a Protected Event EFCS to mitigate the risk of system black following a loss of multiple generators in South Australia.

ElectraNet is working with AEMO to refine the scope of the recommended Stage 2 upgrade of the SIPS, to implement a Wide Area Protection Scheme (WAPS).

8.2 Power System Frequency Risk Review

The Power System Frequency Risk Review (PSFRR)[53] is an integrated, periodic review of power system frequency risks associated with non-credible contingency events in the National Electricity Market (NEM).

ElectraNet supported AEMO to identify non-credible contingencies and emergency control schemes that could be within the scope of the PSFRR. From a preliminary list of events, AEMO, in consultation with TNSPs, ruled out some events and prioritised others for assessment based on criteria consistent with the NER. AEMO shared and discussed initial

[53] AEMO. Power System Frequency Risk Review. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Power-System-Frequency-Risk-Review.

findings with TNSPs and preliminary versions of the PSFRR draft report. AEMO incorporated feedback from TNSPs into the draft and final PSFRR.

ElectraNet further supported AEMO to assess the performance of existing Emergency Frequency Control Schemes (EFCS). AEMO also assessed high priority non-credible contingency events identified in consultation with TNSPs. Techniques used for assessment varied on a case by case basis and included:

- Review of previous studies, or reports on historical events
- PSCAD studies
- PSS/E studies
- Single Mass Model Studies

From these assessments AEMO determined whether further action may be justified to manage frequency risks. ElectraNet has reviewed AEMO's work and supports the outcomes of the PSFRR.

8.2.1 Recommendations for South Australia

The 2018 PSFRR made two recommendations for South Australia.

System Integrity Protection Scheme Upgrade

The 2018 PSFRR recommends an upgrade to the recently commissioned South Australian System Integrity Protection Scheme (SIPS), to reduce the likelihood that a loss of multiple generators in South Australia will lead to separation and a black system. AEMO has estimated that the required modifications can be made in two years, and recommends that it be progressed as a protected event EFCS.

ElectraNet is currently working with AEMO to design and implement the scope of works to upgrade the SIPS to a Wide Area Protection Scheme (WAPS, section 8.1.3).

Declaration of a protected event in South Australia

After the 28 September 2016 system black event in South Australia, AEMO initiated an operation action plan to limit flow on the Heywood interconnector during destructive wind conditions in South Australia (under Rules clause 4.3.1(v)). For transparency, and to provide certainty to the market, AEMO recommends that this condition be declared a protected event.

If approved by the Reliability Panel, AEMO expects this protected event will be activated approximately twice per year, based on historical weather conditions.

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APPENDICES

Bungala Solar Farm and ElectraNet's Emeroo Substation

Appendix A Summary of changes from the 2017 Transmission Annual Planning Report

As listed in Appendix C, clauses 5.12.2(c)(1)(iii), 5.12.2(c)(1)(iv), and 5.12.2(c)(11) of the National Electricity Rules require us to provide an analysis and explanation of any aspects of forecast loads, and other aspects of the 2018 Transmission Annual Planning Report, that have changed significantly from the 2017 report. The following table includes a summary of the significant changes to our Transmission Annual Planning Report, which may be due to:

- changes to input datasets, assumptions or methodologies
- actual outcomes or future forecasts being different from the previously reported forecasts
- additional information being included to meet new Rule requirements.

Section	Section Name	Significant changes between the 2017 and 2018 TAPR	Analysis and explanation for the significant change
1.1	Renewable energy generators are continuing to connect in South Australia	The 2017 TAPR forecast that approximately 10% of South Australia's overall generation in 2016-17 would be from interstate generation. The actual result shown in Figure 1-1 of this TAPR was approximately 20%.	While actual results for 2016-17 differ from the values forecast last year, the intent of Figure 1-1 is to illustrate the ongoing trend of increasing penetration of renewable energy generation within South Australia.
1.2	Future directions and key priorities	We have included the directions from our customer representative's and other stakeholder's, and our priorities when planning for the future of the network. This information was not included in the 2017 TAPR.	Engagement with our customer representatives and other stakeholders is critical to informing the way in which we plan for the future of the network and deliver the greatest value, which we wanted to reflect in our TAPR. Inclusion of this new section is aimed at demonstrating ElectraNet's innovative and transparent approach to planning through engagement with our customers and stakeholders.
1.3	Strategic South Australian transmission developments	This section of the 2018 TAPR discusses the rationale behind our new or altered strategic initiatives that support the energy transformation occurring in South Australia. While the 2017 TAPR included this information, this year the information is being discussed earlier in the TAPR to highlight key developments such as a new 330kV interconnection between mid-north South Australia and Wagga Wagga in New South Wales.	This section has been included to provide our customers and stakeholders with a summary of our strategic decisions and developments, which is more focused and detailed than our previous TAPR due to the maturity of ElectraNet's project scoping and planning process.

Section	Section Name	Significant changes between the 2017 and 2018 TAPR	Analysis and explanation for the significant change
2.1	Integrated System Plan	In response to a recommendation by the Finkel Review, AEMO has developed an Integrated System Plan (ISP). The observations and recommendations within this plan form a new series of inputs for the planning of our transmission network that were not available for our 2017 TAPR.	AEMO's draft ISP was not available for the 2017 TAPR. ElectraNet has sought to integrate the observations and recommendations of the ISP with our 2018 TAPR in the same way that we have integrated with AEMOs NDNTP in previous TAPRs.
4.1	Transmission network constraints in 2017	ElectraNet assessed a number of constraints as part of the 2018 TAPR that were not part of the 2017 TAPR. Additionally, not all constraints included within the 2017 TAPR were assessed as part of the 2018 TAPR.	Each year we assess the top binding network constraints that impacted transmission network and interconnector flows during the calendar year. Constraints selected for assessment are in the top ten by impact on marginal value or by binding duration. This means the location of constraints may vary year-by-year. For example, AEMO has imposed a new constraint in the form of an upper limit of 1200MW for South Australian wind generation. We plan to address this constraint through improvements to our system strength and the construction of a new interconnector.
5.3	Summary of connection opportunities	The information in this section has been updated since the corresponding section in the 2017 TAPR.	We have updated the information to account for new generator and customer connections since the 2017 TAPR.
5.4	Proposed new connection points	The 2018 TAPR includes significantly more new and proposed connection points than the 2017 TAPR. For example, the proposed new connection point at Mount Gunson South was not included in the 2017 TAPR.	The additional new and proposed connection points has largely been driven by new generator and customer connections. The new connection point at Mount Gunson South became necessary because of a new mine load that will be connected from December 2018.
5.5.2	Recent, current and upcoming consultations	The 2018 TAPR identifies a number of additional recently completed, in-progress, and planned consultations that were not included in the 2017 TAPR.	The majority of new consultations relate to asset replacements, which we are now required to report in our 2018 TAPR for the first time due to recent Rule changes.
6.1.1	Recently completed projects: Dalrymple ESCRI-SA Battery Project	ElectraNet's grid-connected, utility scale battery energy storage system at Dalrymple has been completed.	This project was still subject to further analysis and approvals in 2017 TAPR but was delivered throughout the year, was registered in June 2018 and will be fully commissioned by July 2018.

Section	Section Name	Significant changes between the 2017 and 2018 TAPR	Analysis and explanation for the significant change
6.2	Committed projects	The following projects are now committed in the 2018 TAPR: • Templers West 50 MVar 275 kV reactor • Back Up Control and Data Centre • Substation Lighting and Infrastructure Replacement • Davenport-Pimba 132 kV Line Low Span Uprating • AC Board Replacement 2013-18 • Line Support Systems Refurbishment 2018-23 • Motorised Isolator LOPA Improvement • Line Insulator Systems Refurbishment 2018-23	These committed projects were classified as proposed in Appendix G3 of the 2017 TAPR but are now committed to be carried out for replacement, refurbishment and security purposes.
7.1	Summary of planning outcomes	The 2018 TAPR includes additional detail such as commentary on Interconnector Capacity and National Transmission Planning.	The 2017 TAPR included a discussion on emerging system issues. This year, consistent with the results of AEMO's Integrated Systems Plan, we have included additional information about system strength, system inertia, interconnector capacity and national transmission planning.
7.2	Committed urgent and unforeseen investments	This is a new section that was not part of the 2017 TAPR.	This section of the 2018 TAPR has been added to more clearly meet NER requirements.
7.3.1	National transmission planning: New high capacity interconnector	The RIT-T assessment identified construction of a new high capacity interconnector as the preferred option to address the identified need.	ElectraNet has assessed the outcomes of the RIT-T and chosen a draft preferred option. This section includes a summary of the options, assessment process and outcomes, including estimated costs and timing.
7.4.1	Committed urgent and unforeseen investments: Install synchronous condensers	On 13 October 2017, AEMO declared a gap in system strength in South Australia, which ElectraNet has opted to treat as a fault level shortfall under the new system strength framework.	AEMO has made a decision on system strength and ElectraNet has finished evaluating options. This section includes a summary of ElectraNet's plan to address the fault level shortfall by upgrading existing protection devices and installing synchronous condensers at selected locations across the 275 kV transmission network.

Section	Section Name	Significant changes between the 2017 and 2018 TAPR	Analysis and explanation for the significant change
7.8	Minimum demand	The 2017 TAPR identified four projects required to be undertaken to mitigate the risks associated with minimum demand scenarios. The 2018 TAPR revises this to two projects.	Of the four projects identified in the 2017 TAPR one (install a 50 Mvar 275 kV switched reactor at Templers West) has been committed for delivery, and another (install a 50 Mvar 275 kV switched reactor at Blyth West) has been deferred due the benefits to be provided by the newly committed synchronous condensers (discussed above).
7.10	Network asset retirements and replacements	This is a new section that was not part of the 2017 TAPR.	This section of the 2018 TAPR has been added to meet a new NER requirement
7.11	Network asset re-ratings	This is a new section that was not part of the 2017 TAPR.	This section of the 2018 TAPR has been added to meet a new NER requirement
7.12	Grouped network asset retirements, de-ratings and replacements	This is a new section that was not part of the 2017 TAPR.	This section of the 2018 TAPR has been added to meet a new NER requirement
Appendix C	Asset Management Approach	This section of the 2018 TAPR was not discussed in the 2017 TAPR.	This section of the 2018 TAPR has been added to meet a new NER requirement
Appendix F	Committed, pending, proposed and potential projects	The forecast project timings of several projects have been extended by 12 to 24 months.	As a result of our more advanced project planning and scoping, ElectraNet now has a clearer view on when these projects will be required, which has resulted in several project being delayed by 12 to 24 months.

Appendix B Joint Planning

ElectraNet undertakes a wide range of joint planning activities with both transmission and distribution entities, on both a regular and as-needed basis and through a range of forums.

Historically and since market inception, ElectraNet has always worked very closely with SA Power Networks on every potential and realised development to ensure optimal solutions have always been fully investigated.

Joint planning activities also include significant engagement with AEMO (as both national planner and Victorian transmission planner), TransGrid, APA (owner of Murraylink interconnector), AusNet Services, Powerlink, and major customers.

Our joint planning activities over the last year are described more fully in the following sections.

B1 National transmission planning working groups and regular engagement

ElectraNet has collaborated with the other NEM jurisdictional planners through active involvement in the following groups:

- Executive Joint Planning Committee
- Joint Planning Committee
- Market Modelling Working Group
- Regulatory Working Group
- Planning Reference Group
- Forecasting Reference Group
- Regular coordination meetings
- ENA.

B1.1 Executive Joint Planning Committee

The Executive Joint Planning Committee coordinates effective collaboration and consultation between Jurisdictional Planning Bodies, and AEMO on electricity transmission network planning issues so as to:

- develop the framework for the Finkel recommended Integrated System Plan
- continuously improve current network planning practices
- coordinate on energy security across the NEM.

B1.2 Joint Planning Committee

The Joint Planning Committee is a working committee, supporting the Executive Joint Planning Committee to achieve effective collaboration, consultation and coordination between Jurisdictional Planning Bodies, Transmission System Operators and AEMO on electricity transmission network planning issues.

B1.3 Market Modelling Working Group

The Market Modelling Working Group is a working committee that supports the Executive Joint Planning Committee in effective collaboration, consultation and coordination between Jurisdictional Planning Bodies, Transmission System Operators and AEMO on modelling techniques, technical knowledge, industry experience, and a broad spectrum of perspectives on market modelling challenges.

B1.4 Regulatory Working Group

The Regulatory Working Group is a working group that supports the Executive Joint Planning Committee (EJPC) to achieve effective collaboration, consultation and coordination between Jurisdictional Planning Bodies, Transmission System Operators and AEMO on key areas related to the application of the regulatory transmission framework and suggestions for improvement.

B1.5 Planning Reference Group

The Planning Reference Group is a monthly forum with AEMO and industry planning specialists. The forum seeks to facilitate constructive discussion on matters relating to gas and electricity market modelling and strategic network planning. It is an opportunity to share expertise and explore new approaches to addressing the challenges of planning in a rapidly changing energy industry.

B1.6 Forecasting Reference Group

The Forecasting Reference Group is a monthly forum with AEMO and industry forecasting specialists. The forum seeks to facilitate constructive discussion on matters relating to gas and electricity forecasting and market modelling. It is an opportunity to share expertise and explore new approaches to addressing the challenges of forecasting in a rapidly changing energy industry.

B1.7 Regular joint planning meetings

For the purpose of effective network planning, ElectraNet conducts regular joint planning meetings with:

- SA Power Networks (the South Australian distribution network service provider)
- AEMO National Planning
- AEMO Victorian Planning (in their role as Jurisdictional Planning Body for the Victorian transmission system)

B2 Joint Planning Projects

ElectraNet has coordinated with other jurisdictional planners on the following projects:

- Integrated System Plan (section 2.1)
- Power System Frequency Risk Review (section 8.2)
- South Australian Energy Transformation (section 1.3.1 and 7.3.1).

Appendix C Asset Management Approach

C1 ElectraNet's asset management strategy

As electricity demand is only forecast to increase in response to the occasional connection of individual large loads, there is minimal load-related investment required over the planning horizon. 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[54].

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 continuing focus is to address transmission line condition and risk to ensure reliability of the network for South Australian households and businesses.

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 committed to delivering a safe and reliable network and to meeting our compliance obligations at an efficient cost. The table 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.

[54] AEMO. *Independent Planning Review – ElectraNet Capital Expenditure Projects*, March 2017, p. 3. Available from www.aemo.com.au.

Inputs and Analysis	Our Approach
Demand forecasts and reliability	Forecast demand is an important driver of reliability capital expenditure. We have adopted AEMO's latest demand forecasts[55] and estimates of the Value of Customer Reliability (VCR)[56]. Adopting these independent values provides confidence in these inputs. The demand forecasts are compared against the ability of the transmission system to meet the reliability standard set by the ETC and the Rules.
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. The RIT-T is applied for all relevant projects that have a credible option with a cost that exceeds the threshold set in the Rules.
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.

C2 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

[55] AEMO, 2018 Electricity Forecasting Insights – March 2018 Update, available at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Electricity-Forecasting-Insights/2018-Electricity-Forecasting-Insights.

[56] 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.

- our Safety, Reliability, Maintenance and Technical Management Plan (SRMTMP), which is required by our transmission licence.

C2.1 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[57].

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[58]; and
- 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;

57 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.

58 National Electricity Rules, Schedule 5.1

- 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.

ESCOSA most recently amended the reliability standards contained in the ETC, to be effective from 1 July 2018, as shown in the following table.[59]

ESCOSA is currently undertaking a targeted review of the ETC, with the stated aim to clarity the operations of (but not change) certain obligations, make consequential changes to reflect recent legislative amendments and improve the readability of the Code. The review is planned to be completed in August 2018.[60]

Note that the provision of 'N' and 'N-1' equivalent capacity, as described by the ETC, includes the capacity that is provided by in-place network support arrangements through distribution system capability, generator capability, load interruptability, or any combination of these services.

[59] The full version of the ETC version TC/09 is available at escosa.sa.gov.au.

[60] The draft decision and ElectraNet's submission are available at https://www.escosa.sa.gov.au/projects-and-publications/projects/electricity/electricity-transmission-code-review-2018.

Load category	1	2	3	4	5
Generally applies to…	Small loads, country radials, direct connect customers	Significant country radials	Medium-sized loads with non-firm backup	Medium-sized loads and large loads	Adelaide central business district (CBD)
Transmission line capacity					
'N' capacity	100% of agreed maximum demand (AMD)				
'N-1' capacity	Nil		100% of AMD		
'N-1' continuous capability	Nil			100% of AMD for loss of single transmission line or network support arrangement	
Restoration time to 'N' standard after outage (as soon as practicable – best endeavours*)	2 days		1 hour	12 hours (or 4 hours if grouped with category 5 connection point)	4 hours for 176 MW
Restoration time to 'N-1' standard after outage	N/A		As soon as practicable - best endeavours		
Transformer capacity					
'N' capacity	100% of AMD				
'N-1' capacity	Nil	100% of AMD			
'N-1' continuous capability	None stated	100% of AMD for loss of single transformer or network support arrangement	Nil	100% of AMD for loss of single transformer or network support arrangement	
Restoration time to 'N' standard after outage (as soon as practicable – best endeavours*)	8 days		1 hour	12 hours (or 4 hours if grouped with category 5 connection point)	4 hours for 176 MW
Restoration time to 'N-1' standard after outage	N/A	As soon as practicable – best endeavours			
Spare transformer requirement	Sufficient spares of each type to meet standards in the event of a failure				
Allowed period to comply with required contingency standard following a change in forecast AMD that causes the specific reliability standard to be breached	N/A	12 months			

* As defined in the ETC

C2.2 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;
- 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.

C2.3 Safety, Reliability, Maintenance and Technical Management Plan

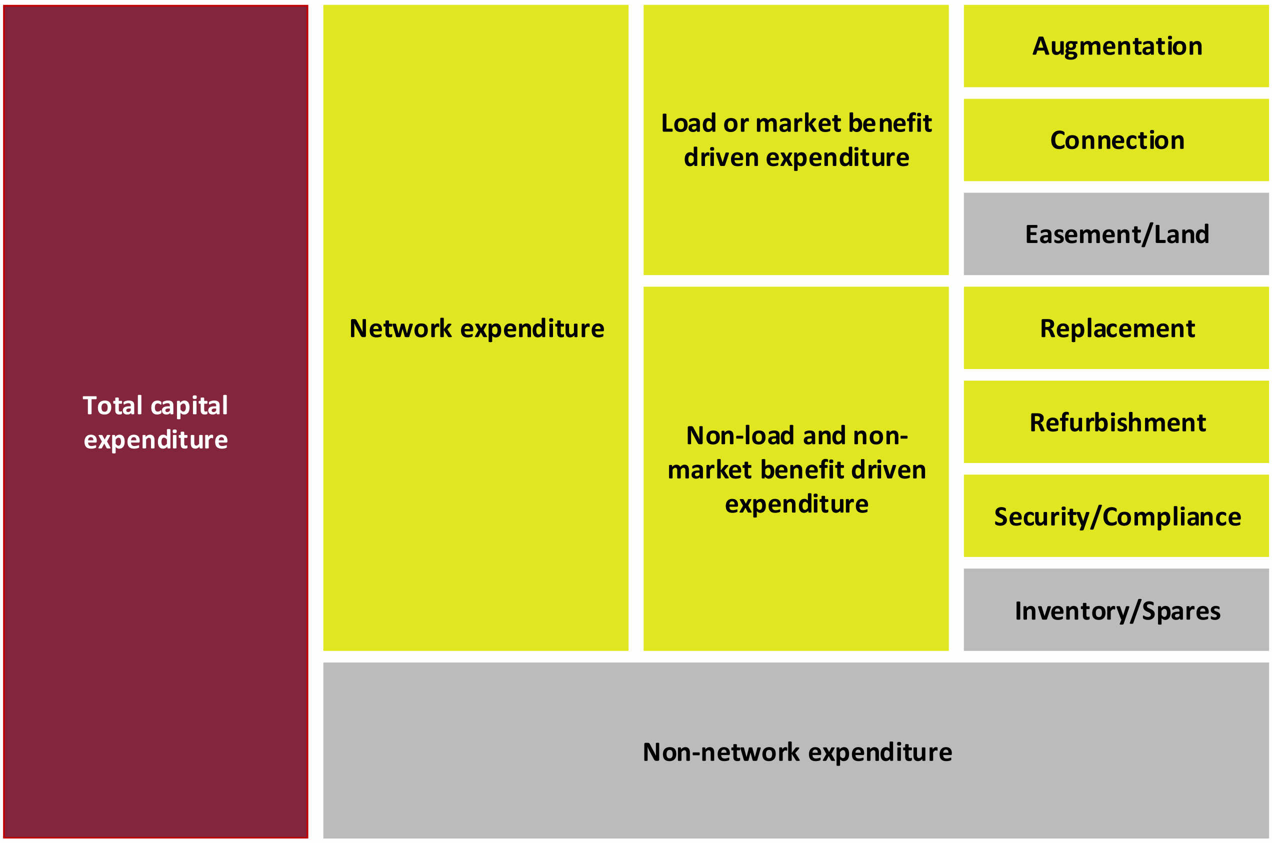
In accordance with clause 7 of our transmission licence, we are required to:

- 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.

C3 Capital expenditure categories

We apply capital expenditure categories as broken down in the following figure.



The table below describes each of the five expenditure categories that are relevant to Transmission Annual Planning Reports, as presented in the right hand column of the above figure. For each category, we also identify the AER's proposed reporting category as indicated in their consultation paper on the development of a TAPR Guideline.[61]

Expenditure Category	Definition	Service Category	AER's proposed TAPR reporting category
Network – Load or Market Benefit Driven			

[61] Consultation paper available from www.aer.gov.au.

Expenditure Category	Definition	Service Category	AER's proposed TAPR reporting category
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)	Reliability driven or Market benefit
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	Reliability driven
Network Non-Load and Non-Market Benefit 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	Replacement
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	Replacement
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	Security

C4 Expenditure forecasting methodology

Our capital expenditure forecasting methodology is illustrated on the following page.

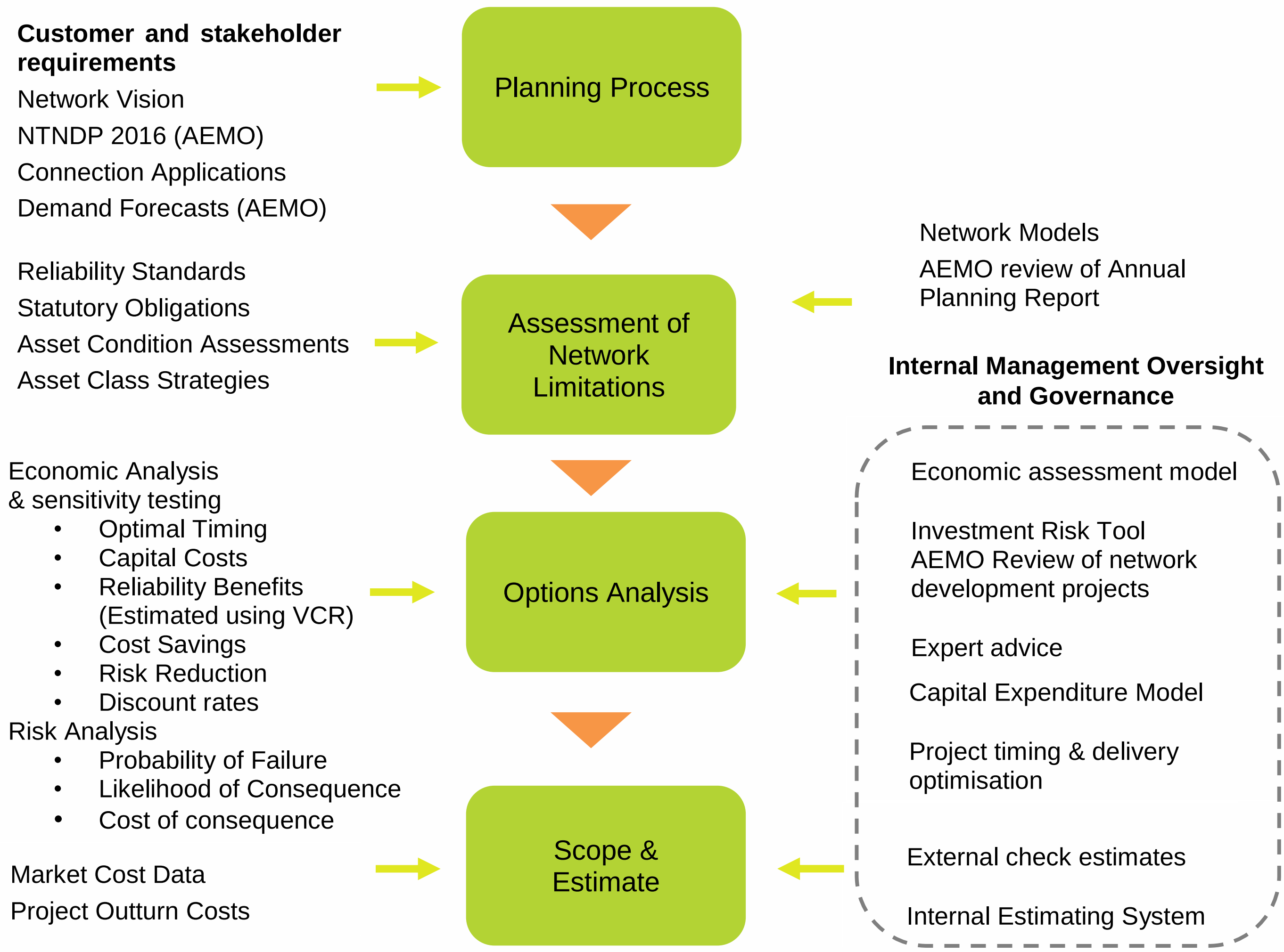
Our capital expenditure forecasting process is integrated with our business as usual budgetary, planning and governance processes. In addition to the internal controls governing these 'business-as-usual' processes, the input assumptions are subject to rigorous review and sign off.

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.

C4.1 Customer and stakeholder requirements

The starting point for our capital expenditure forecasting methodology is understanding our customers' requirements through effective engagement. Our expenditure priorities are shaped by the feedback we have received through our customer engagement process.



C4.2 Planning process

The planning process operates within a strategic framework informed by our Network Vision[62], 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.

C4.3 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 forecast period. The application of this approach differs by expenditure category, as follows:

- Load and market benefit driven network investment requirements are identified through modelling of future power system capability and analysis of network constraints.
- Non-load and non-market benefit 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.

C4.4 Options analysis

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.

C4.5 Scope and estimate

All network solutions are designed to meet the identified need while complying with legislated safety, environmental and technical obligations.

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.

Approved projects that are currently in progress have been subject to a more detailed cost assessment than those which have yet to commence.

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

C5 Key inputs and assumptions

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

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62 Available from www.electranet.com.au.

- demand forecasts
- asset health and condition assessments
- planning and design standards
- network model
- economic assessments
- risk assessments
- project cost estimation, and
- project timing and delivery.

These are discussed in turn below.

C5.1 Demand forecasts

Refer to chapter 3 of this report for information on how we develop and use demand forecasts.

C5.2 Asset health and condition assessments

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 technical health (condition, serviceability, maintainability, operability and safety) of the asset and its strategic importance in the network (related to the level of risk).

We apply a systematic, continuous process for collecting, recording and analysing detailed information on the condition of our network assets.

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

C5.3 Planning and design standards

Our planning standards are derived from the Rules and the ETC and are presented in more detail in section C2. 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.

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.

C5.4 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.

C5.5 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 'business as usual', network solutions, deferred network investment, and non-network alternatives. 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.

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[63]
- 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.

The RIT-T is applied to all projects that meet the criteria that are set in the Rules.

C5.6 Non-network alternatives

We consider the scope for non-network alternatives when we address identified needs on the network, as described in section 5.5.

C5.7 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:

[63] 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.

- 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 driven by considerations of detailed asset condition, risk, and reliability, balanced against the cost of replacement.

The key input assumptions to our asset risk cost evaluation include, among 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)[64] together with appropriate sensitivity assumptions and disproportionate factors to reflect our approach to safety risks in accordance with applicable WHS legislation and regulations; and
- other key cost inputs with respect to the value of customer reliability, the potential for bushfire related property damage, and environmental costs.

C5.8 Project cost estimation

Project cost estimates are derived as described earlier in section C4.5.

C5.9 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.

C6 Further information on ElectraNet's asset management strategy and methodology

Further information can be obtained from:

Rainer Korte, Executive Manager Asset Management, consultation@electranet.com.au.

[64] 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.

Appendix D Compliance Checklist

This section sets out a compliance checklist which demonstrates the compliance of ElectraNet's 2018 Transmission Annual Planning Report with the requirements of clause 5.12.2(c) of version 108 of the Rules (the latest version at time of writing).

Table C-1: Compliance Checklist

Summary of requirements	Section
The Transmission Annual Planning Report must be consistent with the TAPR Guidelines[65] and set out:	
(1) the forecast loads submitted by a Distribution Network Service Provider in accordance with clause 5.11.1 or as modified in accordance with clause 5.11.1(d), including at least: (i) a description of the forecasting methodology, sources of input information, and the assumptions applied in respect of the forecast loads; (ii) a description of high, most likely and low growth scenarios in respect of the forecast loads; (iii) an analysis and explanation of any aspects of forecast loads provided in the Transmission Annual Planning Report that have changed significantly from forecasts provided in the Transmission Annual Planning Report from the previous year; and (iv) an analysis and explanation of any aspects of forecast loads provided in the Transmission Annual Planning Report from the previous year which are significantly different from the actual outcome;	Chapter 3, and the *2018 South Australian Connection Point Forecasts Report*[66]
(1A) for all network asset retirements, and for all network asset de-ratings that would result in a network constraint, that are planned over the minimum planning period specified in clause 5.12.1(c), the following information in sufficient detail relative to the size or significance of the asset: (i) a description of the network asset, including location; (ii) the reasons, including methodologies and assumptions used by the Transmission Network Service Provider for deciding that it is necessary or prudent for the network asset to be retired or de-rated, taking into account factors such as the condition of the network asset; (iii) the date from which the Transmission Network Service Provider proposes that the network asset will be retired or de-rated; and (iv) if the date to retire or de-rate the network asset has changed since the previous Transmission Annual Planning Report, an explanation of why this has occurred;	Sections 6.2, 7.10, 7.11, 7.12 and Appendix F section F3

65 The first TAPR Guideline is yet to be developed by the AER.
66 Available at electranet.com.au

Summary of requirements	Section
(1B) for the purposes of subparagraph (1A), where two or more network assets are: (i) of the same type; (ii) to be retired or de-rated across more than one location; (iii) to be retired or de-rated in the same calendar year; and (iv) each expected to have a replacement cost less than $200,000 (as varied by a cost threshold determination), those assets can be reported together by setting out in the Transmission Annual Planning Report: (v) a description of the network assets, including a summarised description of their locations; (vi) the reasons, including methodologies and assumptions used by the Transmission Network Service Provider, for deciding that it is necessary or prudent for the network assets to be retired or de-rated, taking into account factors such as the condition of the network assets; (vii) the date from which the Transmission Network Service Provider proposes that the network assets will be retired or de-rated; and (viii) if the calendar year to retire or de-rate the network assets has changed since the previous Transmission Annual Planning Report, an explanation of why this has occurred;	Sections 6.2, 7.12 and Appendix F section F3
(2) planning proposals for future connection points;	Section 5.4
(3) a forecast of constraints and inability to meet the network performance requirements set out in schedule 5.1 or relevant legislation or regulations of a participating jurisdiction over 1, 3 and 5 years, including at least: (i) a description of the constraints and their causes; (ii) the timing and likelihood of the constraints; (iii) a brief discussion of the types of planned future projects that may address the constraints over the next 5 years, if such projects are required; and (iv) sufficient information to enable an understanding of the constraints and how such forecasts were developed;	Chapter 7
(4) in respect of information required by subparagraph (3), where an estimated reduction in forecast load would defer a forecast constraint for a period of 12 months, include: (i) the year and months in which a constraint is forecast to occur; (ii) the relevant connection points at which the estimated reduction in forecast load may occur; (iii) the estimated reduction in forecast load in MW needed; and (iv) a statement of whether the Transmission Network Service Provider plans to issue a request for proposals for augmentation, replacement of network assets, or a non-network option identified by the annual planning review conducted under clause 5.12.1(b) and if so, the expected date the request will be issued;	Section 5.5

Summary of requirements	Section
(5) for all proposed augmentations to the network and proposed replacements of network assets the following information, in sufficient detail relative to the size or significance of the project and the proposed operational date of the project: (i) project/asset name and the month and year in which it is proposed that the asset will become operational; (ii) the reason for the actual or potential constraint, if any, or inability, if any, to meet the network performance requirements set out in schedule 5.1 or relevant legislation or regulations of a participating jurisdiction, including load forecasts and all assumptions used; (iii) the proposed solution to the constraint or inability to meet the network performance requirements identified in subparagraph (ii), if any; (iv) total cost of the proposed solution; (v) whether the proposed solution will have a material inter-network impact. In assessing whether an augmentation to the network will have a material inter-network impact a Transmission Network Service Provider must have regard to the objective set of criteria published by AEMO in accordance with clause 5.21 (if any such criteria have been published by AEMO); and (vi) other reasonable network options and non-network options considered to address the actual or potential constraint or inability to meet the network performance requirements identified in subparagraph (ii), if any. Other reasonable network and non-network options include, but are not limited to, interconnectors, generation options, demand side options, market network service options and options involving other transmission and distribution networks;	Sections 7.3 to 7.12
(6) the manner in which the proposed augmentations and proposed replacements of network assets relate to the most recent NTNDP and the development strategies for current or potential national transmission flow paths that are specified in that NTNDP;	Section 2.2
(6A) for proposed new or modified emergency frequency control schemes, the manner in which the project relates to the most recent power system frequency risk review;	Chapter 0
(7) information on the Transmission Network Service Provider's asset management approach, including: (i) a summary of any asset management strategy employed by the Transmission Network Service Provider; (ii) a summary of any issues that may impact on the system constraints identified in the Transmission Annual Planning Report that has been identified through carrying out asset management; and (iii) information about where further information on the asset management strategy and methodology adopted by the Transmission Network Service Provider may be obtained.	Appendix C
(8) any information required to be included in an Transmission Annual Planning Report under: (i) clause 5.16.3(c) in relation to a network investment which is determined to be required to address an urgent and unforeseen network issue; or (ii) clauses 5.20B.4(h) and (i) and clauses 5.20C.3(f) and (g) in relation to network investment and other activities to provide inertia network services, inertia support activities or system strength services.	Section 7.2 and 7.4

Summary of requirements	Section
(9) emergency controls in place under clause S5.1.8, including the Network Service Provider's assessment of the need for new or altered emergency controls under that clause;	Chapter 0
(10) facilities in place under clause S5.1.10; and	Section 8.1.1
(11) an analysis and explanation of any other aspects of the Transmission Annual Planning Report that have changed significantly from the preceding year's Transmission Annual Planning Report, including the reasons why the changes have occurred; and	Chapter 6, Appendix A
(12) the results of joint planning (if any) undertaken with a Transmission Network Service Provider under clause 5.14.3 in the preceding year, including a summary of the process and methodology used by the Transmission Network Service Providers to undertake joint planning and the outcomes of that joint planning.	Appendix B

Appendix E Fault levels and circuit breaker ratings

We have estimated the three-phase and single phase-to-ground fault levels under the 10% POE loading conditions for the South Australian transmission system (Table E-1). The fault level interruption capacity of the lowest rated circuit breaker(s) at each location should be taken only as a guide.

The results are purely indicative and cannot be used for the purposes of substation design, line design, equipment uprating or any other investment related decision making purposes. Fault levels may be higher than shown at some locations, predominantly due to the impact of embedded generation. Interested parties needing to consider the impacts of their proposals on fault levels should consult ElectraNet and the distribution network service provider, SA Power Networks, for more detailed information.

When calculating maximum fault levels, we have:

- applied a solid fault condition (i.e. no fault impedance modelled)
- assumed all wind farms are online
- assumed embedded generation at Starfish Hill, Angaston, Lonsdale, Port Stanvac, Whyalla, Canunda and KCA is online
- applied a system normal network configuration, with all network elements are in service.

When calculating minimum fault levels, we have:

- applied a solid fault condition (i.e. no fault impedance modelled)
- depending on the type of wind farm, assumed their contribution to be either zero, or limited to their active power rating
- assumed seven large conventional generator units are in-service, to allow for provision of satisfactory South Australian system strength following any single credible generator contingency
- assumed that embedded generation is offline
- in each case, provided the outcome for the single credible contingency that yields the lowest three-phase and lowest single-phase fault level.

Location	Bus Voltage (kV)	Circuit Breaker Lowest Rating	2017-18 Maximum Fault Level		2017-18 Minimum Fault Level	
			3-phase	1-phase	3-phase	1-phase
Angas Creek	132	31.5	4.9	4.6	1.8	2.0
Angas Creek	33	13.1	5.3	6.6	2.8	3.1
Ardrossan West	132	21.9	2.6	2.6	0.9	1.2
Ardrossan West	33	17.5	4.4	3.3	2.3	1.8
Back Callington	132	31.5	4.7	4.0	3.1	3.0
Back Callington	11	25	9.0	0.6	4.8	0.3

Location	Bus Voltage (kV)	Circuit Breaker Lowest Rating	2017-18 Maximum Fault Level		2017-18 Minimum Fault Level	
			3-phase	1-phase	3-phase	1-phase
Baroota	132	4.4	3.4	3.0	1.7	1.8
Baroota	33	17.5	1.6	1.7	1.3	1.5
Belalie	275	31.5	6.2	3.8	1.4	1.3
Berri	132	10.9	2.4	2.8	1.0	1.1
Berri	66	21.9	3.9	4.9	2.7	3.1
Berri	11	20	10.3	8.7	8.5	6.6
Black Range	275	40	8.6	4.1	4.4	3.0
Blanche	132	21.9	5.5	5.6	1.7	2.0
Blanche	33	17.5	8.4	11.4	4.3	5.7
Blyth West	275	31.5	5.4	4.8	1.4	1.7
Brinkworth	275	21	5.1	4.0	1.7	1.7
Brinkworth	132	15.3	7.9	8.8	2.9	2.8
Brinkworth	33	17.5	3.0	3.6	1.5	1.8
Bungama	275	31.5	5.3	4.4	1.9	2.0
Bungama	132	10.9	7.0	8.0	2.3	2.7
Bungama	33	13.1	10.6	6.5	6.0	4.1
Canowie	275	31.5	7.4	4.1	1.4	1.2
Cherry Gardens	275	31.5	13.0	13.2	4.3	5.5
Cherry Gardens	132	15.3	7.1	7.5	2.5	2.3
City West	275	40	14.4	17.7	4.3	5.7
City West - CBD	66	40	22.6	21.8	12.0	13.7
City West - South	66	40	18.7	13.6	11.1	10.1
Clare North	132	40	6.8	6.8	2.3	2.7
Clare North	33	31.5	9.3	6.9	4.8	3.5
Cultana	275	31.5	5.0	4.7	2.0	2.4
Cultana	132	31.5	6.1	6.5	2.7	3.3
Dalrymple	132	40	2.2	2.2	0.7	0.9
Dalrymple	33	8	4.1	5.5	1.8	2.5
Davenport	275	31.5	7.5	7.2	2.5	3.0
Davenport	132	40	8.1	9.4	3.1	4.1
Davenport	33	31.5	9.7	9.6	4.8	4.9
Dorrien	132	21.9	7.2	7.3	2.8	3.4

Location	Bus Voltage (kV)	Circuit Breaker Lowest Rating	2017-18 Maximum Fault Level		2017-18 Minimum Fault Level	
			3-phase	1-phase	3-phase	1-phase
Dorrien	33	17.5	15.5	10.2	7.4	6.1
Dry Creek (West)	66	21.9	20.9	17.9	10.3	9.3
Dry Creek (East)	66	21.9	20.3	18.7	10.3	7.8
East Terrace	275	N/A	12.7	13.5	4.1	5.4
East Terrace	66	31.5	23.9	23.0	12.3	14.1
Emeroo	132	N/A	6.3	6.9	2.7	3.4
Happy Valley	275	31.5	12.5	12.9	4.2	5.4
Happy Valley	66	21.9	25.0	22.0	13.2	14.1
Hummocks	132	10.9	4.0	4.1	1.2	1.5
Hummocks	33	17.5	4.7	4.7	2.4	2.4
Kadina East	132	40	2.2	2.5	1.0	1.3
Kadina East	33	17.5	5.8	4.3	3.1	2.4
Kanmantoo	132	10.9	4.9	4.2	3.2	3.1
Kanmantoo	33	N/A	1.6	1.7	1.5	1.6
Kanmantoo	11	13.1	3.9	2.4	3.5	2.3
Keith	132	15.3	2.2	2.1	0.8	1.0
Keith	33	31.5	4.0	5.1	2.3	3.1
Kilburn	275	31.5	15.7	16.3	4.4	5.5
Kilburn	66	21.9	20.9	17.9	10.3	7.8
Kincraig	132	15.3	2.6	2.6	0.7	0.9
Kincraig	33	17.5	4.3	6.0	2.2	3.1
Le Fevre	275	40	19.7	23.3	4.6	5.5
Le Fevre	66	25	29.7	27.5	15.4	16.5
Leigh Creek Coalfield	132	N/A	0.6	0.8	0.6	0.7
Leigh Creek Coalfield	33	8.7	1.5	2.1	1.1	1.5
Leigh Creek South	132	N/A	0.6	0.8	0.6	0.7
Leigh Creek South	33	18.4	0.9	1.3	0.3	1.1
Magill	275	15.7	14.1	14.7	4.3	5.5
Magill	66 (1)	21.9	23.6	27.7	4.4	2.7
Magill	66 (2)	21.9	11.9	8.2	8.3	6.9
Mannum	132	40	5.1	4.8	1.7	1.8
Mannum	33	31.5	5.2	4.9	2.8	2.6

Location	Bus Voltage (kV)	Circuit Breaker Lowest Rating	2017-18 Maximum Fault Level		2017-18 Minimum Fault Level	
			3-phase	1-phase	3-phase	1-phase
Mannum – Adelaide Pump 1	132	N/A	4.5	4.0	1.6	1.7
Mannum – Adelaide Pump 1	3.3	N/A	25.2	24.8	20.4	20.7
Mannum – Adelaide Pump 2	132	N/A	4.7	4.1	1.9	2.0
Mannum – Adelaide Pump 2	3.3	N/A	25.3	25.0	21.4	21.8
Mannum – Adelaide Pump 3	132	N/A	4.7	4.0	2.0	2.1
Mannum – Adelaide Pump 3	3.3	N/A	25.3	25.0	21.7	22.0
Mayurra	132	40	7.4	5.8	2.5	2.6
Middleback	132	40	2.8	2.5	1.4	1.6
Middleback	33	N/A	1.5	2.1	1.4	1.9
Millbrook	132	10.9	5.3	4.6	2.9	2.7
Millbrook	3.3	N/A	26.0	25.9	23.5	23.3
Mintaro	132	20	8.0	8.2	2.0	2.0
Mobilong	132	15.3	6.2	6.3	3.1	3.5
Mobilong	33	31.5	9.3	7.0	5.3	3.7
Mokota	275	50	6.7	4.2	1.3	1.1
Monash	132	31.5	2.5	2.9	1.6	1.7
Monash	66	N/A	3.8	4.9	2.7	3.0
Morgan – Whyalla Pump 1	132	15.3	4.3	4.1	2.5	2.5
Morgan – Whyalla Pump 1	3.3	N/A	25.6	25.8	22.1	23.7
Morgan – Whyalla Pump 2	132	15.3	4.9	4.1	3.2	3.0
Morgan – Whyalla Pump 2	3.3	N/A	18.1	18.1	15.8	17.5
Morgan – Whyalla Pump 3	132	15.3	8.0	6.9	4.1	4.1
Morgan – Whyalla Pump 3	3.3	N/A	18.7	18.9	16.2	18.1
Morgan – Whyalla Pump 4	132	15.3	9.8	8.4	4.2	4.2
Morgan – Whyalla Pump 4	3.3	N/A	18.9	19.1	16.3	18.2
Morphett Vale East	275	31.5	11.5	11.6	4.1	5.2
Morphett Vale East	66	25	20.5	16.6	11.1	10.1
Mount Barker	132	31.5	6.7	6.6	3.3	3.4
Mount Barker	66	31.5	11.2	11.9	4.4	5.5

Location	Bus Voltage (kV)	Circuit Breaker Lowest Rating	2017-18 Maximum Fault Level		2017-18 Minimum Fault Level	
			3-phase	1-phase	3-phase	1-phase
Mount Barker South	275	40	11.2	10.4	3.8	3.9
Mount Barker South	66	66	11.5	11.3	8.1	8.5
Mount Gambier	132	15.3	6.8	6.6	1.5	1.8
Mount Gambier	33	17.5	7.1	5.9	3.1	2.7
Mount Gunson	132	15.3	1.1	1.1	0.9	1.0
Mount Gunson	33	N/A	1.3	1.3	1.2	1.2
Mount Lock	275	31.5	6.5	3.8	1.6	1.5
Mount Millar	132	40	2.2	1.6	0.7	0.8
Mount Millar	33	31.5	10.3	1.4	2.2	1.2
Munno Para	275	40	12.6	11.6	1.6	1.7
Munno Para	66	40	14.1	10.5	8.0	4.6
Murray – Hahndorf Pump 1	132	15.3	5.4	5.2	2.9	3.2
Murray – Hahndorf Pump 1	11	N/A	12.6	13.0	10.9	11.6
Murray – Hahndorf Pump 2	132	15.3	5.9	5.5	3.2	3.5
Murray – Hahndorf Pump 2	11	N/A	12.9	13.2	11.3	11.9
Murray – Hahndorf Pump 3	132	15.3	5.7	5.1	3.5	3.5
Murray – Hahndorf Pump 3	11	N/A	12.9	13.2	11.7	12.0
Neuroodla	132	N/A	1.5	1.4	1.2	1.1
Neuroodla	33	8.7	1.4	1.4	1.3	1.3
New Osborne	66	40	31.9	30.9	15.9	17.2
North West Bend	132	10.9	4.3	4.4	2.3	2.4
North West Bend	66	13.1	4.4	4.9	3.1	3.4
Northfield	275	31.5	15.5	15.7	4.3	5.5
Northfield	66	31.5	27.7	24.7	13.0	13.2
Para	275	31.5	18.3	20.4	4.5	6.1
Para	132	21.9	8.5	9.0	3.2	2.8
Para	66	21.9	18.5	15.6	10.2	9.3
Para	11 (SVC)	N/A	32.6	28.2	29.2	25.2
Parafield Gardens West	275	31.5	16.6	18.0	4.4	5.8
Parafield Gardens West	66	31.5	18.4	15.3	9.4	8.5
Pelican Point	275	40	19.4	22.7	4.3	4.8
Penola West	132	31.5	5.1	5.8	0.6	0.8

Location	Bus Voltage (kV)	Circuit Breaker Lowest Rating	2017-18 Maximum Fault Level		2017-18 Minimum Fault Level	
			3-phase	1-phase	3-phase	1-phase
Penola West	33	31.5	5.3	5.4	2.8	2.2
Pimba	132	31.5	0.9	0.9	0.8	0.8
Port Lincoln Terminal	132	10.9	2.4	2.7	0.5	0.7
Port Lincoln Terminal	33	17.5	4.9	4.0	1.7	1.9
Port Lincoln Terminal	11	13.1	7.8	6.7	3.8	3.3
Port Pirie	132	40	5.6	5.9	0.8	0.9
Port Pirie	33	13.1	8.9	5.3	5.0	2.9
Quarantine 1	66	N/A	14.5	14.0	8.9	7.3
Quarantine 2	66	N/A	16.6	12.8	9.7	7.5
Redhill	132	N/A	6.6	5.4	2.9	2.8
Robertstown	275	31.5	9.5	7.1	2.8	3.1
Robertstown	132	31.5	10.8	10.8	4.7	5.2
Roseworthy	132	31.5	7.3	6.2	3.0	2.6
Roseworthy	11	25	8.9	12.3	4.8	6.5
Sleaford	132	40	2.2	1.7	0.4	0.6
Snowtown	132	N/A	4.4	3.1	1.7	1.7
Snuggery	132	10.9	8.5	8.9	1.8	2.2
Snuggery (Industrial)	33	8.7	13.1	16.6	4.5	6.3
Snuggery (Industrial)	11 (Cap.)	13.1	12.6	10.9	7.6	6.6
Snuggery (Rural)	33	8.7	3.4	4.6	2.5	3.5
Snuggery (Rural)	11 (Cap.)	13.1	5.6	4.9	4.8	4.1
South East	275	31.5	8.7	8.6	6.0	6.6
South East	132	20	10.8	11.8	4.4	5.4
Stony Point	132	31.5	3.4	2.6	2.0	1.9
Stony Point	11	N/A	9.5	0.3	5.2	0.2
Tailem Bend	275	21	8.6	5.6	4.4	3.5
Tailem Bend	132	21.9	6.9	7.6	2.5	2.7
Tailem Bend	33	25	6.0	7.6	3.1	4.0
Templers	132	10.9	7.8	7.3	3.5	3.8
Templers	33	8.7	10.0	7.2	5.3	3.7
Templers West	275	31.5	8.5	7.3	1.6	1.8

Location	Bus Voltage (kV)	Circuit Breaker Lowest Rating	2017-18 Maximum Fault Level		2017-18 Minimum Fault Level	
			3-phase	1-phase	3-phase	1-phase
Templers West	132	40	7.3	7.0	2.2	2.2
Torrens Island	275	31.5	20.7	25.6	4.7	6.3
Torrens Island	66	40	32.2	30.8	16.2	17.6
Tungkillo	275	50	12.6	10.6	4.3	4.6
Waterloo	132	10.9	9.9	8.6	3.3	3.5
Waterloo	33	13.1	6.1	4.3	3.0	2.2
Waterloo East	132	N/A	9.8	8.0	3.1	2.7
Whyalla Central	132	40	5.3	5.8	2.5	3.1
Whyalla Central	33	40	10.5	7.1	5.7	3.8
Whyalla Terminal (LMF)	132	10.9	5.2	5.5	2.5	3.1
Whyalla Terminal (LMF)	33	17.5	4.6	4.5	3.8	3.9
Willalo	275	31.5	6.5	4.0	1.4	1.2
Wudinna	132	31.5	1.0	1.1	0.5	0.6
Wudinna	66	21.9	1.5	1.7	0.8	0.8
Yadnarie	132	10.9	2.5	2.5	0.8	1.1
Yadnarie	66	40	2.7	3.2	1.1	1.4
Yadnarie	11 (React.)	18.4	6.3	5.4	4.5	3.8

Appendix F Committed, pending, proposed and potential projects

Our planning process has identified emerging network limitations and solution options (section F1). The committed, pending, proposed and potential solutions are based on evaluating network as well as non-network options using high level cost estimates. Each proposed solution is one of potentially several options available to resolve the corresponding network limitation. We've also included committed, pending and proposed projects already covered in chapters 6 and 7 to provide a complete overview of all augmentation and market benefit projects.

The proposed solutions are subject to variation and change due to customer activity, network developments and refined analysis. Due to uncertainties in the timing and number of customer connections within the state, the timing and scope of projects are indicative only.

We also have a range of committed, pending and proposed projects that relate to the maintenance of our security and compliance obligations (section F2), including the security and compliance projects already covered in section 6.2.

There are many significant asset replacement projects (>$3M at a single site) proposed, which are planned based on asset condition (section F3), including the projects already covered in sections 6.2, 7.10 and 7.12. Currently there are no economically feasible non-network solutions that could resolve the limitations presented.

ElectraNet has assessed detailed asset condition and replacement requirements for the 2018-19 to 2022-23 regulatory control period. Summary entries for line, substation and protection system unit asset replacements are provided. These summaries relate to types of projects that are included in our 2018-19 to 2022-23 revenue allowance, as agreed to by the AER in April 2018.

Contingent projects that are included in our 2018-19 to 2022-23 revenue proposal are listed in section F4.

F1 Summary of committed, pending, proposed and potential augmentation projects

Project timing	Limitation	Proposed solution	Category	Region	$ million
Committed and Pending Projects					
2018	Congestion on the 132 kV network between Robertstown and Monash restricts exports from South Australia to Victoria across the Murraylink Interconnector	Uprate the Robertstown – North West Bend #2 and the North West Bend – Monash #2 132 kV lines to 100˚C line clearances	Market benefit (NCIPAP)	Riverland	<5
2018	Heywood Interconnector transfer limitations due to system stability and thermal constraints	Minor works outstanding, including implementation of control scheme to bypass the capacitors under certain conditions	Augmentation and market benefit	Main Grid and South East	35-40 (ElectraNet costs only)
2018	Large scale renewable energy sources connected to the transmission network are intermittent and do not contribute to frequency control to the same extent as conventional generation, causing potential frequency control issues that may threaten South Australian system security at times when few conventional generators are dispatched	Design and build a grid-connected, utility scale battery energy storage system at Dalrymple that will help to manage frequency related system security issues, as well as improve the reliability of supply for customers at Dalrymple connection point and provide other market benefits	Augmentation and market benefit	Mid North	<6 Regulated 10-14 Unregulated
Proposed Projects					
2019	Congestion on the Waterloo-Templers 132 kV line limits power flows in the Mid North region	Install power flow control technology that will increase impedance of the Waterloo-Templers 132 kV line and thereby improve overall transfer capacity by increasing power flows on lines with surplus capacity	Market benefit (NCIPAP)	Mid North	3-6
2019	Thermal congestion across the Heywood interconnector between Tailem Bend and Tungkillo and between Tailem Bend and Mobilong when the interconnector is limited below 650 MW	Apply dynamic ratings to the key circuits that make up the Heywood interconnector in South Australia to better account for favourable weather conditions and release further transfer capacity	Market benefit (NCIPAP)	Main Grid	<5

Project timing	Limitation	Proposed solution	Category	Region	$ million
2019	Substation plant and secondary system ratings limit full utilisation of the Davenport-Robertstown 275 kV transmission lines thermal capacity	Remove, replace or change plant and secondary systems that are rated lower than the design capability of the conductors	Market benefit (NCIPAP)	Main Grid	<5
2020	Transient (rotor angle) and voltage stability limit the inter-regional transfer capacity of the Heywood interconnector	Turn the Tailem Bend - Cherry Gardens 275 kV line into Tungkillo substation, fully populating the diameter that is benched and prepared ready for this	Market benefit (NCIPAP)	Main Grid	<6
2020	Difficulty in manually and effectively controlling the increasing number of reactive plant and voltage control facilities across the Main Grid	Install a coordinated control scheme to better use existing reactive plant and voltage control facilities to minimise system constraints, whilst managing system voltage levels	Augmentation	Main Grid/ Various	3-6
2020	Voltage limitations around South East substation prevent the full thermal capacity of the Heywood interconnection corridor being utilised	Install an additional 100 Mvar capacitor at South East substation	Market benefit (NCIPAP)	Main Grid	<5
2022	Thermal design ratings of the Robertstown 275/132 kV transformers limit transfer capability across the Murraylink interconnector	Install new transformer management relays and bushing monitoring add-on equipment and apply short term ratings to the two 275/132 kV transformers at Robertstown (NCIPAP)	Market benefit (NCIPAP)	Mid North / Murraylink Inter-connector	<5
2021	Expiry of existing contract for network support at Port Lincoln Significant lengths of conductor on the Whyalla to Yadnarie and the Yadnarie to Port Lincoln 132 kV lines are in poor condition and need to be replaced	Construct new double circuit lines from Cultana to Yadnarie and from Yadnarie to Port Lincoln, and decommission the existing 132 kV lines	Augmentation (Contingent)	Eyre Peninsula	200-250
2023	Significant residential developments near Gawler that cannot be supplied by SA Power Networks' existing distribution network in the area	Establish a new 132 kV exit point on the Para – Roseworthy 132 kV line at Gawler East to provide supply to a 132/11 kV distribution substation that will be constructed and owned by SA Power Networks	Connection	Mid North	3-6 (ElectraNet costs only)

Project timing	Limitation	Proposed solution	Category	Region	$ million
2023	Facilitate greater competition in the wholesale electricity market, provide appropriate security of supply, and facilitate the transition to lower carbon emissions	Establish a new high capacity interconnector between South Australia and the eastern states, or implement a range of network support solutions	Market benefit (Contingent)	Main Grid	200 – 500 (SA component only)
2024-2028	Constraints applied to generation connected to Davenport-Robertstown 275 kV transmission lines	Uprate selected spans to achieve T120 rating, uprate protection and metering systems, and implement calculation of real-time ratings	Market benefit	Main Grid	<5
2024-2028	Transient (rotor angle) and voltage stability limit the inter-regional transfer capacity of the Heywood interconnector	Turn the Robertstown - Para 275 kV line into Tungkillo substation, fully populating the diameter that is benched and prepared ready for this	Market benefit	Main Grid	4-8
Potential Projects					
When or if needed: by 2027?	Connection of a step load increase that could cause the line loading to exceed its thermal limit of 76 MVA	Rebuild the Davenport to Pimba 132 kV line and establish associated substation assets (including reactive support)	Augmentation (Contingent)	Upper North	110
When or if needed: by 2027?	Connection of a step load increase that could cause the line loading to exceed its thermal limit of 10 MVA	Uprate or rebuild the Davenport to Leigh Creek 132 kV line and establish associated substation assets (including reactive support)	Augmentation (Contingent)	Upper North	60

F2 Summary of committed, pending and proposed security and compliance projects

Project timing	Limitation	Proposed solution	Region	$ million
Committed and Pending Projects				
2018	Uncontrolled tripping of SA generation due to over-frequency could lead to significant loss of frequency control capability in SA	Implement Over-frequency Generation Shedding (OFGS) scheme for SA wind farms, including a backup scheme on the network side of the wind farm connections	Various	<5
2018	Transformer oil containment systems need refurbishing in accordance with environment protection regulations	Install, upgrade or replace transformer oil containment systems and associated equipment at various sites where assessment indicates a clear need.	Various	8-10
2018	Existing backups for ElectraNet's control centre and data centre requirements require improvement to address emerging security threats	Construct a new Backup Control and Data Centre to meet current physical and electronic security requirements	Metropolitan	4-8
2018	Following a single contingency of an in-service generator, steady-state voltage levels on the South Australian transmission system may breach 110% of the nominal 275 kV at times of light load, high solar PV generation and low wind generation from 2018	Install a switched 50 Mvar 275 kV reactor at Templers West substation	Main Grid	4-6
2018	Inadequate access tracks in difficult terrain hinder inspection and restoration of transmission lines following a fault	Upgrade transmission line access tracks at vulnerable locations across the network	Various	<5
2018	Substandard circuit breaker arrangement at Tailem Bend substation constrains the Heywood interconnector and places network security and reliability at risk	Extend the Tailem Bend substation to accommodate an additional 275 kV diameter with two circuit breakers, associated plant and secondary systems, and rearrange 275 kV line exits	Main Grid	8-10
2019	High voltage switching training conducted on live network results in network and asset performance impacts and training limitations	Create a high voltage switching training facility to improve training standards across all aspects of high voltage switching	Metropolitan	8-10

Project timing	Limitation	Proposed solution	Region	$ million
2020	Minimum fault levels in South Australia may fall below the level that is needed to ensure the ongoing stable operation of South Australia's electricity system	Upgrade existing protection devices and install up to six synchronous condensers at selected locations across the 275 kV transmission network	Main Grid	80-120
2020	The Heywood interconnector is constrained during an outage of the existing single 275/132 kV transformer at Tailem Bend substation	Install, connect and commission the spare 160 MVA 275/132 kV transformer as a second transformer on hot standby at Tailem Bend substation	South East	<5
2020	Changing generation patterns have resulted in complex voltage interactions in the Eyre Peninsula and Upper North regions leading to potential violations of voltage limits stipulated in the Rules and connection agreements	Install automated regional voltage control schemes for Eyre Peninsula and Upper North regions	Eyre Peninsula/ Upper North	<5
2020	Loss of multiple generators and/or islanding of South Australia from the remainder of the NEM puts SA system security at risk from loss of synchronism	Implement a Special Protection Scheme (SIPS, completed in 2018) and Wide Area Monitoring Scheme (WAMS) utilising transmission-level load tripping and phasor measurement capabilities	Various	4-8
2021	High voltage hazard due to risk of failure of mechanical or electrical lock-off points on motorised air insulated high voltage isolators	Replace or refurbish mechanical and electrical isolation lock-off points on all motorised air insulated isolators	Various	10-15
Proposed Projects				
2019	High voltage hazard due to lack of remote visibility of manually operated isolator and earth switch status	Install status indication on isolators and earth switches where there currently is none	Various	<5
2020	Unavailability of Gas Insulated Switchgear (GIS) connection spares hinders restoration of supply following a 225 MVA 275/66 kV transformer failure at East Terrace, Northfield or Kilburn substation	Design and procure all the plant and equipment required to support the rapid restoration of a failed GIS-connected 225 MVA 275/66 kV transformer	Metropolitan	<5
2020	Geomagnetic induced currents resulting from enhanced solar activity may induce DC currents on transmission lines and possible transformer damage or failure	Install protective monitoring and alarming to enable affected transformers to be tripped prior to serious damage occurring	Various	<5

Project timing	Limitation	Proposed solution	Region	$ million
2020	Loss of AC auxiliary supplies hinders restoration of supply during black start or other abnormal operating conditions	Provide alternative diesel generator supplies to critical substations (where not already provided), connection points for mobile generators to non-critical substations, and related AC and DC supply improvements	Various	5-10
2020	Spencer Gulf high tower crossings for the Davenport-Cultana 275 kV transmission lines, supplying the entire Eyre Peninsula region, would prove difficult or impossible to restore to in a timely manner following an asset failure	Undertake preparatory site works and procure spares to support a rapid restoration	Eyre Peninsula	<5
2020	Failure of Gas Insulated Switchgear (GIS) plant at Kilburn substation places significant load at risk from the next single contingency	Design, procure and have on standby the necessary line components to bypass Kilburn substation	Metropolitan	<5
2021	Either Murraylink interconnection or generation north of Robertstown must be constrained during scheduled maintenance of centre breakers or associated plant at the Robertstown substation	Install a single 275 kV circuit breaker and associated equipment between the 275 kV busses at the Robertstown substation	Mid North / Murraylink Inter-connector	5-8
2021	Generator disconnection during outages of the Canowie to Robertstown 275 kV transmission line	Install a 275 kV circuit breaker and associated equipment on the Robertstown exit at Canowie substation	Mid North	<5
2018-21	Improvements have been identified to control safety risks associated with enclosed high voltage areas in substations	Implement a program of safety improvement activities for infrastructure associated with high voltage plant areas, such as fencing, earthing, entry locking and surface treatment	Various	<5
2022	Risk of thermal damage to neutral earthing reactors and resistors, and consequent unsafe operating conditions and risk of damage to larger plant	Install a monitoring and protection scheme for the neutral earthing reactor and resistor installations across the network	Various	<5
2023	High voltage hazard due to risk of failure of mechanical or electrical lock-off points on motorised air insulated high voltage isolators at Templers substation	Replace mechanical and electrical isolation lock-off points on all motorised air insulated isolators at Templers substation	Mid North	<5
2023	Operational difficulties with starting Quarantine Power Station #5 generator during black start conditions	Install a 66 kV circuit breaker and associated equipment to tie the two Torrens Island North lines in the Torrens Island North 66 kV switchyard	Metropolitan	<5

Project timing	Limitation	Proposed solution	Region	$ million
2024-2028	Following a single contingency of an in-service generator, steady-state voltage levels on the South Australian transmission system may breach 110% of the nominal 275 kV at times of light load, high solar PV generation and low wind generation from 2021	Install a switched 50 Mvar 275 kV reactor at Blyth West substation	Main Grid	4-6
2024–2028	Generation constraints and/or loss of load during plant outages at the Blanche substation	Install an additional 132 kV circuit breaker and associated equipment at the Blanche substation	South East	<5
2024–2028	Mintaro and Angaston generators are constrained off during 132 kV outages that result in these generators being radialised	To be considered for 2024-2028 NCIPAP Implement full single pole reclosing capability on the 132 kV circuits in the Mid North region	Mid North	<5
2024–2028	Ladbroke Grove and Snuggery generators are constrained off during 132 kV outages that result in these generators being radialised	To be considered for 2024-2028 NCIPAP Implement full single pole reclosing capability on the 132 kV circuits in the South East region	South East	<5

F3 Summary of committed, pending and proposed asset replacement projects

Project timing	Limitation	Recommended solution	Region	$ million	Alternative option(s)
Committed and Pending Projects					
2017	Porcelain disc insulators on the Brinkworth to Mintaro 132 kV line are at end-of-life, leading to a high failure rate and fire start risk	Replace all porcelain disc insulators, along with defective poles and cross arms, on the Brinkworth to Mintaro 132 kV line to achieve a 15-year life extension	Mid North	6-8	Assess and replace insulators on sample-based testing results
2018	A number of substation battery charger units have reached the end of their practical life. Spare parts are not available	Implement a planned replacement program to remove battery chargers from service and replace with modern, fit-for-purpose equipment	Various	<5	Replace battery chargers on failure

Project timing	Limitation	Recommended solution	Region	$ million	Alternative option(s)
2018	The majority of the primary equipment at Baroota substation is in poor condition	Replace plant in poor condition at Baroota substation and implement flood mitigation measures. Retain only the existing single 10 MVA 132/33 kV transformer	Mid North	5-8	Rebuild substation at a new location
2018	Many items of online condition monitoring equipment are now nearing the end of their usable lives (12–20 years old) and are exhibiting high failure rates	Replace obsolete online asset condition monitoring equipment	Various	7-10	Continue corrective maintenance program only
2018	Review of substation lighting identified compliance issues and safety hazards with some existing lighting systems	Replace substation lighting and associated infrastructure at sites where hazards exist	Various	8-12	Cost and risks assessments were undertaken for the various lighting functions to determine the optimal solution to meet the requirements under the WHS Act and Australian Standards
2018	Load-releasing cross arms on the Para-Brinkworth-Davenport 275 kV line are a safety risk and inadequate for access and maintenance. Porcelain disc insulators are at end-of-life, which can lead to high failure rate and fire start risk	Replace load-releasing cross arms and all porcelain disc insulators on Para-Brinkworth-Davenport 275 kV line to achieve a 15-year life extension	Main Grid	50-60	Rebuild 275 kV line in an adjacent easement and retire old line or Replace load-releasing cross arms with standard cross arms (and also strengthen the towers) and use sample-based testing results to assess and replace insulators
2018	Davenport-Pimba 132 kV transmission line cannot safely achieve its designed nominal ratings at T65 operating temperature	Treat low spans to achieve the designed nominal ratings for Davenport – Mt Gunson section	Upper North	10-14	Treat low spans for Davenport – Mt Gunson – Pimba or Install grid support

Project timing	Limitation	Recommended solution	Region	$ million	Alternative option(s)
2014-2019	Substation assets have been identified with high failure rates and safety risks or have been assessed to be at the end of their technical and economic lives	Program of unit asset replacements at multiple substations	Various	40-50	Replace individual assets on failure
2019	Gas Insulated Switchgear (GIS) plant at East Terrace substation requires an effective monitoring system to mitigate operational and environmental risks associated with a gas leak	Replace existing combined phases gas monitoring system with isolated per phase systems	Metro-politan	<5	Install additional barriers for separate monitoring of gas compartments or Replace GIS plant
2019	AC auxiliary supplies at older substations are not compliant with current Australian standards and have some safety hazards and operational deficiencies	Replace AC auxiliary supply equipment, switchboards and cabling at 11 substations	Various	10-15	Replacing sub-standard and hazardous equipment is considered to be the only viable option
2019	Operational risks and delays in protection and control systems at Monash and Berri substations	Replace protection relays and communication gateway	Riverland	<5	Replace communication gateway only
2019	Outages and constraints on the Murraylink Interconnector	Redesign and replace the Murraylink control scheme	Riverland / Murraylink Inter-connector	<5	Replace the Murraylink control scheme with no redesign
2019	Risk of unplanned outages on Magill - East Terrace 275 kV underground cable	Replace degraded underground fluid instrumentation and associated telecommunications and infrastructure	Metro-politan	<4-6	Defer replacement and manage risk or Continue corrective maintenance program only
2019	Transmission line support systems (towers, poles) components at end-of-life, leading to a high failure rate, and safety and network availability risk	Refurbish transmission line support systems and extend the life of the Snuggery – Blanche – Mt Gambier 132 kV line by renewing line asset components	South East	5-8	Replace individual components or sections on failure or Full line replacement

Project timing	Limitation	Recommended solution	Region	$ million	Alternative option(s)
2019–2023	Transmission line insulator systems at end-of-life, leading to a high failure rate, safety and network availability risk, and fire start risk	Implement a program of transmission line insulator system refurbishment to renew line asset components and extend line life	Various	50–70	Replace individual components or sections on failure or Full line replacement
Proposed Projects					
2019	Transformer fire suppression systems at Magill substation have been identified as a safety hazard and asset risk	Investigate, design and install refurbished or replacement fire suppression systems	Metro-politan	<5	Replace fire suppression systems with no redesign
2020	Individual transformer bushings have been assessed to be at the end of their technical and/or economic lives, leading to an increased risk of failure that could cause safety and reliability issues	Implement a program to replace transformer bushings on selected transformers at various substations	Various	6-8	Replace complete transformers
2021	Individual substation instrument transformers have been assessed to be at the end of their technical and/or economic lives. An increased risk of failure could cause safety and reliability issues.	Implement a program to replace selected instrument transformers at various substations	Various	<4-6	Replace assets on failure
2021	Leigh Creek South transformers 1 and 2 have been assessed to be at the end of their technical lives and at high risk of failure	Replace the existing two 5 MVA transformers with a single new 5 MVA 132/11 kV transformer and associated plant at Leigh Creek South substation	Upper North	<5	Replace asset on failure or Establish micro-grid
2021	Individual surge arrestors have been assessed to be at the end of their technical and/or economic lives. An increased risk of failure could cause safety and reliability issues.	Implement a program to replace selected porcelain surge arrestor units at various substations	Various	<5	Replace assets on failure

Project timing	Limitation	Recommended solution	Region	$ million	Alternative option(s)
2022	A number of substation DC battery charger units have reached the end of their practical life and spare parts are not available	Implement a planned replacement program to remove battery chargers from service and replace with modern, fit-for-purpose equipment	Various	<5	Replace battery chargers on failure
2022	AC auxiliary supplies at older substations are not compliant with current Australian standards and have some safety hazards and operational deficiencies	Replace AC auxiliary supply equipment, switchboards and cabling at 17 substations	Various	8-12	Replacing sub-standard and hazardous equipment is considered to be the only viable option
2022	A number of substation PC-based systems that enable users to view the status of primary plant, protection systems and site auxiliary system within substations are at end of their technical life and require replacement to ensure safe operation of the system.	Implement a program to replace selected substation PC-based local control systems at various substations	Various	<5	Replace assets on failure
2022	South East SVC computer control system at end-of-life, leading to SVC reliability risk and interconnector constraints	Replace the existing SVC computer control system at South East substation with a new fully supported system	SA-Vic Inter-connector	4-6	Replace South East substation SVCs
2023	Mount Gambier transformer 1 has been assessed to be at the end of its technical life and at high risk of failure	Replace the existing 50 MVA transformer with a new 25 MVA 132/33/11 kV transformer at Mount Gambier substation	South East	<5	Replace asset on failure
2023	Mannum transformers 1 and 2 have been assessed to be at the end of their technical lives and at high risk of failure	Replace the existing 20 MVA transformers with two new 25 MVA 132/33 kV transformers (nearest ElectraNet standard transformer size) at Mannum substation	Eastern Hills	<5	Replace assets on failure

Project timing	Limitation	Recommended solution	Region	$ million	Alternative option(s)
2023	Individual high voltage circuit breakers have been assessed to be at the end of their technical and/or economic lives. An increased risk of failure could cause safety and reliability issues.	Implement a program to replace selected circuit breaker units at various substations	Various	4-6	Replace assets on failure
2023	Substation perimeter fences at several sites have deteriorated and are at end of life and require replacement to ensure security and public safety is maintained.	Implement a program to replace substation fences at selected substations	Various	4-6	Replacing substation fences that have deteriorated is considered the only viable option
2023	The 132 kV isolators and the 132 kV bus at Templers have been assessed to be at the end of their technical and economic lives and no longer manufacturers support. An increased risk of failure could cause safety and reliability issues	Replace 8 isolators and the 132 kV busbar at Templers substation	Mid North	<5	Extend the Templers West substation to include 132 kV and decommission the Templers substation
2018–2023	Transmission line conductor and earthwire components at end-of-life, leading to a high failure rate, safety and network availability risk, and fire start risk	Implement a program of transmission line conductor and earthwire refurbishment to renew line asset components and extend line life	Mid North / Riverland	10-20	Replace individual corroded conductor sections or Full line replacement
2019–2023	Significant lengths of conductor on the Cultana to Yadnarie 132 kV line are in poor condition, leading to a high failure rate, safety and network availability risk, and fire start risk	Refurbish conductor and earthwire and extend the life of the Cultana to Yadnarie 132 kV transmission line	Eyre Peninsula	30-45	Replace individual corroded conductor sections or Full line replacement
2019–2023	Significant lengths of conductor on the Yadnarie to Port Lincoln 132 kV line are in poor condition, leading to a high failure rate, safety and network availability risk, and fire start risk	Refurbish conductor and earthwire and extend the life of the Yadnarie to Port Lincoln 132 kV transmission line	Eyre Peninsula	30-45	Replace individual corroded conductor sections or Full line replacement

Project timing	Limitation	Recommended solution	Region	$ million	Alternative option(s)
2019-2023	Individual substation isolators have been assessed to be at the end of their technical and economic lives and no longer manufacturers support. An increased risk of failure could cause safety and reliability issues	Implement a program to replace selected isolator units at various substations	Various	8-12	Replace assets on failure
2019–2023	Various individual substation protection and control systems have been assessed to be at the end of their technical and economic lives. An increased risk of failure could cause safety and reliability issues	Implement a program of unit protection relay and control system replacements at various substations	Various	25-35	Replace assets on failure
2019–2023	Many items of online condition monitoring equipment will be near the end of their usable lives in the 2019-2023 period (12-20 years old) and are exhibiting high failure rates	Implement a program to replace selected obsolete online asset condition monitoring units	Various	4-6	Continue corrective maintenance program only
2024–2028	Transmission line support systems (towers, poles) components at end-of-life, leading to a high failure rate, and safety and network availability risk	Implement a program of transmission line support system refurbishment to renew line asset components and extend line life	Various	10-15	Replace individual components or sections on failure or Full line replacement
2024–2028	Transmission line insulator systems at end-of-life, leading to a high failure rate, safety and network availability risk, and fire start risk	Implement a program of transmission line insulator system refurbishment to renew line asset components and extend line life	Various	50-80	Replace individual components or sections on failure or Full line replacement
2024–2028	Transmission line conductor and earthwire components at end-of-life, leading to a high failure rate, safety and network availability risk, and fire start risk	Implement a program of transmission line conductor and earthwire refurbishment to renew line asset components and extend line life	Mid North / Riverland	70-100	Replace individual corroded conductor sections or Full line replacement

Project timing	Limitation	Recommended solution	Region	$ million	Alternative option(s)
2024–2028	Substation assets have been identified with high failure rates and, safety risks or have been assessed to be at the end of their technical and economic lives	Implement a program of unit asset and infrastructure replacement projects at various substations	Various	50-80	Replace assets on failure
2024–2028	Various individual substation protection and control systems have been assessed to be at the end of their technical and economic lives. An increased risk of failure could cause safety and reliability issues	Implement a program of unit protection relay and control system replacement projects at various substations	Various	30-50	Replace assets on failure
2024–2028	Transformer Replacement at specific sites at end-of-life, leading to a high failure rate, safety and network availability risk.	Implement a program of transformer and infrastructure replacement projects at various substations	Various	10-20	Replace assets on failure

F4 Summary of contingent projects

Project	Proposed trigger[67]	Current status	Reference	$ million
Eyre Peninsula major upgrade Address asset retirement needs and continue to meet the reliability standard at Port Lincoln	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	A PACR is planned to be issued in July 2018 Refer to section 7.5.1 for more details	Sections 1.3.3 and 7.5.1	200[68]
Insufficient system strength Install synchronous condensers specifically designed to contribute strongly to fault currents at a central location or locations	• 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 • Successful completion of the RIT-T (or equivalent economic evaluation) including an assessment of credible options showing a transmission investment is justified	ElectraNet is working with AEMO to develop a scope that will meet the identified system strength need Refer to section 7.4.1 for more details	Section 7.4.1	80-120
South Australian Energy Transformation Produce net market benefits, improve South Australian system security, and enable the further integration of generation from renewable sources	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	A PADR has been issued in June 2018 Refer to section 7.3.1 for more details	Sections 1.3.1 and 7.3.1	200-500[69]

67 In addition, the following two trigger conditions are proposed to apply to each of the projects listed:
- Determination (if applicable) by the AER under clause 5.16.6 of the Rules that the proposed investment satisfies the RIT-T
- ElectraNet board commitment to proceed with the project subject to the AER amending the revenue determination pursuant to the Rules.

68 The differential cost over the alternative partial replacement option (two projects presented in section F3, one to replace sections of conductor on each of the Cultana to Yadnarie and Yadnarie to Port Lincoln 132 kV lines) at about $80 million would be around $150 million, for which funding would be sought should the contingent project be triggered.

69 This represents an estimate of the South Australian portion of the cost of a new interconnector.

Project	Proposed trigger[67]	Current status	Reference	$ million
Upper North region eastern 132 kV line upgrade Rebuild the Davenport to Leigh Creek 132 kV line	• 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 • Successful completion of the RIT-T including an assessment of credible options showing a new connection point and line upgrade is justified	N/A	Section 7.7.1	60
Upper North region western 132 kV line upgrade Uprate or rebuild the Davenport to Pimba 132 kV line	• 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 • Successful completion of the RIT-T including an assessment of credible options showing a transmission investment is justified	N/A	Section 7.7.2	110

Abbreviations

Abbreviation	Definition
AC	Alternating current
ADE	Adelaide zone as outlined in the NTNDP.
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AMD	Agreed maximum demand
ARENA	Australian Renewable Energy Agency
CBD	Central business district
DNSP	Distribution network service provider
ESCOSA	Essential Services Commission of South Australia
ESCRI-SA	Energy Storage for Commercial Renewable Integration – South Australia
ESD	Energy storage device
ESOO	Electricity statement of opportunities, published by AEMO
ETC	Electricity Transmission Code (South Australia)
FCAS	Frequency control ancillary service
HVAC	High voltage alternating current
HVDC	High voltage direct current
km	Kilometres
kV	Kilovolts
MVA	Megavolt-ampere (a unit of apparent power)
Mvar	Megavolt-ampere reactive (a unit of reactive power)
MW	Megawatt (a unit of active power)
NCIPAP	Network Capability Incentive Parameter Action Plan
NEFR	National Electricity Forecast Report, published by AEMO
NEM	National Electricity Market
NNOR	Non Network Options Report (part of the RIT-D)
NPV	Net present value
NSA	Northern South Australia zone as identified in the NTNDP
NSCAS	Network support and control ancillary service
NTNDP	National Transmission Network Development Plan.
PACR	Project Assessment Conclusions Report (part of the RIT-T)
PADR	Project Assessment Draft Report (part of the RIT-T)
POE	Probability of exceedance
PSCR	Project Specification Consultation Report (part of the RIT-T)

Abbreviation	Definition
PV	Photovoltaic
RET	Renewable energy target
REZ	Renewable Energy Zone
RIT-D	Regulatory investment test for distribution
RIT-T	Regulatory investment test for transmission
RoCoF	Rate of change of frequency
Rules	National Electricity Rules
SESA	South East South Australia region as identified in the NTNDP
SVC	Static Var compensator
TNSP	Transmission Network Service Provider
UFLS	Under-frequency Load Shedding. The primary control measure used to maintain viable frequency operation following a system separation event.
Var	Volt-ampere reactive (a unit of reactive power: one million Var equal one Mvar)

Glossary of terms

Term	Description
10% POE	10% probability of exceedance. This is used to indicate a value that is expected to be exceeded once in every 10 years
90% POE	90% probability of exceedance. This is used to indicate a value that is expected to be exceeded nine times in every 10 years
Base scenario	A planning scenario developed and evaluated as part of ElectraNet's planning process. This scenario informs ElectraNet's business plan.
Constraint	A limitation on the capability of a network, load or a generating unit that prevents it from either transferring, consuming or generating the level of electrical power which would otherwise be available if the limitation was removed
Dynamic rating	A thermal rating for equipment that is variable, based on prevailing conditions such as: ambient temperature, actual plant loading, wind speed and direction, solar irradiation, and thermal mass of plant
Eastern Hills Region	One of ElectraNet's seven regional networks in South Australia. See Appendix B for details
Eyre Peninsula Region	One of ElectraNet's seven regional networks in South Australia. See Appendix B for details
Frequency control ancillary service (FCAS)	Contingency FCAS helps to stabilise system frequency from the first few seconds after a separation event, while regulation FCAS raise and lower services help AEMO control system frequency over the longer term
Jurisdictional Planning Body	ElectraNet is the Jurisdictional Planning Body for South Australia under clause 11.28.2 of the Rules. This means that ElectraNet has specific obligations with regard to network connection, network planning and establishing or modifying a connection point
Main Grid	ElectraNet's Main Grid is a meshed 275 kV network that is connected to two interconnectors and seven regional networks in South Australia
Maximum demand	The highest amount of electricity drawn from the network within a given time period
Metropolitan Region	One of ElectraNet's seven regional networks in South Australia. See Appendix B for details
Mid North Region	One of ElectraNet's seven regional networks in South Australia. See Appendix B for details
N	System normal network, with all network elements in-service
N-1	One network element out-of-service, with all other network elements in-service
National Electricity Rules (Rules)	The Rules prescribe the obligations of national electricity market participants, including a TNSP's obligations regarding network connection, network planning, network pricing and establishing or making modifications to connection points
Net present value (NPV)	Net present value, usually expressed as cost per megawatt, is used to help assess the economic feasibility of network and non-network solutions to network limitations

Term	Description
Nominal voltage levels	The design voltage level, nominated for a particular location on the power system, such that power lines and circuits that are electrically connected other than through transformers have the same nominal voltage. In ElectraNet's transmission system the nominal voltage level is typically 275 kV, 132 kV, or 66 kV
Non-network options	Non-network options, generally refers to options which address a network that don't include network infrastructure, such as generation, market network services and demand-side management initiatives
Over voltage	A system condition in which actual voltage levels at one or more locations exceeds 110% of the nominal voltage
Over-frequency generator shedding (OFGS)	A control scheme that coordinates tripping of generators when the system frequency increases due to supply exceeding demand
Peaking power plant	A power plant that only generally runs during periods of very high wholesale electricity prices, which typically correlate with times of very high electricity demand
Reactive power margin	The reactive power margin at a given location is the amount of additional reactive power that could be drawn that location without initiating voltage collapse
Registered participants	As defined in the Rules
Riverland Region	One of ElectraNet's seven regional networks in South Australia. See Appendix B for details
Rules	The National Electricity Rules which prescribe the obligations of national electricity market participants, including a TNSP's obligations regarding network connection, network planning, network pricing and establishing or making modifications to connection points
South East Region	One of ElectraNet's seven regional networks in South Australia. See Appendix B for details
Thermal ratings	The maximum amount of electrical power that a piece of equipment can accommodate without overheating
Transfer limit	The maximum permitted power transfer through a transmission or distribution network
Under frequency load shedding (UFLS)	The primary control measure used to maintain viable frequency operation following a system separation event
Upper North Region	One of ElectraNet's seven regional networks in South Australia. See Appendix B for details
Voltage collapse	An uncontrolled decay in voltage due to reactive power losses and loads exceeding reactive power sources, culminating in a sudden and precipitous collapse of voltage. Voltage collapse is associated with cascading network outages due to the mal-operation of protection equipment at low voltage levels, leading to widespread load loss

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