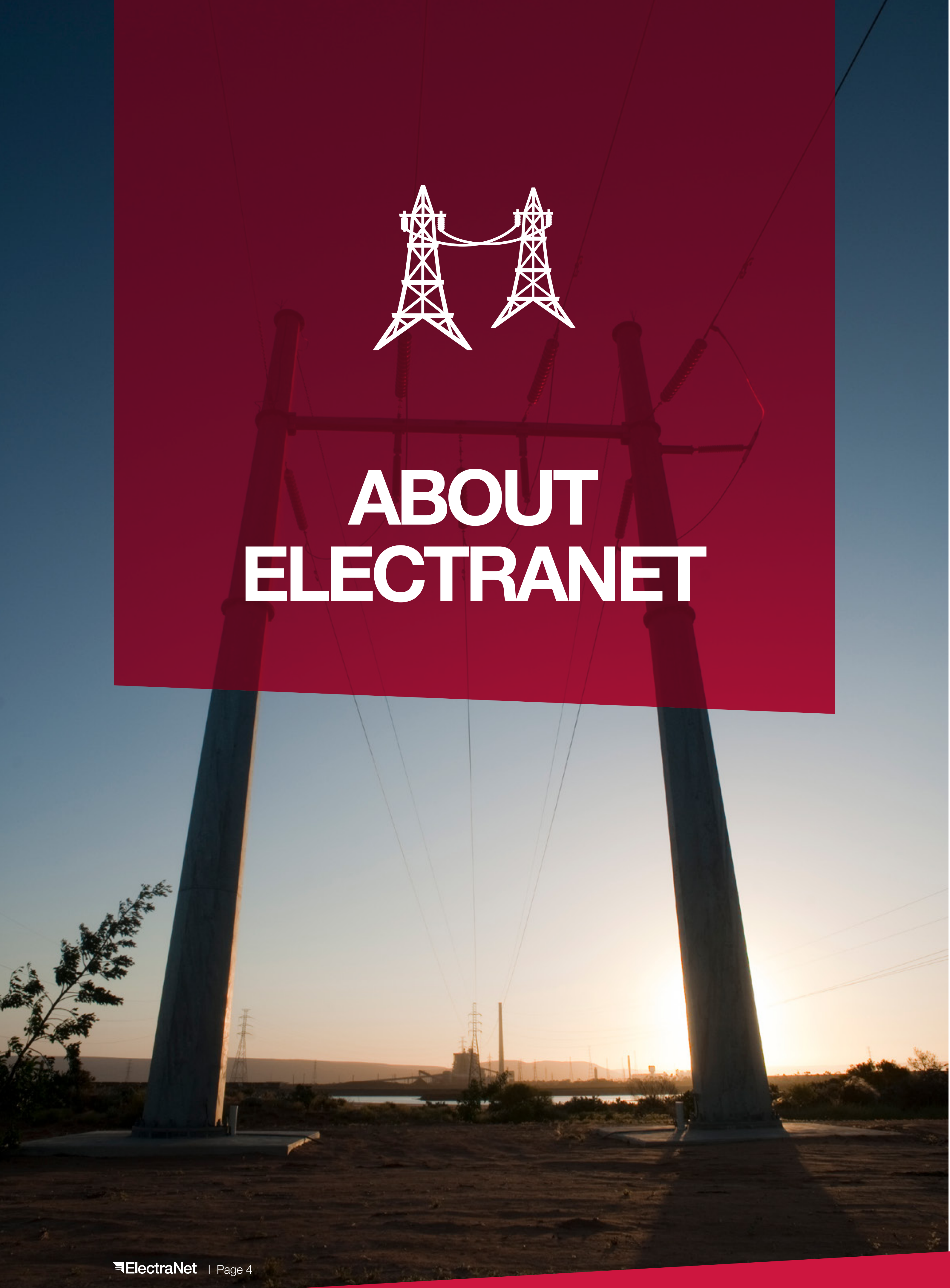
TRANSMISSION ANNUAL PLANNING REPORT

JUNE 2019

ElectraNet

Contents



ABOUT ELECTRANET

About ElectraNet

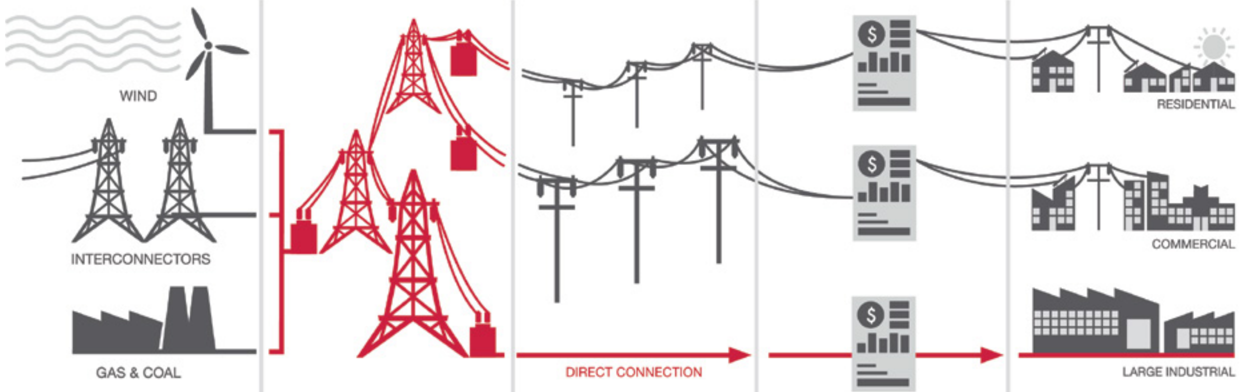
ElectraNet powers people's lives by delivering safe, affordable and reliable solutions to power homes, businesses and the economy.

As South Australia's principal Transmission Network Service Provider (TNSP), 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 (NEM) and maintains close working relationships with electricity market bodies including the Australian Energy Market Commission (AEMC), Australian Energy Regulator (AER), Australian Energy Market Operator (AEMO) and the Essential Services Commission of South Australia (ESCOSA).



Generation

Electricity is generated from traditional and renewable energy sources such as wind, solar, gas and coal.

Transmission

Electricity enters ElectraNet's network where it is converted to higher voltages, for efficient long-distance transport to cities and towns around South Australia. The voltage is then lowered so it can enter the distribution network or be supplied directly to some large industrial customers.

Distribution

The distribution network, operated in South Australia by SA Power Networks, transports low-voltage electricity to residential and commercial customers.

Retail

Retailers are the primary point of contact for residential and commercial customers. They coordinate connections and manage billing and payments.

Consumers

The traditional flow of electricity supply is changing. Around one in three South Australian homes now combines the electricity they draw from the network with power generated by rooftop solar panels, and also contributes surplus electricity back to the network.

Purpose of the Transmission Annual Planning Report

Each year, ElectraNet reviews the capability of South Australia's electricity 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 B).

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

This report 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. The report covers a 10-year planning period (1 July 2019 to 30 June 2029) and identifies potential network capability limitations and possible solution options.

The report provides information on:

- preparing for the future (Chapter 1)
- national transmission planning (Chapter 2)
- demand forecast for the next 10-year period (Chapter 3)
- system capability and performance (Chapter 4)
- connection and demand management opportunities (Chapter 5)
- recently completed, committed, and planned projects (Chapter 6)
- transmission system development plans (Chapter 7).

The report does not identify 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. Your feedback will help us to serve you better and ensure we can provide reliable electricity transmission services that contribute to an affordable electricity supply to customers.

Comments and suggestions can be directed to:

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EXECUTIVE SUMMARY

Executive Summary

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

System security and reliability are critically important as Australia's energy supply transitions to a lower carbon emissions future. Our annual planning process focusses on ensuring system security and reliability during this time of transition and seeks to forecast network limitations and opportunities, and ensure plans are in place to address them in a timely and efficient manner.

This South Australian Transmission Annual Planning Report summarises the latest outcomes of our planning process. Together with information available from our Transmission Annual Planning Report webpage, it provides information on the current capacity, connection opportunities, and emerging limitations of South Australia's electricity transmission network.[1] It covers a 10-year planning period and describes the current network, historical performance, demand projections, emerging network limitations or constraints, and information on completed, committed, pending and proposed transmission network developments.

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

We also look further ahead and assess potential major developments over a 20-year period as we consider AEMO's July 2018 Integrated System Plan (ISP) and December 2018 National Transmission Network Development Plan.

ElectraNet is responding to the challenges facing South Australia's changing electricity system, including by:

- participating in the ongoing national conversation about energy transformation and engaging with AEMO, other TNSPs and stakeholders in developing AEMO's next iteration of the ISP
- implementing a new interconnector between South Australia and New South Wales in partnership with TransGrid to deliver economic benefits to customers by better sharing of energy resources in the National Electricity Market (NEM)
- installing large synchronous condensers to raise the existing cap on non-synchronous generation, and ensure ongoing system security with adequate levels of system strength, system inertia, and voltage control for South Australia's electricity transmission system
- building a new transmission line that will improve reliability for customers on Eyre Peninsula
- investigating potential challenges and solutions to ensure that South Australia can be operated as an islanded system, if needed in extreme circumstances, such as if interconnection to the eastern states is unavailable.

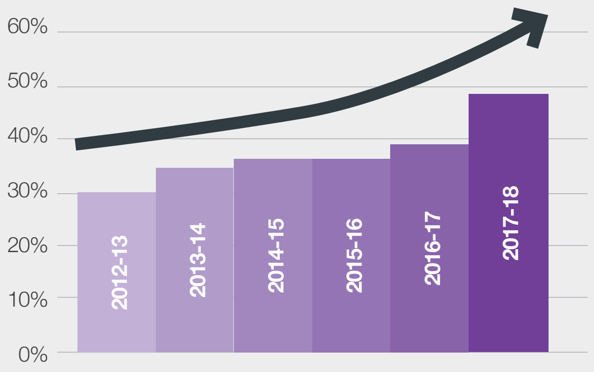
This report is designed to inform stakeholders and help potential generators and users of electricity to identify and assess opportunities in the South Australian region of the NEM.

The key planning outcomes in this report are summarised on the next page.

[1] Our Transmission Annual Planning Report web page is available at electranet.com.au/what-we-do/network/regulated-network-reports-and-studies

2018-19 Highlights

Renewable generation as a % of total South Australian electricity demand



New renewable generation connected or underway in 2018-19:
Wind farms
333 MW
Solar farms
227 MW

Project EnergyConnect

South Australian Energy Transformation RIT-T conclusions report published in February 2019.

Preferred solution: Project EnergyConnect – a new 330 kV interconnector between South Australia and New South Wales.

Transfer capability will be about 800 MW.[2]

Economic modelling shows the new interconnector will deliver substantial benefits as soon as it is built – **reductions in wholesale and retail electricity prices in South Australia and New South Wales.**

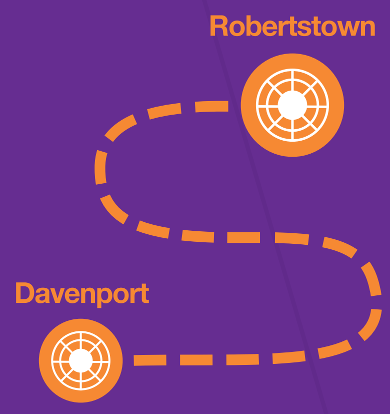
The AER is currently determining whether Project EnergyConnect satisfies the requirements of the RIT-T.

Subject to the AER's determination, **implementation is planned by August 2023.**

Project EnergyConnect

[2] A combined transfer limit with the existing Heywood interconnector of about 1,300 MW for import and about 1,450 MW for export will be applied, to manage system security.

Synchronous Condensers

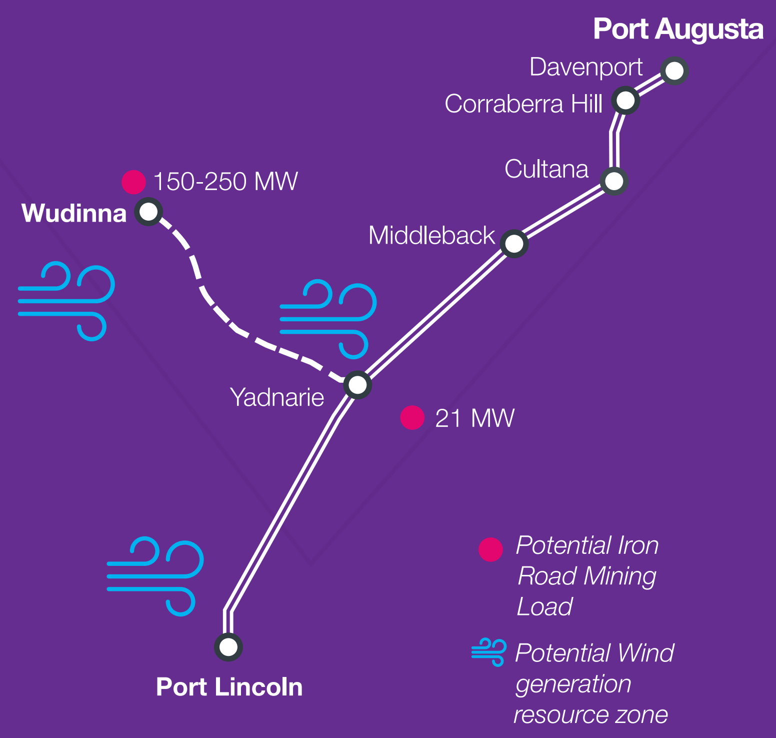


We are installing synchronous condensers at Davenport and Robertstown by February 2021.

These will:

- address system strength and synchronous inertia needs identified by AEMO; and
- contribute to ongoing voltage control.

Eyre Peninsula



Eyre Peninsula Electricity Supply Options RIT-T conclusions report published in October 2018.

Preferred solution: to replace the existing 132 kV lines between Cultana and Port Lincoln with:

- between Cultana and Yadnarie: a new double-circuit line that is initially energised at 132 kV, for a capacity of about 300 MW, with the option to be energised at 275 kV if required in the future, for a capacity of about 600 MW; and
- a new double-circuit 132 kV line between Yadnarie and Port Lincoln, with a capacity of about 240 MW.

The AER has determined that the preferred option satisfies the requirements of the RIT-T.

Implementation is planned by the end of 2021.

Market benefit opportunities

A range of projects is proposed to reduce the impact of existing and forecast network constraints to deliver net market benefits.

This includes the projects that form our **2018-19 to 2022-23 Network Capability Incentive Parameter Action Plan.**

New connections

The South Australian transmission system continues to have capacity to connect new load, generators, and storage. Generation output may occasionally be limited by system constraints, particularly at times of very low system demand.

We are extending the 275 kV system to develop **a new 275 / 132 kV connection point at Mount Gunson South** to service OZ Minerals' new and existing mines in the area.

A new connection point has been forecast by SA Power Networks to be required **at Gawler East sometime after 2025.**

Upgrading the operating voltage of the planned new Cultana to Yadnarie transmission lines from 132 kV to 275 kV may be needed if potential large loads connect on the Eyre Peninsula.

Network asset retirements and de-ratings

Asset replacement programs are based on an assessment of asset condition, risk, cost and performance.

We plan to address emerging condition needs for a range of assets on South Australia's electricity transmission network over the planning period.

Emergency control schemes

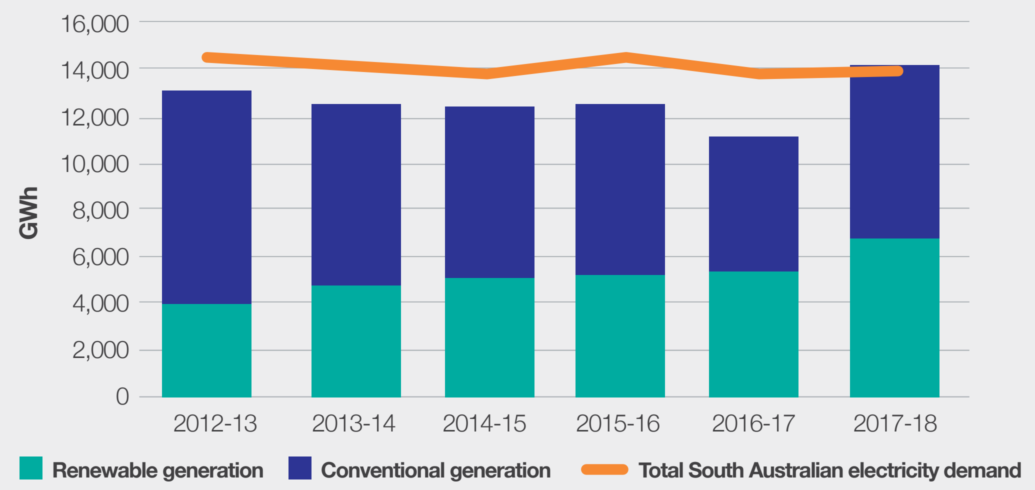
We are collaborating with AEMO to augment the existing System Integrity Protection Scheme to a more sophisticated **Wide Area Protection Scheme**, which will satisfy the requirements of AEMO's 2018 Power System Frequency Review.

1. Preparing for the future

1.1 Renewable generation development continues to drive the evolution of South Australia's electricity system

South Australia is at the forefront of energy transformation with world-leading levels of intermittent renewable energy relative to demand. Renewable energy generation continues to grow (Figure 1.1), with energy from renewable sources in 2017-18 representing more than 48% of South Australian electricity demand. Connections of renewable energy generation continued during 2018-19, and the number of active enquiries and applications indicates that this trend seems likely to continue for some time.

Figure 1.1: Contributions from South Australian renewable energy generation continue to grow



Source: The Australian Energy Market Operator's (AEMO's) 2018 South Australian Electricity Report

Note: The balance between total South Australian generation and electricity demand is made up by net imports or exports across the interconnectors between South Australia and Victoria. In 2017-18, South Australian electricity exports slightly exceeded imports.

South Australia presently 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 to other parts of the world such as Denmark, which have strong interconnection to other large power systems.

As more renewable energy generation such as wind and solar has come online, traditional synchronous generation sources such as coal and gas-fired units have now retired or begun to operate less often, creating challenges in managing the security of the power system.

Our annual planning process focusses on ensuring system security and reliability and seeks to forecast limitations and opportunities, and ensure plans are in place to address them efficiently.

1.2 Future directions and key priorities

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. We also engage with customer representatives and other stakeholders to ensure we understand their concerns, needs, priorities and points of view to enhance our ability to plan and develop the transmission network so it delivers the greatest possible value.

The following directions and priorities (Table 1.1) provide guidance on the practical ways we plan for the future of the network as outlined in our Network Vision.[3]

Table 1.1: Directions and priorities for planning the future of the electricity transmission network

Theme	Directions	Priorities
The transmission network will continue to play an important role into the future to support safe, reliable and affordable electricity supply	• 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 is 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 • 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	• Create a sustainable network for the long-term by seeking to deliver the most cost effective solutions for customers • Identify opportunities to deliver energy price reductions for customers • 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 approach • Retire assets unlikely to be needed in the future 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
The ongoing uptake of distributed energy resources by customers is changing the role of the grid	• Further significant installation of rooftop solar PV capacity and distribution-connected solar PV farms is expected, with periods of net zero or negative 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 increase over the planning horizon • Distributed energy growth rates are uncertain and will be driven by customer preferences, technology costs and government 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 a safe, reliable and secure supply under reasonably foreseeable demand and supply conditions
The generation mix is changing, creating new challenges for the secure and reliable operation of the grid	• 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 a secure and reliable electricity supply	• Develop efficient solutions to maintain a secure and reliable system with less conventional generation • Investigate and pursue interconnection opportunities which enhance benefits to customers by facilitating market competition, and supporting competitive, secure and stable power supplies, and renewable generation exports
New technologies are changing the way some network services can be delivered	• 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 • In a flat demand environment, non-network solutions and new technologies such as storage may offer more economic alternatives to traditional network options • Ongoing advances in information technology and network control systems provide access to a wealth of 'big data' to inform decision making	• Continue to investigate the application of grid scale energy storage and gain experience in the deployment, operation, and emerging capabilities of this technology • Actively pursue cost effective demand side solutions and innovations in the deployment of non-network solutions and new technology • Adopt best practice data analytics to improve decision making in asset management and network operation

[3] Our Network Vision is available at electranet.com.au/what-we-do/network/vision-for-our-network.

1.3 What is ElectraNet doing now, to prepare for the future?

Consistent with our strategic themes, directions and priorities, we are pursuing a number of strategic initiatives and investigations to support South Australia's energy transformation.

1.3.1 Interconnection

In November 2016 we began consultation on the SA Energy Transformation RIT-T, to examine the economic case for increased interconnection between South Australia and the eastern states of the NEM through:

- lowering dispatch costs through increasing access to supply options across regions;
- facilitating the transition to a lower carbon emissions future in the NEM and the adoption of new technologies through improving access to high quality renewable resources across all regions; and
- enhancing security of electricity supply in South Australia.

The RIT-T Project Assessment Conclusions Report identified that the preferred option is to construct a new 800 MW, 330 kV interconnector from Robertstown in South Australia, to Buronga and Wagga Wagga in New South Wales, called Project EnergyConnect.

The AER is currently determining whether the preferred option satisfies the requirements of the RIT-T. In the meantime, we are performing early works, such as route selection and easement acquisition, to support a staged delivery of Project EnergyConnect.[4]

Sections 6.3 and 7.3 provide more specific information about Project EnergyConnect.

1.3.2 System strength and inertia

Given that South Australia has become a world leader in intermittent renewable energy generation penetration levels, traditional synchronous generation sources, such as gas-fired units, now operate less often. This has created an operational challenge to provide ongoing adequate levels of system strength.[5]

In October 2017, AEMO formally declared a system strength gap in South Australia.

As reported in our 2018 Transmission Annual Planning Report, we analysed options to address the declared gap and determined that installing synchronous condensers on the network is the most efficient and least cost option.[6]

In December 2018, AEMO declared a gap in system inertia in South Australia in the 2018 National Transmission System Development Plan (NTNDP).[7]

We are now installing high-inertia synchronous condensers at Davenport and Robertstown in a staged approach, by February 2021 to address the AEMO declared system strength and synchronous inertia requirements. We also plan to investigate by the end of 2019 whether there will be a need for additional inertia, taking into account the current approval status of Project EnergyConnect.

Refer to sections 6.3 and 7.4 for more specific information about the planned installation of synchronous condensers.

[4] The early works for Project EnergyConnect are being underwritten by the South Australian and New South Wales state governments.
[5] System strength relates to the ability of a power system to manage fluctuations in supply or demand while maintaining adequate voltage levels.
[6] Our 2018 Transmission Annual Planning Report is available at electranet.com.au/what-we-do/ network/regulated-network-reports-and-studies
[7] Inertia relates to the ability of a power system to manage fluctuations in supply or demand while maintaining stable system frequency.

1.3.3 Voltage control

For many years, minimum demands on South Australia's electricity transmission network typically occurred at roughly 4am during periods of mild weather, such as occur during April or 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 demand conditions at the transmission level can correlate closely with a decreased level of dispatch of large synchronous generators, which have historically been a source of voltage control for the system.

We are working with SA Power Networks to analyse the challenges presented by a declining minimum demand. High voltage levels across the system are expected to occur at such times of extremely low demand.

Investment may be needed to prevent voltage levels at such times from exceeding equipment ratings during system normal conditions or after an unplanned outage of any single line, transformer, or other network element.

This joint study with SA Power Networks is ongoing. We plan to report relevant results in the 2020 Transmission Annual Planning Report.

1.3.4 Ability to operate the South Australian system if islanded from the rest of the NEM

Operating the South Australian electricity transmission system in an "islanded" condition, such as when the existing Heywood HVAC interconnector between South Australia and Victoria is unavailable, is very rare.[8]

However, the increasing penetration of intermittent renewable generation and embedded rooftop solar PV generation has the potential to present significant challenges to the ability to operate the system in an islanded condition if needed.

During islanded conditions, all market and system services must be supplied from within South Australia. This includes the requirement to maintain the balance between supply and demand, and to provide adequate inertia and system strength to enable satisfactory control of system frequency and voltage levels.

The likelihood of needing to operate the South Australian electricity system in an islanded condition is currently very low and will reduce further following implementation of the proposed Project EnergyConnect, which is intended to provide an additional HVAC interconnection to the rest of the NEM, including a Special Protection Scheme (SPS) designed to prevent an unexpected loss of either interconnector from causing the other interconnector to be lost.

We are investigating whether there is a need for additional facilities or controls in South Australia to maintain adequate provision of system services during islanded conditions before the expected completion of Project EnergyConnect.

We plan to report relevant results in the 2020 Transmission Annual Planning Report.

[8] Since 1999, the South Australian electricity system has been operated in islanded condition 13 times, for 10 to 65 minutes on each occasion (excluding the September 2016 state-wide blackout).

NATIONAL TRANSMISSION PLANNING

2. National Transmission Planning

2.1 Integrated System Plan

ElectraNet worked closely with AEMO to support the development of the first Integrated System Plan (ISP) in 2018. 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.

Work continues to review and update the ISP to reflect the dynamically changing nature of the power system and the need to continually innovate and evolve strategies for the future.

AEMO currently intends to publish a draft of the next ISP by the end of 2019, with a final version to be published in the middle of 2020. We, along with other TNSPs, are supporting AEMO to review the assumptions, inputs and methodologies that will underpin the development of the next iteration of the ISP.

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 (REZs) over the coming 20 years. The 2018 ISP is available on AEMO's website.[9] ElectraNet supports the ISP network development plan.

The following sections provide a short description of the specific priorities that relate to the South Australian electricity transmission network, with reference to the Group 1 (immediate priorities), Group 2 (medium term priorities) and Group 3 (longer term priorities) identified in the ISP development plan.

2.1.1 System strength

In October 2017, AEMO formally declared a system strength gap in South Australia. This gap was also reported in the 2018 ISP as a Group 1 priority.

As indicated earlier (section 1.3.2), we are installing synchronous condensers at Davenport and Robertstown, which will address the system strength gap that AEMO have identified.

Refer to section 7.4 for more information regarding our current activity in this area.

2.1.2 Distributed energy resources orchestration

The 2018 ISP identified as a Group 1 priority a need to coordinate the operation of 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 continue to work with AEMO, SA Power Networks and other stakeholders to explore how ElectraNet can contribute to achieving the required coordination of distributed energy resources.

We support the Open Energy Networks project, jointly undertaken by Energy Networks Australia and AEMO, which is seeking ways to integrate household solar generation and energy storage into energy networks in ways that help ensure quality and reliability of supply and lower household power bills.

We are also working to understand any impact DER may have on grid stability, and to identify any grid enhancements required to support an expected continued increase in the amount of connected DER.

[9] AEMO. Integrated System Plan. Available at: aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan

2.1.3 South Australia to New South Wales Interconnector

AEMO's 2018 ISP identified that interconnection between South Australia and New South Wales will have an overall net market benefit from the early 2020s as a Group 2 priority.

As indicated earlier (section 1.3.1), the SA Energy Transformation RIT-T has identified that Project EnergyConnect, to construct a new 330 kV, 800 MW interconnector from Robertstown in South Australia to Buronga and Wagga Wagga in New South Wales, is the preferred option.[10]

In assessing options under the SA Energy Transformation RIT-T, ElectraNet took into account the latest available data and modelling, including AEMO's 2018 ISP and its August 2018 Electricity Statement of Opportunities (ESOO). ElectraNet also accounted for 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.

Refer to sections 7.3 for more information regarding our current activity in this area.

2.1.4 South Australian Renewable Energy Zone candidates

AEMO's 2018 ISP identified nine REZ candidates 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.

[10] A combined transfer limit with the existing Heywood interconnector of about 1,300 MW for import and about 1,450 for export will be applied, to manage system security.

[11] AEMO's 2018 NTNDP is available from aemo.com.au/Electricity/National-Electricity-Market-NEM/ Planning-and-forecasting/National-Transmission-Network-Development-Plan

Figure 2.1 shows a number of conceptual and planned transmission network investments that would support the development of the identified REZs.

The 2018 ISP 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.

The ISP modelling indicates the further connection between 2030 and 2040 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.[11]

The 2018 NTNDP built on the first ISP, assessing the short-term system adequacy of the national transmission grid over the next five years.

The 2018 NTNDP:

- gave an update on the implementation of the ISP
- provided an assessment of the short-term power system adequacy of the NEM
- identified a minimum inertia shortfall in South Australia.

The following sections provide a short description of the specific outcomes that relate to South Australia's electricity transmission network and how they relate to and inform our plans.

Figure 2.1: Potential long-term transmission system developments that would unlock identified potential South Australian Renewable Energy Zones

2.2.1 System strength and inertia requirements

The system strength gap discussed in section 2.1.1 was also reported in the 2018 NTNDP. As previously discussed in section 2.1.1, the planned installation of synchronous condensers by the end of 2020 will address the identified system strength gap.

In the early stages of the procurement process, ElectraNet identified the possibility that additional inertia services may be required in South Australia. To allow for this possibility, we requested potential synchronous condenser suppliers to include an option for the proposed synchronous condensers to be supplied with high rotating inertia, for example by the inclusion of a flywheel.

In section 3.2.2 of the 2018 NTNDP, AEMO declared an inertia shortfall in South Australia, specifying for the first time a secure operating level of 6,000 MWs for inertia in South Australia.

Section 3.2.2 of the 2018 NTNDP states that the inertia requirements for South Australia are currently being met as an additional outcome of the continuing directions made by AEMO for a minimum number of conventional generating units to remain online in South Australia to meet the previously declared system strength gap.

When the system strength gap has been addressed by the planned installation of synchronous condensers, AEMO expects this would result in an inertia shortfall in South Australia compared to the 6,000 MWs secure operating level.

In the 2018 NTNDP, AEMO recommended that ElectraNet procure at least 4,400 MWs of inertia services through synchronous condensers or contracting with synchronous generation, coinciding with the time at which ElectraNet meets the declared system strength shortfall. In conjunction, AEMO stated that ElectraNet should:

- ensure this 4,400 MWs of inertia can be online for periods when the South Australian region is at a credible risk of islanding
- equip the synchronous condensers with flywheels as an efficient means of supplying both system strength requirements and providing additional inertia needed to maintain a secure operating state
- consider contracting non-synchronous generation and batteries that can provide a fast frequency response to provide additional inertia services up to the secure operating level.

The procurement of high inertia synchronous condensers for installation at Davenport and Robertstown in 2020 will meet the identified need for the provision of 4,400 MWs of synchronous inertia in South Australia. ElectraNet plans to consider by the end of 2019 whether there will be a need for additional inertia, taking into account the approval status of Project EnergyConnect.

2.2.2 Voltage control at times of minimum demand

Section 3.3.1 of the 2018 NTNDP indicates AEMO's assessment that potential high voltage levels at times of minimum demand can be managed using existing plant, committed synchronous condensers, and temporary operational measures (for example, temporarily de-energising the Magill – East Terrace 275 kV cable).

ElectraNet agrees with this assessment. At forecast levels of minimum demand, the 50 Mvar reactor that we installed at Templers West in 2018 and the synchronous condensers we plan to install at Davenport and Robertstown in 2020 will enable system voltage levels to be maintained within limits for the duration of the planning period.

The use of measures such as temporarily de-energising the Magill-East Terrace 275 kV cable are undesirable under normal operating conditions, keeping them to be utilised only if needed to address extreme needs such as following multiple or non-credible contingencies.

2.3 Power System Frequency Risk Review

The Power System Frequency Risk Review (PSFRR) is an integrated, periodic review of power system frequency risks associated with non-credible contingency events in the National Electricity Market (NEM), undertaken by AEMO. The most recent PSFRR was undertaken in 2018.[12]

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 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.

2.3.1 Recommendations for South Australia

The 2018 PSFRR made two recommendations for South Australia.

System Integrity Protection Scheme Upgrade

The 2018 PSFRR recommended 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 from the rest of the NEM and a system black event. AEMO has estimated that the required modifications can be made in two years and recommends it be progressed as a protected event EFCS.

ElectraNet is currently working with AEMO to design and implement the scope of works required to upgrade the SIPS to a Wide Area Protection Scheme (WAPS, section 7.4).

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)). To provide certainty to the market, AEMO recommended that this condition be declared a protected event.

On 5 November 2018, AEMO submitted a request to the Reliability Panel seeking to declare the risk to South Australia's power system from destructive winds as a protected event. On 20 June 2019 the Reliability Panel declared a protected event in accordance with AEMO's request.[13]

AEMO expects this protected event will be activated approximately twice per year, based on historical weather conditions.

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

[13] Information on the Reliability Panel's consultation and determination process is available at aemc.gov.au/market-reviews-advice/request-declaration-protected-event-november-2018

ELECTRICITY DEMAND

3. Electricity Demand

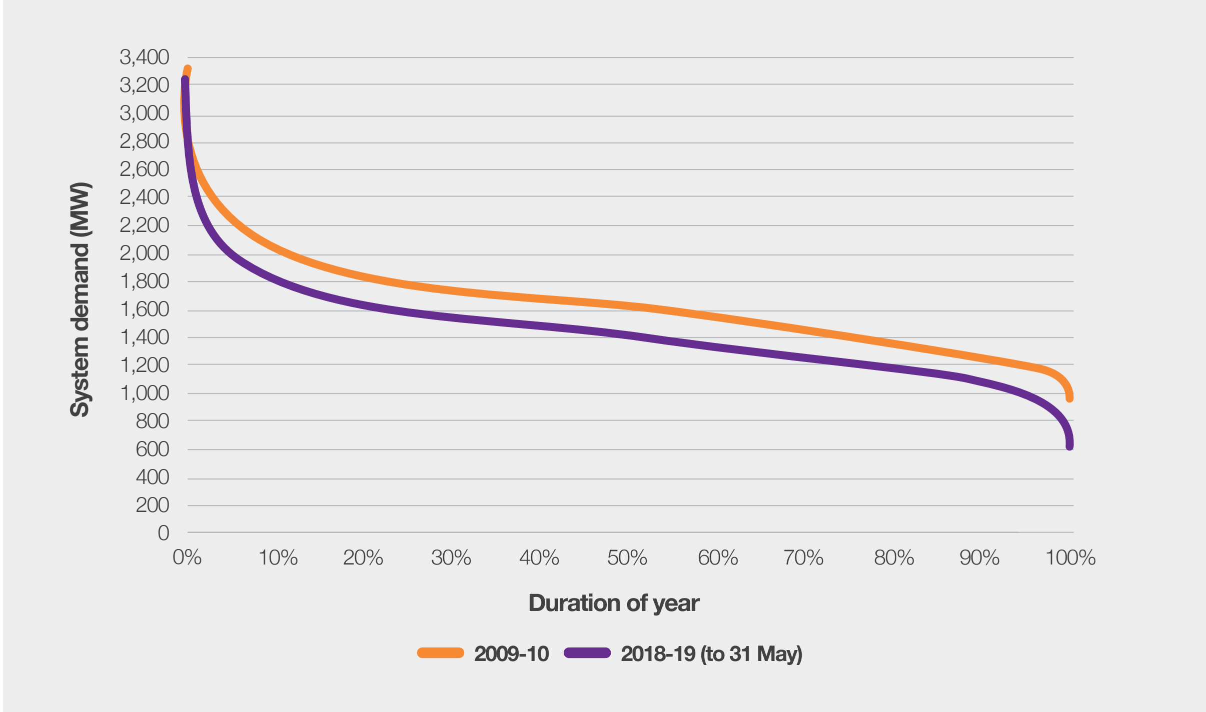
Forecasting electricity demand and network loading conditions is important because transmission system projects take significant time to implement.

Each registered participant connected to the transmission 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 to forecast electricity demand.

3.1 South Australian electricity demand

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 MW and 2000 MW are most common throughout the year.

Figure 3.1: South Australian system wide load duration curves for 2009-10 and 2018-19 (to 31 May)



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 2018-19.

3.2 Demand forecasting methodology

ElectraNet annually receives 10-year demand forecasts from SA Power Networks and collaborates with AEMO to receive forecasts from direct connect customers.

A description of the load forecasting process used by SA Power Networks is provided in SA Power Networks' 2018 Distribution Annual Planning Report.[14] ElectraNet and SA Power Networks collaborate 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 November 2018. Details of the forecast can be found on ElectraNet's *Transmission Annual Planning Report Portal*.[15]

In August 2018, AEMO produced and published maximum and minimum demand forecasts for South Australia to support the *2018 Electricity Statement of Opportunities* (ESOO).[16] These forecasts are updated periodically by AEMO, most recently in February 2019.

ElectraNet has used those forecasts, in conjunction with connection point minimum demand forecasts provided by SA Power Networks in February 2019, 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.[17]

ElectraNet compares its forecasts (as published on the Transmission Annual Planning Report Portal)[18] 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 2018 ESOO 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 material impact on network limitations or development plans within the next 10 years. ElectraNet uses both the AEMO state-wide forecasts and our own connection point forecasts depending on the needs of a particular planning study.

3.3 2018-19 demand forecast

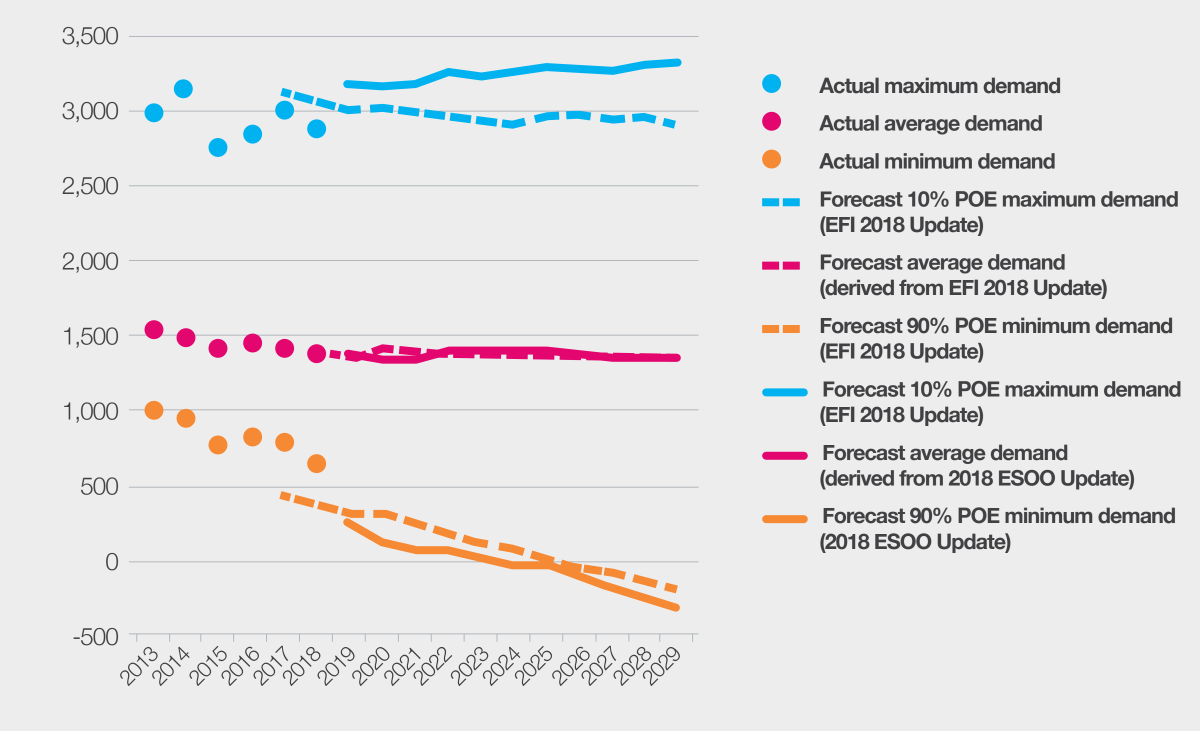
In most cases there is very little change in the projections of future demand for connection points compared to the demand forecast which was used as the basis for the augmentation plans presented in the 2018 Transmission Annual Planning Report. Our plans for individual connection points have not needed to be updated.

AEMO makes state-wide demand forecasts for South Australia available on its *Forecasting Data Portal*.[19]

The most recent update to AEMO's South Australian State-wide forecasts was published in February 2019.

We have compared AEMO's February 2019 neutral growth forecasts for South Australian maximum and minimum demand to the March 2018 forecasts that formed the basis of the plans presented in the 2018 Transmission Annual Planning Report, along with the previous five years and current year of actual maximum, average and minimum demands (Figure 3.2).[20] While the forecast average demand remains similar, the more recent forecasts are higher for maximum demand, and lower for minimum demand.

Figure 3.2: AEMO's EFI (March 2018 Update) and 2018 ESOO (February 2019 Update) neutral growth forecasts



Source: AEMO's Electricity Forecasting Insights (March 2018 Update), and AEMO's 2018 ESOO (February 2019 Update). Forecast average demands have been derived from AEMO's central forecast of energy consumption.

14 Available from sapowernetworks.com.au/industry/annual-network-plans

15 Accessible at electranet.com.au/what-we-do/network/regulated-network-reports-and-studies

16 Available from aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Satement-of-Opportunities

17 Available from aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/ Transmission-Connection-Point-Forecasting

18 Accessible at electranet.com.au/what-we-do/network/regulated-network-reports-and-studies

19 Accessible at http://forecasting.aemo.com.au/

20 AEMO's Electricity Forecasting Insights (EFI) provided the forecasts that informed the plans reported in our 2018 Transmission Annual Planning Report.

3.4 Performance of 2018-19 demand forecasts for summer 2018-19

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 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, South Australia's mean maximum temperature for summer was the highest on record. Heatwave events in December and January saw daytime temperatures reach the high-40s and numerous sites had their highest summer temperatures on record, including 46.6 °C on Thursday 24 January at the Bureau's official Adelaide city site at West Terrace (Table 3.1).[21]

Table 3.1: 2018-19 summer temperature data compared with long term trends

	December		January		February		March	
	Long term trend	2018-19	Long term trend	2018-19	Long term trend	2018-19	Long term trend	2018-19
Max temp (°C)	44.2	42.4	46.6	46.6	43.4	37.9	41.8	40.3
Date of max temp	31 Dec 1904	27 Dec 2018	24 Jan 2019	24 Jan 2019	1 Feb 1912	2 Feb 2019	3 Mar 1942	1 Mar 2019
Average max temp	26.8	30.1	28.6	33.0	28.6	29.5	26.0	26.6
Days[22]>30°C	9.1	14	11.7	17	10.8	14	7.1	7
Days[22] >35°C	3.7	9	5.5	10	4.4	8	1.6	2
Days[22] >40°C	0.5	1	1.1	5	0.6	0	0.1	2
Difference between 2018-19 average max temp and long term trend	3.3		4.4		0.9		0.6	

Source: Bureau of Meteorology, Adelaide (West Terrace/Ngayirdaripira)

State-wide demand reached a maximum of 3,264 MW on Thursday 24 January 2019, the day on which Adelaide's West Terrace site recorded a maximum temperature of 46.6°C, despite a reduction in actual load relative to demand caused by an outage of a major zone substation transformer on the distribution network.

Demand exceeded 2,700 MW on 5 days during the 2018-19 summer (Table 3.2).

Table 3.2: Highest demand days in summer 2018-19

Date	Maximum demand (MW)[23]	Maximum temperature (°C)	Temperature demand index (°C)[24]
Thursday 24 January	3,264[25]	46.6	42.4
Wednesday 23 January	3,020	40.9	36.9
Tuesday 15 January	2,919	41.9	36.6
Friday 1 March	2,896	40.3	36.4
Thursday 3 January	2,859	41.5	35.8
Tuesday 22 January	2,805	38.9	34.9

A key high-level indicator of demand is the temperature demand index. It identifies temperature patterns that have the potential to deliver a 10% Probability of Exceedance (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[26]) occurring on a weekday after Australia Day provides the necessary temperature conditions to achieve 10% POE at a state level.[27]

The temperature index exceeded 38°C by a significant margin on Thursday 24 January, the day of maximum demand for the summer, when the temperature index reached an unprecedented 42.4°C.

Given that the temperature index significantly exceeded 38°C on a weekday before Australia Day, ElectraNet expects the maximum state demand recorded during the 2018-19 summer roughly reflects the 10% POE maximum demand level. Results at individual connection points are expected to vary due to local conditions, with some connection points exceeding their 10% POE maximum demand forecast, and others not doing so.

[21] On the same day, the Bureau of Meteorology's nearby Kent Town weather station recorded a maximum temperature of 47.7 °C, the highest maximum temperature ever recorded in the Adelaide metropolitan area.

[22] Mean days for long term trend data, actual days for 2018-19 data

[23] These values represent the total as-generated demand from the SA electricity transmission system. They include generator "house loads" but exclude demand supplied by rooftop solar PV generation.

[24] Calculated using data from the Bureau of Meteorology's Kent Town weather station.

[25] Measured maximum demand – lower than actual maximum demand due to a reduction in total demand caused by an outage of a major zone substation transformer on the distribution network.

[26] For calculation of the temperature demand index, ElectraNet calculates the previous day's average temperature using the average of the 24 hourly temperature readings.

[27] 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.

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 2018-19, just over half of all bulk supply connection points recorded maximum demands that exceeded their forecast 10% POE maximum demand. This is consistent with expectations, given the maximum state demand recorded during the 2018-19 summer roughly reflected AEMO's 10% POE forecast maximum demand.

Of the 20 bulk connection points that met or exceeded ElectraNet's 10% POE connection point demand forecasts (Table 3.3), all were still operating within their capability.

Table 3.3: Recorded maximum demands more than 100% of 10% POE demand forecast in summer 2018-19

Connection point	ElectraNet 10% POE forecast (MW)	AEMO 10% POE forecast (MW)	Actual Maximum (MW)	Actual demand as a percentage of ElectraNet 10% POE forecast (%)	Date and time of maximum demand (Market time)
Mt Barker	91.7	91.6	107.8	118%	24/01/2019 19:30
Port Lincoln	30.4	30.9	35.2	116%	24/01/2019 18:30
Angas Creek	18.3	19	20.5	112%	24/01/2019 20:00
Ardrossan West	10.9	11.4	12.2	112%	24/01/2019 19:00
Kanmantoo	1.6	1.6	1.8	111%	24/01/2019 19:30
Clare North	11.9	13.1	13.0	110%	24/01/2019 18:00
Kadina East	25.7	27.4	28.0	109%	24/01/2019 19:30
Wudinna	14.1	14.1	15.3	109%	23/01/2019 19:30
Neuroodla	0.9	0.9	1.0	108%	15/01/2019 19:00
Waterloo	8.6	8.7	9.2	107%	24/01/2019 19:30
Kincraig	19.9	21.1	21.3	107%	24/01/2019 19:00
Tailem Bend	24.7	23.4	25.9	105%	24/01/2019 20:30
Baroota	8.3	8.1	8.7	105%	24/01/2019 20:00
Templers	30.3	33.8	31.6	104%	24/01/2019 20:30
Brinkworth	4.8	4.9	5.0	104%	24/01/2019 20:00
Yadnarie	8	8.1	8.3	104%	24/01/2019 19:00
Snuggery Rural	14.5	13.3	14.9	103%	24/01/2019 19:30
Davenport West	30.6	41.1	31.3	102%	24/01/2019 20:00
Mt Gambier	21.3	23.9	21.8	102%	24/01/2019 18:00
Hummocks	14.1	15	14.4	102%	24/01/2019 19:30

The four metropolitan bulk connection points each recorded maximum demands that were lower than their 10% POE forecast by between 13 MW and 58 MW, while two small connection points failed to reach 85% of their 10% POE forecast (Table 3.4). However:

- The maximum demand in the Western Suburbs would be higher than was recorded, as the demand was reduced by the impact of an outage of a major zone substation transformer in the distribution network
- The maximum demand measured in the Northern Suburbs and Southern Suburbs does not account for the operation of the State government's emergency generators, which are embedded within these connection points.

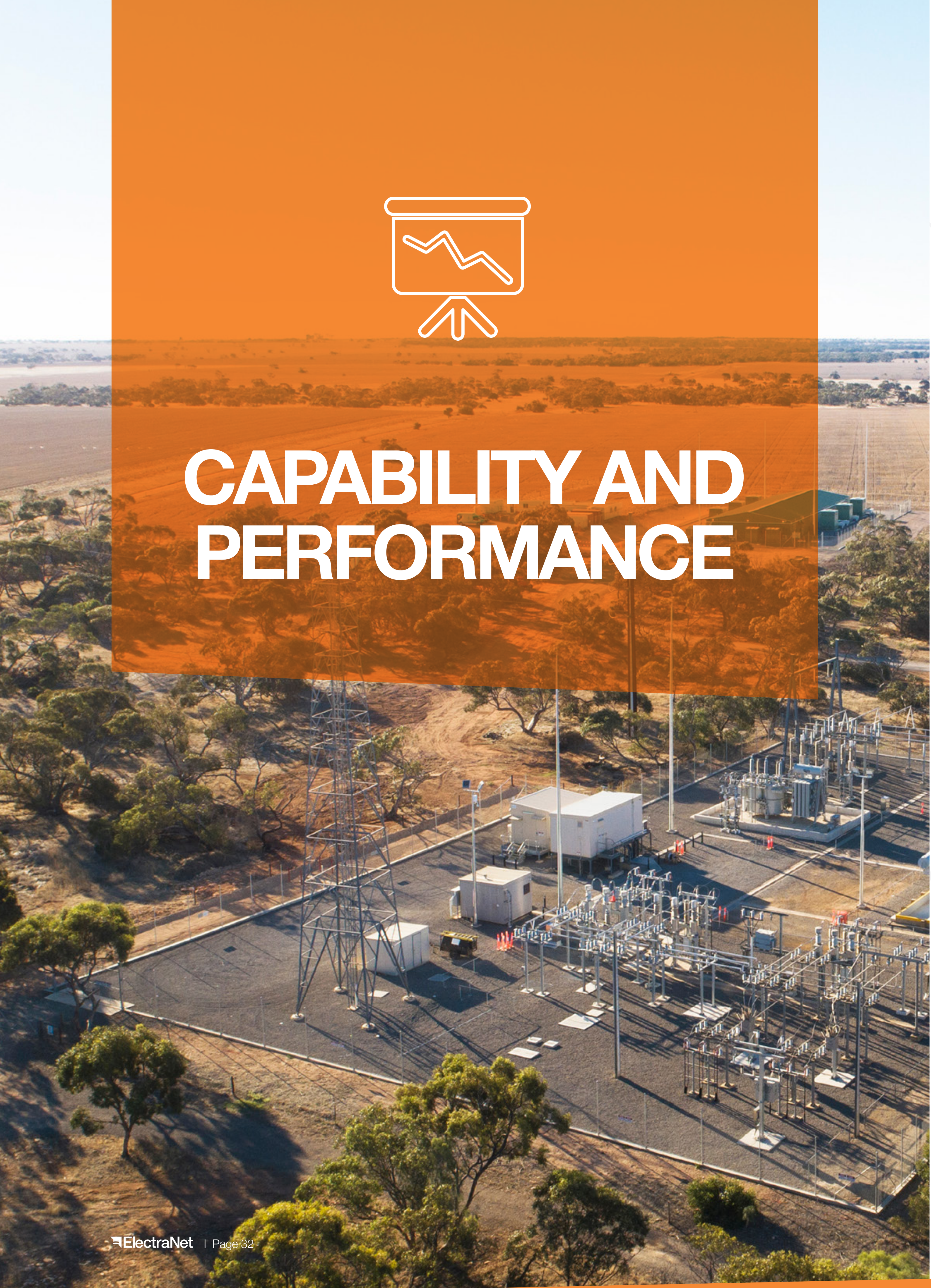
ElectraNet and SA Power Networks' 2019 review of connection point forecasts will consider the impact of measured maximum demands from summer 2018-19. It is likely that an upwards adjustment will be made to forecasts for the connection points that exceeded their 10% POE maximum demand forecast in the 2018-19 summer, most notably Mount Barker and Port Lincoln.

Table 3.4: Recorded maximum demands either lower than the 10% POE demand forecast by at least 10 MW, or lower than 85% of 10% POE demand forecast, in summer 2018-19

Connection point	ElectraNet 10% POE forecast (MW)	AEMO 10% POE forecast (MW)	Actual Maximum (MW)	Actual demand as a percentage of ElectraNet 10% POE forecast (%)	Date and time of maximum demand (Market time)
Western suburbs	432.3	429.1	419.1[28]	97%	24/01/2019 17:30
Eastern suburbs	735.7	733.1	697.1	95%	24/01/2019 19:30
Northern suburbs	320.7	313.5	302.1[29]	112%	24/01/2019 20:00
Southern suburbs	675.5	666.2	616.7[29]	91%	24/01/2019 21:30
Stony Point	0.2	0.1	0.1	66%	21/01/2019 22:00
Mt Gunson	0.2	0.2	0.1	65%	23/01/2019 11:30

[28] Measured maximum demand – lower than actual maximum demand due to a reduction in total demand caused by an outage of a major zone substation transformer on the distribution network.

[29] Measured maximum demand – lower than the actual maximum demand due to the operation of the State government's emergency generators



CAPABILITY AND PERFORMANCE

4. System capability and performance

4.1 The South Australian electricity transmission system

The South Australian transmission network is one of the most extensive regional transmission systems in Australia, extending across some 200,000 square kilometres of the State. This network consists of transmission lines operating at 132 kV and 275 kV, which are supported by both lattice towers and large stobie poles. It connects the major South Australian load centres with various sources of generation (Figures 4.1 and 4.2).

Most base and intermediate conventional generators are located in the Adelaide metropolitan area, while peaking power stations are spread throughout the state.

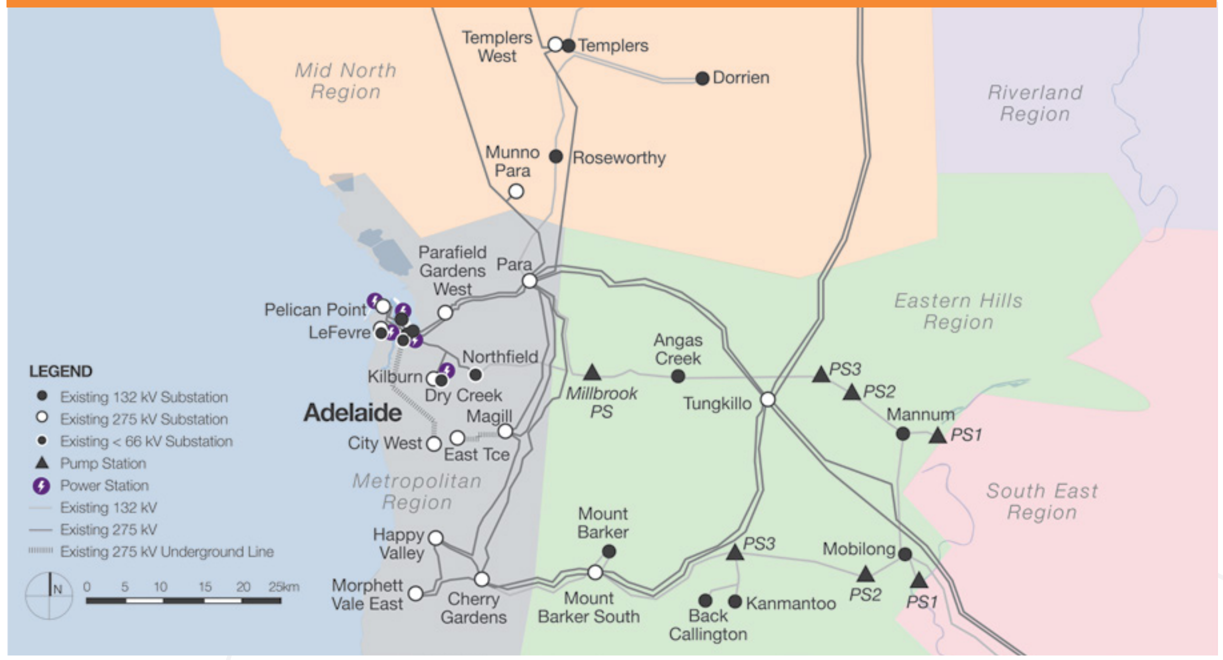
The Main Grid is a meshed 275 kV network that extends from Cultana substation (near Whyalla) to South East substation (near Mount Gambier). The Main Grid overlays regional networks that cover seven regions: Metropolitan, Eastern Hills, Mid North, Riverland, South East, Eyre Peninsula and Upper North.

South Australia also currently has two interconnectors that connect South Australia to the Victorian region of the NEM: the Heywood HVAC interconnector (established in 1989) in the state's South East, and the Murraylink HVDC interconnector (established in 2002) in the Riverland. South Australian generation has typically been supplemented by imported energy from Victoria since these interconnectors were established, especially at times of high demand.

Interconnector transfer capacity has increased since the upgrade to the Heywood interconnector was completed in mid-2016. The combined maximum transfer capacity between South Australia and Victoria under normal conditions is now about 820 MW[30] for imports to South Australia, and 650 MW[31] for exports.

We continue to work with AEMO to allow the release of the full 650 MW capability of the Heywood interconnector.

Figure 4.1: South Australian electricity transmission system map - metropolitan area



30 Consisting of 600 MW import through Heywood interconnector and 220 MW import through Murraylink interconnector.

31 Consisting of 500 MW export through Heywood interconnector and 150 MW import through Murraylink interconnector (constrained by typical voltage limits in the Riverland).

**Figure 4.2:
South Australian electricity transmission system map**

4.2 Transmission system constraints in 2018

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.

We have assessed the top binding network constraints that impacted transmission network and interconnector flows during the 2018 calendar year (Table 4.1). Constraints selected for assessment were in the top 10 by impact on marginal value or by binding duration in 2018. 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

Constraint equation and description	2018 marginal values (2017)	Rank by 2018 marginal value	2018 hours binding (2017)	Rank by 2018 hours binding	Commentary
NSA_S_POR01_ISLD Run Port Lincoln generators for network support	14,981,543 (374,035)	1	87 (12)	5	ElectraNet dispatches this generation under a network support arrangement to supply Port Lincoln demand when supply from the transmission network is unavailable The planned replacement by the end of 2021 of the 132 kV lines between Cultana and Port Lincoln with double circuit lines will alleviate the need for this constraint (section 7.5)
NSA_S_POR03_ISLD Run Port Lincoln generators for network support	14,924,930 (273,972)		87 (11)		
#OSB-AG_P_E Discretionary limit for New Osborne Power Station	5,387,855 (2,998,973)	2	354 (206)	1	AEMO invokes these constraints when needed to satisfactorily manage the transmission system During 2018, these constraints have typically been invoked to ensure that adequate system strength services continue to be provided for the South Australian electricity system The planned installation during by February 2021 of synchronous condensers at Davenport and Robertstown will address the system strength and synchronous inertia needs that AEMO has identified for South Australia, alleviating the need for these constraints (section 7.4) Note: this grouping continues on the next page
#PPCCGT_P_E Discretionary limit for Pelican Point Power Station	2,753,546 (1,817,898)		600 (19)		
#TORRB2_P_E Discretionary limit for Torrens Island B2 generator unit	2,346,622 (840,775)		333 (168)		
#TORRA1_P_E Discretionary limit for Torrens Island A1 generator unit	1,658,791 (171,837)		729 (26)		
#QPS5_P_E Discretionary limit for Quarantine 5 generator unit	1,024,199 (18,248)		71 (1)		
#TORRA3_P_E Discretionary limit for Torrens Island A3 generator unit	970,508		497		
#TORRA4_P_E Discretionary limit for Torrens Island A4 generator unit	783,490 (121,394)		483 (23)		
#TORRB1_P_E Discretionary limit for Torrens Island B1 generator unit	733,100		230		
#TORRB3_P_E Discretionary limit for Torrens Island B3 generator unit	577,009 (294,524)		218 (23)		
#TORRB4_P_E Discretionary limit for Torrens Island B4 generator unit	548,543 (665,364)		109 (41)		
#TORRA2_P_E Discretionary limit for Torrens Island A2 generator unit	368,117 (540,718)				
S_NIL_STRENGTH_1 Constrain non-synchronous generation based on system strength requirements in South Australia	13,582,745	3	1,094	3	This constraint replaces the 2018 constraint S_WIND_1200_AUTO Since 2018, AEMO has further refined the relationship between the amount of dispatched South Australian conventional generation and the upper limit for South Australian non-synchronous generation The planned installation of synchronous condensers at Davenport and Robertstown during 2020 will address the system strength and synchronous inertia needs that AEMO has identified for South Australia. This constraint will be updated to take the synchronous condensers into account, alleviating the impact of this constraint by raising the level at which it is expected to bind (section 7.4)

Constraint equation and description	2018 marginal values (2017)	Rank by 2018 marginal value	2018 hours binding (2017)	Rank by 2018 hours binding	Commentary
#BNGSF2_E Discretionary limit for Bungala 2 Solar Farm	2,250,989	4	1,704	2	AEMO invokes this constraint when needed to satisfactorily manage the transmission system
#BNGSF1_E Discretionary limit for Bungala 1 Solar Farm	2,105,653	5	164	7	AEMO invokes this constraint when needed to satisfactorily manage the transmission system
V::S_SETB_MAXG_2 Avoid transient instability of generators if an outage of SA's largest online generator was to occur, with one South East to Tailem Bend 275 kV line out of service	1,965,779	6	134	8	The planned construction by August 2023 of a new interconnector between South Australia and New South Wales will alleviate this constraint (section 7.3)
S::V_TBSE_TBSE_2 Avoid transient instability of generators if an outage of one of the Tailem Bend to South East 275 kV lines was to occur, with the other Tailem Bend to South East 275 kV line out of service	1,950,956	7	102	9	The planned construction by August 2023 of a new interconnector between South Australia and New South Wales will alleviate this constraint (section 7.3)
#SNOWTWN1_E Discretionary limit applied to Snowtown Wind Farm	1,402,282 (78,986)	8	86 (6)		AEMO invokes this constraint when needed to satisfactorily manage the transmission system
S>SE6161_SETX2_SGBL Avoid overload of Snuggery to Blanche 132 kV line if an outage of the South East 275/132 kV was to occur, with CB6161 at South East out of service	978,072	9	67		AEMO invokes this constraint when needed to satisfactorily manage the transmission system
S_SNOW_N+S_190 Combined output of Snowtown North and South wind farms limited to 190 MW	777,640	10	122	10	AEMO invokes this constraint when needed to satisfactorily manage the transmission system

Constraint equation and description	2018 marginal values (2017)	Rank by 2018 marginal value	2018 hours binding (2017)	Rank by 2018 hours binding	Commentary
S>V_NIL_NIL_RBNW Avoid overload of Robertstown-North West Bend #1 or #2 132kV lines during system normal conditions	224,349 (112,551)		315 (283)	4	This constraint limits the ability to export power from South Australia across the Murraylink interconnector The uprate of the Robertstown to North West Bend No. 2 and North West Bend to Monash No. 2 132 kV lines in late 2018 (section 6.1) have alleviated the impact of this constraint by raising the level at which it binds
V::S_SETB_TBSE_2 Avoid transient instability of generators if an outage of one of the Tailem Bend to South East 275 kV lines was to occur, with the other Tailem Bend to South East 275 kV line out of service	516,200 (11,969)		172 (45)	6	The planned construction by August 2023 of a new interconnector between South Australia and New South Wales will alleviate this constraint (section 7.3)

4.3 Emerging and future network constraints and performance limitations

The planned implementation of Project EnergyConnect to build a new interconnector between South Australia and New South Wales, and changing dispatch patterns of existing conventional generators and continuing significant renewable energy generation connections in South Australia, are expected to lead to significant changes in congestion patterns on the transmission network. This will depend on where future generators connect or retire.

The limitations that could bind as a result of additional generator 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)
Combined interconnector limits constrain import or export to and from South Australia	Forecast to occur after the planned completion of Project EnergyConnect	Heywood, Murraylink, EnergyConnect	No project currently proposed Consider enhancing Wide Area Protection Scheme to allow operation of the interconnectors closer to their thermal limits without compromising system security (see entry in Table 4.3)
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)
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 (see entry in Table 4.3)
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) Consider applying dynamic line ratings to 275 kV lines between Davenport and Robertstown (see entry in Table 4.3)
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, EnergyConnect (import)	Robertstown to Para 275 kV line to be tied in at Tungkillo as part of the Main Grid System Strength project Consider applying dynamic line ratings to Robertstown to Tungkillo and Robertstown to Para 275 kV lines (see entry in Table 4.3)
Mid North Region: thermal ratings of 132 kV lines between Robertstown and North West Bend	Existing	Murraylink (export)	Establish Project EnergyConnect (section 7.3)
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)
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 4.3)
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 (see entry in Table 4.3)
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)
South East Region: thermal ratings of 275 kV lines between Tailem Bend and Tungkillo	Forecast to occur after the full capacity of Heywood interconnector is released	Heywood (import and export)	Connect the Tailem Bend to Cherry Gardens 275 kV line at Tungkillo (section 7.6). Consider stringing vacant circuit to create third Tailem Bend to Tungkillo 275 kV line (see entry in Table 4.3)
South East Region: voltage stability limitations	Existing	Heywood (import and export)	Install an additional 100 Mvar switched capacitor bank at South East (section 7.6)
System strength limits total output of SA renewable generation at times of low SA conventional generation	Existing	Intra-regional	Install synchronous condensers to maintain minimum South Australian system strength needs (sections 1.3.2 and 7.4)
Transient instability between South Australia and the rest of the NEM	Existing	Heywood and Murraylink (import and export)	Establish a new interconnector between South Australia and the rest of the NEM (section 7.3)
Upper Eyre Peninsula: thermal ratings of 275 kV lines between Cultana and Davenport	Depends on future generation connections	Intra-regional	No project currently proposed – consider establishing the third and fourth 275 kV lines between Davenport and Cultana (see entry in Table 4.3)

4.4 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 changing gas prices. Such developments may lead to network constraints which 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 projects to address inter-regional and intra-regional constraints that may emerge in the future (Table 4.3). Some of these projects will 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), 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 projects to address inter-regional and intra-regional constraints that may emerge in the future

Project name and potential driver	Project description and expected benefit	Lead time	Cost ($M)
New Davenport–Para High Capacity 275 kV Lines Increased generation, large scale storage or loads through the Mid North, Eyre Peninsula, or Upper North	Replace one or both of the Davenport–Brinkworth–Para and the Davenport–Bungama–Para 275 kV lines with high capacity AC double circuit lines with twin conductors Capacity increase of the Davenport to Adelaide corridor would be about 1000-1200 MW	1-3 years RIT-T 5 years easement acquisition (if required), detailed design and delivery	300-600
Install synchronous condensers in or near the metropolitan region Increasing penetration of DER in the metropolitan area may require system strength to be increased, to ensure continued stable system response to disturbances	Install one or two synchronous condensers in or near the metropolitan region to increase system strength. We will also consider whether new technologies can provide system strength services Continued growth in DER installations would be enabled	1-2 years RIT-T 2-3 years detailed design and delivery	50-100
Third and Fourth 275 kV lines between Davenport and Cultana Increased generation or large scale storage southwest of Port Augusta	Establish the third and fourth 275 kV circuits between Davenport and Cultana Capacity increase of the Cultana to Davenport corridor would be about 1200 MW	1-2 years RIT-T 3-4 years easement acquisition, detailed design and delivery	50-100
Upgrade operation of Cultana to Yadnarie 132 kV lines to 275 kV New large load or extensive generation connections on Eyre Peninsula	Swing the Cultana to Yadnarie lines from the 132 kV bus to the 275 kV bus at Cultana and establish a new 275 kV bus and 275 / 132 kV transformation at Yadnarie Capacity increase for each Cultana to Yadnarie circuit would be about 300 MW	1-2 years RIT-T 2-3 years detailed design and delivery	30-60
Upper South East network augmentation 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 if required at Tailem Bend Capacity increase between Tailem Bend and Tungkillo would be about 400-600 MW	1-2 years RIT-T 2-3 years detailed design and delivery	20-80
Maintain adequate suppression of grid harmonic voltage levels Changing generation mix and system characteristics increase grid harmonic voltage levels	Install tuned harmonic voltage filter bank(s) designed to address any emerging issues Maintain adequate voltage quality for generators and customers	1-2 years RIT-T 2 years detailed design and delivery	15-30
Enhance Wide Area Protection Scheme Market driven requirement for increased combined interconnector transfer capability in either direction	Incorporate additional loads and storage facilities into WAPS to enable all interconnectors to be operated closer to their thermal limits Combined transfer capability could be increased by up to 650 MW	1-2 years RIT-T 2 years detailed design and delivery	5-100
Increase Robertstown to Adelaide 275 kV network transfer capacity Increased generation or large scale storage in the Mid North, Upper North, or Eyre Peninsula at times of high import from the new SA to NSW interconnector	Various line uprating, removal of plant limits and application of dynamic line ratings depending on generator developments Capacity increase would depend on location of generation and local network capability	1-2 years detailed design and delivery	3-6
Additional reactive support at Monash SA-Vic exports across Murraylink constrained by voltage limitations at Monash	Install additional 132 kV switched capacitor at Monash Increased voltage support would allow maximum exports across Murraylink to increase from about 160 MW to up to 220 MW	1-2 years detailed design and delivery	3-6
Increase Mid North 275 kV network transfer capacity Increased generation or large scale storage in the Mid North, Upper North, or Eyre Peninsula	Various line upratings, removal of plant limits and application of dynamic line ratings between Davenport and Robertstown or between Davenport and Para, depending on generator developments Capacity increase would depend 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 or large scale storage in the Mid North, Upper North, or Eyre Peninsula	Various potential reconfiguration options depending on generator and load developments[32] Capacity increase would depend on location of generation and load	Dependent on location of generation and load and scope	Dependent on location of generation and load and scope

[32] Potential examples range from implementing a control scheme to 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, to constructing new 132 kV lines, retiring other 132 kV lines and installing additional 275/132 kV transformers to "de-mesh" the Mid North 132 kV network from the 275 kV Main Grid

4.5 Frequency control schemes

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

- a distributed automatic under-frequency load shedding scheme (section 4.5.1)
- a distributed automatic over-frequency generator shedding scheme (section 4.5.2)
- a System Integrity Protection Scheme (section 4.5.2).

4.5.1 Automatic under-frequency load shedding

South Australia's existing UFLS scheme is designed to return system frequency to normal following an event that leads to South Australia separating from the rest of the NEM. The basic design premise of the UFLS scheme is that, in response to a separation event or a multiple contingency event[33], the frequency fall should be limited to 47 Hz by the controlled disconnection of load.

AEMO most recently reviewed the design of the UFLS scheme for South Australia in 2018, when its assessment indicated that the present South Australian UFLS settings are adequate.[34] AEMO is currently undertaking another review of the South Australian UFLS settings.

4.5.2 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.

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.

System inertia is the most predominant factor for effective operation of the OFGS and has typically been provided by synchronous generation. As the proportion of non-synchronous generation has increased, the system inertia has declined. This has led to the potential for increased RoCoF for large contingency events, which could cause loss of discrimination between OFGS groups, increasing the 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 most recently reviewed the design of the OFGS scheme for South Australia in 2018.[35] AEMO's assessment indicated that the present South Australian OFGS settings are adequate.

The OFGS scheme for South Australia is expected to be fully implemented in mid-2019.

[33] As defined in the Frequency Operating Standards.

[34] See section 5.2.1 of AEMO's 2018 Power System Frequency Risk Review, available from www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Power-System-Frequency-Risk-Review.

[35] See section 5.2.2 of AEMO's 2018 Power System Frequency Risk Review, available from www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Power-System-Frequency-Risk-Review.

4.5.3 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 excessive flows on the Heywood Interconnector, causing it to trip. This loss of multiple generators and loss of 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 targeted loads, to assist in re-balancing supply and demand in South Australia, preventing 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 each 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 by an independent trigger 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 trigger is initiated from a pair of redundant distance protection relays located at the Tailem Bend substation. The trigger will 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 Australian power system.

AEMO most recently reviewed the design of the South Australian SIPS scheme in 2018.[36] AEMO's assessment concluded that:

- Under all scenarios, activation of Stage 1 has not shown any detrimental effect on South Australian 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 in some simulations
- 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
- 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).

[36] See section 5.2.3 of AEMO's 2018 Power System Frequency Risk Review, available from www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Power-System-Frequency-Risk-Review.

CONNECTION OPPORTUNITIES AND SUPPORT

5. Connection opportunities and network support

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

AEMO's August 2018 Electricity Statement of Opportunities (ESOO) continues to project a tight supply-demand balance in parts of the NEM.[37] AEMO's modelling continues to show a heightened risk of significant unserved energy over the next 10 years, confirming results from recent years that additional investment will be required in a portfolio of resources to replace retiring generation capacity, and that, for peak summer periods, targeted actions to provide additional firming capability are necessary to reduce risks of supply interruptions.

The 2018 ESOO projected that investment in resources beyond those currently committed will be required to maintain reliability within the standard in Victoria, New South Wales, and South Australia.

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), in each case discussing 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

We have 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 carry out a detailed network access and market impact assessment.

[37] Available from www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities

5.1.1 General observations about connection opportunities for generators

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.

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.

While the existing Metropolitan 275/66 kV system may have capacity to accept new generation connections, population density limits the ability to economically extend the network. Also, existing maximum fault levels 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). Connection of new generation could initiate a need for major replacement of transmission or distribution assets to address fault level issues.[38]

5.1.2 Implications of South Australian system strength requirements

As discussed earlier (section 1.3.2), AEMO declared a system strength gap in SA in October 2017. Subsequently, AEMO determined the minimum required fault level at specific fault level nodes in SA. ElectraNet is installing four high-inertia synchronous condensers to meet the minimum system strength requirements specified for South Australia (section 7.4).

Currently, AEMO maintains adequate levels of system strength in South Australia by directing synchronous generation when necessary, and applying a non-synchronous generation system constraint that takes into account the amount of synchronous generators online within South Australia.

The four synchronous condenser solution is expected to allow for the dispatch of about 2,000 MW of non-synchronous generation within South Australia for most operating conditions, without the need for AEMO to direct synchronous generation to maintain a minimum level of system strength.

The total installed capacity of non-synchronous generation in South Australia exceeds 2,000 MW, so the non-synchronous generation system constraint is expected to remain in place after the four synchronous condensers have been installed.

ElectraNet and AEMO have developed an agreed approach of how a generator can be excluded from the non-synchronous generation system constraint. The following conditions must be met:

1. The generator performance standard compliance must be verified with validated R2 models; and
2. The generator must propose mitigation measures which may include control system modifications or installation of additional plant that increases the non-synchronous generation system constraint limit by their rated capacity. An increase in the constraint by part of a non-synchronous generator's rated capacity would be considered but the removal of the generator from the constraint would then be on a pro-rata basis. This assessment will be performed as a Full Impact Assessment.

5.1.3 Approach to generation connection opportunity calculations

We have assessed the ability to accommodate additional generation for four different system conditions (Table 5.1). These were selected to represent a range of dispatch conditions that may result in higher than usual inter-regional constraints on generator dispatch, at times when South Australian generation is not constrained by limits on export from South Australia to the rest of the NEM.

Table 5.1: System conditions considered in the assessment of the ability of the South Australian transmission system to accommodate additional generation

System condition	SA demand (MW)	SA system losses (MW)	Interconnector flow (MW)	Conventional generator output (% of capacity)	Wind farm output (% of capacity)	Solar farm output (% of capacity)
High summer demand sunny at noon	2,500	100	300 (import)	30%	50%	95%
High winter demand very windy and overcast	2,000	140	No flow	9%	90%	0
Medium demand sunny and still	1,400	80	600 (import)	15%	5%	90%
Very low daytime demand sunny and still	200	30	270 (export)	2%	5%	95%

At each location, we gradually increased the output of a new generator while reducing interconnector flows to maintain the supply-demand balance. The output of the new generator was increased until a voltage limitation or a thermal overload was observed, with single credible contingencies considered. The impact of existing run back schemes was also considered (where practicable).

We have not considered potential impacts on new or existing generators that could arise from any system strength limitations.

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 2019 (section 6.2).

[38] Expected maximum and minimum fault levels for each connection point are available from our Transmission Annual Planning Report web page, available at electranet.com.au/what-we-do/network/regulated-network-reports-and-studies.

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. Further load connections in this area would be incorporated into this scheme to ensure that voltage levels continue to be adequately managed.

Until 10 years ago, metropolitan electricity demand grew steadily as a result of residential, commercial and industrial development in the Adelaide metropolitan area. However, recently the loads have generally remained flat. SA Power Networks' distribution network supplies individual electricity customers, and the existing Metropolitan 275 / 66 kV network can accommodate new load connections. Depending on size and location, new load connections 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, without upgrades, could be connected to the connection point's high voltage bus in addition to the forecast South Australian 2018-19 10% POE load, with:

- Conventional generators dispatched to 80% of capacity
- Wind farms dispatched to 9% of capacity
- Solar farms dispatched to 5% of capacity
- Import of 600 MW across the Heywood interconnector.

5.3 Summary of connection opportunities

An indicative summary of the ability of the South Australian transmission network to accept generator or load connections in 2020-21 is given in Table 5.2. The summary includes the impact of the installation of synchronous condensers at Davenport and Robertstown, as well as other upgrade works that are planned to be completed by that time.

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. For some system conditions that are not included in Table 5.2, such as at times of very high wind generation output with moderate to low demand, the total dispatch of South Australian generation may be constrained by the capacity of the existing interconnectors to export electricity from South Australia.

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

The available capacity to connect new load and generation represents the capability of the existing transmission network only and does not account for any additional transformer capacity that may be required to facilitate connection at lower voltage levels.

For each system condition we have indicated the amount of additional generation dispatch or new load that could be accommodated at each connection point without exceeding voltage or capacity limits, should the most onerous single credible contingency occur. We have not considered constraints that AEMO would apply to restore system security after a contingency has occurred.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 may be subject to co-optimisation with the existing Heywood or Murraylink interconnectors are marked with an asterisk.

Table 5.2: Indication of available capacity to connect generation and load in 2020-21

Connection point	Additional generation that could be connected (MW)				Additional load that could be connected (MW)
	High summer demand sunny at noon	High winter demand very windy, overcast	Medium demand sunny and still	Very low daytime demand sunny and still	Very high summer demand low wind, early evening
MAIN GRID					
Belalie (275 kV)	400	150	600+	400	300+
Blyth West (275 kV)	100	200	400	250	300+
Brinkworth (275 kV)	300	100	500	400	190
Bungama (275 kV)	200	200	500	400	300
Canowie (275 kV)	400	150	600+	400	300+
Cherry Gardens (275 kV)*[39]	600+	550	600+	400	300+
Cultana (275 kV)	400	150	500	400	300+
Davenport (275 kV)	350	150	600+	400	300+
Mokota (275 kV)	400	150	600+	400	300+
Mount Lock (275 kV)	400	150	600+	400	300+
Robertstown (275 kV)	500	150	600+	350	300+
South East (275 kV)*	600+	600+	600+	400	300+
Tailem Bend (275 kV)*	600+	550	600+	400	300+
Templers West (275 kV)	200	100	350	300	140
Tungkillo (275 kV)*	600+	550	600+	400	300+
EASTERN HILLS					
Angas Creek (132 kV)*	100	100	100	100	70
Cherry Gardens (132 kV)*	150	150	150	150	110
Kanmantoo (132 kV)*	50	50	50	50	60
Mannum (132 kV)*	150	150	150	100	70
Mobilong (132 kV)*	250	300	250	175	120
Mount Barker (132 kV)*	250	250	200	225	150
Mount Barker South (275 kV)*	600+	550	600+	400	300+
EYRE PENINSULA					
Cultana (132 kV)	200	150	200	200	70
Port Lincoln, Wudinna, Yadnarie (132 kV)	25	<10	75	75	30
Stony Point (132 kV)	25	25	25	25	30
Whyalla Central (132 kV)	150	150	150	125	50

[39] Connection points marked with an asterisk are on an interconnector flow path, indicating that generator connections will be subject to co-optimization and constraints.

Connection point	Additional generation that could be connected (MW)				Additional load that could be connected (MW)
	High summer demand sunny at noon	High winter demand very windy, overcast	Medium demand sunny and still	Very low daytime demand sunny and still	Very high summer demand low wind, early evening
MID NORTH					
Ardrossan West, Dalrymple (132 kV)	50	25	100	75	40
Baroota (132 kV)	<10	<10	<10	<10	10
Brinkworth (132 kV)	250	75	250	250	190
Bungama	150	100	250	200	110
Clare North (132 kV)	150	50	150	150	100
Dalrymple (132 kV)	50	25	100	75	40
Dorrien (132 kV)	150	100	100	100	90
Hummocks, Kadina East (132 kV)	50	50	100	75	50
Robertstown (132 kV)*	250	75	300	200	40
Templers West (132 kV)	100	125	100	100	90
Waterloo (132 kV)*	150	25	250	250	70
RIVERLAND					
Monash, North West Bend, Berri (132 kV)*	200	75	150	100	10
SOUTH EAST					
Blanche, Mt Gambier, Snuggery, South East (132 kV)	25	<10	75	75	40
Keith*, Kincraig (132 kV)*	50	<10	100	50	40
Penola West (132 kV)*	25	<10	75	50	30
South East (132 kV)*	25	<10	150	75	60
Tailem Bend (132 kV)*	100	200	75	50	90
UPPER NORTH					
Davenport (132 kV)	25	150	25	<10	80
Leigh Creek South, Neuroodla (132 kV)	<10	<10	<10	<10	<10
Mt Gunson, Pimba (132 kV)	25	50	<10	50	30

5.4 Proposed and committed new connection points

Several new connection points have recently been energised, committed, or are proposed, to enable the connection of new generators or loads (Table 5.3).

As reported in previous Transmission Annual Planning reports, a new connection point is proposed by SA Power Networks at Gawler East in the Mid North to meet localised growing demand (Section 7.5). The planned date for Gawler East is subject to the actual rate of new residential development in the local area, 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 5.3: Proposed, committed and recently energised new connection points for generators and customers

Connection point	Planning region	Project year	Connection voltage	Scope of work
Corraberra Hill	Eyre Peninsula	Energised October 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	Energised November 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
			Upgrade to 275 kV	In 2019-20, construct a new Davenport to Mount Gunson South 275 kV line and upgrade to a 275/132 kV connection point at Mount Gunson South
		2020		Prominent Hill mine to be connected at 132 kV
Gawler East	Mid North	After 2025 (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 7.5 for more details

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

There are a number of recently completed, in-progress, and planned consultations for forecast limitations on which we have sought or seek proposals for network support solutions (Table 5.4).

Dates are indicative only. Reports will be published on ElectraNet's website, with a summary on AEMO's website.[40,41] We also liaise with AEMO to notify interested parties when we publish new RIT-T reports through the "AEMO Communications" email notifications.[43]

Table 5.4: Recently completed, in-progress, and planned consultations for which ElectraNet has sought or seeks proposals for network support solutions

Connection point	Expected project commitment date	Consultation status
Robertstown Circuit Breaker Arrangement Upgrade	Included in the scope of the Main Grid System Strength project (section 7.4)	Our 2018 Transmission Annual Planning Report had indicated that a PSCR would be published in the second half of 2019 As the rearrangement is included in the scope of the Main Grid System Strength project, a stand-alone project to rearrange these assets is no longer needed
Eyre Peninsula Electricity Supply Options Refer to section 7.5 of this report	By the end of 2019, planned for completion by December 2021	We published a PACR on 18 October 2018, which describes the preferred option to meet the identified need[43] On 12 April 2019 the AER determined the preferred option identified in the PACR satisfies the RIT-T
South Australian Energy Transformation Refer to section 7.3 of this report	2019, planned for completion by August 2023	We published a PACR on 13 February 2019, which describes the preferred option to meet the identified need[44] The next step involves the AER making a final decision as to whether the preferred option identified in the PACR satisfies the RIT-T, which we anticipate will be made in mid-2019
Transformer Bushing Unit Asset Replacement 2018-23 Refer to section 7.12 of this report	2019, planned for completion by July 2021	Application of the RIT-T began with publication of a PSCR on 22 August 2018 We published a PACR on 11 December 2018, which describes the preferred option to meet the identified need[45]
Protection Systems Unit Asset Replacement 2018-23 Refer to section 7.12 of this report	2019, planned for completion by June 2023	Application of the RIT-T began with publication of a PSCR on 22 August 2018 We published a PACR on 11 December 2018, which describes the preferred option to meet the identified need
AC Board Unit Asset Replacement 2018-23 Refer to section 7.10 of this report	2019, planned for completion by August 2023	Application of the RIT-T is planned to begin with publication of a PSCR in the second half of 2019 The replacement of these assets is not expected to have any credible non-network alternatives
Isolator Unit Asset Replacement 2018 23 Refer to section 7.12 of this report	2019, planned for completion by June 2023	Application of the RIT-T is planned to begin with publication of a PSCR in mid-2019 The replacement of these assets is not expected to have any credible non-network alternatives
Instrument Transformer Unit Asset Replacement 2018-23 Refer to section 7.12 of this report	2019, planned for completion by June 2023	Application of the RIT-T is planned to begin with publication of a PSCR in the second half of 2019 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 of this report	After 2025	Application of the RIT-D[46] is planned to begin with publication by SA Power Networks of a Non Network Options Report (NNOR) for this project before project commitment Proponents of potential network support solutions will be encouraged to make a submission in response to the NNOR

[40] ElectraNet's RIT-T page is available at www.electranet.com.au/what-we-do/network/regulatory-investment-test/.

[41] AEMO's website is available at www.aemo.com.au.

[42] 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.

[43] Available from www.electranet.com.au/projects/eyre-peninsula-electricity-supply-options/

[44] Available from www.electranet.com.au/projects/south-australian-energy-transformation/

[45] Available from www.electranet.com.au/projects/transformer-bushing-replacements/

[46] Regulatory Investment Test for Distribution.

COMPLETED, COMMITTED AND PENDING

6. Completed, committed, and pending projects

This chapter provides a high-level summary 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.

6.1 Recently completed projects

We have 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 2018 and 31 May 2019

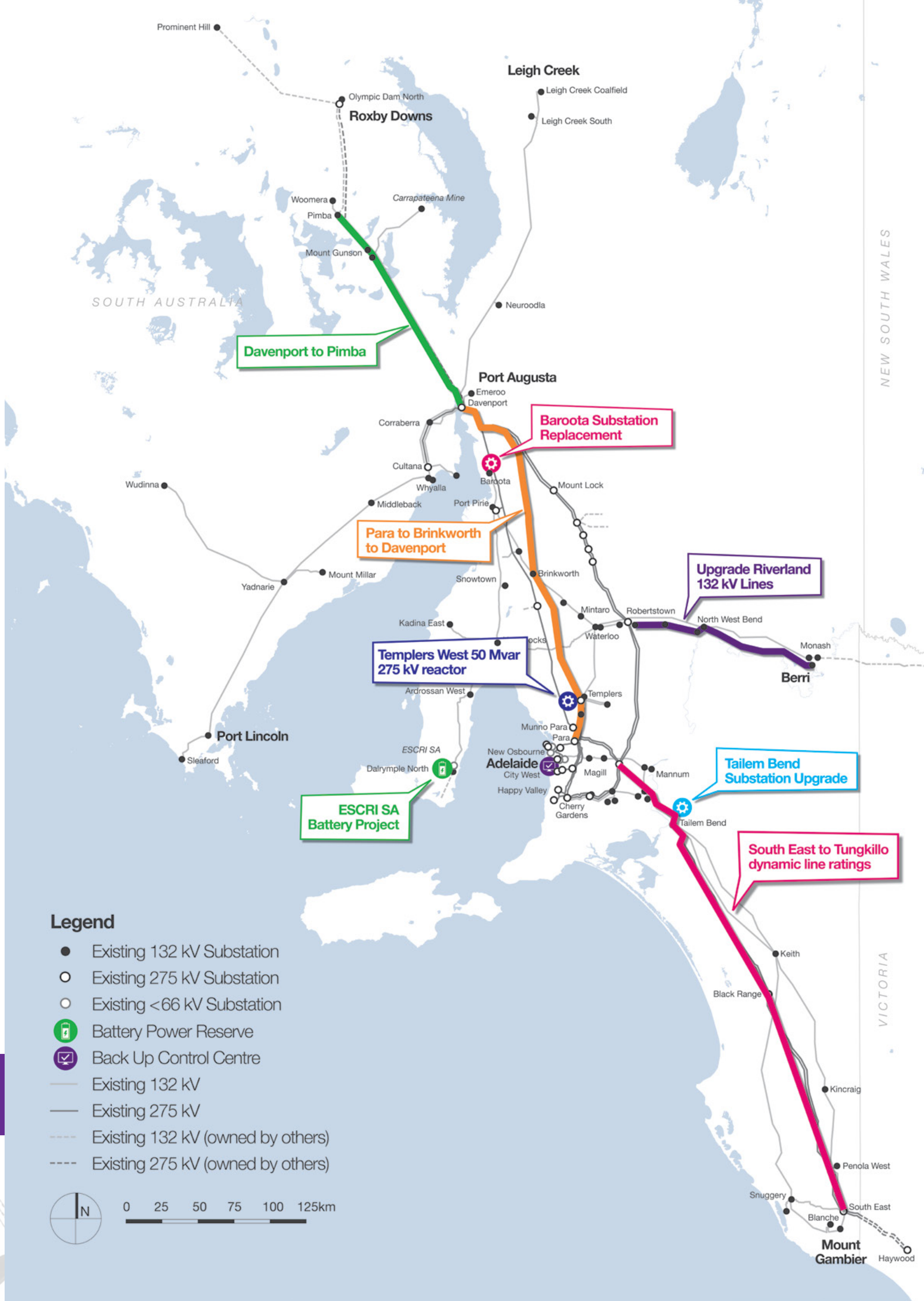
Project Description	Region	Constraint driver and investment type	Asset in service
Tailem Bend substation upgrade Extend the Tailem Bend substation to accommodate an additional 275 kV diameter with two circuit breakers, associated plant and secondary systems, and rearrange 275 kV line exits	Main Grid	Compliance and market benefit Asset renewal	August 2018
Templers West 50 Mvar 275 kV reactor Install a 50 Mvar 275 kV switched reactor at Templers West	Main Grid	Reactive support Augmentation	August 2018
Baroota substation asset replacement Maintain the reliability of Baroota substation by replacing assets that are at end of life	Mid North	Asset condition Asset renewal	September 2018
System Integrity Protection Schemes (SIPS) Stage 1 Implement special protection schemes to mitigate risk to SA transmission system prior to SA islanding contingencies, utilising rapid transmission-level load tripping and injection from batteries where available	Multiple	Security/ Compliance	December 2018[47]

[47] Initial implementation of the scheme was completed in December 2017. The battery energy storage system component was rolled into the SIPS in December 2018.

Project Description	Region	Constraint driver and investment type	Asset in service
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	Market benefit Augmentation	December 2018
South East – Tungkillo 275 kV Dynamic Line Ratings Apply dynamic ratings within ElectraNet's SCADA system to the key circuits that make up the Heywood Interconnector corridor within South Australia to enable increased transfer under favourable conditions	Main Grid	Market benefit (NCIPAP) Augmentation	March 2019
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	May 2019
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	May 2019
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	Market benefit Augmentation	May 2019
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	May 2019[48]

[48] One structure remains to be completed, planned for October 2019.

Figure 6.1: Recently completed projects



6.2 Committed projects

Committed projects are those projects for which the RIT-T has been completed (where required) and the ElectraNet Board has given approval.

We are currently undertaking several committed projects which are expected to be completed between now and mid-2022 (Table 6.2 and Figure 6.2).

Table 6.2: Committed projects as of 31 May 2019

Project Description	Region	Constraint driver and investment type	Planned asset in service date
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	Asset condition and performance Asset renewal	June 2019
Davenport-Robertstown 275 kV Removal of Plant Limits Remove, replace or change low-rated plant and secondary systems that limit full utilisation of the Davenport-Robertstown 275 kV transmission lines' thermal capacity .	Main Grid	Market benefit (NCIPAP) Augmentation	June 2019
Various unit asset replacements 2013 – 2018 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	Asset condition Asset renewal	August 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	Asset condition and performance Asset renewal	August 2019
Substation Lighting and Infrastructure Replacement Replace substation lighting and associated infrastructure at the following 82 sites where safety hazards exist: *Angas Creek, Ardrossan West, Back Callington, Baroota, Belalie, Berri, Blanche, Blyth West, Brinkworth, Bungama, Canowie, Cherry Gardens, City West, Clare North, Cultana, Dalrymple, Davenport, Dorrien, Dry Creek, East Terrace, Happy Valley, Hummocks, Kadina East, Kanmantoo, Keith, Kilburn, Kincraig, Lefevre, Leigh Creek South, Magill, Mannum, Mannum Adelaide Pump Station No. 1, Mannum Adelaide Pump Station No. 2, Mannum Adelaide Pump Station No. 3, Mayurra, Middleback, Millbrook, Mintaro, Mobilong, Mokota, Monash, Morgan Whyalla Pump Station No. 1, Morgan Whyalla Pump Station No. 2, Morgan Whyalla Pump Station No. 3, Morgan Whyalla Pump Station No. 4, Morphett Vale East, Mt Barker, Mt Barker South, Mt Gambier, Mt Gunson, Mt Millar, Munno Para, Murray Bridge Hahndorf Pump Station No. 1, Murray Bridge Hahndorf Pump Station No. 2, Murray Bridge Hahndorf Pump Station No. 3, Neuroodla, New Osborne, North West Bend, Northfield, Para, Parafield Gardens West, Pelican Point, Penola West, Pimba, Pt Lincoln Terminal, Pt Pirie, Redhill, Robertstown, Roseworthy, Sleaford, Snowtown, Snuggery, South East, Stony Point, Tailem Bend, Templers, Templers West, Torrens Island A, Torrens Island B, Torrens Island North, Tungkillo, Waterloo, Waterloo East, Whyalla Terminal, Whyalla Central, Wudinna, Yadnarie*	Various	Replacement	September 2019
Westinghouse Remote Terminal Unit (RTU) replacement This project will remove thirteen Westinghouse "Giant" type RTUs that are no longer supported by the manufacturer and have reached the end of their technical and economic lives, and replace them at various substations across the transmission network: *Angas Creek, Blanche, Dorrien, Happy Valley, Heywood, Hummocks, Mount Barker, Mount Gambier, New Osborne, Northfield, North West Bend, Parafield Gardens West, Snuggery, Whyalla Terminal, South East*	Various	Asset condition and performance Asset renewal	October 2019

Project Description	Region	Constraint driver and investment type	Planned asset in service date
AC Board Replacement 2013-18 Replace and improve AC auxiliary supply equipment, switchboards and cabling at 11 substations: *Brinkworth, Happy Valley, Hummocks, Magill, Mannum, Northfield, South East, Templers, Pt Lincoln Terminal, Snuggery, Whyalla Terminal*	Various	Replacement	December 2019
Line support systems refurbishment 2018 – 2023 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	Asset condition Asset renewal	April 2020
Spencer Gulf Emergency Bypass Preparation Undertake preparatory site works and procure spares to support a rapid restoration of Spencer Gulf high tower crossings for the Davenport-Cultana 275 kV transmission lines, which supply the entire Eyre Peninsula region	Eyre Peninsula	Security/ Compliance	May 2020
Maintain minimum levels of system strength and inertia in South Australia Install four synchronous condenser units, two at Davenport and two at Robertstown to provide system strength services and to address the NSCAS gap for system strength in South Australia as declared by AEMO	Main Grid	Stability Augmentation	September 2020 (Davenport) February 2021 (Robertstown)
Motorised Isolator LOPA Improvement Modify 876 isolators and replace 33 isolators to provide satisfactory 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

Project Description	Region	Constraint driver and investment type	Planned asset in service date
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, for the following lines: *Torrens Island – New Osborne 66 kV No. 3* *Torrens Island – New Osborne 66 kV No. 4* *Davenport – Leigh Creek 132 kV* *Keith – Kincraig 132 kV* *Kincraig – Penola West 132 kV* *Murray Bridge Hahndorf Pump Station No. 3 – Back Callington 132 kV* *North West Bend – Monash 132 kV No. 1* *South East – Mt Gambier 132 kV* *Waterloo – Mintaro 132 kV* *Cherry Gardens – Happy Valley 275 kV* *Para – Munno Para 275 kV* *Para – Robertstown 275 kV* *Para – Tungkillo 275 kV* *Parafield Gardens West – Para 275 kV* *Pelican Point – Parafield Gardens West 275 kV* *Torrens Island – Cherry Gardens 275 kV* *Torrens Island – Magill 275 kV* *Torrens Island – Para 275 kV No. 4*	Various	Refurbishment	April 2022

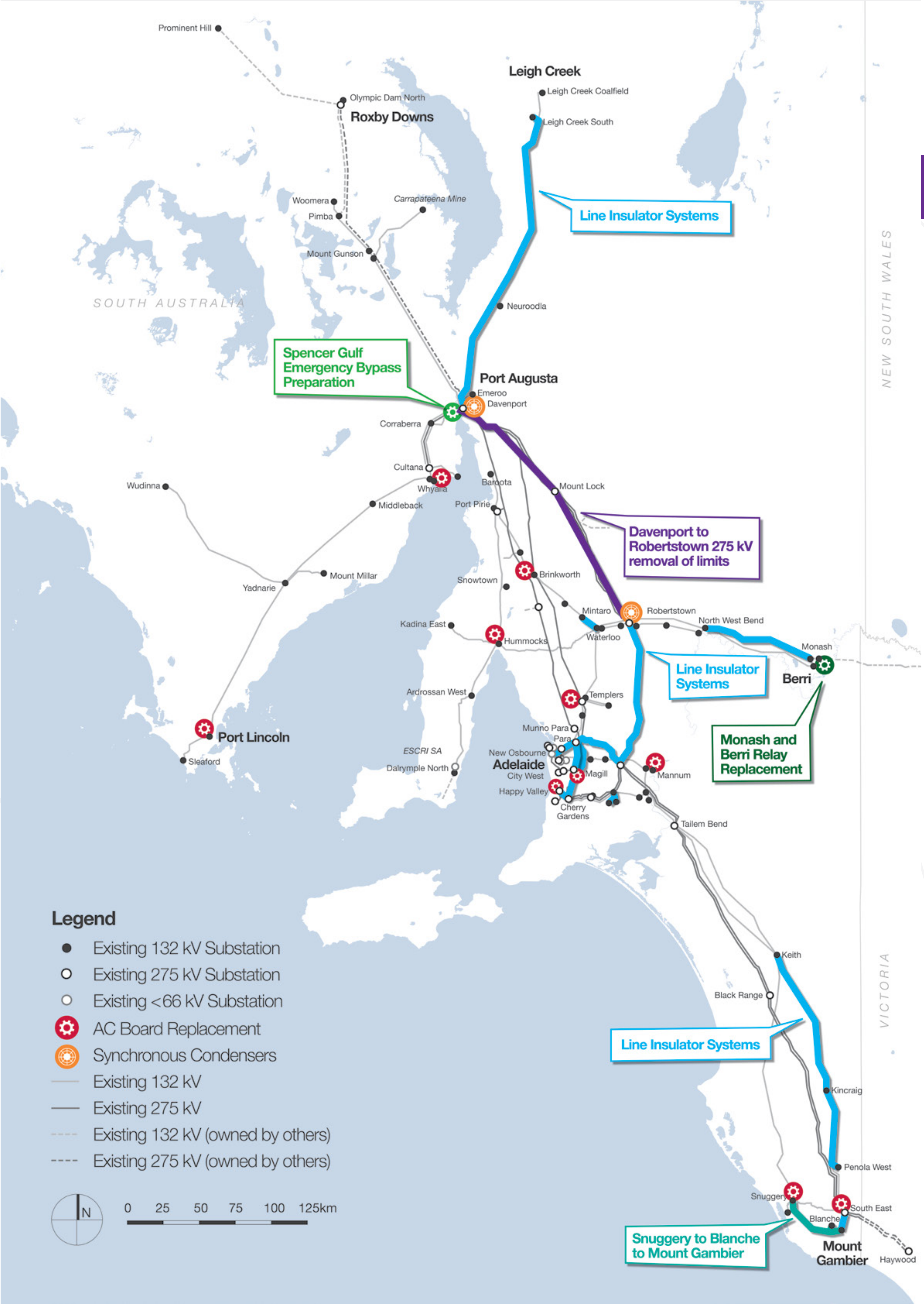


Figure 6.2:
Committed projects

6.3 Pending projects

Pending projects are those projects that have completed the RIT-T or equivalent process but have not yet been fully approved by the ElectraNet Board.

We are currently progressing several pending projects which are expected to become committed in the near future (Table 6.3).

Further information about each of these projects is available in sections 7.3, 7.5 and 7.12.

Table 6.3: Pending projects

Project Description	Region	Constraint driver and investment type	Asset in service
Transformer Bushing Replacement 2018-2023 Replace of transformer bushings that are at end of life on 18 transformers at 10 substations. This work will extend the life of the 18 transformers	Various	Asset condition and performance Asset renewal	June 2021
Eyre Peninsula upgrade Construct a new double-circuit line from Cultana to Yadnarie initially energised at 132 kV with a rating of about 300 MVA per circuit, with the option to be energised at 275 kV with a rating of about 600 MVA if required in the future Construct a new double-circuit 132 kV line from Yadnarie to Port Lincoln, rated to about 240 MVA per circuit	Eyre Peninsula	Reliability Augmentation	December 2021
Project EnergyConnect: South Australia to New South Wales interconnector Construct a new 330 kV, 800 MW interconnector from Robertstown in South Australia to Wagga Wagga in New South Wales, via Buronga	Main Grid	Market benefit Augmentation	August 2023

7. Transmission System 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 2019 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 10 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	Region
Connection point demand forecasts	As published for each connection point on the Transmission Annual Planning Report web page[49]
SA transmission system coincident demand forecasts	AEMO's 2018 ESOO (February 2019 Update) 10% POE maximum demand forecast and 90% POE minimum demand forecast
New load connections	
New or retired conventional generators	As shown in Figure 7.1
New renewable generators	

[49] Web page available at electranet.com.au/what-we-do/network/regulated-network-reports-and-studies

Figure 7.1: Assumptions considered in ElectraNet's planning process, including potential future step load increases, generator retirements, new 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 are covered in sections 7.2 to 7.12.

Potential projects that may be required to support the sensitivities were covered earlier, in section 4.4.

Table 7.2: Summary of planning outcomes

Planning focus	Key outcomes
National transmission planning	**Project EnergyConnect** We published a conclusions report for the South Australian Energy Transformation Regulatory Investment Test for Transmission (RIT-T) on 13 February 2019. The conclusions report identifies that the preferred option is a new 330 kV interconnector between South Australia and New South Wales, with a transfer capability of about 800 MW. Economic modelling shows that the new interconnector will deliver substantial net market benefits as soon as it is built, with associated reductions in wholesale and retail electricity prices in both South Australia and New South Wales. The AER is currently determining whether the identified preferred option satisfies the requirements of the RIT-T. Subject to the AER's determination, ElectraNet and TransGrid plan to implement the preferred option by August 2023.
Existing interconnector capacity	We are working with AEMO to allow the full 650 MW nominal transfer capacity of the Heywood interconnector to be released in 2019. At times, transfers over the Heywood interconnector will be limited by other constraints. Our NCIPAP includes the planned installation of an additional 100 Mvar capacitor bank at South East substation to alleviate forecast congestion on the Heywood interconnector due to voltage stability limits, providing increased availability of the interconnectors full capacity. The need for this project will be reviewed if Project EnergyConnect becomes committed.
System security	**Synchronous Condensers** We plan to install four synchronous condensers at Davenport and Robertstown by February 2021. The installation of these synchronous condensers will address the system strength and synchronous inertia needs that AEMO has identified for South Australia, and also contribute to the ongoing provision of adequate voltage control for the South Australian transmission system, including at times of low demand. We plan to investigate by the end of 2019 whether there is a need for additional inertia.

Planning focus	Key outcomes
Connection points	**Eyre Peninsula** We published a conclusions report for the Eyre Peninsula Electricity Supply Options RIT-T on 18 October 2018. The conclusions report identifies that the preferred option is to replace the existing 132 kV lines between Cultana and Port Lincoln with a new double-circuit line between Cultana and Yadnarie that is initially energised at 132 kV, but which has the option to be energised at 275 kV if required in the future, and with a new double-circuit 132 kV line between Yadnarie and Port Lincoln. The AER has determined that the preferred option satisfies the requirements of the RIT-T. We plan to implement the preferred option by the end of 2021. **Other connection points** All other connection points are forecast to remain within design and equipment limits for the duration of the planning period.
Market benefit opportunities	A range of projects is proposed to reduce the impact of existing and forecast network constraints to deliver net market benefits. This includes the projects that form ElectraNet's 2018-19 to 2022-23 Network Capability Incentive Parameter Action Plan.
New connections	The South Australian transmission system continues to have capacity to connect new load, generators, and storage. Generation output may occasionally be limited by system constraints, particularly at times of very low system demand. We are extending the 275 kV system to develop a new 275 / 132 kV connection point at Mount Gunson South to service OZ Minerals' new and existing mines in the area. A new connection point has been forecast by SA Power Networks to be required at Gawler East after 2025. Upgrading the operating voltage of the planned new Cultana to Yadnarie transmission lines from 132 kV to 275 kV may be needed if potential large loads connect on the Eyre Peninsula.
Minimum demand	The minimum demand supplied by the transmission network is forecast to continue to decrease. The synchronous condensers we plan to install at Davenport and Robertstown during 2020 to meet the identified system strength and inertia needs will also enable improved system voltage control.
Maximum fault levels	Fault levels are forecast to remain within design and equipment limits for the duration of the planning period.
Network asset retirements and de-ratings	We plan to address emerging condition needs for a range of assets on South Australia's electricity transmission network during the planning period. Asset replacement programs are based on an assessment of asset condition, risk, cost and performance.
Emergency control schemes	We are collaborating with AEMO to develop and refine a scope of works to upgrade the existing System Integrity Protection Scheme (SIPS) to a more sophisticated Wide Area Protection Scheme (WAPS), which will satisfy the requirements of AEMO's most recent Power System Frequency Review.

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. We have not made any such investments.

7.3 National transmission planning

Consistent with the results of AEMO's July 2018 ISP and December 2018 NTNDP, we have developed Project EnergyConnect to address emerging South Australian and National transmission planning needs (Table 7.3 and Figure 7.2).

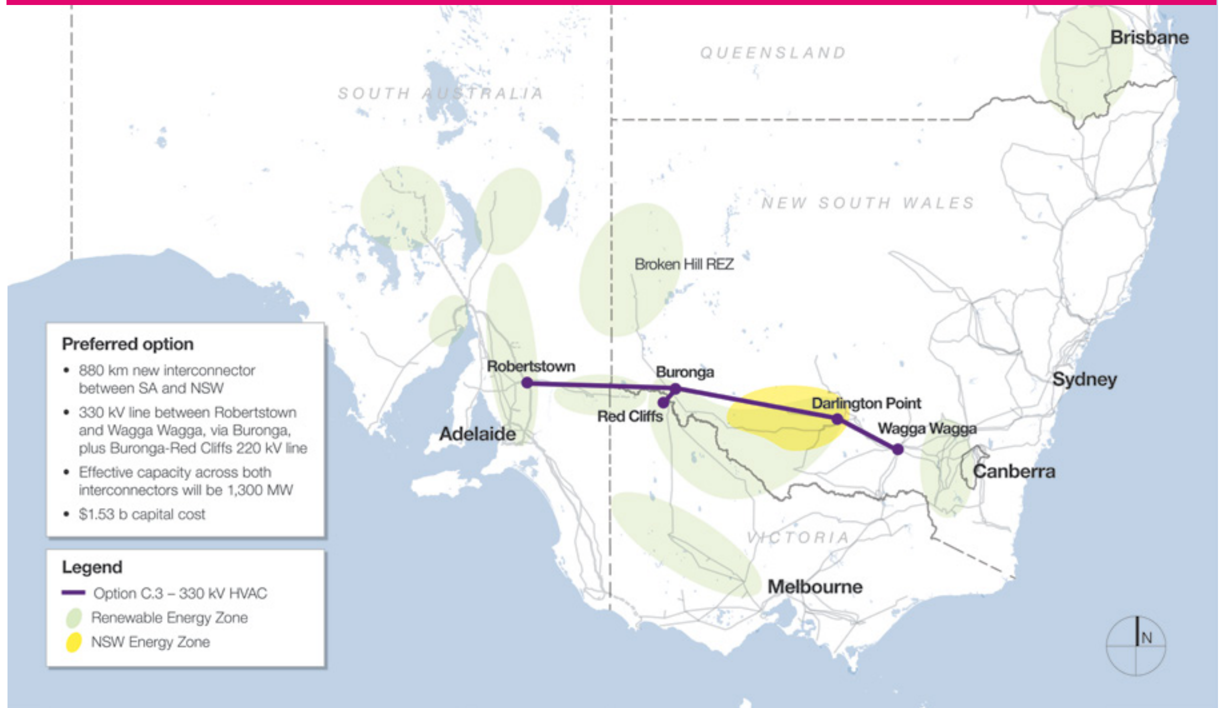
ElectraNet envisages that Project EnergyConnect will impact inter-regional transfer in a manner that is expected to place downward pressure on electricity market prices in South Australia and New South Wales.

Table 7.3: Project EnergyConnect, planned to meet national transmission planning identified needs

Project	Region	Constraint driver and investment type	Asset in service
Project EnergyConnect: New interconnector between South Australia and New South Wales **Estimated cost:** $1.53 billion **Status:** Pending AER determination and full Board approval Construct a new 330 kV, 800 MW interconnector from Robertstown in South Australia to Wagga Wagga in New South Wales, via Buronga We published the PACR for the South Australian Energy Transformation RIT-T on 13 February 2019, which provides information about the considered options[50] The next step of the RIT-T process involves the AER making a final decision as to whether the preferred option identified in the PACR satisfies the RIT-T, which we anticipate later in 2019 In the meantime we are proceeding with route selection and stakeholder engagement, with these early works underwritten by the South Australian State Government	Main Grid	Market benefit Augmentation	August 2023

[50] The South Australian Energy Transformation PACR is available from www.electranet.com.au/projects/ south-australian-energy-transformation/

Figure 7.2: Project EnergyConnect



7.4 System security

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.

We have proposed a number of projects to meet the system strength and inertia shortfalls that AEMO has identified and to implement emergency frequency control schemes (Table 7.4 and Figure 7.3).

ElectraNet envisages that the project to maintain minimum levels of system strength and inertia in South Australia will impact inter-regional transfer in a manner that is expected to place downward pressure on electricity market prices in South Australia. The other projects in Table 7.4 are not expected to impact inter-regional transfer.

Table 7.4: Synchronous Condensers at Davenport and Robertstown, planned to meet system security needs

Project	Region	Constraint driver and investment type	Asset in service
Maintain minimum levels of system strength and inertia in South Australia **Estimated cost:** $160-200 million **Status:** Committed Install two high-inertia synchronous condensers at Davenport and two at Robertstown, to address the system strength need declared by AEMO in October 2017 and the system inertia need identified by AEMO in the December 2018 NTNDP On 18 February 2019, the AER published its determination that our economic assessment for this project is equivalent to the RIT-T and proportionate to the identified need, and that the identified solution reasonably satisfies the economic evaluation requirement[51] On 8 March 2019, AEMO provided technical approval for the identified solution Final revenue approval from the AER is anticipated later in 2019	Main Grid	Compliance Augmentation	September 2020 (Davenport) February 2021 (Robertstown)
Wide Area Monitoring Scheme pilot **Estimated cost:** $3-5 million **Status:** Planned Undertake a pilot project to install a number of Power Monitoring Units (PMUs) and develop a Wide Area Monitoring Scheme to real time monitor and process system parameters and incorporate suitable new technologies to further enhance SA system security	All	Stability Operational	December 2020
Wide Area Protection Scheme **Estimated cost:** $4-6 million **Status:** Planned Enhance the existing SIPS to investigate the use of PMUs for event detection, and include dynamic arming of participating loads and battery energy storage systems, to enable a proportionate response to specific events	All	Stability Operational	December 2021
Wide Area Monitoring Scheme **Estimated cost:** $10-25 million **Status:** Proposed Extend the roll-out of PMUs to real time monitor and process system parameters and incorporate suitable new technologies to further enhance South Australian system security, providing improved operational situational awareness and system monitoring and data for planning, benchmarking, fault and incident investigation and power system model validation	All	Stability Operational	2024 – 2028

[51] Our economic evaluation report contains information about the considered options, and is available at www.electranet.com.au/wp-content/uploads/2019/02/2019-02-18-System-Strength-Economic-Evaluation-Report-FINAL.pdf

Figure 7.3: Planned synchronous condenser installation locations to improve minimum levels of system strength and inertia 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 South Australian Electricity Transmission Code (ETC, redundancy requirements summarised in Appendix C section C2.1). This is coordinated through joint planning with SA Power Networks, in which connection point projects are considered, proposed, and planned.

Consistent with the 2018 Transmission Annual Planning Report, two connection point projects are proposed over the 10-year planning period (Table 7.5 and Figure 7.4).

Further detail regarding each project is available from our Transmission Annual Planning Report web page.[52]

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

Table 7.5: Projects planned to meet connection point needs

Project	Region	Constraint driver and investment type	Asset in service
Eyre Peninsula upgrade **Estimated cost:** $240 million **Status:** Pending full Board approval Replace the existing Cultana to Yadnarie 132 kV transmission line with a new double-circuit line initially energised at 132 kV with a rating of about 300 MVA, with the option to be energised at 275 kV with a rating of about 600 MVA if required in the future Replace the existing Yadnarie to Port Lincoln 132 kV transmission line with a new double-circuit 132 kV line with a rating of about 240 MVA We published the PACR for the Eyre Peninsula Electricity Supply Options RIT-T on 18 October 2018[53] On 12 April 2019 the AER published its determination that the preferred option satisfies the requirements of the RIT-T	Eyre Peninsula	Reliability Augmentation	December 2021
Establish new connection point at Gawler East **Estimated cost:** Less than $5 million (transmission component comprising 132 kV bus and connection point) **Status:** Proposed Cut into the Para to Roseworthy 132 kV line and create a 132 kV connection point for a new 132/66/11 kV 1x25 MVA transformer substation	Mid North	Capacity Augmentation	After 2025 (depending on local demand growth)

Figure 7.4: Planned connection point projects

[52] Our Transmission Annual Planning Report web page is available at electranet.com.au/what-we-do/network/regulated-network-reports-and-studies

[53] The Eyre Peninsula Electricity Supply Options PACR is available from www.electranet.com.au/ projects/eyre-peninsula-electricity-supply-options/

7.6 Market benefit opportunities

ElectraNet monitors congestion on the South Australian transmission system (chapter 4). We also consider information regarding future likely generator and load connections, along with AEMO's most recent NTNDP and ISP, to predict new constraints that may develop in future years.

Consistent with the 2018 Transmission Annual Planning Report, we plan to complete projects that form part of our 2018-19 to 2022-23 Network Capability Incentive Parameter Action Plan (NCIPAP) (Table 7.6 and Figure 7.5).

In the 2018 Transmission Annual Planning Report, we had proposed a dedicated project to address the need to improve the Robertstown circuit breaker arrangement. However, the scope of the installation of synchronous condensers at Robertstown will address that need, and so a dedicated project for that purpose is no longer required.

Further detail regarding each project is available from our Transmission Annual Planning Report web page.[54]

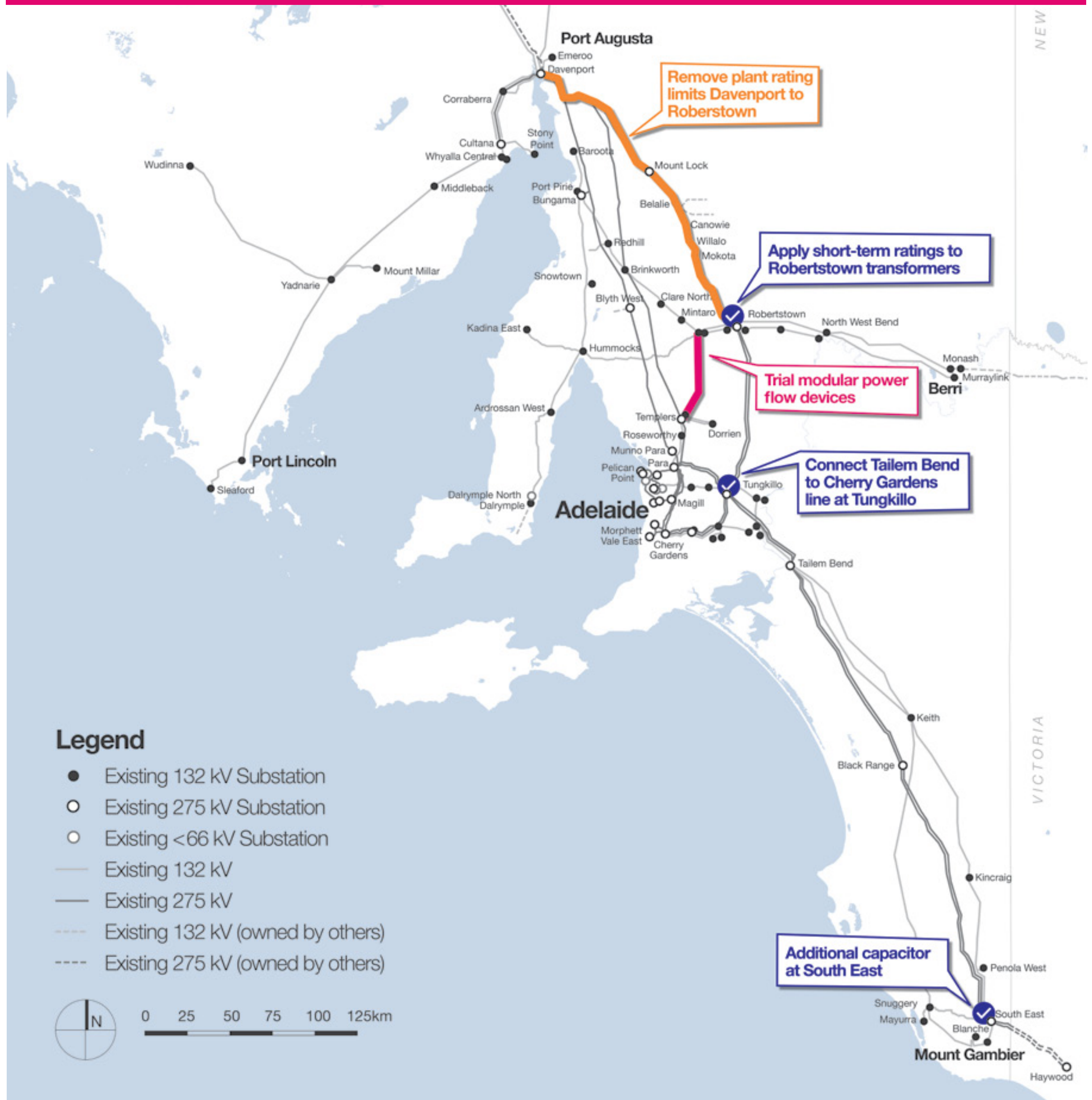
Unless otherwise stated in Table 7.6, ElectraNet envisages that each of these projects will impact inter-regional transfer, by increasing the capacity that can be utilised across either the Heywood or the Murraylink interconnectors.

Table 7.6: Projects planned to address market benefit opportunities

Project	Region	Constraint driver and investment type	Asset in service
Remove plant rating limits from the Robertstown to Davenport 275 kV lines **Estimated cost:** Less than $5 million **Status:** Committed Remove, replace or change 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 ElectraNet envisages that this project will impact intra-regional transfer, but not inter-regional transfer	Mid North	Market benefits (NCIPAP) Augmentation	June 2019
Trial modular power flow elements to relieve congestion **Estimated cost:** Less than $6 million **Status:** Committed 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 ElectraNet envisages that this project will impact intra-regional transfer, but not inter-regional transfer	Mid North	Market benefits (NCIPAP) Augmentation	December 2019
Alleviate forecast congestion on the Heywood interconnector due to voltage stability limits **Estimated cost:** Less than $5 million **Status:** Planned Connect the Tailem Bend to Cherry Gardens 275 kV line at Tungkillo	Eastern Hills	Market benefits (NCIPAP) Augmentation	January 2020
Further alleviate forecast congestion on the Heywood interconnector due to voltage stability limits **Estimated cost:** Less than $5 million **Status:** Planned Install an additional 100 Mvar 275 kV switched capacitor at South East substation	South East	Market benefits (NCIPAP) Augmentation	June 2021
Alleviate forecast export constraints on the Murraylink interconnector **Estimated cost:** Less than $5 million **Status:** Planned Install transformer management relays and bushing monitoring equipment to enable the application of short term ratings to the Robertstown 275/132 kV transformers	Mid North	Market benefits (NCIPAP) Augmentation	June 2022

[54] Our Transmission Annual Planning Report web page is available at electranet.com.au/what-we-do/network/regulated-network-reports-and-studies

Figure 7.5: Planned and proposed market benefits projects



7.7 Maximum demand

Maximum demands on South Australia's electricity transmission network typically occur during heatwave conditions in summer (chapter 3).

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 system 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 (Table 7.7).

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

Table 7.7: Projects planned to address maximum demand if potential significant spot loads connect

Project	Region	Constraint driver and investment type	Asset in service
Upper North region eastern 132 kV line reinforcement **Estimated cost:** $60 million **Status:** Contingent Uprate or rebuild the Davenport to Leigh Creek 132 kV line and establish associated substation assets (including reactive support)	Upper North	Capacity Contingent – refer to Appendix E for trigger	Uncertain
Upper North region western 132 kV line reinforcement **Estimated cost:** Less than $110 million **Status:** Contingent Rebuild the Davenport to Pimba 132 kV line and establish associated substation assets (including reactive support)	Upper North	Capacity Contingent – refer to Appendix E for trigger	Uncertain

7.8 Minimum demand

Minimum demands on South Australia's electricity transmission network typically occur in the middle of mild, sunny weekend days or public holidays (chapter 3). Times of low demand typically correlate with times of high voltage levels on the transmission system.

We have assessed the ability of the network to deliver minimum demand while maintaining system voltage levels within equipment limits with all system elements in service, and allowing for any one item of plant to be out of service.

Our analysis has shown that the installation of synchronous condensers at Davenport and Robertstown (section 7.4) is expected to enhance and maintain the ability to maintain adequate system voltage levels over the planning period. We will review this finding after the specifications and parameters of the synchronous condensers are finalised.

Subject to the results from the joint study into voltage control across the distribution and transmission networks (section 1.3.3), no projects are currently proposed over the 10-year planning period to manage the impact of declining minimum demand. However, detailed work in the coming years may identify future needs that would need to be addressed.

7.9 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 and the modelling we performed for the SA Energy Transformation RIT-T, the total conventional generation in South Australia is expected to reduce over the next 10 years. Substation fault levels were assessed to ensure they will remain within design and equipment limits.

Expected maximum and minimum fault levels at each connection point are available from the supporting data published on our Transmission Annual Planning Report web page.[55]

[55] Our Transmission Annual Planning Report web page is available at electranet.com.au/what-we-do/network/regulated-network-reports-and-studies

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 are listed in this section if the total estimated cost exceeds $2 million (Table 7.8).

Further details are available from our Transmission Annual Planning Report web page.[56]

Table 7.8: Projects planned to address asset retirement and replacement needs

Project	Region	Constraint driver and investment type	Asset in service
Westinghouse Remote Terminal Unit (RTU) replacement **Estimated cost:** $2-4 million **Status:** Committed This project will remove thirteen Westinghouse "Giant" type RTUs that are no longer supported by the manufacturer and have reached the end of their technical and economic lives, and replace them at various substations across the transmission network: *Angas Creek, Blanche, Dorrien, Happy Valley, Heywood, Hummocks, Mount Barker, Mount Gambier, New Osborne, Northfield, North West Bend, Parafield Gardens West, Snuggery, Whyalla Terminal, South East*	Various	Asset condition and performance Asset renewal	October 2019
Magill to East Terrace 275 kV cable link box replacement **Estimated cost:** Less than $3 million **Status:** Planned The Magill - East Terrace 275 kV underground fluid-filled underground cable is one of two transmission lines supplying the Adelaide CBD. Condition of the earthing link boxes at cable joints has deteriorated to the point that replacement of the link boxes is required	Metropolitan	Asset condition and performance Asset renewal	July 2020
Magill substation transformer fire extinguishing systems replacement **Estimated cost:** Less than $3 million **Status:** Planned Replace the existing fire suppression systems fitted to the three 275/66 kV transformer enclosures at Magill substation, which are unique in ElectraNet and have been assessed to be at the end of their technical and economic life	Metropolitan	Asset condition and performance Asset renewal	July 2020
Mount Gambier 132/33 kV Transformer No. 1 replacement **Estimated cost:** Less than $3 million **Status:** Planned Replace the existing 50 MVA 132/33 kV transformer, assessed to be at the end of its technical life with a corresponding high risk of failure, with a new 25 MVA transformer A size of 25 MVA has been chosen to match the other 132 / 33 kV transformer at Mount Gambier, and provides sufficient capacity to meet the forecast demand at Mount Gambier connection point	South East	Asset condition and performance Asset renewal	January 2021
Templers plant replacement **Estimated cost:** $2-4 million **Status:** Planned Replace eight 132 kV isolators and the 132 kV bus at Templers, which have been assessed to be at the end of their technical and economic lives and no longer have manufacturer's support	Mid North	Asset condition and performance Asset renewal	May 2021
South East SVC computer control system replacement **Estimated cost:** $3-6 million **Status:** Planned Replace the end-of-life South East SVC computer control system with a new system	Main Grid	Asset condition and performance Asset renewal	May 2022
Line Conductor and Earthwire Refurbishment 2018 – 2023 Program **Estimated cost:** $15-20 million **Status:** Planned Program of projects to replace transmission line conductors and earthwire to extend the life of seven 132 kV transmission lines in the Mid North and Riverland: *Waterloo – Waterloo East* *Waterloo East – Morgan Whyalla Pump Station #4* *Morgan Whyalla Pump Station #4 – Robertstown* *Robertstown – Morgan Whyalla Pump Station #3* *Morgan Whyalla Pump Station #3 – Morgan Whyalla Pump Station #2* *Morgan Whyalla Pump Station #2 – Morgan Whyalla Pump Station #1* *Morgan Whyalla Pump Station #1 – North West Bend* As the individual line projects do not exceed $6 million in estimated cost, we do not plan to apply the RIT-T to these planned investments	Mid North and Riverland	Asset condition and performance Asset renewal	June 2022

[56] Our Transmission Annual Planning Report web page is available at electranet.com.au/what-we-do/network/regulated-network-reports-and-studies

Project	Region	Constraint driver and investment type	Asset in service
Leigh Creek South transformer replacement **Estimated cost:** $3-6 million **Status:** Planned Replace the two existing 5 MVA transformers that are at end of life with a single new 5 MVA 132 / 11 kV transformer	Upper North	Asset condition and performance Asset renewal	July 2022
Mannum 132/33 Transformer Nos. 1 and 2 replacement **Estimated cost:** $2-4 million **Status:** Planned Replace the two existing 20 MVA transformers, assessed to be at the end of their technical life with a corresponding high risk of failure, with two new 25 MVA 132 / 33 kV transformers (nearest ElectraNet standard size)	Eastern Hills	Asset condition and performance Asset renewal	May 2023
Circuit breaker unit asset replacement **Estimated cost:** $4-6 million **Status:** Planned Implement a program to replace selected circuit breakers at various substations that are at the end of their technical and economic lives This project includes the replacement of assets at the following sites: *Davenport (2x 275 kV circuit breakers)* *Happy Valley (1x 66 kV circuit breaker)* *Kincraig (1x 132 kV circuit breaker)* *Morphett Vale East (2x 275 kV circuit breakers)* *Torrens Island A (2x 275 kV circuit breakers)* *Torrens Island B (7x 275 kV circuit breakers)*	Various	Asset condition and performance Asset renewal	June 2023
AC Board Replacement 2018 – 2023 **Estimated cost:** $20-25 million **Status:** Planned Program to replace and improve AC auxiliary supply equipment, switchboards and cabling at seventeen substations across the South Australian electricity transmission system that have been assessed to be at the end of their technical and economic lives This project includes the replacement of assets at the following sites: *Berri, Blanche, Davenport, East Terrace, Hummocks, Kanmantoo, Kilburn, Kincraig, LeFevre, Leigh Creek South, Mobilong, Morphett Vale East, Monash, Mount Gambier, Murray Bridge-Hahndorf No. 1 Pump Station, Murray Bridge-Hahndorf No. 2 Pump Station, Murray Bridge-Hahndorf No. 3 Pump Station, Tailem Bend, Parafield Gardens West, Penola West, Pimba, Robertstown, Stony Point* We plan to initiate a RIT-T for this program of work early in the second half of 2019	Various	Asset condition and performance Asset renewal	August 2023

Project	Region	Constraint driver and investment type	Asset in service
Transmission line support system refurbishment **Estimated cost:** $10-15 million **Status:** Proposed Implement a program to refurbish transmission line support systems (towers, poles) across the network that have been assessed to be at end-of-life, to renew line asset components and extend line life	Various	Asset condition and performance Asset renewal	2024 – 2028
Transmission line insulator system refurbishment **Estimated cost:** $50-80 million **Status:** Proposed Implement a program to refurbish transmission line insulator systems across the network that have been assessed to be at end-of-life, to renew line asset components and extend line life	Various	Asset condition and performance Asset renewal	2024 – 2028
Transmission line conductor and earthwire replacement **Estimated cost:** $70-100 million **Status:** Proposed Implement a program of transmission line conductor and earthwire replacement for components that are assessed to be at end-of-life, to renew line asset components and extend line life	North and Riverland	Asset condition and performance Asset renewal	2024 – 2028
Various substation unit asset replacement programs **Estimated cost:** $50-80 million **Status:** Proposed Implement a number of programs of unit asset and infrastructure replacement projects at various substations, to address substation assets that have been identified to be at end-of-life	Various	Asset condition and performance Asset renewal	2024 – 2028
Transformer replacement **Estimated cost:** $10-20 million **Status:** Proposed Replace selected transformers and associated infrastructure at specific sites that have been identified to be at end-of-life	Various	Asset condition and performance Asset renewal	2024 – 2028

7.11 Network asset de-ratings

ElectraNet reviews the condition of its network assets on an ongoing basis to ensure that these assets can continue to provide customer service. Where condition assessment indicates that an asset's condition is beginning to decline, a planned refurbishment or replacement program is put in place.

We continue to review our approach to equipment ratings to optimise network transfer capability.

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

7.12 Grouped network asset retirements, de-ratings and replacements

Clause 5.12.2 (c) of the Rules allows asset retirements, de-ratings and replacements to be "grouped" for reporting in the Transmission Annual Planning Report where two or more network assets are:

- of the same type
- to be retired or de-rated across more than one location
- to be retired or de-rated in the same calendar year
- each expected to have a replacement cost less than $200,000 (as varied by a cost threshold determination).

Five programs of work that exceed $6 million for grouped network asset retirement and replacement are proposed over the 10-year planning period. Three of these were reported in the main body of the 2018 Transmission Annual Planning Report. One of the additional projects, the 2018-19 to 2022-23 program of work for unit asset replacement of instrument transformers, is now also included in this section due to an increase in the expected cost since the 2018 Transmission Annual Planning Report.

Projects are listed in this section if their total estimated cost exceeds $2 million (Table 7.9).

Table 7.9: Grouped projects planned to meet asset retirement and replacement needs

Project	Region	Constraint driver and investment type	Asset in service
GE D20 Remote Terminal Unit (RTU) product upgrades **Estimated cost:** $2-4 million **Status:** Committed Older versions of GE D20 RTUs are no longer supported and are at the end of the technical and economic life This project will replace boards at 22 sites across the system Doing nothing is not considered a viable alternative because sufficient spares are unavailable. The failure of one of these RTUs would mean that ElectraNet would not be able to operate plant and equipment remotely. The loss of system data would prevent the use of the state-estimators used by both ElectraNet and AEMO, and would also impact on response and restoration times after system events	Various	Asset condition and performance Asset renewal	November 2019
Transformer bushing unit asset replacement 2018-19 to 2022-23 **Estimated cost:** $7-10 million **Status:** Pending Replace 101 individual transformer bushings that have been assessed to be at the end of their technical or economic lives on 18 transformers across 10 substation sites We published a PACR on 11 December 2018, concluding the RIT-T for this program of work[57]	Various	Asset condition and performance Asset renewal	July 2021 (work at Snuggery is committed and expected to be completed by August 2019)
Substation and building security system replacement **Estimated cost:** $4-6 million **Status:** Planned Replace and upgrade all existing substation fire and security systems to a new technology, as the existing systems are all end-of-life and no longer have manufacturer support	Various	Asset condition and performance Asset renewal	October 2021
Substation computer based local control facilities replacement **Estimated cost:** $2-4 million **Status:** Planned Replace 22 Human Machine Interface or Local Control Facilities that have been assessed to be at the end of their economic or technical life	Various	Asset condition and performance Asset renewal	February 2022
Substation battery unit asset replacement **Estimated cost:** Less than $3 million **Status:** Planned Replace 154 battery banks that have been assessed to be at end of life, across 69 sites	Various	Asset condition and performance Asset renewal	December 2022
Replace online asset condition assessment equipment 2018-19 to 2022-23 **Estimated cost:** $4-6 million **Status:** Planned Implement a program to replace selected obsolete online asset condition monitoring units across the network that are near the end of their usable lives and are exhibiting high failure rates	Various	Asset condition and performance Asset renewal	April 2023

57 The Managing the Risk of Transformer Bushing Failure PACR is available from www.electranet.com.au/ projects/transformer-bushing-replacements/

Project	Region	Constraint driver and investment type	Asset in service
Isolator unit asset replacement 2018-19 to 2022-23 **Estimated cost:** $8-12 million **Status:** Planned 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, at 16 sites across South Australia where the asset won't be replaced as part of an augmentation or substation rebuild during the 2018-19 to 2022-23 regulatory period We plan to initiate a RIT-T for this program of work early in the second half of 2019	Various	Asset condition and performance Asset renewal	June 2023
Instrument Transformer unit asset replacement 2018-19 to 2022-23 **Estimated cost:** $10-15 million **Status:** Planned Replace 55 voltage transformers and 121 current transformers across the South Australian electricity transmission system that have reached the end of their technical or economic lives and have an increased likelihood of catastrophic explosion We plan to initiate a RIT-T for this program of work early in the second half of 2019	Various	Asset condition and performance Asset renewal	June 2023
Protection systems unit asset replacement 2018-19 to 2022-23 **Estimated cost:** $25-35 million **Status:** Planned Replace protection scheme relays across the South Australian electricity transmission system that have reached the end of their technical or economic lives We plan to initiate a RIT-T for this program of work early in the second half of 2019	Various	Asset condition and performance Asset renewal	June 2023
Surge arrestor unit asset replacement **Estimated cost:** Less than $3 million **Status:** Planned Implement a program to replace 163 surge arrestors across 19 substations that are at the end of their technical and economic lives	Various	Asset condition and performance Asset renewal	June 2023

Project	Region	Constraint driver and investment type	Asset in service
Protection systems unit asset replacement 2023-24 to 2027-28 **Estimated cost:** $30-50 million **Status:** Planned Replace protection relays and control schemes across the South Australian electricity transmission system that have reached the end of their technical or economic lives This project will include the replacement of assets at a number of sites, which will be determined based on asset needs We plan to initiate a RIT-T for this program of work prior to commitment	Various	Asset condition and performance Asset renewal	June 2023

7.13 Security and compliance projects

There are a range of committed and planned projects that relate to the maintenance of our security and compliance obligations.

Projects are listed in this section if their total estimated cost exceeds $2 million (Table 7.10).

Table 7.10: Projects planned to meet security and compliance needs

Project	Region	Constraint driver and investment type	Asset in service
High voltage switching training facility **Estimated cost:** $7-10 million **Status:** Committed Presently, high voltage switching training is conducted on live network, which limits training possibilities due to network and asset performance impacts This project will create a high voltage switching training facility to improve training standards across all aspects of high voltage switching	Various	Safety Operational	September 2019
Eyre Peninsula and Upper North voltage control scheme **Estimated cost:** $3-5 million **Status:** Committed Install automated regional voltage control schemes for the Eyre Peninsula and Upper North regions, to ensure that changing generation patterns that are resulting in complex voltage interactions do not lead to violations of voltage limits stipulated in the Rules and connection agreements	Eyre Peninsula and Upper North	Reactive support Operational	December 2019
East Terrace, Northfield and Kilburn emergency transformer deployment preparation **Estimated cost:** Less than $3 million **Status:** Planned East Terrace and Northfield substations both have 225 MVA 275/66 kV transformers that require direct connection to 275 kV Gas Insulated Switchgear (GIS), together with a variety of 66 kV connections (both cable and GIS). This project will identify and procure equipment and plant and put in place the procedure to enable rapid restoration of these transformers in the event that one of them should fail, to be able to meet the expectations of the best endeavours requirement specified in the ETC	Metropolitan	Operational Operational	November 2020
Substation improvements for system black conditions **Estimated cost:** $4-6 million **Status:** Planned 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, to improve ability to restore supply during black start or other abnormal operating conditions	Various	Operational Operational	June 2021
Capacitor bank infrastructure safety improvement **Estimated cost:** $4-8 million **Status:** Planned Implement a program of safety improvement activities for infrastructure associated with high voltage plant areas within substations, such as improvements to fencing, earthing, entry locking and surface treatment	Various	Safety Operational	October 2021

APPENDICES

Appendix A: Summary of changes from the 2018 Transmission Annual Planning Report

As listed in Appendix D, 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 2019 Transmission Annual Planning Report (TAPR) that have changed significantly from the 2018 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 2018 and 2019 TAPR	Analysis and explanation for the significant change
1.1	Renewable generation development is continuing in South Australia	The 2018 TAPR forecast that about 51% of energy generated in South Australia would come from renewable energy sources in 2017-18. The actual result reported in this year's TAPR is equivalent to over 48% of South Australian demand.	While actual results from 2017-18 differ slightly 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.
1.3	What is ElectraNet doing now, to prepare for the future?	This section was titled "Strategic South Australian transmission developments" in the 2018 TAPR. The information in this section has been updated since the corresponding section in the 2018 TAPR.	We have updated this information to reflect our current areas of focus.
2.2	National Transmission Network Development Plan	This section has significantly more content than in the corresponding section of the 2018 TAPR.	With the agreement of the AER, AEMO did not publish a 2017 NTNDP. However, AEMO did publish a 2018 NTNDP, which we discuss in this section.
2.3	Power System Frequency Risk Review	This section of the 2018 TAPR discusses AEMO's most recent Power System Frequency Risk Review. The 2018 TAPR included this information in section 8.2.	This information has been included in this section to group it with the discussion of the ISP and NTNDP, also produced by AEMO.
4	System capability and performance	This chapter was titled "Forecast network and system constraints" in the 2018 TAPR.	The title of this chapter has been updated to reflect the enhanced scope of this part of the report, which now includes a description of the existing South Australian electricity transmission system.

Section	Section Name	Significant changes between the 2018 and 2019 TAPR	Analysis and explanation for the significant change
4.1	The South Australian electricity transmission system	This section is new in the 2019 TAPR. The 2018 TAPR included some of this information in the "About ElectraNet" section.	This information has been incorporated into chapter 4 to provide an overview of the capability and performance of the South Australian electricity transmission system.
4.2	Transmission system constraints in 2018	ElectraNet assessed a number of constraints as part of the 2019 TAPR that were not part of the 2018 TAPR. Additionally, not all constraints included within the 2018 TAPR were assessed as part of the 2019 TAPR. The corresponding section in the 2018 TAPR was section 4.1.	Each year we assess the top binding network constraints that impacted the transmission system and interconnector flows during the 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 typical varies year-by-year.
4.3	Emerging and future network constraints and performance limitations	The corresponding section in the 2018 TAPR was section 4.2.	The results in this table have been updated to reflect our current view of where future constraints may arise.
4.4	Potential projects to address constraints	Tables 4.3 and 4.4 in the 2018 TAPR have been combined into a single table (Table 4.3) in the 2019 TAPR. The corresponding section in the 2018 TAPR was section 4.3.	The results in this table have been updated to reflect our current view of projects that may be warranted to address potential future constraints.
4.5	Frequency control schemes	The corresponding section in the 2018 TAPR was section 8.1.	This information has been incorporated into chapter 4 as it closely relates to the capability and performance of the South Australian electricity transmission system.
5.1	Connection opportunities for generators	The number of dispatch scenarios assessed has reduced from eight in 2018, to four.	The dispatch scenarios in the 2019 TAPR have been selected to represent a range of conditions that may result in higher than usual inter-regional constraints on generators dispatch, at times when South Australian generation is not constrained by limits on export from South Australia to the rest of the NEM.
5.3	Summary of connection opportunities	The information in this section has been updated since the corresponding section in the 2018 TAPR.	We have updated the information to account for new generator and customer connections since the 2018 TAPR, and to include the expected impact of committed projects up until February 2021.

Section	Section Name	Significant changes between the 2018 and 2019 TAPR	Analysis and explanation for the significant change
5.5	Projects for which network support solutions are being sought or considered	The information in this section has been updated since the corresponding section in the 2018 TAPR.	We have updated the information to reflect the latest status for projects for which we have recently sought, are seeking, or will soon seek non-network proposals.
6.1	Recently completed projects	The information in this section has been updated since the corresponding section in the 2018 TAPR.	We have updated the information to reflect the latest status of projects completed up until 31 May 2019. Many of these were listed as committed projects in the 2018 TAPR.
6.2	Committed projects	The following projects are now committed in the 2019 TAPR: • Davenport – Robertstown 275 kV removal of plant limits • Substation lighting and infrastructure replacement • Westinghouse Remote Terminal Unit (RTU) replacement • Spencer Gulf emergency bypass preparation • Maintain minimum levels of system strength and inertia in South Australia	These committed projects were proposed in the 2018 TAPR but are now committed to be carried out for market benefit, safety, asset condition and performance, reliability, and security purposes.
6.3	Pending projects	The following projects are now pending in the 2019 TAPR:	These projects were proposed in the 2018 TAPR but are now pending full approval to be carried out for asset condition and performance, reliability, and market benefit purposes.
7.1	Summary of planning outcomes	The information in this section has been updated since the corresponding section in the 2018 TAPR.	We have updated the information to reflect the latest results of our ongoing planning processes.

Section	Section Name	Significant changes between the 2018 and 2019 TAPR	Analysis and explanation for the significant change
7.3 to 7.13	National transmission planning to Security and compliance 0rojects	The presentation of information in this section has been simplified in the 2019 TAPR, making greater use of tables and including information presented in Appendix G of the 2018 TAPR. Project timings and costs have been updated. The expected month of completion is listed for all projects.	We have simplified the presentation of information in this section as further details are available from the accompanying data sets available from our TAPR web page. As a result of our more advanced project planning and scoping, we now have a clearer view on when projects will be delivered. We do not consider any of the changes in timing to materially affect their ability to address the need driving each project.
7.4	System security	We have planned and proposed the following projects: • Wide Area Protection Scheme • Wide Area Monitoring Scheme	These projects are planned and proposed as a result of continuing to refine the scope of the upgrade of the SIPS that was discussed in section 8.1.3 and F2 of the 2018 TAPR.
7.10	Network asset retirements and replacements	This section contains more projects than were reported in the corresponding section of the 2018 TAPR	The corresponding section in the 2018 TAPR included projects or programs for which the total cost exceeded the RIT-T threshold ($6 million). In the 2019 TAPR, projects are included if their forecast cost exceeds $2 million.
7.12	Grouped network asset retirements, de-ratings and replacements	This section contains more projects than were reported in the corresponding section of the 2018 TAPR	The corresponding section in the 2018 TAPR included projects or programs for which the total cost exceeded the RIT-T threshold ($6 million). In the 2019 TAPR, projects are included if their forecast cost exceeds $2 million.
7.13	Security and compliance projects	The corresponding section in the 2018 TAPR was Appendix F2.	The corresponding section in the 2018 TAPR included projects or programs for which the total cost exceeded the RIT-T threshold ($6 million). In the 2019 TAPR, projects are included if their forecast cost exceeds $2 million.
N/A	Fault levels and circuit breaker ratings	This appendix is not included in the 2019 TAPR	The information that was included in this appendix of the 2018 TAPR is now included in the accompanying data that is available from our TAPR web page.

Appendix B: Joint Planning

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

Historically and since market inception, ElectraNet has always worked closely with SA Power Networks on every potential and realised development to ensure optimal solutions 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 joint planning meetings
- Power System Modelling Reference Group
- ENA[58]

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:

- collaborate on development of the Integrated System Plan
- continuously improve current network planning practices
- coordinate on energy security across the NEM.

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.

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. The committee focuses on modelling techniques, technical knowledge, industry experience, and a broad spectrum of perspectives on market modelling challenges.

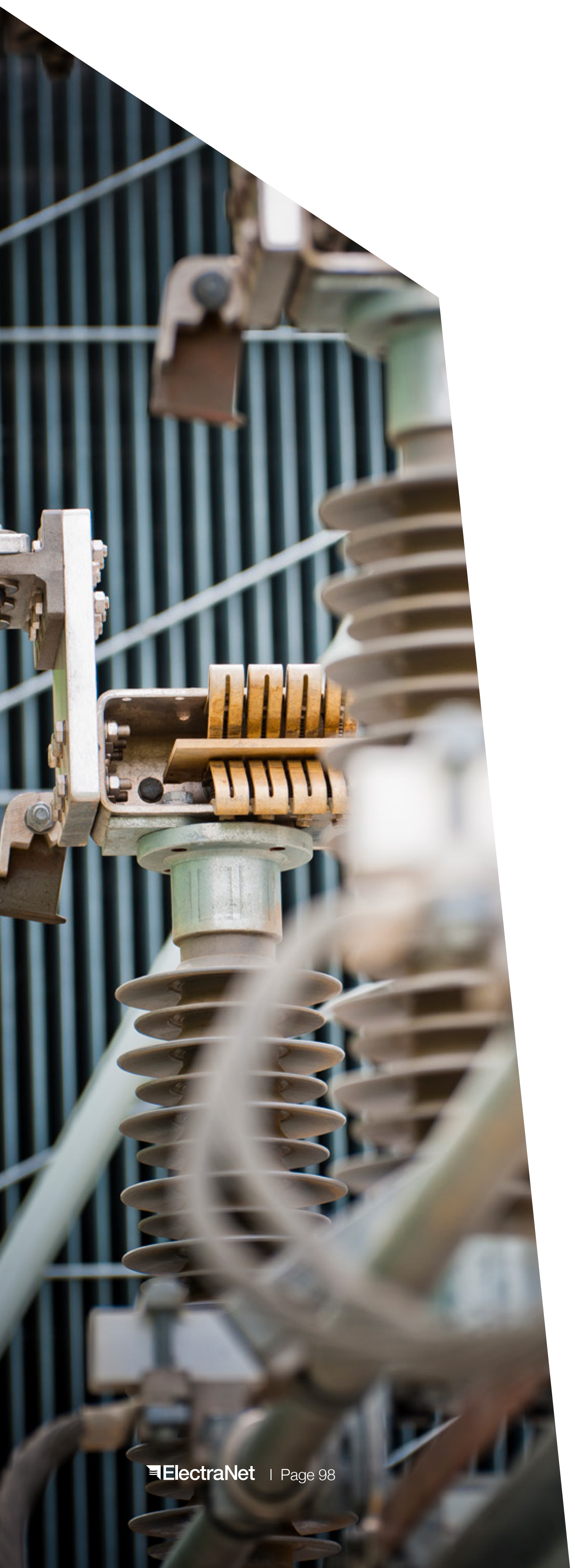
Regulatory Working Group

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.

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.

[58] See www.energynetworks.com.au



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.

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).

Power System Modelling Reference Group

The Power System Modelling Reference Group is a quarterly forum with AEMO and industry power system modelling specialists. The forum seeks to focus on power system modelling and model development to ensure an accurate power system model is maintained for power system planning and operational studies.

B2 Joint Planning Projects

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

- Integrated System Plan development (section 2.1)
- Project EnergyConnect (section 1.3.1 and 7.3).

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.[59]**

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.

[59] 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 state-level demand forecasts[60] and estimates of the Value of Customer Reliability (VCR)[61]. 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 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
- our Safety, Reliability, Maintenance and Technical Management Plan (SRMTMP), which is required by our transmission licence.

C2.1Transmission 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
- manage quality of supply (frequency, harmonics and flicker).

The transmission licence is issued by ESCOSA.[62]

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[63]
- jurisdictional standards, such as those set out under the ETC, provide for security and reliability standards which align with technical standards set out under the Rules.

In particular, the ETC contains provisions relating to:

- service standards
- interruptions
- design requirements
- technical requirements
- general requirements
- access to sites
- telecommunications access
- 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. These are summarised in the following table.[64]

ESCOSA is undertook a targeted review of the ETC in 2018, 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 was completed in August 2018.[65]

The ETC was most recently amended in March 2019, to apply a Category 1 reliability standard to the new Mount Gunson South exit point, consistent with the standard that the ETC applies to other single-customer transmission exit points.[66]

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.

[60] AEMO, 2018 ESOO – February 2019 Update, available at www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Demand-Forecasts.

[61] 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.

[62] 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

[63] National Electricity Rules, Schedule 5.1

[64] The full version of the ETC version TC/09.2 is available at escosa.sa.gov.au

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

[66] Submissions and the final decision are available at escosa.sa.gov.au/projects-and-publications/projects/electricity/electricity-transmission-code-variation-2019

<table>
<tr><th>Load category</th><th>1</th><th>2</th><th>3</th><th>4</th><th>5</th></tr>
<tr><td>Generally applies to…</td><td>Small loads, country radials, direct connect customers</td><td>Significant country radials</td><td>Medium-sized loads with non-firm backup</td><td>Medium-sized loads and large loads</td><td>Adelaide central business district (CBD)</td></tr>
<tr><td colspan="6">Transmission line capacity</td></tr>
<tr><td>'N' capacity</td><td colspan="5">100% of agreed maximum demand (AMD)</td></tr>
<tr><td>'N-1' capacity</td><td colspan="2">Nil</td><td colspan="3">100% of AMD</td></tr>
<tr><td>'N-1' continuous capability</td><td colspan="3">Nil</td><td colspan="2">100% of AMD for loss of single transmission line or network support arrangement</td></tr>
<tr><td>Restoration time to 'N' standard after outage (as soon as practicable – best endeavours*)</td><td colspan="2">2 days</td><td>1 hour</td><td>12 hours (or 4 hours if grouped with category 5 connection point)</td><td>4 hours for 176 MW</td></tr>
<tr><td>Restoration time to 'N-1' standard after outage</td><td colspan="2">N/A</td><td colspan="3">As soon as practicable – best endeavours</td></tr>
<tr><td colspan="6">Transformer capacity</td></tr>
<tr><td>'N' capacity</td><td colspan="5">100% of AMD</td></tr>
<tr><td>'N-1' capacity</td><td>Nil</td><td colspan="4">100% of AMD</td></tr>
<tr><td>'N-1' continuous capability</td><td>None stated</td><td>100% of AMD for loss of single transformer or network support arrangement</td><td>Nil</td><td colspan="2">100% of AMD for loss of single transformer or network support arrangement</td></tr>
<tr><td>Restoration time to 'N' standard after outage (as soon as practicable – best endeavours*)</td><td colspan="2">8 days</td><td>1 hour</td><td>12 hours (or 4 hours if grouped with category 5 connection point)</td><td>4 hours for 176 MW</td></tr>
<tr><td>Restoration time to 'N-1' standard after outage</td><td>N/A</td><td colspan="4">As soon as practicable – best endeavours</td></tr>
<tr><td>Allowed period to comply with required contingency standard following a change in forecast AMD that causes the specific reliability standard to be breached</td><td>N/A</td><td colspan="4">12 months</td></tr>
</table>

* 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

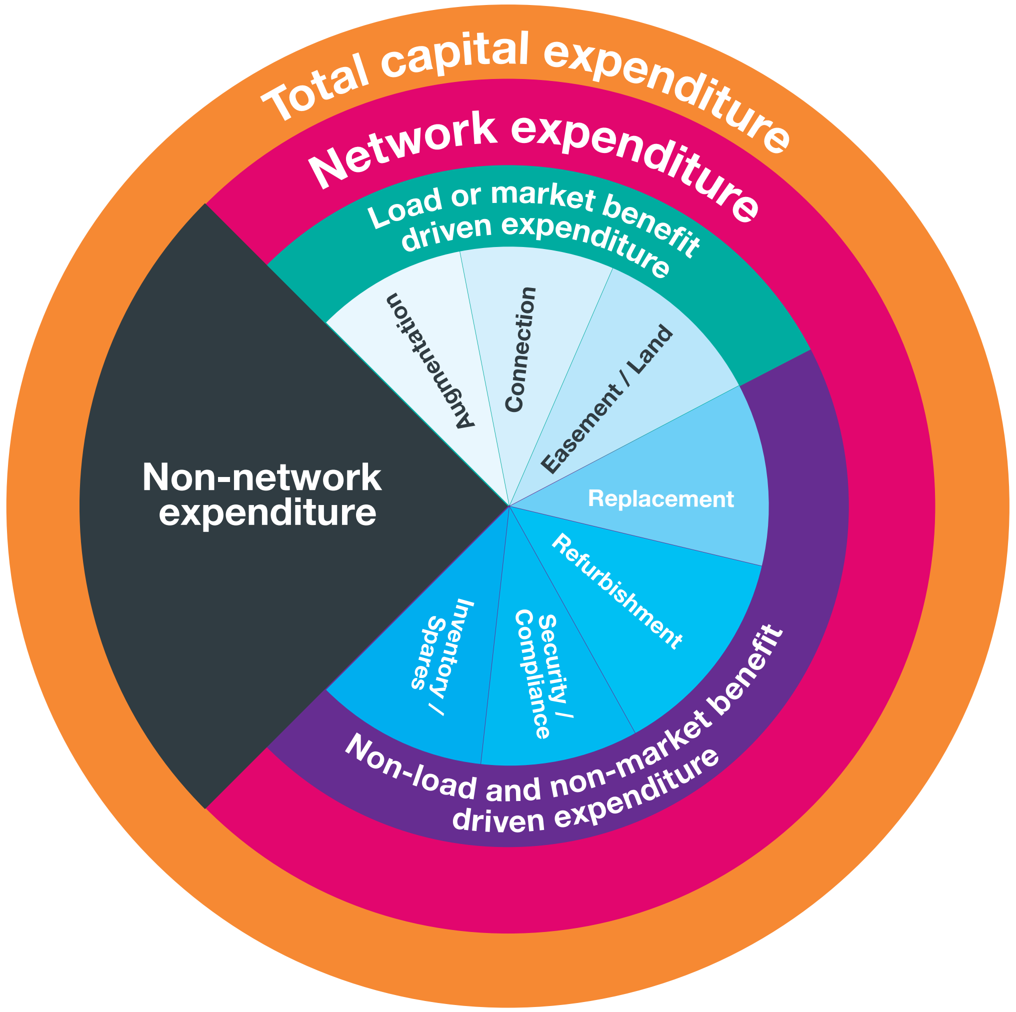
In accordance with clause 7 of our transmission licence, we are required to:

- 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 C2.1 and C2.1, 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 inner core of the above figure. For each category, we also identify the AER's reporting category as indicated in their TAPR Guideline.[67]

Expenditure Category	Definition	Service Category	AER's TAPR reporting category
	Network – Load or Market Benefit Driven		
Augmentation	Works to enlarge the system or to increase its capacity to transmit electricity. This includes projects to which the RIT-T applies and involves the construction of new transmission lines or substations, reinforcement or extension of the existing shared network. The projects may be driven by reliability or market benefits requirements, and are inclusive of any supporting communications infrastructure, land and IT systems.	Transmission Use of System Services (TUOS)	Capacity, reliability, market benefit, stability or reactive support
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	Capacity 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	Asset condition and performance
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 economical alternative to wholesale asset replacement.	TUOS	Asset condition and performance
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	Power quality, operational, compliance, environmental or safety

67 TAPR Guideline available from www.aer.gov.au

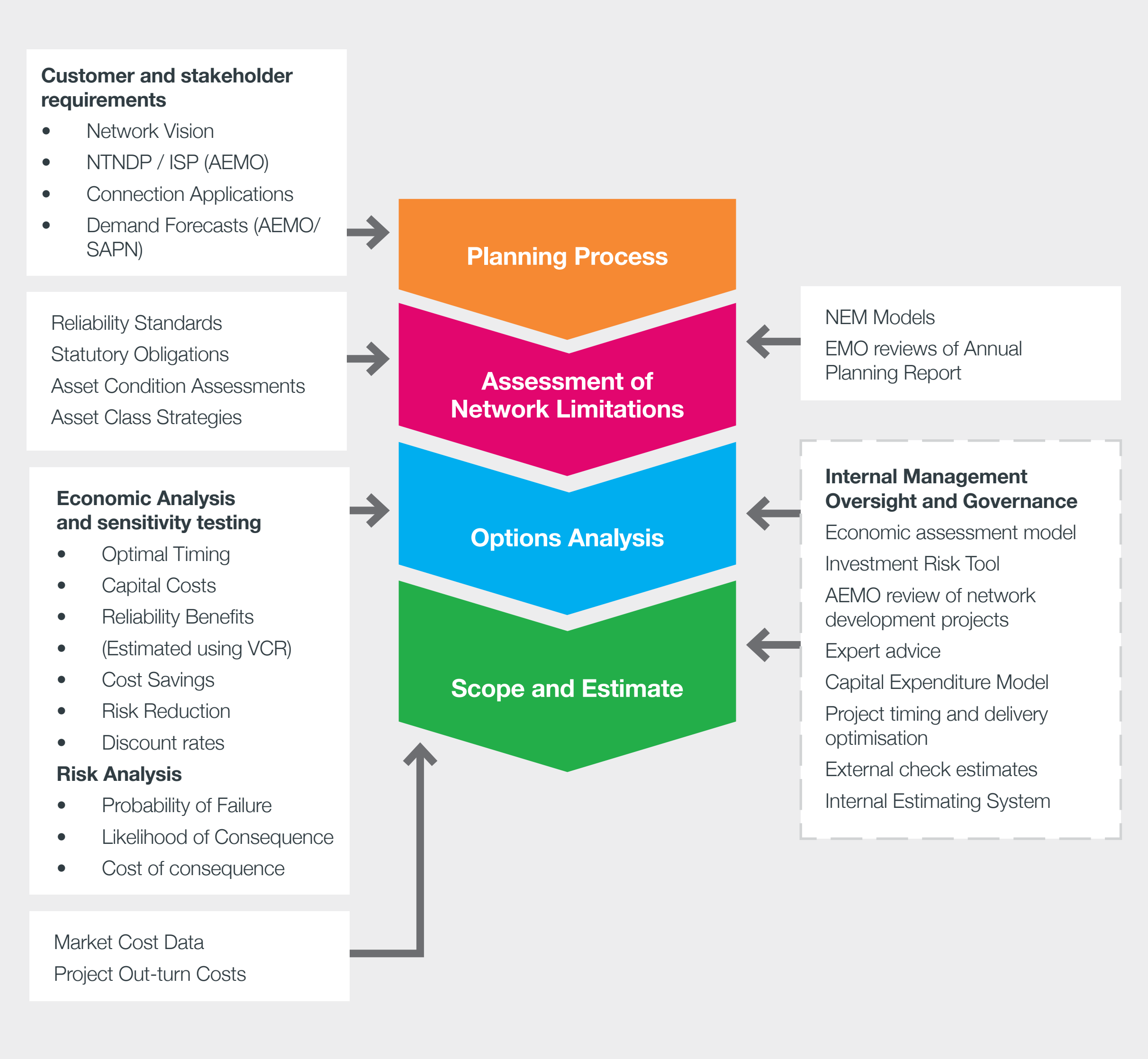
C4 Expenditure forecasting methodology

Our capital expenditure forecasting methodology is illustrated below.

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.



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.

Planning process

The planning process operates within a strategic framework informed by our Network Vision[68], and industry planning documents prepared by AEMO such as the National Transmission Network Development Plan (NTNDP) and the Integrated System Plan (ISP). The planning process also relies on inputs such as demand forecasts and connection applications.

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.

Options analysis

A range of solutions (including both network and non-network options) are considered 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.

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 out-turn 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:

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

These are discussed in turn below.

Demand forecasts

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

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

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.

Planning and design standards

Our planning standards are derived from the Rules and the ETC, and are presented in more detail in section C1. 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.

Network modelling

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.

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[69]
- 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
- 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.

[69] 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

Non-network alternatives

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

Risk assessments

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

This risk analysis considers:

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

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

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

Project cost estimation

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

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:

consultation@electranet.com.au

Appendix D: Compliance Checklist

This section sets out a compliance checklist which demonstrates the compliance of ElectraNet's 2019 Transmission Annual Planning Report with the requirements of clause 5.12.2(c) of version 122 of the Rules (the latest version at time of writing).

Summary of requirements	Section
The Transmission Annual Planning Report must be consistent with the TAPR Guidelines[70] 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; (3) 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 our Transmission Annual Planning Report web page[71]
(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: (3) a description of the network asset, including location; (3) 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; (3) 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 and our Transmission Annual Planning Report web page[70]

[70] The AER published the TAPR Guideline in December 2018.
[71] Our Transmission Annual Planning Report web page is available at electranet.com.au/what-we-do/network/regulated-network-reports-and-studies

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 our Transmission Annual Planning Report web page[72]
(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; (3) 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; (3) 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 and our Transmission Annual Planning Report web page[72]

[72] Our Transmission Annual Planning Report web page is available at electranet.com.au/what-we-do/network/regulated-network-reports-and-studies

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; (3) 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	Chapter 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	Section 2.3
(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

Summary of requirements	Section
(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 7.5
(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	Sections 4.5 and 7.4
(10) facilities in place under clause S5.1.10	Sections 4.5 and 7.4
(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	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: Contingent projects (2018-19 to 2022-23)

Project	Our Trigger[73]	Current status	Reference
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	The RIT-T was completed with the publication of a PACR in October 2018 In April 2019 the AER determined that the preferred solution satisfies the requirements of the RIT-T We intend to submit a contingent project application to the AER in the second half of 2019	Section 7.5
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	In February 2019 the AER determined that our economic assessment for this project is equivalent to the RIT-T and proportionate to the identified need, and that the identified solution reasonably satisfies the economic evaluation requirement In March 2019, AEMO provided technical approval for the identified solution We intend to submit a contingent project application to the AER in the second half of 2019	Section 7.4
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	The RIT-T was completed with the publication of a PACR in February 2019 One party lodged a dispute with the AER. In June 2019, the AER published its finding that ElectraNet's application of the RIT-T is in accordance with the NER specifically on the matters raised in the dispute notice The AER will now formally consider the next step in the RIT-T process, which involves a broader review of the application of the RIT-T. The AER expects to release its determination in the second half of 2019	Section 7.3
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	Not applicable	Section 7.7
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	Not applicable	Section 7.7

[73] In addition, the following two trigger conditions apply to each of the projects listed:
- Determination (if applicable) by the AER under clause 5.16.6 of the Rules (or equivalent process) 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.

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Abbreviations

AC	Alternating current
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
EFCS	Emergency Frequency Control Scheme
EFI	Electricity Forecasting Insights, published by AEMO in 2017 (updated in March 2018)
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)
MWs	Megawatt-seconds (a unit of energy, used to quantify system inertia)
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
NSCAS	Network support and control ancillary service
NTNDP	National Transmission Network Development Plan.
OFGS	Over-Frequency Generation Shedding
PACR	Project Assessment Conclusions Report (part of the RIT-T)
PADR	Project Assessment Draft Report (part of the RIT-T)
PMU	Power Monitoring Unit
POE	Probability of exceedance
PSCR	Project Specification Consultation Report (part of the RIT-T)
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
SIPS	System Integrity Protection Scheme
SVC	Static Var compensator
TNSP	Transmission Network Service Provider
UFLS	Under-frequency Load Shedding
Var	Volt-ampere reactive (a unit of reactive power: one million Var equal one Mvar)
WAMS	Wide Area Monitoring Scheme
WAPS	Wide Area Protection Scheme

Glossary

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.
Eyre Peninsula Region	One of ElectraNet's seven regional networks in South Australia.
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.
Mid North Region	One of ElectraNet's seven regional networks in South Australia.
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.
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.
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.
Thermal ratings	The maximum amount of electrical power that a piece of equipment can accommodate without overheating.
Transfer limit	The maximum amount of electrical power that a piece of equipment can accommodate without overheating.
Under frequency load shedding (UFLS)	The primary control measure used to maintain viable frequency operation following a system separation event that results in a deficit of generation compared to demand.
Upper North Region	One of ElectraNet's seven regional networks in South Australia.
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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Contact Us

If you have a question or would like to discuss any aspects of our 2019 Transmission Annual Planning Report, please contact ElectraNet.

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