TRANSMISSION ANNUAL PLANNING REPORT

2020

ElectraNet

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Contents

About ElectraNet

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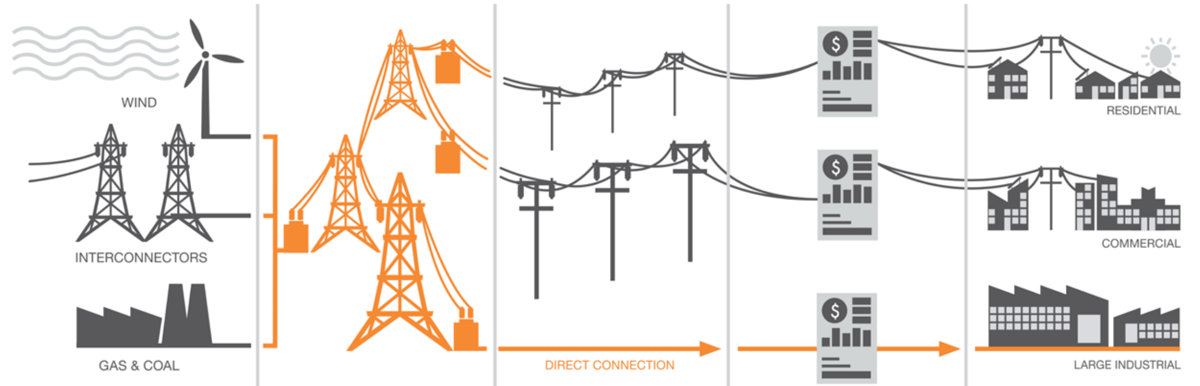
ElectraNet's transmission network powers people's lives by providing safe and future-focused energy and infrastructure solutions.

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.

Role of ElectraNet in the supply chain

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 demand for electricity transmission services, forecast under a variety of operating scenarios. ElectraNet works with SA Power Networks, who is responsible for distributing electricity throughout South Australia, to complete the review. We engage with the findings of AEMO's Integrated System Plan and consider 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 November 2020 to 31 October 2030) and identifies potential network capability limitations and possible solution options.

The report provides information on:

- trends and directions for the future of the electricity transmission system (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 remains at the forefront of the energy transformation with world-leading levels of intermittent renewable energy compared to energy demand.

System security, reliability and capacity are critically important as Australia's energy supply transitions to a lower carbon emissions future. Our annual planning process focuses on ensuring system security and reliability during this time of transition. It 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 our supporting datasets and online interactive map,[1] it provides information on the current capacity, connection opportunities, and emerging limitations of South Australia's electricity transmission network. It covers a ten-year planning period and describes the current network, 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, including supply-side developments that would be needed to meet the South Australian government's aspirational target of 100% net renewable generation in South Australia by the 2030s.

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

Subject to obtaining all necessary regulatory approvals, ElectraNet is responding to the challenges facing South Australia's changing electricity system, including:

- participating in the ongoing national conversation about energy transformation and engaging with AEMO, other TNSPs, AEMC and stakeholders in developing AEMO's 2020 ISP
- implementing Project EnergyConnect, a new interconnector between South Australia and New South Wales to deliver economic benefits to customers by better sharing of energy resources across the National Electricity Market (NEM)
- installing large synchronous condensers to raise the existing cap on the dispatch of non-synchronous generation, and assist in delivering a secure system with adequate levels of system strength, system inertia, and voltage control for South Australia's electricity transmission system
- building Eyre Peninsula Link, a new double-circuit transmission line that will improve reliability for customers on Eyre Peninsula
- investigating potential challenges and solutions to meet the future needs of South Australia's electricity customers.

Connection of renewable energy generation continued during 2019-20, and based on the continuing large number of active connection enquiries and applications, we expect that the amount of South Australian generation coming from renewable sources will continue to increase. This anticipated connection activity contrasts with the results of NEM-wide generation expansion economic modelling, such as has been undertaken by ElectraNet to support the assessment of Regulatory Investment Tests for Transmission (RIT-Ts) and by AEMO to develop the 2020 Integrated System Plan, which indicates minimal new connections in South Australia until at least the late 2020s.

If new generators do connect more quickly than currently indicated by generation expansion modelling, plans to strengthen parts of the electricity transmission system may need to be accelerated. At ElectraNet, we are developing plans to enable us to respond in a timely way if this occurs.

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 https://www.electranet.com.au/what-we-do/network/transmission-annual-planning-reports/

2020 Highlights

Project EnergyConnect

A new 330 kV interconnector from Robertstown in South Australia, to Buronga and Wagga Wagga in New South Wales.

Transfer capacity will be up to approximately 800 MW

Implementation will **increase the maximum amount that can be transferred across the Heywood interconnector** to about 750 MW

In January 2020, the AER published a RIT-T determination including that Project EnergyConnect remained the most **"credible option that maximises the net economic benefit"** in the NEM, ultimately benefitting electricity consumers.

AEMO's 2020 ISP identifies Project EnergyConnect as part of the optimal development path for the NEM.

Project EnergyConnect will support Australia's growing renewable energy industry with new wind and solar projects planned for South Australia, New South Wales and Victoria expected to benefit from the new interconnector.

The AER is currently considering two Contingent Project Applications, one for ElectraNet and one for TransGrid, to provide funding for each business to undertake their portion of the works to create Project EnergyConnect.

The AER's determinations are expected by the end of 2020.

Eyre Peninsula Link

To continue to meet reliability requirements and address asset condition on the Eyre Peninsula, we plan to establish Eyre Peninsula Link:

- **replace the existing 132 kV lines between Cultana and Yadnarie with a new double-circuit line** that is initially energised at 132 kV, with the option to be energised at 275 kV in the future
- **replace the existing 132 kV line between Yadnarie and Port Lincoln with a new double-circuit 132 kV line.**

In future, upgrading the operating voltage of the planned new Cultana to Yadnarie transmission lines from 132 kV to 275 kV would enable potential large loads to connect on the Eyre Peninsula.

In April 2019 The AER determined that the preferred option satisfies the requirements of the RIT-T.

On 28 September 2020, the AER published its determination on our Contingent Project Application to provide funding for Eyre Peninsula Link.

We plan to implement the preferred option by the end of 2022.

System security and power quality

Synchronous Condensers

We are installing synchronous condensers at Davenport and Robertstown in 2021.

These will:

- address the system strength and synchronous inertia needs that AEMO identified in 2018 for South Australia
- contribute to the ongoing provision of adequate voltage control for the South Australian transmission system, including at times of low demand
- allow the amount of non-synchronous generation that can be dispatched at times of minimum conventional generation in South Australia to be increased from 2,000 MW to about 2,500 MW.

Fast frequency response

AEMO has published the 2020 inertia requirements in South Australia, replacing the 2018 inertia requirements.

AEMO proposes for **fast frequency response (FFR) to be made available for network support** on a basis that enables AEMO to determine a reduced inertia shortfall.

We have initiated the procurement process and plan to engage soon with the market for the provision of FFR services.

Managing voltage levels at times of low system demand

We have identified an emerging need to reduce the system's reliance on dynamic reactive power devices to satisfactorily manage voltage levels at times of low system demand.

Potential solution: **install a suite of up to five 50 Mvar 275 kV reactors at various locations.**

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 (NCIPAP).

We have identified that the project we had proposed to turn in the Tailem Bend to Cherry Gardens 275 kV line at Tungkillo no longer meets the criteria for inclusion in our 2018-19 to 2022-23 NCIPAP, and we are working to identify another suitable project or projects to replace it in the 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 aware of significant interest in new generator and load developments, especially in the Mid North, Eyre Peninsula and Riverland regions.

To allow increased power transfers between these regions and South Australia's load centre in metropolitan Adelaide, **we are investigating opportunities to increase transfer capability through the Mid North to the Adelaide metropolitan area.**

We are also **investigating ways to further increase the transfer capability between the South East region and the Adelaide metropolitan area**, to address potential future interest in the South East.

We have extended 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.

Network asset retirements & 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.

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 Risk Review.

AEMO's July 2020 Final Power System Frequency Risk Review – Stage 1 report identified that a high level of distributed energy resources in the system may result in inadequate under frequency load shedding response being available to arrest frequency declines following a separation event.

- A Protected Event is proposed to manage this challenge. AEMO has also identified that imports on the Heywood interconnector need to be limited in some periods to address the challenge of losing distributed energy resources in response to credible contingency events
- A preliminary constraint has been implemented by AEMO, and ElectraNet is completing analysis to provide refined network limit advice that will enable the preliminary constraint to be refined
- Control schemes are potential solutions to manage these challenges, to reduce the need to apply constraints.

With the rapid evolution of the power system, we expect a growing need for emergency control schemes to manage both credible and non-credible system events.

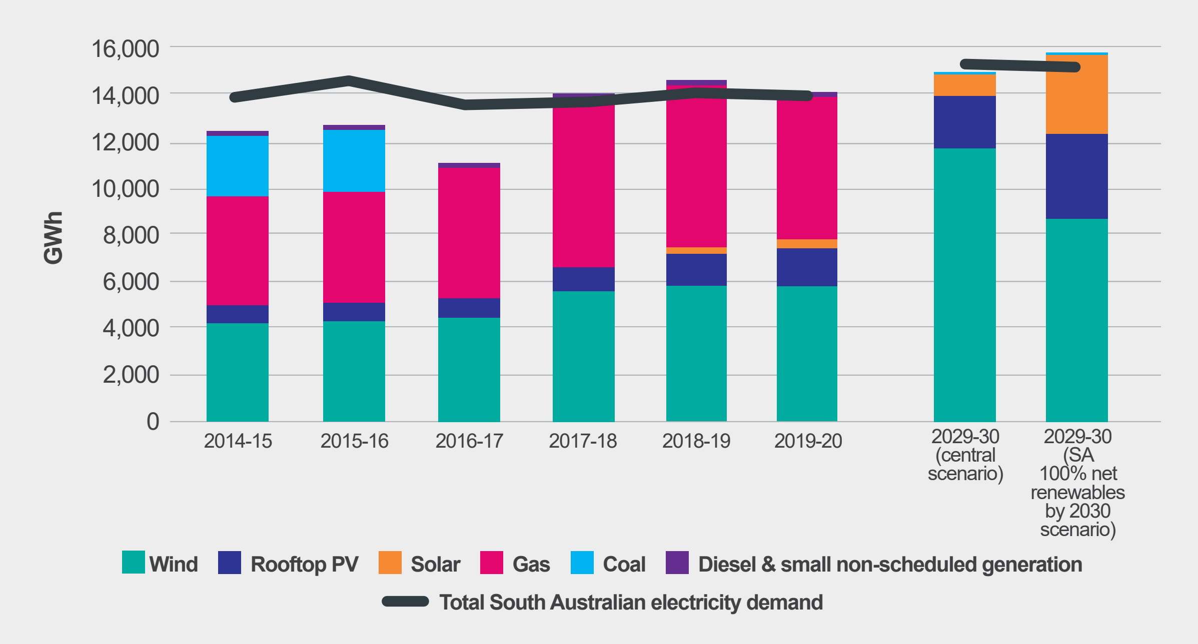
1. The future is coming

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 is forecast to continue to grow (Figure 1.1), with energy from renewable sources estimated to have represented 57% of South Australian electricity demand and exceed 56% of all South Australian generation in 2019-20.

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



Source: Historical figures up to and including 2018-19 are drawn from the Australian Energy Market Operator's (AEMO's) 2019 South Australian Electricity Report, with the remaining data representing ElectraNet estimates.

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. Since 2017-18, South Australian electricity exports have slightly exceeded imports.

Connection of renewable energy generation continued during 2019-20 and based on the number of active connection enquiries and applications, we expect that generation from South Australian renewable sources is likely to continue to increase.

These anticipated new connections contrast with the results of NEM-wide modelling, such as has been undertaken by ElectraNet to support the assessment of RIT-Ts and by AEMO to develop the 2020 Integrated System Plan, which in most scenarios indicates minimal new connections in South Australia until at least the late 2020s.

If new generators do connect earlier than currently indicated by generation expansion modelling, plans to strengthen parts of the electricity transmission system may need to be accelerated. This level of interest seems to align with, or may even exceed, the 2020 Integrated System Plan's (ISP's) Step Change scenario. At ElectraNet, we are developing plans to enable us to respond in a timely way if this occurs.

In the past, conventional generators contributed significantly to the appropriate management of key technical parameters in the AC power system (Table 1.1). 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.

Table 1.1: AC power system key technical parameters significantly influenced by synchronous generators

Technical parameter	Why is it important?	Sources of control (other than synchronous generators)
Inertia	• Systems with a higher inertia will avoid rapid and uncontrollable changes in frequency if a large amount of load or supply was unexpectedly lost • In systems with low inertia, there is a risk that wider frequency deviations following perturbations can lead to widespread loss of supply and load	• Synchronous condensers • Synthetic sources of Fast Frequency Response (FFR) e.g. batteries, VSC HVDC links, solar and wind farm fast runback, fast load response
System strength	Sufficient levels of system strength help to: • limit fluctuations in voltages that occur during and after system disturbances, improving the ability of all forms of generators and loads to remain stably connected during and after a disturbance • reduce unwanted interactions between inverter-based generator installations in weak power systems with low system strength • support reliable operation of protection systems, as protection schemes may not operate correctly due to low system strength	• Synchronous condensers • VSC HVDC/Batteries (limited contribution) • Network strengthening
Frequency control	• Frequency control helps to keep the system's frequency within the technical limits. Failure to do so can cause damage to plant and equipment, while also increasing the risk of loss of supply and load during larger frequency deviations • Frequency control services are provided over various timeframes to ensure that the frequency remains within appropriate limits	• Batteries and other storage • HVDC links • Four-quadrant inverter connected generation • Under frequency load shedding (arrest rapid frequency decay) • Over frequency generator shedding (arrest rapid frequency rise) • Demand response
Voltage control	• Voltage control is required to coordinate and ensure that voltage levels across the system remain within appropriate limits for system, customer and generator equipment to operate correctly and not experience damage due to voltage levels that exceed their withstand capability or trip due to low voltage excursions • With the proliferation of rooftop solar PV installations, one of the challenges is their sensitivity to voltage changes which is becoming an important issue in systems such as South Australia with large penetration of distributed energy resources in proportion to the system size	• Synchronous condensers • SVCs and STATCOMs • Capacitors and reactors • Generators • Batteries and storage • Under voltage load shedding (arrest rapid voltage decay)

Our annual planning process focuses on ensuring system security and reliability of supply. Based on projections of future changes in electricity supply and demand, we seek to forecast limitations and opportunities and ensure plans are in place to address them in a timely and efficient manner.

1.2 Future directions and key priorities

We continue to monitor emerging industry trends and technological developments and undertake scenario-based modelling, network planning and 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.

Our Network Vision provides directions and key priorities to guide the practical ways we plan for the future of the network (Figure 1.2).[2]

Figure 1.2: Our Network Vision - directions and key priorities

We are commencing a refresh of our Network Vision, which was last reviewed in 2015 and 2016. This will be done in consultation with customer representatives and stakeholders.

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

Table 1.2 outlines key trends and issues that we anticipate will feature in our Network Vision consultation.

Table 1.2: Looking to the future: anticipated key trends and issues

Category	Key trends and issues
Investment and technology drivers	Distributed energy resources Battery energy storage systems – large and small-scale Further uptake of renewable, intermittent generation (e.g. wind and solar) Reduced dispatch of conventional plant and potential retirements Electric vehicles
Climate drivers	Increased incidence of extreme weather • Heatwaves • Storm events Increased incidence of non-credible contingencies Impact on asset ratings including generator derating
System security requirements	Increasing complexity in operating the Power System System security impacts of embedded PV disconnection during disturbances System security challenges of low system strength on fault ride through capability of renewable generation Need for dynamic voltage management across the system Inadequate net load available for Under Frequency Load Shedding (UFLS) schemes Frequency control Increased need for high resolution wide area monitoring of the system Increased need for Protected Event declaration and development of wide area Special Protection Schemes

1.3 How are our directions and key priorities helping us prepare for the future?

Driven by our strategic themes, directions and priorities, we are pursuing strategic initiatives and investigations to support South Australia's energy transformation (Table 1.3).

Table 1.3: How our key directions and priorities drive our planning

Theme	Priorities	Strategic initiatives and investigations
The ongoing uptake of distributed energy resources by customers is changing the role of the grid	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	• Continue to liaise with AEMO and SA Power Networks to forecast evolving trends in customer demand and technologies (e.g. rooftop solar PV, household batteries, electric vehicles) [3] • Explore the challenges of the increasing penetration of distributed energy resources, including intermittency/rapid changes, controllability, stable operation during system events and overall system stability
	Plan for emerging technologies in order to maintain a safe, reliable and secure supply under reasonably foreseeable demand and supply conditions	• Explore generation mix, network developments and technologies to support 100% renewables in SA • Consider a range of scenarios in our planning • Develop learnings from the early 2020 extended South Australian islanding event • Develop plans to agilely and efficiently accommodate anticipated supply-side changes
The generation mix is changing, creating new challenges for the secure and reliable operation of the grid	Develop efficient solutions to maintain a secure and reliable system with less conventional generation	• Install synchronous condensers in 2020 and 2021 • Investigate whether forecast potential changes in generator dispatch patterns may give rise to a need for further system strength or frequency control needs
	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	• Pursue Project EnergyConnect • Engage with and support AEMO's ongoing development of the ISP • Examine future opportunities to firm up and enhance interconnector capability, such as stringing the vacant Tungkillo to Tailem Bend 275 kV circuit, implementing a Wide Area Protection Scheme, or identifying and implementing other solutions such as an appropriately configured battery energy storage system
New technologies are changing the way some network services can be delivered	Continue to investigate the application of grid scale energy storage and gain experience in the deployment, operation, and emerging capabilities of this technology	• Ongoing knowledge sharing from Dalrymple battery operation • Consider opportunities for future batteries to enhance the Wide Area Protection Scheme (WAPS) • Consider application of batteries to provide FFR • Consider opportunities for future batteries to operate as virtual synchronous generators and provide network support to enhance network transfer capacity
	Actively pursue cost effective demand side solutions and innovations in the deployment of non-network solutions and new technology	• Develop a new special protection scheme for system security when Project EnergyConnect is built • Review and suitably modify the existing system integrity protection scheme to support reliable and secure operation of Project EnergyConnect
	Adopt best practice data analytics to improve decision making in asset management and network operation	• Enhance high resolution time synchronized wide area system monitoring by pursuing a rollout of the Wide Area Monitoring Scheme (WAMS) • Obtain ISO55001 accreditation

[3] See chapter 3 of this report for more information about our forecasts of future electricity demand.

1.3.1 Responding to the COVID-19 pandemic

ElectraNet is sensitive to the many pressures that the COVID-19 pandemic continues to have on households and businesses. We are committed to developing the most efficient plans we can, to deliver the lowest achievable electricity costs for all customers in South Australia.

To this end, we continue to explore cost-effective ways to further unlock the capacity of South Australia to host new connections of low cost renewable generation and increase electrical interconnection with other states, in ways that deliver the greatest benefit to electricity market participants. This includes large generators to residential customers.

We explore the potential impacts of the COVID-19 pandemic on short and long-term electricity market trends in chapter 3.

1.3.2 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
- Enhancing security of electricity supply in South Australia.

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

In January 2020, the AER published a RIT-T determination that Project EnergyConnect remained the most "credible option that maximises the net economic benefit" in the NEM, ultimately benefitting electricity consumers. AEMO's 2020 ISP identifies Project EnergyConnect as part of the optimal development path for the NEM.

Project EnergyConnect will support Australia's growing renewable energy industry, with many new wind and solar projects planned for South Australia, New South Wales and Victoria expected to benefit from the new transmission line.

The AER is currently considering two Contingent Project Applications, one for ElectraNet and one for TransGrid, to provide funding for each business to undertake their portion of the works to create Project EnergyConnect. The AER is expected to release its determinations by the end of 2020.

1.3.3 Planning to efficiently accommodate potential supply-side changes

Based on projections in AEMO's 2020 ISP, significant investment in renewable generation within South Australia is expected in the 2030s.

Many dispatchable conventional generators have expected withdrawal dates in the mid-2030. Owners of some generation units such as at Torrens Island A and New Osborne have indicated that generator withdrawal will occur in the early 2020s.

We are investigating ways to unlock the network capacity that will be needed to facilitate the connection of the new renewable generation and the retirement of dispatchable conventional generation, and have developed high level scopes for projects that would improve transfer capacity through the Mid North, Eastern Hills and South East regions.

Based on the number of active enquiries and applications, we expect that the amount of South Australian generation coming from renewable sources is likely to continue to increase throughout the 2020s. These anticipated connections contrast with the results of NEM-wide generation expansion economic modelling which indicates minimal new connections in South Australia until at least the late 2020s and may even exceed the level of interest indicated by AEMO's 2020 ISP Step Change scenario.

If new generators do connect more quickly than currently indicated by generation expansion modelling, plans to strengthen parts of the electricity transmission system may need to be accelerated.

We are working on plans that will enable us to respond in a timely way if the projected new developments occur earlier than currently forecast.

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1.3.4 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.

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.

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

We are now installing high-inertia synchronous condensers at Davenport and Robertstown in a staged approach to address the AEMO declared system strength and synchronous inertia requirements. The first two condensers, at Davenport, are currently being commissioned. Installation and commissioning of the next two synchronous condensers, at Robertstown, is planned for early 2021.

AEMO has published the 2020 inertia requirements for South Australia, replacing the 2018 inertia requirements. AEMO has determined the secure operating level of inertia for South Australia proposing FFR to be made available for network support on a basis that enables AEMO to determine a reduced inertia shortfall. We have initiated the procurement process and plan to engage soon with the market for the provision of FFR services. Interested parties are encouraged to contact consultation@electranet.com.au.

We are also investigating whether forecast potential changes in generator dispatch patterns after Project EnergyConnect becomes commissioned may give rise to a need for further system strength needs in the mid-2020s.

1.3.5 Challenges of increasing DER penetration of distributed energy resources

For many years, minimum demands on South Australia's electricity transmission network typically occurred at about 4 am during periods of mild weather, such as can occur during April or spring. More recently, the increasing penetration of rooftop solar PV has seen even lower demand levels recorded in the middle of the day, 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. When these conditions coincide with periods of low wind, wind farms are also limited in their ability to contribute reactive power to enable satisfactory voltage control of the system.

We have been working with SA Power Networks to jointly analyse the challenges presented by a declining minimum demand, including the impact on system voltage levels. Studies and observations have shown that high voltage levels across the system can occur at such times of extremely low demand.

Our studies have found that investment in a number of 275 kV switched reactors will be required as minimum demand levels continue to fall, 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. Investment in the proposed 275 kV switched reactors will also ensure that dynamic control capability on equipment such as SVCs and synchronous condensers will be preserved, to maximise the system's capability to ride through unforeseen severe disturbances. Refer to section 7.4 for more detail of the proposed project.

In May, AEMO released a report outlining actions required to ensure the ongoing stability of the South Australian electricity system at high penetration levels of distributed energy resources.[4] We are working with AEMO to update transfer limits in line with the findings of the report.

1.3.6 Potential impacts of climate change

Climate change has the potential to impact the secure operation of electricity systems the world over, and South Australia is no exception.

We are beginning to evaluate the potential risks that climate change could present to the South Australian electricity system. This includes our engagement with the Electricity Sector Climate Information project which is designed to improve the reliability and resilience of the National Electricity Market to the risks from climate change and extreme weather. [5]

Potential risks to the South Australian electricity network include:

- Impacts on key sites or electricity corridors caused by an increased risk of bushfires, or coastal inundation
- Higher wind speeds and more extreme storm events could make contingencies and combinations of contingencies that are currently considered non-credible become more likely.

Increased maximum temperatures could de-rate generators and transmission assets at times of extreme heat, impacting on supply sufficiency and network thermal capacity at times of peak demand.

4 Minimal operation demand thresholds in South Australia, published May 2020. Available at https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/sa_advisory/2020/ minimum-operational-demand-thresholds-in-south-australia-review.pdf?la=en.

5 The Electricity Sector Climate Information project is funded by the Australian Government through the Department of Industry, Science, Energy and Resources and is being undertaken by CSIRO and the Bureau of Meteorology in collaboration with AEMO. For more information, see https://www.climatechangeinaustralia.gov.au/en/climate-projections/future-climate/esci/.

2. National transmission planning

2.1 Integrated System Plan

ElectraNet has worked closely with AEMO to support the development of the 2020 ISP.

The 2020 ISP has been developed to be an actionable roadmap for the NEM to optimise consumer benefits through a transition period of great complexity and uncertainty, with clear observations and recommendations for the short to medium-term development of the transmission network which form the basis of an over-arching long-term strategy.

The ISP identifies an optimal development path which comprises projects to augment the transmission grid as well as other ISP development opportunities. In determining the optimal development path, AEMO has sought to trade-off upfront costs against the possibility of greater future costs, in line with consumer appetite for risk.

The ISP has identified four categories of transmission projects – committed, actionable, actionable with decision rules, and future ISP projects. They have been selected from a wide range of options to achieve power system needs through a complex, energy sector transition.

Further major network investments beyond what is currently committed will be needed by 2040, to strengthen the NEM and enable delivery of the identified generation resources. Six major transmission projects have been selected from a large range of credible options and combinations to determine the mix of investments that optimises the net market benefit.

AEMO's economic and power system analysis identified the least-cost development paths for five core scenarios (Table 2.1). The least-cost development paths for each of the five core scenarios project that the four low-regret projects already being progressed by Transmission Network Service Providers (TNSPs) – VNI Minor, Project EnergyConnect, HumeLink and Central-West Orana REZ Transmission Link – will be completed by 2025-26 at the latest.

Table 2.1: Ideal timing for key national transmission investments under the five core scenarios examined in the ISP, based on the least-cost development path

Network project / Scenario/ sensitivity	VNI Minor	Central West Orana	Project EnergyConnect	HumeLink	QNI Medium	QNI Large	VNI West	Marinus Link 1st Cable	Marinus Link 2nd Cable
Central	2022-23	2024-25	2024-25	2025-26	2032-33	2035-36	2035-36	2036-37	Not needed
Slow Change[6]			No further interconnections needed as this scenario delays the retirement of coal-fired generation and the need for replacement variable renewable energy						
Fast Change			2024-25	2025-26	2032-33	2035-36	2035-36	2031-32	Not needed
Step Change								2028-29	2031-32
High DER				Not needed[7]			Not needed	2031-32	2035-36

Source: AEMO's 2020 ISP, Table 6

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

2.1.1 System strength

The 2020 ISP includes the installation of four high-inertia synchronous condensers, previously recommended in the 2018 ISP, as a committed project.

We are on track to complete the installation of these synchronous condensers at Davenport and Robertstown during 2021. The impact that the synchronous condensers will have on the amount of non-synchronous generation that can be dispatched in South Australia while meeting system strength limits is described in section 5.2.2.

2.1.2 Project EnergyConnect

The network options AEMO has assessed as having the most merit include Project EnergyConnect, which is expected to deliver fuel cost savings and unlock already-stranded renewable investments. Recommended in the 2018 ISP, the 2020 ISP confirms Project EnergyConnect as a low regret investment.

Section A7.6 in Appendix 7 of the ISP is dedicated to a discussion about the South Australian system in transition. It articulates why Project EnergyConnect will make an important contribution to maintaining system security in South Australia.

AEMO identifies that new system security risks are emerging in in South Australia which are expected to grow over time. The risks are being driven by the changes to power system characteristics resulting primarily from the increasing uptake of distributed PV generation. To secure South Australia's power system in the absence of Project EnergyConnect, AEMO expects:

- a need for new constraints on Heywood interconnector flows to provide headroom to manage increasing contingency sizes relating to coincident tripping of distributed energy resources
- a need to contract inverter-based resources such as batteries or solar farms to provide a total of up to 400 MW of FFR for online inertia and conventional frequency control services by 2025.

These measures would be needed to enable AEMO to maintain power system security, avoid load shedding for credible contingencies and reduce the likelihood of a system black event.

In contrast, the delivery of Project EnergyConnect would:

- deliver a wide range of market benefits (captured by ISP modelling) that outweigh its cost
- significantly reduce the likelihood of operating South Australia as an electrical island, and therefore mitigate the need to procure FFR to manage islanded operation
- resolve the need to maintain headroom on the Heywood interconnector to manage credible contingencies in South Australia
- reduce the likelihood of operating in conditions where a separation is credible and therefore reduce the impact of limits that manage those conditions.

The 2020 ISP identifies that Project EnergyConnect will support development of the following Renewable Energy Zones:

- South West New South Wales (New South Wales)
- Murray River (Victoria)
- Riverland (South Australia).[8]

Subject to obtaining all necessary approvals, Project EnergyConnect is planned to be energised by the end of 2023, or sooner if possible, followed by inter-network testing.

[6] While HumeLink and Project EnergyConnect are not part of the least-cost development path under the Slow Change scenario under current cost estimates, they are low-regret investments given the relatively low likelihood of this scenario and are therefore included in all candidate development paths.

[7] While HumeLink is not part of the least-cost development path under the High DER scenario under current cost estimates, the majority of the ISP analysis was performed based on a lower cost estimate that resulted in HumeLink still being part of the least cost development path for this scenario. Therefore, any reference to the High DER least cost development path in the remainder of the 2020 ISP report includes HumeLink.

[8] AEMO's Final 2020 Integrated System Plan, page 17. Available at https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2020-integrated-system-plan-isp

2.1.3 Network expansion to release South East SA REZ capacity

The 2020 ISP forecasts that network expansion to release REZ capacity in the South East of South Australia will be needed in the late 2030s, or possibly as early as 2030-31 if the Step Change scenario eventuates.[9]

This network expansion would facilitate the connection of 400 MW to 600 MW of generation within this large REZ, such as wind generation near Mount Gambier or solar generation near Tailem Bend. The proposed scope is to string the vacant Tailem Bend to Tungkillo 275 kV circuit and if necessary, install additional dynamic reactive support to enable increased transfers between the South East of South Australia and the Adelaide metropolitan load centre.

The network expansion would also firm up transfer capacity between Heywood Interconnector and the Adelaide metropolitan load centre. The transfer capacity between Heywood Interconnector and the Adelaide metropolitan load centre could otherwise reduce due to the impact of declining average demand in the Eastern Hills region due to increasing local penetration of distribution-connected solar farms and rooftop solar PV.

Delivery of this network expansion as early as the mid-2020s may be optimal if new generators in the South East or in the Eastern Hills connect earlier than forecast in the 2020 ISP, or if the network expansion can be shown to deliver net market benefits.

High level details of this forecast project are provided in section 7.5 and Table 7.5.

2.1.4 South Australian Renewable Energy Zone candidates

The 2020 ISP forecasts the need to alleviate constraints between Davenport and Adelaide and between Davenport and Robertstown in 2034-35 or 2035-36.[10] This would unlock increased capacity to support about 1000 MW of additional hosting capacity for additional wind farms, solar farms and storage north of Adelaide in the Yorke Peninsula, Riverland, Mid North SA, Northern SA and Roxby Downs REZs by increasing transfer capacity between the northern part of the South Australian system and the Adelaide metropolitan load centre.

The network expansion would also firm up transfer capacity between Project EnergyConnect and the Adelaide metropolitan load centre.

We are investigating the benefits of implementing a series of projects to deliver the proposed transfer capacity increase in stages:

- EC.15209 Second Templers West transformer
- EC.15205 Increase capacity of the Robertstown to Adelaide transmission corridor
- EC.15153 Increase capacity of the Davenport to Adelaide transmission corridor.

See section 7.5 for more detail about each of these potential projects.

Delivery of some stages as early as the mid-2020s may be optimal if new generators or storage facilities north of Adelaide connect earlier than forecast in the 2020 ISP, and if the network expansion can be shown to deliver net market benefits.

High level details of these forecast staged projects are provided in section 7.5 and Table 7.5.

2.1.5 Overview of South Australian candidate Renewable Energy Zones

The 2020 ISP identifies nine candidate Renewable Energy Zones in South Australia (Figure 2.1). We have identified potential network investments to release capacity in each of the candidate REZs (Table 2.2).

Chapter 7 provides more detail about each of the numbered projects such as high-level scope, cost and potential timing.

[9] AEMO's Final 2020 Integrated System Plan, page 91. Available at https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2020-integrated-system-plan-isp.

[10] AEMO's Final 2020 Integrated System Plan, page 91. Available at https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2020-integrated-system-plan-isp.

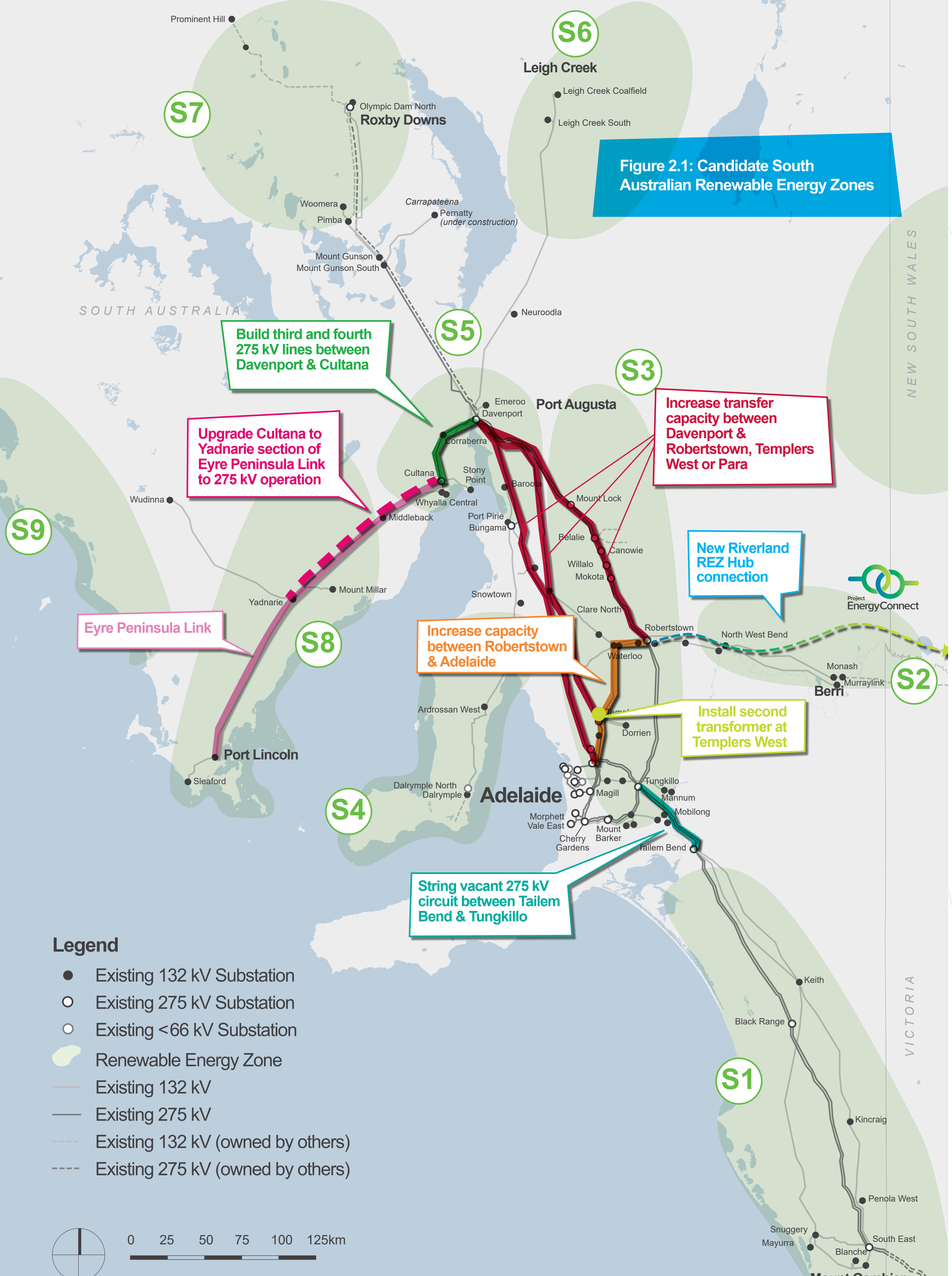


Figure 2.1: Candidate South Australian Renewable Energy Zones

Table 2.2: Potential network investments to release capacity in South Australian Renewable Energy Zones

REZ number	REZ name	Potential network investments
S1	South East SA	Increase transfer capacity between the South East SA REZ and the Adelaide metropolitan load centre by stringing the vacant 275 kV circuit between Tailem Bend and Tungkillo (EC.11011) and turning in the Tailem Bend to Cherry Gardens 275 kV line at Tungkillo (EC.11002) Consider increasing transfer capacity between the South East SA REZ and the Melbourne metropolitan load centre by increasing the capacity of the Heywood interconnector, such as by constructing new double circuit 500 kV lines between Heywood and South East
S2	Riverland	Establish Project EnergyConnect (EC.14171) Establish a new shared connection point at a suitable location along the route of Project EnergyConnect (EC.15201)
S3	Mid North SA	Increase transfer capacity between the northern parts of the South Australian electricity transmission network and the Adelaide metropolitan load centre in stages by: • Installing a second 275/132 kV transformer at Templers West and decommissioning the Templers to Waterloo 132 kV line to provide an initial increase in transfer capacity between Robertstown in the Mid North and the Adelaide metropolitan load centre (EC.15209) • Significantly increasing transfer capacity between Robertstown and Adelaide by building new double circuit 275 kV lines between Robertstown and Templers West, and rebuilding the Templers West to Para 275 kV line as a new double circuit 275 kV line (EC.15205) • Significantly increasing transfer capacity between Davenport and Adelaide by building new double circuit 275 kV lines between Davenport and Robertstown, Templers West or Para (EC.15153)
S4	Yorke Peninsula	Establish a new shared connection point that extends the 275 kV network from Blyth West to a suitable location on the Yorke Peninsula
S5	Northern SA	If new generator developments are to be west of Spencer Gulf, build additional double circuit 275 kV lines between Davenport and Cultana (EC.15261) Increase transfer capacity between the northern parts of the South Australian electricity transmission network and the Adelaide metropolitan load centre in stages, as described above for the S3 Mid North SA REZ

REZ number	REZ name	Potential network investments
S6	Leigh Creek	Establish a new shared connection point that extends the 275 kV network from Davenport to a suitable location near Leigh Creek Increase transfer capacity between the northern parts of the South Australian electricity transmission network and the Adelaide metropolitan load centre in stages, as described above for the S3 Mid North SA REZ
S7	Roxby Downs	Establish a new shared connection point that extends the 275 kV network from Mount Gunson South or Davenport to a suitable location near Roxby Downs Increase transfer capacity between the northern parts of the South Australian electricity transmission network and the Adelaide metropolitan load centre in stages, as described above for the S3 Mid North SA REZ
S8	Eastern Eyre Peninsula	Eyre Peninsula Link (EC.14172) will provide increased capacity to facilitate additional generator connections in the Eastern Eyre Peninsula REZ Increase capacity further by upgrading the operation of the lines between Cultana and Yadnarie from 132 kV to 275 kV (EC.15104) If necessary due to the combined impact of new generator connections in the Eastern Eyre Peninsula REZ, Western Eyre Peninsula REZ and Northern SA REZ west of Spencer Gulf, build additional double circuit 275 kV lines between Davenport and Cultana (EC.15261) Increase transfer capacity between the northern parts of the South Australian electricity transmission network and the Adelaide metropolitan load centre in stages, as described above for the S3 Mid North SA REZ
S9	Western Eyre Peninsula	Eyre Peninsula Link (EC.14172) will provide increased capacity to facilitate additional generator connections in the Western Eyre Peninsula REZ Increase capacity further by upgrading the operation of the lines between Cultana and Yadnarie from 132 kV to 275 kV (EC.15104) Establish a new shared connection point that extends the 132 kV or 275 kV network from Yadnarie to a new suitable location in the western Eyre Peninsula If necessary due to the combined impact of new generator connections in the Eastern Eyre Peninsula REZ, Western Eyre Peninsula REZ and Northern SA REZ west of Spencer Gulf, build additional double circuit 275 kV lines between Davenport and Cultana (EC.15261) Increase transfer capacity between the northern parts of the South Australian electricity transmission network and the Adelaide metropolitan load centre in stages, as described above for the S3 Mid North SA REZ

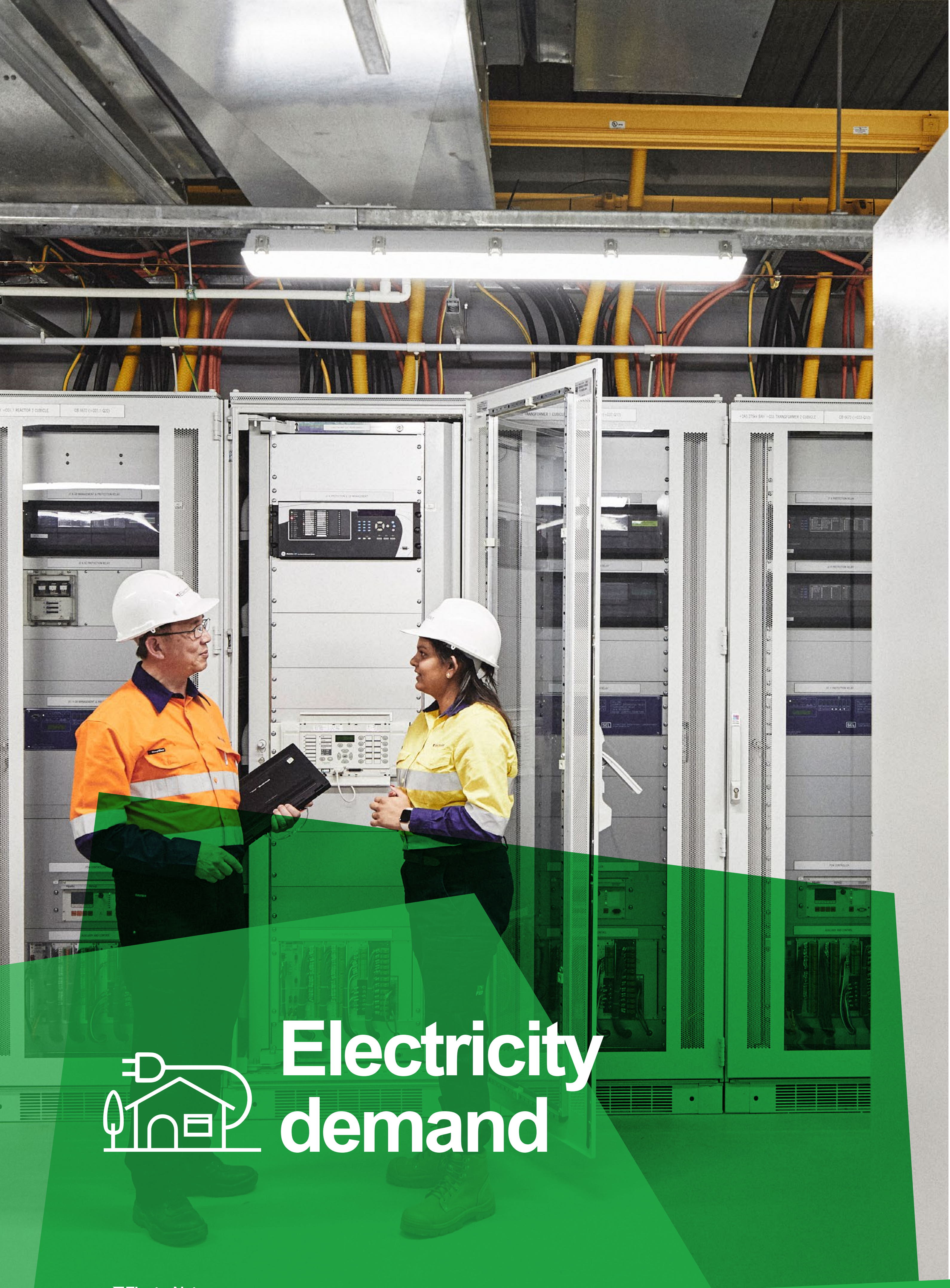
2.2 Power System Frequency Risk Review

AEMO is undertaking the Power System Frequency Risk Review (PSFRR) for 2020 and will publish reports in two stages. AEMO published a Stage 1 report in July 2020 which provides recommendations for each jurisdiction, with details planned to be determined prior to the publication of the final (Stage 2) report by the end of 2020.

2.2.1 System strength and inertia requirements

For South Australia, the Stage 1 report recommends that a Protected Event be declared to manage the risk that there may be insufficient under frequency load shedding facilities available at times of high generation output from distributed energy resources. A protected event declaration will facilitate a range of possible solutions to address the identified risks, possibly including constraints on the Heywood interconnector, or enablement of additional frequency control services. AEMO is also collaborating with ElectraNet, SA Power Networks and the South Australian Government to pursue a suite of other measures to improve UFLS response.

ElectraNet is working closely with AEMO in developing this year's PSFRR including investigation of options to manage the proposed declaration of a Protected Event. Declaration of a Protected Event could create an identified need that ElectraNet would be required to address.



3. Electricity Demand

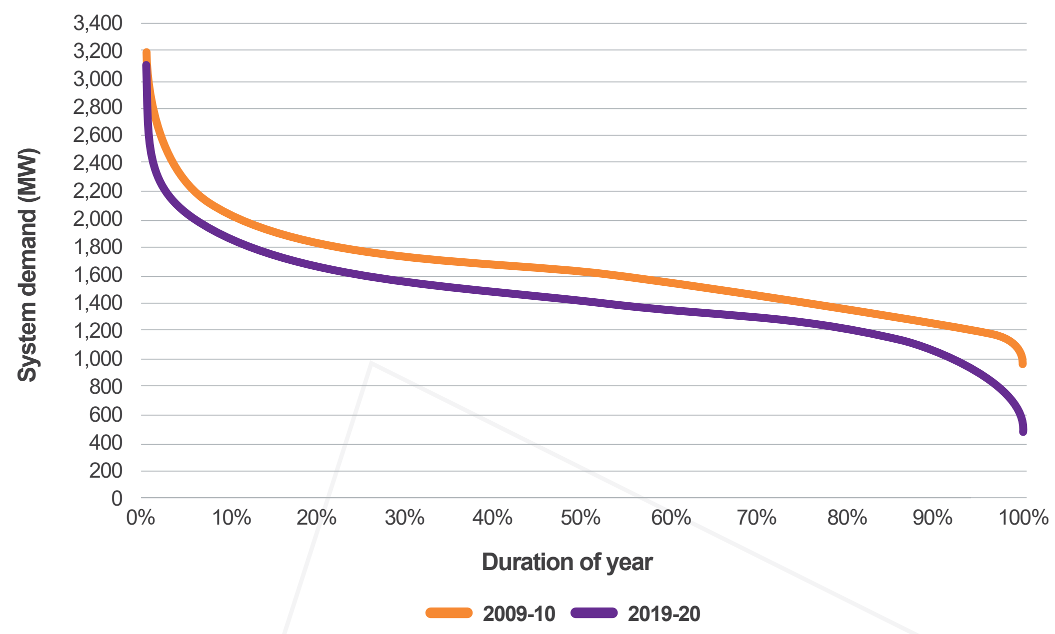
Forecasting electricity demand and network loading conditions well ahead of time is important because transmission system projects can take significant time to implement.

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 National Electricity Rules (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 and 2000 MW are most common throughout the year. The continued uptake of embedded solar PV in recent years has significantly lowered demand supplied by the transmission system during the day, especially on weekends and public holidays.

Figure 3.1: South Australian system-wide load duration curves for 2009-10 and 2019-20



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 demand levels at other times have reduced from 2009-10 to 2019-20.

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' 2019 Distribution Annual Planning Report.[11] 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 maximum demand forecasts that were provided by SA Power Networks in October 2019. We have reviewed the latest connection point maximum demand forecasts provided by SA Power Networks in October 2020 and determined that the development plans remain appropriate. Details of the latest connection point forecasts can be found on ElectraNet's Transmission Annual Planning Report webpage.[12]

In August 2020, AEMO produced and published forecasts of energy, maximum demand and minimum demand for South Australia to support the 2020 Electricity Statement of Opportunities (ESOO).[13] ElectraNet has considered those forecasts to determine future needs for improved voltage control on the 275kV main grid at times of 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. [14]

ElectraNet compares its forecasts (as published on the Transmission Annual Planning Report webpage)[15] 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 2020 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.

[11] Available from sapowernetworks.com.au/industry/annual-network-plans
[12] Accessible at electranet.com.au/what-we-do/network/regulated-network-reports-and-studies
[13] Available from aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Satement-of-Opportunities
[14] Available from aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/ Transmission-Connection-Point-Forecasting
[15] Accessible at electranet.com.au/what-we-do/network/regulated-network-reports-and-studies

3.3 2019-20 demand forecast

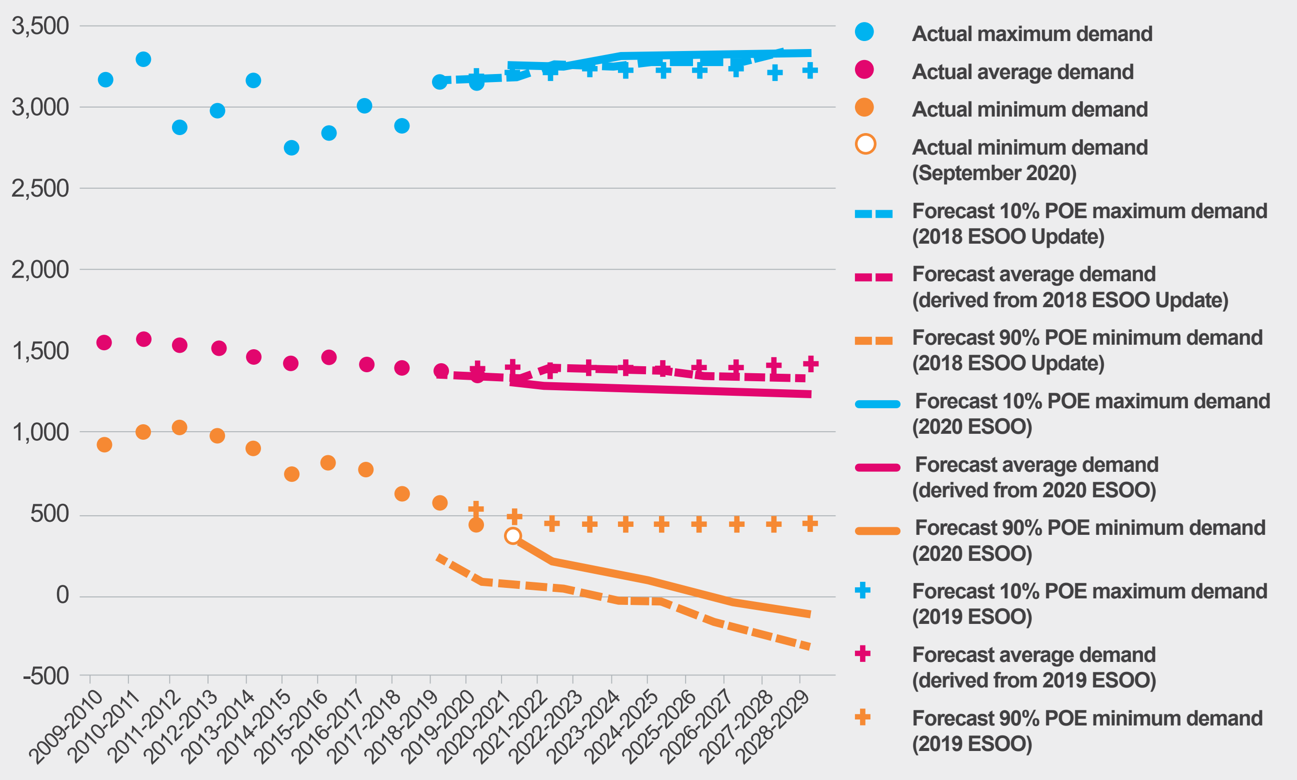
In most cases there is very little change in the projections of future demand for connection points compared to the demand forecast which was used as the basis for the plans presented in the 2019 Transmission Annual Planning Report. Our plans for individual connection points have not needed to be updated.

AEMO makes state-wide demand forecasts for South Australia available on its *Forecasting Data Portal*.[16]

The most recent update to AEMO's South Australian state-wide forecasts was published in August 2020, alongside AEMO's 2020 ESOO.

We have compared AEMO's August 2020 central forecasts for South Australian maximum and minimum demand to the February 2019 update of the 2018 ESOO forecasts that formed the basis of the plans presented in the 2019 Transmission Annual Planning Report, along with the previous 10 years and current year of actual maximum, average and minimum demands (Figure 3.2). While the forecast maximum demand remains similar, the more recent forecasts are higher for minimum demand and lower for average demand.

Figure 3.2: AEMO's 2018 ESOO (February 2019 update) neutral and 2020 ESOO central forecasts



Source: AEMO's 2018 ESOO (February 2019 Update), AEMO's 2019 ESOO, and AEMO's 2020 ESOO. Forecast average demands have been derived from AEMO's central forecast of energy consumption.

[16] Accessible at http://forecasting.aemo.com.au/

3.4 Impact of COVID-19 pandemic on forecasts

The COVID-19 pandemic continues to have a widespread and significant impact on life in Australia. Many livelihoods have been disrupted and many workers have adopted working from home for the first time.

Despite this, the impact of the pandemic on South Australian electricity demand appears to have been relatively muted. For example, AEMO's Quarterly Energy Dynamics Q2 2020 report found that South Australian electricity demand from April to June 2020 was slightly higher than during the corresponding period in 2019, which could be explained by overall cooler temperatures in this period in 2020 compared to 2019.[17]

It is possible that an increase in maximum demands in suburban areas may occur if widespread working from home arrangements continue into the summer months. This may be at least partially offset at a state level by reductions in maximum demand in the central business district if office buildings are only partially re-staffed.

The trend of increasing customer installations of rooftop PV generation so far appears to be continuing at its rapid pace, consistent with predictions from before the onset of the pandemic. This is expected to continue to drive decreasing minimum demands in South Australia, especially on weekends and public holidays with mild, sunny weather.

In the longer term, we expect the current trends of a slowly increasing maximum demand, slowly decreasing average demand and rapidly decreasing minimum demand to continue.

[17] See AEMO's Quarterly Energy Dynamics Q2 2020, pages 7 and 8, available from https://www.aemo.com.au/-/media/files/major-publications/qed/2020/qed-q2-2020.pdf?la=en&hash=D1A82334D16E915FCB1B628640A05223.

3.5 Performance of 2019 demand forecasts for summer 2019-20

3.5.1 Weather conditions over summer 2019-20

Weather conditions 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 heatwave, can drive state-wide demands to levels of more than double the average.

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

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

Heatwave events in December and January saw daytime temperatures reach the mid to high-40s, including 45.2 °C on Thursday 19 December at the Bureau's official Adelaide city site at West Terrace (Table 3.1).

Table 3.1: 2019-20 summer temperature data compared with long term trends

	December		January		February		March	
	Long-term trend	2019-20	Long-term trend	2019-20	Long-term trend	2019-20	Long-term trend	2019-20
Max temp (°C)	45.3	45.3	46.6	43.3	43.4	32.9	41.8	34.1
Date of max temp	19 Dec 2019	19 Dec 2019	24 Jan 2019	30 Jan 2020	1 Feb 1912	24 Feb 2020	3 Mar 1942	18 Mar 2020
Average max temp (°C)	26.9	30.6	28.6	28.7	28.5	26.4	26.0	25.6
Days[18] >30°C	9.1	15	11.7	12	10.8	6	7.0	6
Days[18] >35°C	3.8	11	5.5	6	4.3	0	1.6	0
Days[18] >40°C	0.6	6	1.1	3	0.6	0	0.1	0
Difference between 2019-20 average max temp and long-term trend (°C)	3.7		0.1		-2.1		-0.4	

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

[18] Mean days for long term trend data, actual days for 2019-20 data

3.5.2 State-wide demand review

State-wide demand reached a maximum of 3,238 MW on Thursday 19 December 2019, the day on which Adelaide's Bureau of Meteorology West Terrace site recorded a maximum temperature of 45.3 °C, the highest of the 2019-20 summer.

Demand supplied by the transmission system exceeded 2,800 MW on seven days during the 2019-20 summer (Table 3.2).

Table 3.2: Highest demand days in summer 2019-20

Date	Maximum demand (MW)[20]	Maximum temperature (°C)	Preceding overnight minimum temperature (°C)	Preceding day maximum temperature (°C)
Thursday 19 December	3,238	45.3	21.3	43.7
Thursday 30 January	3,127	43.3	23.1	38.8
Wednesday 18 December	3,075	43.7	28.6	42.1
Friday 20 December	3,067	43.9	33.6	45.3
Thursday 9 January	2,912	42.1	22.6	35.3
Friday 31 January	2,885	35.6	29.0	43.3
Tuesday 17 December	2,817	42.1	19.6	34.1

Temperature patterns with the potential to deliver very high demand levels are typically characterised by very high Adelaide maximum temperatures on the day and preceding day of 40 °C or more, combined with a high preceding overnight minimum temperature of about 25 °C or higher.

Demand levels corresponding to a 10% Probability of Exceedance (POE) typically occur if such weather conditions occur mid-week, before or after the traditional holiday period between Christmas Day and Australia Day, as was the case on Thursday 19 December 2019 and Thursday 30 January 2020.

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.

3.5.3 Connection point demand 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 2019-20, only five bulk supply connection points recorded maximum demands that exceeded their forecast 10% POE maximum demand between 1 December 2019 and 31 March 2020.

Of the five 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.

[20] These values represent the total as-generated demand from the SA electricity system. They include generator "house loads" and major distribution-connected generators but exclude demand supplied by rooftop solar PV generation.

Table 3.3: Recorded maximum demands more than 100% of 10% POE demand forecast in summer 2019-20

Connection point	ElectraNet 10% POE forecast	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)
Ardrossan West	10.9	11.5	12.3	113%	3/01/2020 18:30
North West Bend	23.4	27.1	26.0	111%	29/12/2019 22:00
Mannum	13.8	13.8	14.7	106%	29/12/2019 19:30
Tailem Bend	26.4	26.0	26.7	101%	19/12/2019 19:00
Port Lincoln	31.2	33.5	31.5	101%	30/01/2020 19:30

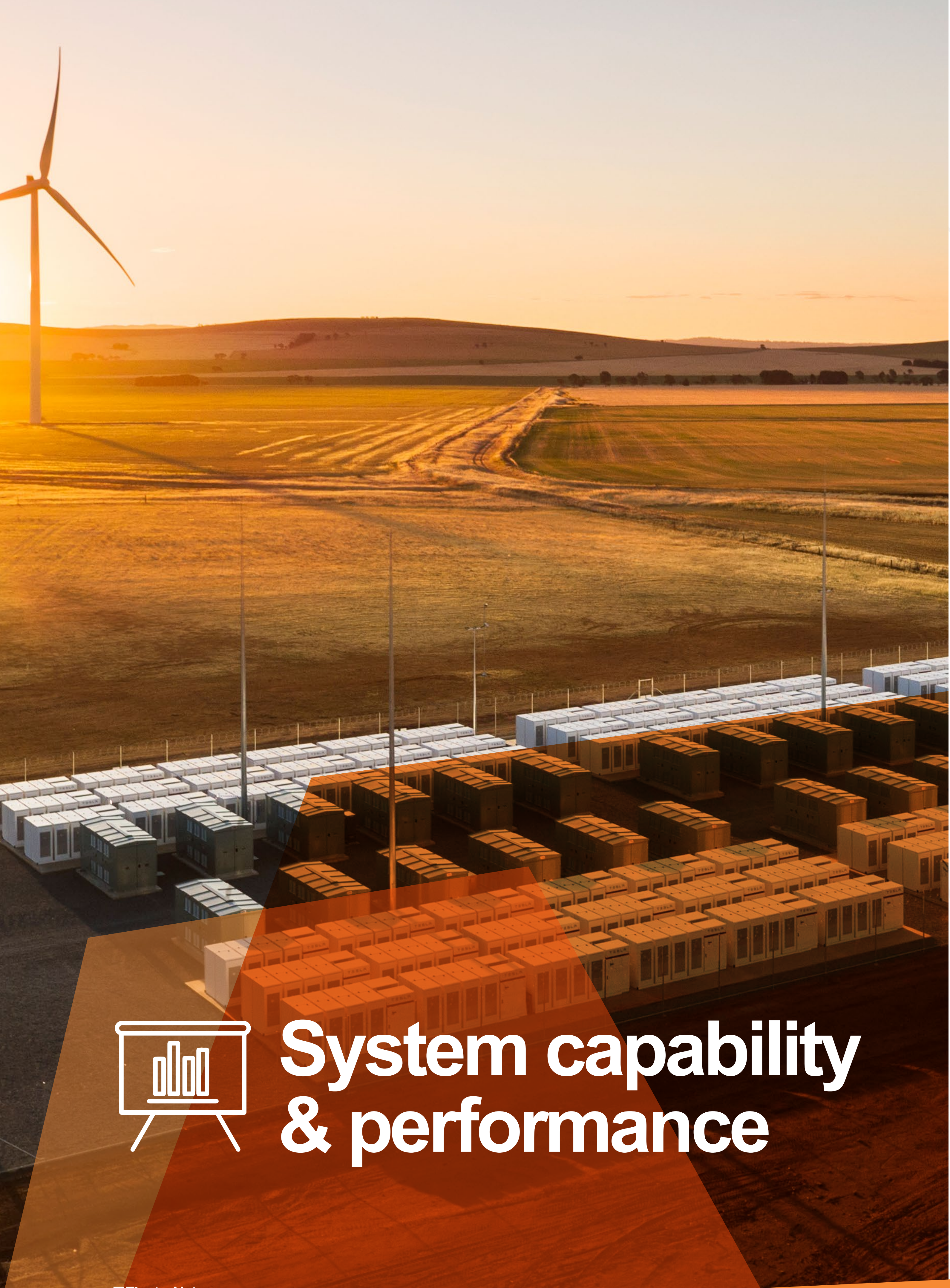
The four metropolitan bulk connection points each recorded maximum demands that were lower than their 10% POE forecast by at least 20 MW. Two small and five medium connection points failed to reach 85% of their 10% POE forecast (Table 3.4).

The 2020 review of connection point forecasts considered the impact of measured maximum demands from summer 2019-20. The latest connection point forecasts are available in the connection point information published on our Transmission Annual Planning Report webpage.[21]

Table 3.4: Recorded maximum demands either lower than the 10% POE demand forecast by at least 20 MW, or lower than 85% of 10% POE demand forecast, in summer 2019-20

Connection point [22]	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)
Southern suburbs	680.0	693.7	653.8	96%	20/12/2019 15:00
Western suburbs	443.4	425.9	422.9	95%	20/12/2019 14:30
Eastern suburbs	769.5	746.8	706.4	92%	20/12/2019 15:00
Northern suburbs	352.6	333.5	313.9	89%	19/12/2019 19:30
Dorrien	63.8	61.5	53.1	83%	18/12/2019 18:30
Keith	25.8	27.9	21.4	83%	18/12/2019 19:30
Hummocks	15.6	15.2	12.7	82%	20/12/2019 17:00
Snuggery Rural	14.4	13.1	11.7	81%	3/01/2020 18:30
Mt Gambier	27.0	26.1	18.4	68%	30/01/202017:30
Leigh Creek South	1.2	1.1	0.8	68%	19/12/2019 19:00

[21] Available from www.electranet.com.au/what-we-do/network/regulated-network-reports-and-studies
[22] Low-demand connection points where the actual demand was within 0.1 MW of the 10% POE forecast have not been included in this table.



4. System capability and performance

4.1 The South Australian electricity transmission system

The South Australian transmission system 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).

The Main Grid is a meshed 275 kV network that extends from the Cultana substation (near Whyalla) to the 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.

The South Australian transmission system is relatively skinny and long, which can make it challenging to enable significant power transfers while ensuring appropriate levels of stability and voltage. The section between South East and Adelaide has been series compensated to manage some of these challenges.

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

There are no longer any coal fired generators in South Australia. The significant uptake of renewables and resulting reduced dispatch of conventional generation has resulted in emerging system security challenges such as the need to actively manage levels of system inertia and system strength. These are currently being addressed by the installation of synchronous condensers at Davenport and Robertstown (section 7.4).

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. In recent times, due to the high penetration of renewable generation in South Australia, surplus generation is often exported through the two interconnectors.

Interconnector transfer capacity has increased to 600 MW (import) and 550 MW (export) 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 [23] for imports to South Australia, and 700 MW [24] for exports.[25]

New challenges such as the impact of shake-off of distributed energy resources and managing interconnector flows to their schedules are hindering the release of the full 650 MW capability of the Heywood interconnector in both directions.

Emergency control schemes such as under frequency load shedding (UFLS), over frequency generator shedding (OFGS) and the System Integrity Protection Scheme (SIPS) are in place to manage system security for significant events. These enable higher transfers across the interconnectors than if the schemes were not in place.

Operation of the South Australian electricity transmission network is supported by an extensive telecommunications network.

[23] Consisting of 600 MW import through Heywood interconnector and 220 MW import through Murraylink interconnector.
[24] Consisting of 550 MW export through Heywood interconnector and 150 MW export through Murraylink interconnector (constrained by typical voltage limits in the Riverland).
[25] At the time of publication, transfer capability is restricted to lower levels due to the outage of one Para SVC.

Figure 4.1: South Australian electricity transmission system map

Figure 4.2: South Australian electricity transmission system map - metropolitan area

4.2 Transmission system constraints in 2019

AEMO uses constraint equations to manage system security and market pricing. When a constraint binds on dispatch 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 2019 calendar year (Table 4.1). Constraints selected for assessment were in the top 10 by impact on marginal value or by binding duration in 2019. Some constraints have been grouped as they manage the same network limit or operating condition. For example, two constraints might both manage the overload of the same network element for different contingency events.

Table 4.1: Constraint equations, descriptions and ranking

Where constraints are closely related, they have been grouped together for ranking. Note that constraints used to manage frequency control ancillary services or that are related to AEMO's Reserve Trader activities have not been included.

Constraint equation and description	Marginal values in $ 2019 (2018)	Rank by 2019 marginal value	Hours binding 2019 (2018)	Rank by 2019 hours binding	Commentary
S_NIL_STRENGTH_1 Constrain non-synchronous generation based on system strength requirements in South Australia	8,084,358 (13,582,753)	1	669 (1094)	2	The installation of synchronous condensers at Davenport and Robertstown during 2020 and 2021 will address the system strength and synchronous inertia needs that AEMO identified in 2018 for South Australia These constraints will be updated to take the synchronous condensers into account, alleviating the impact of this constraint by raising the levels at which they are expected to bind
SA_ISLE_STRENGTH Constrain non-synchronous generation based on system strength requirements in South Australia while islanded or at a credible risk of islanding	158,915 (0)		16 (0)		
SA_ISLE_STRENGTH_LB Constrain Lake Bonney Wind Farm based on system strength requirements in South Australia while islanded or at a credible risk of islanding	21,056 (0)		5 (0)		
SA_ISLE_STRENGTH_BU Constrain Bungala Solar Farm based on system strength requirements in South Australia while islanded or at a credible risk of islanding	1,529 (0)		0.25 (0)		
#BNGSF2_E Discretionary limit for Bungala 2 Solar Farm	5,866,142 (2,250,922)	2	539 (1704)	3	AEMO invokes this constraint when needed to satisfactorily manage the transmission system

Constraint equation and description	Marginal values in $ 2019 (2018)	Rank by 2019 marginal value	Hours binding 2019 (2018)	Rank by 2019 hours binding	Commentary
#TORRB4_D_E Discretionary limit for Torrens Island B4 generator unit	4,600,080 (0)	3	27 (0)	42	The installation of synchronous condensers at Davenport and Robertstown during 2021 will address the system strength and synchronous inertia needs that AEMO identified in 2018 for South Australia These constraints will be updated to take the synchronous condensers into account, alleviating the impact of these constraints by raising the levels at which they are expected to bind
#PPCCGT_D_E Discretionary limit for Pelican Point Power Station	4,576,419 (0)		26 (0)		
#TORRA4_D_E Discretionary limit for Torrens Island A4 generator unit	2,989,892 (0)		17 (0)		
#TORRB2_D_E Discretionary limit for Torrens Island B2 generator unit	2,121,818 (0)		12 (0)		
#OSB-AG_D_E Discretionary limit for Osborne Power Station	1,802 (0)		5 (0)		
N^^V_NIL_1 Avoid voltage collapse at Southern NSW for loss of the largest Vic generating unit or Basslink	2,543,881 (1,000,023)	4	2105 (1166)	1	This constraint can limit the ability to transfer power from South Australia to Victoria on the Murraylink interconnector AEMO monitors the performance of this constraint in its role as Victorian transmission planner
#QPS1_E Discretionary limit for Quarantine 1 generator unit	1,954,871 (0)	5	146 (0)	10	AEMO invokes this constraint when needed to satisfactorily manage the transmission system
#LGAPWF1_E Discretionary limit for Lincoln Gap Wind Farm	1,889,417 (0)	6	321 (0)	5	AEMO invokes this constraint when needed to satisfactorily manage the transmission system
S>V_NIL_SETX_SETX1 Avoid overloading a South East 275/132 kV transformer on trip of the remaining South East 275/132 kV transformer when control scheme out of service	1,332,092 (0)	7	218 (0)	6	A control scheme to alleviate this constraint is in service under system normal conditions
S_PLN_ISL_01 Run Port Lincoln generators for network support	1,330,853 (0)	8	8 (0)	91	ElectraNet dispatches this generation under a network support arrangement to supply Port Lincoln demand when supply from the transmission network is unavailable The construction of Eyre Peninsula Link will remove the need for this network support arrangement

Constraint equation and description	Marginal values in $ 2019 (2018)	Rank by 2019 marginal value	Hours binding 2019 (2018)	Rank by 2019 hours binding	Commentary
S>V_NIL_NIL_RBNW Avoid overloading Robertstown-North West Bend #1 or #2 132 kV lines during system normal conditions	894,162 (195,921)	9	331 (315)	4	This constraint limits the ability to export power from South Australia across the Murraylink interconnector
#TBSF1_E Discretionary limit for Tailem Bend Solar Farm	840,116 (0)	10	64 (0)	19	AEMO invokes this constraint when needed to satisfactorily manage the transmission system
S:V_500_HY_TEST_DYN SA to VIC on Heywood upper transfer limit of 500 MW, limit for testing of Heywood interconnection upgrade	330,410 (54,435)	31	212 (78)	7	An Over Frequency Generator Shedding (OFGS) scheme has been implemented in SA, which has enabled AEMO to raise the export transfer limit on the Heywood interconnector to 550 MW, alleviating this constraint
S>>PARB_RBTU_ WEWT Avoid overloading Waterloo East-Waterloo 132 kV line on trip of Robertstown-Tungkillo 275 kV line if an outage of Para-Robertstown 275 kV line was to occur	582,902 (16,263)	21	195 (26)	8	AEMO invokes this constraint when needed to satisfactorily manage the transmission system
V^^N_NIL_1 Avoid voltage collapse around Murray for loss of all APD potlines	96,627 (57,329)	60	151 (68)	9	This constraint can limit the ability to transfer power from Victoria to South Australia on the Murraylink interconnector AEMO monitors the performance of this constraint in its role as Victorian transmission planner

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, 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.

ElectraNet has conducted a 10-year forecast of generator expansion to achieve a 100% renewable energy target in South Australia by 2030, to identify potential development of generation in REZs.

The limitations that could bind as a result of the modelled generator connections are highlighted in Table 4.2.

Due to the forecast high volume of renewable energy developments in the South East zone, congestion is expected in lines from South East to Tailem Bend to Tungkillo.

In addition, renewable energy development in the northern parts of South Australia (including the Mid North, Eyre Peninsula, Yorke Peninsula and possibly Roxby Downs zones) together with imported flows from Project EnergyConnect could constrain transfers from the northern part of the state to the Adelaide metropolitan area (Robertstown to Tungkillo and Robertstown to Para).

These areas are consistent with the zones identified for potential development in AEMO's 2020 ISP, although the required timing of projects to alleviate constraints may differ.

Where possible, references are provided to projects listed in other sections of this report 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	Forecast average binding hours (hrs/year)[26]	Reference to potential mitigating project(s)
Tailem Bend – Tungkillo 275 kV	After 2020/2021	Tailem Bend – Tungkillo 275kV	759	String vacant Tailem Bend – Tungkillo 275 kV circuit (EC.11002)
Loss of Robertstown – Para 275 kV overloads Robertstown – Tungkillo 275 kV	After 2021/2022	Robertstown – Tungkillo 275kV	143	Increase capacity of the Robertstown to Adelaide transmission corridor (EC.15205)
Loss of Robertstown – Tungkillo 275 kV overloads Waterloo East – Waterloo 132 kV	After 2023/2024	Waterloo East – Waterloo 132kV	131	Increase capacity of the Robertstown to Adelaide transmission corridor (EC.15205)
South East to Tailem Bend 275 kV	After 2023/2024	South East – Tailem Bend 275kV	89	Develop N-1 control schemes (e.g. coordination of batteries, or load or generator shedding)
South East to Tailem Bend 275 kV	After 2023/2024	South East – Tailem Bend 275kV	89	Develop N-1 control schemes (e.g. coordination of batteries, or load or generator shedding)
Loss of South East-Tailem Bend 275 kV overloads Tailem Bend – Keith 132 kV	After 2023/2024	Tailem Bend – Keith 132kV	66	Install a Smartwires Guardian on the 132 kV lines between Tailem Bend and South East
Loss of South East – Tailem Bend 275 kV overloads Penola West – Kincraig 132 kV	After 2023/2024	Penola West – Kincraig 132kV	59	Install a Smartwires Guardian on the 132 kV lines between Tailem Bend and South East
Heywood – South East 275 kV	After 2023/2024	Heywood – South East 275kV	44	Establish HorshamLink (a potential new interconnector between Horsham in Victoria and Tungkillo in South Australia), or extend 500 kV system from Heywood to South East
Loss of Tailem Bend – Tungkillo – Cherry Gardens (275 kV) overloads Tailem Bend – Mobilong 132 kV	After 2023/2024	Tailem Bend – Mobilong 132kV	12	Remove plant limits on Tailem Bend – Mobilong 132 kV

[26] Calculated as the average over 10 years (2020/21 – 2030/31) from 3 different input scenarios.

4.4 Potential projects to address constraints

The connection of significant new loads, a change in the nature of the generation fleet, or changing gas prices can impact on the efficient development and operation of the transmission network. 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 2020 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. 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.

We have identified high-level potential projects through constraint and planning analysis (Table 4.3). These projects would reduce network congestion in the future, warranting development if they deliver net benefits to customers. Some of these projects may also deliver 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)
EC.15209 Install 2nd Templers West transformer and reconfigure Mid North 132 kV network Increased generation or large-scale storage in the Mid North, Upper North and Eyre Peninsula	Install 2nd Templers West 275/132 kV transformer, decommission the Templers to Waterloo 132 kV line and relocate the modular power flow equipment installed on that line (EC.15209) Enable increased dispatch of renewable generation and energy storage in the Mid North and North of South Australia, and enable increased export to New South Wales from South Australia	1-2 years RIT-T (if required) 2-3 years detailed design and delivery	5-15
EC.15205 Increase transfer capacity between Robertstown and Adelaide Increased generation or large-scale storage in the Mid North, Upper North, Eyre Peninsula and Riverland (Robertstown)	Construct new double circuit 275 kV high capacity lines between Robertstown and Templers West, and rebuild the 275 kV Davenport east circuit as high capacity double circuit lines between Templers West and Para (EC.15205) Enable increased dispatch of renewable generation and energy storage in the Mid North and North of South Australia, and enable increased export from South Australia to New South Wales	Stage 1: 2-3 years RIT-T[27] 2-3 years design and delivery of "shovel-ready" works[28] Stage 2: 2-3 years RIT-T[27] 2 years detailed design and full delivery	200-350
EC.15153 Increase transfer capacity between Davenport and Adelaide Increased generation, large scale storage or loads through the Mid North, Eyre Peninsula, or Upper North	Augment the Davenport to Para transmission path by building new double circuit 275 kV lines between Davenport and Robertstown, Templers West or Para (EC.15153) Displacement of conventional generation and displacement of imports from interconnectors during high demand. Increased dispatch of renewable generation from the Northern part of SA to the Metro and export interstate Cost based on new double circuit high capacity 275 kV line	Stage 1: 2-3 years RIT-T[27] 2-3 years design and delivery of "shovel-ready" works29 Stage 2: 2-3 years RIT-T[27] 2 years detailed design and full delivery	350-650
EC.15149 Install synchronous condensers in or near the Adelaide metropolitan region Increasing penetration of distributed energy resources in the metropolitan area may require system strength or dynamic voltage control to be increased, to ensure continued stable system response to disturbances	Install one or two synchronous condensers or other source of fast voltage control (e.g. STATCOM) in or near the metropolitan region to increase system strength. We will also consider whether new technologies can provide system strength services. Enable continued growth in distributed energy resources	1-2 years RIT-T[27] 2-3 years detailed design and delivery	50-100
EC.11002 Strengthen the Eastern Hills transmission corridor Increased generation including rooftop solar PV and large-scale wind and solar farms in the Eastern Hills and South East	Connect the Tailem Bend to Cherry Gardens 275 kV line at Tungkillo, and uprate the Eastern Hills 275 kV lines to 120 °C design clearances where practicable Enable increased flexibility to dispatch Heywood and Project EnergyConnect interconnector flows to supply the Adelaide metropolitan load centre	1-2 years RIT-T 1-2 years detailed design and delivery	5-15
EC.15261 Build new 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 Increase the system normal transfer capacity of the Cultana to Davenport corridor by about 1200 MW	1-2 years RIT-T[27] 3-4 years easement acquisition, detailed design and delivery	80-130
EC.11011 Upper South East network augmentation New generation connection(s) at Tailem Bend, Tepko or in the South East, or a market-driven requirement for increased interconnector capacity in either direction	String the vacant 275 kV circuit between Tailem Bend and Tungkillo and install dynamic reactive support if required at Tailem Bend Increase the system normal transfer capacity between Tailem Bend and Tungkillo by about 400-600 MW	1-2 years RIT-T[27] 2-3 years detailed design and delivery	30-80
EC.15297 Maintain adequate suppression of grid harmonic voltage distortion and ongoing management of voltage fluctuation and unbalance levels Changing generation mix, equipment interactions and system characteristics increase the magnitude of emission levels	Install harmonic filter bank(s) and STATCOM(s) designed to address existing and emerging issues Maintain adequate power quality for generators and customers	1-2 years RIT-T 2 years detailed design and delivery	15-30
EC.15206 Project EnergyConnect Upgrade 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, and/or improve the ability to independently control power flows across Project EnergyConnect and the Heywood interconnector Increase the combined transfer capability of the Heywood interconnector and Project EnergyConnect by up to 650 MW	1-2 years RIT-T[2] 2-3 years detailed design and delivery	40-75
EC.15175 Additional reactive support at Monash SA-Vic exports across Murraylink constrained by voltage limitations at Monash	Install additional 132 kV switched capacitor at Monash Enable maximum exports across Murraylink to increase from about 160 MW to up to 220 MW	1-2 years detailed design and delivery	3-6
REC.15154 Increase Mid North 275 kV network transfer capacity Increased generation or large scale storage in the Mid North, Upper North, or Eyre Peninsula	Apply dynamic line ratings between Davenport and Robertstown or between Davenport and Para, depending on generator developments Increase transfer capacity through the Mid North of South Australia, depending on location of generation and local network capability	1-2 years detailed design and delivery	<5 (total)

27 May be shorter duration if a future ISP identifies this to be an actionable project.

28 "Shovel-ready" includes project specification, route selection, equipment specification and design, and preliminary environmental impact assessment.

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 4.5.3).

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[29] , the frequency fall should be limited to 47 Hz by the controlled disconnection of load.

AEMO is currently reviewing the design of the UFLS scheme for South Australia as part of the 2020 Power System Frequency Risk Review.[30] AEMO's stage 1 assessment indicated that:

- there are periods during which insufficient load is forecast to be available for disconnection in the existing South Australian UFLS scheme. The amount of net load available for disconnection will continue to decrease as a result on the ongoing growth of distributed PV generation
- the existing UFLS scheme may not be adequate to arrest reductions in the power system frequency following the non-credible separation of South Australia from the NEM
- a protected event is likely to be required to manage the risk of cascading failures and prevent a system black if a non-credible separation of South Australia from the NEM was to occur during periods where UFLS is inadequate. AEMO is preparing a submission to the Reliability Panel on this basis.

In the interim, AEMO has implemented a power system constraint that limits import into South Australia on the Heywood interconnector to an appropriate level such that risk of cascading failures is reduced if non-credible separation of South Australia from the NEM was to occur. As input to this constraint ElectraNet and SA Power Networks provide to AEMO the available load in South Australia on UFLS at any moment using SCADA data.

ElectraNet is working with:

- transmission network direct-connect customers to ensure UFLS arrangements for each customer comply with Rules obligations
- AEMO to assess the impact of the loss of a large generator and subsequent distributed PV disconnection in order to refine Heywood interconnector limit advice.

Stage 2 of the AEMO 2020 Power System Frequency Risk Review is scheduled to conclude with the publication of a final report in December 2020.

Declaration of a Protected Event could create an identified need that ElectraNet would be required to address.

[29] As defined in the Frequency Operating Standards

[30] AEMO's 2020 Power System Frequency Risk Review, available from www.aemo.com.au.

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 exacerbation of the rate of change of frequency (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.[31] AEMO's assessment indicated that the present South Australian OFGS settings are adequate. This scheme will be reviewed as part of Stage 2 of the AEMO 2020 Power System Frequency Risk Review.

[31] See section 5.2.2 of AEMO's 2018 Power System Frequency Risk Review, available from www.aemo.com.au.

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 extreme flows on the Heywood Interconnector, causing it to trip due to instability. This loss of multiple generators and islanding of South Australia would result in rapid frequency decline and poses 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 and subsequent islanding of South Australia from the NEM.

The SIPS operates in three discrete, progressive stages. These stages operate in an escalating manner, in that the operation of each stage is intended to minimise the need to progress to 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**[32]

An unstable power swing trigger is initiated from a pair of redundant loss of synchronism detection 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 is initiated by redundant loss-of-synchronism relays at South East substation. The out-of-step signal trips 275 kV circuit breakers at South East substation to open the Heywood interconnector, islanding the South Australian power system.

[32] As is the case with underfrequency load shedding, the amount of net load available for disconnection will decrease as a result on the ongoing growth of distributed PV generation

AEMO reviewed the design of the South Australian SIPS scheme in 2018.[33] AEMO's 2018 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 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 Australian power system
- This SIPS upgrade should be progressed as a Protected Event emergency frequency control scheme to mitigate the risk of system black following a loss of multiple generators in South Australia.[34]

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). We have implemented a pilot Phasor Measurement Unit (PMU) scheme which gathers high-resolution time-synchronised real-time system data from across the South Australian power system. We are evaluating the PMU scheme's quality and performance before proceeding to integrate the scheme with the WAPS. In conjunction with AEMO, ElectraNet is also progressing with a feasibility study into deployment of the PMUs in developing the WAPS.

We expect to complete the feasibility study by February 2021, with deployment of the upgraded WAPS planned by June 2022.

[33] 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

[34] On 20 June 2019 the Reliability Panel published a final determination declaring a protected event in accordance with AEMO's request, including:

- upgrading the existing system integrity protection scheme (SIPS) in South Australia
- limiting imports across the Heywood interconnector during periods of forecast destructive wind conditions.

The Reliability Panel's determination is available at https://www.aemc.gov.au/market-reviews-advice/request-declaration-protected-event-november-2018.

5. Connection opportunities and demand management

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

AEMO's August 2020 Electricity Statement of Opportunities (ESOO) projects an improved reliability outlook over the next five years.[35] AEMO's modelling shows that unserved energy is not forecast to exceed the reliability standard in any region over the next 10 years, except for New South Wales which is forecast to significantly exceed the reliability standard in the 2029-30 when Vales Point is expected to close.

The 2020 ESOO projects that due to the projected continuing strong uptake of distributed PV, minimum demand is forecast to decline rapidly. This trend that is particularly strong in South Australia and Victoria, with minimum demands potentially becoming negative during the 2020s.[36] We continue to work with AEMO to address resultant emerging challenges related to voltage control, system strength, and inertia (section 7.4).

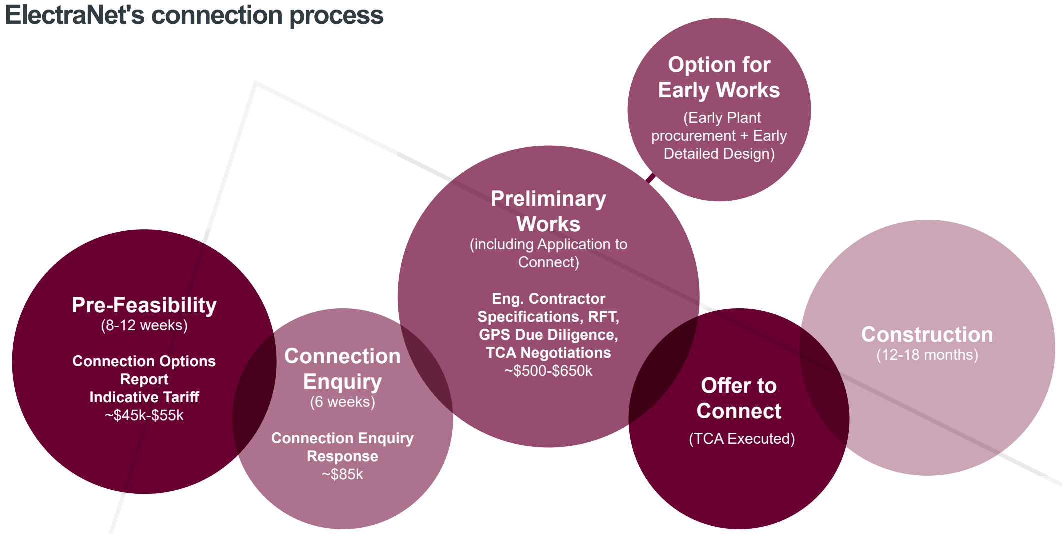
In this section we outline connection opportunities for generators (section 5.1) and customers (section 5.2), in each case discussing the factors that influence them. We also identify proposed new connection points (section 5.3) and information relating to projects for which network support solutions are being sought or considered (section 5.4).

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

5.1 ElectraNet's connection process

ElectraNet's connection process (Figure 5.1) begins with the production of a Connection Options Report which provides an overview of connection options for proposed projects. The process then leads through the stages of a formal Connection Enquiry, preliminary works (with the option for early works such as plant procurement and detailed design), culminating in a formal offer to connect. We are committed to working flexibly with customers to progress the connection of their projects, while maintaining strict compliance with the Rules.

Figure 5.1: ElectraNet's connection process



[35] Available from https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/nem-electricity-statement-of-opportunities-esoo.

[36] AEMO's 2020 ESOO, page 9.

5.2 Connection opportunities for generators

In previous years we have conducted high-level assessments of the ability of existing transmission network nodes and connection points to accommodate new generator connections. In doing this 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.

According to AEMO's generator information page, only a few generators have committed or connected that were not considered as connected in the assessment we performed for the 2019 Transmission Annual Planning Report. These new and committed connections include:

- Commitment of the Simply Energy VPP: 6 MW
- Commitment of the SA Government Virtual Power Plant – stage 2: 5 MW
- Increase of Quarantine Power Station nameplate capacity from 224 MW to 229 MW
- Commitment to relocate the South Australian Emergency Generators
- Hornsdale Power Reserve expansion – 50 MW capacity increase
- Hallett GT capacity expansion – 35 MW new generator unit.[37]

Given that these changes represent only a small fraction of the total South Australian generation fleet, the results of the assessment that were provided in chapter 5 of our 2019 Transmission Annual Planning Report[38] are still broadly relevant. The discussion in the sections that follow is based on the outcomes of that assessment.

The 2019 assessment was limited to a few operating conditions and did not attempt to define the amount and value of constraints that could be experienced in terms of energy lost by connecting generation at any location. We recommend that parties seeking connection to the network carry out a detailed network access and market impact assessment.

In the 2021 Transmission Annual Planning Report we intend to significantly update the connection opportunity assessment to reflect the expected impact of initiatives such as Project EnergyConnect and the installation of synchronous condensers at Davenport and Robertstown, including any impact of updated demand forecasts.

Connection points on the 132 kV system typically have a much lesser ability to accommodate additional generation connections than connection points have that are on the 275 kV system.

5.2.1 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. 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, as 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, it should be expected that dispatch would be co-optimised with flows across Heywood interconnector.

While the existing Metropolitan 275/66 kV system may have thermal 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. Connection of new generation could initiate a need for major replacement of transmission or distribution assets to address fault level issues.[39]

5.2.2 Implications of South Australian system strength requirements

AEMO currently maintains adequate levels of system strength in South Australia by directing synchronous generation when necessary and applying a non-synchronous generation system constraint that considers the synchronous generators online at the time within South Australia.

ElectraNet is installing four high-inertia synchronous condensers to meet minimum system strength requirements specified by AEMO in 2018 for South Australia (section 7.4). The four synchronous condensers will also meet the minimum threshold of inertia of 4,400 MWs that AEMO determined for South Australia in 2018, with no other synchronous plant on-line in South Australia.

The four synchronous condenser minimum system strength solution in combination with the requirement for at least two large synchronous generating units to be online to provide active power response is expected to allow about 2,500 MW of non-synchronous generation to be dispatched within South Australia for most operating conditions. ElectraNet is developing limit advice defining this non-synchronous generation system constraint prior to the commissioning of the synchronous condensers.

The total installed capacity of non-synchronous generation in South Australia exceeds 2,500 MW, so the non-synchronous generation system constraint is expected to remain in place after the four synchronous condensers have been installed. However, it is anticipated that constraints other than system strength are also likely to bind at times to limit non-synchronous generation at levels below the non-synchronous generation system strength constraint.

The successful completion of a Full Impact Assessment conducted in accordance with clause 5.3.4B of the Rules is a pre-requisite for the connection and inclusion in the non-synchronous generation system constraint of a non-synchronous generator.

ElectraNet and AEMO continue to utilise an agreed approach for 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.

5.2.3 Generator connection impacts on power quality

The ongoing connection and integration of new generation technologies (in particular non-synchronous generation) within the power system has required ElectraNet and generators to develop models suitable for the complex power quality studies and assessments needed to meet Rules obligations.

ElectraNet requires generators to submit a site-specific power quality model for use in the PowerFactory simulation tool that is consistent with Section 4.6 of the *AEMO Power System Model Guidelines*[40], and a power quality design report that incorporates sufficient supporting studies and assessment results as part of the 5.3.4A(b2) submission under the Rules.

[37] However, some connection proponents have signed Transmission Connection Agreements with ElectraNet, as documented in the new generator connection data published on ElectraNet's Transmission Annual Planning Report webpage, available at https://www.electranet.com.au

[38] Available at https://www.electranet.com.au

[39] Expected maximum and minimum fault levels for each connection point are available from our Transmission Annual Planning Report web page, available at https://www.electranet.com.au

[40] AEMO's Power System Model Guidelines are available at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/participate-in-the-market/network-connections/modelling-requirements.

5.3 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.

5.4 Proposed and committed new connection points

New connection points have recently been energised, committed, or are proposed, to enable the connection of new generators or loads (Table 5.1).

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 5.1: Proposed, committed and recently energised new connection points for generators and customers

Connection point	Planning region	Project year	Connection voltage	Scope of work
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
		Energised September 2020	upgraded to 275 kV	In 2019 and 2020, construct a new Davenport to Mount Gunson South 275 kV line and upgrade to a 275/132 kV connection point at Mount Gunson South Prominent Hill mine to be connected at 132 kV
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 several recently completed, in-progress, and planned consultations for forecast limitations on which we have sought or seek proposals for network support solutions (Table 5.2).

Future dates are indicative only. Reports will be published on ElectraNet's website, with a summary on AEMO's website.[41,42] We also liaise with AEMO to notify interested parties when we publish new RIT-T reports through the "AEMO Communications" email notifications.[43]

Table 5.2: Recently completed, in-progress, and planned consultations for which ElectraNet has sought or seeks proposals for network support solutions

RIT-T	Expected project commitment date	Consultation status
Eyre Peninsula Electricity Supply Options Refer to section 7.5 of this report	Committed (subject to final Board approval)	We published a Project Assessment Conclusions Report (PACR) on 18 October 2018, which describes the preferred option to meet the identified need [44] On 12 April 2019 the AER determined the preferred option identified in the PACR satisfies the RIT-T We submitted our Contingent Project Application for project funding to the AER on 15 May 2020 The AER delivered its final decision on the Contingent Project Application on 28 September 2020, providing the incremental revenues required to deliver Eyre Peninsula Link
South Australian Energy Transformation Refer to section 7.3 of this report	Conditionally committed, subject to the conditions outlined in Appendix E	We published a PACR on 13 February 2019, which describes the preferred option to meet the identified need [45] On 24 January 2020 the AER published its determination that the preferred option identified in the PACR satisfies the RIT-T We submitted our Contingent Project Application for project funding to the AER on 30 September 2020 The AER is expected to deliver its final decision on the application by the end of 2020
Protection Systems Unit Asset Replacement 2018-23 Refer to section 7.9 of this report	Already committed	Application of the RIT-T began with publication of a Project Specification Consultation Report (PSCR) on 1 August 2019 On 6 December 2019 we published a PACR which describes the preferred option to meet the identified need [46]

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

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

[43] 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.

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

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

[46] Available from https://www.electranet.com.au/projects/managing-the-risk-of-protection-relay-failure/.

RIT-T	Expected project commitment date	Consultation status
AC Board Unit Asset Replacement 2018-23 Refer to section 7.7 of this report	Already committed	Application of the RIT-T began with publication of a PSCR on 15 October 2019 On 14 January 2020 we published a PACR which describes the preferred option to meet the identified need[47]
Isolator Unit Asset Replacement 2018-23 Refer to section 7.9 of this report	Already committed	Application of the RIT-T began with publication of a PSCR on 4 July 2019 We published a PACR on 18 November 2019, which describes the preferred option to meet the identified need[48]
Instrument Transformer Unit Asset Replacement 2018-23 Refer to section 7.9 of this report	Already committed	Application of the RIT-T began with publication of a PSCR on 8 October 2019 On 7 January 2020 we published a PACR which describes the preferred option to meet the identified need[49]
Managing voltage levels at times of low system demand Refer to section 7.4 of this report	2022 or 2023	We plan to commence application of the RIT-T with publication of a PSCR prior to project commitment Proponents will be invited to make submissions by early 2021
Increasing transfer capability through the Eastern Hills Refer to sections 7.5 of this report	If viable, after a likely trigger event has been identified	We are performing preliminary studies to determine whether there is a trigger for investment to meet an identified need to reduce constraints on the 275 kV system through the Eastern Hills, such as significant generation investment at or south east of Tailem Bend or within the Eastern Hills If we identify that a trigger for such an investment is likely to occur during or before the 2023 24 to 2027 28 regulatory control period, then we plan to commence a RIT-T
Increasing transfer capability between Robertstown and the Adelaide region Refer to sections 7.5 of this report	Mid to late 2020s	We are performing preliminary studies to determine whether investment to meet an identified need to reduce constraints between Robertstown and the Adelaide region is likely to deliver net benefits in the future If there is a likely case for investment before 2033, we plan to commence a RIT-T during the 2023-24 to 2027-28 regulatory control period
Gawler East New Connection Point Refer to section 7.5 of this report	After 2025	Application of the RIT-D[50] 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

[47] Available from https://www.electranet.com.au/projects/managing-the-risk-of-ac-board-failure/.
[48] Available from https://www.electranet.com.au/projects/isolator-replacement-and-refurbishment-project/
[49] Available from https://www.electranet.com.au/projects/managing-the-risk-of-instrument-transformer-failure-project/
[50] Regulatory Investment Test for Distribution.

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 2019 and 30 October 2020

Project description	Region	Constraint driver and investment type	Asset in service
EC.11890 Various unit asset replacements 2013 – 2018 Replace individual unit assets, such as circuit breakers, voltage transformers, current transformers or protection relay sets that are at end of life at 36 substations	Various	Asset condition and performance Asset renewal	August 2019
EC.14041 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	October 2019
EC.14126 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	October 2019
EC.11733 Online asset condition monitoring equipment replacement Replace or upgrade the majority of primary plant online condition monitoring equipment, which is at end of life and experiencing high failure rates	Various	Asset condition and performance Asset renewal	December 2019

Project description	Region	Constraint driver and investment type	Asset in service
EC.11747 Substation lighting and infrastructure replacement Replace substation lighting and associated infrastructure at 82 sites where safety hazards exist	Various	Asset condition and performance Asset renewal	April 2020
EC.11751 Westinghouse Remote Terminal Unit (RTU) replacement Remove thirteen Westinghouse "Giant" type RTUs that are no longer supported by the manufacturer and are at the end of their technical and economic lives, replacing them at various substations across the transmission network	Various	Asset condition and performance Asset renewal	May 2020
EC.11560 Magill – East Terrace Cable Pit and Link Box Replacement Replace link boxes and associated cable pits, where required, on the Magill – East Terrace 275 kV fluid filled underground cable, to extend the life of the cable	ACR	Asset condition and performance Asset renewal	October 2020
EC.14068 Murraylink Control Scheme Replacement The Murraylink Control Scheme is undergoing a complete redesign and replacement of existing schemes and associated components, and the removal of any unnecessary components	Murraylink interconnector	Asset condition and performance Asset renewal	October 2020
EC.14076 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	October 2020

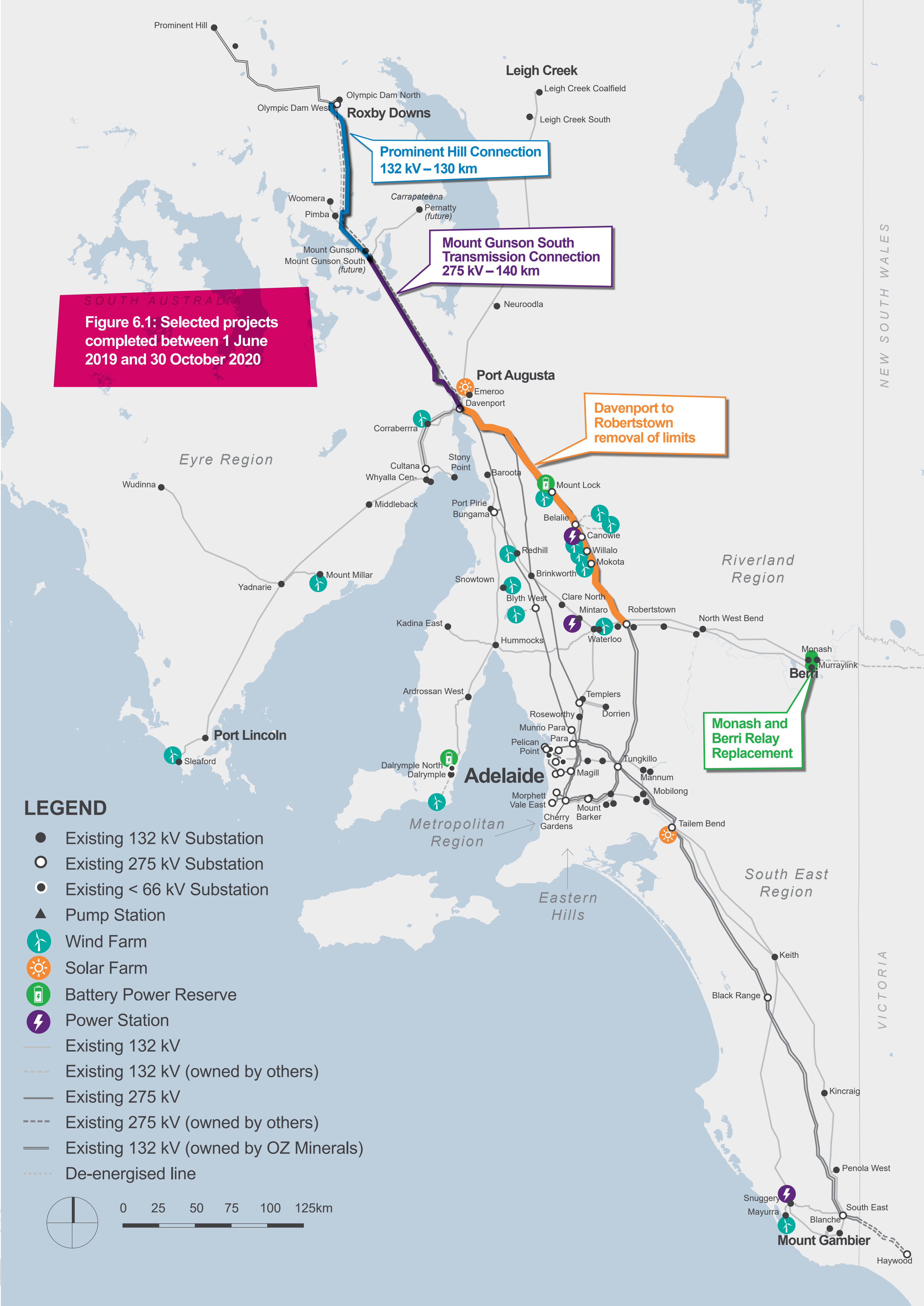


Figure 6.1: Selected projects completed between 1 June 2019 and 30 October 2020

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 30 October 2020
Note: Projects that are newly committed since the 2019 Transmission Annual Planning Report are marked with an asterisk (*)

Project description	Region	Constraint driver and investment type	Planned asset in service
EC.14127 GE D20 RTU Product Upgrades* Extend the operating life of the GE D20 RTU equipment, avoid obsolescence issues and maintain satisfactory performance standards by replacing CPU boards in RTUs at 22 different substation sites	Various	Asset condition and performance Asset renewal	December 2020
EC.14219 Main Grid system strength support Install four synchronous condenser units, two at Davenport and two at Robertstown to provide system strength services and to address the gaps for system strength and inertia in South Australia as declared by AEMO	Main Grid	Stability	January 2021 (Davenport) April 2021 (Robertstown)
EC.11749 AC Board Replacement 2013 – 2018 Replace and improve AC auxiliary supply equipment, switchboards and cabling at 11 substations that are at the end of technical life	Various	Asset condition and performance Asset renewal	April 2021
EC.14168 NCIPAP Smart Wires Power Guardian Technology Trial* Install Smart Wires Power Guardian units on the Templers to Waterloo 132 kV line and uprate the Robertstown to Para 275 kV and the Templers to Roseworthy 132 kV lines to increase the transfer capacity of the transmission network in the Mid North region of South Australia	Mid North	Market benefit (NCIPAP)\ Augmentation	November 2020 (Smart Wires Power Guardian) April 2021 (Line uprates)
EC.14131 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	Safety Asset renewal	October 2021
EC.14236 Capacitor Bank Infrastructure Safety Improvement Improve the safety of personnel accessing enclosed high voltage areas having low height high voltage equipment at 18 substations, so far as is reasonably practicable, by: • upgrading fences on low height high voltage equipment to current standards • improving earthling of high voltage equipment within enclosures • upgrading entry points to current standards	Various	Safety Asset renewal	February 2022
EC.14047 Transformer Bushing Unit Asset Replacement 2018 – 2023* Replace transformer bushings fitted on 16 power transformers located in nine substations that are at the end of their technical lives and require replacement based on their condition, due to an increasing risk of failure that may result in safety and reliability issues, or in the worst case, catastrophic failure of the transformer and the resultant loss and associated damage	Various	Asset condition and performance Asset renewal	May 2022
EC.14172 Eyre Peninsula Link* 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 2022
EC.14081 Line Insulator Systems Refurbishment 2018 – 2023 Refurbish transmission line support systems and extend the life of 18 transmission lines by renewing line asset components	Various	Asset condition and performance Asset renewal	January 2023
EC.14032 Instrument Transformer Unit Asset Replacement * Replace instrument transformers at 19 substations which are at the end of their technical life, due to an increased risk of failure which may result in an increasing rate of explosive asset failure causing unpredictable damage resulting in potential substation failure and involuntary load shedding on parts of the network	Various	Asset condition and performance Asset renewal	June 2023

Project description	Region	Constraint driver and investment type	Planned asset in service
EC.14033 Circuit Breaker Unit Asset Replacement 2018 – 2023* Replace 15 circuit breakers located in six substations that are at the end of their technical lives and require replacement based on their condition due to an increasing risk of catastrophic failure with consequential safety risks and the potential for involuntary load shedding on parts of the network	Various	Asset condition and performance Asset renewal	June 2023
EC.11646 Eyre Peninsula and Upper North Voltage Control Scheme* An automated voltage control scheme is being implemented to ensure the complex voltage interactions throughout the Eyre Peninsula and Upper North regions are managed efficiently	Eyre Peninsula and Upper North	Power Quality Operational	June 2024
EC.14218 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	Operational Operational	March 2024
EC.14031 Protection System Unit Asset Replacement* Replace protection relays aged between 38 and 60 years old at 23 substations that are at the end of their technical and economic lives, having an increased risk of failure which may result in increased safety and reliability issues and cause involuntary load shedding on parts of the network	Various	Asset condition and performance Asset renewal	September 2024
EC.14034 Isolator Unit Asset Replacement 2018 – 2023* Remove, and replace where required, approximately 73 isolators at 18 substations that no longer have original manufacturer support and create inventory spares to support the ongoing maintenance of ElectraNet's ageing isolator fleet	Various	Asset condition and performance Asset renewal	September 2024
EC.14176 Surge Arrestor Unit Asset Replacement 2018 - 2023* Replace porcelain surge arrestors and arcing horns at 18 substations that are at the end of their technical and economic lives due to their increasing risk of failure and potential to cause injury to personnel and collateral damage to other plant within the substation as a result of an explosive failure	Various	Asset condition and performance Asset renewal	October 2024

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 fully committed soon (Table 6.3).

Further information about each of these projects is available in chapter 7.

Table 6.3: Pending projects as of 30 October 2020
Note: Projects that are newly committed since the 2019 Transmission Annual Planning Report are marked with an asterisk (*)

Project Description	Region	Constraint driver and investment type	Asset in service
EC.14246 Wide Area Protection Scheme (WAPS)* Implement a Wide Area Protection Scheme with the use of PMUs to real time monitor and process system parameters for event detection, and include dynamic arming of participating loads and battery energy storage systems to enable a proportionate response to specific events to further enhance SA system security	Various	Stability Operational	June 2022
EC.14171 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	December 2023
EC.14046 AC Board Replacement 2018 – 2023* Replace and improve AC auxiliary supply equipment, switchboards and cabling at 23 substations that are at the end of technical life	Various	Replacement	March 2025

Figure 6.3 Key pending project: Project EnergyConnect

7. Transmission System Development Plan

ElectraNet and SA Power Networks analyse the expected future operation of the South Australian network, considering 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 2020 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.

Two scenarios have been developed and evaluated as part of ElectraNet's planning process, considering a range of different assumptions about the future development of demand and generation in South Australia. The scenarios, together with the range of assumptions, are intended to represent a range of credible potential futures.

The scenarios and assumptions have been characterised (Table 7.1) and a range of potential new loads and generation connections over the next 10 years (generic, based on received enquiries and modelling outcomes) are graphically represented in Figure 7.1.

Table 7.1: Characteristics and assumptions of ElectraNet's planning scenarios

Characteristic	Central scenario	100% net renewables in South Australia
Connection point demand forecasts	As published in the 2020 connection point data on our Transmission Annual Planning Report webpage[51]	
South Australian transmission system coincident demand forecasts	AEMO's 2020 ESOO 10% POE maximum demand forecast and 90% POE minimum demand forecast	
Potential new load connections	As shown in Figure 7.1	As shown in Figure 7.1
Potential new or retired conventional generators		As required to achieve renewable energy generation within South Australia that meets or exceeds South Australian demand
New renewable generators		

[51] Web page available at www.electranet.com.au

Figure 7.1: Assumptions considered in ElectraNet's planning process, including potential future step load increases, generator retirements, and new generator and battery connections

7.1 Summary of planning outcomes

Analysis of the scenarios led to a range of high-level outcomes or project recommendations that are required across both scenarios (Table 7.2). Detailed outcomes are covered in sections 7.2 to 7.12.

Potential projects that may be required to support only one scenario were covered earlier, in section 4.4.

Table 7.2: Summary of planning outcomes

Planning focus	Key outcomes
National transmission planning	**Project EnergyConnect** The SA Energy Transformation RIT-T identified that Project EnergyConnect, to construct a new 330 kV interconnector from Robertstown in South Australia to Buronga and Wagga Wagga in New South Wales, is the preferred option. Transfer capacity will be up to about 800 MW. Implementation of Project EnergyConnect will also increase the maximum amount that can be transferred across Heywood interconnector to a transfer capacity of up to about 750 MW. In January 2020, the AER published a RIT-T determination that Project EnergyConnect remained the most "credible option that maximises the net economic benefit" in the NEM, ultimately benefitting electricity consumers. AEMO's 2020 ISP identifies Project EnergyConnect as part of the optimal development path for the NEM. Project EnergyConnect will support Australia's growing renewable energy industry, with new wind and solar projects planned for South Australia, New South Wales and Victoria expected to benefit from the new interconnector. The AER is currently considering two Contingent Project Applications, one for ElectraNet and one for TransGrid, to provide funding for each business to undertake their portion of the works to create Project EnergyConnect. The AER is expected to deliver its determinations by the end of 2020.

Planning focus	Key outcomes
System security and power quality	**System strength, inertia and fast frequency response** We are installing synchronous condensers at Davenport and Robertstown in 2021. The installation of these high-inertia synchronous condensers will address the system strength and synchronous inertia needs that AEMO identified in 2018 for South Australia and contribute to the ongoing provision of adequate voltage control for the South Australian transmission system including at times of low demand. Commissioning of the synchronous condensers will allow the amount of non-synchronous generation that can be dispatched at times of minimum conventional generation in South Australia to be increased from 2,000 MW to about 2,500 MW. AEMO has published the 2020 inertia requirements in South Australia, replacing the 2018 inertia requirements. AEMO has determined the secure operating level of inertia for South Australia, proposing fast frequency response to be made available for network support on a basis that enables AEMO to determine a reduced inertia shortfall. We have initiated the procurement process and plan to engage soon with the market for the provision of FFR services. We are investigating with AEMO whether forecast changes to dispatch patterns of existing conventional generators after the completion of Project EnergyConnect could produce a need for additional synchronous condensers to be installed in the 2023-24 to 2027-28 period. **Voltage control** We have identified an emerging need to reduce the system's reliance on dynamic reactive power devices to satisfactorily manage voltage levels at times of low system demand. A potential solution is to install a suite of up to five 50 Mvar 275 kV reactors at various strategic locations. We plan to commence a RIT-T in late 2020 or early 2021 to determine the preferred solution for this identified need. **Maximum fault levels** Fault levels are forecast to remain within design and equipment limits for the duration of the planning period.
Connection points	**Eyre Peninsula Link** The Eyre Peninsula Supply Options RIT-T identified that the preferred option to continue to meet reliability requirements and address asset condition on the Eyre Peninsula 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. This solution is now known as Eyre Peninsula Link. In April 2019 The AER determined that the preferred option satisfies the requirements of the RIT-T. On 28 September 2020, the AER published its determination on our Contingent Project Application to provide funding for Eyre Peninsula Link. We plan to implement Eyre Peninsula Link by the end of 2022. 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. **Other connection points** Loads at all other connection points are forecast to remain within design and equipment limits for the duration of the planning period. A new connection point for SA Power Networks at Gawler East may be needed after 2025, depending on local demand growth.

Planning focus	Key outcomes
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 NCIPAP. Our project planning has identified that the project we had proposed to turn in the Tailem Bend to Cherry Gardens 275 kV line at Tungkillo no longer meets the criteria for inclusion in our 2018-19 to 2022-23 NCIPAP. We are working to identify another suitable project or projects to replace that project in the 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 aware of significant interest in new generator and load developments, especially in the Mid North, Eyre Peninsula and Riverland regions. To allow increased power transfers between these regions and South Australia's load centre in metropolitan Adelaide, we are investigating opportunities to increase transfer capability through the Mid North. Similarly, we are also investigating ways to further increase the transfer capability between the South East region and the Adelaide metropolitan area, to address potential future interest in the South East as indicated in AEMO's 2020 ISP.
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 during the planning period.
Emergency control schemes	We are collaborating with AEMO to augment the existing SIPS to a more sophisticated WAPS, which will satisfy the requirements of AEMO's 2018 Power System Frequency Review. AEMO's July 2020 Final Power System Frequency Risk Review – Stage 1 (PSFRR) report has identified that high distributed energy resources in the system may result in inadequate UFLS response available to arrest frequency declines following a separation event.[52] A Protected Event is proposed to be declared to manage this challenge. AEMO has also identified that imports on the Heywood interconnector need to be limited in some periods to address the challenges of losing distributed energy resources in response to credible contingency events. A preliminary constraint has been implemented by AEMO, and ElectraNet is completing analysis to provide refined network limit advice that will enable the preliminary constraint to be refined. Control schemes are potential solutions to manage these challenges, to reduce the need to apply constraints. With the rapid evolution of the Power System, we expect a growing need for emergency control schemes to manage both credible and non-credible system events.

[52] AEMO's Final Power System Frequency Risk Review – Stage 1 is available from the consultation page at https://aemo.com.au/consultations/current-and-closed-consultations/2020-psfrr-consultation

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 Interconnector and Smart Grid planning

ElectraNet is progressing projects and investigating opportunities to increase interconnector capacity between South Australia and the rest of the NEM, including the development of Project EnergyConnect and the deployment of "smart grid" technology such as wide area monitoring and protection schemes (Table 7.3 and Figure 7.2).

Consistent with the results of AEMO's 2020 ISP, we are developing Project EnergyConnect to address emerging South Australian and National transmission planning needs.

We are also progressing the upgrade of our SIPS to a more sophisticated WAPS, which will satisfy the requirements of AEMO's 2018 Power System Frequency Review.

In the mid-2020s we propose a more extensive wide area monitoring scheme. We are considering opportunities to further increase the firm transfer capacity of Project EnergyConnect and the Heywood interconnector, for example by installing dynamic voltage control devices, series capacitors or other flow control devices.

Table 7.3: Project EnergyConnect, planned to meet national transmission planning identified needs
Note: Projects that are newly proposed since the 2019 Transmission Annual Planning Report are marked with an asterisk (*)

Project	Region	Constraint driver and investment type	Asset in service
EC.14207 System Integrity Protection Scheme (SIPS) **Estimated cost: $5-6 million** **Status: Planned** Implement a system integrity protection scheme to mitigate risk to the South Australian electricity transmission system prior to South Australian islanding contingencies, utilising rapid transmission-level load tripping and injection from batteries where available (completed in two stages in December 2017 and December 2018) Investigate the feasibility of upgrading the SIPS to a Wide Area Protection Scheme (WAPS) with the use of Power Monitoring Units (PMUs) for more precise event detection, and investigate dynamic and proportionate arming of participating loads and battery energy storage systems ElectraNet does not envisage that this project will impact inter-regional transfer	All	Stability Operational	SIPS already in-service February 2021 (WAPS feasibility study)

Project	Region	Constraint driver and investment type	Asset in service
EC.14246 Wide Area Protection Scheme (WAPS) **Estimated cost: $5-6 million** **Status: Planned** Implement a Wide Area Protection Scheme with the use of PMUs to real time monitor and process system parameters for event detection, and include dynamic arming of participating loads and battery energy storage systems to enable a proportionate response to specific events to further enhance SA system security ElectraNet does not envisage that this project will impact inter-regional transfer	All	Stability Operational	June 2022
EC.14171 Project EnergyConnect: New interconnector between South Australia and New South Wales **Estimated cost: $2.43 billion total (in 2018-19 dollars)** **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 and strengthening the Buronga link to Red Cliffs (Victoria) This project will also increase the maximum amount that can be transferred across Heywood interconnector to a transfer capacity of up to about 750 MW In January 2020, the AER published its determination that Project EnergyConnect remained the most "credible option that maximises the net economic benefit" in the NEM, ultimately benefitting electricity consumers. AEMO's 2020 ISP identifies Project EnergyConnect as a 'no regrets' investment The AER is currently considering two Contingent Project Applications, one for ElectraNet and one for TransGrid, to provide funding for each business to undertake their portion of the works to create Project EnergyConnect ElectraNet envisages that this project will impact inter-regional transfer	Main Grid	Market benefit Augmentation	December 2023

Project	Region	Constraint driver and investment type	Asset in service
EC.15272 Wide Area Monitoring Scheme 2023-2028 **Estimated cost: $5-15 million** **Status: Proposed** Extend the roll-out of PMUs for high-resolution real-time data monitoring of key system parameters to improve operational awareness and decision making, detailed fault and incident investigation including event modelling and benchmarking, power system model benchmarking and validation ElectraNet does not envisage that this project will impact inter-regional transfer If the estimated cost of this project is shown to exceed the RIT-T threshold then we plan to apply the RIT-T prior to project commitment.	All	Stability Operational	2024 – 2028
EC.15241 Wide Area Protection Scheme expansion 2023-24 to 2027-28 **Estimated cost: $4-6 million** **Status: Proposed** Integrate the data available from PMUs for wide area control/ protection schemes to further enhance utilisation and security of the South Australian system	All	Stability Operational	2024 – 2028
EC.15206 Project EnergyConnect Upgrade* **Estimated cost: $40-75 million** **Status: To be considered for proposal as a contingent project** Improve the ability to independently control power flows across Project EnergyConnect ElectraNet envisages that this project will impact inter-regional transfer	Main Grid	Market benefit Augmentation	2024 – 2028 (if shown to deliver net market benefits)
EC.15112 Heywood Interconnector dynamic voltage stability increase* **Estimated cost: $30-60 million** **Status: To be considered for proposal as a contingent project** Install dynamic reactive support at Tailem Bend to firm up increase and export capability across Heywood interconnector, especially if needed to cater for early coal retirements in Victoria, if need not addressed by other developments ElectraNet envisages that this project will impact inter-regional transfer	Main Grid	Market benefit Augmentation	2024 – 2028 (if shown to deliver net market benefits)

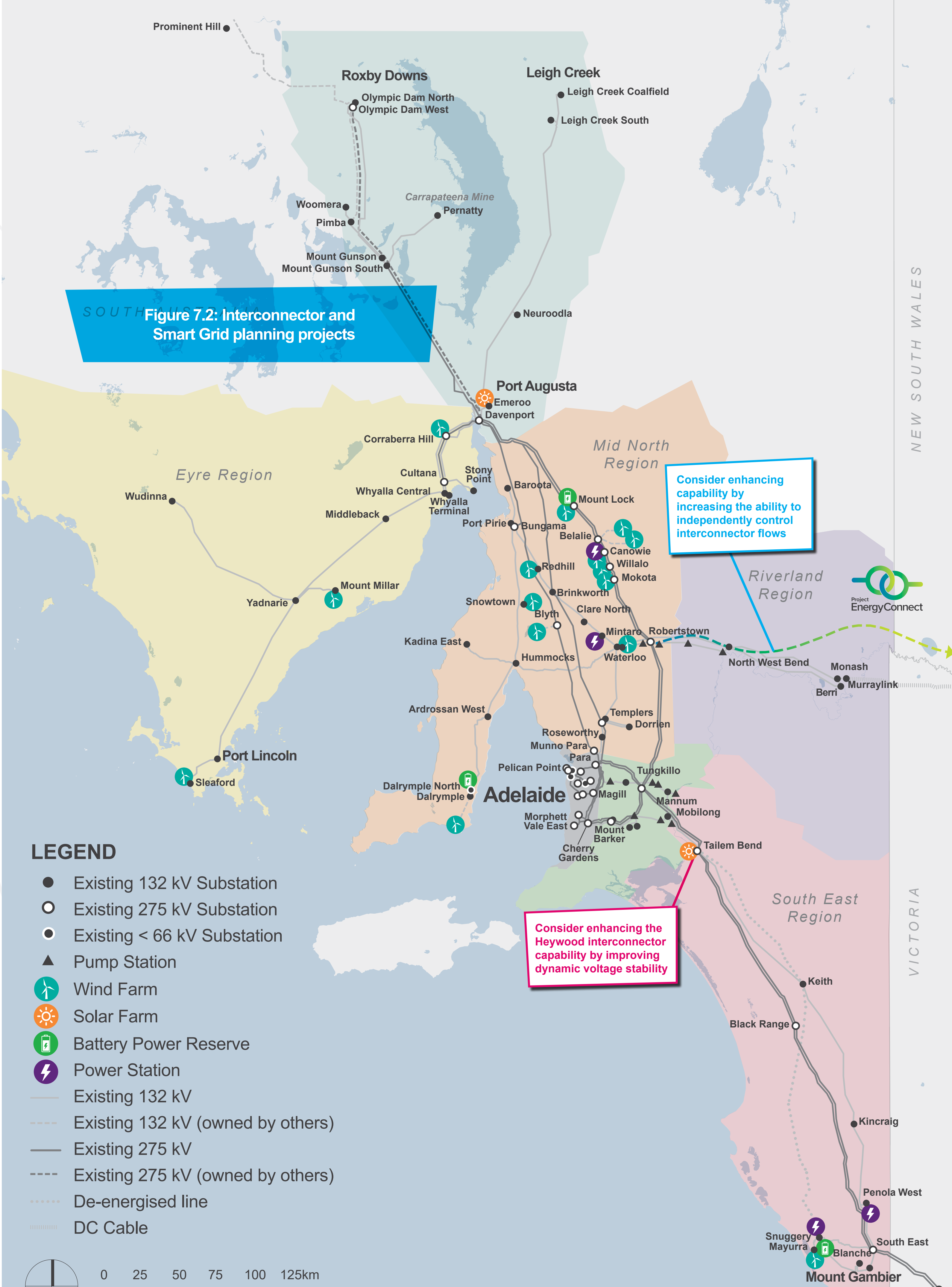


Figure 7.2: Interconnector and Smart Grid planning projects

7.4 System security, power quality and fault levels

A secure power system needs adequate levels of system strength, inertia and voltage control, which in the past have been provided by synchronous power generation. We have proposed several projects to meet system strength, inertia and voltage control needs (Table 7.4 and Figure 7.3), including the committed installation of synchronous condensers at Davenport and Robertstown in 2021.

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.

AEMO has now published the 2020 inertia requirements in South Australia, replacing the 2018 inertia requirements. AEMO has determined the secure operating level of inertia for South Australia, proposing fast frequency response (FFR) to be made available for network support on a basis that enables AEMO to determine a reduced inertia shortfall. We have initiated the procurement process and plan to engage soon with the market for the provision of FFR services.

Fault levels are related to system strength. 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 2020 ISP and confirmed by our own modelling, the total of 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.

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.

The installation of synchronous condensers at Davenport and Robertstown during 2021 will enhance and maintain the ability to adequately control system voltage levels. Additional investment in reactors is forecast to be needed in 2024 to maintain the ability of the system to control system voltage levels within equipment limits as the penetration of distributed solar PV generation continues to the extent that it delivers a net infeed to the transmission system.

The installation of tuned harmonic filter banks is required at various locations to mitigate harmonic voltage distortion levels to within the limits specified in schedule S5.1.6 of the Rules.

The installation of a STATCOM solution is required at Whyalla substation for the ongoing management of voltage fluctuations to within the limits specified in schedule S5.1.5 of the Rules.

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.[53]

[53] Our Transmission Annual Planning Report web page is available at www.electranet.com.au

Table 7.4: Projects planned or proposed to maintain or enhance system security or power quality
Note: Projects that are newly proposed since the 2019 Transmission Annual Planning Report are marked with an asterisk (*)

Project	Region	Constraint driver and investment type	Asset in service
EC.14219 Main Grid System Strength Support **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 Final revenue approval was provided by the AER on 9 August 2019 ElectraNet envisages that this project will impact inter-regional transfer	Main Grid	Compliance Augmentation	January 2021 (Davenport) April 2021 (Robertstown)
EC.15438 Maintain dynamic reactive margin at times of very low demand* **Estimated cost: $30-45 million** **Status: Proposed** Install five 50 Mvar 275 kV reactors at strategic locations to maintain adequate reserve margin on dynamic reactive power devised while maintaining satisfactory management of system voltage levels at times of low system demand ElectraNet does not envisage that this project will impact inter-regional transfer	Main Grid	Reactive support Augmentation	2024 (timing to be refined as project planning progresses)
EC.15297 Maintain adequate suppression of grid harmonic voltage distortion and ongoing management of voltage fluctuation and unbalance levels* **Estimated cost: $15-30 million** **Status: Proposed** Install a STATCOM solution at Whyalla substation to support the management of voltage fluctuations Install harmonic filters at various locations to mitigate harmonic voltage distortion including: • Mid North region • North West Bend • South East • Mount Gunson ElectraNet does not envisage that this project will impact inter-regional transfer	Eyre Peninsula, Mid North, Upper North and Riverland	Compliance Augmentation	2024-2028
EC.15441 Maintain local voltage control at times of low demand* **Estimated cost: $8-15 million** **Status: Proposed** Initiate a program to install switched reactors to maintain the ability to provide adequate voltage control at times of increasingly low or negative demand on selected regional 132 kV networks including: • Eyre Peninsula • Yorke Peninsula • Riverland	Eyre Peninsula, Yorke Peninsula and Riverland	Reactive support Augmentation	2024 - 2028 (timing to be refined as project planning progresses)
EC.15149 Install synchronous condensers in or near the Adelaide metropolitan region* **Estimated cost: $80-130 million** **Status: To be considered for proposal as a contingent project** Install one or two synchronous condensers or other source of fast voltage control (e.g. STATCOM) in or near the Adelaide metropolitan region to increase system strength, to enable continued growth in distributed energy resources ElectraNet envisages that this project will impact inter-regional transfer	Main Grid	Compliance Augmentation	2024 – 2028 (if shown to deliver net market benefits or due to revised system security framework)

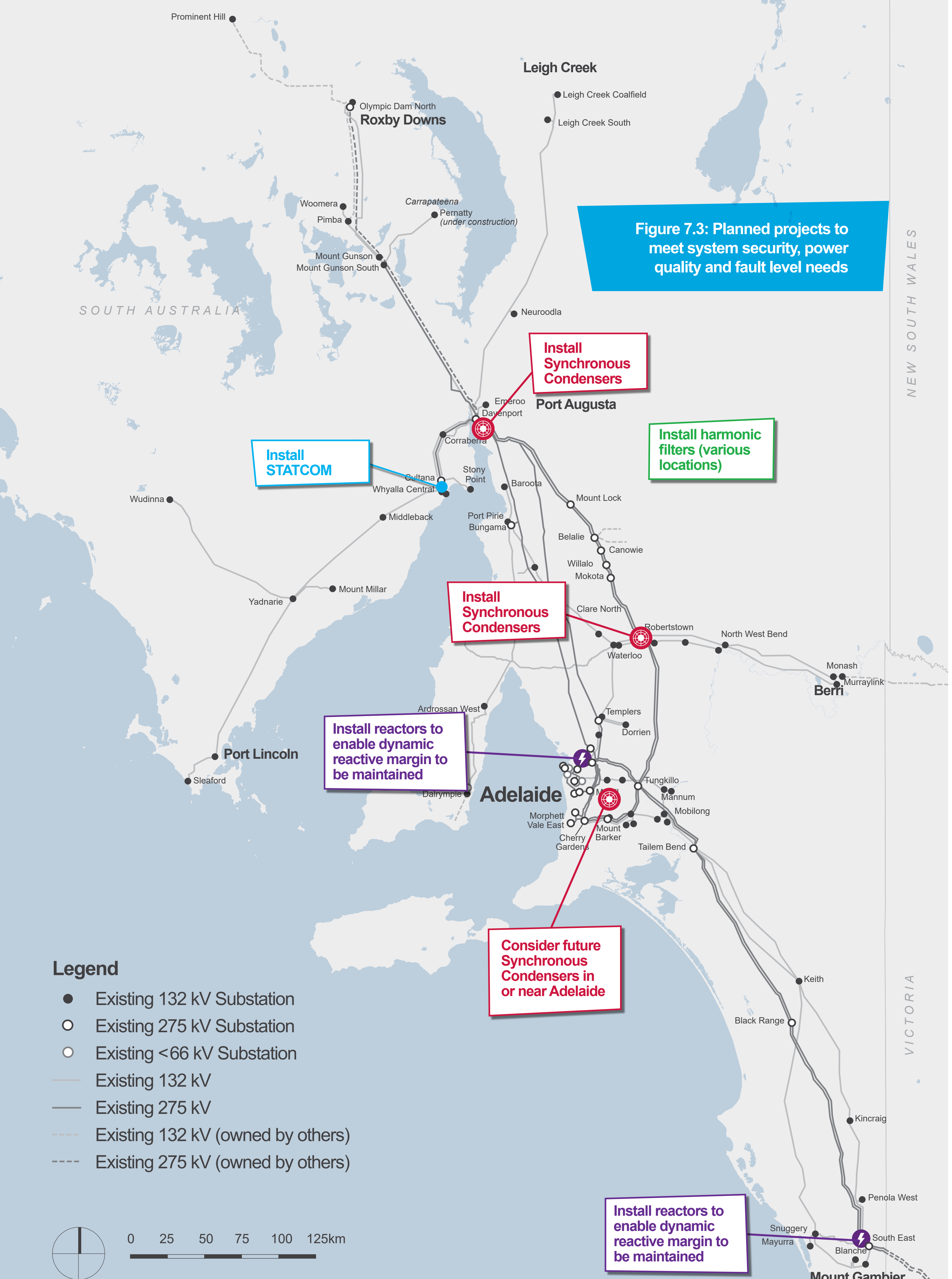


Figure 7.3: Planned projects to meet system security, power quality and fault level needs

7.5 Capacity and Renewable Energy Zone development

We are progressing the development of Eyre Peninsula Link to continue to efficiently meet reliability standards on the Eyre Peninsula, and have also identified potential projects to provide capability for future new customers and generators (Table 7.5).

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 (Appendix B).

Through joint planning with SA Power Networks we have identified that a new connection point at Gawler East may be required after 2025, depending on load developments in the local area.

If a new large customer connects on the Eyre Peninsula in the future it may become necessary to upgrade the Cultana to Yadnarie section of Eyre Peninsula Link from 132 kV to 275 kV operation.

We also assess the capability of the network to accommodate new generator connections. In doing so we consider the REZs that AEMO identifies for potential development in the ISP along with the results of our own analysis to identify potential projects to provide additional capacity for new generator connections.

Given the continuing high level of interest in new generator connections in South Australia, we consider that the future developments identified in the ISP could be needed much earlier than indicated.

As outlined in section 2.1 of this report, AEMO's 2020 ISP forecasts that network expansion to release REZ capacity in the South East of South Australia will be needed in the late 2030s, or in 2030-31 if the Step Change scenario eventuates. To meet this need we propose to string the vacant 275 kV circuit between Tailem Bend and Tungkillo to increase transfer capacity between the South East and the Adelaide metropolitan load centre and install dynamic reactive support if needed to improve dynamic voltage stability.

The 2020 ISP also forecasts a need to alleviate constraints between Davenport and Adelaide and between Davenport and Robertstown in 2034-35 or 2035-36.[54] To meet this need we are proposing a series of projects to progressively release capacity:

- EC.15209, to install a second 275/132 kV transformer at Templers West and decommission the existing Templers to Waterloo 132 kV line
- EC.15205, to increase transfer capacity between Robertstown and Adelaide, perhaps by building new double circuit 275 kV lines between Robertstown and Para via Templers West
- EC.15153, to increase transfer capacity by constructing new 275 kV lines between Davenport and Robertstown, Para or Templers West.

The second and third of these projects are proposed to be developed in stages, with the first stage of each project consisting of preparatory works (such as RIT-T, project planning and easement acquisition) during the 2023-24 to 2027-28 regulatory control period. The second stage of each project is to bring the project to completion when shown to deliver net market benefits, expected to be between the mid-2020s and late 2030s depending on generator developments.

We have also proposed other projects that might be required to release additional capacity for new generator connections in the South East, the Riverland, and on the Eyre Peninsula.

Projects to improve generator or load hosting capacity in the Upper North are included in the current regulatory control period as contingent projects.

Further detail is available from our Transmission Annual Planning Report web page. [55]

[54] AEMO's Final 2020 Integrated System Plan, page 91. Available at https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2020-integrated-system-plan-isp

[55] Our Transmission Annual Planning Report web page is available at www.electranet.com.au

Table 7.5: Projects planned or proposed to meet capacity or REZ development needs

Note: Projects that are newly proposed since the 2019 Transmission Annual Planning Report are marked with an asterisk (*)
Projects for which the asset in service date has been adjusted since the 2019 Transmission Annual Planning Report are marked with a hash (#)

Project	Region	Constraint driver and investment type	Asset in service
EC.14172 Eyre Peninsula Link # **Estimated cost: $280-320 million** **Status: Committed** 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 In April 2019 The AER determined that the preferred option satisfies the requirements of the RIT-T On 28 September 2020, the AER published its determination on our Contingent Project Application to provide funding for Eyre Peninsula Link ElectraNet does not envisage that this project will impact inter-regional transfer	Eyre Peninsula	Reliability Augmentation	December 2022
EC.15104 Eyre Peninsula upgrade* **Estimated cost: $50-90 million** **Status: To be considered for proposal as a contingent project** Upgrade the operating voltage of the committed new Cultana to Yadnarie transmission lines from 132 kV to 275 kV if potential large loads connect on the Eyre Peninsula ElectraNet does not envisage that this project will impact inter-regional transfer	Eyre Peninsula	Capacity Augmentation	2024 – 2028 (if required to facilitate large new customer connections on Eyre Peninsula)
EC.14085 Establish new connection point at Gawler East **Estimated cost: $6-10 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 ElectraNet does not envisage that this project will impact inter-regional transfer	Mid North	Capacity Augmentation	After 2025 (depending on local demand growth)
EC.11011 Upper South East network augmentation* **Estimated cost: $30-80 million** **Status: To be considered for proposal as a contingent project** String the vacant third 275 kV circuit between Tailem Bend and Tungkillo and install static and dynamic reactive compensation if needed to increase transfer capability between the South East and the Adelaide metropolitan area ElectraNet envisages that this project may impact inter-regional transfer	Eastern Hills	Market benefits Augmentation	2024 – 2028 (if shown to deliver net market benefits)
EC.15201 Riverland REZ Hub Connection* **Estimated cost: $30-80 million** **Status: To be considered for proposal as a contingent project** Enable the connection of renewable energy in the Riverland region by establishing a connection hub at a suitable location along the route of Project EnergyConnect ElectraNet envisages that this project may impact inter-regional transfer	Riverland	Market benefits Augmentation	2024 – 2028 (if shown to deliver net market benefits)
EC.15209 Second Templers West transformer and reconfigure Mid North 132 kV network* **Estimated cost: $10-18 million** **Status: Proposed** Install a second 275/132 kV transformer at Templers West and reconfigure the Mid North 132 kV network by decommissioning the Templers-Waterloo 132 kV line and connecting the new Templers West 275/132 kV transformer to the Templers 132 kV bus, to enable greater power flows between sources of renewable power generation in the northern parts of South Australia and the Adelaide metropolitan load centre ElectraNet does not envisage that this project will impact inter-regional transfer	Mid North	Market benefits Augmentation	2024 – 2028 (if shown to deliver net market benefits)

Project	Region	Constraint driver and investment type	Asset in service
EC.15205 Increase transfer capacity between Robertstown and Adelaide* **Estimated cost: $200-350 million** **Status: To be considered for proposal as a contingent project** Construct new double circuit 275 kV high capacity lines between Robertstown and Templers West and rebuild the Templers West to Para 275 kV line with high capacity double circuit 275 kV lines, to enable greater power flows to the Adelaide metropolitan load centre from sources of renewable power generation in the northern parts of South Australia and from Project EnergyConnect ElectraNet envisages that this project will impact inter-regional transfer	Mid North	Market benefits Augmentation	Stage 1 (preparatory works) in 2024 – 2028 Stage 2 (full project completion) between the mid-2020s and late-2030s (if shown to deliver net market benefits)
EC.15153 Increase transfer capacity between Davenport and Adelaide* **Estimated cost: $350-650 million** **Status: To be considered for proposal as a contingent project** Augment the Davenport to Para transmission path by building new double circuit 275 kV lines between Davenport and Robertstown, Templers West or Para, to enable greater power flows between sources of renewable power generation in the northern parts of South Australia and the Adelaide metropolitan load centre ElectraNet envisages that this project will impact inter-regional transfer	Mid North	Market benefits Augmentation	Stage 1 (preparatory works) in 2024 – 2028 Stage 2 (full project completion) between the mid-2020s and late-2030s (if shown to deliver net market benefits)

Project	Region	Constraint driver and investment type	Asset in service
EC.15261 Build new third and fourth 275 kV lines between Davenport and Cultana* **Estimated cost: $50-100 million** **Status: To be considered for proposal as a contingent project** Build a new double circuit 275 kV line to establish the third and fourth Davenport to Cultana 275 kV lines, to provide increased capacity for significant new loads and renewable generation connections on Eyre Peninsula ElectraNet does not envisage that this project will impact inter-regional transfer	Eyre Peninsula	Market benefits Augmentation	2024 – 2028 (if shown to deliver net market benefits)
EC.14212 Upper North region eastern 132 kV line reinforcement **Estimated cost: $60 million** **Status: Contingent – refer to Appendix E for trigger** Uprate or rebuild the Davenport to Leigh Creek 132 kV line and establish associated substation assets (including reactive support) ElectraNet does not envisage that this project will impact inter-regional transfer	Upper North	Capacity Augmentation	Uncertain
EC.14093 Upper North region western 132 kV line reinforcement **Estimated cost: Less than $110 million** **Status: Contingent – refer to Appendix E for trigger** Rebuild the Davenport to Pimba 132 kV line and establish associated substation assets (including reactive support) ElectraNet does not envisage that this project will impact inter-regional transfer	Upper North	Capacity Augmentation	Uncertain

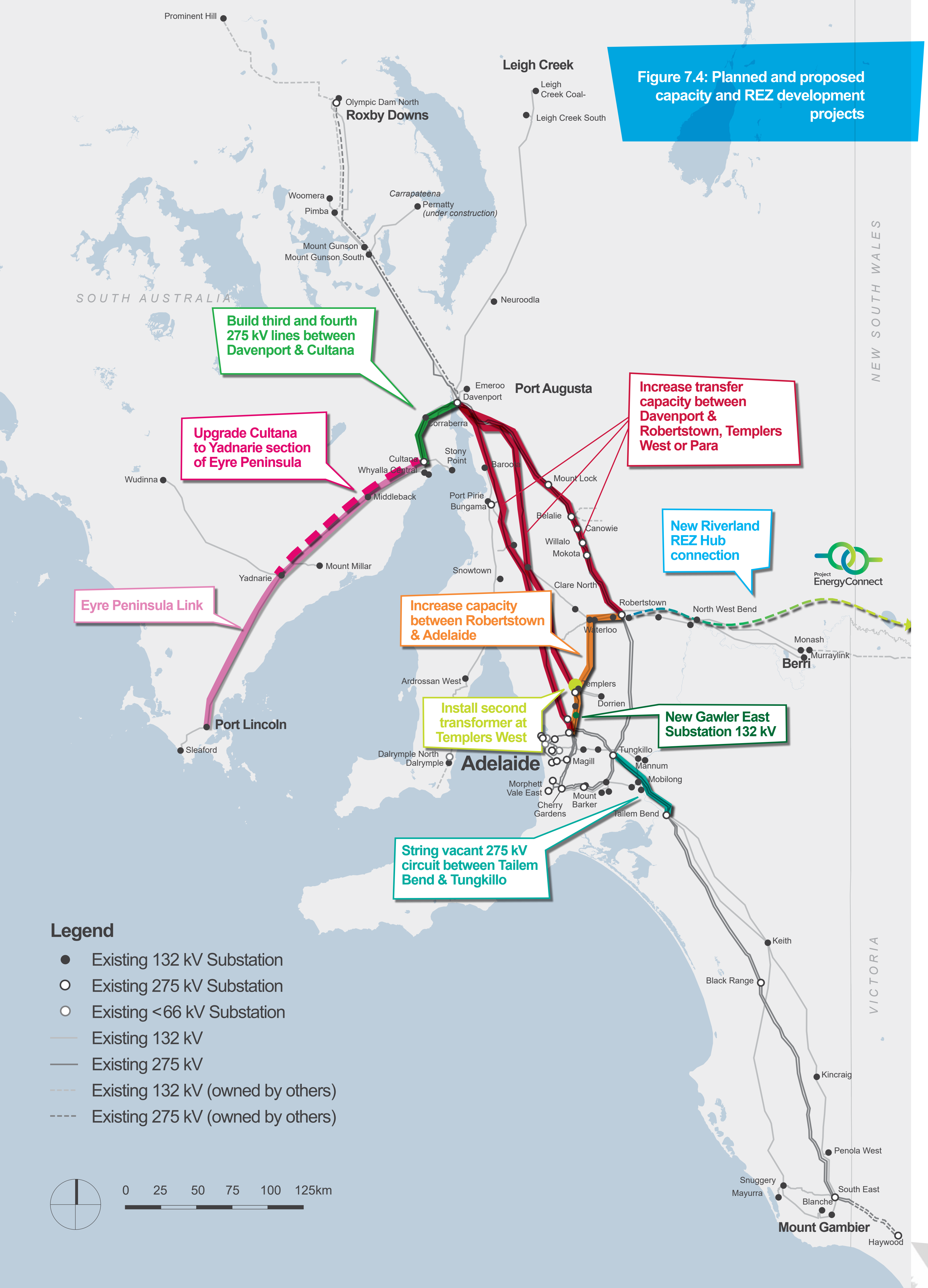


Figure 7.4: Planned and proposed capacity and REZ development projects

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 ISP, to predict new constraints that may develop in future years.

We plan to complete projects that form part of our 2018-19 to 2022-23 NCIPAP (Table 7.6 and Figure 7.5).

Our project planning has identified that the project we had previously proposed to turn in the Tailem Bend to Cherry Gardens 275 kV line at Tungkillo no longer meets the criteria for inclusion in our 2018-19 to 2022-23 NCIPAP. We are working to identify another suitable project or projects to replace that project in the plan.

We are considering projects to propose for inclusion in our 2023-24 to 2027-28 NCIPAP and intend to provide information on those projects in our 2021 Transmission Annual Planning Report.

Further detail is available from our Transmission Annual Planning Report web page.[56]

Table 7.6: Projects planned to address market benefit opportunities
Note: Projects for which the planned asset in service date has been adjusted since the 2019 Transmission Annual Planning Report are marked with a hash (#)

Project	Region	Constraint driver and investment type	Asset in service
EC.14168 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	November 2020 (Smart Wires Power Guardian) April 2021 (Line uprates)
EC.14211 South East capacitor bank # **Estimated cost: Less than $4-6 million** **Status: Planned** Further alleviate forecast congestion on the Heywood interconnector by installing an additional 100 Mvar 275 kV switched capacitor at South East substation to 'firm up' transfer capability by maintaining voltage stability at higher transfer levels ElectraNet envisages that this project will impact inter-regional transfer	South East	Market benefits (NCIPAP) Augmentation	December 2021

56 Our Transmission Annual Planning Report web page is available at www.electranet.com.au

Project	Region	Constraint driver and investment type	Asset in service
EC.14065 Robertstown transformer management relay **Estimated cost: Less than $5 million** **Status: Planned** Alleviate constraints on Murraylink interconnector by installing transformer management relays and bushing monitoring equipment to enable the application of short term ratings to the Robertstown 275/132 kV transformers ElectraNet envisages that this project will impact inter-regional transfer	Mid North	Market benefits (NCIPAP) Augmentation	June 2022
EC.11002 Strengthen the Eastern Hills transmission corridor **Estimated cost: $6-10 million** **Status: Planned** Connect the Tailem Bend to Cherry Gardens 275 kV line at Tungkillo, and uprate the Eastern Hills 275 kV lines to 120 °C design clearances where practicable The scope of this project will be considered for implementation with project EC.11011 (Table 7.5) ElectraNet envisages that this project will impact inter-regional transfer	Eastern Hills	Market benefits Augmentation	Project deferred until 2023 – 2028 (to be removed from NCIPAP as forecast cost is above NCIPAP threshold)
EC.14042 Canowie circuit breaker arrangement upgrade **Estimated cost: Less than $3 million** **Status: Proposed** Install one 275 kV circuit breaker and all associated equipment at Canowie on the Robertstown exit, to eliminate the need for generators connected at Canowie to be disconnected during planned and unplanned outages of the Canowie to Robertstown 275 kV line	Mid North	Market benefits Augmentation	2024 - 2028

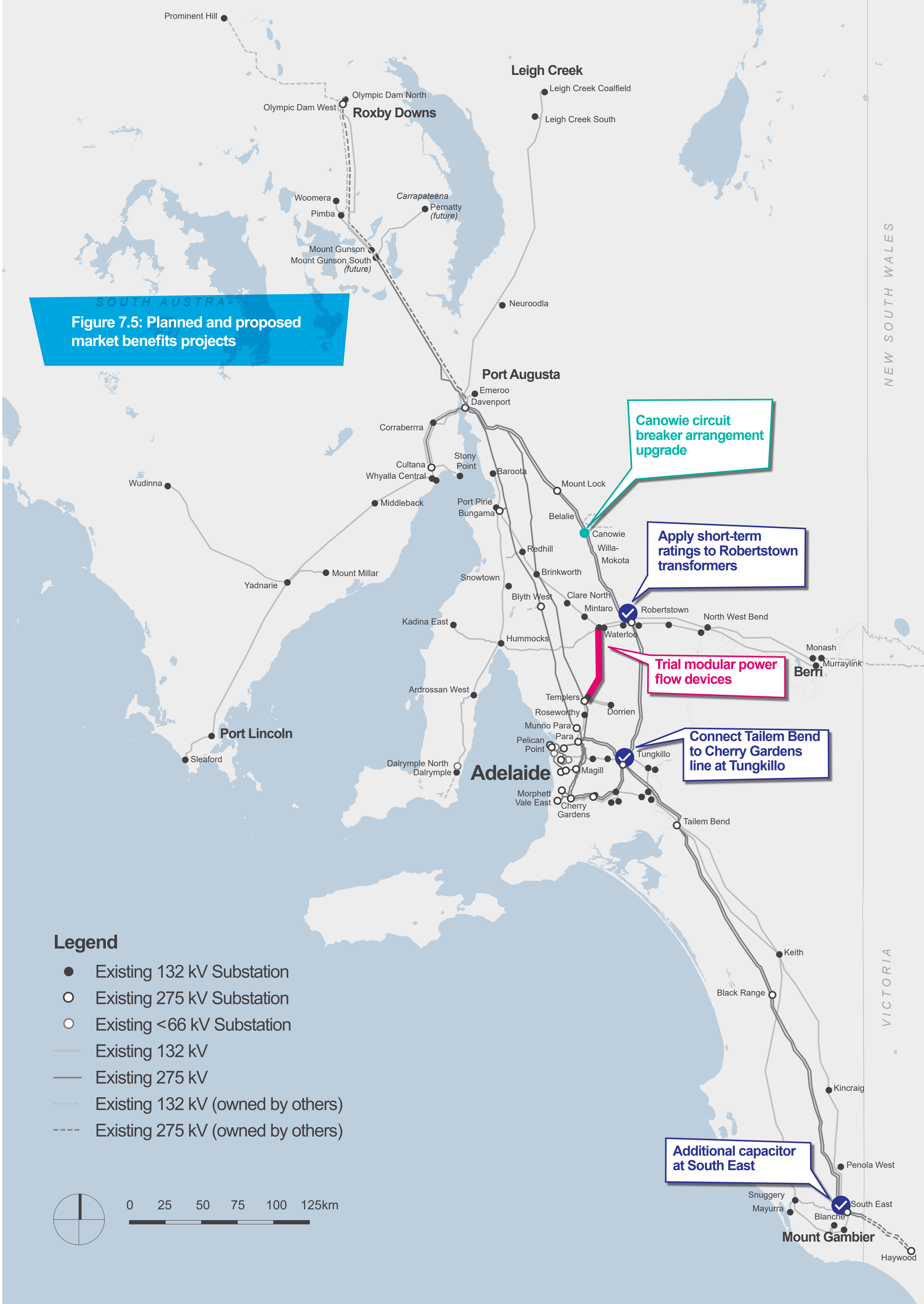


Figure 7.5: Planned and proposed market benefits projects

7.7 Network asset retirements and replacements

ElectraNet carries out projects that are planned to address needs that arise from planned retirements of assets, for example due to condition (Table 7.7).

Projects are listed in this section if they are subject to the RIT T, or if they would have been subject to the RIT-T if they had not already been committed by 30 January 2018. Projects are also listed if they relate to the replacement of a power transformer at a substation, even if their estimated cost is below the RIT-T threshold.

Further details, including for projects with costs that are lower than the RIT-T cost threshold, are available from our Transmission Annual Planning Report web page.[57]

We do not envisage that any of these projects will impact inter-network transfer.

Table 7.7: Projects planned to address asset retirement and replacement needs

Note: Projects which are newly proposed since the 2019 Transmission Annual Planning Report are marked with an asterisk (*)
Projects for which the planned asset in service date has been adjusted since the 2019 Transmission Annual Planning Report are marked with a hash (#)

Project	Region	Constraint driver and investment type	Asset in service
EC.14049 Leigh Creek South transformer replacement # **Estimated cost: $4-6 million** **Status: Planned** Replace the two existing 132/33 kV 5 MVA transformers, assessed to be at the end of their technical life with a corresponding high risk of failure, and the two SA Power Networks 33/11 kV transformers with a single new 5 MVA 132/11 kV transformer	Upper North	Asset condition and performance Asset renewal	December 2021
EC.11749 AC Board replacement 2013 - 2018 # **Estimated cost: $15-20 million** **Status: Committed** Replace and improve AC auxiliary supply equipment, switchboards and cabling at 11 substations that are at the end of technical life	Various	Asset condition and performance Asset renewal	April 2021
EC.14081 Line Insulator Systems Refurbishment 2018-19 to 2022-23 # **Estimated Cost: $50-60 million** **Status: Committed** 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	Asset condition and performance Asset renewal	January 2023
EC.14046 AC Board Replacement 2018-19 to 2022-23 # **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 completed a RIT-T for this program of work by publishing a PACR on 14 January 2020	Various	Asset condition and performance Asset renewal	November 2026

Project	Region	Constraint driver and investment type	Asset in service
EC.14084 Line Conductor and Earthwire Refurbishment 2018-19 to 2022-23 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 2026
EC.14090 Mount Gambier transformer 1 replacement # **Estimated cost: Less than $3m** **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 capacity to meet the forecast demand at Mount Gambier connection point Options for partial or complete replacement of Mount Gambier substation are currently being considered for the 2023-24 to 2027-28 period, which would be conducted in conjunction with this project	South East	Asset condition and performance Asset renewal	Project deferred until 2024-2028 period
EC.14077 Mannum transformer nos. 1 and 2 replacement # **Estimated cost: $6-12 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) We plan to initiate a RIT-T prior to commitment	Eastern Hills	Asset condition and performance Asset renewal	Project deferred until 2024-2028 period
EC.15060 Circuit breakers unit asset replacement 2023-24 to 2027-28* **Estimated cost: $8-15 million** **Status: Proposed** Replace and improve circuit breakers across the South Australian electricity transmission system that will be assessed to be at the end of their technical and economic lives during the 2023-24 to 2027-28 regulatory control period We plan to initiate a RIT-T prior to commitment	Various	Asset condition and performance Asset renewal	2024 – 2028

Project	Region	Constraint driver and investment type	Asset in service
EC.15279 Emergency unit asset replacement 2023-24 to 2027-28 # **Estimated cost: $8-12 million** **Status: Proposed** Emergency replacement of individual assets is undertaken for assets that fail unexpectedly, to meet reliability standards The average annual value of stock turn-over is about $2 million	Various	Asset condition and performance Asset renewal	2024 – 2028
EC.15043 AC Board unit asset replacement 2023-24 to 2027-28 # **Estimated cost: $8-15 million** **Status: Proposed** Replace and improve AC auxiliary supply equipment, switchboards and cabling across the South Australian electricity transmission system that will be assessed to be at the end of their technical and economic lives during the 2023-24 to 2027-28 regulatory control period We plan to initiate a RIT-T prior to commitment	Various	Asset condition and performance Asset renewal	2024 – 2028
EC.15233 Transmission line insulation system refurbishment 2023-24 to 2027-28 **Estimated cost: $40-70 million** **Status: Proposed** Implement a program to refurbish transmission line insulator systems across the network that will be assessed to be at end-of-life during the 2023-24 to 2027-28 regulatory control period, to renew line asset components and extend line life We plan to initiate a RIT-T prior to commitment	Various	Asset condition and performance Asset renewal	2024 – 2028
EC.15239 Transmission line conductor systems refurbishment 2023-24 to 2027-28 **Estimated cost: $10-20 million** **Status: Proposed** Replace line conductor and earthwire for parts of the Hummocks to Ardrossan West 132 kV line that have been assessed to be at end-of-life during the 2023-24 to 2027-28 regulatory control period, to renew line asset components and extend line life We plan to initiate a RIT-T prior to commitment	Mid North and Riverland	Asset condition and performance Asset renewal	2024 – 2028
EC.15116 Hummocks substation replacement* **Estimated cost: Up to $50 million** **Status: Proposed** We are considering options to address condition and performance needs at Hummocks substation, ranging from replacement of targeted individual components to replacement of the entire substation on a nearby site We plan to initiate a RIT-T prior to commitment	Mid North	Asset condition and performance Asset renewal	2024 – 2028
EC.15168 Mount Gambier substation replacement* **Estimated cost: Up to $50 million** **Status: Proposed** We are considering options to address condition and performance needs at Mount Gambier substation, ranging from replacement of targeted individual components to replacement of the entire substation on a nearby site We plan to initiate a RIT-T prior to commitment	South East	Asset condition and performance Asset renewal	2024 – 2028

Project	Region	Constraint driver and investment type	Asset in service
EC.15432 Transmission line refurbishment 2023-24 to 2027-28* **Estimated cost: $8-15 million** **Status: Proposed** Perform structure refurbishment on the Bungama to Port Pirie 132 kV line including tower painting, tower fastener replacement and climbing aid replacement as required to extend line life on selected structures of the 132 kV line We plan to initiate a RIT-T prior to commitment	Mid North	Asset condition and performance Asset renewal	2024 – 2028
EC.15069 Circuit breakers unit asset replacement 2028-29 to 2032-33 **Estimated cost: $6-10 million** **Status: Proposed** Replace and improve circuit breakers across the South Australian electricity transmission system that will be assessed to be at the end of their technical and economic lives during the 2028-29 to 2032-33 regulatory control period We plan to initiate a RIT-T prior to commitment	Various	Asset condition and performance Asset renewal	2029 – 2033
EC.15295 Emergency unit asset replacement 2028-29 to 2032-33* **Estimated cost: $8-12 million** **Status: Proposed** Emergency replacement of individual assets is undertaken for assets that fail unexpectedly, to meet reliability standards The average annual value of stock turn-over is about $2 million	Various	Asset condition and performance Asset renewal	2029 – 2033
EC.15042 AC Board unit asset replacement 2028-29 to 2032-33* **Estimated cost: $8-15 million** **Status: Proposed** Replace and improve AC auxiliary supply equipment, switchboards and cabling at seventeen substations across the South Australian electricity transmission system that will be assessed to be at the end of their technical and economic lives during the 2028-29 to 2032-33 regulatory control period We plan to initiate a RIT-T prior to commitment	Various	Asset condition and performance Asset renewal	2029 – 2033
EC.15251 Transmission line insulation unit asset replacement 2028-29 to 2032-33* **Estimated cost: $12-20 million** **Status: Proposed** Refurbish transmission line insulator systems across the network that will be assessed to be at end-of-life during the 2028-29 to 2032-33 regulatory control period, to renew line asset components and extend line life We plan to initiate a RIT-T prior to commitment	Various	Asset condition and performance Asset renewal	2029 – 2033
EC.15253 Transmission line conductor unit asset replacement 2028-29 to 2032-33* **Estimated cost: $12-20 million** **Status: Proposed** Replace transmission line conductor and earthwire for components that will be assessed to be at end-of-life during the 2028-29 to 2032-33 regulatory control period, to renew line asset components and extend line life We plan to initiate a RIT-T prior to commitment	Various	Asset condition and performance Asset renewal	2029 – 2033

7.8 Network asset ratings

We are continually exploring ways to improve the capacity of our network to supply additional customer load and enable connected generators to access the market. To support this, we have developed a Plant and Line Rating Strategy that describes how network and public risk can be understood and mitigated, while maximising network utilisation and capacity.

The Strategy proposes initial refinements to the application of static ratings, followed by a more widespread deployment of dynamic line ratings, which will be supported by improvements to the infrastructure (including weather stations) that is needed to apply and validate the dynamic line ratings. The Strategy also includes the development of software modules to support analysis and quantification of risk and data management.

We are developing a series of projects to support our Plant and Line Rating Strategy, and plan to provide further details in the 2021 Transmission Annual Planning Report.

ElectraNet continually reviews the condition of network assets to ensure that these assets are suitable to support the forecast load. Where condition assessment indicates that an asset's condition and performance is declining to an unacceptable level, a planned refurbishment or replacement program is put in place.

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

7.9 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).

Various programs of work that exceed $6 million for grouped network asset retirement and replacement are proposed over the 10-year planning period (Table 7.8).

Further details, including for projects that do not exceed the RIT-T cost threshold, are available from our Transmission Annual Planning Report web page. [58]

We do not envisage that any of these projects will have impact inter-network transfer.

[58] Our Transmission Annual Planning Report web page is available at www.electranet.com.au

Table 7.8: Grouped projects planned to meet asset retirement and replacement needs

Note: Projects which are newly proposed since the 2019 Transmission Annual Planning Report are marked with an asterisk (*) Projects for which the planned Asset in service date has been adjusted since the 2019 Transmission Annual Planning Report are marked with a hash (#)

Project	Region	Constraint driver and investment type	Asset in service
EC.14047 Transformer bushing unit asset replacement 2018-19 to 2022-23 # **Estimated cost: $6-8 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 This project includes the replacement of assets at the following sites: *Berri, Cherry Gardens, LeFevre, Murray Bridge–Hahndorf No. 1 Pump Station, Murray Bridge–Hahndorf No. 3 Pump Station, North West Bend, Para, Robertstown, Yadnarie* We published a PACR on 11 December 2018, concluding the RIT-T for this program of work [59]	Various	Asset condition and performance Asset renewal	May 2022
EC.14032 Instrument Transformer unit asset replacement 2018-19 to 2022-23 **Estimated cost: $10-14 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 This project includes the replacement of assets at the following sites: *Angas Creek, Berri, Brinkworth, Davenport, East Terrace, Happy Valley, Hummocks, Kanmantoo, Keith, Kilburn, Kincraig, Leigh Creek South, Morphett Vale East, Murray Bridge/Hahndorf No.1 Pump Station, North West Bend, Northfield, Parafield Gardens West, Port Lincoln Terminal, Robertstown, Snuggery, South East, Stony Point, Tailem Bend, Templers, Yadnarie* We published a PACR on 7 Janurary 2020, concluding the RIT-T for this program of work [60]	Various	Asset condition and performance Asset renewal	June 2023
EC.14034 Isolator unit asset replacement 2018-19 to 2022-23 # **Estimated cost: $8-12 million** **Status: Committed** 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 This project includes the replacement of assets at the following sites: *Berri, Cultana, Dorrien, LeFevre, Magill, Middleback, Monash, Mount Gambier, Para, Penola West, Robertstown, Snuggery, Tailem Bend, Torrens Island A, Torrens Island B* We published a PACR on 18 November 2019, concluding the RIT-T for this program of work [61]	Various	Asset condition and performance Asset renewal	September 2024
EC.14031 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** This project includes the replacement of assets at the following sites: *Angas Creek, Berri, Brinkworth, Davenport, East Terrace, Happy Valley, Hummocks, Kanmantoo, Keith, Kilburn, Kincraig, Leigh Creek South, Morphett Vale East, Murray Bridge/Hahndorf No.1 Pump Station, North West Bend, Northfield, Parafield Gardens West, Pimba, Port Lincoln Terminal, Robertstown, Snuggery, South East, Stony Point, Tailem Bend, Templers, Yadnarie* We published a PACR on 6 December 2019, concluding the RIT-T for this program of work [62]	Various	Asset condition and performance Asset renewal	September 2024
EC.15242 Transformer bushing unit asset replacement 2023-24 to 2027-28* **Estimated cost: $5-10 million** **Status: Proposed** Replace individual transformer bushings that will be assessed to be at the end of their technical or economic lives during the 2023-24 to 2027-28 regulatory control period This project will include the replacement of assets which will be determined based on asset needs We plan to initiate a RIT-T prior to commitment	Various	Asset condition and performance Asset renewal	2024 – 2028

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

[60] The Managing the Risk of Instrument Transformer Failure PACR is available from https://www.electranet.com.au/projects/managing-the-risk-of-instrument-transformer-failure-project/.

[61] The Managing the Risk of Isolator Failure PACR is available from https://www.electranet.com.au/projects/isolator-replacement-and-refurbishment-project/.

[62] The Managing the Risk of Protection Relay Failure PACR is available from https://www.electranet.com.au/projects/managing-the-risk-of-protection-relay-failure/.

Project	Region	Constraint driver and investment type	Asset in service
EC.15120 Instrument Transformer unit asset replacement 2023-24 to 2027-28* **Estimated cost: $20-30 million** **Status: Proposed** Replace voltage transformers and 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 This project will include the replacement of assets which will be determined based on asset needs We plan to initiate a RIT-T prior to commitment	Various	Asset condition and performance Asset renewal	2024 – 2028
EC.15189 Protection relay unit asset replacement 2023-24 to 2027-28* **Estimated cost: $10-30 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 We are also assessing whether there is a need to replace existing distance protection with unit protection to ensure protection systems operate correctly when the system fault level is very low This project will include the replacement of assets which will be determined based on asset needs We plan to initiate a RIT-T prior to commitment	Various	Asset condition and performance Asset renewal	2024 – 2028
EC.15275 Earth leakage protection replacement 2023-24 to 2027-28* **Estimated cost: $12-20 million** **Status: Proposed** Replace earth leakage protection equipment across the South Australian electricity transmission system that has reached the end of its technical or economic lives This project will include the replacement of assets which will be determined based on asset needs We plan to initiate a RIT-T prior to commitment	Various	Asset condition and performance Asset renewal	2024 – 2028
EC.15397 Isolator unit asset replacement 2023-24 to 2027-28* **Estimated cost: $25-50 million** **Status: Proposed** Replace individual substation isolators that will be assessed to be at the end of their technical or economic lives during the 2023-24 to 2027-28 regulatory control period This project will include the replacement of assets which will be determined based on asset needs We plan to initiate a RIT-T prior to commitment	Various	Asset condition and performance Asset renewal	2024 – 2028
EC.15123 Instrument Transformer unit asset replacement 2028-29 to 2032-33* **Estimated cost: $50-80 million** **Status: Proposed** Replace voltage transformers and 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 This project will include the replacement of assets which will be determined based on asset needs We plan to initiate a RIT-T prior to commitment	Various	Asset condition and performance Asset renewal	2029 – 2033

Project	Region	Constraint driver and investment type	Asset in service
EC.15244 Transformer bushing unit asset replacement 2028-29 to 2032-33* **Estimated cost: $5-10 million** **Status: Proposed** Replace individual transformer bushings that will be assessed to be at the end of their technical or economic lives during the 2028-29 to 2032-33 regulatory control period This project will include the replacement of assets which will be determined based on asset needs We plan to initiate a RIT-T prior to commitment	Various	Asset condition and performance Asset renewal	2029 –2033
EC.15211 Protection relays unit asset replacement 2028-29 to 2032-33* **Estimated cost: $8-15 million** **Status: Proposed** 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 which will be determined based on asset needs We plan to initiate a RIT-T prior to commitment	Various	Asset condition and performance Asset renewal	2029 – 2033
EC.15214 Protection signal equipment replacement stage 1 2028-29 to 2032-33* **Estimated cost: $5-10 million** **Status: Proposed** Replace protection signal equipment across the South Australian electricity transmission system that has reached the end of its technical or economic lives This project will include the replacement of assets which will be determined based on asset needs We plan to initiate a RIT-T prior to commitment	Various	Asset condition and performance Asset renewal	2029 – 2033

7.10 Security and compliance projects

There are a range of committed and planned projects that relate to the maintenance of our security and compliance obligations for which planned expenditure exceeds $6 million (Table 7.9).

Further details, including for projects that do not exceed $6 million, are available from our Transmission Annual Planning Report web page.[63]

Table 7.9: Projects planned to meet security and compliance needs
Note: Projects that are newly proposed since the 2019 Transmission Annual Planning Report are marked with an asterisk (*) Projects for which the planned Asset in service date have been adjusted since the 2019 Transmission Annual Planning Report are marked with a hash (#)

Project	Region	Constraint driver and investment type	Asset in service
EC.14131 Motorised isolator LOPA improvement # **Estimated cost: $10-12 million** **Status: Committed** 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	Safety Asset renewal	October 2021
EC.11828 Substation perimeter video monitoring and security* **Estimated cost: $12-20 million** **Status: Proposed** Implement perimeter video monitoring at substation selected sites to improve site security	Various	Safety Operational	2024 – 2028
EC.15235 Transmission line anti-climb installation 2023-24 to 2027-28* **Estimated cost: $25-50 million** **Status: Proposed** Replace or install effective climbing deterrent devices on all identified line tower assets and replace or install updated warning signage on all tower structures, to meet and maintain requirements to prevent unauthorised access to electricity infrastructure We plan to initiate a RIT-T for this program of work prior to commitment	Various	Safety Asset renewal	2024 – 2028
EC.15231 – Transmission line anti-climb 2028-29 to 2032-33* **Estimated cost: $25-50 million** **Status: Proposed** Replace or install effective climbing deterrent devices on all identified line tower assets and replace or install updated warning signage on all tower structures, to meet and maintain requirements to prevent unauthorised access to electricity infrastructure We plan to initiate a RIT-T for this program of work prior to commitment	Various	Safety Asset renewal	2029 – 2033

[63] Our Transmission Annual Planning Report web page is available at www.electranet.com.au

Appendices

Appendix A: Summary of changes since the 2019 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 2020 Transmission Annual Planning Report (TAPR) that have changed significantly from the 2019 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 2019 and 2020 TAPR	Analysis and explanation for the significant change
1.1	Renewable generation development continues to drive the evolution of South Australia's electricity system	Figure 1.1 has been extended to provide an indication of the outcome of ElectraNet's market modelling for 2029-30 Section 1.1 has been expanded to include a description of the emerging technical challenges that are arising as a result of the electricity transformation that is occurring in South Australia	The changes to section 1.1 help to indicate the magnitude of the change that is forecast in South Australia's electricity system in the coming decade and the consequential emerging challenges
1.2	Future directions and key priorities	The presentation of this section has been reconfigured, and information added about the refresh we are commencing for our Network Vision	Our Network Vision will be refreshed in consultation with customer representatives and stakeholders
1.3	How are our directions and key priorities helping us prepare for the future?	This section has been re-titled	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
2.1	Integrated system plan	This section has been updated and expanded based on the information provided in AEMO's 2020 ISP	We have updated this information to show how our plans relate to AEMO's 2020 ISP
N/A	National Transmission Network Development Plan	This section has been removed	AEMO is no longer required to publish a National Transmission Network Development Plan
2.2	Power System Frequency Risk Review	This section has been updated based on the Stage 1 2020 PSFRR report that AEMO published in July 2020	This section will be updated further in 2021 to reflect the final 2020 PSFRR report that AEMO plan to publish by the end of 2020
3.1	South Australian electricity demand	Figure 3.1 has been updated to include data for 2019-20	This updated reflects the latest available information

Section	Section Name	Significant changes between the 2019 and 2020 TAPR	Analysis and explanation for the significant change
3.3	2019-20 demand forecast	Figure 3.2 has been updated to include data from AEMO's 2020 ESOO	The change in Transmission Annual Planning Report publication date has enabled AEMO's 2020 ESOO forecasts to be considered in our planning
3.4	Inpact of COVID-19 pandemic on forecasts	This section is new in 2020	This section has been added to indicate the impact that the COVID-19 pandemic may have on demand forecasts
3.5	Performance of 2019 demand forecasts for summer 2019-20	The information in this section has been updated	We have updated this section to consider the 2019-20 summer
4.2	South Australian transmission system constraints in 2019	We assessed constraints that were not included in the 2019 Transmission Annual Planning Report	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
4.3	Emerging and future network constraints and performance limitations	The information in Table 4.2 has been substantially reviewed	We have reflected the results of our market modelling undertaken in 2020 to reflect our current view of where future constraints may emerge
4.4	Potential projects to address constraints	The information in Table 4.3 has been substantially updated	We have reflected our latest planning regaring potential projects to alleviate constraints, which is based on our own modelling and the findings of the 2020 ISP
4.5	Frequency control schemes	The information in section 4.5.1 regarding under frequency load shedding has been extended and updated	The updated information is based on the outcomes of AEMO's Stage 1 2020 PSFRR report and describes actions we are undertaking with others to ensure address risks related to periods during which insufficient load is forecast to be available for disconnection in the South Australian UFLS scheme
5.1	ElectraNet's connection process	This is a new section in 2020	We have added this information to help proponents have a high-level understanding of ElectraNet's connection process
5.2.3	Generator connection impacts on power quality	This is a new section in 2020	We have added this information to assist proponents have a high-level understanding of ElectraNet's power quality modelling requirements
N/A	Summary of connection opportunities	This section has been removed from the 2020 report	Given the small amount of committed or connected changes to South Australia's generation fleet that were not considered in our 2019, we refer interested parties to the results in our 2019 Transmission Annual Planning Report In the 2021 Transmission Annual Planning Report we intend to significantly update the connection opportunity assessment to reflect the expected impact of initiatives such as Project EnergyConnect and the installation of synchronous condensers at Davenport and Robertstown, including any impact of updated demand forecasts

Section	Section Name	Significant changes between the 2019 and 2020 TAPR	Analysis and explanation for the significant change
5.4	Proposed and committed new connection points	Table 5.1 has been updated	We have updated the information to reflect the latest status of proposed and committed new connection points
5.5	Projects for which network support solutions are being sought or considered	Table 5.2 has been updated	We have updated the information to reflect the latest status for projects for which we have recently sought, are seeking, or plan to soon seek non-network proposals
6, 7	Completed, committed and pending projects, and Transmission system development plan	Project numbers have been added for all projects in these sections and where they are referenced elsewhere in the document	Including project numbers will improve the ability of readers to cross-reference projects between the document and the additional data that is published on the Transmission Annual Planning Report website to meet the TAPR Guideline requirements
6.1	Recently completed projects	The information in this section has been updated	We have updated the information to reflect the latest status of projects completed up until 30 October 2020
6.2	Committed projects	The following projects are now committed: • EC.14127 • EC.14168 • EC.14047 • EC.14236 • EC.14172 • EC.14032 • EC.14033 • EC.11646 • EC.14031 • EC.14034 • EC.14176	These committed projects were proposed in the 2019 Transmission Annual Planning Report but are now committed to address market benefit, safety, asset condition and performance, reliability, and security drivers
6.3	Pending projects	The following projects are now pending: • EC.14246 • EC.14046	These projects were proposed in the 2019 Transmission Annual Planning Report but are now pending full approval to be address stability and asset condition and performance drivers
7	Transmission system development plan	Figure 7.1 has been updated to reflect our latest planning assumptions regarding potential new generator and load connections	This information has been updated based on our latest information relating to generalised credible generator and load connections that could materially impact the performance of the transmission system
7.1	Summary of planning outcomes	Table 7.1 has been updated	We have updated this information to reflect the latest results of our ongoing planning processes
7.3 – 7.6	Various	These focus of each of these sections has been re-focussed around key themes that reflect the current outcomes of our planning processes	The new breakdown gives an increased understanding of the key themes that can be seen in our planning outcomes
7.3	Interconnector and Smart Grid planning	This section lists the following new projects, which are being considered for proposal as contingent projects: • EC.15206 • EC.15112	These potential projects would increase the ability to provide independent, firm transfer capability across Project EnergyConnect and the Heywood interconnector

Section	Section Name	Significant changes between the 2019 and 2020 TAPR	Analysis and explanation for the significant change
7.4	System security, power quality and fault levels	This section lists the following new proposed projects: • EC.15438 • EC.15297 • EC.15441 Project EC.15149 is a new project being considered for proposal as a contingent project	These projects have been proposed to address forecast needs between 2024 and 2028 Project EC.15149 may address an emerging need between 2024 and 2028 to provide increase system strength in the Adelaide metropolitan region
7.5	Capacity and Renewable Energy Zone development	The planned asset in service timing of EC.14172 has been delayed by 12 months The following new projects are proposed: • EC.15209 • EC.15441 We have listed the following new projects to be considered for proposal as contingent projects: • EC.15104 • EC.11011 • EC.15201 • EC.15205 • EC.15153 • EC.15261	The adjusted timing of EC.14172 reflects the outcome of our detailed project planning The new proposed projects and the projects that are being considered for proposal as contingent projects would release new capacity in the South Australian REZs that AEMO has identified in the 2020 ISP, and would increase transfer capacity between REZs in the north and south of South Australia and the Adelaide metropolitan load centre
7.6	Market benefit opportunities	The planned asset in service timings of EC.14168 and EC.14211 have been adjusted	Project timings were adjusted as a result of detailed project planning The estimated cost of EC.11002 has increased to the extent that it no longer qualifies for inclusion in our NCIPAP We are considering other potential projects to replace EC.11002 in the NCIPAP for 2018-19 to 2022-23
7.7	Network asset retirements and replacements	This section now only lists projects if they were subject to the RIT-T, or would have been subject to the RIT-T if they had not already been committed by 30 January 2018 Project EC.14081 was not listed in the corresponding section of the 2019 Transmission Annual Planning Report The asset in service timings of the following projects have been adjusted: • EC.14049 • EC.11749 • EC.14081 • EC.14046 • EC.14084 • EC.14090 • EC.14077 The following new projects are proposed: • EC.15060 • EC.15279 • EC.15043 • EC.15069 • EC.15295 • EC.15042 • EC.15251 • EC.15253 • EC.15432 • EC.15116 • EC.15168	Further details for all projects, including those with estimated costs that are lower than the RIT-T threshold, are available from our Transmission Annual Planning Report webpage Project EC.14081 was listed in section 6.2 of the 2019 Transmission Annual Planning Report Project timings were adjusted as a result of detailed project planning and to manage ElectraNet's capex spend to remain at a level consistent with our allowance for the 2018-19 to 2022-23 regulatory control period The new projects are proposed for completion between 2024 and 2034 to address emerging asset performance and condition needs
7.9	Grouped network asset retirements, de-ratings and replacements	This section now only lists projects if they were subject to the RIT-T, or would have been subject to the RIT-T if they had not already been committed by 30 January 2018 The asset in service timings of the following projects have been adjusted: • EC.14047 • EC.14034 • EC.14031 The following new projects are proposed: • EC.15242 • EC.15120 • EC.15189 • EC.15275 • EC.15123 • EC.15244 • EC.15211 • EC.15214 • EC.15397	Further details for all projects, including those with estimated costs that are lower than the RIT-T threshold, are available from our Transmission Annual Planning Report webpage Project timings were adjusted as a result of detailed project planning and to manage ElectraNet's capex spend to remain at a level consistent with our allowance for the 2018-19 to 2022-23 regulatory control period The new projects are proposed for completion between 2024 and 2034 to address emerging asset performance and condition needs
7.10	Security and compliance projects	This section now only lists projects if their estimated cost exceeds $6 million Project EC.14131 was not listed in the corresponding section of the 2019 Transmission Annual Planning Report The asset in service timings of the following projects have been adjusted: • EC.14131 The following new projects are proposed: • EC.11828 • EC.15235 • EC.15231	Further details for all projects, including those with an estimated cost lower than $6 million, are available from our Transmission Annual Planning Report webpage Project EC.14131 was listed in section 6.2 of the 2019 Transmission Annual Planning Report Project timings were adjusted as a result of detailed project planning The new projects are proposed for completion between 2024 and 2034 to address emerging security and compliance needs
Appendix E	Contingent projects (2018-19 to 2022-23)	This section has been updated to include the current status of each contingent project	This information has been included to enable stakeholders to understand the current status of each contingent project

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 worked closely with SA Power Networks on to ensure optimal solutions are identified and implemented.

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.[64]

B1.1 Executive Joint Planning Committee

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

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

The Executive Joint Planning Committee directs and coordinates the activities of the Joint Planning Committee, the Regulatory Working Group, and the Market Modelling Working Group.

B1.2 Joint Planning Committee

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

B1.3 Regulatory Working Group

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

B1.4 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.

B1.5 Forecasting Reference Group

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

B1.6 Regular joint planning meetings

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

- SA Power Networks, the South Australian Distribution Network Service Provider (DNSP)

  Joint planning activities with SA Power Networks include regular Joint Planning Meetings to coordinate joint planning activities, and a Voltage Control Working Group that coordinates the planning of voltage control across the South Australian system and reports to the Joint Planning Meeting
- AEMO (in their roles as National Planner and Jurisdictional Planning Body for the Victorian transmission system)
- TransGrid.

B1.7 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 (sections 1.3.2, 2.1.2, 6.3 and 7.3).

[64] See www.energynetworks.com.au

Appendix C: Asset management approach

C1 ElectraNet's Asset Management Strategy

Our asset management objectives are to ensure the:

- safety of people
- protection of the environment
- affordable and reliable network
- power system security and resilience.

As electricity demand is currently only forecast to increase significantly 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.[65]**

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 can no longer meet the required performance levels
- 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, performance 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, performance 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.

Most 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 customer and stakeholder 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 appendix.

[65] 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 utilised AEMO's latest state-level demand forecasts and have until now used AEMO's estimates of the Value of Customer Reliability (VCR).[66,67] In the future we plan to use estimates of VCR as determined by the AER.[68] 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 update our estimates for the latest actual project costs and market rates. We also incorporate efficiencies expected to arise as we combine the delivery of related projects. We obtain 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 economic assessments to determine whether the benefits of undertaking a project exceed its costs and we review all available options. We examine the optimal timing of each 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	Any decision to replace an asset is driven by asset condition, risk and reliability considerations balanced against cost, not asset age. Our risk analysis considers the: • 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. The risk cost reduction and other benefits of a proposed asset replacement are compared to the cost of the replacement project to determine whether the proposed expenditure delivers a net economic benefit.

C2 Obligations relating to capital expenditure

An important objective when developing our capital expenditure plans is to satisfy 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.

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

[67] 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.

[68] AER, Values of customer reliability final decision, available from https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/values-of-customer-reliability/final-decision.

C2.1 Transmission licence and ETC obligations

Under section 15 of the Electricity Act 1996 (SA), we are required to be licensed in order to operate a transmission network in South Australia. The transmission licence authorises us to operate 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.[69]

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 [70]
- jurisdictional standards, such as those set out under the ETC, provide for security and reliability standards which align with technical standards set out under the Rules.

In particular, the ETC contains provisions relating to service standards, interruptions, design requirements, technical requirements, general requirements, access to sites, telecommunications access and emergencies.

Clause 2 of the ETC mandates specific reliability standards at each transmission exit point (a customer connection point) or group of exit points and supply restoration standards. These are summarised in the following table. [71]

[69] Our transmission licence as currently in force (last varied 16 October 2019) is available at https://www.escosa.sa.gov.au/industry/electricity/licensing/licence-register/exemption-register

[70] National Electricity Rules, Schedule 5.1

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

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

* As defined in the ETC.

ESCOSA 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.[72]

The ETC was most recently amended in August 2020, to apply a Category 1 reliability standard to the new Davenport MGS exit point, consistent with the standard that the ETC applies to other single-customer transmission exit points, and to remove reference to the temporary Mount Gunson South exit point.[73]

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

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 regarding 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 DNSPs and other TNSPs whose networks can impact the South Australian transmission network;
- provide information to registered participants and interested parties on projected network limitations and the required timeframes for action; and
- develop recommendations to address projected network limitations through joint planning with DNSPs, and consultation with registered participants and interested parties.

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

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

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

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

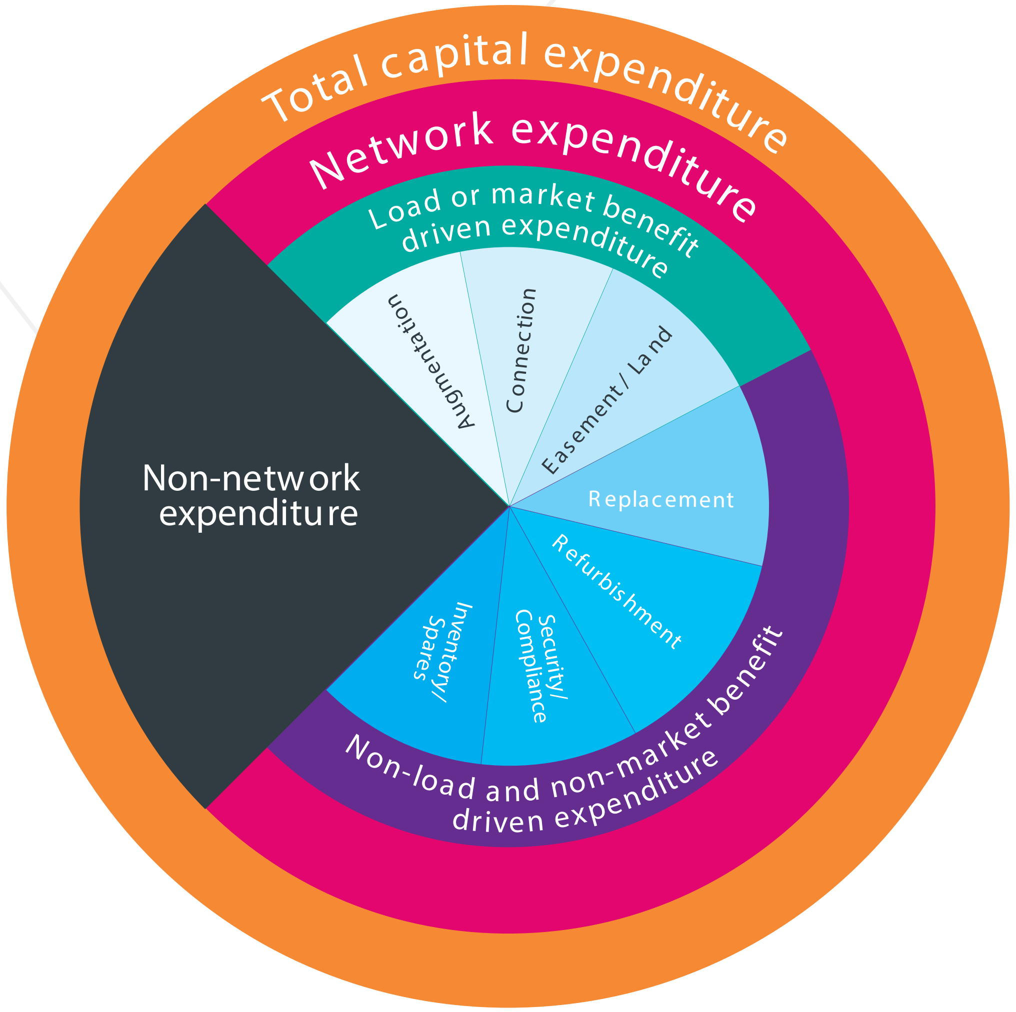
The SRMTMP must address, amongst other things, the safe design, installation, commissioning, operation, maintenance and decommissioning of electricity infrastructure owned or operated by a licensed person. As such, the SRMTMP, in addition to the obligations described in Sections 6.5.1 and 6.5.2, is an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

[72] 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.

[73] Submissions and the final decision are available at https://www.escosa.sa.gov.au/projects-and-publications/projects/electricity/transmission-code-variation-2020.

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 circle of the above figure. For each category, we also identify the AER's reporting category as indicated in their TAPR Guideline.[74]

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
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 condition, asset performance 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 maintain or 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

[74] Final decision paper available from www.aer.gov.au.

C4 Expenditure forecasting methodology

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[75], and industry planning documents prepared by AEMO such as 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:

- 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 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 outturn cost information from delivered projects.

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

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

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

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.

Asset health and condition assessments

Our Transmission Asset Life Cycle 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[76]
- 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.

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 rely 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.

[76] 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

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 2020 Transmission Annual Planning Report with the requirements of clause 5.12.2(c) of version 143 of the Rules (the latest version at time of writing).

Table D-1: Copliance checklist

Summary of requirements	Section
The Transmission Annual Planning Report must be consistent with the TAPR Guidelines[77] and set out:	
(1) the forecast loads submitted by a Distribution Network Service Provider in accordance with clause 5.11.1 or as modified in accordance with clause 5.11.1(d), including at least: i. a description of the forecasting methodology, sources of input information, and the assumptions applied in respect of the forecast loads; ii. a description of high, most likely and low growth scenarios in respect of the forecast loads; iii. an analysis and explanation of any aspects of forecast loads provided in the Transmission Annual Planning Report that have changed significantly from forecasts provided in the Transmission Annual Planning Report from the previous year; and iv. an analysis and explanation of any aspects of forecast loads provided in the Transmission Annual Planning Report from the previous year which are significantly different from the actual outcome;	Chapter 3, and our Transmission Annual Planning Report web page[78]
(1A) For all network asset retirements, and for all network asset de-ratings that would result in a network constraint, that are planned over the minimum planning period specified in clause 5.12.1(c), the following information in sufficient detail relative to the size or significance of the asset: i. a description of the network asset, including location; ii. the reasons, including methodologies and assumptions used by the Transmission Network Service Provider for deciding that it is necessary or prudent for the network asset to be retired or de-rated, taking into account factors such as the condition of the network asset; iii. the date from which the Transmission Network Service Provider proposes that the network asset will be retired or de-rated; and iv. if the date to retire or de-rate the network asset has changed since the previous Transmission Annual Planning Report, an explanation of why this has occurred	Sections 6.2, 7.10, 7.11 and our Transmission Annual Planning Report web page[78]
(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: i. a description of the network assets, including a summarised description of their locations; ii. the reasons, including methodologies and assumptions used by the Transmission Network Service Provider, for deciding that it is necessary or prudent for the network assets to be retired or de-rated, taking into account factors such as the condition of the network assets; iii. the date from which the Transmission Network Service Provider proposes that the network assets will be retired or de-rated; and iv. 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[78]
(2) planning proposals for future connection points	Section 5.4
(3) a forecast of constraints and inability to meet the network performance requirements set out in schedule 5.1 or relevant legislation or regulations of a participating jurisdiction over 1, 3 and 5 years, including at least: i. a description of the constraints and their causes; ii. the timing and likelihood of the constraints; iii . a brief discussion of the types of planned future projects that may address the constraints over the next 5 years, if such projects are required; and iv. sufficient information to enable an understanding of the constraints and how such forecasts were developed	Chapter 7 and our Transmission Annual Planning Report web page[78]
(4) in respect of information required by subparagraph (3), where an estimated reduction in forecast load would defer a forecast constraint for a period of 12 months, include: i. the year and months in which a constraint is forecast to occur; ii. the relevant connection points at which the estimated reduction in forecast load may occur; iii. the estimated reduction in forecast load in MW needed; and iv. a statement of whether the Transmission Network Service Provider plans to issue a request for proposals for augmentation, replacement of network assets, or a non-network option identified by the annual planning review conducted under clause 5.12.1(b) and if so, the expected date the request will be issued	Section 5.5 and our Transmission Annual Planning Report web page[78]

[77] The AER published the TAPR Guidelines in December 2018.

[78] Our Transmission Annual Planning Report web page is available at electranet.com.au

[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; iii. the proposed solution to the constraint or inability to meet the network performance requirements identified in subparagraph (ii), if any; iv. total cost of the proposed solution; v. whether the proposed solution will have a material inter-network impact. In assessing whether an augmentation to the network will have a material inter-network impact a Transmission Network Service Provider must have regard to the objective set of criteria published by AEMO in accordance with clause 5.21 (if any such criteria have been published by AEMO); and vi. other reasonable network options and non-network options considered to address the actual or potential constraint or inability to meet the network performance requirements identified in subparagraph (ii), if any. Other reasonable network and non-network options include, but are not limited to, interconnectors, generation options, demand side options, market network service options and options involving other transmission and distribution networks	Sections 7.3 to 7.6
(6) the manner in which the proposed augmentations and proposed replacements of network assets relate to the most recent Integrated System Plan	Section 2.1
(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 2.2
(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) and 5.16A.3 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	Sections 1.3.4, 7.2 and 7.4
(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 7.3
(10) facilities in place under clause S5.1.10	Sections 4.5 and 7.3
(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	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[79]	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	Committed (subject to final Board approval)	Sections 6.2 and 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	Committed	Sections 1.3.4, 2.1.1, 5.2.2, 6.2 and 7.4
South Australian Energy Transformation Produce net market benefits, improve South Australian system security, and enable the further integration of generation from renewable resources	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 construction of Project EnergyConnect is now committed, subject to the AER awarding incremental regulated revenue commensurate with the capital and operating costs for ElectraNet's section of the project, ElectraNet obtaining funding as necessary and on terms satisfactory to it, and the Board of TransGrid making a firm commitment to proceed with the New South Wales component of the project following the AER's revenue determination on its corresponding application	Sections 1.3.2, 2.1.2, 6.3 and 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 132 kV line to exceed its thermal limit of 10 MVA Successful completion of the RIT-T including an assessment of credible options showing a transmission investment is justified	Not applicable	Section 7.5
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 132 kV line to exceed its thermal limit of 76 MVA	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
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)
PMU	Power Monitoring Unit
POE	Probability of exceedance
PSCR	Project Specification Consultation Report (part of the RIT-T)
PV	Photovoltaic
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
SRMTMP	Safety, Reliability, Maintenance and Technical Management Plan
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
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	One of ElectraNet’s seven regional networks in South Australia
Eyre Peninsula	One of ElectraNet’s seven regional networks in South Australia
Frequency control ancillary service	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
Adelaide Metropolitan	One of ElectraNet’s seven regional networks in South Australia
Mid North	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
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
Registered participants	As defined in the Rules
Riverland	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	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 permitted power transfer through a transmission or distribution network
Under frequency load shedding (UFLS)	The primary control measure used to maintain viable frequency operation following a system separation event that results in a deficit of generation compared to demand
Upper North	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

ElectraNet

Contact Us

If you have a question or would like to discuss any aspects of our 2020 Transmission Annual Planning Report, please contact ElectraNet.

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