Transmission Annual Planning Report

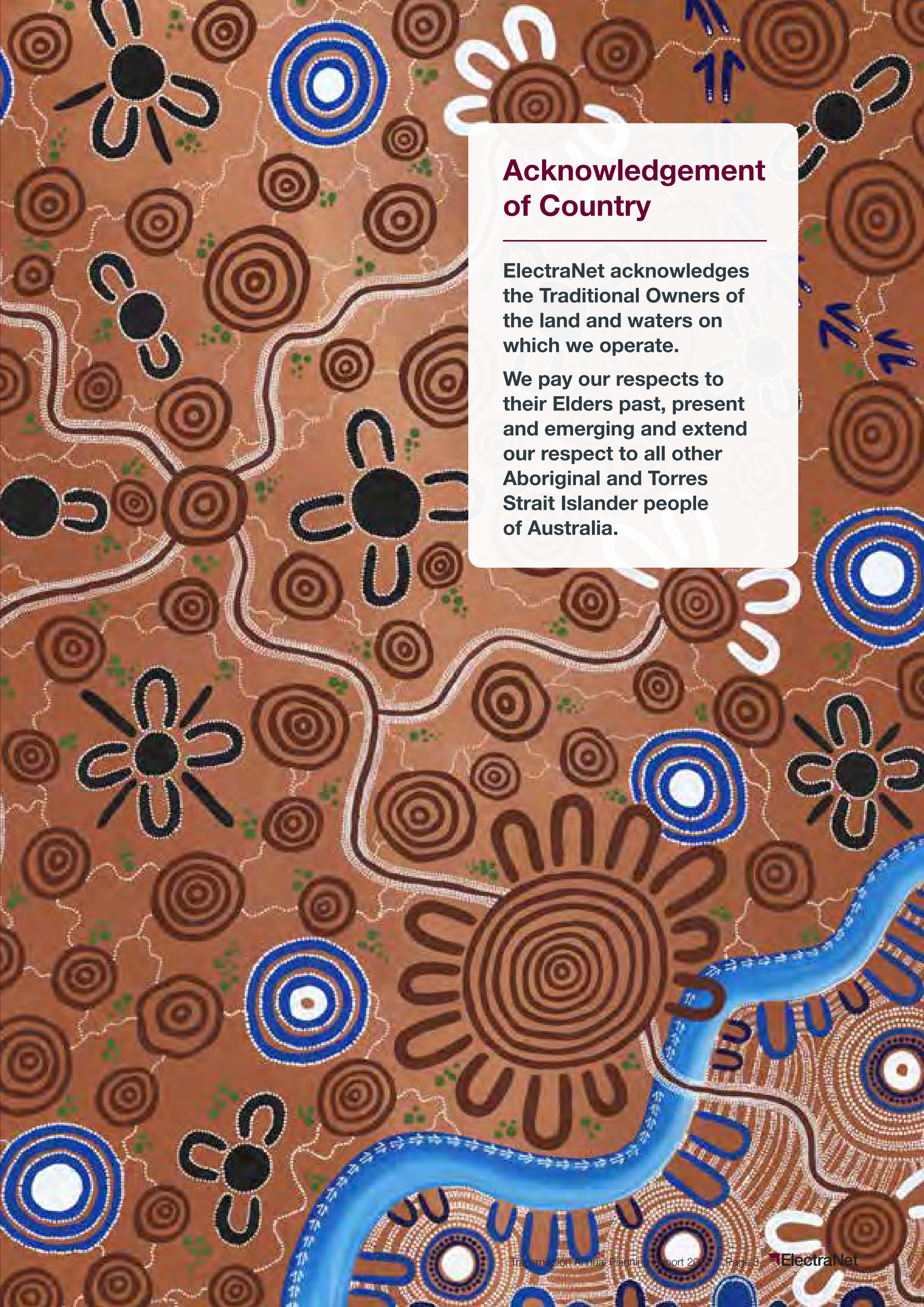
October 2024

ElectraNet

Artwork

Artist Gabriel Stengle is a proud Kaurna, Ngarrindjeri, Narungga and Wirangu Woman of South Australia.

The artwork represents the story of country where ElectraNet operates and moving forward in the understanding of culture and reconciliation.



Acknowledgement of Country

ElectraNet acknowledges the Traditional Owners of the land and waters on which we operate.

We pay our respects to their Elders past, present and emerging and extend our respect to all other Aboriginal and Torres Strait Islander people of Australia.

Contents

Appendices

About ElectraNet

Energising South Australia’s Clean Energy Future

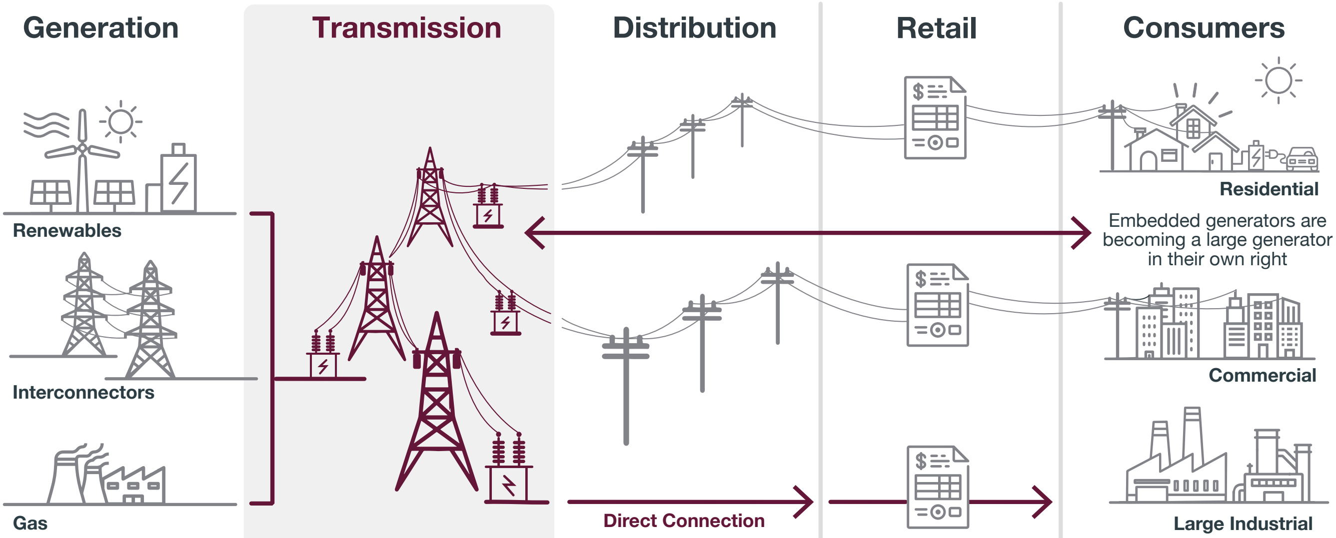
We are leaders in the clean energy transition, delivering reliable and sustainable electricity transmission services and valued customer connections.

As South Australia’s principal electricity Transmission Network Service Provider (TNSP), we are a critical part of the electricity supply chain, that includes enabling the transition to a clean energy future. We own and manage the high-voltage transmission lines and substations that connect this State’s electricity customers, including those connected to SA Power Networks’ lower-voltage distribution network, to generation sources both locally and interstate.

We also provide connection and other services to customers and generators wanting to connect to the high-voltage electricity transmission network.

To deliver on our Vision, ElectraNet has developed a 5-year strategy, comprising of six initiatives, to deliver an efficient and sustainable 5GW network that will enable South Australia’s renewables, resources and economic potential through:

- Enhancing our ways of working
- Developing a roadmap for a 5GW network
- Leverage our talent, skills and experience to become the industry preferred partner
- Co-creating a workplace of choice
- Keeping the lights on in all scenarios
- Investing in strong and enduring relationships to enrich the communities in which we operate.



Electricity is mainly generated from renewable energy such as wind and solar. Traditional sources such as gas provide the rest.

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.

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

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

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

Purpose of the Transmission Annual Planning Report

Each year, ElectraNet reviews the capability of South Australia's electricity transmission network and regulated connection points to ensure it is adequate to meet the ongoing demand for electricity transmission services under a variety of operating scenarios.

ElectraNet undertakes joint planning with SA Power Networks, which is responsible for the power distribution network throughout South Australia, to complete the review. We also consider the findings of AEMO's Integrated System Plan and the 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).

This report presents the outcomes of the annual planning review and forecasts to help you understand the current capacity of the transmission network and how we think this may change in the future. The report covers a 10-year planning period (2024–2034) and identifies potential network capability limitations and possible solution options.

This report forms part of an ongoing consultation process to ensure the efficient development of the transmission network to meet forecast electricity demand and support the transition to renewable energy sources over the planning period. Decisions by ElectraNet to invest in the South Australian transmission system are subject to further detailed investigation and economic assessment that will be undertaken closer to the time the investments are needed.

The report provides information on:

- Trends and directions for the future of the electricity transmission system (Chapter 1)
- National transmission planning (Chapter 2)
- Demand forecasts 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)

We are committed to ongoing improvement of the Transmission Annual Planning Report, and its value to our customers, consumers, 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 continue to provide reliable and affordable electricity transmission services.

Comments and suggestions can be directed to:

consultation@electranet.com.au

+61 8 8404 7966

www.electranet.com.au

Executive Summary

South Australia is a world leader in the adoption of Variable Renewable Energy (VRE) from wind and solar resources. In just over 20 years it has transitioned its electricity production from coal and natural gas to renewable sources which now provide over 70% of supply on an annual basis, supported by batteries and some natural gas.[1]

Connected directly to ElectraNet's network are 3,500 MW of large-scale wind and solar farms, and 750 MW of grid-scale battery energy storage systems (BESSs). An estimated 3,000 MVA[2] of distribution connected Customer Energy Resources (CER) are also installed, comprised of household and business solar PV systems and BESSs.

South Australia regularly exceeds 100% electricity demand on the transmission network on an instantaneous basis. At times more than 100% of demand is supplied by CER on the distribution network. The South Australian Government has set a target to achieve net 100% renewables on an annual basis by 2027.

The South Australian and Federal Governments entered into a Renewable Energy Transformation Agreement in July 2024 that will see the Federal Government support 1,000 MW of wind or solar and 400 MW of new storage capacity in South Australia, ensuring South Australia reaches and likely exceeds its 100% net renewable generation target.

In August 2024 the federal government announced the outcome of a pilot tender under the Capacity Investment Scheme (CIS), which awarded contracts for 530 MW of BESS in South Australia with a total of 1,996 MWh of storage, as well as 230 MW of transmission connected solar.

South Australia's progress to decarbonise the electricity supply system is a key attraction for energy intensive large industrial loads. There is more than 2,000 MW of large industrial load actively exploring connection to the transmission network in South Australia.

The potential for rapid increase in load will require an expanding transmission network, as South Australia continues the transition to a net zero carbon emission economy firmed by storage and backed up by gas generators.

Expansion of the transmission network is necessary to ensure we can continue to connect renewables and BESSs to supply the demands emerging at new points on the network. An expanded transmission network is one of the key enablers of VRE sources across the NEM, allowing geographic diversity to smooth out intermittent supply from VRE.

AEMO has identified an actionable transmission project required in South Australia to expand the Mid-North Renewable Energy Zone. Expansion of this zone is needed to meet forecast load growth in South Australia. It will also support the development of Large Industrial Loads (LILs) in the north of South Australia as the state takes advantage of our unique position and to maintain South Australia as a renewable based energy economy.

This and other transmission development priorities form the focus of this report.

[1] ElectraNet | Network Transition Strategy, March 2024

[2] AEMO | Distributed Energy Resource

Energy Demand

Large Industrial Loads

Energy consumption on the transmission network declined by 4.4% in 2023–24, largely due to the impact of a mild winter in 2023. Energy offtake from the distribution network declined partially offset by an increase in offtake from the transmission connected LILs. This continues recent trends of declining distribution connected loads and increasing LIL consumption, which has increased from 10% of the state's total load in 2010, to 23% in 2023–24.

The trend of increasing LIL is expected to accelerate over the coming years.

Our **Network Transition Strategy** provides a pathway and framework for working with our customers and stakeholders to navigate the challenges and opportunities of the energy transition including a rapid increase in LIL. The strategy supports and is guided by our asset management objectives: safety, affordability, reliability and sustainability.

The strategy is focused on by three key themes:

Energy reliability	Power system security and resilience	Operability
Plan and deliver timely and efficient transmission infrastructure to connect customer loads with renewable energy and storage and maintain reliability of supply.	Deliver system services and protection and emergency control schemes to maintain power system security and resilience during the energy transition.	Uplift network planning and operations capabilities, systems and tools to manage the increasing complexity and risk of the power system.

ElectraNet priorities

What we have delivered

- Inertia and Syn Cons
- Project EnergyConnect
- Upper North Connection
- Eyre Peninsula Stage 1

Immediate priorities

- Mid North REZ Expansion (Northern and Southern)
- Eyre Peninsula Upgrade
- Efficient level of system strength
- South East Expansion (Stage 1)
- Readying strategies to respond to massive demand growth

Future Priorities

- Eyre Peninsula Grid (Stage 1 & 2)
- Mid North Reinforcement
- Metropolitan Reinforcement
- South East Expansion (Stage 2)
- Increased interconnection
- Current new load connection interests

The 2024 ISP declared augmentation of the Mid North transmission network as an actionable project. We will conduct the Regulated Investment Test for Transmission (RIT-T) in 2025 to consult with stakeholders and identify the most efficient solution to meet this need. This significant project for South Australia has the potential to support massive load growth, underpinning our vision to *Energise South Australia's clean energy future*.

This project will safeguard the reliability and security of the South Australia's transmission network for households and businesses, especially in Adelaide. It will also ensure South Australia can harness the economic benefits of large-scale renewable energy projects in the upper north.

We are progressing studies and investigations to identify the most suitable possible options considering aspects such as costs, benefits, environmental factors, land access, impacts on Traditional Owner's and community acceptance. This process includes comprehensive stakeholder engagement with consumers, the community, and Traditional Owners to ensure we develop the right solution to maximum benefit for South Australians, building on our track record of successfully delivering projects in partnership with the community.

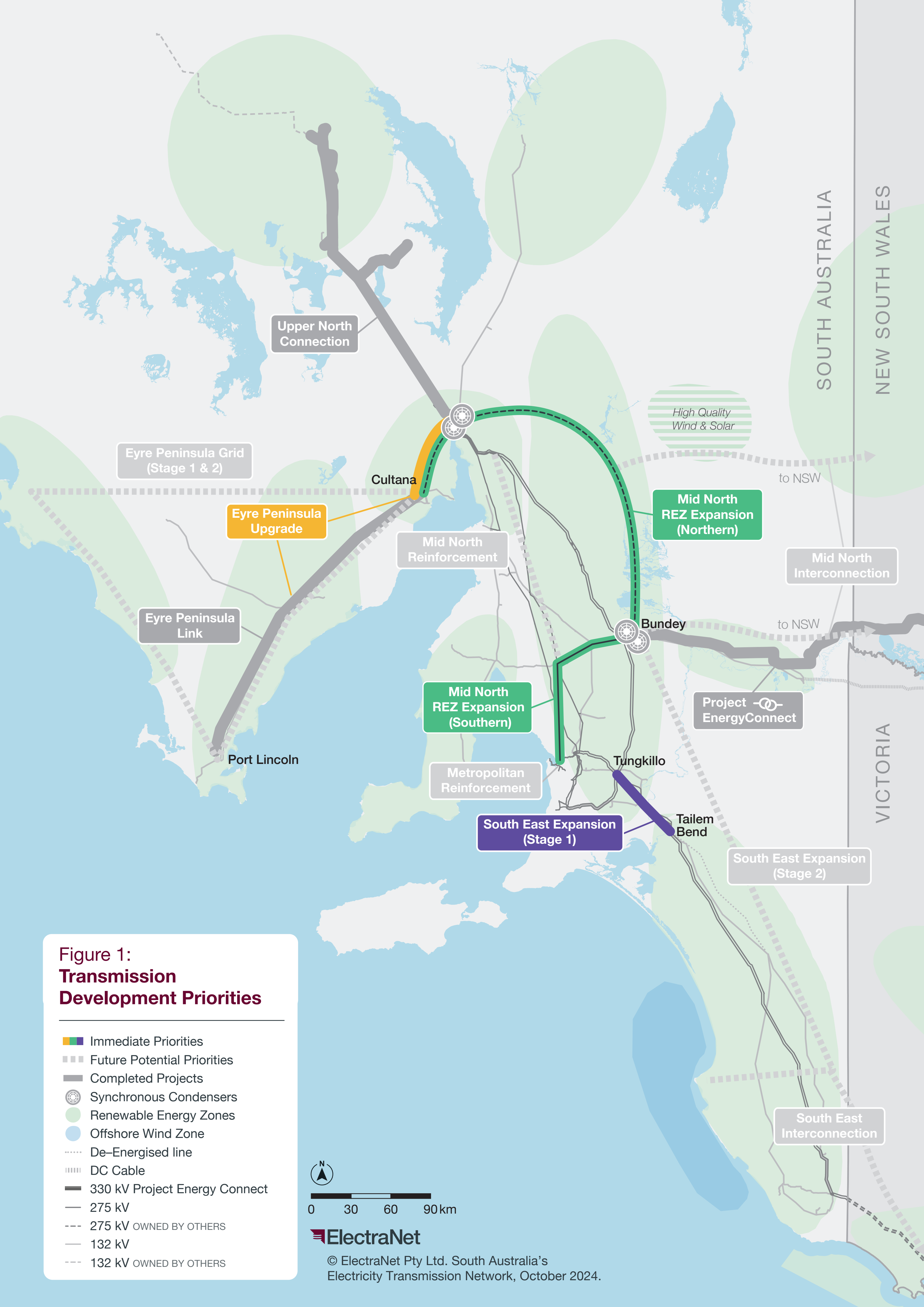


Figure 1: Transmission Development Priorities

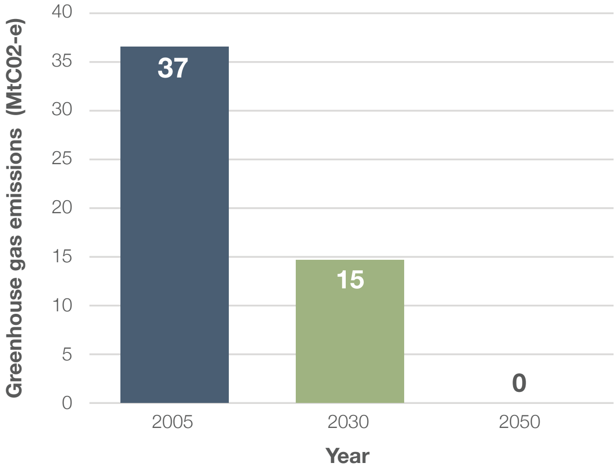
South Australian Government's policies endorsing renewables

The South Australian Government is supporting a variety of initiatives to exploit the state's abundance of high-quality wind and solar resources including a reindustrialization of the state's economy. This is an extraordinary opportunity that will deliver benefits for all of South Australia.

The South Australian Government is legislating:

- 100% net renewables on the electricity network by 2027
- 60% state green house gas emissions reduction from 2005 levels (37MT) by 2030 (15 MT)
- Net zero by 2050.

Figure 2: Carbon Emissions targets for South Australia



Source: Australia's National Greenhouse Accounts

Since 2022 South Australia has achieved a 57% reduction in greenhouse gas emissions bringing it closer to achieving the South Australian Government's statewide goal of reducing net greenhouse gas emissions by 60% by 2030.

Figure 2: SA Carbon Emission Trend, currently shows South Australia greenhouse gas emissions at 15.82 MT in 2022.

Hydrogen and Renewable Energy Act 2023

The first release areas are under consultation by the South Australian Government as part of the Hydrogen and Renewable Energy Act 2023 (HRE Act). The HRE Act establishes Australia's first dedicated licensing and regulatory framework for large-scale hydrogen and renewable energy projects. Consultation is the next stage in determining if the lands within the release area are suitable for declaration as a release area. Following this declaration renewable energy companies will be able to submit a competitive tender to develop large scale renewable energy projects on the land.[3]

Consultation on the Gawler Ranges East and Whyalla West proposed release areas closes on 22 October 2024.

July 2024 Bilateral Energy Transitional Agreement between the Federal and State Government

The state and federal governments announced a bilateral agreement on 26 July to delivery more renewable energy electricity generation and storage including:

- 400 MW of long duration storage
- 1,000 MW of solar or wind power for South Australia.

[3] YourSay.SA.Gov.Au | Release Areas – Hydrogen and Renewable Energy Act

Figure 3: **SA Government Projects**

What's changed since the 2023 TAPR

AEMO has declared the Mid North Renewable Energy Zone an actionable ISP project. ElectraNet will be conducting the RIT-T over 2025 with the Project Assessment Draft Report due by December 2025.

The Tailem Bend transformer upgrade has been deferred from 2028 to the mid-2030s due to lower demand forecasts from SA Power Networks.

Inertia shortfall was reduced by AEMO in December 2023 and subsequently cancelled in June 2024 with increased registrations of one second Frequency Control Services within South Australia.

The Transmission Network Voltage Control RIT-T was completed in May 2024. ElectraNet is deploying 4 reactors in metropolitan Adelaide and one reactor at South East. Devices will be progressively deployed over the next two years.

Technical Challenges of the network transition

As traditional synchronous generators have been replaced by variable renewable energy sources, the system services provided by these generators are being displaced.

This has created shortfalls in services such as system strength and inertia in South Australia. These gaps need to be addressed to maintain the stability of the power system. System strength and inertia shortfalls are increasingly becoming an issue elsewhere in the NEM.

With rooftop solar now the largest single generator in South Australia it has been necessary to develop ways to curtail rooftop solar output, when necessary, as a last resort, to maintain system security.

There is also the opportunity to use excess solar power in the middle of the day for electric vehicle charging, hydrogen production and other uses incentivised by solar sponge tariffs, or to store the energy for use at other times.

What is system strength?

System strength helps the power system withstand disturbances while maintaining stable voltage levels.

Without adequate system strength:

- **Generators may trip after disturbances**
- **Voltages may fluctuate**
- **Protection systems may not operate properly**

This may result in supply interruptions to customers and can also lead to constraints being applied to generation output levels.

What is inertia?

Inertia helps the power system withstand disturbances while maintaining stable system frequency.

Without adequate levels of inertia:

- **Generators may trip after disturbances**
- **Limits may be required to manage the power system, such as reduced power flows between regions**

This may result in supply interruptions to customers and can also lead to regional 'islanding' events.

Technical challenges arising from the energy transition:

System security

Shortfalls in frequency control, system strength and inertia services, historically provided by synchronous generators

Voltage control

Increasing VRE, reducing minimum demand and changes in customer load characteristics (more capacitive) are increasing voltage control challenges

Protection adequacy

Changing requirements require more frequent review, including for minimum fault level conditions

Increasing system complexity and risk

Wider range of system operating conditions with more frequent stress points, including under minimum, zero and negative grid demand conditions

Extreme events

Greater reliance on complex special protection schemes to manage risk and maximise power transfer capability

Harnessing customer energy resources

Integrating CER to deliver lowest cost outcomes while addressing system security risks

1 South Australia's energy transformation

1.1 Meeting South Australia's climate change targets and maintaining reliability

South Australia is leading the world in demonstrating that intermittent and inverter-based systems can deliver clean green energy to consumers. The South Australian Government is legislating the following targets:

- By 2030 a 60% reduction in South Australia carbon emissions by 2030 from 2005 levels
- By 2050 a statewide net zero carbon emission economy.

To support this transition, the government has set a target to achieve net 100% renewable electricity generation by 2027. This will set a foundation for the economy to transition to a net zero economy by establishing a low emission power supply for customers as they seek to electrify other energy sources.[4]

AEMO recently announced the outcomes of the first Capacity Investment Scheme tender which awarded contracts for 530 MW of BESS in South Australia with a total of 1,996 MWh of storage, as well as 230 MW of transmission connected solar.

The South Australia and Federal Governments have entered into the Renewable Energy Transitional Agreement with the Federal government committing to a further 1,000 MW of new solar or wind VRE generators in South Australia.

The continued connection of intermittent inverter-based renewable generation – at both transmission and distribution levels – is creating greater variability in electricity generation and demand and is challenging the power system's technical limits, presenting new challenges to reliability, affordability, and system security.

The South Australian Government is working with ElectraNet to ensure that customers continue to receive affordable and reliable power during the transition, taking advantage of VRE and meeting greenhouse gas emission targets.

4 South Australian Government | Climate Change and Greenhouse Emissions Reduction legislation

1.2 ElectraNet is energising South Australia's clean energy future

South Australia already has world leading levels of variable renewable energy wind and solar resources and has continued to regularly experience 100% or more instantaneous variable renewable energy generation since October 2021.

Inverter based resources increase the complexity of the power system with the introduction of electronic logic controllers that require greater modelling and engineering time to understand the performance of the power system during faults or in a stressed state. Further, inverter-based generators have not provided the same range of services that conventional generators have provided in the past.

ElectraNet plays a critical role in addressing these challenges. While the grid once used to "deliver" electricity from large remote generators to customers, it is increasingly being used to move electricity back and forth between regions and local areas and to provide essential system services that were once provided by thermal generators. The transmission network facilitates the connection of large-scale renewable energy sources, located usually in geographically distant areas to the load centres, which are cities or large industrial parks. Similarly, distributed rooftop PV generation, which is concentrated in the Adelaide metropolitan area, can feed the load across the state.

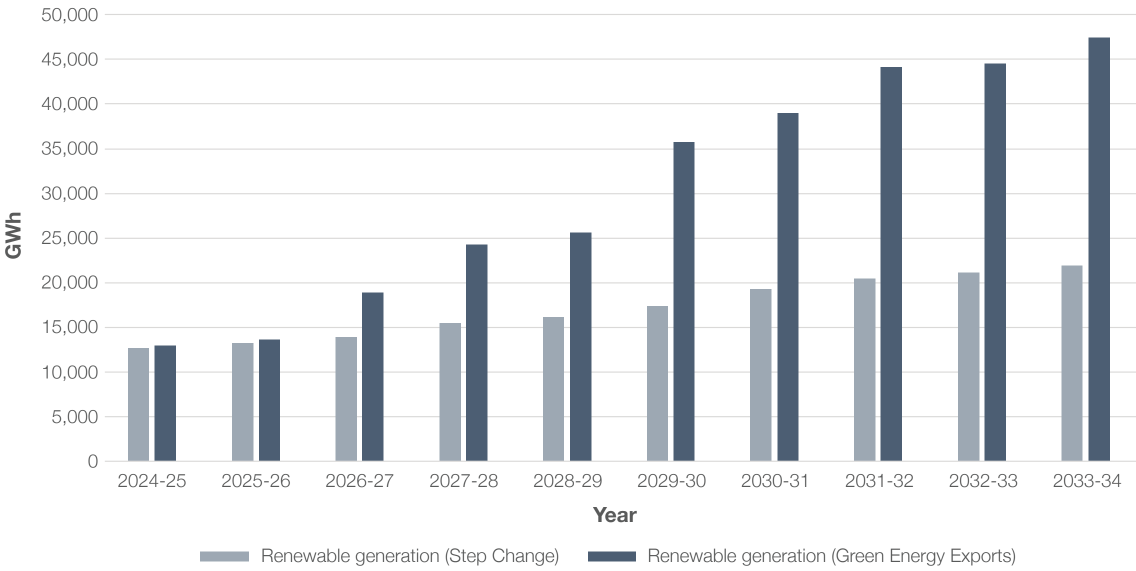
We are progressing the System Strength RIT-T to determine the short to medium term system strength needs of the power system. ElectraNet is paying close attention to the rapidly developing technical characteristics of grid forming batteries along with other non-network sources of system strength services to meet the need presented by AEMO's transmission-connected Inverter Based Resource forecasts. We plan to report our draft findings later in the year.

We continue to examine the changing nature of the power system in ever-increasing detail. We are using this understanding to implement special protection schemes to protect the power system from disturbances that allow us to more fully use the network's capability while maintaining reliability. As part of this, we have completed the installation of our Wide Area Monitoring System (WAMS) to establish enhanced monitoring of power system conditions from the control room. WAMS has allowed us to develop a Wide Area Protection System (WAPS) with the use of phasor measurement units (PMUs) to real-time monitor and detect events and enable dynamically proportionate responses from connected participants to help maintain the network stability. This will be extended as part of Project EnergyConnect into the South Australia Interconnector Trip Remedial Action Scheme (SAITRAS).

Energy from renewable sources in South Australia is forecast to grow strongly in AEMO's Step Change scenario, and very rapidly in AEMO's Green Energy Exports scenario (Figure 4).[5] Increases in demand are also forecast to materially increase the need for transmission in South Australia to connect and transport renewable generation and enable supply to be met at the least overall cost.

[5] AEMO | 2023 Inputs, Assumptions and Scenarios Report

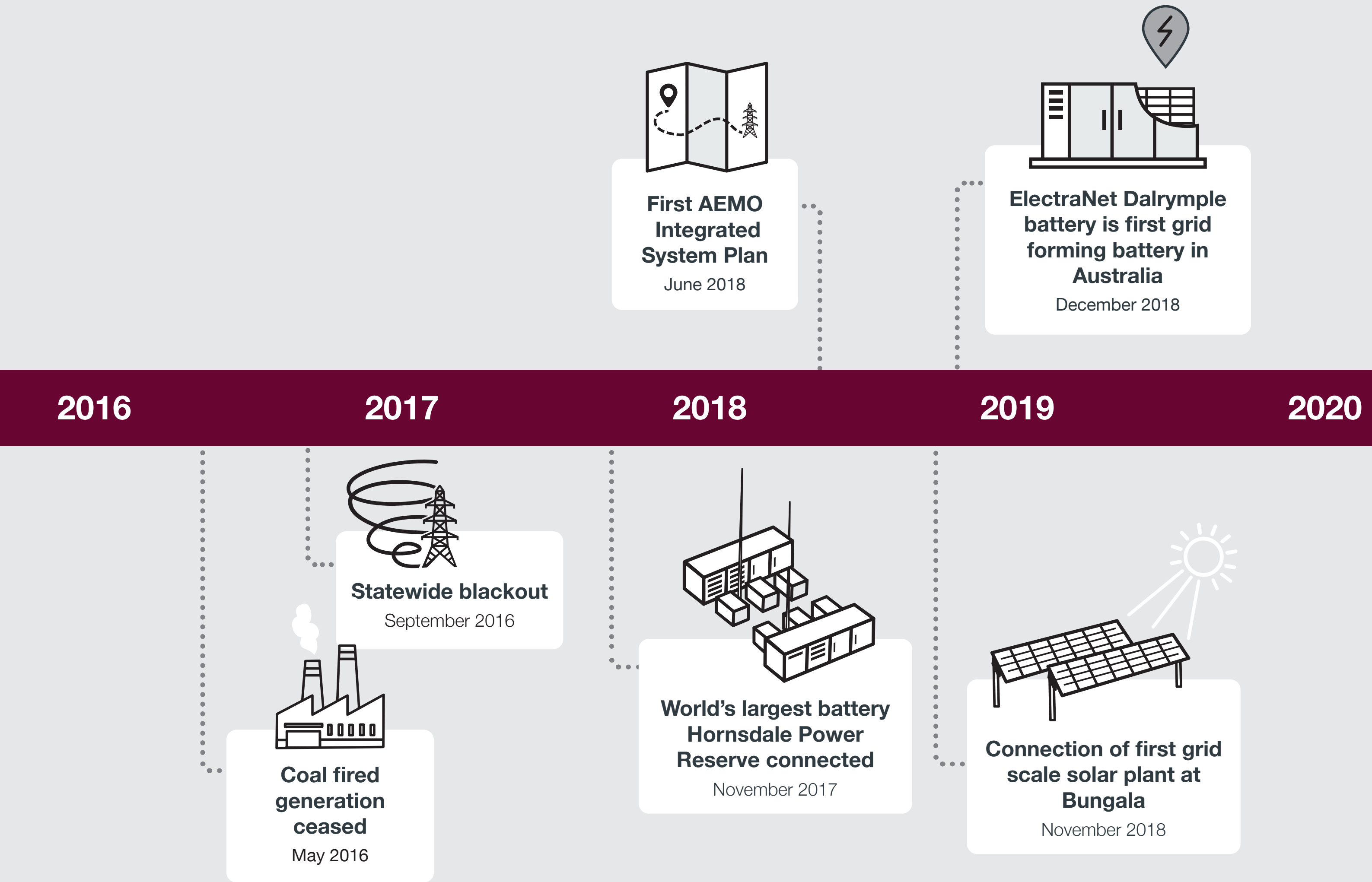
Figure 4: South Australian renewable generation output forecasts



Source: 2024 ISP generation and storage outlook

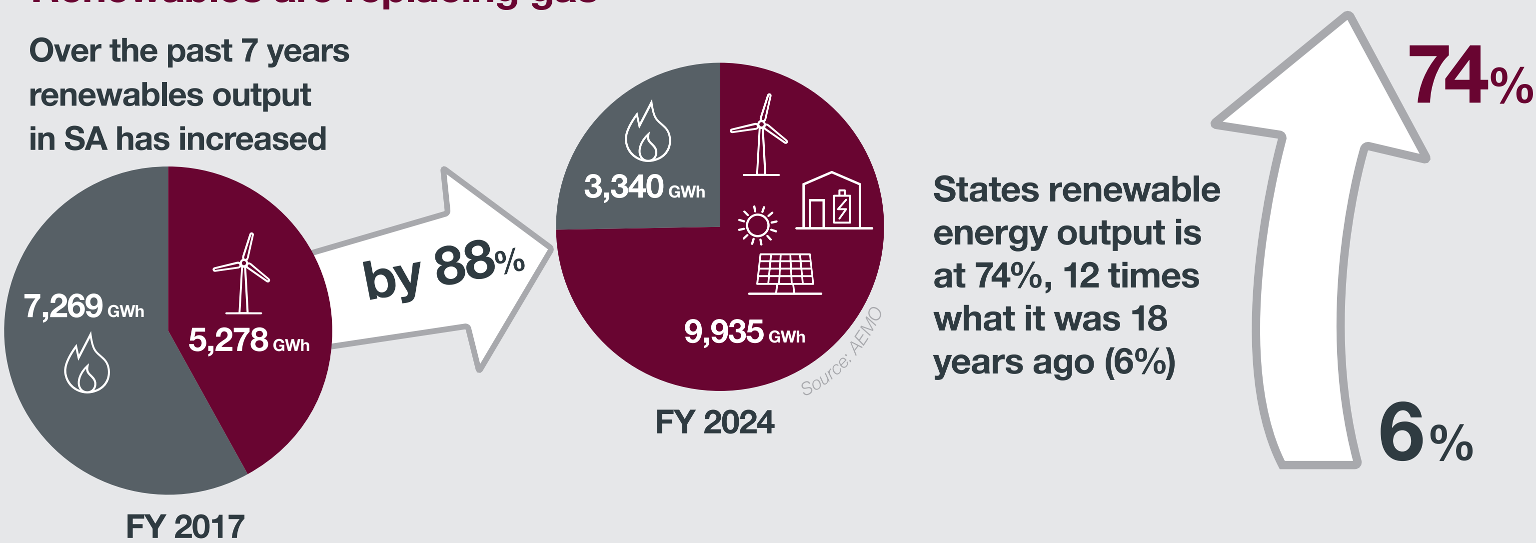
Our annual planning process focuses on balancing system security, reliability of supply and affordability for all South Australian customers. Based on projections of future electricity supply and demand, we forecast network limitations and opportunities and ensure plans are in place to address them in a timely and efficient manner.

Figure 5:
Our transformational journey



Renewables are replacing gas

Over the past 7 years renewables output in SA has increased



States renewable energy output is at 74%, 12 times what it was 18 years ago (6%)

ElectraNet synchronous condensers begin operation
October 2021

Regulatory approval for new interconnector to NSW Project EnergyConnect
June 2021

Hornsdale Power Reserve
First battery in the world to provide grid-scale synthetic inertia
July 2022

Fast Frequency Response
We have contracted FFR services since July 2022 in two back to back contracts to provide additional inertia strength. This will not be required once Project EnergyConnect is energized
July 2022

Retirement of first major gas-fired power station
September 2022

Negative peak system demand reached
October 2022

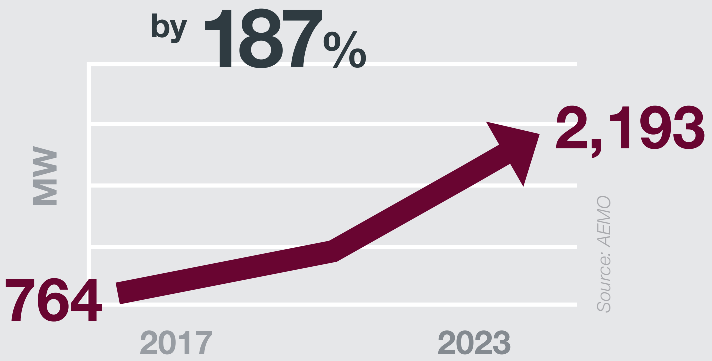
Eyre Peninsula Link
Completion of a new double-circuit 132 kV electricity transmission line from Cultana to Port Lincoln
March 2023

Completion of Project EnergyConnect interconnector in SA
December 2023

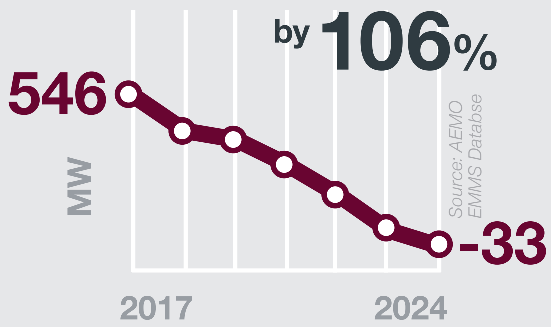
2021 | 2022 | 2023 | 2024

A grid in transition

Rooftop PV installation has increased over the past 6 years



Minimum grid demand has decreased over the past 6 years



as at October 2024

1.2.1 Large Industrial Loads

We have received many enquiries from potential large industrial loads, seeking to take advantage of South Australia's low-emission electricity, which may lead to demands being considerably higher than forecast in AEMO's Step Change scenario. Active interest in new load connections in the short-medium term currently exceeds 2,000 MW, which aligns with load forecasts under the Green Energy Export scenario.

This is also occurring at the distribution level with SA Power Networks exploring LIL connections at five distribution connection points.

Demand forecasts are discussed further in Chapter 3.

1.2.2 New solar and wind generation

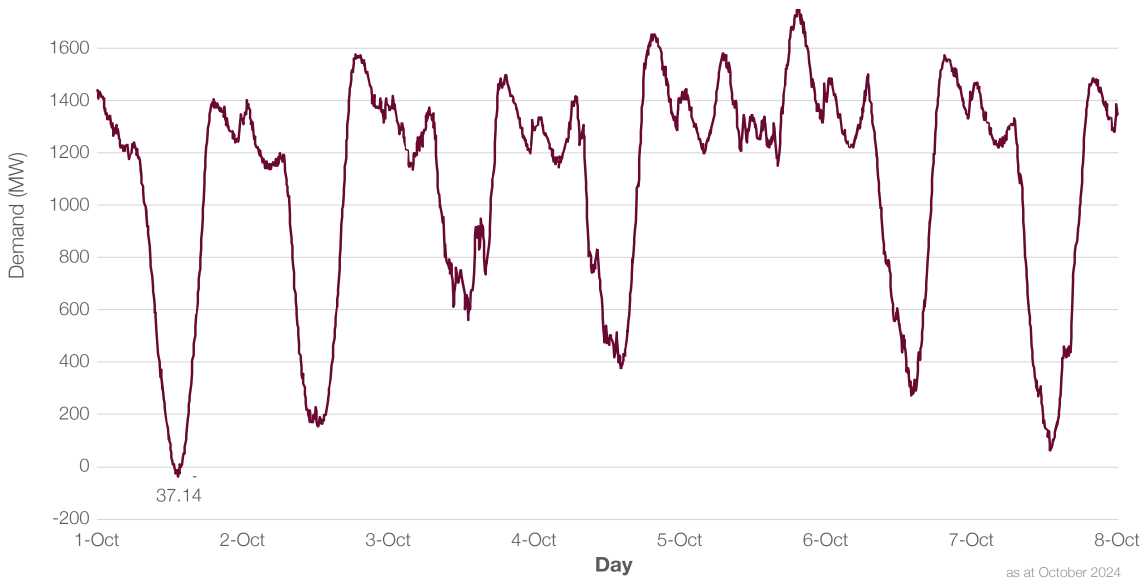
South Australia has the wind and solar resources to supply a very large system. We are receiving enquiries from proponents of increasingly large renewable energy generation developments.

There are numerous large-scale VRE generation developments proposed that individually exceed 1,000 MW in size, with interest spanning the state from the South East, through the Mid North, to the Eyre Peninsula.

The South Australian Government has opened consultation on two proposed release areas under the Hydrogen and Renewable Energy Act to facilitate very large renewable energy developments at Whyalla West and Gawler Ranges East.[6] The federal and state governments have an agreement to support 1,000 MW of solar or wind developments in the state.

ElectraNet is monitoring these developments to understand how our plans can best support the state's development.

Figure 6: Example demand variability (October 2023)



Source: AEMO MMS database

6 Department of Energy & Mining, South Australia | Release areas – Hydrogen and Renewable Energy Act

1.2.3 Distributed solar PV generation

South Australians have adopted distributed solar PV generation at world-leading rates, with its accumulated contribution approaching two gigawatts under the right conditions. As a result, 88% of transmission connection points with the SA Power Networks distribution network have experienced times when the output of distributed solar PV systems exceeded the local demand during the day. When this happens, the transmission network transports the excess electricity away from the local area, to be used by customers elsewhere.

These high levels of distributed renewables are causing transmission flows to vary from high levels of supply to the distribution network, with power flows then reversing direction at times of high solar PV generation output, and then reversing direction once more over the course of the day. As a result, the system regularly achieves a need to ramp down around 1,200 MW in the morning and ramp up around 1,400 MW in the afternoon. This was well demonstrated over a week in September 2023 (Figure 6). This is both changing the patterns of congestion over the course of the day and also influencing the value proposition for network augmentation. Median prices range from $33/MWh during the daily demand trough to $150/MWh at 6 pm. That is, prices are typically negative during the middle of the day and high during the evening peak.

At the state-wide level, the lowest recorded South Australian operational demand[7] was -44 MW on 31 December 2023, meaning that all demand in the State was met by distribution connected generators (predominantly distributed rooftop solar). Under such conditions, South Australia is almost entirely reliant on interconnection with the eastern states to balance supply and demand, given the limited control currently available over rooftop solar. These conditions are expected to occur more frequently in the future.

1.2.4 Battery Energy Storage Systems

Interest in Battery Energy Storage Systems (BESS) connections to the transmission network is expected to increase installed capacity in South Australia from 756 MW today to almost 4,000 MW pursuing connection in the next 3 years.

[7] AEMO defines operational demand as the one which is met by local scheduled and semi-scheduled generating units and non-scheduled intermittent generating units of aggregate capacity >= 30 MW and by generation imports to the region.

1.3 Network Transition Strategy

ElectraNet's Network Transition Strategy was published in March 2024 and is designed to ensure the South Australian transmission system continues to operate safely and securely and to deliver reliable and sustainable electricity transmission services through the current transition to more frequent and longer periods of 100% variable renewable energy generation.

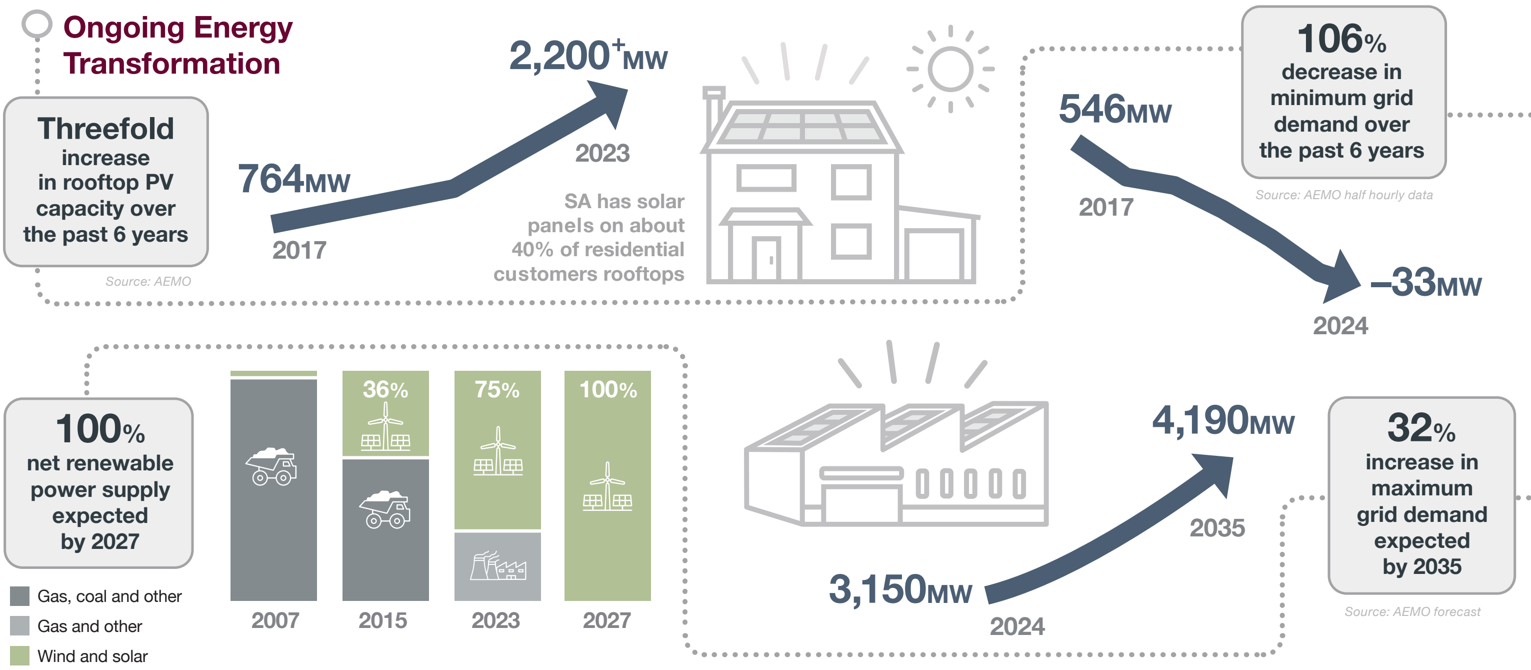
The strategy includes the following three pillars:

Energy Reliability – timely and efficient development of transmission infrastructure is essential to connect new renewable generation and storage to supply existing customer demand and meet increasing demand from electrification and new industrial loads.

Power System Security and Resilience – we must plan and deliver new investments and system services to maintain power system security and resilience during the energy transition.

Operability – we need to build new capabilities, including advanced tools, for network planning and operations to manage the increasing complexity and risk of operating a network with 100% variable renewable energy.

Figure 7:
Network Transition Strategy



How we are Responding

Our Objectives	Safety	Affordability	Reliability	Sustainability

The Network Transition Strategy is guided by our asset management objectives and underpinned by three key themes.

Energy Reliability

Eyre Peninsula Link
Delivered in 2023 providing improved reliability and unlocking future growth on the Eyre Peninsula

Project EnergyConnect
Completed in SA in 2023 to improve reliability, enable more renewable energy and deliver price savings for customers

Pursuing priority network developments
Mid-North (Southern and Northern) Expansion
South-East Expansion
Eyre Peninsula upgrade

Power System Security & Resilience

Synchronous condensers
Installed in 2021 to meet system strength and inertia requirements

System Security
Procured inertia support services to protect SA when electrically islanded
Implemented Wide Area Protection Scheme
Implemented an automated Voltage Control Scheme at Davenport

System Strength
Developing solutions to meet forward-looking system strength requirements

Voltage Control
Developing solutions to manage voltage across the changing network

Operability

Control Room Capability
Replaced Energy Management System to improve capability to operate the network

Wide Area Monitoring
Implemented a new system for improved power system monitoring

Network planning and operations capability uplift
Realtime operations
Near real-time planning
Outage planning
Longer-term planning

Operational Systems
Expand operational system capabilities to manage increasing network complexity and risk

Challenges and opportunities

- Unlocking demand growth and renewables
- Supply and demand variability
- System security services
- Voltage control
- Protection adequacy
- Increasing system complexity and risk
- Harnessing customer energy resources
- Extreme events
- Underlying Network Challenges

LEGEND

- What we have done
- What we are doing

Protection

Ensuring system protection and emergency control schemes are effective for changing system conditions

Connection Arrangements

Optimising distribution and customer contributions to system security

Ongoing engagement with customers and stakeholders and development of solutions to emerging challenges and opportunities

The Network Transition Strategy provides a pathway and framework for working with our customers and stakeholders to manage the challenges and opportunities of the energy transition.

2 South Australia's Transmission Network Outlook

2.1 Integrated System Plan

AEMO's 2024 Integrated System Plan (ISP) finds that renewable energy connected with transmission and distribution, firmed with storage, and backed up by gas-powered generation is the lowest-cost way to supply electricity to homes and businesses through Australia's transition to a net zero economy.[8]

The ISP provides a comprehensive road map for the National Electricity Market. It seeks to facilitate the efficient development and connection of renewable energy zones across the National Electricity Market.

The ISP identifies an Optimal Development Path (ODP) for development of the NEM, which will see fossil fuelled legacy assets replaced with low-cost renewables, the addition of energy storage and other new forms of firming capacity, and reconfiguration of the grid to support two-way energy flow. AEMO published the ISP in June 2024.

AEMO's 2023–24 Inputs, Assumptions and Scenarios Report (IASR) contains descriptions of the inputs, assumptions and scenarios used in the 2024 ISP.

The broad and deep push to decarbonise across jurisdictions has reduced some of the uncertainty faced by AEMO's previous IASR publications. Due to the rapid pace of ongoing policy development, policies that meet the 'public policy clause' of the Rules, or where jurisdictions have demonstrated clear pathways to AEMO to meeting this clause prior to publication of the 2024 ISP, have been included in the policy collection influencing AEMO's planning functions.

AEMO synthesised stakeholder feedback to develop three scenarios (Figure 11). In developing these scenarios, AEMO recognised that the Slow Change scenario described in the 2021 IASR and 2022 ISP is no longer consistent with the pace of transformation required by the collection of policies facing Australia's energy industry. In AEMO's stakeholder activities conducted prior to the release of the Draft 2023 IASR, most stakeholders supported the Slow Change scenario's removal, consistent with its very low relative likelihood in the 2022 ISP.

AEMO is currently reviewing the scenarios with updated narratives expected to be published in November 2024.

Figure 8: AEMO's 2023 IASR planning scenarios

Source: AEMO's 2023 Inputs Assumptions and Scenarios Report[9]

We utilise AEMO's ISP scenarios for our planning, with the appropriate application of scenarios varying according to the need:

- In annual planning, we primarily consider the Step Change and Green Energy Export scenarios. While the Green Energy Exports scenario was given a low weighting by AEMO, we are increasingly seeking to use a higher demand forecast due to the high interest in new large industrial loads
- We do not consider the Progressive Change scenario is appropriate for South Australia but note that on many of the core parameters such as the demand forecast, Progressive Change and Step Change have strong alignment within South Australia
- For a RIT-T that is triggered by AEMO's ISP, we will consider and apply scenarios as directed by AEMO. For the Mid North REZ Expansion this involves using all three scenarios
- For other RIT-Ts, we will assess the appropriate treatment of scenarios on a case-by-case basis – for example, 2024 ISP Green Energy Exports is a key scenario to consider in RIT-Ts where option value is a potentially significant market benefit.

[8] AEMO | 2024 Integrated System Plan

[9] AEMO | 2023 Inputs, Assumptions and Scenarios Report

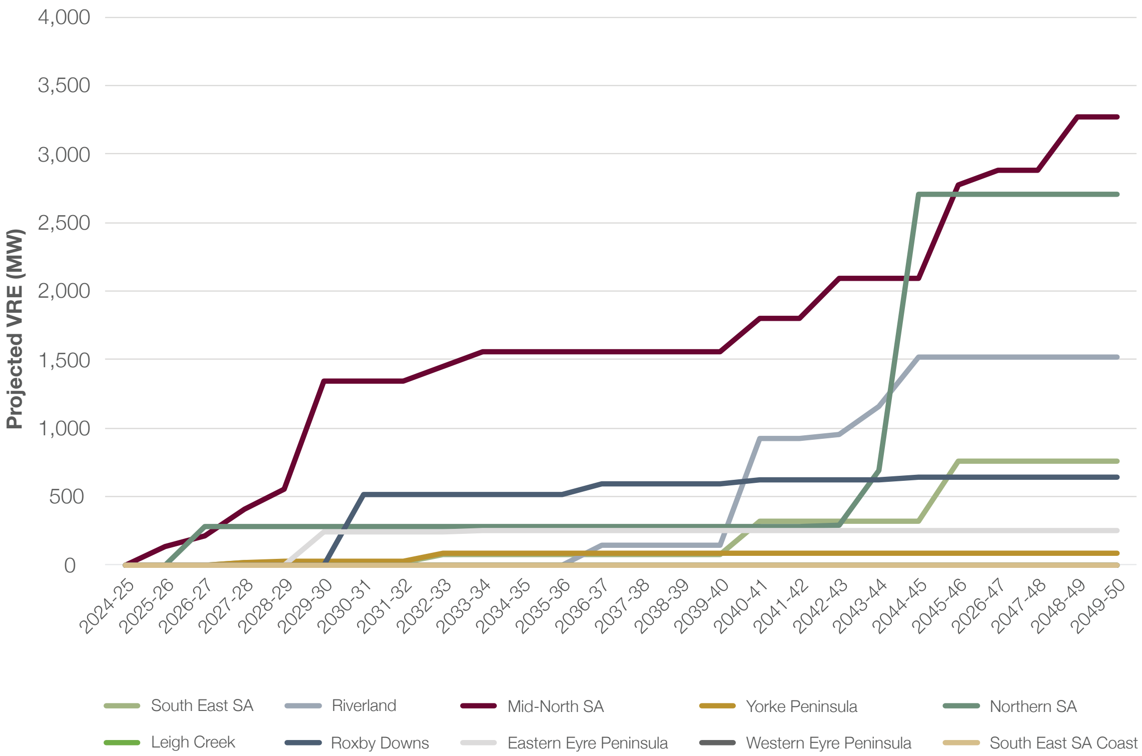
2.1.1 Step Change Outlook

The 2024 ISP has forecast a requirement for approximately 10 GW of new utility-scale wind and solar VRE within South Australia by 2050 to replace retiring gas generation capacity. Figure 9 shows a projection of the utility-scale VRE for each REZ in South Australia as per the Step Change scenario.

The modelling indicates:

- The projected VRE is shared over many REZs throughout South Australia, with the largest share of early development occurring in the Mid-North South Australia REZs due to the high-quality wind resource
- The Mid-North South Australia REZ sees an immediate increase in VRE, with an additional 1,200 MW of new VRE capacity by 2029–30, 1,800 MW by 2041–42 and finally reaching 3,600 MW by 2049–50
- The South East South Australia REZ sees a gradual increase in VRE with close to 500 MW new capacity after 2040 and just under 1,000 MW by 2050
- The Northern South Australia REZ is projected to see developments particularly in solar after 2044–45, with 2,650 MW new VRE capacity by 2049–50
- The Riverland REZ is projected to see developments particularly in solar after 2040–41, with 1,500 MW of new VRE capacity by 2044–45
- The Eastern Eyre Peninsula and Roxby Downs REZs also see small amounts of VRE developments in the order of 350–600 MW in the mid-2030s

Figure 9: South Australia utility-scale VRE developments in REZs for Step Change (MW)



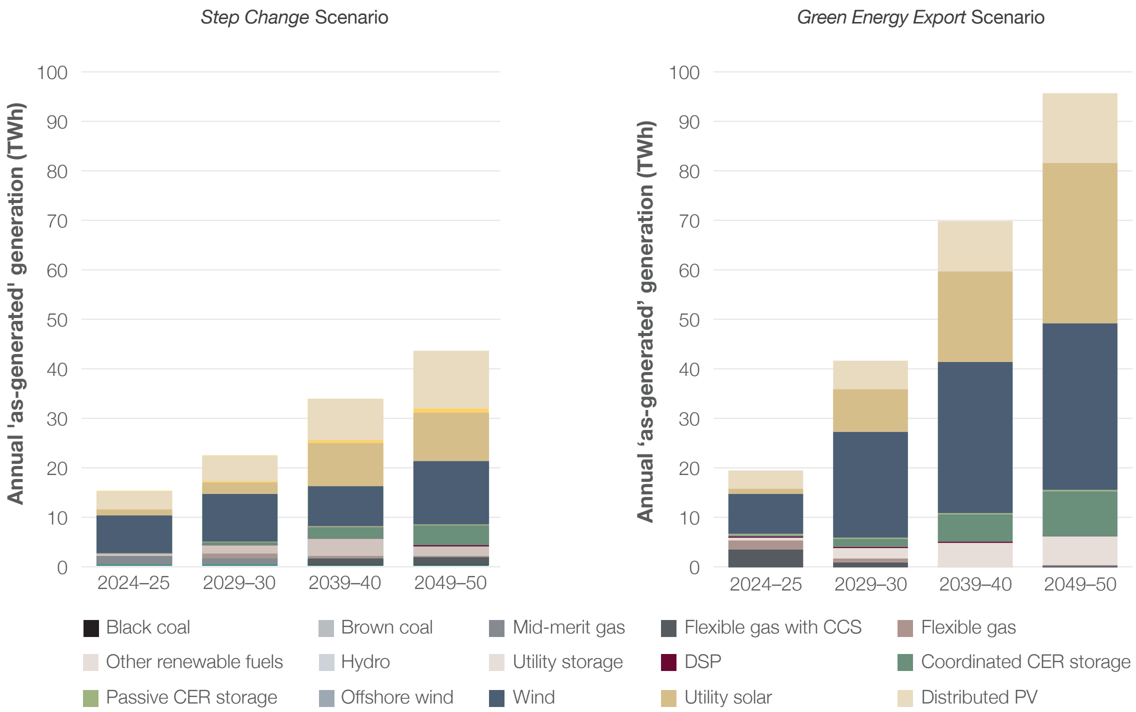
Source: 2024 ISP Appendix 3 – Renewable Energy Zones[10]

[10] AEMO | 2024 Integrated System Plan (ISP) – Appendix 3 Renewable Energy Zones

2.1.2 *Green Energy Export* Outlook

The 2024 ISP Green Energy Export scenario forecasts a level of renewable generation that far exceeds the forecasts of development in the other scenarios. Should interest in Large Industrial Loads translate into developments in the short term, South Australia will be on track for demand growth that aligns with the 2024 ISP Green Energy Export scenario at least in the short term. In the short to medium term this may be driven by LIL for purposes other than direct energy exports, such as green steel and other energy intensive industries. Hydrogen for domestic consumption is a feature of these plans and allows for the potential to leverage hydrogen for exports into the future.

Figure 10: Comparison of Step Change and Green Energy Export Scenario



Source: 2024 ISP generation and storage outlook

Using scenarios from the 2024 ISP we have compared the amount of renewable generation forecast to be developed in each REZ by 2050 (Table 1). This shows that if the Green Energy Exports scenario materialises, the scope of development to unlock the Mid North, Eastern Eyre Peninsula and Western Eyre Peninsula REZs would need to far exceed the scope required in other scenarios.

Demand forecasts for the Green Energy Exports scenario are discussed in Section 3.3.1. In addition, high-level potential scopes to unlock REZs to the extent required for the Green Energy Exports scenario are proposed in Section 4.4.

2.1.3 South Australia and New South Wales demand sensitivity

AEMO considers sensitivities in the ISP, to explore uncertainties pertaining to key assumptions. As part of the 2024 ISP AEMO tested the sensitivity of the Optimal Development Path for increases in LILs in South Australia and New South Wales. We provide more information in Chapter 3 on why this is necessary.

This sensitivity – based on the Step Change scenario – was used to analyse the effect of demand increases on the augmentation plan for South Australia and New South Wales, and included LILs that were expected to commit by June 2024.

In South Australia, this sensitivity included an additional 13 TWh of load on the Eyre Peninsula and Upper North by 2030, increasing to 16 TWh by 2050. In NSW this sensitivity included an additional 2.6 TWh of load by 2030, increasing to 20 TWh by 2050 is included.

The outcomes of the SA demand sensitivity demonstrated that the benefits of the ODP increased by around $27.3B to $44.0B compared to the Step Change scenario with benefits of $16.7B.

2.1.4 South Australian projects in the 2024 ISP

The primary driver for additional investment in transmission ins South Australia is to match increasing load growth and to ensure the new load centres are connected to existing and emerging renewable zones in the future.

Project EnergyConnect is recognised as a committed project in the 2024 ISP with Stage 1 due to be completed end of 2024 and Stage 2 inter-network testing in July 2027.

The 2024 ISP identifies two network investments in South Australia as part of the ODP. These are:

- **Actionable project** – Mid North South Australia REZ Expansion, anticipated to be completed by July 2029
- **Future ISP project** – Mid North South Australia REZ Extension needed as early as 2037–38.

These projects are described in more detail below.

Project EnergyConnect

Project EnergyConnect was conceived on the back of South Australia's energy transition to a greater mix of renewables, while also catering to the customer demands for lower electricity bills. Once completed, Project EnergyConnect will be a high-capacity interconnector between Robertstown, South Australia and Wagga Wagga, in New South Wales, with a connecting double-circuit 220 kV transmission line to Red Cliffs in Victoria. It will provide a geographically diverse second AC path between South Australia and the rest of the National Electricity Market, traversing east and to west, linking the REZs of Riverland, Murray River and South West NSW and providing additional hosting capacity in each of these REZs.

The interconnector will increase access to other regions and increase competition in the wholesale electricity market, putting downward pressure on electricity prices.

Project EnergyConnect remains on track to be delivered in two stages:

- Construction and commissioning of Bundey 330/275 kV Substation was completed in late 2023.
- Included in the first stage is construction of the 360 km of the 330 kV section from Bundey in South Australia to Buronga in NSW. Construction of the South Australian section was complete in late 2023. Inter-network testing and release of initial transfer capability up to 150 MW by the end of 2024 is planned, subject to availability of suitable test conditions.
- The completion of the second section from Buronga to Wagga Wagga in NSW, with inter-network testing and release of transfer capacity up to 800 MW will take place from 2026, subject to market demand.

The Project EnergyConnect System Integration Steering Committee, a collaboration between AEMO, ElectraNet, Transgrid and AusNet Services, is preparing procedures to coordinate a timely integration of Project EnergyConnect into the National Electricity Market. A major goal of the steering committee was the preparation of a methodology for the capacity release of the interconnector, following an agreed inter-network test program. This program has now been finalised and published.[11]

Mid–North Renewable Energy Zone Expansion

The Mid North REZ Expansion project is a major new electricity transmission project that will power South Australia's clean energy future and support the State's Prosperity Project. The project is comprised of two components, being a southern and a northern section. Mid North REZ Expansion was declared an 'actionable project' by AEMO in the 2024 ISP with the Mid North REZ Expansion (Southern) as the 'candidate ISP project'.

ElectraNet will consider options to expand power system capacity from the Mid North to Adelaide (southern section) and from the Mid North to Whyalla (northern section).

The southern section will enable higher transfers of low-cost renewable energy from the Mid North region to the Adelaide Metropolitan load centre, unlocking potential for increased connection of renewables in the Mid North SA, Riverland and Northern SA REZs. Additionally, it aims to make Adelaide's energy supply more diverse and resilient to extreme weather, particularly bushfires that could affect the transmission corridors in the Eastern Hills.

The southern section is expected to consist of new high capacity double-circuit twin conductor lines from Bundey to Para or to a new site between Parafield Gardens and Torrens Island.

The northern section will unlock potential for increased connection of low-cost renewables in the Mid North SA, Northern SA, and Eastern Eyre Peninsula REZs and provide a new high-capacity transmission path connecting the existing Adelaide metropolitan major load centre and emerging hydrogen hub major load centres on the Eyre Peninsula (e.g. at Port Bonython or Cape Hardy) with sources of renewable energy generation.

Additionally, it will unlock potential for development of a good quality wind and solar zone near Yunta that has not yet been identified as a REZ due to its distance from the existing grid. This will also provide capacity to supply developing iron ore deposits in the Braemar region, which are near Yunta.

The northern section is expected to consist of new high capacity double-circuit twin conductor lines between Bundey and Cultana.

As AEMO has deemed this project an 'actionable project', Electranet has commenced a RIT-T process, which is a cost benefit analysis of various options to identify the preferred solution to benefit customers.

[11] AEMO | Final Project EnergyConnect Stage 1 and HIC Test Program – published 12/04/2024

Table 1: Potential network investments to release capacity in South Australian candidate Renewable Energy Zones

REZ Name	Potential network investments
S1 **South East SA**	Increase transfer capacity between the South East region of South Australia and the Adelaide metropolitan load centre by stringing the vacant 275 kV circuit between Tailem Bend and Tungkillo and installing dynamic reactive support if needed to support increased transfers. This will unlock potential for increased connection of low-cost renewables near Tailem Bend. We provided AEMO with the results of our preparatory activities for this project in 2022–23. Given the updated demand outlook this project should be delivered before 2030. A second stage of this project could consider increasing transfer capacity between the South East SA REZ and the Melbourne metropolitan load centre by increasing the capacity of the Heywood interconnector, with for example a new double circuit 500 kV line between Heywood and a new major substation in the South East SA. AEMO have identified the Western Victoria Grid Reinforcement is a future ISP project and is needed by 2033–34 in the Step Change scenario.
S2 **Riverland**	Establish Project EnergyConnect (EC.14171). The first stage of the project (150MW) is expected to be in service by the end of 2024. The second stage of the project, under the remit of NSW TNSP Transgrid, Inter-network testing will then commence in 2026 for release of up to 800 MW transfer capacity, subject to availability of suitable test conditions and successful test outcomes. The South Australian works for Project EnergyConnect included the creation of the new Bundey 330/275 kV substation, which is able to facilitate new 275 kV or 330 kV connections near Robertstown.
S3 **Mid North SA**	The 2024 ISP has declared expansion of the Mid North to be an actionable project. The identified need for Mid North South Australia REZ Expansion is to increase power system capability of the transmission network to: • support the expected increase in renewable generation north of Adelaide to support growing demand in Adelaide, • ensure adequate network capacity and supply for large industrial loads, and • alleviate congestion on renewables from the Mid North to rest of the NEM. The southern expansion of the Mid North will enable higher transfers of low-cost renewable energy from the Mid North region to the Adelaide Metropolitan load centre, unlocking potential for increased connection of renewables in the Mid North SA, Riverland and Northern SA REZs. Additionally, it may improve geographical diversification of transmission corridors to increase security of supply to the Adelaide Metropolitan load centre as climate change increases bushfire risks to the transmission corridors in the Eastern Hills. We are also considering options for expansion of the northern section, to unlock potential for increased connection of low-cost renewables in the Mid North SA, Northern SA, and Eastern Eyre Peninsula REZs and provide a new high-capacity transmission path connecting the existing Adelaide metropolitan major load centre and emerging hydrogen hub major load centres on Eyre Peninsula (e.g. at Port Bonython or Cape Hardy) with sources of renewable energy generation. We are progressing the RIT-T to investigate possible options to meet the identified need. We expect to finalize the PADR by the end of 2025.
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. Development of this REZ may be considered if the level of maximum demand on the Yorke Peninsula is forecast to increase significantly in future. We will continue monitoring connection proposals and requests in the region and identify the appropriate time to start any investigation.
S5 **Northern SA**	Assessment of the Mid North REZ may also result in expansion of Northern SA zone. This will be considered as part of the Mid North REZ Expansion RIT-T. The SA Government is consulting on two release areas under the HRE Act that if declared will prioritise development of the Gawler East and Whyalla West release areas and this REZ.
S6 **Leigh Creek**	Establish a new shared connection point that extends the 275 kV network from Davenport or Yunta (following expansion of the northern section of the Mid North northern expansion) to a suitable location near Leigh Creek.

Table 1: Potential network investments to release capacity in South Australian candidate Renewable Energy Zones (cont.)

REZ Name	Potential network investments
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) was completed early 2023 and it has increased capacity to facilitate additional generator connections in the Eastern Eyre Peninsula REZ. Capacity can be further increased by upgrading the operation of the lines between Cultana and Yadnarie from 132 kV to 275 kV, unlocking potential for increased connection of low-cost renewables in the Eastern Eyre Peninsula REZ and increasing the ability for Eyre Peninsula renewables to supply proposed hydrogen facilities near Whyalla (EC.15104). Based on increasing customer interest on the Eyre Peninsula, we commenced the RIT-T process at the end of last year, with the publication of the Project Specification Consultation Report (PSCR). We are progressing our investigation and expect to publish the PADR in November this year. If found to deliver net market benefits, and with the commitment of sufficient additional load on Eyre Peninsula, we will seek approval to activate the Eyre Peninsula Upgrade contingent project that is included in our 2023–24 to 2027–28 revenue determination. If there are many new generator or load connections in the Eastern Eyre Peninsula REZ, Western Eyre Peninsula REZ or Northern SA REZ west of Spencer Gulf, it could be necessary to build additional double circuit 275 kV lines between Davenport and Cultana. This REZ may also be impacted by the Mid North REZ expansion RIT-T.
S9 **Western Eyre Peninsula**	Eyre Peninsula Link (EC.14172) has increased capacity to facilitate additional generator connections in the Western Eyre Peninsula REZ. Capacity can be further increased by upgrading the operation of the lines between Cultana and Yadnarie from 132 kV to 275 kV and 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. We have proposed a contingent project (EC.15104) to deliver this increased capacity if the need arises (Section 7.5). If large scale new generation and/or load is established on the western side of the Eyre Peninsula, there might be a need to connect to the network. To extend the grid to the western side of the Eyre Peninsula will require a new shared connection point that extends the 132 kV or 275 kV network from Yadnarie to a new suitable location on the western Eyre Peninsula.
S10 **Offshore South East SA Coast**	There are no plans to develop this zone at this stage. Any future development most probably will require the prior capacity increase on the South East Zone (S1).

2.2 System Security Reports

AEMO published the 2023 System Security Reports in December 2023. AEMO identifies system security needs across the NEM for the coming five-year period in the areas of system strength, inertia and Network Support and Control Ancillary Services (NSCAS).

2.2.1 System Strength

Under the system strength framework,[12] ElectraNet is required to deliver a system strength services for South Australia on a forward-looking basis, based on forecasts from AEMO for inverter-based resources. The new framework is intended to enable more rapid connection of inverter-based resources such as solar and wind, with system strength solutions that achieve economies of scale while also preserving the option for new entrants to bring their own solutions. This creates an environment where we can ensure the system remains stable and allows for competition to drive lowest long run costs. The framework is biased towards early procurement of services rather than late procurement with competition ensuring that costs are kept as low as possible. The provision of a required level of system strength services is mandated from 2 December 2025.

The system strength framework identifies a minimum requirement and a higher efficient level of services. AEMO's forecasts indicates that the minimum requirement in South Australia will continue to be met. That is, no further action is required by ElectraNet for the foreseeable future to maintain the minimum level.

The efficient level is based on AEMO's forecast of IBR in the Step Change scenario. In South Australia AEMO has forecast around 5,000 MW of IBR in South Australia (including existing transmission connected IBR, but excluding distribution connected IBR).

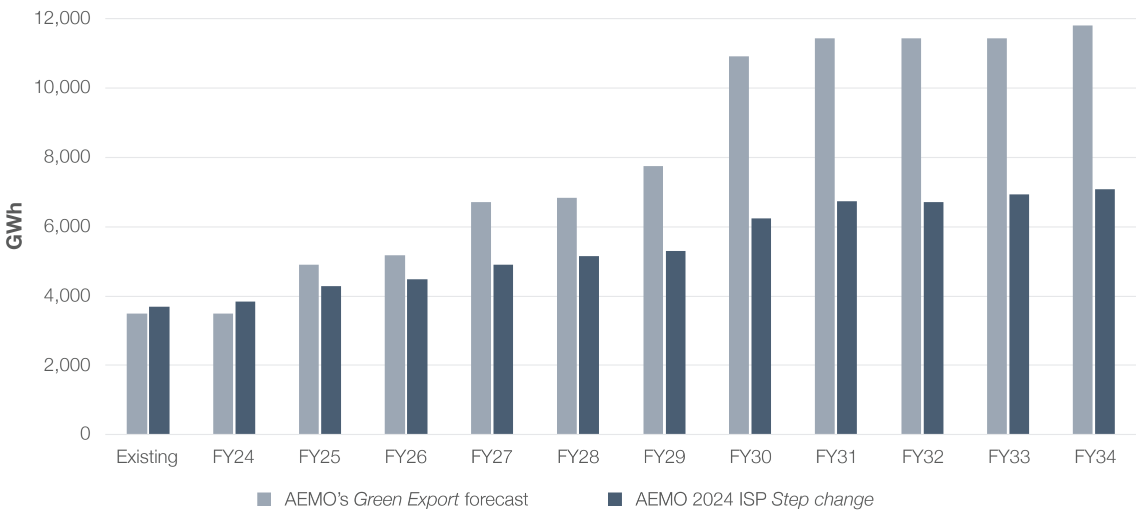
A much higher level, exceeding 11 GW of IBR is forecast under the Green Energy Exports scenario.

ElectraNet is currently undertaking RIT-T to determine the most efficient means to meet the efficient level of system strength balancing affordability, reliability and flexibility to respond to rapid deployment of IBR on the system. We anticipate publishing our Project Assessment Draft Report by February 2025.

We are examining the potential to deliver services through low-cost alternative means including repurposing existing synchronous machines, grid forming inverters and the potential to fit conventional generators with clutches to allow them to operate as synchronous condensers on a permanent basis or as needed, along with static synchronous compensators (STATCOMs) and potentially other novel technologies.

The required efficient level of system strength is likely to continue to increase in future years. We are currently studying the actual asynchronous generation hosting capacity improvement that is expected to be delivered by Project EnergyConnect [BP1]. AEMO's forecast on IBR volume under Green Energy Exports scenario exceeds eleven (11) GW of wind, solar and batteries over the next ten (10) years (see Figure 14). Potential system strength solutions may include additional synchronous condensers, hydrogen gas based synchronous generators, synchronous clutch enabled gas generators, grid-forming (GFM) inverter-based plants such as batteries.

Figure 11: Green Energy Export scenario and Step Change scenario



Source: Source: 2024 ISP generation and storage outlook

[12] AEMC | Efficient management of system strength on the power system

2.2.2 Inertia

In December 2023, AEMO declared an inertia shortfall of 500 MWs from 1 July 2024 until Project EnergyConnect Stage 2 is operational and appropriate control schemes are in place. This shortfall could be met by an equivalent quantity of 30 MW of FFR contracts, or by further registrations in the 1-second FCAS market.[13] On 12 June 2024, AEMO notified ElectraNet that sufficient registrations of 1-second FCAS had been registered and that ElectraNet would not be required to provide FFR from 1 July 2024. ElectraNet has subsequently cancelled all inertia shortfall agreements.

2.2.3 Network Support and Control Ancillary Services (NSCAS)

In the 2023 NSCAS report, AEMO declared an ongoing Reliability and Security Ancillary Service (RSAS) gap of 200 MVAr during periods when South Australian demand is below 600 MW, and South Australia is not islanded or at credible risk of islanding.

AEMO noted that ElectraNet's plans to install switched 275 kV reactors or equivalent services as part of EC.11645 Transmission Network Voltage Control (Section 7.4) are reasonable steps to close this gap. The RIT-T for this identified need has been completed with a conclusion to install 3x50MVAr and 3x60MVAr reactors on the 275kV network. These reactors will be deployed progressively by 2026.

AEMO has sought expressions of interest from the market for another service provider until the Transmission Network Voltage Control project is completed.[14]

2.3 General Power System Risk Review (GPSRR)

AEMO published the final report for the 2024 General Power System Risk Review (GPSRR), in July 2024. The GPSRR is intended to help AEMO, Network Service Providers (NSPs) and other market participants to better understand the nature of new risks and monitor them over time.

The GPSRR is completed annually, and it has a broad scope to explore a wide range of risks that could have adverse impacts on the power system. It requires AEMO to work in collaboration with NSPs to identify and assess risks to power system security that it expects would be likely to lead to cascading outages or major supply disruptions. Risks to be reviewed include:

- Non-credible contingency events, the occurrence of which AEMO expects would be likely to involve uncontrolled increases or decreases in frequency, alone or in combination, leading to cascading outages, or major supply disruptions
- Other events and conditions (including contingency events) the occurrence of which AEMO expects, alone or in combination, would be likely to lead to cascading outages, or major supply disruptions.

The GPSRR considers how the effects of these type of events will impact the NEM, their risk level and recommends possible actions to mitigate them.

13 AEMO | 2023 Inertia Report

14 AEMO | NSCAS procurement

2.3.1 Recommendations and findings relating to South Australia

There is currently a constraint which limits import into South Australia over the Heywood interconnector based on the net Under Frequency Load Shedding (UFLS) load, distributed PV generation, power system inertia and the availability of Fast Active Power Response (FAPR). There is also currently a constraint set in place to maintain South Australia's rate of change of frequency (RoCoF) below 2 Hz/s immediately following the non-credible loss of the Heywood interconnector, which was introduced to meet the requirements of under regulation 88A of the Electricity (General) Regulations 2012 (SA). Given Project EnergyConnect Stage 1 will be inter-tripped for the non-credible loss of the Heywood interconnector AEMO recommends that these constraints will remain in place following commissioning of Project EnergyConnect Stage 1.

Due to the South Australian rollout of dynamic arming of UFLS arming and additional battery head room the the minimum emergency under frequency response defined by AEMO can be met ~ approximately 99.8% of the time in South Australia. This delivers a similar level of residual risk to historical levels. Therefore, no further action is required in South Australia to meet the minimum emergency under frequency response.

At present a 250 MW import limit is applied to the Heywood Interconnector for destructive wind conditions that could result in the loss of multiple transmission elements causing generation disconnection in South Australia to reduce the risk of South Australia islanding. The studies completed as part of the 2024 GPSRR indicate that the existing 250 MW limit for South Australia import under destructive wind conditions could be increased after the full capacity of Project EnergyConnect Stage 1 is released. The revised destructive wind transfer limits will be formally defined in an update to the Interconnector Capabilities report after the release of the full capacity of Project EnergyConnect Stage 1. This is distinct from the South Australia import constraints that are invoked for destructive wind conditions impacting Heywood where South Australia islanding is reclassified as credible. As Project EnergyConnect Stage 1 will be inter-tripped with Heywood, the South Australia destructive wind transfer import limit for the credible loss of Heywood will remain at 250 MW.

Given the growing number and complexity of NEM Remedial Action Schemes (RASs), AEMO recommends that, as part of the existing obligations under NER S5.1.8 and S5.14, NSPs in collaboration with AEMO engage in extensive and detailed joint planning. In the design and testing of RASs, the impact on other NEM regions/inter-regional interconnectors should be considered to ensure that all existing and future RASs operate effectively and do not cause adverse interactions or exacerbate non-credible contingency events. Given the increasing consequences of non-credible events, AEMO plans to review the RAS guidelines to ensure adequate guidance is provided regarding:

- Provision of limit advice associated with operational conditions where emergency controls are ineffective.
- Consideration of system strength impacts.
- Consideration of anticipated generator retirements.
- Requirement for NSP joint planning under NER S5.14.

To reduce the number of transmission line trips due to lightning in South Australia, AEMO recommends that ElectraNet investigate South Australia transmission tower earthing and lightning protection based on recent contingency events to identify or rule-out any existing design weaknesses. Additionally, consistent with NER 5.20A.1, AEMO has identified the potential need for a RAS to manage South Australia intra-regional separation. Therefore, to reduce the likelihood that multiple trips due to lightning or other risk factors in South Australia result in severe cascading failures, AEMO recommended, in accordance with NER S5.1.8, that ElectraNet investigate the suitability of a RAS to prevent South Australia intra-regional separation.

South Australia has significantly greater large-scale BESS capacity installed (including the new 250 MW Torrens Island BESS) than the rest of the mainland NEM. This means that the aggregate response of South Australian BESSs present an increasing risk for a remote generation contingency during South Australia export conditions, and for a remote load contingency during South Australia import conditions. ElectraNet is collaborating with AEMO to consider suitable remedial measures to address this risk as part of the 2025 GPSRR.

The growth in the number of RASs will increase power system operational complexity and increase the risk of maloperation or unintended interactions between schemes. To address this, the 2023 GPSRR included a recommendation for NSPs, in line with the requirements of NER S5.1.8, to continue to consider non-credible contingency events which could adversely impact the stability of the power system. In considering these non-credible contingency events, NSPs should identify and implement suitable controls to mitigate any identified risks. It is anticipated that these controls may involve the implementation of new remedial action schemes, in which case NSPs should consult with AEMO and refer to the RAS Guidelines developed by AEMO and NSPs165. Additionally, if an effective RAS cannot be practically implemented or the operation of a RAS could cause cascading failures, NSPs should investigate alternative remedial measures, including the installation of additional assets, changing of operational arrangements or integration of storage at the location of the contingency, thereby reducing the effective maximum contingency size.

3 Electricity Demand

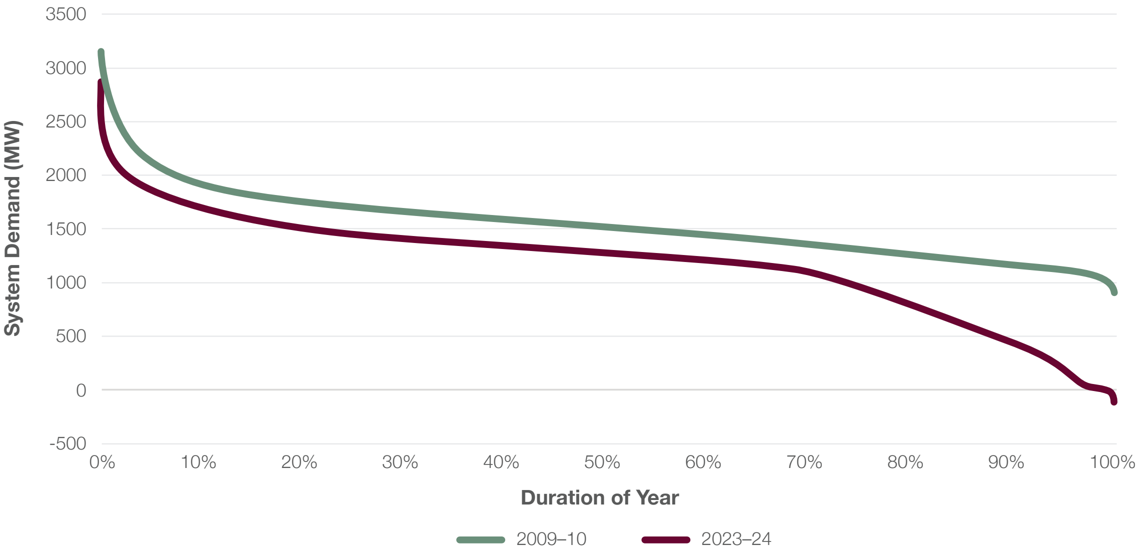
3.1 South Australia's historical electricity usage

The South Australian demand profile is very 'peaky' in nature with relatively low energy content (Figure 12). South Australia has a dry climate featuring high extremes of summer temperature, especially during extended periods of heatwave conditions. During these heatwave periods, summer daytime temperatures can exceed 40ºC for several days in a row and overnight minimums can remain above 30ºC.[15]

More than 90% of South Australian households have air conditioning and during these heatwave periods there is a high demand for cooling. As a result, South Australia has a very "peaky" load duration curve. Even though demand can exceed 3,000 MW on hot summer days, demands between 1,000 and 2,000 MW are most common throughout the year. The continued uptake of distributed solar PV in recent years has significantly lowered demand supplied by the transmission system during the day, especially on weekends and public holidays.

Minimum demand on the South Australian electricity system has declined in the period 2009–10 to 2022–23. We expect that the continuing uptake of distributed solar PV will continue to produce even lower minimum demands while we expect the connection of large industrial loads will reverse the trend of declining energy more generally. Average daily profiles show that most of the reduction has occurred in the middle of the day with more recent increases overnight (Figure 13).

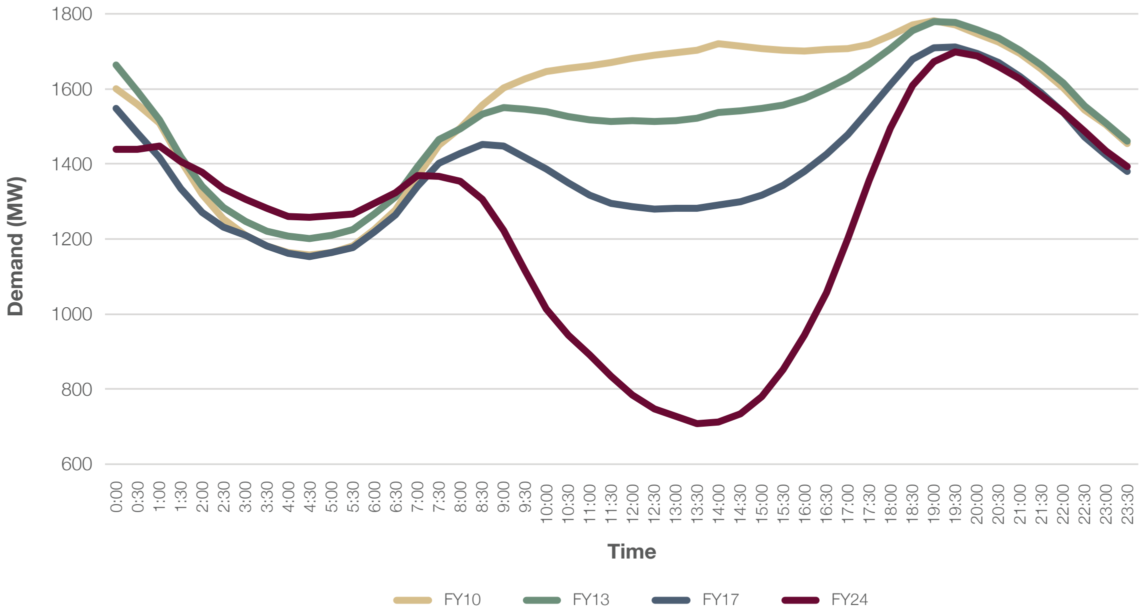
Figure 12: South Australian system wide load duration curves for 2009–2010 and 2023–24



Source: National Grid Metering (NGM) database

[15] SA Power Networks | Distribution Annual Planning Report

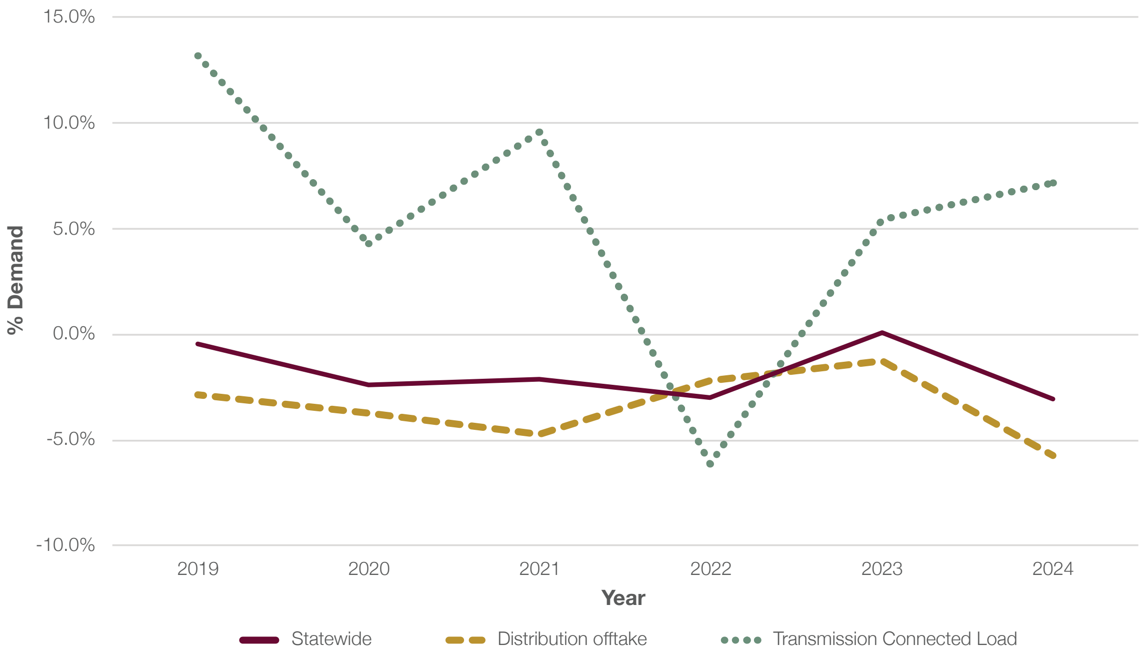
Figure 13: Daily average demand changes since 2009–10



Source: National Grid Metering (NGM) database

Along with the changing shape of South Australia's electricity demand is a reduction in distribution connected demands while Large Industrial Load (LIL) consumption increases. LIL consumption has increased from 10% of the state's total load in 2009–10, to 23% in 2023–24. Over the last five years, and largely driven by distribution PV, demand from distribution loads has decreased in each year by as much as 7% compared to the previous year. Over the same time, transmission connected LIL demand has typically increased by 5% or more in each year, partially offsetting the decreases on the distribution network (Figure 14).

Figure 14: Recent distribution and transmission connected load: annual percentage change



Source: ElectraNet analysis National Grid Metering 2024

3.2 Demand forecasting methodology

ElectraNet annually receives 10-year demand forecasts from SA Power Networks and direct connect customers.

A description of the load forecasting process used by SA Power Networks is provided in SA Power Networks' 2023/24–2027/28 Distribution Annual Planning Report.[16] 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.

SA Power Networks' forecasts are derived from AEMO's Step Change scenario. In August this year, AEMO presented and published forecasts of energy, maximum and minimum demand for South Australia in the 2024 Electricity Statement of Opportunities (ESOO).[17]

AEMO's Step Change forecast only includes LILs in the short term if they meet the following commitment criteria:

- Publicly announced Final Investment Decision and/or commenced construction
- Connection approvals with a TNSP
- Environmental approvals.

SA Power Networks develops connection point forecasts by reconciling them with AEMO's state-level growth rate for the Step Change scenario forecast. As a result, core demand forecasts do not include the potential for near-to-medium term LIL customers. Alternatively, loads that have Government support via policies or approved funding, such as the Hydrogen Jobs Plan, may be included in the forecast.

Transmission network development plans are revised as connection point demand forecasts are updated. The development plans presented in this report were based on the connection point maximum demand forecasts that were provided by SA Power Networks in December 2023. Details of the 2023 connection point forecasts can be found on ElectraNet's Transmission Annual Planning Report webpage.[18] SA Power Networks have confirmed updated forecasts in September 2024. Preliminary review of these updated forecasts indicates no major impact on our plans to support SA Power Networks over the 10-year planning horizon.

ElectraNet uses both the AEMO state-wide forecasts and our own connection point forecasts depending on the needs of a particular planning study.

16 SA Power Networks | Distribution Annual Planning Report

17 AEMO | 2024 Electricity Statement of Opportunities

18 ElectraNet | Transmission Annual Planning Report

3.3 Key drivers of demand

South Australia's energy transformation is impacting not only the supply side but also powering the connection of emerging new industries like "green" hydrogen production, hydrogen export, "green steel" and data centres. These loads would like to take advantage of South Australia's low-cost and low emission electricity from renewable sources. Additionally, the South Australian government has enacted the Hydrogen and Renewable Act, which is a regulatory framework to ensure a fair, efficient, flexible and transparent pathway for companies that want to develop hydrogen or renewable energy projects.[19]

Key developments that could influence demand forecasts include:

- The South Australian Government's Hydrogen Jobs Plan,[20] which aims to realise the construction of world leading hydrogen power station, electrolyser, and storage facility within the Whyalla City council in the upper north of South Australia. These facilities will be powered by renewable sources and will consist of 250 MW of electrolysers and 200 MW power generation. The plan is expected to be operational by early 2026. AEMO considers this load as "committed" and it is included in their forecasts.
- The development of hydrogen export hubs, such as the Port Bonython hydrogen export hub which has recently been allocated state and federal government funding and which has received significant interest from overseas companies, which are considering developing hydrogen production facilities.[21]
- South Australia has large resources of minerals such as copper, gold and magnetite. Large mining companies interested in magnetite are not only looking to extract the mineral, but to use it in combination with "green" hydrogen and electric furnaces to produce "green" steel.[22] ElectraNet is aware of multiple projects, across many different minerals and proponents that are each many hundreds of megawatts.
- Data centres are increasing in size. Some forecasts show that as much as 15% of NEM demand could be from data centres by 2030, up from approximately 4% today.[23] AEMO is making updates to their demand forecast methodology to better account for this potentially rapid increase.
- The South Australian Government's Northern Water project[24] to support developments mentioned above.
- Large Industrial Load connections across the state connecting to the distribution network. SA Power Networks is currently exploring five such connections.

19 South Australian Government | Hydrogen and Renewable Energy Act

20 SA government, Hydrogen Jobs Plan

21 Hydrogen Power SA | Port Bonython Hydrogen Hub

22 South Australian Government | Green iron and steel Strategy

23 Australian Energy Council | Article: Data Centres and Energy Demand

24 Northern Water Project

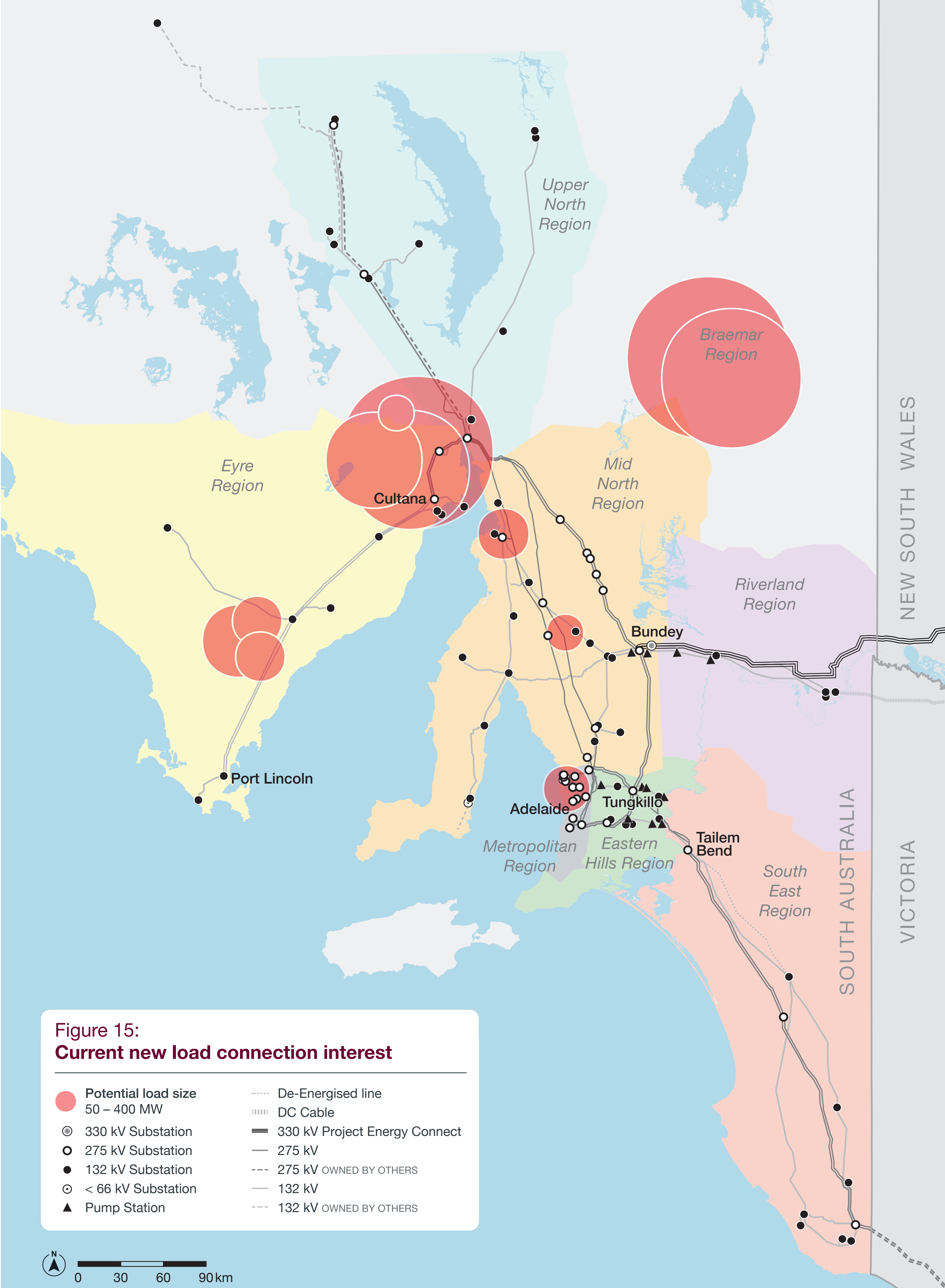


Figure 15:
Current new load connection interest

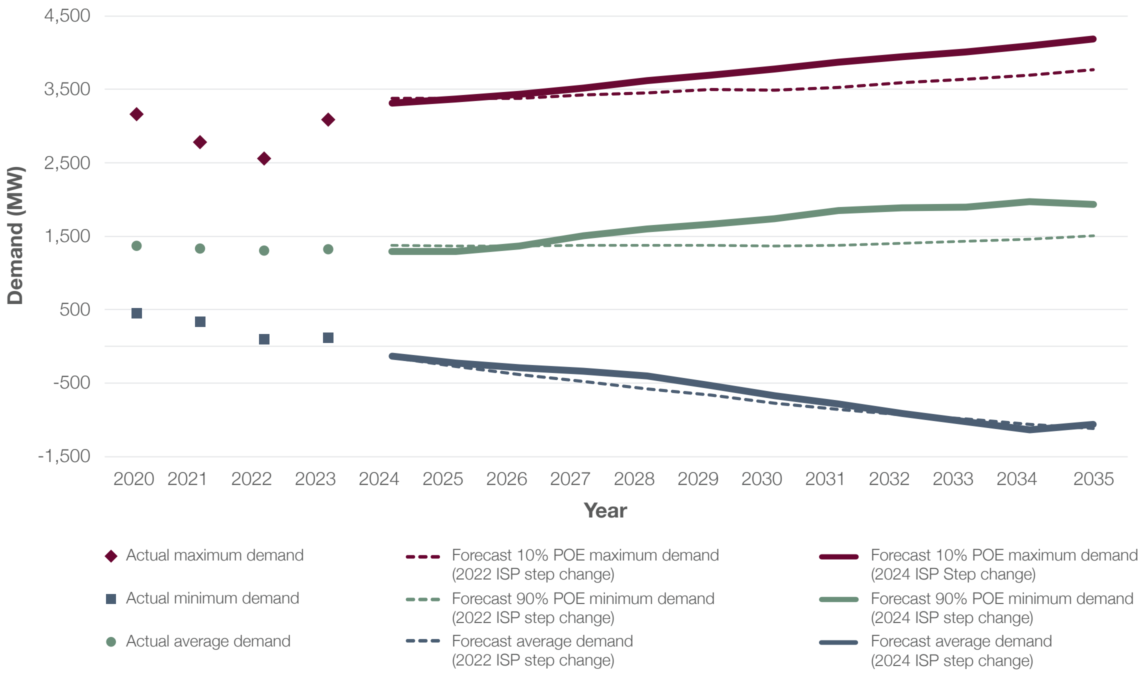
3.4 Demand forecasts

South Australia's energy transformation is impacting not only the supply of electricity but also the connection of new loads. In our TAPR Update,[25] published in May 2023, we reported how the interest in large new load connections has risen sharply. This interest has continued, and we are seeing more customers wanting to connect large loads to our network. LIL customers are seeking to take advantage of South Australia's low-cost and low-emission electricity from renewable sources and favourable policies implemented by the SA government.

We have compared AEMO's 2024 Step Change forecasts for South Australian maximum and minimum demands to the 2023 ESOO forecasts that formed the basis of the plans presented in last year's Transmission Annual Planning Report, along with the previous five years and current year of actual maximum, average and minimum demands (Figure 16).

The 2024 ESOO demands are lower than those presented in the 2023 ESOO over the forecasting horizon.

Figure 16: AEMO's 2023 ESOO Central/Step Change scenario forecast differences with 2024 ESOO



Source: AEMO Electricity Forecasting Data Portal

(AEMO's forecast data was obtained from AEMO's forecast portal. Average demand values were derived from the forecasts for annual energy consumption)

The forecast maximum, average and minimum demands are all lower in the 2024 ESOO than was forecast in the 2023 ESOO. Minimum demands are forecast to drop rapidly to below -1,000 MW from the early 2030s, while maximum and average demands are forecast to grow very slowly.

[25] ElectraNet | TAPR Update 2023

3.4.1 Integrated System Plan (ISP) Sensitivity

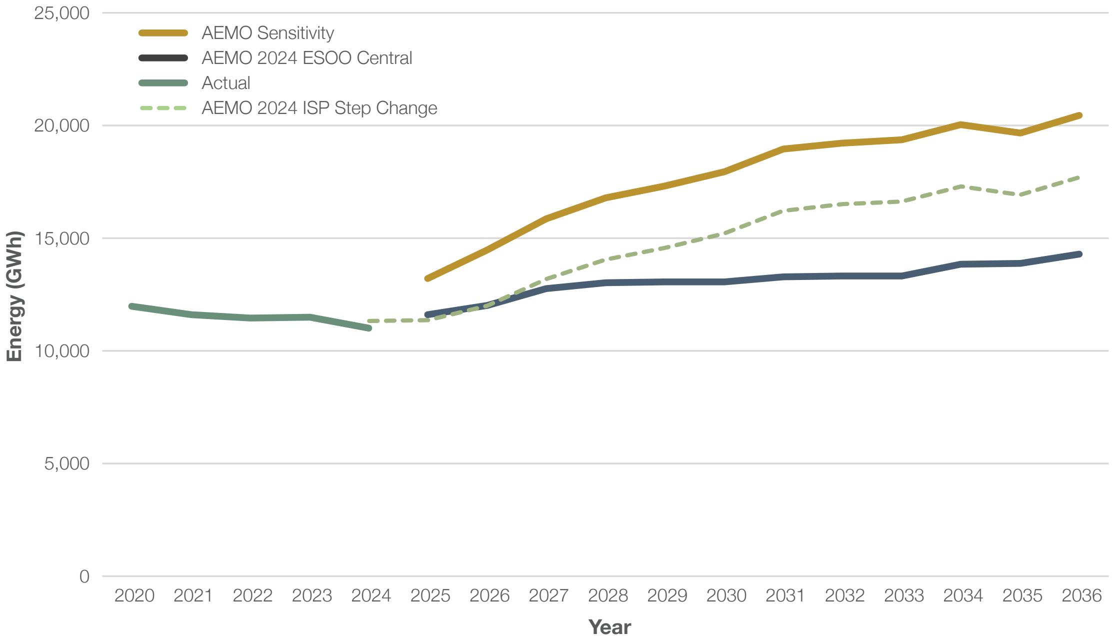
AEMO's ISP demand forecasts are based on the forecasts developed for the 2023 IASR and used for the 2023 ESOO. As discussed in Section 2.1.4, these forecasts only include near term load connections that are considered committed. AEMO may also consider loads that reflect the outcomes of multisector modelling in the longer term.

In an environment of a rapidly increasing demand outlook, for the 2024 ISP AEMO included in its modelling a South Australian and New South Wales demand forecast sensitivity case. This sensitivity included additional industrial loads that were considered to have a high likelihood of reaching committed status in the very near term, including those being driven by South Australia Government policy (Figure 17).

We believe it is important to include all anticipated load in demand forecasts for planning purposes, using a probabilistic approach that acknowledges that not all projects will occur yet reflecting the likelihood that some will.

Timely action is critical to prepare for this expected load in order to meet South Australia's energy needs, support the State's economic growth and deliver a least cost energy transition to net zero carbon emissions. Further information on the transmission development priorities to meet this expected demand is presented in the following sections.

Figure 17: AEMO Sensitivity



Source: AEMO Electricity Forecasting Data Portal

3.5 Performance of 2023 demand forecasts

3.5.1 Weather conditions during summer

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

Weekends, public holidays, and the holiday period that begins at Christmas time and extends until Australia Day reduce the impact of high temperatures on demand. For state-wide electricity demand to reach high levels, metropolitan Adelaide needs to experience high temperatures, generally on working days early in February.

Individual connection points, however, can 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).

The recorded daily maximum temperatures were, on average, roughly in line with long-term trends; however, the maximum recorded temperature in each month was well below the historical extremes.

The highest recorded temperature for the year 2023–24 at the Bureau of Meteorology's official Adelaide city site at West Terrace was 41.2°C on Tuesday 23 January 2024 (Table 2).

Table 2: 2023–24 Summer Temperature data compared with long term trends[26]

	November		December		January		February		March	
	Long-term trend	2023–24	Long-term trend	2023–24	Long-term trend	2023–24	Long-term trend	2023–24	Long-term trend	2023–24
Max temp (C)	42.7	40.3	45.3	36	46.6	41.2	43.4	39.6	41.2	39.9
Date of max temp	30 Nov 1962	10 Nov 2023	19 Dec 2019	4 Dec 2023	24 Jan 2019	23 Jan 2024	1 Feb 1912	4 Feb 2024	3 Mar 1942	9 Mar 2024
Average max temp (C)	24.4	24.6	26.9	25.5	28.6	29.3	28.5	30.1	26.1	29.9
Days > 30	6	2	9.1	5	11.7	12	10.7	13	7	15
Days > 35	1.5	1	3.8	1	5.5	4	4.3	4	1.6	5
Days > 40	0.1	1	0.6	0	1.1	1	0.6	0	0.1	0
Difference between 2023–24 average max temp and long-term trend	0.2		-1.4		0.7		1.6		3.8	

26 Australian Government Bureau of Meteorology - Daily Maximum Temperature Adelaide (West Terrace/Ngayirdapira)

3.5.2 State-wide demand review

State-wide demand during 2023–24 reached a maximum of 2781 MW on Tuesday 23 January 2024. There was only one day on which demand exceeded 2,500 MW during the 2023–24 summer (Table 3).

Table 3: Highest demand day 2023–24

Date	Maximum Demand (MW)	Maximum temperature (ºC)	Preceding day maximum temperature (ºC)
Wednesday 23 January 2024	2,781	41.2	31.7

4 System Capability and Performance

4.1 The South Australian electricity transmission system

The South Australian transmission network is one of the most extensive regional transmission systems in Australia, extending across some 200,000 square kilometres of the state.

This network consists of transmission lines operating at 132,000 Volts (132 kV) and 275,000 Volts (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 (Figure 21).

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

The South Australian transmission system is relatively "skinny and long," which can make it challenging to enable significant power transfers through the system 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. 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. Synchronous condensers were installed at Davenport and Robertstown in 2021 to maintain required levels of system inertia and system strength.

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.

An upgrade of Heywood interconnector was completed in mid-2016, increasing interconnector transfer capacity to 600 MW (import) and 550 MW (export). The combined maximum transfer capacity between South Australia and Victoria under normal conditions is now about 820 MW[27] for imports to South Australia, and 700 MW[28] for exports.

Stage one of Project EnergyConnect, a new interconnector linking South Australia, New South Wales and Victoria, was first energised in August 2024. Up to 150 MW of transfer capacity is expected to be released following the completion of internetwork testing later in 2024.

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

4.1.1 Designated network assets

Designated network assets are defined in the Rules. They are apparatus, equipment, plant, and buildings that are used from a "boundary point" to convey electricity for an identified user group and are owned by a member or members of that identified user group. They do not provide prescribed transmission services, form part of a network loop, form part of a transmission system for which a Market Network Service Provider is registered under Chapter 2 of the Rules, or form part of a declared transmission system of an adoptive jurisdiction.

There are two designated network assets in South Australia:

- Davenport – Upper North Large DCA
- Clements Gap DNA.

Access policies can be found on ElectraNet's website.[29]

[27] Consisting of 600 MW import through Heywood interconnector and 220 MW import through Murraylink interconnector

[28] Consisting of 550 MW export through Heywood interconnector and 150 MW export through Murraylink interconnector

[29] ElectraNet | Connection Services resources

Figure 18: **South Australian electricity transmission system**

ElectraNet

4.2 Transmission system constraints in 2024

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 off (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.

The binding constraints reflecting the normal operating limitations of the network are presented below. Alleviating these constraints typically require augmentation of the transmission network.

Table 4: Constraint equations, descriptions, and impact in 2023

Network limitation	Binding impact in 2023 [$]	Binding duration in 2023 [hours]	Comments, with proposed and implemented actions
S>NIL_MHNW1_MHNW2 Out= Nil, avoid O/L Monash – North West Bend #2 132kV on trip of Monash– North West Bend #1 132kV line, Feedback	8,148,305.5	1366.7	This constraint will be alleviated when project EC.15175 Increase Murraylink Transfer Capacity upgrades the existing runback control scheme to include bi-directionality and allow it to run forward if required.
S>NIL_HUWT_STBG3 Out = Nil; Limit Snowtown WF generation to avoid Snowtown – Bungama line OL on loss of Hummocks – Waterloo line. (Note: Constraint Swamped when Wattle PT when generating >=60 MW)	3,243,037.7	368.3	We are monitoring this constraint. Implementation of EC.15571 10-band rating NCIPAP project is likely to alleviate this constraint.
S>NIL_NWRB2_NWRB1 Out= NIL, avoid O/L North West Bend – Robertstown #1 132kV line on trip of North West Bend – Robertstown #2 132kV line (this trips MWP1-3 SFs), Feedback	2,716,676.1	376.8	This constraint will be alleviated when project EC.15175 Increase Murraylink Transfer Capacity upgrades the existing runback control scheme to include bi-directionality and allow it to run forward if required.
SVML^NIL_MH-CAP_ON Out=NIL, SA to Vic on ML upper transfer limit to manage voltage collapse at Monash (Note: applies when capacitor banks at Monash are available and I/S for switching.)	1,754,573.6	520.7	Proposed project EC.15175 Increase Murraylink transfer capacity will alleviate this constraint.
S>>NIL_TWPA_TPRS Out= NIL, avoid O/L Templers – Roseworthy 132kV line on trip of Templers West – Para 275kV line, Feedback	352,652.4	64.3	This constraint would be alleviated by the installation of a second 275/132 kV transformer at Templers West and reconfiguration of the Mid North 132 kV system as part of the EC.15424 – Mid North REZ Expansion project.
S>NIL_BWMP_RHBR-T Out= Nil, avoid O/L Redhill – Brinkworth T 132kV line on trip of Blyth West – Munno Para 275kV line, Feedback	138,366.1	22.8	We are monitoring this constraint.

Table 4: Constraint equations, descriptions, and impact in 2023 (cont.)

Network limitation	Binding impact in 2023 [$]	Binding duration in 2023 [hours]	Comments, with proposed and implemented actions
S>NIL_SGBN_SGSE-T2 Out= NIL, avoid O/L Snuggery Mayura – South East T 132kV line on trip of Snuggery – Blanche 132kV line (for Line component SECS assumed O/S), Feedback	116,853.7	19.6	We are monitoring this constraint.
S>NIL_BWMP_HUWT Out= Nil, avoid O/L Hummocks – Waterloo 132kV on trip of Blyth West – Munno Para 275kV line, Feedback	102,338.3	13.1	We are monitoring this constraint to determine if options such as automatic runback control schemes for 132 kV wind farms in the Mid North are likely to alleviate this constraint.
V::S_NIL_MAXG_1 Out = Nil(Both Black Range series capacitors I/S); Vic to SA Transient Stability limit for loss of the largest generation block in SA (Both South East Capacitor Available).	84,409.6	29.7	The commissioning of Project EnergyConnect Stage 2 is expected to alleviate this constraint
S>>NIL_RBTU_RBTU Out= NIL, avoid O/L Robertstown – Tungkillo 275kV line 1 or 2 on trip of parallel Robertstown – Tungkillo 275kV line 2 or 1, Feedback	72,496.6	27.7	Constraint will be alleviated by Robertstown to Tungkillo Line Uprating
S>>NIL_RBTU_WTTP Out= Nil, avoid O/L Waterloo – Templers 132kV on trip of one Robertstown – Tungkillo 275kV line, Feedback	66,116.3	20.3	This constraint would be alleviated by the installation of a second 275/132 kV transformer at Templers West and reconfiguration of the Mid North 132 kV system as part of the EC.15424 – Mid North REZ Expansion project.
S^NIL_CRK+MTM_95 Out= Nil, upper limit for Cathedral Rocks WF + Mt Millar WF <= 95 MW to maintain voltage stability limits	51,176.8	35.8	This constraint has been alleviated by the completion of Eyre Peninsula Link.
S_WATERLWF_RB Out= Nil, Limit Waterloo WF output to its runback MW capability,	49,901.3	157.0	We are monitoring this constraint to determine if options such as inclusion of other 132 kV wind farms in the Mid North in existing or additional automatic runback control schemes are likely to alleviate this constraint.
S_LB2WF_CONF Out= Nil; Limit Lake Bonney 2 & 3 generation based on DVAR availability.	45,066.3	7.3	
V_S_NIL_ROCOF Out = NIL, limit VIC to SA Heywood interconnection flow to prevent Rate of Change of Frequency exceeding 2 Hz/sec in SA immediately following loss of Heywood interconnector.	32,461.3	29.5	The commissioning of Project EnergyConnect Stage 2 is expected to alleviate this constraint.

Table 4: Constraint equations, descriptions, and impact in 2023 (cont.)

Network limitation	Binding impact in 2023 [$]	Binding duration in 2023 [hours]	Comments, with proposed and implemented actions
V_S_HEYWOOD_UFLS Out= Nil, Limit Heywood flows when SA under frequency load shedding (UFLS) is insufficient (i.e. when UFLS blocks in SA <1000 MW) to manage for double-circuit loss of Heywood IC. Note: Constraint is swamped if UFLS blocks >= 1000 MW.	22,097.9	22.8	Market impacts expected to be alleviated by fully operational Project EnergyConnect.
S>>NIL_RBTU_RBPA Out= Nil, avoid O/L Robertstown–Para 275kV line on trip of Robertstown–Tungkillo 275kV line, Feedback	16,237.6	4.8	Market impacts expected to be alleviated by fully operational Project EnergyConnect.

4.3 Emerging and future network constraints and performance limitations

The committed implementation of Project EnergyConnect, establishing a new interconnector between South Australia and New South Wales, is expected to change dispatch patterns of existing generators. Together with continuing significant renewable energy generation connections in South Australia, this is expected to lead to substantial changes in congestion patterns on the transmission network. This will depend on where future generators connect or retire.

ElectraNet 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 due to the modelled generator connections are indicated in Table 5 below.

ElectraNet operates under and open access framework and connects any project subject to meeting the generator performance requirements. Emerging congestion over a ten-year time scale includes inherent uncertainty and may occur in different locations than we forecast. The information below is informative but should not be relied upon.

Table 5: Forecast South Australian transmission network congestion

Limitation	Timing indication	Affected corridor	Forecast average binding hours (hrs/year)[30] 2021–22 to 2030–31	2030–31 to 2040–41	Potential mitigating project(s)
Loss of Templers West 275/132 kV transformer overloads Para 275/132 kV transformer	From 2025	Robertstown – Adelaide	853	1025	Install second Templers West 275/132 kV transformer
Loss of Robertstown 275/132 kV transformer overloads Waterloo East – Waterloo 132 kV	Now	Robertstown – Adelaide	300	845	Increase capacity of the Robertstown to Adelaide transmission corridor
Loss of Robertstown – Tungkillo 275 kV overloads Waterloo East – Waterloo 132 kV	Now	Robertstown – Adelaide	119	473	Increase capacity of the Robertstown to Adelaide transmission corridor
Loss of one 275 kV circuit between Davenport and Cultana overloads the other 275 kV circuit	From 2026	Davenport – Cultana	66	90	Remove plant rating limitations on the Davenport – Cultana 275 kV corridor
Loss of Mt Lock – Davenport 275 kV overloads Waterloo – Waterloo East 132 kV	From 2025	Robertstown – Adelaide	31	98	Increase capacity of the Robertstown to Adelaide transmission corridor
Loss of Tungkillo – Robertstown 275 kV overloads remaining Tungkillo– Robertstown 275 kV	Now	Robertstown – Adelaide	24	100	Increase capacity of the Robertstown to Adelaide transmission corridor
Heywood – South East 275 kV	After 2026	Heywood – South East	34	66	Establish a new interconnector between a new location in the South East and Victoria (Bulgana?)
Loss of Tailem Bend – Tungkillo – Cherry Gardens 275 kV overloads Tailem Bend – Mobilong 132 kV	After 2025	Tailem Bend – Adelaide	19	138	Remove plant limits on Tailem Bend – Mobilong 132 kV String vacant Tailem Bend – Tungkillo 275 kV circuit (EC.11011)

30 Based on the 2020 ISP step change scenario

4.4 Potential projects to enable growth

The connection of potential significant large new loads and generation, the change in the nature of the generation fleet and the speed with which the community seeks to decarbonise the economy will have an 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 projects to address inter-regional and intra-regional constraints that may emerge in the future.

Specific projects that will provide net market benefits are often uncertain until generator or load 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. These projects would reduce network congestion in the future, warranting development if they deliver net benefits to customers. These potential developments could enable large-scale growth of new electricity demand and growth in renewable energy and hydrogen production in South Australia, while delivering the energy transition at lowest cost to customers. Additionally, some of these projects may also deliver improvements in network reliability.

Table 6 shows the project options that could deliver benefit if development occurs within approximately 5 years (near-term). We are mindful of the upward pressures on transmission project costs in the current environment and continue to review these cost assumptions in our analysis. We are also conscious of the growing challenges for our supply chains, and we are factoring this into the potential timing of the project options.

Given the new LIL connections we expect in South Australia it is likely that the Eyre Peninsula Upgrade and South East Expansion (Stage 1) project will be required in the near future, even though they have not been identified as actionable projects in the 2024 ISP. Earlier in 2024 we commenced a RIT-T to assess options for the Eyre Peninsula Upgrade, and we are considering starting a RIT-T for South East Expansion (Stage 1) in the near future.

Table 6: Near-term potential projects

Project options[31]	Options	Customer benefits	Proposed next steps
Eyre Peninsula Upgrade **Indicative cost: $100–140 million** **Timing: Mid to late 2020s** Upgrade the operating voltage of the new Cultana to Yadnarie transmission lines from 132 kV to 275 kV	Upgrade the Cultana – Yadnarie lines from 132 kV to operate at 275 kV and establish a new 275/132 kV substation adjacent to Yadnarie There are no other comparable options	Increase the capacity to supply large new loads on the Eyre Peninsula, unlocking potential for increased connection of low-cost renewables in the Eastern Eyre Peninsula REZ Increase the ability for renewable generation on the Eyre Peninsula to supply proposed Hydrogen facilities near Whyalla	Early 2023 we completed Eyre Peninsula Link, which delivered a new double-circuit 132 kV transmission line between Cultana and Port Lincoln. The Cultana to Yadnarie section was built 275 kVcapable to enable it to be cost effectively upgrade to 275 kV operation when needed in the future. Based on current customer interest on the Eyre Peninsula, we have commenced a RIT-T to investigate increasing the capacity of the Cultana to Yadnarie section of Eyre Peninsula Link If found to deliver net market benefits, and with the commitment of sufficient additional load on Eyre Peninsula, we will seek approval of the Eyre Peninsula Upgrade contingent project that is included in our 2023–24 to 2027–28 revenue determination[32]
South East Expansion (Stage 1) **Indicative cost: $30–50 million** **Timing: late 2020s** String the vacant 275 kV circuit between Tailem Bend and Tungkillo	String the existing vacant circuit that exists on one of the Tailem Bend to Tungkillo 275 kV lines There are no other comparable options	Increase transfer capacity between the South East region and the rest of South Australia, unlocking potential for increased connection of low-cost renewables near Tailem Bend Improve firmness of Heywood interconnector limit at 750 MW	Given the demand outlook and based on our modelling we expect that this project would deliver net market benefits. We have commenced a RIT-T for this project.
Mid North REZ Expansion (Southern and Northern) **Southern Indicative cost: $750–1200 million (depending on option)** **Timing: Mid to late 2020s** **Northern Indicative cost: $1100–2300 million (depending on option)** **Timing: Late 2020s**	New lines between Adelaide, Bundey and Cultana could be constructed as high-capacity 275 kV, 330 kV or 500 kV lines For the Southern section, we will consider the immediate incremental benefits of installing a second 275/132 kV transformer at Templers West and reconfiguring the 132 kV system to alleviate constraints caused by parallel operation of the Mid North Southern 275 kV and 132 kV systems For the Northern section, we will also consider options to connect the new lines to the 275 kV main grid at Wilmington or just east of Davenport or duplicate the existing Cultana to Davenport 275 kV lines. We consider staging the construction of the new transmission line	For the Southern section, to provide a new high-capacity transmission path enabling electrical growth of the Adelaide load centre with low-cost renewables from the Mid-North, Riverland and Northern SA REZs. Additionally, to improve geographical diversification of transmission corridors, improving security of supply to Adelaide Metro as climate change increases bushfire risks to the transmission corridors in the Eastern Hills The Northern section will increase the renewable catchment area of the mid north REZ. Enable LIL connections north of Adelaide including for mining, green steel and hydrogen developments.	AEMO's 2024 ISP declared the expansion of the Mid North SA REZ as an actionable project with a tentative completion date by FY 2029 The identified need formulated by AEMO for the project is to increase power system capability of the transmission network to: • Support the expected increase in renewable generation north of Adelaide to support growing demand in Adelaide • Ensure adequate network capacity and supply for large industrial loads • Alleviate congestion on renewables from the Mid North to the rest of the NEM. We are progressing the option analysis as part of the RIT-T process and we expect to publish the Project Assessment Draft Report before December 2025

31 Indicative cost ranges only, currently under review

32 Australian Energy Regulator | ElectraNet 2023–28 Determination, 2023

Table 7: Future potential needs

Project options	Description	Customer benefits
South East Expansion (Stage 2)	Construct new high capacity double-circuit twin conductor lines from the South East SA and South East SA Offshore REZs to Bundey, via a location near Kincraig	Provide strong connection for new low-cost renewable generation developments in the South East SA REZ and Offshore REZ to the South Australian transmission backbone
Eyre Peninsula Grid	Develop an HVDC link from Cultana to a new 500 kV HVAC system on the Eyre Peninsula that is ACislanded from the rest of the NEM, with double circuit 500 kV lines to connect new REZs and large loads	Develop REZs on the Eyre Peninsula to support large Hydrogen projects near Whyalla, Port Bonython, and Cape Hardy, unlocking potential for increased connection of low-cost renewables in the Eastern Eyre Peninsula and Western Eyre Peninsula REZs
South East Interconnection	Develop a new HVAC interconnector between the South East of South Australia and Heywood in Victoria	Increase transfer capability between South Australia and Victoria to unlock cheaper energy sources Enable access for South East SA wind to Victoria and the rest of the NEM
Mid North Reinforcement	Establish new substations at Cultana, Wilmington (if required), Bundey and between Parafield Gardens West and Torrens Island if needed to enable operation of the Cultana to Adelaide transmission path at a higher-voltage operation, and/or replace existing lower capacity lines	Enable increased access for new low-cost renewable generation in the Mid North SA that may connect in locations that don't optimally use existing network This project represents a further stage of expansion beyond the actionable Mid North Expansion project
Metropolitan Reinforcement	Establish a second 275 kV underground cable to provide a second transmission supply to City West, and establish a new 275 kV underground cable from City West to the Southern Suburbs	Improve geographical diversification of transmission supply to the Southern Suburbs of Adelaide to improve supply security, which will become increasingly important as climate change increases bushfire risks to the transmission corridors in the Eastern Hills Increase supply capability to Western Suburbs, Eastern Suburbs and Southern Suburbs to cater for potential increased electrification
Mid North Interconnection	Develop a new 500 kV HVAC interconnector between the Mid north of South Australia and New South Wales	Increase transfer capability between South Australia and New South Wales to unlock cheaper energy sources

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 UFLS scheme (Section 4.5.1)
- a distributed automatic OFGS scheme (Section 4.5.2)
- Emergency Control Schemes (Section 4.6)

4.5.1 Automatic under-frequency load shedding (UFLS)

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 while importing across the Heywood interconnector.

The basic design premise of the UFLS scheme is that in response to a separation event or a multiple contingency event,[33] the frequency fall should be limited to 47 Hz by the controlled disconnection of load.

AEMO has recently updated the UFLS requirements within South Australia, based on system studies to a maximum of either:

- 700 MW, or
- 60% of operational demand

ElectraNet has worked with AEMO to develop a power system constraint that limits import into South Australia on the Heywood interconnector to an appropriate level such that the risk of cascading failures is reduced if a non-credible separation of South Australia from the NEM were to occur.

ElectraNet has worked with transmission network direct-connect customers to ensure UFLS arrangements for each customer comply with Rules obligations. SA Power

[33] AEMC | As defined in the Frequency Operating Standards

Networks met targets to roll out "dynamic arming" of UFLS relays (relays designed to dynamically disarm if the circuit is in reverse flows), by September 2024. AGL also recently commissioned a 250 MW BESS at Torrens Island, significantly increasing the amount of BESS headroom that will be typically available in South Australia to provide emergency frequency response.

As a consequence, AEMO's analysis suggests no further action is required at this time to increase UFLS availability in South Australia; the actions already underway (dynamic arming of UFLS and additional BESS capacity) appear sufficient at this time.

UFLS requirement will be reviewed again following the commissioning of Project EnergyConnect Stage 2.

4.5.2 Automatic over-frequency generator shedding (OFGS)

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. Generation to be tripped is split into eight blocks, each with around 150 MW of wind generation, set to trip between 51 Hz and 52 Hz.

AEMO made the following recommendations when they most recently reviewed the OFGS scheme:

- Increasing OFGS capacity by adding additional generators to the scheme, helping to contain and reduce the frequency peak
- Adding a delayed trip setting to some generators in the OFGS scheme, helping to reduce the settled frequency to within frequency operating standards.

ElectraNet is working with AEMO and the generators to implement these recommendations.

4.6 Emergency Control Schemes

4.6.1 New and Modified Control Schemes

Wide Area Protection Scheme (WAPS)

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 a rapid frequency decline and pose a high risk of a state-wide blackout.

The Wide Area Protection Scheme (WAPS) has replaced the previous System Integrity Protection Scheme (SIPS). The WAPS is designed to rapidly identify conditions that could otherwise result in a loss of synchronism between South Australia and Victoria. It is designed to assist with the management of these conditions by rapidly injecting power from batteries or shedding some targeted loads, to assist in rebalancing supply and demand in South Australia, preventing a loss of the Heywood interconnector and subsequent islanding of South Australia from the NEM.

Similar to the SIPS, the WAPS provide two levels of response:

- Level 1 Response: Discharge power from Hornsdale Power Reserve and Dalrymple Battery Energy Storage Systems
- Level 2 Response: Trip load at 11 distribution connection points.

WAPS was placed into service in December 2023 following the satisfactory completion of testing and commissioning activities.

Aligned with the timing of the revocation of the South Australian Protected Event on 31 March 2024,[34] management of the WAPS will be transitioned to ElectraNet and will be managed as an 'emergency control' under NER S5.1.8.

WAPS will be modified again to account for Project EnergyConnect Stage 1 and Heywood Interconnector (HIC) after Project EnergyConnect Stage 2 has been commissioned. The investigations are ongoing.

[34] AEMC | Revoking the South Australian Protected Event

Project EnergyConnect Stage 1 Inter-trip Scheme

Project EnergyConnect Stage 1 Inter-trip Scheme is designed to prevent transient instability between South Australia and New South Wales in the event of the trip of the Heywood interconnector conditions when Project EnergyConnect Stage 1 is in service.

The scheme will transfer an inter-trip signal and trip both Bundey and Buronga ends of the Bundey – Buronga No. 1 330 kV line for the opening of any 500 kV double circuits between the Moorabool Terminal Station and Heywood Terminal Station in Victoria and any 275 kV double circuits between Heywood Terminal Station and Tungkillo in South Australia.

The opening of the double circuit could occur due to a:

- A non-credible loss of both circuits on a double circuit line or
- The planned outage of one circuit on a double circuit line and the credible loss of the remaining 'in-service' parallel circuit.

The scheme will be commissioned prior to the Project EnergyConnect Stage 1 Commissioning, planned for Q4 2024. This scheme is part of the South Australia Interconnector Trip Remedial Action Scheme (SAIT RAS) Event Driven Component (EDC). SNI Stage 1 Inter-trip Scheme will be decommissioned when Project EnergyConnect Stage 2 is commissioned in Q3 2026.

Tailem Bend 132 kV Tripping Scheme

The scheme's objective is to prevent transient instability and overloading of the underlying 132 kV network in the event of a 275 kV double circuit outage between South East and Tailem Bend or Tailem Bend and Tungkillo. This scheme will replace the existing Tailem Bend Reverse Power Tripping Scheme.

This scheme has two separate components:

South East – Tailem Bend Component

The scheme shall transfer an inter-trip signal and trip both Tailem Bend and Keith ends of the Tailem Bend – Keith 132 kV line for opening of 275 kV double circuit between the South East and Tailem Bend.

The opening of a double circuit may occur due to a:

- A non-credible loss of both circuits on a double circuit line or
- The planned outage of one circuit on a double circuit line and the credible loss of the remaining 'in-service' parallel circuit.

Tailem Bend – Tungkillo Component

The scheme will transfer an inter-trip signal and trip both Tailem Bend and Mobilong ends of the Tailem Bend – Mobilong 132 kV line for the opening of 275 kV double circuit between Tailem Bend and Tungkillo.

The opening of a double circuit could occur due to a:

- A non-credible loss of both circuits on a double circuit line or
- The planned outage of one circuit on a double circuit line and the credible loss of the remaining 'in-service' parallel circuit.

The scheme was commissioned in May 2024.

Murraylink Control Scheme

Murraylink Runback and Sever scheme was reviewed as part of the EC.14065 NCIPAP Robertstown 132 kV Uprating project, and several issues with the scheme were rectified:

- Better coordination of Robertstown Transformer 1 and Transformer 2 protection settings with Murraylink Runback Scheme.
- Rectifying the error in Severe scheme logic by incorporating the circuit breaker status to the severe tripping equation
- Limiting the maximum overloading of the Robertstown Transformer 1 or Transformer 2 to 150% of the rating under N-1 conditions
- Removing unnecessary delays in the Runback scheme for tripping of a Robertstown Transformer or transmission line between Robertstown and Monash.

EP Link Anti Islanding Scheme

EP Link Anti-Islanding Scheme was commissioned in December 2023. The scheme sends an inter-trip signal to Mount Millar and Cathedral Rocks wind farms in the event of a double-circuit outage between Port Lincoln and Cultana to prevent unintended islanding between the wind farms and distribution connection points.

Black Range Fixed Series Capacitors Bypass Control Scheme

The scheme was modified to bypass the FSC in the event of a double circuit outage in the Victorian 500 kV network between Moorabool and Heywood. Prior to the modification, operator action was required to manually bypass the FSC due to a prior outage of a 500 kV line in the Victorian network.

ElectraNet has reviewed the Sub-synchronous Resonance and Sub-synchronous Control Interaction risk, considering the impact of the newly connected plants and network augmentations in South Australia and South West Victoria regions. The review has reaffirmed that the existing mitigations are effective and sufficiently address the risks.

Blyth West Control Scheme

The Blyth West Control Scheme was reviewed as part of the Blyth BESS connection project. Modification and additional operator action will be implemented as an interim measure to allow the Blyth BESS project to progress.

This scheme will be transitioned into a new Mid North (West) Remedial Action Scheme to allow future expansion in the region, remove the need for operator intervention, and to segregate from protection systems as per applicable ElectraNet Policies and the AEMO's Remedial Action Scheme Guideline.

Lake Bonney Inter-trip Scheme

This control scheme was implemented as per AEMO and the wind farm operator's request to reduce the pre-contingency constraints applied to Lake Bonney wind farms, when South Australia is at risk of islanding. The scheme is armed by ElectraNet Transmission System Operators at AEMO's request, normally when South Australia is at risk of islanding only.

The scheme will operate in the event of any of the following contingencies:

- The non-credible loss of the double circuit lines (if armed)
- Planned outage (N-1) of one of the circuits, followed by the loss of the parallel circuit

For the 500 kV double circuit lines between Moorabool and Heywood and the 275 kV double circuit lines between Heywood and Southeast, and contingencies a) or b) listed above, the scheme will:

- Disconnect Lake Bonney Stage 1, Lake Bonney Stage 2A, Lake Bonney Stage 2B and Lake Bonney Stage 3 within one second. This will also trip the reactive plant within the Lake Bonney wind farms
- Lake Bonney BESS shall remain connected to the grid.

4.6.2 Other control schemes currently under development

In addition, following control schemes are currently under development.

South Australian Interconnector Trip Remedial Action Scheme (SAIT RAS)

As part of the Project EnergyConnect, ElectraNet will develop a Remedial Action Scheme (RAS) named the South Australian Interconnector Trip Remedial Action Scheme (SAIT RAS). SAIT RAS will be designed to detect the non-credible loss of either HIC or Project EnergyConnect and will take remedial action to prevent the tripping of the remaining interconnector due to power system instability.

The SAIT RAS comprises three main components:

- Event-Driven Component (EDC)
- Response-Driven Component (RDC)
- Resource Controller Component (RCC)

The RCC monitors the loads/ generators/ BESS response availability using ElectraNet's Supervisory Control and Data Acquisition (SCADA) system and issues trip/ control signals to individual loads/ generators/ BESS based on the output from the EDC and the RDC. Three different trigger levels will be available, including:

- Level 3 response, which is initiated by the EDC when a double circuit interconnector outage is detected. The required amount of response depends on the pre-contingency flows and the strength of the remaining interconnector path. In the event of a double circuit interconnector outage, the EDC Level 3 response has been designed to activate first and will initiate tripping of loads/ generators; and
- Level 1 and Level 2 responses, which are initiated by the RDC based on two sets of thresholds. Level 1 response initiates increasing or decreasing the output power of BESS; whereas a Level 2 response initiates tripping of additional loads or generators. The required amount of response depends on the power imbalance within South Australia and the strength of the interconnector path.

SAIT RAS will be a critical and complex wide area emergency control scheme with high dependability and reliability requirements. Given the above, and fast response times required, customers will be tripped at the connection point breaker when required as part of the SAIT RAS response, unless specific arrangements can be made to trip a few breakers within the customer's plant.

The cost of installation, maintenance and operation of the emergency controls must be borne by ElectraNet as the Network Service Provider. ElectraNet is entitled to include this cost when calculating the Transmission Customer Use of System price.

The scheme is planned for commissioning in Q2 2026.

Mid North (West) Remedial Action Scheme

Mid North (West) Remedial Action Scheme will be designed to:

- Prevent an overload of the 66kV at Munno Para following a trip of Para – Munno Para line (F1956)
- Prevent the islanded operation of Snowtown 2 Windfarm and Blyth West BESS
- Prevent some of the pre-contingency constraints or disconnections of Snowtown 2 Windfarm and Blyth West BESS to manage voltage instability and thermal overloading under prior outage conditions
- Be future-proofed to allow for additional generation connections in the 275 kV Mid North Region and make staged improvements to (c)
- Improve operability of the scheme (i.e. does not require operator intervention)
- Remove dependence of the scheme on the relevant line protection relays.

The scheme is planned for commissioning in Q4 2025.

Mannum Anti-Islanding Scheme

A new anti-islanding scheme is being considered as part of the Mannum BESS connection to prevent unintended islanding between the Mannum distribution connection point, Mannum Adelaide Pump Station 01, and a connection proponent. In the future, the scheme may need to be extended to the Para—Angas Creek line.

Dorrien Anti-Islanding Scheme

A new anti-islanding scheme is proposed to prevent an unintended islanding between the Dorrien distribution connection point and a connection proponent for credible contingency during a prior outage condition.

4.7 Future Control Schemes

ElectraNet is currently considering some new control schemes.

Murraylink Runback and Severe Scheme Modifications

The current Murraylink Runback Scheme operates only if the Murraylink transfers are in the South Australia to Victoria direction. ElectraNet is considering modifying the Murraylink Runback Scheme for bi-directional operation and to reduce applicable thermal constraints. The work is planned to be carried out under EC.15175 – NCIPAP Increase Murraylink Transfer Capability 1.

Inter-Area Separation Prevention Scheme

The non-credible loss of either the Tungkillo – Robertstown or Robertstown – Davenport double circuit 275 kV lines under high wind generation conditions could overload the 275 kV and 132 kV network between Para and Davenport, causing transient stability issues. Transient instability issues could lead to complete separation between Davenport and Adelaide, which would cause major supply disruptions. At present, this risk is managed during destructive wind conditions by reclassifying the non-credible loss of the Tungkillo – Robertstown or Robertstown – Davenport double circuit 275 kV lines as credible and constraining generation in the northern parts of South Australia.

A new control scheme is being considered to mitigate the risk. ElectraNet is also considering new transmission lines between Adelaide, Bundey and Cultana as part of the Mid North REZ Expansion. Construction of these additional circuits could also mitigate the risk.

Para – Templers West – Brinkworth – Davenport Corridor Scheme

There is significant interest in new connections to the Para—Templers West—Brinkworth—Davenport 275 kV corridor. However, a planned or unplanned outage in one of those circuits may require a pre-contingency constraint or disconnection of generators to manage the next credible contingency. A new control scheme is being considered to manage thermal loading, islanding, and voltage instability risk (due to low system strength) during prior outage conditions.

Extended EP Link Anti-Islanding Scheme

We are considering extending the current EP Link Anit-Islanding Scheme to cover the loss of both Davenport – Cultana 275 kV lines or both Cultana 275/132 kV transformers (for example, due to loss of a transmission element during a prior outage of the parallel transmission element).

5 Connection Opportunities and Demand Management

This chapter provides an update regarding new connections and withdrawals and identifies proposed new connection points for which network support solutions are being sought or considered. Details about the connection services we offer are available on our website.[35] We encourage any potential new generators or customers to contact our Corporate Development Team.

5.1 New connections and withdrawals

Several generators have connected or withdrawn since the publication of the 2023 Transmission Annual Planning Report, and other generators have committed to connect, or announced their intention to withdraw (Table 8, Table 9 and Figure 19).[36] A full accounting of expected retirements and connection status can be found on AEMO's website.

The trend of increasing amounts of new solar, wind and battery generation continue in the Southern Australian network, with close to 1 GW of projects connected and committed.

Table 8: Generators that have withdrawn since October 2023 or have announced planned withdrawal

Generators	Type	Size	Announced closure date
Port Lincoln GT	OCGT	50 MW	January 2028
Port Lincoln GT	OCGT	23.50 MW	January 2028
Snuggery	OCGT	63 MW	January 2028

Table 9: Generators that connected since October 2023 or are committed or anticipated to connect in future

Generators	Type	Size	Status
Bungala Three Solar Power Plant	Solar – PV	80 MW	Proposed
Bungama Solar	Solar – PV	280 MW	Proposed Dec 2027
Carnodys Hill Wind Farm	Wind Turbine	235 – 250 MW	Proposed
Cultana Solar Farm	Solar PV	357 MW	Anticipated July 2026
Goyder South Wind Farm 1A	Wind Turbine	209 MW	Committed Dec 2024
Goyder South Wind Farm 1B	Wind Turbine	203 MW	Committed Dec 2024
Quarantine	Turbine – OCGT	165 MW	Proposed
Solar River and Solar BESS Project	Solar – PV	255 MW	Proposed
Vast Solar 1	Solar Thermal – Other	34 MW1	Proposed

35 ElectraNet | Connection Services

36 AEMO | NEM Generation Information

Figure 19: **New connections and withdrawals**

5.2 Connection opportunities for generators

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

However, this assessment is limited to a few operating conditions and does not attempt to define the amount and value of constraints that could be experienced in terms of energy lost by connecting generation. We have not considered the potential impact of constraints outside of South Australia on the ability to export power out of South Australia.

In making this assessment, we have included the impact of generators that are considered committed to connect.

We recommend that parties seeking connection to the network carry out a detailed network access and market impact assessment.

5.2.1 Approach to generation opportunity calculations

We have evaluated the anticipated thermal capability of the transmission network to accommodate additional generation, with inclusion of the anticipated full capacity of Project EnergyConnect, under five system conditions (Table 10).

These conditions were selected to reflect a range of dispatch scenarios, capturing various demand levels, generation mixes, and interconnector flows, representing typical situations the network may experience. During the development of these scenarios, BESS operation was excluded from the study, as their impact on overall system conditions is considered minimal. Additionally, conventional generation was limited where possible to better represent the expected future operation of the network, as conventional generation is being phased out, as highlighted in Chapter 1.

Table 10: Initial system conditions considered in the assessment of the ability of the South Australian transmission system to accommodate additional generation

System condition	SA Demand (MW)	Heywood interconnector flow (MW)	Project Energy-Connect flow (MW)	Conventional generator output (% of capacity)	Wind farm output (% of capacity)	Solar farm output (% of capacity)	BESS
High summer demand sunny at noon	2,500	350 (import)	450 (import)	0%	50%	90%	0%
High winter demand very windy and overcast	2,000	230 (export)	250 (export)	0%	90%	0%	0%
Medium demand sunny and still	1,300	250 (import)	195 (import)	0%	5%	90%	0%
Medium demand cloudy and windy	1,300	500 (export)	400 (export)	0%	80%	5%	0%
Very low daytime demand sunny and still	0	400 (export)	450 (export)	0%	5%	95%	0%

The study was conducted across 89 connection points, where we gradually increased the output of the new generator at each location. During this process, the flows on both interconnectors were managed within their secure limits to maintain the supply-demand balance. The new generator output was increased until either a voltage limitation or thermal overload was observed, while considering all possible single credible contingencies. The impact of existing runback schemes was also accounted for where practicable.

Potential impacts on new or existing generators due to system strength limitations have not been considered. The indicative capacity of the South Australian transmission network and its connection points to accommodate additional generation (beyond existing and committed generation) is summarised in Section 5.4.

In some cases, larger generators may be connectable if low-cost upgrades can enhance the network's transfer capacity, for instance, by replacing low-cost equipment that limits the available rating of a transmission line. The impact of committed projects has been included in Section 6.2.

5.2.2 General observations about connection opportunities for generators

Almost any point on 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 Cultana (near Whyalla) to South East (near Mount Gambier); however:

- Connections on the Davenport – Bungama – Blyth West – Munno Para – Para 275 kV lines may be subject to constraints or forced outages under N-1 conditions, and may become increasingly subject to constraints at times of high aggregate generation output under system normal conditions
- Connections on the Davenport – Robertstown 275 kV lines may become subject to constraints under N-1 conditions
- Connections on the Torrens Island – Le Fevre – Pelican Point – Parafield Gardens West – Para 275 kV lines may be subject to constraints under N-1 conditions, and may become subject to constraints at times of high aggregate generation output under system normal conditions
- Generation connected anywhere from Tungkillo through to Tailem Bend and South East may be subject to co-optimised dispatch with the Heywood interconnector, due to its potential impact on the ability to import power from Victoria and the rest of the NEM
- Connection between Tailem Bend and South East is complicated by series compensation at Black Range and may not be cost effective, subject to but not limited to the technical requirements to mitigate the impact of the new connection and the scale of the connection proposal.

Due to physical space constraints, Davenport (near Port Augusta), Cultana (near Whyalla) and Robertstown are each approaching the limit of their ability to physically accommodate new connections. Further connections at any of these locations are likely to require substantial investment by the connecting party to either expand the site or establish a nearby new substation. Bundey is a suitable site for proponents near Robertstown to connect.

At times of coincident high wind generation output and high solar generation output, including from distributed rooftop solar PV, generation constraints can be significantly more onerous than presented in section 5.4. Conversely, such conditions could be favourable for energy storage proposals. Again, we recommend that parties seeking connection to the network carry out a detailed network access and market impact assessment.

While the existing Metropolitan transmission system may have capacity to accept new generation connections, population density may limit the ability to economically extend the network. Also, existing maximum fault levels are approaching the plant capability limits of our assets, particularly in the vicinity of Torrens Island, LeFevre, New Osborne, Kilburn, Northfield, Magill and within the Adelaide Central Business District (CBD). Connection of new synchronous generation could initiate a need for major replacement of transmission assets to address fault l evel issues.[37]

ElectraNet continues to be approached by an increasing number of potential customers interested in connecting large renewable energy projects to the network. In some cases, these large projects are linked to large loads such as hydrogen electrolysers or mining.

5.2.3 Implications of South Australian system strength requirements

We installed synchronous condensers at Davenport and Robertstown in 2021. Commissioning of the synchronous condensers has allowed 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 2,500 MW.

The synchronous condensers have enabled the SA system to be operated securely with only two large synchronous generator units in service.

The total installed capacity of non-synchronous generation in South Australia now exceeds 2,500 MW, so the non-synchronous generation system constraint remains in place

37 ElectraNet | Expected maximum and minimum fault levels for each connection point

at this new increased level now that the four synchronous condensers have been installed. However, other constraints such as for thermal capacity, stability or voltage limitations and interconnector transfer capacity are 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 system strength Full Impact Assessment conducted for a proposed non-synchronous generator in accordance with clause 5.3.4B of the Rules is a pre-requisite for connection and inclusion in the non-synchronous generation system constraint.

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:

- The generator performance standard compliance must be verified with validated R2 models; and
- 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.

We are currently assessing the anticipated impact that the full implementation of Project EnergyConnect will have on the amount of non-synchronous generation that can be dispatched at times of minimum conventional generation in South Australia. We will report the outcome of this assessment in the Project Assessment Draft Report for our System Strength Requirements in South Australia RIT-T.

5.2.4 Opportunities to connect to Project EnergyConnect

Project EnergyConnect, the transmission interlink with NSW and Victoria, is formed of two phases, Project EnergyConnect Stage 1 is the construction of the first 700 km double circuit to release of 150 MW in late 2024. The second stage of the project to release 800 MW is scheduled to be completed in Q2 (May) 2026.

ElectraNet is aware of significant interest among potential renewable energy and storage proponents to take advantage of increased interconnection that will be introduced by Project EnergyConnect.

For proponents interested in connecting to Project EnergyConnect, in many cases the connection process will be similar to the current process for connection to the transmission network. However, proponents interested in connecting to certain sections of Project EnergyConnect in NSW will need to take into account access arrangements relating to the South-West Renewable Energy Zone.

There is a staged approach to progressing connections to Project EnergyConnect. A connections framework outlining pre-requisites for each connection project phase relative to Project EnergyConnect milestones is available on the Project EnergyConnect website.[38] The update provided in April 2024 confirms that Project EnergyConnect models have reached sufficient maturity to be used for planning purposes. Project EnergyConnect models are now available to proponents via the AEMO Data Request[39] process.

More details can be found be in the Project EnergyConnect connections[40] website.

New cut-in connections along Project EnergyConnect

ElectraNet encourages proponents to submit connection enquiries and applications for proposed connections directly to Project EnergyConnect (cut-ins). These will be processed, however, connections can only be physically facilitated once 500 MW of transfer capacity has been released across Project EnergyConnect. This is anticipated to occur in 2026/27, following successful completion of hold point testing under the inter-network test plan.

South Australian Interconnector Trip Remedial Action Scheme (SAIT RAS)

SAIT RAS is being developed to cater for a non-credible trip of either the Project EnergyConnect interconnector or the Heywood interconnector under high power transfer conditions to prevent separation of South Australia from the National Energy Market (NEM). Any cut-in along Project EnergyConnect will likely require a significant amount of analysis and consequential redesign of the SAIT RAS.

38 Project EnergyConnect | Milestones

39 AEMO | Policy on provision of network data

40 Project EnergyConnect | Connections

NSW South–West Renewable Energy Zone Access Arrangements

Proponents seeking a connection to the Project EnergyConnect network infrastructure in NSW will need to consider access arrangements for the South-West Renewable Energy Zone (SW REZ), which may affect the proponent's ability to submit a connection enquiry, apply to connect, or receive an offer to connect to Project Energy Connect network infrastructure both within and outside the SW REZ. Proponents seeking a connection should familiarise themselves with the regulatory and access arrangements for the SW REZ.[41]

5.2.5 System strength locational factors

For each proposed connection or alteration to a generating system, integrated resource system or other connected plant on the South Australian transmission system, ElectraNet determines a system strength locational factor. We do this in our role as the System Strength Service Provider for South Australia, in accordance with AEMO's system strength impact assessment guidelines.

Each proponent has the option to either provide their own required level of system strength, or alternatively elect to pay a system strength charge for ElectraNet to continue to provide a satisfactory level of system strength services in South Australia.

There are currently no committed or connected facilities for which the proponent has elected to pay the system strength charge.

In future Transmission Annual Planning Reports, we will publish system strength locational factors for committed or connected facilities where the proponent has elected to pay the system strength charge.

5.2.6 Generation connection impacts on power quality

Supporting the ongoing connection and integration of new generation technologies within the power system, ElectraNet performs complex power quality studies and assessments to ensure that customers will continue to experience satisfactory power quality.

To support these studies, 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,[42] 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.

5.3 Connection opportunities for load 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 about 2010, metropolitan electricity demand grew steadily because of residential infill, commercial and industrial development in the Adelaide metropolitan area. Since then, loads have generally remained flat. Latest maximum demand forecasts from AEMO and SA Power Networks indicate forecast load growth for the next ten years.

During recent years ElectraNet has been approached by an increasing number of potential customers interested in connecting large loads to the network, in many cases related to hydrogen production, large mining or data centres.

SA Power Networks' distribution network supplies individual electricity customers, and the existing Metropolitan 275/66 kV network can accommodate new load connections. Depending on size and location, new load connections may create a need to substantially augment or replace existing assets.

In other regions, we have assessed the ability of existing connection points to accommodate the connection of new large loads (section 5.4). The values listed represent the additional load that, without transmission network upgrades, could be connected to the high voltage bus in addition to the forecast South Australian 2026–27 10% POE load at the time of early evening maximum demand, with:

- Conventional generators dispatched to 100% of capacity
- Wind farms dispatched to 10% of capacity
- Solar farms off
- Import of 600 MW across the Heywood interconnector and 750 MW across Project EnergyConnect.

[41] NSW Government EnergyCo | South West Renewable Energy Zone

[42] AEMO | Power System Model Guidelines

5.4 Approach to network limits, non-credible events and transmission connections in South Australia

Network planning and design is about ensuring the efficient, safe and secure operation of the power system for energy consumers when the network is 'under stress'.

The lengths to which TNSPs are required to go to ensure that their network will withstand stress conditions is set out in the Rules and a TNSP is also required to follow good electricity industry practice.

The Rules define two levels of 'stress', known as credible and non-credible contingency events.

A credible contingency event is defined in cl 4.2.3(b) of the Rules as an event which AEMO considers reasonably possible in the surrounding circumstances, such as the unexpected loss of either, one generating unit in South Australia or a single item of transmission plant such as a single circuit of a transmission line. The power system is generally designed to withstand these events without disruption to customers.

A non-credible contingency event is defined in cl 4.2.3(e) as a contingency event that is not a credible contingency event, therefore an event that AEMO does not consider reasonably possible. The example given in the Rules includes the simultaneous failure of multiple elements. The power system is not necessarily designed to withstand these without disruption but there is an expectation that methods such as load or generation shedding will minimise disruption and significantly reduce the probability of cascading failure following this type of event.

Under the Rules, the obligation on transmission networks to withstand credible contingencies is higher than the expectation regarding non-credible contingencies. TNSPs are required to do more to prevent loss of supply due to credible contingencies than non-credible contingencies. It would be prohibitively expensive to design and build a transmission system that can withstand any and all non-credible contingencies without impacting on loads or generators. Instead, emergency controls, when available, are used to minimise disruption when non-credible contingencies happen.

To date, ElectraNet has planned and operated the power system to withstand the loss of the single largest generating unit in South Australia without disruption. Historically, that was a Northern Power Station generating unit at 273 MW. In practice, therefore, ElectraNet has sought to ensure that South Australia's electricity transmission network could continue to operate securely even if 273 MW of generation was lost unexpectedly. More recently the Snowtown 2 wind farm and Port Augusta Renewable Energy Park have been connected which are now the equal largest credible contingencies in South Australia at 273 MW each.

As the network has continued to evolve with the ongoing uptake of renewable generation and the expected increase in interconnection capacity with the eastern states, our approach to identifying and quantifying credible contingencies has shifted to rely on system studies demonstrating the network's capacity to withstand contingencies of a certain size.

Accordingly, ElectraNet's approach to managing the network has become to identify the maximum amount of generation or load that could be lost and the network maintained without disrupting others (i.e. without activating load or generation shedding schemes). The focus has been less on particular network elements and more on total load or generation quantity whose loss could be sustained without disruption. This then defines the largest credible contingency.

There are technical considerations for managing credible contingencies which can influence the ability to connect to the NEM in South Australia:

- Contingencies below 273 MW are proven and likely to be technically feasible, subject to local conditions.
- Contingencies beyond 400 MW are unlikely to be feasible in South Australia.

Contingencies between 273 MW and 400 MW would be new for SA, and would require significant work between the connecting party, ElectraNet and AEMO to validate technically and economically. ElectraNet and AEMO (as the market advisory body for connections) works with connecting parties to ensure that their plant design incorporates the ability to maintain the single largest contingency at the value currently defined within South Australia.

SAIT RAS is being designed for the total loss of either the Project EnergyConnect or Heywood interconnector corridor. This is expected to be as high as 800 MW for system normal conditions. This represents an increase in the largest non-credible contingency event from the current multiple generation loss of up to 500 MW in South Australia. SAIT RAS may not be effective for a single non-credible contingency within South Australia that exceeds 800 MW. Any proposed (double circuit) generator connections exceeding 800 MW in capacity are therefore likely to be constrained to prevent them exceeding that level in practice to meet power system security and stability requirements.

Also, SAIT RAS relies on responses from loads, generators and BESSs to be effective. This means that the response from these connections must be predictable. In the first instance, any connection must remain connected for a non-credible loss of either the Heywood or Project EnergyConnect interconnector. If this cannot be achieved for a new connection, the size and location of the connection will have to be reconsidered or the connection arrangements be refined.

ElectraNet does not consider this to be an overly onerous requirement. Our analysis shows that all generator connections made after 2010 ride through the non-credible loss of the Heywood Interconnector.

We invite any comments from our stakeholders on the above.

5.5 Summary of connection opportunities

An indicative summary of the ability of the South Australian transmission network to accept generator or load connections in 2026–27 is given in Table 13. The summary includes the impact of Project EnergyConnect as well as other upgrade works that are planned to be completed by that time. It includes the impact of committed changes to the generation fleet (Table 11).

We emphasise that these values only provide a high-level non-binding indication, as the actual generation or load that can be accommodated often depends on the technical characteristics, operating profile and needs of equipment a customer wishes to connect. For some system conditions that are not included in the table, such as at times of very high wind generation output with moderate to low demand, the total dispatch of South Australian generation could be constrained by the capacity of the interconnectors to export electricity from South Australia.

We have not considered the potential impact of constraints in Victoria and New South Wales, or elsewhere in the NEM. We have not considered any impact of co-optimised dispatch for generators connected on interconnector flow paths.

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

The available capacity to connect new load and generation represents the capability of the existing transmission network only and does not account for any additional transformer or network capacity that may be required to facilitate connection at lower voltage levels. Any connection that proceeds will impact the ability of the system to accommodate connections at other sites.

For each system condition we have indicated the amount of additional generation dispatch or new load that could be accommodated at each connection point without exceeding voltage or capacity limits, should the most onerous single credible contingency occur. We have not considered constraints that AEMO would apply to restore system security after a contingency has occurred.

Table 11: Indication of available capacity to connect generation and load in 2026–27

Connection point	Additional generation that could be connected (MW)					Additional load that could be connected (MW)
	High summer demand sunny at noon	High winter demand very windy and overcast	Medium demand sunny and still	Medium demand cloudy and windy	Very low daytime demand sunny and still	High Summer demand evening peak and not windy
Main Grid (330 kV)						
Bundey	55	210	600+	110	255	300+
Main Grid (275 kV)						
Belalie	75	240	575	70	290	300+
Blyth West	235	70	440	115	325	150
Brinkworth	75	165	425	5	320	85
Bundey	45	185	600+	90	270	300+
Bungama	205	115	540	55	320	125
Canowie	70	260	585	70	290	300+
Cherry Gardens	600+	600+	600+	265	325	270

Table 11: Indication of available capacity to connect generation and load in 2026–27 (cont.)

Connection point	Additional generation that could be connected (MW)					Additional load that could be connected (MW)
	High summer demand sunny at noon	High winter demand very windy and overcast	Medium demand sunny and still	Medium demand cloudy and windy	Very low daytime demand sunny and still	High Summer demand evening peak and not windy
City West	570	600+	550	270	325	225
Corraberra Hill	165	220	290	40	165	255
Cultana	165	220	295	40	170	255
Davenport	165	220	600+	40	165	255
Happy Valley	600+	600+	600+	270	325	260
Kilburn	570	555	535	270	325	225
Le Fevre	600+	600+	600+	270	325	225
Magill	600+	600+	600+	270	325	235
Mokota	60	240	575	75	285	300+
Morphett Vale East	600+	600+	545	270	325	265
Mount Barker South	600+	600+	600+	265	325	285
Mount Lock	95	280	565	65	295	300+
Mt Gunson South	160	220	280	40	180	45
Munno Para	150	115	420	140	325	205
Northfield	600+	600+	600+	270	325	225
Para	600+	600+	600+	270	325	215
Parafield Gardens West	600+	600+	600+	270	325	220
Pelican Point	600+	600+	600+	270	325	225
Robertstown	40	175	600+	90	275	300+
South East	600+	600+	600+	145	265	300+
Tailem Bend	405	600+	600+	220	365	300+

Table 11: Indication of available capacity to connect generation and load in 2026–27 (cont.)

Connection point	Additional generation that could be connected (MW)					Additional load that could be connected (MW)
	High summer demand sunny at noon	High winter demand very windy and overcast	Medium demand sunny and still	Medium demand cloudy and windy	Very low daytime demand sunny and still	High Summer demand evening peak and not windy
Templers West	130	225	285	0	250	130
Torrens Island	600+	600+	600+	270	325	225
Tungkillo	600+	600+	600+	265	325	300+
Willalo	65	240	575	70	285	300+
Upper North (132 kV)						
Leigh Creek South	10	0	0	0	0	0
Mount Gunson	45	45	0	45	45	10
Mount Gunson South	160	220	250	40	170	40
Neuroodla	10	0	0	0	0	0
Pimba	45	45	0	45	45	10
Eyre Peninsula (132 kV)						
Cultana	165	220	250	40	170	90
Port Lincoln Terminal	140	235	180	45	165	90
Whyalla Central	165	155	135	40	105	25
Wudinna	85	80	80	45	45	40
Yadnarie	145	250	170	45	165	90
Mid North and Riverland (132 kV)						
Ardrossan West	35	0	65	0	65	40
Baroota	0	0	0	0	0	0
Berri	50	20	50	10	50	0
Brinkworth	50	55	285	5	210	40
Bungama	80	85	265	20	245	55

Table 11: Indication of available capacity to connect generation and load in 2026–27 (cont.)

Connection point	Additional generation that could be connected (MW)					Additional load that could be connected (MW)
	High summer demand sunny at noon	High winter demand very windy and overcast	Medium demand sunny and still	Medium demand cloudy and windy	Very low daytime demand sunny and still	High Summer demand evening peak and not windy
Clare North	25	5	170	0	130	15
Dalrymple	35	0	70	5	65	20
Dorrien	75	115	130	0	115	40
Hummocks	30	10	95	0	80	10
Kadina East	30	10	100	0	85	0
Monash	50	20	120	10	80	0
Morgan–Whyalla Pump Station No 1	50	20	125	10	80	0
Morgan–Whyalla Pump Station No 2	50	20	125	10	80	0
Morgan–Whyalla Pump Station No 3	50	20	130	10	80	0
Morgan–Whyalla Pump Station No 4	40	0	120	5	90	0
North West Bend	50	20	120	10	80	0
Port Pirie	45	45	45	20	45	50
Roseworthy	80	60	135	20	125	45
Templers	60	50	195	0	195	40
Templers West	90	130	115	0	140	30
Waterloo	15	0	230	0	125	0
Waterloo East	20	0	115	0	110	5
Eastern Hills (132 kV)						
Angas Creek	130	165	120	160	95	30
Back Callington	55	50	55	55	50	20
Cherry Gardens	130	140	140	140	140	25
Kanmantoo	50	50	50	50	50	20
Mannum	125	145	125	140	50	35

Table 11: Indication of available capacity to connect generation and load in 2026–27 (cont.)

Connection point	Additional generation that could be connected (MW)					Additional load that could be connected (MW)
	High summer demand sunny at noon	High winter demand very windy and overcast	Medium demand sunny and still	Medium demand cloudy and windy	Very low daytime demand sunny and still	High Summer demand evening peak and not windy
Mannum–Adelaide Pump Station No 1	0	0	0	0	0	0
Mannum–Adelaide Pump Station No 2	125	150	120	145	60	70
Mannum–Adelaide Pump Station No 3	125	150	120	145	65	80
Millbrook	0	0	0	0	0	0
Mobilong	160	315	170	245	40	125
Mount Barker	200	275	230	260	110	115
Murray Bridge–Hahndorf No 1	75	75	75	75	40	45
Murray Bridge–Hahndorf No 2	185	260	205	240	45	130
Murray Bridge–Hahndorf No 3	175	285	190	255	65	160
Para	105	160	165	140	160	15
South East (132 kV)						
Blanche	95	50	90	15	85	0
Keith	30	150	80	80	20	95
Kincraig	80	135	155	75	20	40
Mt Gambier	105	65	95	20	90	10
Penola West	140	125	150	70	20	85
Snuggery	95	35	90	10	200	80
South East	125	125	170	70	225	145
Tailem Bend	15	210	45	210	15	15

5.6 Proposed and committed new connection points

New connection sites that have recently been energised, committed, or are proposed to enable the connection of new generators or loads are listed in Table 12.

Table 12: Proposed, committed and recently energised new connection points for generators and customers

Connection Point	Planning Region	Project year	Connection Voltage	Scope of work
Bundey	Mid North	2023	275kV	Part of Project EnergyConnect – establish Bundey substation with 3x 400 MVA 275/330 kV transformers to facilitate connection of South Australia via Robertstown 275kV to the new interconnector.

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

There are five planned consultations for forecast limitations for which we plan to seek proposals for network support solutions (Table 13).

Future dates are indicative only. Reports will be published on EletraNet's website[43], with a summary on AEMO's website.[44] We also liaise with AEMO to notify interested parties when we publish new Regulatory Investment Test for Transmission (RIT-T) reports through the "AEMO Communications" email notifications.

Table 13: Planned consultations for which ElectraNet plans to seek proposals for network support solutions

RIT-T	Expected project commitment date	Consultation status
System Strength Requirements in SA	2026	We commenced the RIT-T with publication of the PSCR in November 2023. Potential solutions include contracting with service providers or installing synchronous condensers. PSCR Submissions closed 23 February 2024 – 15 submissions were received. We have progressed technical studies to determine updated stability and voltage limits following the completion of Project EnergyConnect, and are examining the potential need for both Step Change and Green Energy Export scenarios. We expect to publish the PADR later in 2024.
Eyre Peninsula Upgrade	2027	We commenced the RIT-T with publication of the PSCR in December 2023. Three submissions for potential options were received. The project remains dependant on proponent load to proceed. We have engaged with the Office of Hydrogen Power SA to explore the potential for large hydrogen loads. We expect to publish the PADR later in 2024.
Mid North South Australia REZ Expansion project	2027	We expect to publish the PADR by the end of 2025.
South East Expansion (Stage 1)	2027	We expect to initiate this RIT-T with publication of the PSCR later in 2024.

43 ElectraNet | Regulatory Investment Test for Transmission (RIT-T)

44 AEMO | Policy on provision of network data

6 Completed, Committed and Pending Projects

This chapter provides a high-level summary of significant projects that we have completed, committed to or 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 during the past 12 months (Table 14 and Figure 20).

Table 14: Network projects completed between 31 October 2023 and 31 October 2024 (inclusive)

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 monitor real time 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	December 2023
EC.15324 Davenport – Pimba Damaged Section Replacement Replaced the damaged line section along single circuit 132kV transmission line connecting Davenport substation (Port Augusta) and Pimba, that was resulting from the incident that occurred on 20 December 2022.	Upper North	Asset renewal	December 2023
EC.14245 Port Pirie and Bungama 11kV RMU and Aux Transformer Replacement Replace 11 kV Ring Main Units (RMUs) at Port Pirie and Bungama substations that has been identified as a safety and operational issue.	Mid North	Asset condition and performance Asset renewal	October 2022 (Port Pirie) March 2024 (Bungama)
EC.14132 Isolator Status Indication Install status indicators on 54 isolators and 19 earth switches across seven sites, typically in mesh busses, where no status indication is currently installed.	Various	Operational Operational	May 2024
EC.14127 GE D20 RTU Product Upgrades Replace CPU boards in RTUs at 27 different substation sites to extend the operating life of the GE D20 and D25 RTU equipment, avoid obsolescence issues and maintain satisfactory performance standards.	Various	Asset condition and performance Asset renewal	July 2024
EC.14065 Robertstown 132 kV Uprating Alleviate constraints on Murraylink interconnector by replacing low rated plant and formulating new constraint equations and updating the Murraylink and Waterloo East run back schemes . ElectraNet envisages that this project will impact inter-regional transfer.	Mid North	Market benefits (NCIPAP) Augmentation	September 2024

Figure 20: **Key completed projects between 31st October 2023 and September 2024**

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.

Table 15: Committed projects as of October 2024

Project Description	Region	Constraint driver and investment type	Planned Asset in service
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	August 2025
EC.14047 Transformer Bushing Unit Asset Replacement 2018–2023 Replace transformer bushings fitted on 20 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	February 2025
EC.14081 Line Insulator Systems Refurbishment 2018–2023 Program to 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	April 2025
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	June 2025
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.	Riverland	Market benefit Augmentation	Stage 1 (Robertstown to Buronga): November 2024 Stage 2 (Buronga to Wagga Wagga): June 2026
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	September 2025
EC.11646 Eyre Peninsula and Upper North Voltage Control Scheme Implement an automated voltage control scheme 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 2025

Figure 21: **Key committed and pending projects**

Table 15: Committed projects as of October 2024 (cont.)

Project Description	Region	Constraint driver and investment type	Planned Asset in service
EC.15474 Tailem Bend to South East High-Risk Tower Foundation Replacements Replace foundations on 12 high-risk towers along the Tailem Bend to South-East 275kV double circuit interconnector, following an incident on 22 November 2022 when a tower foundation failed on this transmission line.	South East	Asset condition and performance Asset renewal	March 2025
EC.14031 Protection System Unit Asset Replacement 2018–2023 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	June 2026
EC.14032 Instrument Transformer Unit Asset Replacement Replace instrument transformers at 19 substations which are at the end of their technical lives, due to an increased risk of failure which may result in an increasing rate of explosive asset failure.	Various	Asset condition and performance Asset renewal	June 2025
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.	Various	Asset condition and performance Asset renewal	November 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	June 2025
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	June 2025
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	Asset condition and safety Asset renewal	January 2026
EC.15272 Wide Area Monitoring Scheme 2023–2028 Expand the existing WAMS by installing phasor measurement units (PMUs) as required by AEMO at candidate sites across the SA transmission network.	All	Stability Operational	June 2025
EC.11645 Transmission Network Voltage Control Install a total of four 60 Mvar 275 kV reactors around the Adelaide metropolitan region and a single 50 Mvar 275 kV reactor at South East. These and other reactive and voltage control devices on the main 275 kV transmission network will be upgraded to enable coordinated automatic switching of existing and planned reactive power devices. This will require the installation and modification of secondary plant items for monitoring, control and protection covering multiple substation sites including automating Onload Tap Changer operation at SA Power Networks connection points.	Main Grid	Reactive support Augmentation	Installation of five 275 kV reactors by mid-2026 Automated switching by mid- 2028
EC.15279 Emergency Unit Asset Replacement 2023–24 to 2027–28 Emergency replacement of individual assets is undertaken for assets that fail unexpectedly, to meet reliability standards	Various	Asset condition and performance Asset renewal	June 2028

6.3 Pending projects

We define pending projects as those projects that have completed the RIT-T or equivalent process but have not yet been fully approved by the ElectraNet Board (Table 16 and Figure 21: Key committed and pending projects).

Table 16: Pending projects

Project Description	Region	Constraint driver and investment type	Asset in service
EC.14084 Line Conductor and Earthwire Refurbishment 2019 to 2023 **Estimated cost: $24–28 million** **Status: Planned** Program to replace transmission line conductors and earthwire to extend the life of seven 132 kV transmission lines in the Mid North and Riverland regions	Mid North and Riverland	Asset condition and performance Asset renewal	December 2026
EC. 15568 Northfield Transformer 8, 9 and 10 Interface Connection Requirement **Estimated cost: $45–55 million** **Status: Planned** SA Power Networks are planning to replace their aging/failing 66kV GIS switchgear at Northfield substation with a new AIS 66kV switchyard. To support this replacement, we will need to upgrade the 66 kV GIS to AIS connection points to transformers #8 and #9 and install new transformer #10 at Northfield substation. Transformer 10 has been included in the scope since the 2023 TAPR. Through detailed engineering investigations as part of the project it has been determined that the scope of works required to deliver the original brief has increased significantly, this is largely due to complexity of GIS to AIS interfaces, the requirement for a new Transformer (TF10) and the decommissioning and demolition of the out of service synchronous condenser and building to accommodate cable paths and location of new TF10.	Metropolitan	Asset condition and performance Asset renewal	Connection of transformer #9 by November 2026 Connection of transformer #10 by November 2027 Connection of transformer #8 by August 2028

7 Transmission System Development Plan

This chapter presents the Transmission System Development Plan resulting from our annual planning review, and addresses projected limitations on the South Australian transmission network over the next 10 years.

7.1 Urgent and unforeseen investments

There were no urgent and unforeseen investments made since the publication of the last Transmission Annual Planning Report that have avoided a RIT-T.

7.2 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 17 and Figure 22).

These projects have or will be identified by AEMO in a future ISP or GPSRR.

Table 17: Committed and proposed projects to strengthen interconnection, or improve transfer capability by the application of smart grid technology

Project description	Region	Constraint driver and investment type	Asset in service
EC.14171 Project EnergyConnect: New interconnector between South Australia and New South Wales **Estimated cost: $440–500 million (South Australian component only)** **Status: Committed** Construct a new 330 kV, 800 MW interconnector from Robertstown in South Australia to Wagga Wagga in New South Wales, via Buronga and strengthen the link between Buronga and Red Cliffs (Victoria). This project will increase the full combined transfer limit across both the Heywood and Project EnergyConnect interconnectors to 1,300 MW import into South Australia and 1,450 MW export. The AER approved Transgrid and ElectraNet’s Contingent Project Applications in May 2021 with a total cost of $2.27 billion (2017–18 dollars). We envisage that this project will impact inter-regional transfer.	Main Grid	Market benefit Augmentation	Stage 1 (Robertstown to Buronga): November 2024 Stage 2 (Buronga to Wagga Wagga): June 2026

Table 17: Committed and proposed projects to strengthen interconnection, or improve transfer capability by the application of smart grid technology (cont.)

Project description	Region	Constraint driver and investment type	Asset in service
EC.15272 Wide Area Monitoring Scheme 2023–2028 **Estimated cost: $15–18 million** **Status: Committed** Expand the existing WAMS by installing phasor measurement units (PMUs) as required by AEMO at candidate sites across the SA transmission network. The scope of works includes installing hardware and software to integrate new PMUs to existing systems and deploy associated software application analytical tools that will be used to analyse the data collected. The candidate sites cover a range of network locations listed below: • Main transmission network (incremental to existing PMU network) – will monitor the performance of the main transmission network and identify emerging power system challenges • Generator/BESS sites – will monitor the dynamic response of major generators and batteries • Regional Load sites at the periphery of the system – monitoring will help understanding of load dynamics for benchmarking power system models and identification of emerging challenges in the power system • Metro Loads incorporating significant DER Feed-in – monitoring will help understand the response of DER following-system disturbances for benchmarking power system models, network planning and accurate constraint development We do not envisage that this project will impact inter-regional transfer.	All	Stability Operational	AEMO data requirement by August 2024 Remaining site data by June 2025
EC.15466 South East Interconnection **Estimated cost: To be determined** **Status: Being considered as an option for future development** Develop a new HVAC interconnector between the South East of South Australia and Heywood in Victoria This project option would increase transfer capability between South Australia and Victoria to unlock cheaper energy sources, enabling access for South East SA wind-powered generation to Victoria and the rest of the NEM. This project would impact inter-regional transfer.	Main Grid	Market benefit Augmentation	Subject to if or when shown to deliver benefit to customers
EC.15467 Mid North Interconnection **Estimated cost: To be determined** **Status: Being considered as an option for future development** Develop a new 500 kV HVAC interconnector between the Mid North of South Australia at New South Wales. This project option would increase transfer capability between South Australia and New South Wales to unlock cheaper energy sources, enabling access for South Australian wind- and solar-powered generation to New South Wales and the rest of the NEM. This project will impact inter-regional transfer.	Main Grid	Market benefit Augmentation	Subject to if or when shown to deliver benefit to customers

Figure 22: **Interconnector and Smart Grid planning projects**

7.3 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 continue to provide an adequacy supply of system strength, inertia, and voltage control on South Australia's transmission network (Figure 23 and Table 18).

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.

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.

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 continue to assess 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. AEMO has declared a RSAS shortfall in South Australia for voltage control. More can be found on AEMO's website.[45]

The changing nature of the power system has impacted overall power quality performance. Ongoing monitoring and supporting studies indicate that mitigation actions may be required at up to four key locations to rectify power quality performance to within compliance limits. Further investigation is required to ensure appropriate levels of power quality performance for all network connected customers (load and generation).

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.[46]

[45] AEMO | Procurement of RSAS

[46] ElectraNet | Transmission Annual Planning Report

Figure 23: Proposed projects to meet system security, power quality and fault level needs

Table 18: Projects proposed to maintain or enhance system security or power quality

Project description	Region	Constraint driver and investment type	Asset in service
EC.11645 Transmission Network Voltage Control **Estimated cost: $80–90 million** **Status: Committed** Install a total of four 60 Mvar 275 kV reactors around the Adelaide metropolitan region at Para, Magill and Torrens Island Power substation, and a single 50 Mvar 275 kV reactor at South East. The installations will include associated works for reactor connection and switching, monitoring and control, system protection, and site civil works. These and other reactive and voltage control devices on the main 275 kV transmission network will be upgraded to enable coordinated automatic switching of existing and planned reactive power devices. This will require the installation and modification of secondary plant items for monitoring, control and protection covering multiple substation sites including automating Onload Tap Changer operation at SA Power Networks connection points. The RIT-T for this project was completed in June 2024. ElectraNet does not envisage that this project will impact inter-regional transfer.	Main Grid	Reactive support Augmentation	Installation of five 275 kV reactors by mid-2026 Automated switching by mid- 2028
EC.15572 Network Power Quality Remediation **Estimated cost: $30–60 million** **Status: Contingent project in the 2024–2028 regulatory control period** Install relevant equipment to ensure maintain power quality is maintained for customers across the transmission network in relation to voltage harmonic requirements in line with accepted standards. ElectraNet does not envisage that this project will impact i nter-regional transfer.	Various, depending on the outcome of monitoring	Compliance Augmentation	2024 – 2028 (if shown to be required)
EC.15149 Main Grid System Strength Support 2024–2028 **Estimated cost: $100–300 million (depending upon solution)** **Status: Planned** Install or procure additional system strength services to satisfy requirements at System Strength Nodes in South Australia. We published the PSCR in November 2023, we are progressing the PADR and planning to publish in December 2024. ElectraNet envisages that this project will impact inter-regional transfer.	Main Grid	Compliance Augmentation	2026 – 2029 (depending upon solution)

7.4 Capacity and Renewable Energy Zone development

We have identified potential projects to provide capability for future new customers and generators (Figure 24 and Table 19).

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 B Section B2.1). This is coordinated through joint planning with SA Power Networks, in which connection point projects are considered, proposed, and planned (Appendix A1.6).

Several proponents are planning to connect large loads on the Eyre Peninsula which would necessitate an upgrade of the Cultana to Yadnarie section of Eyre Peninsula Link from 132 kV to 275 kV operation. We initiated a RIT-T to investigate this possible upgrade by publishing a PSCR in December 2023. We plan to publish a PADR later in 2024.

We have also assessed 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. In recent years, interest in large new load connections to the South Australian electricity transmission system has risen sharply, with proponents seeking to take advantage of South Australia's low-cost and low-emission electricity from renewable sources.

These potential new demand developments fundamentally change the outlook for the South Australia's transmission network. We are considering prioritised options for development that would unlock capacity for in S3 Mid North SA, S2 Riverland, S5 Northern SA, S9 Eastern Eyre Peninsula, S1 South East SA and O6 South East SA Coast REZs.

AEMO's 2024 ISP highlighted the Mid North South Australia REZ Expansion (South) as a newly actionable project, with required completion in 2029. The 2024 ISP initiated the RIT-T process for this identified need. We plan to publish a PADR by December 2025.

We have identified a set of immediate priorities to efficiently facilitate the continuing high level of interest for connections in South Australia, which include:

- **Mid North REZ Expansion** – Timing: 2029. This project will explore the benefits of increased transfer capacity between Bundey and the Adelaide metropolitan load centre, and Bundey and the anticipated Cultana load centre. Project options are included in section 4.4.
- **South East Expansion (Stage 1)** – Timing: 2028. String the vacant circuit that exists on one of the Tailem Bend to Tungkillo 275 kV lines. AEMO's 2024 ISP did not identify this as an actionable project, but our analysis indicates that it would deliver net market benefits. We plan to commence a RIT-T for this need later in 2024.
- **Eyre Peninsula upgrade** – Timing: Late 2020s. Upgrade the operating voltage of the new Cultana to Yadnarie transmission lines from 132 kV to 275 kV. Depending on the timing and size of future demand this project might require increase of power transfer between Davenport and Cultana. We have commenced the RIT-T for this project.
- We are also considering a range of potential options for future development of the South Australian electricity transmission system to meet supply requirements over the medium term in the South East, Eyre Peninsula, Mid North, and Metropolitan regions. These options represent strategic expansions that would build on the immediate priorities described above.

We monitor updates in forward and reverse power flow forecasts for all connection points. This enables us to consider options for augmentation or implement appropriate reverse power flow management by the time it is required at each connection point.

There is a potential need for a new connection point at Kingsford in the 2029 – 2033 timeframe if potential new residential developments connect to the distribution network in that area.

Tailem Bend connection point may require upgrade in 2034, based on our analysis of current maximum demand forecasts.

Figure 24: **Planned and proposed capacity and REZ development projects**

Table 19: Projects proposed to meet capacity or REZ development needs

Project description	Region	Constraint driver and investment type	Asset in service
EC.15468 Tailem Bend Upgrade **Estimated cost: $12–15 million** **Status: Proposed** Replace the two existing 25 MVA 132/33 kV transformers at Tailem Bend with two 60 MVA units. SA Power Networks' draft 2024 connection point report is forecasting the need for this project in 2034. We plan to commence the RIT-T process in 2028.	South East	Capacity Augmentation	2034
EC.15104 Eyre Peninsula Upgrade **Estimated cost: $20–300 million (depending upon solution)** **Status: Planned** 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. If needed, construct additional double circuit 275 kV line between Davenport and Cultana. We have commenced the RIT-T and published the PSCR in December 2023. We are planning to publish the PADR in November 2024. ElectraNet does not envisage that this project will impact inter-regional transfer.	Eyre Peninsula	Capacity Augmentation	2028 –2030 (depending upon solution)
EC.11011 Upper South East Network Augmentation **Estimated cost: $35–40 million** **Status: Proposed** 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. We have commenced the RIT-T process and published the PSCR in September 2024. ElectraNet envisages that this project may impact inter-regional transfer	Eastern Hills	Market benefits Augmentation	2028
EC.15424 Mid North REZ Expansion **Estimated cost: $750–3,500 million** **Status: Planned** The project has been identified as an actionable project in AEMO 2024 ISP report. The project will explore the benefits of increase transfer capacity between Bundey and the Adelaide metropolitan load centre, and Bundey and the anticipated Cultana load centre. We have commenced the RIT-T process and are planning to publish the PADR by the end of 2025. Project options are included in Section 4.4. Costs are based on AEMO's cost estimating database. We envisage that this project may impact inter-regional transfer.	Mid North	Market benefits Augmentation	2029
EC.14085 Kingsford 275/66kV Connection Point 2029 – 2033 **Estimated cost: $6–10 million (transmission component only)** **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, and one 25 MVA transformer substation.	Mid North	Capacity Augmentation	2029 – 2033 (depending on local load growth)

Table 19: Projects proposed to meet capacity or REZ development needs (cont.)

Project description	Region	Constraint driver and investment type	Asset in service
EC.15112 Heywood Interconnector Dynamic Voltage Stability Increase **Estimated cost: $30–60 million** **Status: To be considered for proposal as a contingent project in 2029 – 2033.** Install dynamic reactive support at Tailem Bend substation, to firm up import and export capability across Heywood interconnector, especially if needed to cater for early coal retirements in Victoria, if not addressed by other developments. ElectraNet envisages that this project will impact inter-regional transfer	Main Grid	Market benefits Augmentation	2029 – 2033
EC.15470 South East Expansion (Stage 2) **Estimated cost: Not yet estimated** **Status: Being considered as an option for future development** Construct new high capacity double-circuit twin conductor lines from the South East SA and South East SA Offshore REZs to Bundey, via a location near Kincraig. This project will provide strong connection for new low-cost renewable generation developments in the South East SA REZ and Offshore REZ to the South Australian transmission backbone.	Main Grid	Market benefits Augmentation	Subject to demonstrating benefits to customers.
EC.15471 Eyre Peninsula Grid **Estimated cost: Not yet estimated** **Status: Being considered as an option for future development** This project will support development of REZs and release areas on the Eyre Peninsula to support large renewable generation projects near Whyalla, Port Bonython, and Cape Hardy, unlocking potential for increased connection of low-cost renewables to supply increasing demand.	Eyre Peninsula	Capacity and Market benefits Augmentation	2029 – 2033 (depending on local load growth)
EC.15472 Metropolitan reinforcement **Estimated cost: Not yet estimated** **Status: Being considered as an option for future development** Establish a second 275 kV underground cable to provide a second transmission supply to City West and establish a new 275 kV underground cable from City West to the Southern Suburbs. This project will improve geographical diversification of transmission supply to the Southern Suburbs of Adelaide to increase supply security, which will become increasingly important as climate change increases bushfire risks to the transmission corridors in the Eastern Hills. In addition, it will increase supply capability to the Western Suburbs, Eastern Suburbs and Southern Suburbs to cater for potential increased electrification.	Metropolitan	Capacity Augmentation	2034 – 2038 (depending on local load growth)
EC.15473 Mid North Reinforcement **Estimated cost: Not yet estimated** **Status: Being considered as an option for future development** Establish new substations at Cultana, Wilmington (if required), Bundey and at Globe Derby if needed to enable operation of the Cultana to Adelaide transmission path at a higher-voltage level, and/or replace existing lower capacity lines. This project will enable increased access for new low-cost renewable generation in the Mid North SA, North SA, and Eyre Peninsula REZs to Adelaide and the proposed Eyre Peninsula hydrogen hub major load centres.	Main Grid	Capacity and Market benefits Augmentation	Step Change: FY 2049 Green Energy Exports: FY 2038

7.5 Market benefit opportunities

ElectraNet monitors congestion on the South Australian transmission system (Section 4.2). We also consider information regarding future probable generator and load connections, along with AEMO's ISP, to predict new constraints that may develop in future years.

Many of the projects discussed in preceding sections also provide net market benefits, for example by improving customer reliability or reducing congestion on the transmission system. In addition, we have included in our 2023–24 to 2027–28 NCIPAP (Table 20 and Figure 25). We are currently considering a new project for inclusion in our 2023–24 to 2027–28 NCIPAP program, to establish a remedial action scheme that will reduce anticipated generation constraints under system normal conditions for generators and batteries in the Mid North.

Table 20: Projects committed, planned and being considered to address market benefit opportunities

Project description	Region	Constraint driver and investment type	Asset in service
EC.15179 Robertstown to Tungkillo Line Uprating **Estimated cost: $1–2 million** **Status: Planned** *This project is included in our 2023–24 to 2027–28 NCIPAP* Alleviate forecast constraints between Robertstown and Para, and Robertstown to Tungkillo by uprating the lines from T100 to T120. This will increase the line ratings by 104 MVA.	Mid North	Market benefits (NCIPAP) Augmentation	April 2025
EC.15171 NCIPAP Davenport to Cultana line uprating **Estimated cost: $1–2 million** **Status: Planned** *This project is included in our 2023–24 to 2027–28 NCIPAP* Alleviate forecast congestion between Cultana and Davenport by removing plant and equipment limitations at either end of the Cultana to Davenport 275 kV lines to release the full design capacity of the lines ElectraNet envisages that this project will impact intra-regional transfer, but not inter-regional transfer	Eyre Peninsula	Market benefits (NCIPAP) Augmentation	Mid 2025
EG.01011 / EC.15571 Transmission Line Rating Improvement **Estimated cost: $5–7 million** **Status: Planned** *This project is included in our 2023–24 to 2027–28 NCIPAP* Alleviate constraints across the South Australian electricity transmission system by delivering a package of works to replace the existing 3-band rating by 10-band rating. ElectraNet does not envisages that this project will impact inter-regional transfer.	All	Market benefits (NCIPAP) Augmentation	Mid 2025
EC.15175 Increase Murraylink Transfer Capacity **Estimated cost: $4–6 million** **Status: Planned** *This project is included in our 2023–24 to 2027–28 NCIPAP* Alleviate forecast congestion on the Murraylink interconnector at times of high export by installing a 132 kV capacitor bank Monash and upgrade the existing runback control scheme to include bi-directionality and allow it to run forward if required ElectraNet envisages that this project will impact inter-regional transfer.	Riverland	Market benefits (NCIPAP) Augmentation	Mid 2026

Figure 25: **Planned and proposed market benefits**

7.6 Network asset retirements and replacements

ElectraNet carries out projects that address needs that arise from planned retirements of assets, for example due to condition (Table 21).

Table 21: Projects committed, planned and proposed to address asset retirement and replacement needs

Project description	Region	Constraint driver and investment type	Asset in service
EC.15321 TIPS IMB300 CT Replacement **Estimated Cost: $14–16 million** **Status: Planned** Urgent removal and replacement of 38 sets of current transformers at TIPS A and B switchyards that have been identified as high risk of failure We are currently applying the RIT-T for this project.	Metro	Asset condition and performance Asset renewal	November 2025
EC.14077 Mannum Transformer #1 and Secondary System Replacement **Estimated cost: $5–7 million** **Status: Planned** Replace transformer #1 and secondary systems at Mannum substation that has been assessed to be at the end of their technical lives with a corresponding high risk of failure, with a new 25 MVA 132/33 kV transformers (nearest ElectraNet standard size) Note that Mannum transformer #2 was replaced in 2021 when the transformer failed.	Eastern Hills	Asset condition and performance Asset renewal	May 2025
EC.14182 South East SVC Computer Control System Replacement **Estimated cost: $7–10 million** **Status: Planned** Replace the computer control system for the SVC 1 and SVC 2 at South East substation that has been assessed as being end of their life cycle, requiring replacement during the 2024–2028 regulatory control period We published a PACR on 16 November 2023, concluding the RITT for this project47.	South East	Asset condition and performance Asset renewal	December 2025
EC.15568 Northfield Transformer #8, #9 and #10 Interface Connection Requirement **Estimated Cost: $45–55 million** **Status: Planned** SA Power Networks are planning to replace their aging/failing 66kV GIS switchgear at Northfield substation with a new AIS 66kV switchyard. To support this replacement, we will need to upgrade the 66 kV GIS to AIS connection points to transformers #8 and #9 and install new transformer #10 at Northfield substation SA Power Networks published the final RIT-D document for Ensuring Reliable Supply for Adelaide's Eastern Suburbs in December 2022.	Metropolitan	Asset condition and performance Asset renewal	Connection of transformer #9 by November 2026 Connection of transformer #10 by November 2027 Connection of transformer #8 by August 2028

[47] ElectraNet | The Managing the Risk of South East SVC Control System Failure PACR

Table 21: Projects committed, planned and proposed to address asset retirement and replacement needs (cont.)

Project description	Region	Constraint driver and investment type	Asset in service
EC.15239 F1803 Hummocks – Ardrossan West 132kV Line Renewal **Estimated cost: $30–35 million** **Status: Planned** The line conductor, earthwire and insulator strings for the entire Hummocks to Ardrossan West 132 kV line has been assessed to be at end-of-life and require replacement, during the 2024–2028 regulatory control period. We are currently applying the RIT-T for this project.[48] The option with the highest Net Present Value is to replace the line in its entirely.	Mid North	Asset condition and performance Asset renewal	June 2028
EC.15432 F1802 Bungama – Port Pirie 132kV Line Refurbishment **Estimated cost: $5–10 million** **Status: Proposed** Decommission the existing Port Pirie to Bungama 132 kV line, which has been assessed to be at end-of-life during the 2029–2033 regulatory control period, and replace with a new 132 kV line alongside the existing easement. We plan to initiate a RIT-T prior to commitment.	Mid North	Asset condition and performance Asset renewal	2029 – 2033
EC.15474 Tailem Bend to South East High-Risk Tower Foundation Replacements **Estimated cost: $15–18 million** **Status: Committed** Replace foundations on 12 high-risk towers along the Tailem Bend to South-East 275 kV double circuit interconnector, following an incident on 22 November 2022 when a tower foundation failed on this transmission line.	South East	Asset condition and performance Asset renewal	March 2025
EC.14090 Mount Gambier Transformer 1 Replacement **Estimated cost: $4–6m** **Status: Proposed** 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 selected to match the other 132/33 kV transformer at Mount Gambier, and provides capacity to meet the forecast demand at Mount Gambier connection point.	South East	Asset condition and performance Asset renewal	2029 – 2033

48 ElectraNet | Managing the Risk of Hummocks to Ardrossan West 132 kV Line Failure Line Failure

7.7 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, our Plant and Line Rating Framework describes how network and public risk can be understood and mitigated, while maximising network utilisation and capacity.

7.8 Grouped network asset retirements, deratings and replacements

Various programs of work that exceed $7 million for grouped network asset retirement and replacement are proposed over the 10-year planning period (Table 22).

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

Table 22: Grouped projects committed, planned and proposed to meet asset retirement and replacement needs

Project description	Region	Constraint driver and investment type	Asset in service
EC.14047 Transformer Bushing Unit Asset Replacement 2019 to 2023 **Estimated cost: $12–16 million** **Status: Committed** Replace transformer bushings that have been assessed to be at the end of their technical or economic lives on 20 transformers across 12 substation sites.	Various	Asset condition and performance Asset renewal	February 2025
EC.14032 Instrument Transformer Unit Asset Replacement 2019 to 2023 **Estimated cost: $15–17 million** **Status: Committed** 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.	Various	Asset condition and performance Asset renewal	June 2025
EC.14031 Protection Systems Unit Asset Replacement 2019 to 2023 **Estimated cost: $45–50 million** **Status: Committed** Replace protection scheme relays across the South Australian electricity transmission system that have reached the end of their technical or economic lives We published a PACR on 6 December 2019, concluding the RITT for this program of work49[50].	Various	Asset condition and performance Asset renewal	June 2025
EC.14033 Circuit Breaker Unit Asset Replacement 2019 to 2023 **Estimated cost: $5–7 million** **Status: Committed** 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	November 2024

49 ElectraNet | The Managing the Risk of Protection Relay Failure PACR

50 ElectraNet | The Managing the Risk of Isolator Failure PACR

Table 22: Grouped projects committed, planned and proposed to meet asset retirement and replacement needs (cont.)

Project description	Region	Constraint driver and investment type	Asset in service
EC.14034 Isolator Unit Asset Replacement 2019 to 2023 **Estimated cost: $12–15 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 18 sites across South Australia where the asset won't be replaced as part of an augmentation or substation rebuild during the 2018–19 to 2022–23 regulatory period. We published a PACR on 18 November 2019, concluding the RITT for this program of work[51].	Various	Asset condition and performance Asset renewal	June 2025
EC.14176 Surge Arrestor Unit Asset Replacement 2018 to 2023 **Estimated cost: $8–10 million** **Status: Committed** 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	June 2025
EC.14046 AC Board Replacement 2019 to 2023 **Estimated cost: $30–35 million** **Status: Committed** Program to replace and improve AC auxiliary supply equipment, switchboards and cabling at 17 substations across the South Australian electricity transmission system that have been assessed to be at the end of their technical and economic lives We completed a RIT-T for this program of work by publishing a PACR on 14 January 2020.[52]	Various	Asset condition and performance Asset renewal	January 2026
EC.14081 Line Insulator Systems Refurbishment 2019 to 2023 **Estimated Cost: $60–65 million** **Status: Committed** Program to refurbish transmission line support systems and extend the life of 18 transmission lines by renewing line asset components. This program of work was committed prior to 30 January 2018	Various	Asset condition and performance Asset renewal	April 2025
EC.15060 Circuit Breakers Unit Asset Replacement 2024 to 2028 **Estimated cost: $14–16 million** **Status: Planned** Replace and improve 26 circuit breakers at 11 substations across the South Australian electricity transmission system that have been assessed to be at the end of their technical and economic lives during the 2024–2028 regulatory control period. We have commenced the RIT-T for this project.[53]	Various	Asset condition and performance Asset renewal	June 2028

[51] ElectraNet | The Managing the Risk of Protection Relay Failure PACR

[52] ElectraNet | The Managing the Risk of Isolator Failure PACR

[53] ElectraNet | Managing the Risk of Circuit Breaker Failure

Table 22: Grouped projects committed, planned and proposed to meet asset retirement and replacement needs (cont.)

Project description	Region	Constraint driver and investment type	Asset in service
EC.15120 Instrument Transformer Unit Asset Replacement 2024 to 2028 **Estimated cost: $20–22 million** **Status: Planned** Replace 26 voltage transformers and 72 current transformers at 12 substations across the South Australian electricity transmission system that have been assessed to be end-of-life during the 2024–2028 regulatory control period to address the increased risk of unsafe operation and poor We have commenced the RIT-T for this project.[54]	Various	Asset condition and performance Asset renewal	June 2028
EC.15189 Protection Relay Unit Asset Replacement 2024 to 2028 **Estimated cost: $16–18 million** **Status: Planned** Replace protection relays and associated components at six substations across the South Australian electricity transmission system that have been assessed to be end-of-life during the 2024–2028 regulatory control period. We have commenced the RIT-T for this project.[55]	Various	Asset condition and performance Asset renewal	June 2028
EC.15237 Surge Arrestor Unit Asset Replacement 2024 to 2028 **Estimated cost: $5–7 million** **Status: Planned** Replace 63 porcelain surge arrestors located in 9 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	June 2028
EC.15397 Isolator Unit Asset Replacement 2024 to 2028 **Estimated cost: $23–25 million** **Status: Planned** Replace or refurbish approximately 50 individual substation isolators at nine substations across the South Australian electricity transmission system that have been assessed to be at end-of-life during the 2024–2028 regulatory control period. We have commenced the RIT-T for this project.[56]	Various	Asset condition and performance Asset renewal	June 2028
EC.15279 Emergency Unit Asset Replacement 2024 to 2028 **Estimated cost: $8–12 million** **Status: Committed** Emergency replacement of individual assets is undertaken for assets that fail unexpectedly, to meet reliability standards.	Various	Asset condition and performance Asset renewal	June 2028

[54] ElectraNet | Managing the Risk of Instrument Transformer Failure 2024–2028

[55] ElectraNet | Managing the Risk of Protection Relay Failure 2024–2028

[56] ElectraNet | Managing the risk of Isolator Failure 2024–2028

Table 22: Grouped projects committed, planned and proposed to meet asset retirement and replacement needs (cont.)

Project description	Region	Constraint driver and investment type	Asset in service
EC.15233 Transmission Line Insulation System Replacement 2024 to 2028 **Estimated cost: $34–38 million** **Status: Planned** Implement a program to replace about 2775 insulator strings on 779 structures with equivalent insulation and associated hardware on 14 transmission lines across the network that have been assessed to be at end-of-life during the 2024–2028 regulatory control period, to renew line asset components and extend line life. We have commenced the RIT-T for this project.[57]	Various	Asset condition and performance Asset renewal	June 2028
EC.15242 Transformer Bushing Unit Asset Replacement 2024 to 2028 **Estimated cost: $12–14 million** **Status: Planned** Replace individual transformer bushings on 15 high voltage transformers at 13 substations across the South Australian electricity transmission system that have been assessed to be at end-of-life during the 2024–2028 regulatory control period. We have commenced the RIT-T for this project.[58]	Various	Asset condition and performance Asset renewal	June 2028
EC.15449 IMB300 CT Hazard Mitigation **Estimated cost: $13–15 million** **Status: Planned** Replace 26 sets of current transformers at six substations that have been identified as high risk of failure, based on failure of similar of current transformers that were of same make, model and age. We have commenced the RIT-T for this project.	Various	Asset condition and performance Asset renewal	December 2025
EC.15394 Invensys C50 RTU Upgrades **Estimated cost: $6–8 million** **Status: Proposed** Replace the main hardware components for all 56 Foxboro Gateway RTUs units and 30 Bay RTU modules at regulated 18 sites with the latest equivalent during the 2024–2028 period.	Various	Asset condition and performance Asset renewal	June 2029
EC.15427 High Crossing Tower Climbing System Replacement **Estimated cost: $6–8 million** **Status: Proposed** Replace all tower climbing systems that includes fixed climbing ladders, climbing aids and platform refurbishment on 13 high crossing tower structures that have been identified as not effective in meeting current WHS Act and Regulations requirements.	Various	Asset condition and performance Asset renewal	December 2027

[57] ElectraNet | Managing the Risk of Line Insulation System Failure 2024–2028

[58] ElectraNet | Managing the Risk of Transformer Bushing Failures 2024–2028

Table 22: Grouped projects committed, planned and proposed to meet asset retirement and replacement needs (cont.)

Project description	Region	Constraint driver and investment type	Asset in service
EC.15069 Circuit Breakers Unit Asset Replacement 2029 to 2033 **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 2029–2033 regulatory control period. We plan to initiate a RIT-T prior to commitment.	Various	Asset condition and performance Asset renewal	2029–2033
EC.15042 AC Board Unit Asset Replacement 2029 to 2033 **Estimated cost: $18–24 million** **Status: Proposed** Replace and improve AC auxiliary supply equipment, switch boards and cabling at 23 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 2029–2033 regulatory control period. We plan to initiate a RIT-T prior to commitment.	Various	Asset condition and performance Asset renewal	2029–2033
EC.15123 Instrument Transformer Unit Asset Replacement 2029 to 2033 **Estimated cost: $50–60 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
EC.15244 Transformer Bushing Unit Asset Replacement 2029 to 2033 **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 2029–2033 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 2029 to 2033 **Estimated cost: $8–15 million** **Status: Proposed** Replace protection relays and control schemes across the South Australian electricity transmission system that will be assessed to be at the end of their technical and economic lives during the 2029–2033 regulatory control period. We plan to initiate a RIT-T prior to commitment.	Various	Asset condition and performance Asset renewal	2029–2033

Table 22: Grouped projects committed, planned and proposed to meet asset retirement and replacement needs (cont.)

Project description	Region	Constraint driver and investment type	Asset in service
EC.15214 Protection Signal Equipment Replacement Stage 1 **Estimated cost: $6–8 million** **Status: Proposed** Replace protection signalling equipment that will be assessed to be at the end of their technical and economic lives during the 2029–2033 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 2029 to 2033 **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 2029–2033 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 2029 to 2033 **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 2029–2033 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.15295 Emergency Unit Asset Replacement 2029 to 2033 **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 emergency replacement is about $2 million	Various	Asset condition and performance Asset renewal	2029–2033
EC.15564 Oil Containment System Improvement 2029 to 2033 **Estimated cost: $30–40 million** **Status: Proposed** Addresses environmental hazards with existing oil containment systems at various ElectraNet substations in 2029–2033 period. By replacing lining of low integrity transformer bunds, upgrading / replacing underground tank oil water separator systems that are not performing to EPA standards and the installation of monitoring systems for water tables for pollutants. Plus the installation of additional oil containment systems for sites with large containment requirements.	Various	Asset condition and performance Asset renewal	2029–2033

It should be noted that we are planning to deliver the following 2024–2028 Unit Asset Replacement projects; EC.15060, EC.15120, EC.15189, EC.15237 and EC.15397, as regional based unit asset replacement projects, once we have completed the RIT-T for these projects.

7.9 Security and compliance projects

There are a range of committed and planned projects that relate to the maintenance of our security and compliance for which planned expenditure exceeds $7 million (Table 23).

Table 23: Committed, planned and proposed security and compliance projects

Project description	Region	Constraint driver and investment type	Asset in service
EC.14131 Motorised Isolator LOPA Improvement **Estimated cost: $18 –22 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	June 2025
EC.11828 Substation Perimeter Intrusion and Motion Detection Security System **Estimated cost: $12–14 million** **Status: Planned** Upgrade substation security systems across 35 ElectraNet substations by installing external motion detection and CCTV systems with built-in analytics reporting back to a networked video management system These external motion detection and CCTV systems will supplement the “deter and delay” primary control measures such as fences and signage with a proactive and responsive secondary system, responding to potential unauthorised presence inside the security fence.	Various	Safety Operational	March 2030
EC.15220 Substation Security Fencing Replacement 2024 to 2028 **Estimated cost: $8–10 million** **Status: Planned** Replace high voltage security fencing and gates located at eleven substations that have been assessed to be at the end of their technical and/or economic lives and require replacement to prevent unauthorised access	Various	Safety Asset renewal	April 2030
EC.15235 Transmission Line Anti-Climb Installation 2024 to 2028 **Estimated cost: $20–25 million** **Status: Planned** Install climbing deterrent devices and warning signage on 2100 transmission towers located on 59 high voltage transmission lines that have been assessed as highly vulnerable to unauthorised access	Various	Safety Asset renewal	June 2030
EC.15399 Substation Technology System Cybersecurity Uplift 2024 to 2028 **Estimated cost: $14–18 million** **Status: Planned** Replace and upgrade substation technology assets identified as being susceptible to cyber-attack breaches by replacing relevant equipment as well and uplifting cyber security of network and intelligent devices. This work will be carried out progressively during the 2024–2028 regulatory period across 57 high risk substations	Various	Security Asset Renewal	June 2026

Table 23: Committed and proposed security and compliance projects (cont.)

Project description	Region	Constraint driver and investment type	Asset in service
EC.15401 Happy Valley Site Drainage Replacement **Estimated cost: $6–10 million** **Status: Proposed** Replace the existing drainage system at Happy Valley substation with a new drainage system to improve site drainage, stability of footings, and trafficability on site roadways and reduce erosion issues	Metropolitan	Safety Asset Renewal	December 2025
EC.15496 Substation LAN Replacement and Cybersecurity Uplift 2028 to 2033 **Estimated cost: $8–12 million** **Status: Proposed** Replace and upgrade substation technology assets identified as being susceptible to cyber-attack breaches by replacing relevant equipment as well and uplifting cyber security of network and intelligent devices at 19 substations This cyber-security uplift continues the work undertaken in 2024–2028 period	Various	Security Asset Renewal	2029 – 2033
EC.15231 Transmission Line Anti-Climb 2029 to 2033 **Estimated cost: $30–40 million** **Status: Proposed** Replace or install climbing deterrent devices and warning signage on all identified line tower assets to meet and maintain requirements to prevent unauthorised access to electricity infrastructure	Various	Safety Asset renewal	2029 – 2033
EC.15275 Earth Leakage Protection Replacement 2029 to 2033 **Estimated cost: $14–18 million** **Status: Proposed** Upgrade the earth frame leakage protection to ensure all assets are protected with a high-speed duplicated protection system. The replacement and upgrade of the earth frame leakage system may require additional primary plant and substation infrastructure works	Various	Safety Asset renewal	2029 – 2033

Appendices

Appendix A: Joint Planning

We undertake 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. This includes working closely with SA Power Networks to ensure optimal solutions for South Australian customers 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.

A1 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
- Regulatory Working Group
- Market Modelling Reference Group
- Forecasting Reference Group
- Regular joint planning meetings
- Power System Modelling Reference Group
- System Strength Service Providers Working Group
- ENA

A1.1 Executive Joint Planning Committee

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

- collaborate on development of the Integrated System Plan
- improve 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.

A1.2 Joint Planning Committee

The Joint Planning Committee 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.

A1.3 Regulatory Working Group

The Regulatory Working Group 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.

A1.4 Market Modelling Working Group

The Market Modelling Working Group 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.

A1.5 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.

A1.6 Joint Planning with SA Power Networks

We have a long-standing relationship with South Australia's electricity distribution business, SA Power Networks. We collaborate through joint planning on things like annual demand forecast updates, network development options and voltage control strategies.

Network Strategy Committee

The Network Strategy Committee is an Executive level forum that facilitates consideration of alignment on key changes impacting on the network. It ensures alignment of long-term vision and strategies and oversee coordination of joint planning.

Routine joint planning activities

The purpose of routine joint planning is to deliver lowest long run costs by identifying efficient network solutions across both transmission and distribution. We hold joint planning meetings every two months, attended by planning personnel from both organisations, including discussion of items such as:

- Demand forecasting
- Connection point planning
- Network connections
- AEMO joint planning and the ISP
- System security matters and initiatives
- Network operations
- Working group status reporting.

Voltage Control Working Group

The Voltage Control Working Group reports to the regular Joint Planning meeting between ElectraNet and SA Power Networks. Its purpose is to coordinate cost effective reactive power and voltage control management outcomes for South Australian electricity customers by developing joint voltage management strategies and plans that efficiently support the distributed energy future.

A1.7 Other joint planning engagements

For effective network planning, ElectraNet also engages in joint planning activities with:

- AEMO (in their roles as National Planner and Jurisdictional Planning Body for the Victorian transmission system)
- Transgrid.

A1.8 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.

A2 Joint Planning Projects

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

- **Integrated System Plan development** (Section 2.1)

  Through engagement with AEMO and other TNSPs through the Executive Joint Planning Committee, Joint Planning Committee, and joint planning meetings we have provided advice about constraints and limitations in the South Australian electricity transmission system, and scopes and costs for projects that could address those limitations. AEMO used that information in the modelling that underpinned the 2022 ISP.

- **Project EnergyConnect** (Sections 1.2, 2.1.4, 2.21, 2.3.1, 4.1, 4.3, 4.6.1, 5.2.1, 5.2.3, 5.2.4, 5.3, 5.4, 5.5, 5.6, 6.2 and 7.2,)

  We continue to engage with AEMO and Transgrid on project implementation planning for Project EnergyConnect. The PEC System Integration Steering Committee, a collaboration between AEMO, ElectraNet, Transgrid and AusNet Services, is preparing procedures and documentation to coordinate a timely integration of PEC into the National Electricity Market (NEM)

- **Transmission Network Voltage Control** (Section 6.2 and 7.3)

  We are engaged with SA Power Networks in joint planning for the Transmission Network Voltage Control Project to ensure the identified need is appropriately defined, and to develop the suite of transmission and distribution solutions available to meet the identified need.

- **Mid North Renewable Energy Zone Expansion** (Section 2.1, 2.1.2, 2.1.4, 4.4, 4.7, 7.4)

  We are engaged with AEMO on the delivery of the RIT-T for this project to determine the preferred option and improve the accuracy of cost estimation for the options.

- **Northfield transformer replacement** (Section 6.3, 7.6)

  We are engaged with SA Power Networks in joint planning to ensure the identified need is appropriately defined, and to develop the transmission requirements to meet the identified need.

Appendix B: Asset Management Approach

B1 ElectraNet's asset management strategy

Our Asset Management Objectives are:

- Safety of people – ensure the safety of staff, contractors and the public
- Protect the environment – ensure the environmental impact of network operations are minimised
- Affordability and reliability – reduce the overall cost of electricity to customers by removing network constraints, operating the network and delivering our capital and maintenance works as efficiently as possible, while maintaining safety and reliability
- Power system security and resilience – ensure the network is resilient and operates within acceptable parameters in the face of electrical, physical, or cyber disruption, and continues to enable the transition to a low carbon emissions future.

These objectives guide our asset management plans and activities.

The Asset Management Objectives were developed in consultation with ElectraNet's Consumer Advisory Panel and are consistent with the National Electricity Objective and the capital expenditure objectives set out in the Rules.[59]

Most of our investment program in the planning period 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.

Our asset management strategic planning framework is designed to deliver a safe and reliable network at an efficient cost. The table below 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.

Our approach to ensuring efficient and prudent capital expenditure forecasts

Inputs and Analysis	Our Approach
Demand forecasts and reliability	Forecast demand is an important driver of reliability capital expenditure. We use estimates of the Value of Customer Reliability (VCR)[60] and Value of Network Resilience (VNR)[61] as determined by the AER. 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. 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 market benefit

59 NER clauses 6.5.6(a), 6.5.7(a), 6A.6.6 and 6A.6.7

60 AER | Values of customer reliability final decision

61 AER | Value of Network Resilience 2024

B2 Obligations relating to capital expenditure

In developing our capital expenditure plans we are guided by the requirements of:

- 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.

B2.1 Transmission licence and ETC obligations

Under section 15 of the Electricity Act 1996 (SA), we are required to be licensed 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.

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[62]
- 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 table overleaf.[63]

[62] AEMC | National Electricity Rules, Schedule 5.1

[63] ESCOSA | The full version of the ETC version TC/09.4

Table 24: Summary of reliability standards at exit points

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

* As defined in the ETC

ESCOSA made minor amendments to the ETC in June 2021.[64]

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.

[64] ESCOSA | The final decision is available at Electricity Transmission Code Review 2021

B2.2 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
- 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.

B2.3 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
- 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.

B3 Capital expenditure categories

We apply a range of categories to our capital expenditure. The table below describes the expenditure categories that are relevant to Transmission Annual Planning Reports. For each category, we also identify the AER's reporting category as indicated in their TAPR Guideline.[65]

Table 25: Capital expenditure categories

ElectraNet Expenditure Category	Definition	Service Category	AER's TAPR Guidelines project driver
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	Nil Works to replace transmission lines, substation primary plant, secondary systems, communications equipment and other transmission system assets in order to maintain reliability of supply. Replacement projects are generally undertaken due to the increased risk of plant failure as a result of asset age, asset condition, obsolescence or safety issues.	Exit Services and TUOS	Asset condition and performance
Refurbishment	For some assets, refurbishment is an alternative to asset replacement. Refurbishment works are generally undertaken based on the asset condition, performance and asset risk to efficiently extend asset life as a more economical alternative to wholesale asset replacement.	TUOS	Asset condition and performance
Security /Compliance	Projects that address network compliance requirements set out in legislation and regulations, and industry standards. Projects required to ensure the physical and system security of critical infrastructure assets.	Entry Services, Exit Services, TUOS, Common Services	Power quality, operational, compliance, environmental or safety

[65] Australia Energy Regulator | Transmission annual planning report guidelines

B4 Expenditure forecasting methodology

Our capital expenditure forecasting methodology is outlined below.

B4.1 Customer and stakeholder requirements

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

B4.2 Planning process

The planning process operates within a strategic framework informed by our Network Transition Strategy, 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.

B4.3 Assessment of network limitations

In developing our forecast capital expenditure, we consider projected network limitations, the condition and performance of the existing assets and the associated supporting facilities and business systems required to efficiently operate the network over the forecast period. The application of this approach differs by expenditure category:

- 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.

B4.4 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.

B4.5 Scope and estimate

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

Project cost estimates are developed for each solution based on a detailed database of materials and transmission construction costs, and recent outturn cost information from delivered projects.

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

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

B5 Key inputs and assumptions

This appendix 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.

B5.1 Demand forecasts

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

B5.2 Asset health and condition assessments

Our Transmission Asset Life Cycle (TALC) assessment framework employs a range of factors to determine where an asset is in its life cycle. The framework assists in optimising our asset management decisions. Our assessment considers both the technical health (condition, serviceability, maintainability, operability and safety) of the asset and its strategic importance in the network (related to the level of risk).

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

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

B5.3 Planning and design standards

Our planning standards are derived from the Rules and the ETC, and are presented in more detail in section C2.1. 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.

B5.4 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.

B5.5 Economic assessments

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

The options generally considered include 'business as usual', network solutions, deferred network investment, and non-network alternatives. Only if a network investment is clearly shown to be the least cost solution do we include such a project in our capital expenditure forecast.

Inputs considered in these assessments include:

- capital and operating costs of alternative options
- reliability benefits – where unserved energy is measured by the VCR and VNR estimates published by the AER
- 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.

B5.6 Non-network alternatives

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

B5.7 Risk assessments

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

This risk analysis considers:

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

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

We 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.

B5.8 Project cost estimation

Project cost estimates are derived as described earlier in section B4.5.

B5.9 Project timing and delivery

We prioritise the delivery of our capital program to ensure that the capital expenditure objectives are met as efficiently as possible. Our capital expenditure forecasts reflect the latest information on the timing of current projects, which is continually updated as projects proceed.

B6 Further information on ElectraNet's asset management strategy and methodology

Further information can be obtained from:

consultation@electranet.com.au

Appendix C: Compliance Checklist

This appendix sets out a compliance checklist which demonstrates the compliance of ElectraNet's 2024 Transmission Annual Planning Report with the requirements of clause 5.12.2(c) of version 203 of the Rules (the latest version at time of writing).

Table 26: Compliance Checklist

Summary of requirements		Section
	The Transmission Annual Planning Report must be consistent with the TAPR Guidelines[66] 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[67]
(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, 7.6 and our Transmission Annual Planning Report web page[68]
(1B)	For the purposes of subparagraph (1A), where two or more network assets are: i. of the same type; ii. to be retired or de-rated across more than one location; iii. to be retired or de-rated in the same calendar year; and iv. each expected to have a replacement cost less than $200,000 (as varied by a cost threshold determination). Those assets can be reported together by setting out in the Transmission Annual Planning Report: v. a description of the network assets, including a summarised description of their locations; vi. the reasons, including methodologies and assumptions used by the Transmission Network Service Provider, for deciding that it is necessary or prudent for the network assets to be retired or de-rated, taking into account factors such as the condition of the network assets; vii. the date from which the Transmission Network Service Provider proposes that the network assets will be retired or de-rated; and viii. if the calendar year to retire or de-rate the network assets has changed since the previous Transmission Annual Planning Report, an explanation of why this has occurred.	Sections 6.2, 7.8 and our Transmission Annual Planning Report web page[68]

66 AER | Transmission annual planning report guidelines

67 ElectraNet | Transmission Annual Planning Reports

Table 26: Compliance Checklist (cont.)

Summary of requirements		Section
The Transmission Annual Planning Report must be consistent with the TAPR Guidelines[66] and set out:		
(2)	Planning proposals for future connection points;	Section 5.5
(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[68]
(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 5.6, section 7.4 and our Transmission Annual Planning Report web page[68]
(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 4.4, 6.2, 7.2 to 7.9
(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 general power system risk review;	Section 2.3, 4.5 and 4.6
(6B)	information about which parts of its transmission network are designated network assets and the identities of the owners of those designated network assets;	Section 4.1.1

Table 26: Compliance Checklist (cont.)

Summary of requirements		Section
The Transmission Annual Planning Report must be consistent with the TAPR Guidelines[66] and set out:		
(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 B
(8)	any information required to be included in a Transmission Annual Planning Report under: i. clauses 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: c. provide inertia network services or inertia support activities; or d. meet the standard in clause S5.1.14 in relation to a system strength node;	Section 7.1 Section 7.3
(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
(9A)	the analysis of the operation of, and any known or potential interactions between: i. any emergency frequency control schemes, or emergency controls place under clause S5.1.8, on its network; and ii. protection systems or control systems of plant connected to its network (including consideration of whether the settings of those systems are fit for purpose for the future operation of its network), undertaken under clause 5.12.1(b)(7), including a description of proposed actions to be undertaken to revise those schemes, controls or systems, or to address any adverse interactions;	Sections 4.5 and 4.6
(10)	facilities in place under clause S5.1.10;	Sections 4.5 and 4.6
(11)	an analysis and explanation of any other aspects of the Transmission Annual Planning Report that have changed significantly from the preceding year's Transmission Annual Planning Report, including the reasons why the changes have occurred; and	Executive Summary
(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 A
(13)	The system strength locational factor for each system strength connection point for which it is the Network Service Provider and the corresponding system strength node.	Section 5.2.5

Appendix D: Contingent Projects

Table 27: Contingent projects for the 2024–28 regulatory control period

Project	Trigger[68]	Current status	Reference
Eyre Peninsula upgrade Upgrade of the 132 kV Eyre Peninsula Link between Cultana and Yadnarie to 275 kV and/or augmentation of power transfer capacity between Davenport and Cultana and/or Cultana and Whyalla and/or Cultana and Stony Point	Commitment for additional load from one or more customers to connect to the transmission network with aggregate load sufficient to cause the: a. Cultana 275/132 kV transformers to exceed their thermal limit of 200 MVA; or b. Whyalla Central 132/33 kV transformers to exceed their thermal limit of 120 MVA; or c. Whyalla Central to Cultana 132 kV lines to exceed their thermal limit of 117 MVA; or d. Cultana to Stony Point 132kV line to exceed its thermal limit of 144 MVA; or e. Davenport to Cultana 275 kV lines to exceed their thermal limit of 597 MVA. Successful completion of the South Australian Energy Transformation RIT-T with the identification of a preferred option or options: a. Demonstrating positive net market benefits and/or b. Addressing a reliability corrective action	We commenced a RIT-T with publication of a PSCR in December 2023 We are planning to publish a PADR before the end of 2024	Section 7.4
Network Power Quality Remediation Installation of harmonic filters, reactors or STATCOMs as required	ElectraNet obtains measurements that demonstrate the voltage harmonics at any one or more of the sites listed below exceed those specified by their planning levels under NER cl. S5.1a.6 in accordance with electromagnetic compatibility standard AS/NZS IEC 61000.3.6:2012. 1. South East 2. Tailem Bend 3. North West Bend 4. Monash 5. Mount Gunson 6. Pimba ElectraNet demonstrates that the voltage harmonic distortion causing the planning levels under NER cl. S5.1a.6 to be breached can be attributed to the extent practicable to the transmission network rather than to one or more Network Users or to a Distribution Network Service Provider.	Not yet triggered	Section 7.3
Project EnergyConnect Upgrade Integration of battery energy storage projects and other technologies to extend the capability of Project EnergyConnect and/or Heywood interconnector	Successful completion of RIT-T with an identified need to increase the capacity of either the combined interconnector limits across Project EnergyConnect and Heywood or an increase in the capability of Project EnergyConnect.	Not yet triggered	

68 In addition, the following two trigger conditions apply to each of the projects listed:
- Determination (if applicable) by the AER under clause 5.15A 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.

Appendix E: Assumptions considered in ElectraNet's planning process – potential future generator retirements and new generator and battery connections

Table 29: Assumptions considered in ElectraNet's planning process, including potential future generator retirements and new generator and battery connections

	Capacity	Status	Location on Map
Potential New Storage			
Blyth BESS	200 MW	Committed	Blyth West
Bungama BESS	150 MW	Anticipated	Bungama
Clements Gap BESS	60 MW	Committed	Redhill
Lincoln Gap WF BESS	10 MW	Anticipated	Corraberra Hill
Mannum BESS	100 MW	Anticipated	Mannum
Tailem Bend Battery Project	42 MW	In service – January 2024	Tailem Bend
Templers BESS	291 MW	Committed	Templers
Potential New Solar Farm			
Cultana Solar Farm	280 MW	Committed	Cultana
Mannum Solar Farm 2	29.9 MW	Committed	Mannum
Tailem Bend Stage 2 Solar Project	105 MW	In Commissioning	Tailem Bend
Potential New Wind Farm			
Goyder South Wind Farm 1A	209 MW	Committed	Robertstown
Goyder South Wind Farm 1B	203.5 MW	Committed	Robertstown
Potential New Thermal Power Station			
Hydrogen Jobs Plan	204 MW	Anticipated	
Retiring/Mothballed Generation			
Osborne (gas)	180 MW	In service – announced withdrawal 2026	New Osborne
TIPS B (gas)	800 MW	In service – announced withdrawal 2026	Torrens Island
Port Lincoln GT	73.5 MW	In service – announced withdrawal 2028	Lincoln
Snuggery	63 MW	In service – announced withdrawal 2028	Snuggery

Abbreviations

Abbreviation	Definition
°C	Degrees Celsius
AC	Alternating Current
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AIS	Air insulated switchgear
AMD	Agreed Maximum Demand
BESS	Battery energy storage system
CBD	Central Business District
CCGT	Combined cycle gas turbine
CEFC	Clean Energy Finance Corporation
CER	Customer Energy Resources
EFCS	Emergency Frequency Control Scheme
EMS	Energy management system
EMT	Electro magnetic transient
ESCOSA	Essential Services Commission of South Australia
ESG	Environment, social and governance
ESOO	Electricity Statement of Opportunities, published by AEMO
ETC	Electricity Transmission Code
EV	Electric Vehicle
FCAS	Frequency Control Ancillary Services
FFR	Fast Frequency Response
GIS	Gas insulated switchgear
GPSRR	General Power System Risk Review
GW	Giga-watt, a unit of active power equivalent to 1000 MW
HVAC	High voltage alternating current
HVDC	High voltage direct current
Hz	Hertz
IASR	Inputs, Assumptions and Scenarios Report, published by AEMO
IBR	Inverter-based resources
ISP	Integrated System Plan, published by AEMO
kV	kilo-Volt, a unit of voltage
LIL	Large industrial load
LOPA	Layer of Protection Analysis
Mvar	Mega-volt-ampere-reactive, a unit of reactive power
MW	Mega-watt, a unit of active power
MVA	Mega Volt-Ampere, a unit of apparent power
NCIPAP	Network Capability Incentive Parameter Action Plan
NEM	National Electricity Market
NER	National electricity rules
NSCAS	Network support and control ancillary services
NSP	Network Service Provider
NSW	New South Wales
OFGS	Over Frequency Generator Shedding
OLTC	On load tap changer

Abbreviations (cont.)

Abbreviation	Definition
OTR	Office of the Technical Regulator
POE	Probability of Exceedance
PACR	Project Assessment Conclusions Report
PADR	Project Assessment Draft Report
PEC	Project EnergyConnect
PMU	Phasor measurement unit
PSCR	Projects Specification Consultation Report
PSFRR	Power System Frequency Risk Review
PV	Photo-voltaic
QNI	Queensland-New South Wales Interconnector
RoCoF	Rate of change of frequency
RMU	Ring Main Unit
RTU	Remote Terminal Unit
Rules	National Electricity Rules
SA	South Australia
SAIT RAS	South Australia interconnector trip remedial action scheme
SIPS	System Integrity Protection Scheme
SPS	Special protection scheme
SRMTMP	Safety, Reliability, Maintenance and Technical Management Plan
STATCOM	Static Compensator
SVC	Static Var Compensator
TAPR	Transmission Annual Planning Report
TNSP	Transmission Network Service Provider
TUOS	Transmission Use of System Services
TWh	Terawatt-hour, a unit of energy, equivalent to a trillion watt-hour
REZ	Renewable Energy Zone, as defined in AEMO's ISP
RIT-T	Regulated Investment Test for Transmission
TNSP	Transmission Network Service Provider
UFLS	Under Frequency Load Shedding
V2G	Vehicle to grid charger
VCR	Value of Customer Reliability
VCS	Voltage control scheme
VPP	Virtual Power Plant
WAMS	Wide Area Monitoring Scheme
WAPS	Wide Area Protection Scheme

Glossary

Term	Description
10% POE	10% probability of exceedance. This is used to indicate a value that is expected to be exceeded once in every 10 years.
90% POE	90% probability of exceedance. This is used to indicate a value that is expected to be exceeded nine times in every 10 years.
Contraint	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.
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.