Transmission Annual Planning Report

October 2023

ElectraNet

Contents

About ElectraNet 6

Purpose of the Transmission Annual Planning report 7

Executive Summary 8

1 South Australia's energy transformation 12
1.1 South Australia's clean energy transition: exceeding expectations 13
1.2 Network Vision, future directions, and key priorities 22
1.3 Network Transition Strategy 26
1.4. How we are preparing for the future 28

2 National Transmission Planning 34
2.1 Integrated System Plan 35
2.2 2022 System Security Reports 48
2.3 Power System Frequency Risk Review 49
2.4 General Power System Risk Review 50

3 Electricity Demand 52
3.1 South Australian electricity demand 53
3.2 Demand forecasting methodology 54
3.3 Key drivers of demand 55
3.4. Demand forecasts 60
3.5 Performance of 2022 demand forecasts 63

4 System Capability and Performance 66
4.1 The South Australian electricity transmission system 67
4.2 Transmission system constraints in 2022 69
4.3 Emerging and future network constraints and performance limitations 72
4.4 Potential projects to enable growth 74
4.5 Frequency control schemes 78

5 Connection Opportunities and Demand Management 82
5.1 New connections and withdrawals 83
5.2 Connection opportunities for generators 85
5.5 Proposed and committed new connection points 92
5.6 Projects for which network support solutions are being sought or considered 93

6 Completed, Committed, and Pending Projects 94
6.1 Recently completed projects 95
6.2 Committed projects 97
6.3 Pending projects 100

7 Transmission System Development Plan 102
7.1 Summary of planning outcomes 105
7.2 Committed urgent and unforeseen investments 109
7.3 Interconnector and Smart Grid planning 109
7.4 System security, power quality and fault levels 112
7.5 Capacity and Renewable Energy Zone development 115
7.6 Market benefit opportunities 120
7.7 Network asset retirements and replacements 123
7.8 Network asset ratings 125
7.9 Grouped network asset retirements, deratings and replacements 125
7.10 Security and compliance projects 132

Appendices

Appendix A: Summary of changes since the 2022 Transmission Annual Planning Report **135**
Appendix B: Joint Planning **142**
B1 National transmission planning working groups and regular engagement 142
B1.1 Executive Joint Planning Committee 142
B1.2 Joint Planning Committee 142
B1.3 Regulatory Working Group 142
B1.4 Market Modelling Working Group 142
B1.5 Forecasting Reference Group 142
B1.6 Joint Planning with SA Power Networks 142
B1.7 Other joint planning engagements 143
B1.8 Power System Modelling Reference Group 143
B2 Joint Planning Projects 143
Appendix C: Asset Management Approach **144**
C1 ElectraNet's asset management strategy 144
C2 Obligations relating to capital expenditure 145
C2.1 Transmission licence and ETC obligations 145
C2.2 Rules requirements 147
C2.3 Safety, Reliability, Maintenance and Technical Management Plan 147
C3 Capital expenditure categories 148
C4 Expenditure forecasting methodology 149
C4.1 Customer and stakeholder requirements 149
C4.2 Planning process 149
C4.3 Assessment of network limitations 149
C4.4 Options analysis 149
C4.5 Scope and estimate 149
C5 Key inputs and assumptions 150
C5.1 Demand forecasts 150
C5.2 Asset health and condition assessments 150
C5.3 Planning and design standards 150
C5.4 Network modelling 150
C5.5 Economic assessments 150
C5.6 Non-network alternatives 150
C5.7 Risk assessments 151
C5.8 Project cost estimation 151
C5.9 Project timing and delivery 151
C6 Further information on ElectraNet's asset management strategy and methodology 151
Appendix D: Compliance Checklist **152**
Appendix E: Contingent Projects **155**
Appendix F: Assumptions considered in ElectraNet's planning process – potential future generator retirements and new generator and battery connections **156**
Abbreviations **157**
Glossary **159**


HIGH VOLTAGE
DO NOT CLIMB
ElectraNet 1800 243 853

About ElectraNet

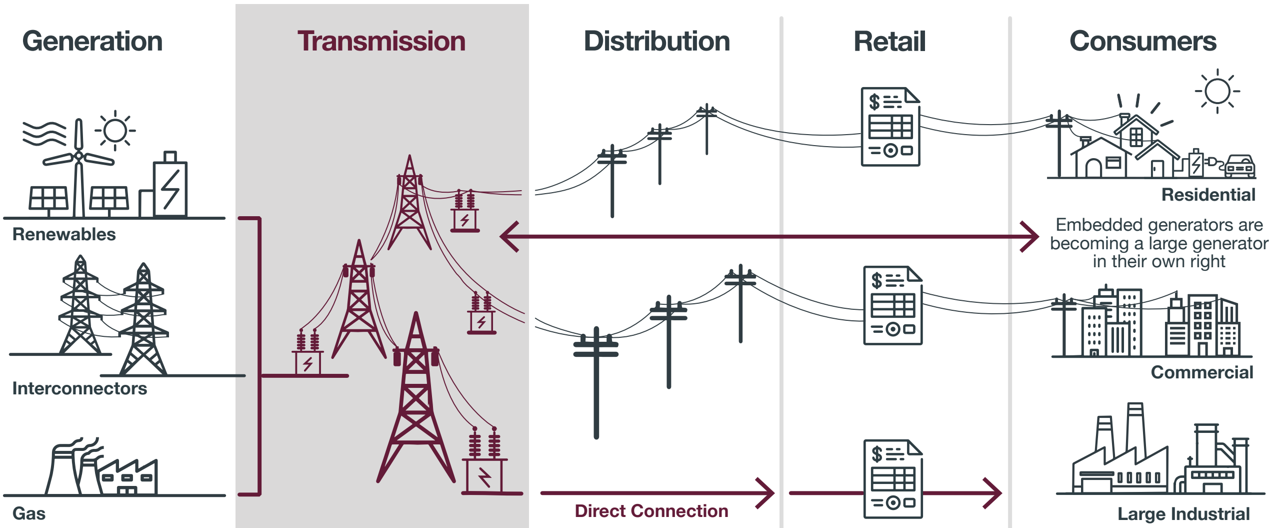
ElectraNet delivers reliable and sustainable electricity transmission services to power homes, businesses, and the economy.

As South Australia's principal electricity Transmission Network Service Provider (TNSP), we are a critical part of the electricity supply chain and in enabling the transition to a clean energy future.

We own and manage South Australia's transmission network which transports energy from local and distant generation sources to where it is needed to serve electricity customers. It also provides system services such as system strength and inertia to support the growth in renewable energy. Increasingly the network is supporting the two-way flow of power from distributed sources such as rooftop solar PV to local and distant customers.

We also provide services to customers and generators wanting to connect to the electricity transmission network.

The role of ElectraNet in the electricity supply chain



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

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

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

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

Consumers: The traditional flow of electricity supply is changing. 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 to ensure it is adequate to meet the ongoing demand for electricity transmission services, forecast under a variety of operating scenarios.

ElectraNet undertakes joint planning with SA Power Networks, which is responsible for the low voltage distribution of electricity throughout South Australia, to complete the review. We also consider the findings of the Australian Energy Market Operator's (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 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 (1 November 2023 to 31 October 2033) and identifies potential network capability limitations and possible solution options.

The report provides information on:

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

This report forms part of an ongoing stakeholder engagement process to ensure the efficient and economical development of the transmission network to meet forecast electricity demand and support the clean energy transition over the planning period. It follows the release of our TAPR Update in May 2023 in which we consulted with stakeholders on the rapidly growing demand outlook and on renewable supply options and network solutions to meet this demand.

Decisions to proceed with planned investments in the South Australian transmission network are subject to further detailed investigation and a public economic assessment process that will be undertaken closer to the time the investments are needed.

We are committed to ongoing improvement of the Transmission Annual Planning Report, and its value to 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 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 has achieved world-leading levels of variable renewable wind and solar energy resources which provide more than 71% of South Australia's electricity generation annually. South Australia has frequently experienced periods of 100% or more instantaneous renewable energy since October 2021, and is forecast to achieve 100% renewable energy on an annual basis by 2026–27.

South Australia has demonstrated that operating at 100% instantaneous variable renewable energy is achievable. We will continue to balance affordability with reliability as we transition to a 100% renewable grid.

What's Changed

↑ 2,000+ MW
Potential new demand seeking connection to the transmission network

↑ 480+ MW
Total new renewable generation capacity connected or committed to connect to the network in the last 12 months

↑ 300 MW
Total new storage capacity connected or committed to connect to the network in the last 12 months

↓ -37 MW
Minimum operational demand level (5-minute) observed on Sunday 1 October 2023 and projected to fall further

282 DAYS
On which renewable wind and solar energy supplied all South Australia's electricity demand for at least part of the day during the 12 months from 1 October 2022 to 30 September 2023

24%
Percentage of time during the 12 months from 1 October 2022 to 30 September 2023 for which renewable wind and solar energy supplied 100% or more of South Australia's electricity demand

71%
Net renewable generation output in 2022–23, projected to reach 100% by 2026–27

↑ 2,000+ GWh
Addition rooftop PV generation forecast by 2030

South Australia is experiencing a rapid and material uplift in its electricity demand outlook driven by electrification, new and expanded mining operations, industrial loads, desalination facilities and other energy-intensive operations such as data centres.

South Australia's economic growth and prosperity rely upon the South Australian transmission network continuing to operate safely and securely to deliver reliable and sustainable electricity transmission services to meet increased demand for electricity through the transition to more frequent and longer periods of 100% variable renewable energy generation.

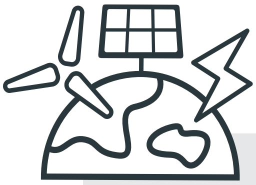
ElectraNet's ***Network Transition Strategy*** is designed to achieve this outcome and includes the following three pillars:

- **Energy reliability** – plan and deliver timely and efficient large-scale transmission infrastructure to connect new renewable generation and storage with customers to ensure reliable supply for existing loads and the increased electricity demand resulting from electrification and new industrial loads
- **Power system security and resilience** – plan and deliver new investments and contracted system services to maintain power system security and resilience during the energy transition
- **Operability** – build capabilities and capacity, including advanced tools, for network planning and operations to manage the increasing complexity and risk of operating a network with more frequent and longer periods of 100% variable renewable energy generation.

A Network in Transition

	What we have done	What we are doing
Energy reliability A capable transmission network	• Completed Eyre Peninsula Link, delivering improved reliability and unlocking future growth on the Eyre Peninsula • Delivering Project EnergyConnect, significantly increasing the power transfer capability between South Australia and the rest of the NEM • Delivered the Upper North project, a significant private network, that unlocks growth opportunities in the region • Published a changed demand and supply outlook and development options for the transmission network in our May 2023 TAPR Update.	• Investing in additional network planning resources to ensure we have capacity to adequately plan required transmission network developments • Developing strategic transmission network development plans • Strengthening asset management of existing network critical elements to ensure ongoing reliability • Building delivery capability considering current supply chain challenges.
Power system security A secure and resilient power system	• Installed four large synchronous condensers to meet minimum inertia and system strength requirements • Contracted additional inertia support services for when South Australia is islanded from the rest of the NEM • Upgraded the System Integrity Protection Scheme (SIPS) to the Wide Area Protection Scheme (WAPS) • Implemented an automated Voltage Control Scheme (VCS) at Davenport • Undertook detailed technical studies with AEMO to confirm the requirements for minimum synchronous generation in SA.	• Taking action to ensure appropriate voltage control on the network, including progressing a Transmission Network Voltage RIT-T • Planning and developing sufficient forward looking system strength and inertia according to new NEM system strength framework, including commencing a System Strength Requirements in SA RIT-T in November 2023 • Ensuring system protection and control systems are effective for changing system conditions • Developing/refining transmission distribution interface and customer connection arrangements.
Operability Manage increasing system complexity and risk	• Established a new Transmission Control Centre and rebuilt the existing one • Replaced old Energy Management System (EMS) with a new EMS • Implementing a Wide Area Monitoring System (WAMS) to establish enhanced monitoring of power system oscillations from the control room • Conducted reviews of ElectraNet's network planning and operations people and systems capability required to meet current and future needs.	• Developing sufficient network planning and operations capabilities to manage power system changes and support: – Realtime operations – Near real-time planning – Outage planning – Longer-term planning. • Developing a prioritised roadmap of operational systems enhancements, with a focus on high priority capability that can be delivered quickly • Developing strategic implementation capability to deliver required systems capability enhancements.

Growth Opportunities for South Australia



Unlocking Renewables to Meet Growing Demand

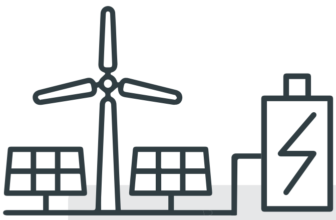
As highlighted in our May 2023 TAPR Update, there is unprecedented interest in load connections in South Australia from industries seeking access to low emission energy. Release of the Update supported significant engagement with stakeholders, including customers, AEMO and governments, to guide ElectraNet's planning process and network augmentation priorities.

Engagement through the TAPR Update reaffirmed our view that there is a need to accelerate network augmentation in the mid-north and north of South Australia to efficiently accommodate new loads including greater electrification, hydrogen, development of green industries and mining investments.

Based on typical capacity factors of renewable generation projects, we expect that the ratio of new renewable energy capacity that will be needed to meet the new demand is about three to one, backed by energy storage.

Development of the Mid North Renewable Energy Zone, including the Mid North Southern Expansion and Mid North Northern Expansion, will create capacity in the network to enable new generation connections to meet the expected growth in demand. Given the increasing demand outlook, we believe these projects should be declared actionable in the 2024 Integrated System Plan to ensure timely delivery in the next ten years.

In an environment of a rapidly increasing demand outlook, we have worked to develop a forecast of demand that reflects likely South Australian industrial load growth. This includes a balanced probabilistic approach that acknowledges that not all projects will occur yet reflecting the likelihood that some will. A realistic assessment of expected demand is vital for planning purposes as AEMO develops the 2024 Integrated System Plan to determine the optimal development pathway for these major projects, balancing the risks of over (early) and under (late) investment in transmission to deliver secure and affordable transmission services for current and future customers. Stakeholder feedback continues to influence this process and is encouraged.



Gigawatt-scale projects: Opportunities and Constraints

South Australia's high penetration of renewable energy, large land mass and abundance of wind and solar resources put it at the centre of the global energy market for interest in large hydrogen export projects. This is an extraordinary opportunity for South Australia's economy.

The future requirements of the transmission network to support this opportunity remains unclear as we continue discussions with multiple gigawatt-scale loads planning to connect to the transmission network. The scale of some of these hydrogen developments, as well as large industrial loads, aligns with AEMO's *Green Energy Exports* scenario.

Investment in very high-capacity transmission network assets will be critical to link gigawatt-scale generation projects to the new gigawatt-scale loads. Planned and proactive strengthening of the transmission system will minimise constraints, enabling greater growth at lower overall cost.

Project EnergyConnect Construction, 50 km NE of Renmark, South Australia

Roberstown Synchronous Condensers

1 South Australia’s energy transformation

1.1 South Australia's clean energy transition: exceeding expectations

ElectraNet's vision is to energise South Australia's clean energy future.

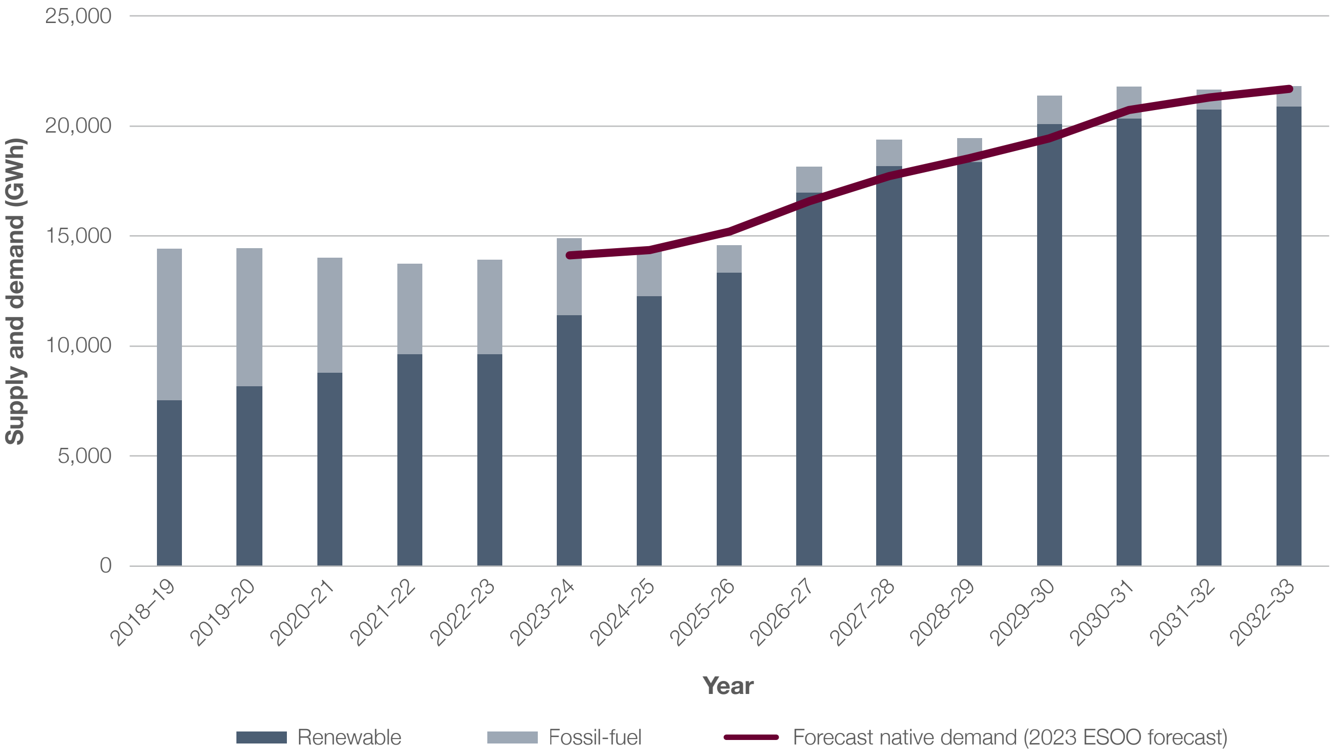
South Australia already has world leading levels of variable renewable energy wind and solar resources and has regularly experienced 100% or more instantaneous variable renewable energy generation since October 2021.

The SA Government has targeted net 100% renewable electricity generation by 2030 and is working towards building a strong green energy base which will support the transformation of the state's economy.[1]

The Australian Federal Government has also committed to a rapid clean energy transition, growing the annual share of renewable energy supply nationally to 82% by 2030 and achieving Net Zero emissions by 2050.

Based on the latest data from AEMO we expect to reach 100% net renewable electricity generation by 2026–27, two years earlier than forecast last year (Figure 1). Energy from renewable sources supplied about 71% of South Australian electricity generation in 2022–23 and is forecast to exceed and remain close to 100% of South Australian demand from 2026–27.

Figure 1: Historical and forecast South Australian generation from renewable and fossil-fuel sources



Sources: data for demand past and forecast taken from AEMO's 2022 South Australian Electricity Report and AEMO's 2023 ESOO forecasting portal forecasting.aemo.com.au; data for generation past and forecast taken from AEMO's 2023 South Australian Generation Forecast and AEMO's 2022 South Australian Electricity Report (Demand forecast includes load supplied by rooftop solar PV).

A power system with regular periods of 100% or more instantaneous variable renewable energy generation has greater complexity and risk from a planning and operational perspective than one based on conventional coal and gas generation. The continued connection of intermittent 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.

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.

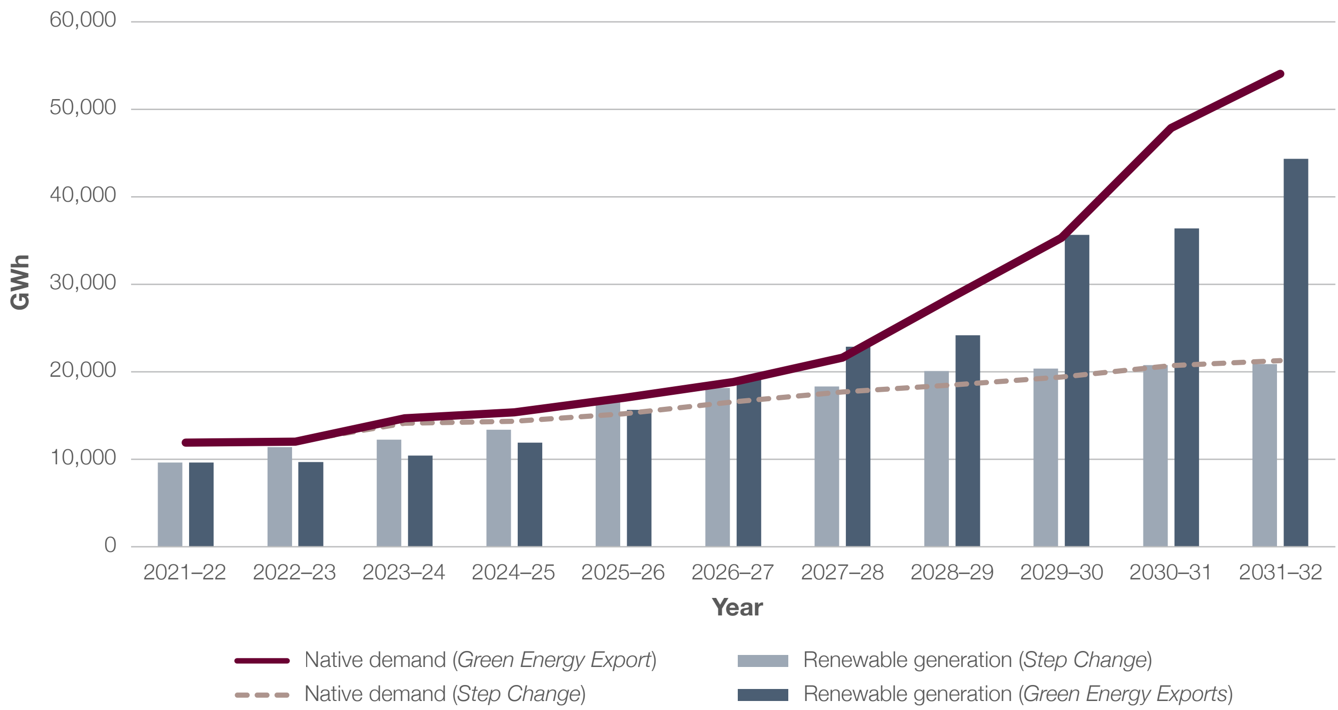
1 Department of Energy & Mining, South Australia | South Australia's Green Paper on the energy transition

In 2021 we installed four synchronous condensers to supply essential system services that are being lost as conventional generators are dispatched less or retire. We estimate that more synchronous condensers, grid forming STATCOMs or other services will be required to provide additional system strength in the future to meet the recent rule changes and AEMO's transmission connected Inverter Based Resource forecasts.

We are also implementing special protection schemes to protect the power system from disturbances in an increasingly complex operating environment.

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 2).[2] 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 least overall cost.

Figure 2: South Australian electricity consumption and renewable generation output forecasts



Sources: data for demand forecasts taken from AEMO's 2023 ESOO and for generation forecasts taken from AEMO's 2023 South Australian Generation Forecast and AEMO's 2022 South Australian Electricity Report (Demand forecast includes load supplied by rooftop solar PV – *Green Energy Export* is a new scenario described in AEMO's 2023 IASR and ESOO.

Our annual planning process focuses on balancing system security, reliability of supply and cost. 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.

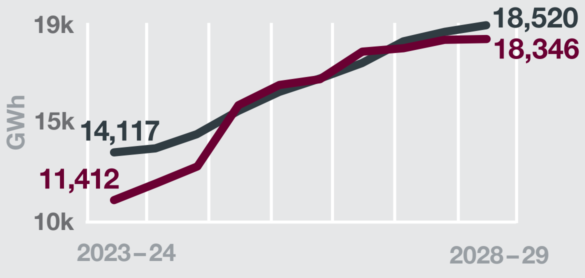
We are developing plans to enable us to respond in a timely way to strengthen the transmission system when needed.

2 AEMO | 2023 Inputs, Assumptions and Scenarios Report


Roberstown Substation

South Australia's transforming power system

Journey towards 100% renewable electricity generation



2016

Coal fired generation ceased
May 2016

Statewide blackout
September 2016

2017

World's largest battery Hornsdale Power Reserve connected
November 2017

2018

First AEMO Integrated System Plan
June 2018

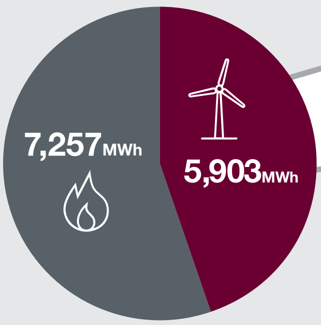
Connection of first grid scale solar plant at Bungala
November 2018

ElectraNet Dalrymple battery is first grid forming battery in Australia
December 2018

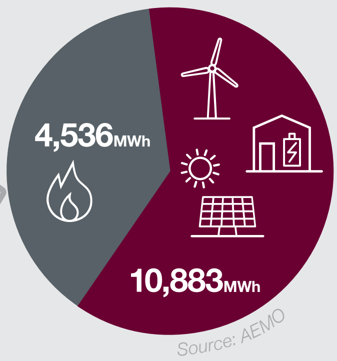
2019

Renewables are replacing gas

Over the past 7 years renewables output in SA has increased

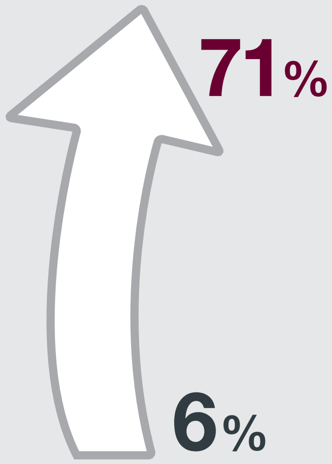


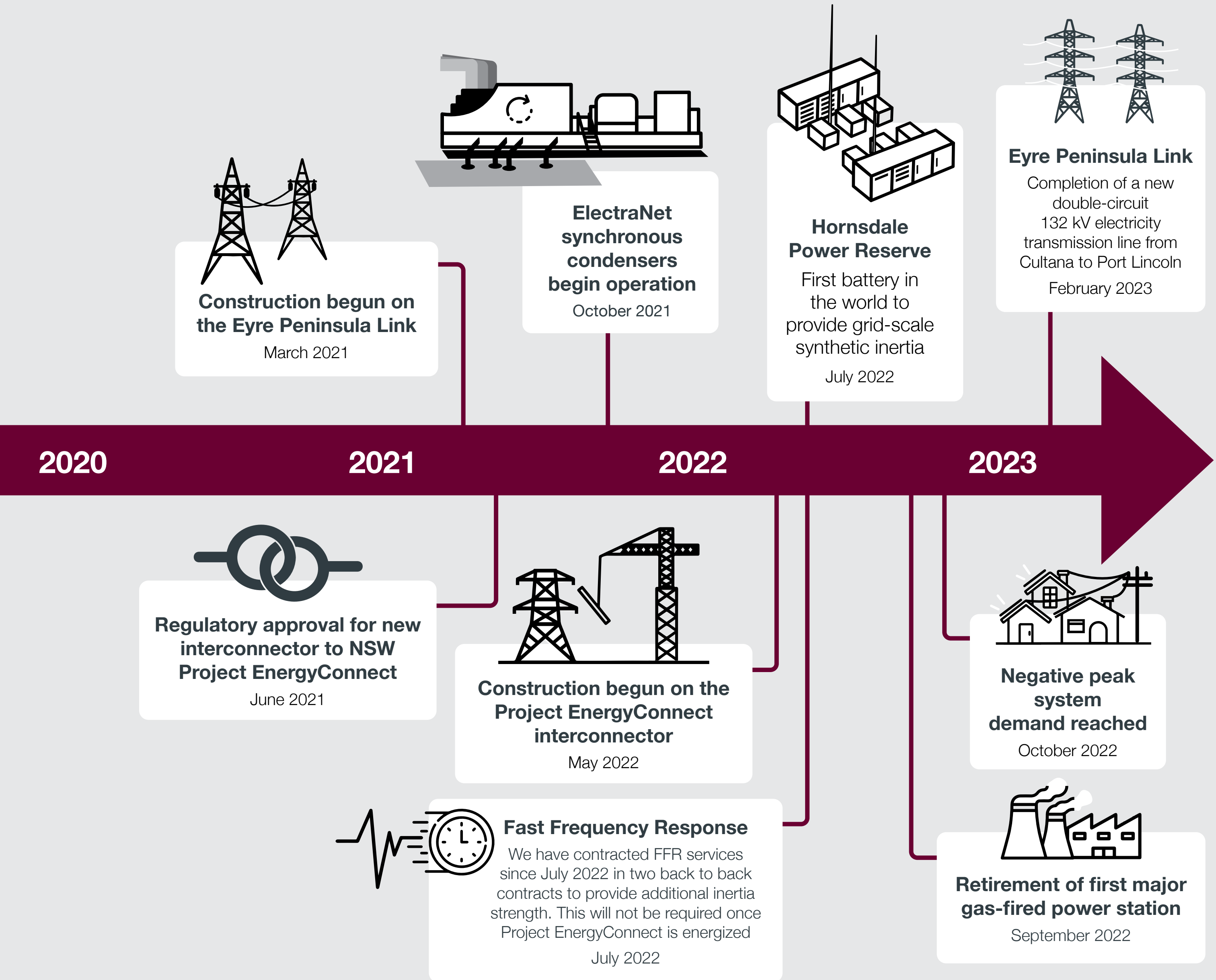
by 84%



Source: AEMO

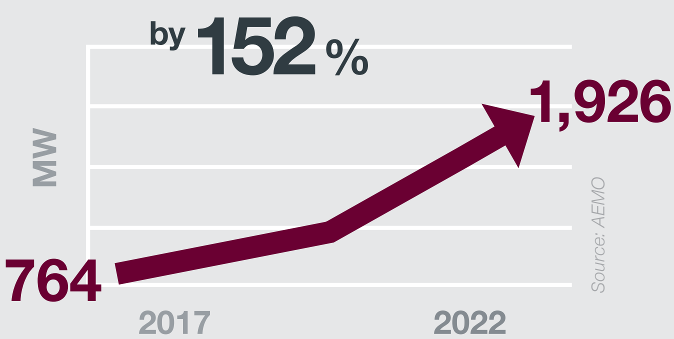
In just over 17 years the State's renewable energy output has increased more than 10 times



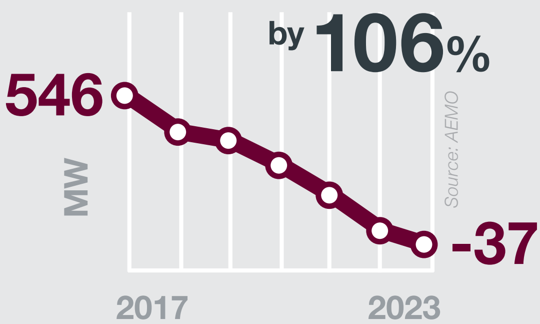


A grid in transition

Rooftop PV installation has increased over the past 6 years



Minimum grid demand has decreased over the past 6 years



The Network of the future

Special protection schemes

Implement a Wide Area Monitoring Scheme and a Special Protection Scheme to manage the increasingly complex operating environment

Project EnergyConnect Stage 1

Completion from Robertstown in SA to Buronga in NSW, with release of initial transfer capacity of up to 150 MW by mid 2024

Project EnergyConnect Stage 2

The section from Buronga to Wagga Wagga in NSW will release transfer capacity up to 800 MW by mid-2026 subject to market demand

Hydrogen Jobs Plan

Construction of a world-leading 200 MW hydrogen power station, 250 MW electrolyser and storage facility

2024 **2025** **2026**

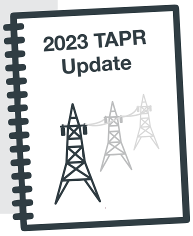
As a priority, we are currently investigating possible options to unlock the Mid North SA REZ, the South East SA REZ and the Eyre Peninsula SA REZ. We have indicated to AEMO that with the changing outlook these projects have to be moved forward.

A renewables future

AEMO's goal to have the NEM power system capable of managing periods of 100% instantaneous penetration of renewable energy

TAPR Update

We published the TAPR Update in May 2023 to inform stakeholders on the rapid changing outlook of load and supply connections to the South Australian's transmission network.



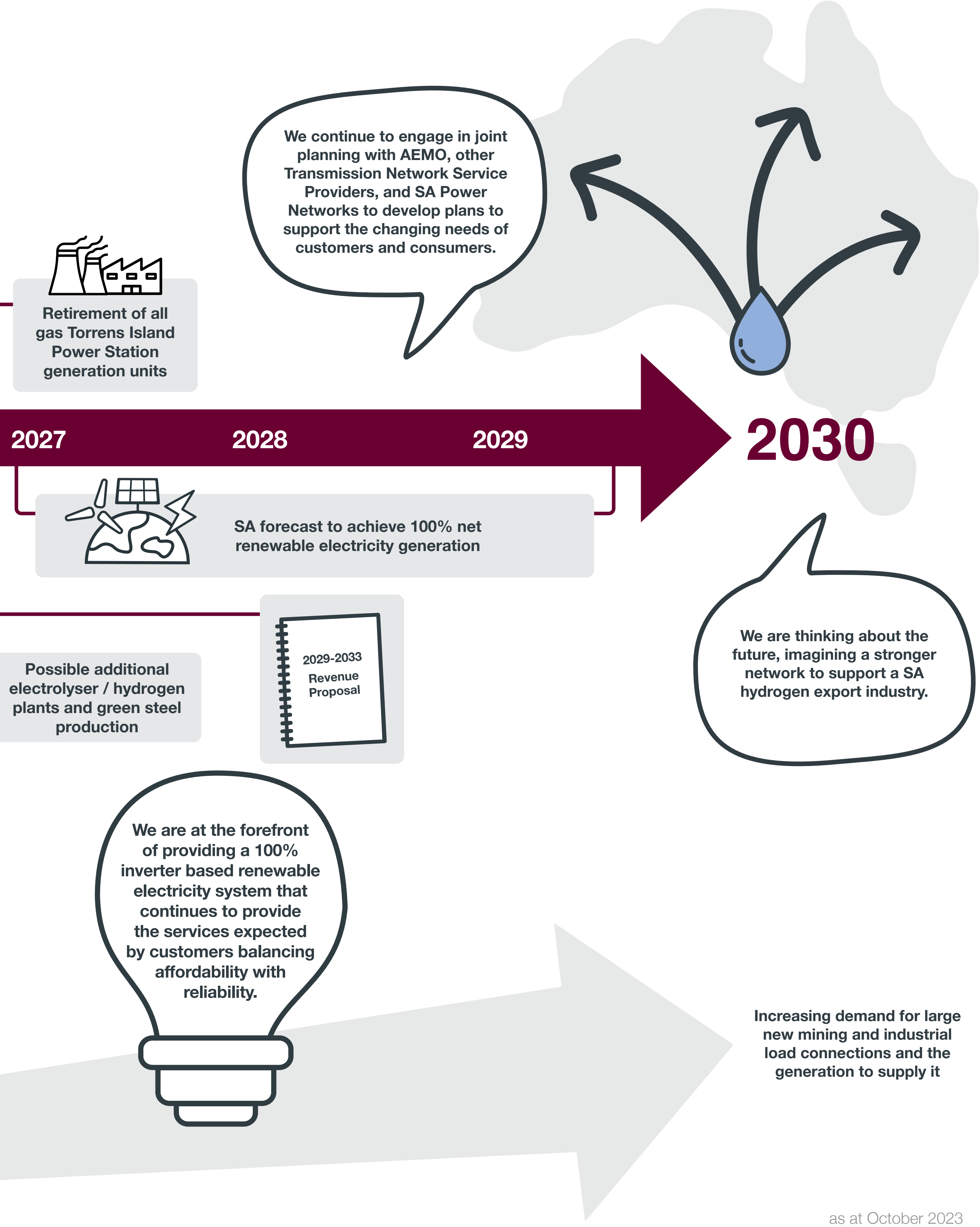
System Strength

We are investigating options to provide increased system strength services in South Australia to meet the needs of forecast new inverter-based resources

Investment for the 2024–2028 regulatory period

Addresses the challenges presented by the ongoing energy transformation, and keep the existing ageing network going for longer. We are planning targeted capital investment to address the challenges arising from the increasing penetration of distributed energy resources:

- Additional reactive support for times of low or negative net system demand
- Expand our Wide Area Monitoring Scheme



as at October 2023

1.1.1 Customer interest

In the last year we have received many enquiries from potential large industrial loads, seeking to take advantage of South Australia's low-cost and low-emission electricity from renewable sources, which may lead to higher demand than forecast. Interest in new load connections currently exceeds 2,000 MW.

Key developments driving material increases in maximum demand include:

- The development of hydrogen facilities near Whyalla and other large hydrogen hubs in accordance with the South Australia Government's hydrogen strategy[3]
- The development of large iron ore mining operations and the production of "green steel" in keeping with South Australian Government's Magnetite Strategy[4]
- The potential connection of large new customer loads such as new or expanded mining operations, new industrial loads, other energy-intensive opportunities such as data centres
- The widespread adoption of electric vehicles, and potential future policy settings that would drive the electrification of sectors that currently utilise other fuel sources.

1.1.2 New generation interest

In addition to load enquiries, we are also receiving enquiries from proponents of increasingly large renewable energy generation developments. Eight of these proposed large-scale generation developments 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 recognises this trend in its recent Green Paper on South Australia's energy transition.[5]

1.1.3 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, 85% of transmission connection points with the SA Power Networks distribution network has 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.

The effect of high levels of distributed renewables is seeing transmission flows varying from high levels of imports to high levels of exports and then back again over the course of the day. As a result, patterns of congestion are changing as experienced over a week in September 2023 which had demand peaks above 2,000 MW and minimums around 130 MW, with very steep increase and decrease ramps (Figure 3).

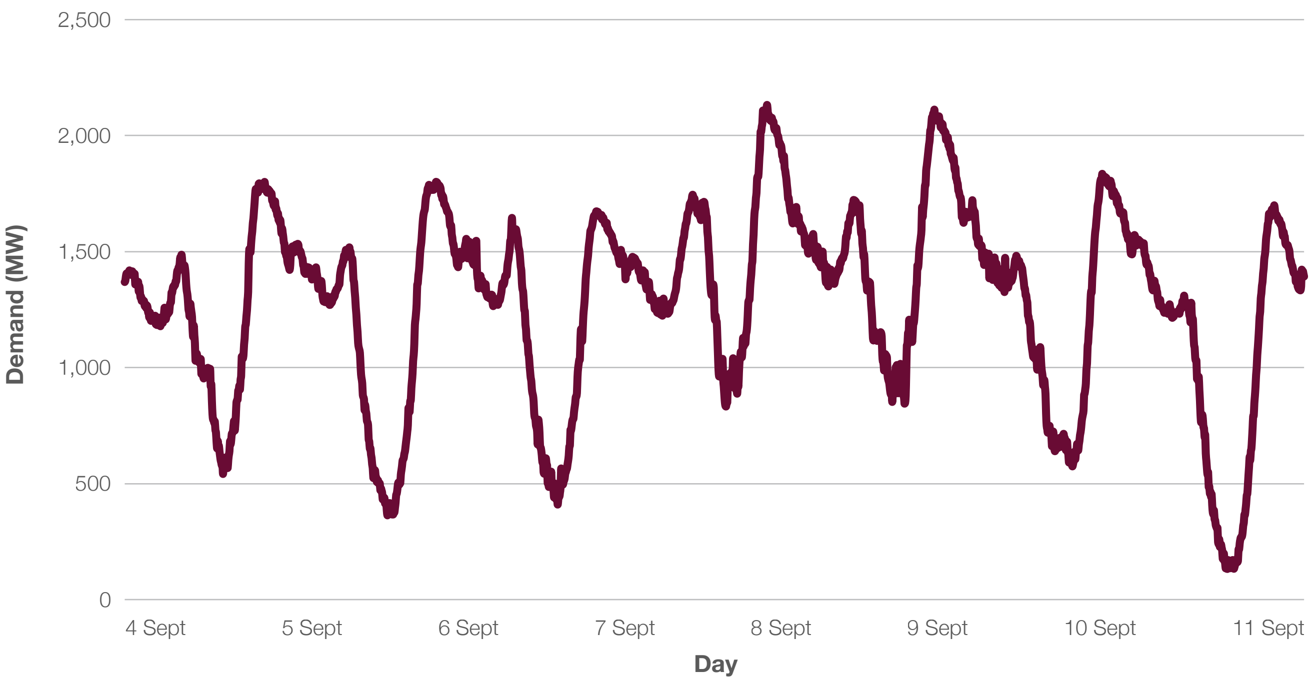
Given the variability of solar and wind generation, dispatching generation to meet demand is an increasing challenge and new methods and tools are needed to operate the network.

3 Office of Hydrogen Power South Australia | Hydrogen South Australia

4 Department of Energy & Mining, South Australia | Magnetite Strategy

5 Department of Energy & Mining, South Australia | South Australia's Green Paper on the energy transition

Figure 3: Example demand variability (September 2023)



At the state-wide level, South Australian operational demand[6] was below 0 MW for two 5-minute dispatch intervals in September 2023 and 33 intervals in October 2023, including to a minimum level of -37 MW, 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.

1.1.4 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 455 MW today to above 1,000 MW in the next 3 years.

6 Operational demand is demand that 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.

1.2 Network Vision, future directions, and key priorities

Our Network Vision is that **South Australia's electricity transmission network will support customer choice and deliver affordable and reliable power supplies for a sustainable future.**

To deliver these outcomes, we monitor emerging industry trends and technological developments and undertake scenario-based modelling, network planning and assessment of emerging system security issues to inform our ongoing decision making.

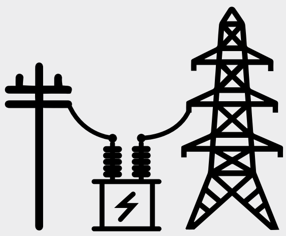
We also engage with customer representatives and other stakeholders to ensure we understand their concerns, needs, priorities and points of view to enhance our ability to plan and develop the transmission network so it delivers the greatest possible value, with very steep increase and decrease ramps.

Through this engagement customers have told us they see an important ongoing role for the transmission network in driving affordable and reliable electricity supply, while harnessing the benefits of new services and technology. The Network Vision provides directions and key priorities to guide the practical ways we plan for the future of the network, based around four themes.[7]

South Australia's electricity transmission network will support customer choice and deliver affordable and reliable power supplies for a sustainable future.

THEME 1

The network will continue to provide an important role into the future



Maximum demand

↑681 MW

is forecast to increase to 3764 MW by 2030

Figures updated for AEMO's 2023 IASR and ESOO

We will continue to maintain the existing network and expand it to serve new loads and facilitate the connection of new renewable resources.

To maintain our network, we will use a risk-based framework driven by the need to manage safety, security and reliability across our ageing network.

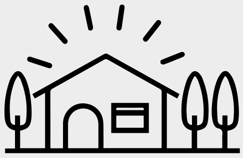
New load and generation investments are occurring much faster than forecast needing augmentation sooner.

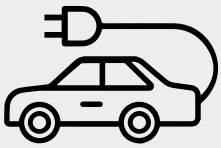
We are pursuing targeted investments in technology that deliver value for customers to maintain and improve key capabilities. Support SA Power Network to progress the role of distributed energy resources in meeting future supply needs.

[7] ElectraNet | 2021 Network Vision

THEME 2

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





Rooftop PV

3,386 MW

rooftop PV to exceed 3,386 MW by 2030

Electric Vehicles

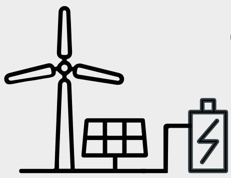
+2.9% in demand

Electric vehicles to consume 567 GWh of energy by 2030 adding +2.9% in demand

We are working in partnership with SA Power Networks to manage the growing challenges of reverse power flows and falling minimum demand levels.

This includes targeted investments in voltage control and power quality investigation, and implementing a wide area monitoring scheme to provide network performance information and maximise our ability to accommodate distributed generation on the network.

THEME 3



The generation mix is changing, creating ongoing challenges for the operation of the grid

Renewables

100% by 2030

Renewables displacing fossil fuels with SA Government targeting net 100% renewables by 2030

Grid Scale Storage

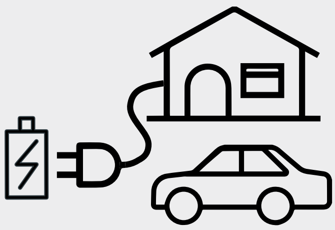
1,350 MW

Grid scale storage to reach 1,350 MW by 2030

We will continue to work with AEMO to maintain a secure power system, including implementing special protection and control schemes and delivering system services such as system strength and inertia to maintain secure and reliable operation of an increasingly complex power system.

THEME 4

New technologies are creating opportunities to change the way network services can be delivered



Virtual Power Plants

426 MW

Virtual power plants to reach 426 MW by 2030

Inertia Support Agreement

360 MW

Fast Frequency Response provided by BESS since mid 2023

THEME 1

The network will continue to provide an important role into the future.

The transmission network will play an increasingly important role in the ongoing transformation of the electricity supply system. ElectraNet will need to maintain the network's capability to transmit electricity between regions, connect large loads and large renewable plants and provide essential services.

AEMO's 2022 ISP highlights a greater need for transmission as electricity supply becomes more geographically dispersed, as generators look to locate where the best renewable resource is. AEMO has incorporated this last aspect with the demarcation of Renewable Energy Zones (REZs) and the need to expand the transmission network to exploit those zones.

THEME 2

The ongoing uptake of distributed energy resources by customers is changing the role of the network.

The uptake of distributed energy resources in South Australia continues at world leading levels. South Australia had around 1,971 MW of distributed solar PV connections as of May 2023.[8] At the state-wide level, SA Power Network observed "negative demand" during several days last year.

This means that for those occasions all demand in the state was met by distribution connected generators (predominantly distributed solar PV). This is expected to occur more frequently in the future, increasing the need for the transmission system to support residential customers to trade power across the National Electricity Market (NEM). Electrification of transportation is introducing large mobile loads/storage to the grid which will influence the demand profile.

THEME 3

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

As the grid continues to evolve with less conventional generation, more renewables and declining midday demand as well as other changes, operational challenges will increase the need for system security services and new control schemes to manage the secure operation of the power system.

We invested in synchronous condensers to provide system strength and inertia services and the deployment of Wide Area Protection Schemes using phasor measurements units. Additionally, we are facilitating the connection of grid scale batteries to provide network support.

THEME 4

New technologies are creating oportunities to change the way network services can be delivered

Rapidly changing technologies are creating both challenges and opportunities for the delivery of transmission services and the evolution of the electricity supply system. Examples of this are the adoption of best-practice data analytics to improve decision making, considering the application of innovative techniques and implementation of complex control/protection systems.

The adoption of new technologies potentially opens new options to provide network services at lower cost and unlock more capacity to connect new generation and support the transition to a low carbon future.

8 SA Power Networks | Distribution Annual Planning Report 2022/23 to 2026/27

1.3 Network Transition Strategy

ElectraNet's Network Transition Strategy is designed to enable the South Australian transmission system to continue 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** – plan and deliver timely and efficient large-scale transmission infrastructure to connect new renewable generation and storage with customers to ensure reliable supply for existing loads and the increased electricity demand resulting from electrification and new industrial loads
- **Power system security and resilience** – plan and deliver new investments and contracted system services to maintain power system security and resilience during the energy transition
- **Operability** – build capabilities and capacity, including advanced tools, for network planning and operations to manage the increasing complexity and risk of operating a network with more frequent and longer periods of 100% variable renewable energy generation.

Energy Reliability (a capable transmission network)	
Strategy Plan and develop the shared transmission network to be ready for a wide range of plausible futures, including electricity demand growth and efficient connections to variable renewable energy generation resources and anticipated private transmission networks. Actively engage in the national transmission planning process including with policy makers to ensure timely transmission investment in South Australia.	
What we have done • Completed Eyre Peninsula Link, delivering improved reliability and unlocking future growth on the Eyre Peninsula • Delivering Project EnergyConnect, significantly increasing the power transfer capability between South Australia and the rest of the NEM • Delivered the Upper North project, a significant private network, that unlocks growth opportunities in the region • Published a changed demand and supply outlook and development options for the transmission network in our May 2023 TAPR Update.	**What we are doing** • Investing in additional network planning resources to ensure we have capacity to adequately plan required transmission network developments • Developing strategic transmission network development plans • Strengthening asset management of existing network critical elements to ensure ongoing reliability • Building delivery capability considering current supply chain challenges.

Power system security and resilience	
Strategy Plan and deliver new investments and contracted system services. Invest in processes, tools, and systems to maintain power system security and resilience during the energy transition.	
What we have done • Installed four large synchronous condensers to meet minimum inertia and system strength requirements • Contracted additional inertia support services for when South Australia is islanded from the rest of the NEM • Upgraded the System Integrity Protection Scheme (SIPS) to the Wide Area Protection Scheme (WAPS) • Implemented an automated Voltage Control Scheme (VCS) at Davenport • Undertook detailed technical studies with AEMO to confirm the requirements for minimum synchronous generation in SA.	**What we are doing** • Taking action to ensure appropriate voltage control on the network, including progressing a Transmission Network Voltage Control RIT-T • Planning and developing sufficient forward looking system strength and inertia according to new NEM system strength framework, including commencing System Strength Requirements in SA RIT-T in November 2023 • Ensuring system protection and control systems are effective for changing system conditions • Developing/refining transmission distribution interface and customer connection arrangements.

Operability (manage increasing system complexity and risk)	
Strategy Manage risk in an increasingly complex operating environment by uplifting network planning and operations resource capability and capacity and implementing systems and advanced tools to assist real time operations.	
What we have done • Established a new Transmission Control Centre and rebuilt the existing one • Replaced old Energy Management System (EMS) with new EMS • Implementing a Wide Area Monitoring System (WAMS) to establish enhanced monitoring of power system oscillations from the control room • Conducted reviews of ElectraNet's network planning and operations people and systems capability required to meet current and future need.	**What we are doing** • Developing sufficient network planning and operations capabilities to manage power system changes and support: – Realtime operations – Near real-time planning – Outage planning – Longer-term planning. • Developing a prioritised roadmap of operational systems enhancements, with a focus on high priority capability that can be delivered quickly • Developing strategic implementation capability to deliver required systems capability enhancements.

AEMO's 2022 ISP highlights that to ensure the NEM power system can operate securely with high penetration of inverter-based resources, the system operator and network service providers like ElectraNet will need to uplift capabilities in operational systems, processes, real time monitoring and power system modelling. We are working closely with AEMO and other stakeholders to develop a roadmap for the uplift required to consistently operate the NEM securely with 100% renewables and are progressing the systems and capability uplift required to protect the power system from disturbances in an increasingly complex operating environment.

1.4. How we are preparing for the future

Driven by our strategic themes, directions, and priorities and guided by our Network Transition Strategy, we are pursuing important initiatives and investigations to support South Australia's ongoing energy transformation.

1.4.1 Interconnection

We are building Project EnergyConnect, to create a new interconnection between South Australia and New South Wales with an added connection to northwest Victoria. This new interconnector will add 800 MW transfer capacity between South Australia and New South Wales.

Project EnergyConnect forms a central feature of the roadmap for the transition of the power system developed by the Australian Energy Market Operator (AEMO) in its 2022 Integrated System Plan (ISP). This project is expected to deliver a range of direct benefits for consumers in South Australia, New South Wales and Victoria including lower power prices, improved energy security and increased economic activity. The new interconnector's route passes through Renewable Energy Zones in South Australia, New South Wales and Victoria, meaning that future renewable projects in these areas will be able to connect to the grid and supply new energy into the network.

We have also identified future projects in line with the 2022 ISP. These include investments that would increase transfer capacity to allow for greater imports and exports of renewables between South East, Tailem Bend and Adelaide (South East SA REZ Expansions) and between Mid North and Adelaide (Mid North SA REZ Expansion). Future projects might be required to increase capacity between Mid North and the Eyre Peninsula, if proposed large new load is connected, especially around Eyre Peninsula. Aside from benefiting intra-regional transfer capacities, these projects would optimise interstate transfer capabilities between the Heywood interconnector, Project EnergyConnect interconnector and Murraylink interconnector.

We continue to investigate potential opportunities to further improve interconnection transfer capability (Section 7.3).

1.4.2 Managing asset condition

South Australia's transmission system is older than many others. Our replacement and refurbishment plans are based on assessment of the condition, risk and performance of the relevant assets (Appendix C). We assess the condition of the various components of each transmission line and substation asset on an ongoing basis through routine inspections and patrols.

This information is used to assess how much longer the component can be expected to keep functioning before it fails. In doing this we consider other information such as failure rates observed elsewhere and environmental conditions surrounding the asset – for example, exposure to salt spray from proximity to a coastline.

We then translate this information into a targeted plan to replace and refurbish individual assets before they fail, thus preventing supply interruptions, safety hazards and other risks. These decisions are taken on a risk basis allowing us to focus on those assets at greatest risk.

Consequently, our major line refurbishment projects and substation asset replacement projects focus on key components with the highest network criticality (Sections 7.7 and 7.9).

1.4.3 Planning to efficiently accommodate supply-side changes

The generation mix in South Australia is undergoing major changes in the medium to long term, and we are an important component of this transition. We anticipate these changes and track the trends. We then create plans to appropriately upgrade the capability of the transmission network.

Based on projections in AEMO's 2023 South Australian Generation Forecasts Report, significant investment in battery storage and wind and large-scale solar generation is expected in the near and medium term, increasing supply steadily for many years. Distributed energy sources are also expected to continue increasing at a steady rate. The number of requests for possible new renewable generation has increased substantially. Proponents are aiming to benefit from good quality South Australian renewable resources and the possibility of supplying some of the large future hydrogen or mining loads or exporting via Project EnergyConnect.

Some significant South Australian dispatchable generation units, such as at Torrens Island A, have recently retired, and Torrens Island B will retire in 2026. Owners of some other generation units such as at New Osborne have indicated that generation withdrawal will occur in the early 2020s. Many of the existing dispatchable conventional generators currently have expected withdrawal dates around 2030.

New dispatchable capacity investment is occurring at Whyalla with the Hydrogen Jobs Plan and by Batteries across the state.

We continue to investigate options to unlock the network capacity and to provide services for facilitating the connection of new renewable generation and the retirement of dispatchable conventional generation. We have developed scopes for projects to increase transfer capacity through the Mid North, Eastern Hills and South East regions, improving the ability for generation in those regions to reach our main load centre in metropolitan Adelaide, or be exported via interconnection to other states. We are advancing plans to increase the capacity of our network in the Eyre Peninsula because there are large, proposed generation and load projects connecting around the peninsula in the near to medium future. As part of this work we are preparing a RIT-T to consult with stakeholders and the market.

We have performed preparatory activities for the South East SA Renewable Energy Zone (REZ) expansion and the Mid North SA REZ expansion, which were identified as future ISP projects in the 2022 ISP. Preparatory activities included delivery of a preliminary engineering design, easement assessment, cost estimates based on preliminary engineering design and route selection, preliminary assessment of environmental and planning approvals and stakeholder engagement.

Based on the number of active enquiries and applications, we expect that the amount of South Australian generation coming from renewable sources is likely to continue increasing throughout the 2020s and 2030s. Connection activity indicates new connections will exceed AEMO's 2022 ISP *Step Change* and 2023 South Australian Generation *Step Change* scenarios in terms of both expected date of commissioning and size.

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

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

1.4.4 Inertia and Fast Frequency Response

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

We have now installed high-inertia synchronous condensers at Davenport and Robertstown to address system strength and synchronous inertia requirements.

In 2020 and 2021 AEMO declared inertia shortfalls for South Australia. AEMO determined the secure operating level of inertia for South Australia proposing Fast Frequency Response (FFR) be made available to address these declared inertia shortfalls. We entered into agreements with third parties service providers for the provision of the required FFR, as this is the lowest cost option to provide these services.

A first set of agreements to provide a total of 200 MW of FFR ended on 30 June 2023. A second set, for 360 MW of FFR, commenced on 1st July 2023 and will end once the inter-network testing for Project EnergyConnect and the commissioning of a special protection scheme to manage the non-credible loss of one of the interconnectors have been completed.

There are two large-scale batteries in South Australia that have 'grid-forming' inverters, Hornsdale Power Reserve[9] and Torrens Island.[10] This type of inverter makes the batteries capable of producing "virtual inertia". This technology still is at a "trial" stage, but as inverter technology advances and battery prices fall, batteries will be able to act as a "virtual synchronous generator" and become a competitor to synchronous condenser.

1.4.5 System strength

We installed synchronous condensers at Davenport and Robertstown in 2021. This 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, as well as significantly alleviating voltage limits in the Mid North. The synchronous condensers have significantly reduced costs to customers, by avoiding the costs that were incurred when AEMO directed synchronous generators to operate to provide system strength services.

From December 2022, a new system strength framework[11] began under the National Electricity Rules, in which ElectraNet is responsible to deliver an efficient level of system strength in South Australia on a forward-looking basis from 2 December 2025 to meet AEMO's forecasts of Inverter Based Resources (IBR). Our studies indicate that further system strength services will be needed to ensure the provision of an efficient level of system strength at Robertstown and Para from 2025. Under the new framework costs will be shared with generators that connect.

Later in 2023 we plan to commence a RIT-T to determine the best option to deliver the efficient level of system strength services to the South Australian power system.

---

9 Hornsdale Power Reserve

10 Energy Storage News | AGL, Wartsila complete 250MW Torrens Island BESS project in South Australia

11 Australian Energy Market Commission | ERC0300 System strength final determination

1.4.6 Voltage control

The increasing customer adoption of customer energy resources (CER) is providing consumers with control over their energy costs with their own investments and an option for those seeking to reduce their carbon footprint.

As a result, historically low demand levels have been recorded in the middle of the day, typically on mild, sunny weekends or public holidays. AEMO forecasts the level of minimum demand in South Australia to continue to decrease over the forecast period (Section 3). This condition presents operational challenges to South Australia's transmission network.

In December 2022, AEMO published the Engineering Roadmap to 100% Renewables. This is a toolkit that defines the full range of operational, technical, and engineering requirements needed to prepare the NEM power system for six identified future operational conditions, including preparation for 100% instantaneous penetration of renewables. It is expected the framework will facilitate an orderly transition to a secure and efficient future NEM power system.

Because of South Australia's leading penetration of distributed rooftop solar PV relative to demand and with the increasing generation coming from large renewable sources, it is very likely that we will be the first state to address these challenges head-on. South Australia has already experienced decreased dispatch of large synchronous generators and we are planning for further reductions.

Low demand conditions at the transmission level can correlate closely with a decreased level of dispatch of large synchronous generators, which have historically been a source of voltage control for the system. When these conditions coincide with periods of low wind, many wind farms are also limited in their ability to contribute reactive power to enable satisfactory voltage control of the system.

We have continued to work with SA Power Networks to jointly analyse the challenges presented by a declining minimum demand, including the impact on system voltage levels. Studies and observations have shown that high voltage levels across the system can occur at such times of extremely low demand or during periods of no wind generation.

In our 2024–2028 Revenue Proposal we identified a need to augment the reactive reserve capability of South Australia's transmission network as minimum demand levels continue to fall, to preserve the dynamic control capability on equipment such as static var compensators and synchronous condensers (Section 7.4). This will maintain the system's capability to ride through unforeseen severe disturbances and prevent voltage levels from exceeding equipment limits during system normal conditions or after an unplanned outage of any single line, transformer, or other network element. We have also identified a need to automate our reactive plant and the voltage control mechanisms of our transformers to manage fluctuations in the voltage profile as we experience more two directional power flows on our substations daily. We are currently undertaking the Transmission Network Voltage Control RIT-T to identify the preferred solution to meet these reactive power and voltage control needs.

Some of the other challenges of high distributed rooftop solar PV include output variability (for example, due to cloud cover) and their impact of reducing the effectiveness of load-based emergency control schemes during the daytime.

1.4.7 Managing system security

AEMO's Power System Frequency Review Report (PSFRR), which studied mainly events related to frequency was replaced this year by the General Power System Risk Review (GPSRR).

The GPSRR is intended to look at a broader set of events and help AEMO, Network Service Providers and other market participants better understand the nature of new risks and monitor them over time, all of which is particularly important given the transition is underway.

The final report for the 2023 General Power System Risk Review Report (GPSRR)[12] was published in July 2023 and recommends that ElectraNet:

- continue to collaborate with AEMO and other jurisdictional planning bodies on development of special schemes and analysis of constraints around the interconnectors
- review with AEMO the South Australian over frequency generation shedding (OFGS) and under-frequency load shedding (UFLS) schemes and establish a wide area protection scheme (WAPS), all of which can be affected by high levels of distributed generation
- consider non-credible contingencies for planning and uplift operational tools and capability.

The report also details some of the work that AEMO has been doing in collaboration with ElectraNet to manage future NEM ramping events resulting from the increasing penetration of distributed solar PV generation and transmission-connected inverter-based resources. ElectraNet has been managing these events for some time due to its large penetration of distributed solar PV.

To keep pace with the challenges posed by the ongoing transformation of the power system we are planning investments to maintain performance requirements and extend the capabilities of the network, while harnessing the benefits of new and emerging technology. Committed and planned investments include:

- implement a Wide Area Protection Scheme with the use of phasor measurement units (PMUs) to real time monitor and process system parameters for event detection (Section 7.3)
- enhance high resolution time synchronised wide area system monitoring by rolling out a Wide Area Monitoring Scheme (WAMS, Section 7.3)
- as part of establishing Project EnergyConnect, implement a Special Protection Scheme to address the risk that a non-credible loss of either Project EnergyConnect or Heywood interconnector would not lead to the loss of the other interconnector – this protection scheme is to be called the South Australian Interconnector Trip Remedial Action Scheme (SAIT RAS).

The development of CER – as an extension of distributed rooftop solar PV – and the adoption of more advanced operating capabilities is enabling the development of Virtual Power Plants (VPPs). South Australia's Virtual Power Plant (SA VPP) is the first and the largest network of home solar and battery systems in Australia. The SA VPP has helped stabilise frequency in the grid during some events and demonstrated that this type of ancillary service can be provided by a distributed network. Over the next ten years, VPPs have the potential to be new providers of services for both ElectraNet and SA Power Networks.

12 AEMO | 2023 General Power System Risk Review Report

1.4.8 Increased demand outlook

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, and data centres. These loads would like to take advantage of South Australia's low-cost and low-emission electricity from renewable sources.

Key developments that could, if they occur, drive a significant increase in maximum demands include:

- The South Australian Government's Hydrogen Jobs Plan,[13] 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, 200 MW power generation and hydrogen storage. The plan is expected to be operational by early 2026
- The development of hydrogen export hubs, such as the Port Bonython hydrogen export hub which has recently been allocated state and federal government funding[14] and which has received significant interest from overseas companies, which are considering developing alike hydrogen production facilities
- The South Australian Government's strategies and plans to increase the exploration and production 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[15]
- The potential connection of large new customer loads such as new or expanded mining operations, new industrial loads, other energy-intensive opportunities such as data centres
- The widespread adoption of electric vehicles (EVs) which is supported by the South Australian Government via subsidies, investment into a state-wide EV charging network and other incentives. There is potential for future policy settings that would drive the electrification of sectors that currently utilise other fuel sources.

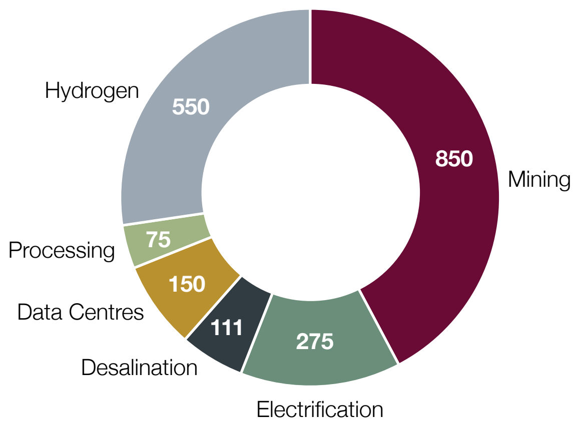
SA Power Networks is also forecasting a step increase in demand on the distribution network, with large numbers of load connection enquiries and interest in electric vehicle charging stations, electrified residential and commercial developments with no mains gas connections, and increased uptake of non-registered small BESS connections in the distribution network.

The Hydrogen Jobs Plan and hydrogen export hubs[16] are setting up South Australia for an initial development of the hydrogen industry aligned with the *Hydrogen Superpower* scenario in the 2022 ISP.

The 2022 ISP identified the *Step Change* scenario as the most likely future based on extensive consultation with the industry. The 2023 ESOO has developed an equivalent Central *(Step Change)* scenario that is considerably higher, due to projected expansion in large industrial loads and other underlying factors. Under this 2023 ESOO scenario we will experience a substantial increase in the maximum demand for the next ten years.

We have considered these different scenarios in our studies, and we have created plans to develop the transmission infrastructure and services to support a scenario as high as the *Hydrogen Superpower* scenario in the 2022 ISP and in some cases even higher. As indicated in the South Australia's Green Paper:[17] *"In South Australia, by 2050, the Hydrogen Superpower scenario leads to over three times more utility-scale storage capacity (5 GW), over six times more wind capacity (55 GW), and over seven times more utility-scale solar capacity (63 GW). This is broadly consistent with the Government of South Australia's understanding of current privately proposed projects".*[18]

Figure 4: Sector breakdown of potential future industrial load growth (MW)



[13] Office of Hydrogen Power South Australia | Hydrogen Jobs Plan

[14] ABC News | Hydrogen port gets funding deal as federal government spruiks Whyalla 'green steel'

[15] Department of Energy & Mining, South Australia | Magnetite Strategy

[16] Department of Energy & Mining, South Australia | Hydrogen export hubs

[17] Department of Energy & Mining, South Australia | South Australia's Green Paper on the energy transition

[18] The multipliers take as their base the installed capacities at 2023

1.4.9 Climate Change

Bushfire risk

Climate change is expected to increase temperatures and influence rainfall patterns increasing the incidence of extreme weather such as drought. These factors are expected to combine to increase the incidence and severity of bushfires.[19]

Studies have determined that due to climate change by 2030 the number of days with a severe fire danger rating will increase from the baseline by 35% in the Rangelands, 28% in the Murray Basin and 12% in the Southern and South Western Flatlands.[20]

The Greater Adelaide area is responsible for the majority of South Australia's economic activity. Adelaide is bordered to the south and east by the Adelaide Hills, which is a high bushfire risk area. The major transmission substations of Para, Magill, Tungkillo and Cherry Gardens are all located in the Adelaide Hills.

With the retirement and mothballing of gas fired generation at Torrens Island, these locations are becoming more important for the transmission of electricity to Adelaide. These substations are all within 50 km of each other, covering an area of 200,000 hectares. By comparison, the NSW bushfires of 2019–20 burnt an area that covered over 17 million hectares. Individual fires in NSW, such as Hospers Mountain (Hawkesbury), Green Wattle Creek (Wollondilly) and Currowan (Shoalhaven) each burnt areas of more than 200,000 hectares.[21]

Intermittent and short duration interruptions to transmission services can occur due to the presence of smoke, meaning even small fires in the wrong location could have consequences for electricity transmission services. Longer, more persistent outages could eventuate if fires damaged lines or substations. Such events are more likely to occur with catastrophic events.

An example of this is the bushfires of January 2021, close to our Cherry Gardens substation. The bushfires did not directly affect the site, as they were never closer than several kilometres from the substation. However, three transmission lines, two 275 kV and one 132 kV, were tripped because of the smoke of fires close or running under them. As a result, the transfer capacity of the Heywood Interconnector was greatly limited, challenging the available supply capacity in South Australia.

Due to the potential impacts a bushfire might have on electricity supply to the Adelaide area during a natural disaster, this risk warrants consideration in our medium -term and long-term planning of the transmission network.

Coastal inundation

With South Australia's population typically situated on the coast, electrical transmission infrastructure is often quite close to the coast.

Climate change is forecast to lead to increases in sea level which may cause coastal inundation. By mid-century sea levels are projected to rise around 24 cm along the South Australian coast.[20] Regions such as the Lefevre Peninsula and Torrens Island are low lying and exposed to this risk. Other areas such as Davenport may be exposed but at a lesser risk.

Sea levels are not forecast to rise quickly, however major tidal storm surges can occur at short notice. The rise of sea levels will increase the extent and frequency of coastal flooding.

Using tools like the web portal for Coastal Risk Australia 2100 it is possible to observe some of the probable outcomes. This tool shows that all the substations located on Torrens Island and Garden Island (Snapper Point, Pelican Point, Lefevre Substation, Torrens Island North and Torrens Island A & B) and associated transmission lines are at high risk of being flooded or stranded due to flooding of access roads. Similarly, Port Pirie substation would be at high risk, while Hummocks substation has a medium risk.

We will continue monitoring water level rise projections, to have a better understanding of the potential future risk to the network and the need to consider it in our long-term planning.

Increasing temperatures

Climate change is forecast to increase global temperatures. By the mid-century annual mean maximum temperatures are projected to increase by up to 2.2ºC in South Australia, with a greater increase projected in the north of the state. Additionally, the number of days per year above 35ºC is projected to increase by more than 40%.[20]

An increase in temperature is expected to lead to de-rating of transmission network assets. Deratings will be correlated with maximum demand conditions which are driven by high temperatures.[22]

In our medium-term planning of the transmission network we are considering the potential effects of higher temperatures and the risk of de-rating.

---

[19] Climate Change in Australia | Bushfire risks for transmission 2021

[20] Department for Environment and Water | Guide to climate projections for risk assessment and planning in South Australia 2022

[21] Australian Parliament House | 2019–20 Australian bushfires – frequently asked questions: a quick guide

[22] Climate Change in Australia | The Impact of Climate Change on Transmission Line Ratings

2 National Transmission Planning

2.1 Integrated System Plan

AEMO's 2022 Integrated System Plan (ISP)[23] recognises the once-in-a-century transformation that is currently underway in how electricity is generated and consumed in the National Electricity Market (NEM).

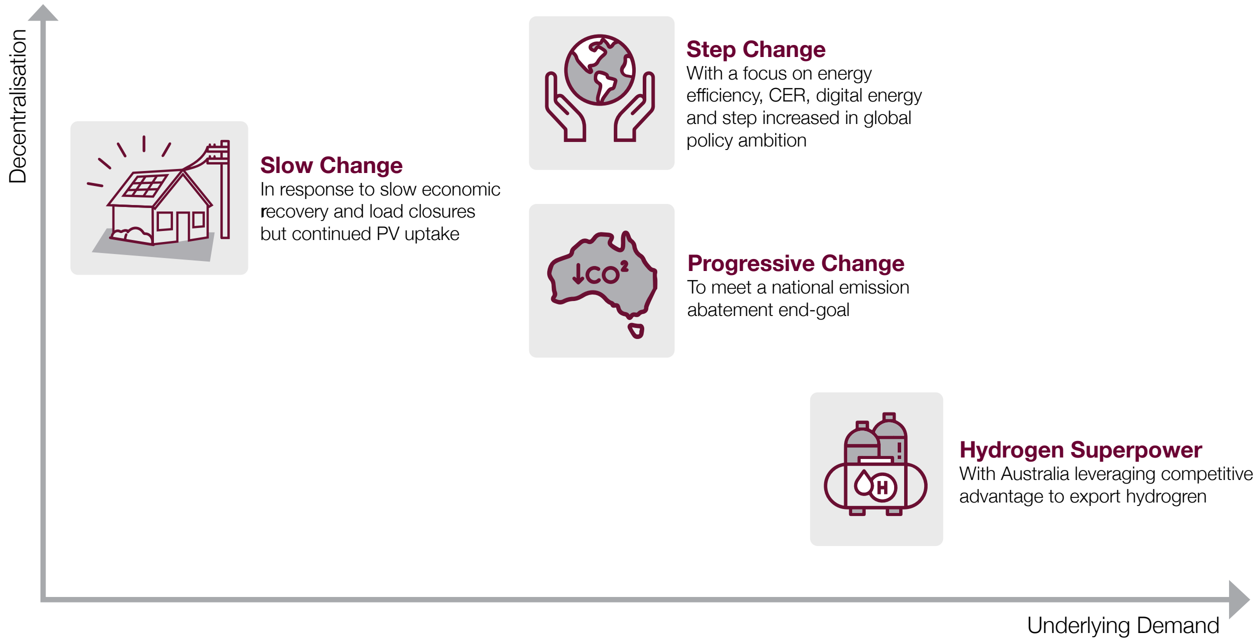
The ISP provides a comprehensive road map for the National Electricity Market. It seeks to facilitate the efficient development and connection of renewable energy zones across the National Electricity Market.

The ISP identifies an Optimal Development Path for development of the NEM, which will see fossil fuelled legacy assets replaced with low-cost renewables, add energy storage and other new forms of firming capacity, and reconfigure the grid to support two-way energy flow.

AEMO is currently carrying out planning studies and analysis to support the publication of a draft 2024 ISP by December 2023 and a final 2024 ISP by June 2024. We typically reference the conclusions of the 2022 ISP and underlying assumptions in this report but will draw out any material differences in updated input assumptions.

The 2022 ISP considered four scenarios, which will be replaced by three scenarios in the 2024 ISP[24], each reflecting a range of assumptions regarding the pace of energy transformation on the path to reach net zero by 2050 (Figure 5). Each of the four scenarios reflects the scale of electricity demand is influenced by the extent to which other sectors electrify (for example, the transportation sector through the uptake of electric vehicles). Decentralisation is the extent to which business and household consumers manage their own electricity generation, storage or services, rather than just draw power from the grid. In the case of *Hydrogen Superpower*, this decentralisation is forecast to be swamped by the scale of electricity demand needed for a hydrogen export industry.

Figure 5: AEMO's 2022 ISP planning scenarios



Source: AEMO's 2022 ISP[18], Figure 6

[23] AEMO | 2022 Integrated System Plan

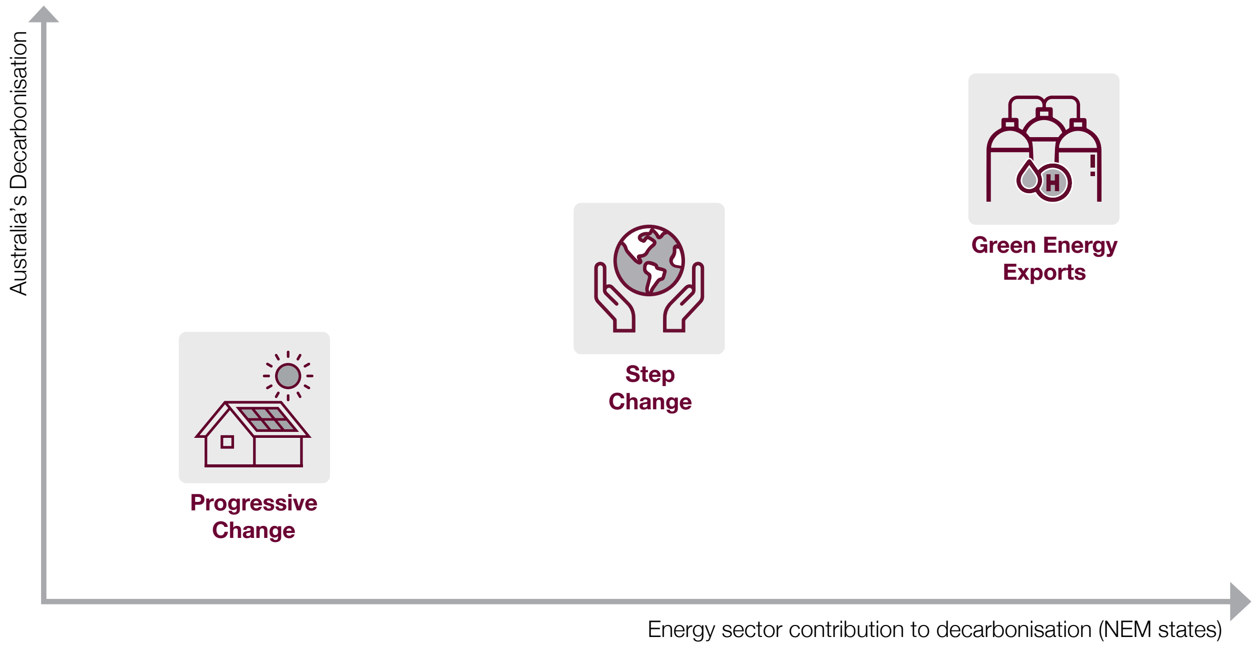
[24] AEMO | 2024 ISP will be based on three scenarios, as described in 2023 Inputs, Assumptions and Scenarios Report

On 28 July 2023 AEMO published the 2023 Inputs, Assumptions and Scenarios Report (IASR) which contains descriptions of the inputs, assumptions and scenarios to be used in AEMO's 2023-24 forecasting and planning publications for the NEM, including the Draft 2024 ISP and the 2024 Final 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 6). In developing these scenarios, AEMO has 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.

Figure 6: AEMO's 2023 IASR planning scenarios



Source: AEMO's 2023 Inputs Assumptions and Scenarios Report[25], Figure 1

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 ISP 2022 *Step Change* scenario. We are increasingly seeking to use a higher demand forecast due to the high interest in new large industrial loads (in the future we might consider using 2023 ESOO Central)
- For a RIT-T that is triggered by AEMO's ISP, we will consider and apply scenarios as directed by AEMO
- For other RIT-Ts, we will assess the appropriate treatment of scenarios on a case-by-case basis – for example, ISP 2022 *Hydrogen Superpower* or 2023 ESOO *Green Energy Exports* are key scenarios to consider in RIT-Ts where option value is a potentially significant market benefit.

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

2.1.1 South Australian projects in the 2022 ISP

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

The 2022 ISP identified four network investments in South Australia as part of the Optimal Development Path. These are:

- **One committed project** – Eyre Peninsula Link (completed February 2023)
- **One anticipated project** – Project EnergyConnect (now committed and under construction)
- **Two future ISP projects** – South East South Australian REZ Expansion and Mid North South Australian REZ Expansion (for which Preparatory Activities were required by AEMO to be undertaken).

These projects are described in more detail below.

Eyre Peninsula Link

Eyre Peninsula Link has been in service since February 2023 replacing an ageing 132 kV single-circuit line from Cultana to Yadnarie and from Yadnarie to Port Lincoln with a higher thermal capacity new 132 kV double-circuit line. The Cultana to Yadnarie section was built 275 kV capable 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 will soon commence a RIT-T to investigate further increasing the capacity to supply Eyre Peninsula. This will include stage 2 of Eyre Peninsula Link, increasing the capacity between Cultana and Yadnarie. This will facilitate the connection of expected large loads and unlock the potential for renewable generation in the Peninsula.

Project EnergyConnect

Project EnergyConnect is a new 330 kV interconnector between New South Wales (NSW) and South Australia. The interconnector will run from Robertstown in South Australia to Wagga Wagga in New South Wales, via the most north section of the transmission network in Victoria.

Project EnergyConnect is a geographically diverse second AC interconnector between South Australia and the rest of the National Electricity Market. The project traverses between east and west, linking the REZs of Riverland, Murray River, and South West NSW, 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:

- The completion of construction of a new substation Bundey, close to Robertstown. The three large 330 kV/275 kV – 400 MVA transformers for this site have been received and the site will be commissioned in late 2023
- Included in the first stage is construction of the 360 km 330 kV section from Robertstown in South Australia to Buronga in NSW. Inter-network testing and release of initial transfer capability up to 150 MW by July 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 during 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 is the preparation of a methodology for the capacity release of the interconnector, following an agreed inter-network test program. This program will be released for public consultation around November 2023 and a final test plan is expected to be finalised by February 2024.

South East SA REZ Expansion

The South East SA REZ lies on the major 275 kV route of the South Australia – Victoria Heywood interconnector. The REZ has moderate to good quality wind resources as evidenced by the high proportion of wind generation (over 300 MW) in or near the South East border with Victoria.

Network expansion would facilitate the connection of 400 MW to 600 MW of generation within this large REZ, such as wind and solar generation near Tailem Bend. The proposed scope is to string the vacant Tailem Bend to Tungkillo 275 kV circuit to enable increased transfers between the South East of South Australia and the Adelaide metropolitan load centre, with an estimated cost of $30 – 50 million.

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

Based on the analysis presented in 2022 ISP, Stage 1 of the South East SA REZ expansion is required in the mid to late 2020s in the *Hydrogen Superpower* scenario and the *Step Change* scenario to facilitate the connection of generation within this REZ. We delivered our Preparatory Activities report to AEMO for this project in June 2023.[26] Given the updated demand outlook it is likely that this project will be aligned with an earlier timing, and we believe it should be declared as an actionable project in AEMO's 2024 ISP.

Interest in new connections to the South East network well exceeds the additional capability that would be facilitated by this project.

Mid North SA REZ Expansion

The Mid-North SA REZ has moderate quality wind and solar resources. There are several major wind farms in service in this REZ, totalling over 1,300 MW installed capacity and it includes several high voltage transmission lines which facilitate the transfer of electric power from the North to the Adelaide region.

The Mid North SA REZ Expansion can be divided into two stages:

- **Southern area** – Improve the power transfer from Bundey/Robertstown to the Adelaide load centre area to facilitate the transfer of generation in the North of South Australia to the main loads in the South. AEMO's 2022 ISP identified that this project would be needed by the late 2020s in the *Hydrogen Superpower* scenario, and by the early 2030s in the *Step Change* scenario.

  We have delivered preparatory activities for this project to AEMO. Given the updated demand outlook it is likely that the need for this project will be brought forward, and we believe it should be declared as an actionable project in AEMO's 2024 ISP.

  This project would also reduce the risk of bushfires impacting on reliability of supply to Adelaide and alleviate congestion on renewables into Adelaide. See Section 4.2 for constraints in the South Australia network over the last twelve months.

- **Northern area** – Unlock the potential for increased connection of low-cost renewables in the Mid North SA, Northern SA and Eastern Eyre Peninsula REZs. Facilitate the development and connection to the network of good quality renewable resources and large iron ore mining from the area around Yunta, which is located far from the existing grid. We see this project as a priority option for further investigation given the extent of the potential for greatly increased electricity demand in the Mid North and on the Eyre Peninsula.

We are progressing these investigations and undertaking activities to support AEMO's consideration of this project in its 2024 ISP. We delivered our Preparatory Activities report to AEMO for the Southern area of the Mid North SA REZ in June 2023.[27]

[26] ElectraNet | South East SA REZ Preparatory Activities Report

[27] ElectraNet | Mid North SA REZ Preparatory Activities Report

2.1.2 Overview of all candidate REZs in South Australia

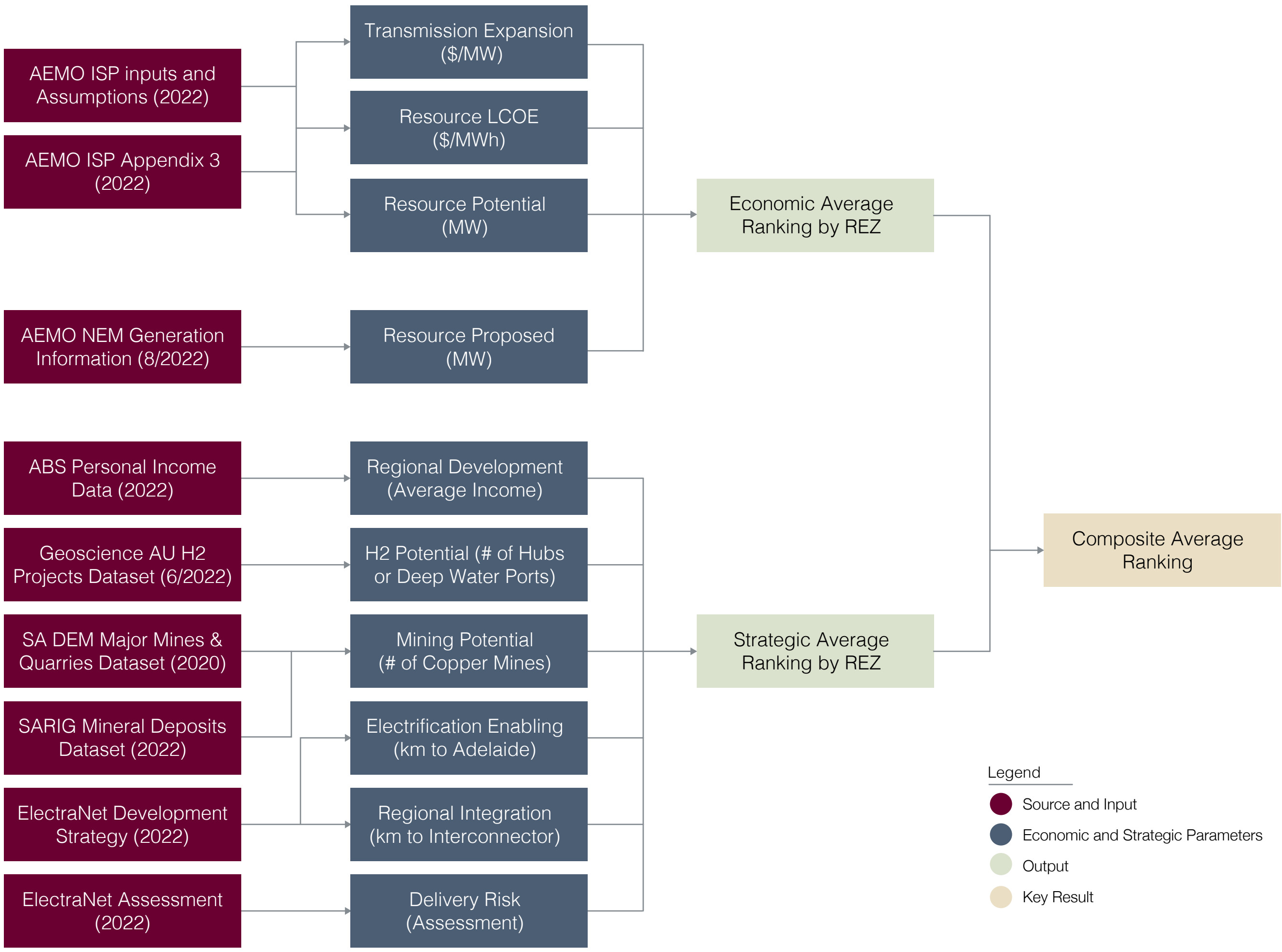
The 2022 ISP identified nine candidate Renewable Energy Zones (REZs) in South Australia, which are consistent with the REZs identified in the 2020 ISP. We have identified potential network investments to release capacity in each of the candidate REZs.

The 2022 ISP indicated that under most scenarios, most of these South Australian REZs are not forecast to require development within the next 20 years, except for the developments discussed in the previous section. In contrast, the *Hydrogen Superpower* scenario would require significant development of many of the candidate REZs and we believe some of them would have to be acted on in the near-term based on potentially higher demand and generation forecasts.

ElectraNet engaged consultant Energeia to undertake a prioritisation of REZs that considers development cost, delivery risk, and strategic leverage for State policy objectives.

This prioritisation used key metrics and inputs to perform economic and strategic ranking assessments as shown in Figure 7, which were combined into a composite ranking Table 1.

Figure 7: Diagram of proposed REZ prioritisation inputs and framework



Source: Energeia

As an outcome of our REZ prioritisation work, we are considering prioritised options for development that would unlock capacity for new generation in Mid North SA, Riverland, Northern SA, Eastern Eyre Peninsula, South East SA and South East SA Coast REZs as shown in Figure 8.

Currently, we are not considering the development of the Leigh Creek REZ as a near term priority. We believe this REZ will require to address significant environmental, cultural, and social concerns for any possible future development options. We will continue monitoring possible connection requests in the region and identify the appropriate response, if required.

Table 1: REZ rankings

REZ	Economic rank	Strategic rank	Composite rank
S3 **Mid North SA**	1	3	1
S2 **Riverland**	6	1	2
S5 **Northern SA**	8	1	3
S8 **Eastern Eyre Peninsula**	4	5	4
S1 **South East SA**	2	8	5
S6 **Leigh Creek**	4	6	5
S10 **Offshore South East SA Coast**	3	9	7
S4 **Yorke Peninsula**	6	7	8
S7 **Roxby Downs**	10	4	9
S9 **Western Eyre Peninsula**	9	10	10

As a result of this work, and the interest in new connections for renewables and loads we proposed the following in our May 2023 TAPR Update as near term priorities.

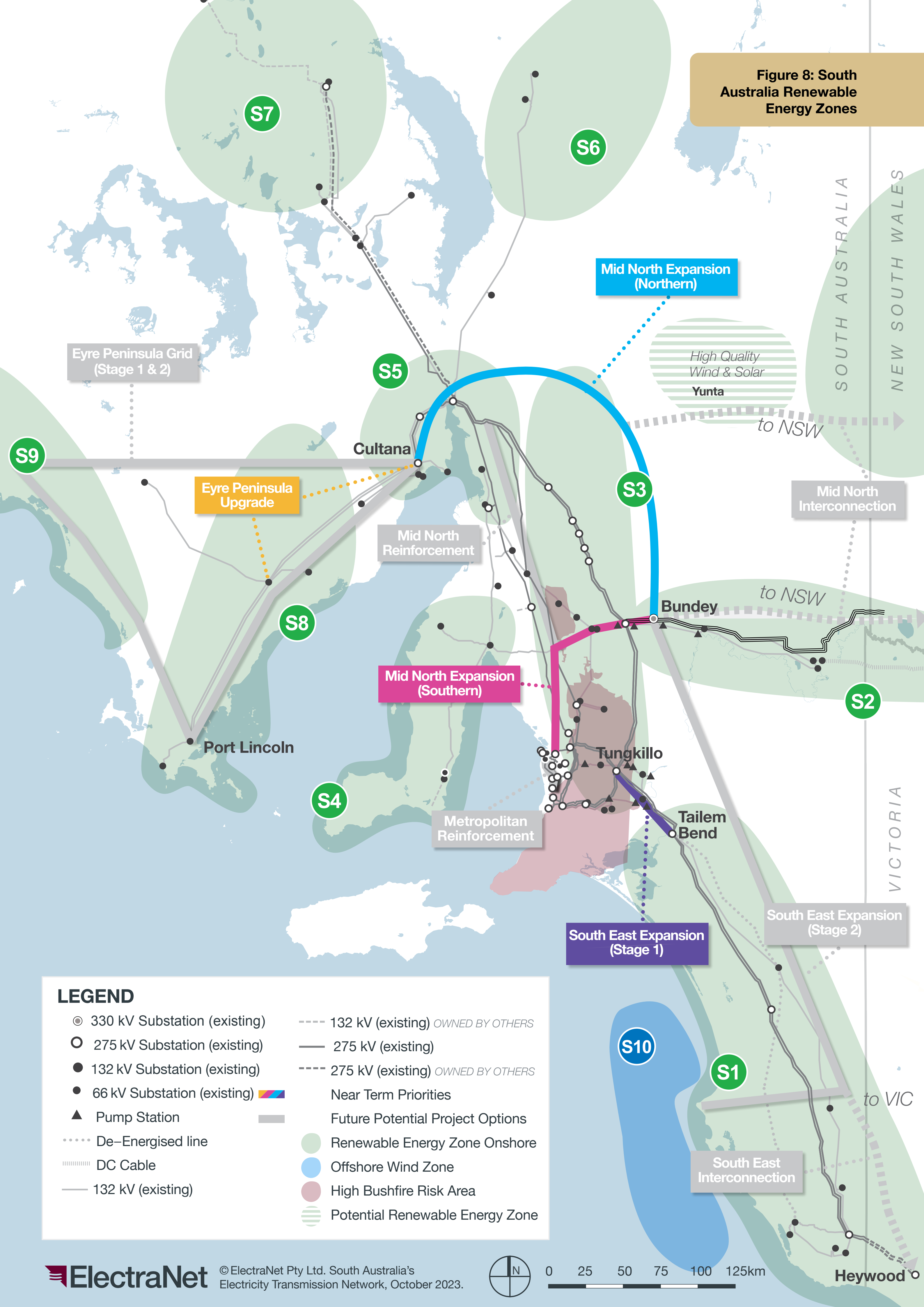


Figure 8: South Australia Renewable Energy Zones

Table 2: Potential network investments to release capacity in South Australian candidate Renewable Energy Zones

REZ	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. AEMO's 2022 ISP identified that this project (EC.11011) would be needed by the mid-2020s in the *Hydrogen Superpower* scenario and by 2029 in the *Step Change* scenario. We have delivered to AEMO analysis of the preparatory activities for this project. Given the updated demand outlook it is likely that the need for this project will be aligned with the earlier timing, and we believe it should be declared as an actionable project in AEMO's 2024 ISP. If identified as an actionable project in AEMO's 2024 ISP, we will undertake the applicable RIT-T and contingent project process. 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 South East.
S2	**Riverland**	Establish Project EnergyConnect (EC.14171) Establish a new shared connection point at a suitable location along the route of Project EnergyConnect (EC.15201 – Riverland REZ Hub Connection). Establish 330 kV bus to provide connection facility on EnergyConnect near Robertstown.
S3	**Mid North SA**	A southern expansion of the Mid North (EC.15205) 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 will improve geographical diversification of transmission corridors to improve security of supply to the Adelaide Metropolitan load centre, which will become increasingly important as Adelaide's dispatchable gas generation retires and as climate change increases bushfire risks to the transmission corridors in the Eastern Hills. The project will construct new high capacity double-circuit twin conductor lines from Bundey to Para or to a new site between Parafield Gardens and Torrens Island. Some of the options to provide this additional capacity are: • New lines to be 275 kV (rating at least 1100 MVA per circuit) or • New lines to be 330 kV (rating at least 1300 MVA per circuit) or • New lines to be 330 kV but operated initially at 275 kV These new lines could also connect at Templers West. Also included in the scope is: • installation of a second 275/132 kV transformer at Templers West • reconfiguration the Mid North 132 kV system to alleviate constraints caused by parallel operation of the Mid North 275 kV and 132 kV systems • construction works to "turn in" the Bungama – Blyth West 275 kV line at Brinkworth. This will provide an initial increase in transfer capacity between Robertstown in the Mid North and the Adelaide metropolitan load centre. AEMO's 2022 ISP identified that this project would be needed across the scenarios and as early as 2029. Given the updated demand outlook it is likely that the need for this project will be brought forward, and we believe it should be considered for actionable status in the 2024 ISP. We have delivered to AEMO analysis of the preparatory activities for this project. If identified as an actionable project in the 2024 ISP, we will undertake the applicable RIT-T and contingent project process.
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. We do not see the development of this REZ as a priority, given its position in our ranking table. We will continue monitoring connection proposals and requests in the region and identify the appropriate time to start any investigation.

Table 2: Potential network investments to release capacity in South Australian candidate Renewable Energy Zones (cont.)

REZ	REZ name	Potential network investments
S5	**Northern SA**	A northern expansion of the Mid North 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 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 network connectivity will also provide capacity to supply developing iron ore deposits in the Braemar region, which are near Yunta. This would be done by constructing new high capacity double-circuit twin conductor lines between Bundey and Cultana. Some of the options to provide this additional capacity are: • New lines to be 275 kV (rating at least 1100 MVA per circuit) or • New lines to be 330 kV (rating at least 1300 MVA per circuit) or • New lines to be 500 kV (rating between 2,000–3,400 MVA per circuit) or • New lines to be 330 kV but operated initially at 275 kV or • New lines to be 500 kV but operated initially at 275 kV. It might be possible to stage the project with a potential initial build from Bundey to Yunta, and a subsequent build from Yunta to Cultana to support very large load growth around Whyalla. We see this project as a priority option for further investigation given the extent of the potential for greatly increased electricity demand in the Mid North and on the Eyre Peninsula. We are currently progressing these investigations to support AEMO's consideration of this project in its 2024 ISP. Depending on the scale and timing of the loads and generation connecting in the Eyre Peninsula it could be necessary to increase the transfer capacity between Davenport and Cultana by the addition of new transmission lines.
S6	**Leigh Creek**	Establish a new shared connection point that extends the 275 kV network from Davenport or Yunta following mid-north northern development to a suitable location near Leigh Creek. Increase transfer capacity between the northern parts of the South Australian electricity transmission network and the Adelaide metropolitan load centre in stages, as described above for the S3 Mid-North SA REZ.
S7	**Roxby Downs**	Establish a new shared connection point that extends the 275 kV network from Mount Gunson South or Davenport to a suitable location near Roxby Downs. Increase transfer capacity between the northern parts of the South Australian electricity transmission network and the Adelaide metropolitan load centre in stages, as described above for the S3 Mid-North SA REZ.
S8	**Eastern Eyre Peninsula**	Eyre Peninsula Link (EC.14172) was completed early this year 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 current customer interest on the Eyre Peninsula, we will commence a RIT-T soon 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 to activate the Eyre Peninsula Upgrade contingent project that is included in our 2023–24 to 2027–28 revenue determination.[28] If there is a large number of 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. We have proposed a contingent project (EC.15104) in our submission for regulatory period 2024–2028 to deliver this increased capacity if the need arises (Section 7.5).

[28] AER | ElectraNet 2023-28 Determination

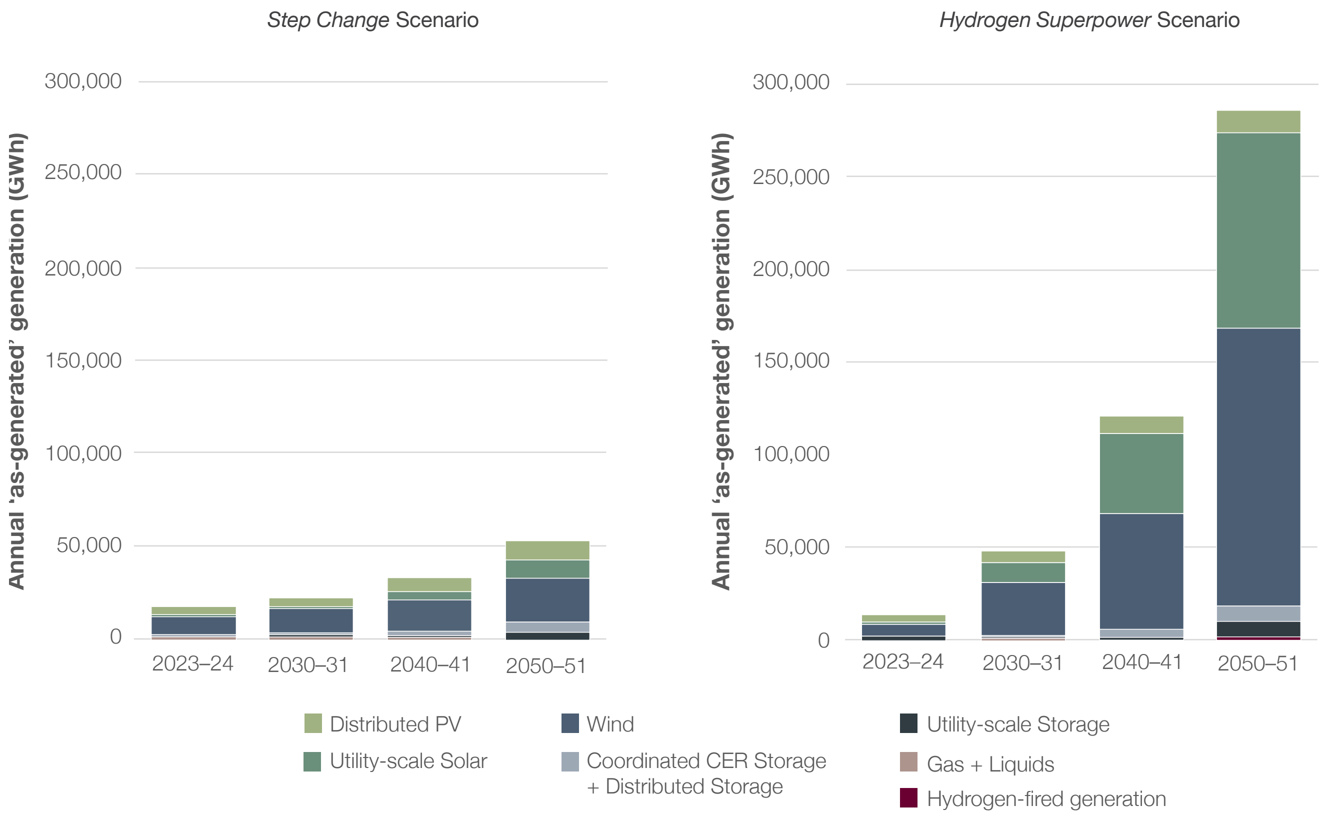
Table 2: Potential network investments to release capacity in South Australian candidate Renewable Energy Zones (cont.)

REZ	REZ name	Potential network investments
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 West side of the Eyre Peninsula will require to establish 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).

2.1.3. Generation development in the *Hydrogen Superpower* scenario

The 2022 ISP's *Hydrogen Superpower* scenario forecasts a level of renewable generation development that far exceeds the forecasts of development in other scenarios. It forecasts that by 2050, the total capacity of installed generation in South Australia would increase more than 20-fold (Figure 9).

Figure 9: Comparison of *Step Change* and *Hydrogen Superpower* generation scenarios AEMO's 2022 ISP



The South Australian Government's Hydrogen Jobs Plan targets the construction of a world-leading hydrogen power station, electrolyser and storage facility within the Whyalla City Council by early 2026. This is planned to include:

- 250 MW (electrical demand) of electrolysers
- 200 MW of power generation, powered by hydrogen powered gas turbines
- Hydrogen storage equivalent to several weeks of hydrogen consumption for power generation.[29]

The Hydrogen Jobs Plan, hydrogen export hubs and multiple potential hydrogen factories[30] are setting up South Australia for an initial development of the hydrogen industry that is aligned with the *Hydrogen Superpower* scenario in the 2022 ISP, as mentioned in the Government's Green Paper on Energy Transition.[31]"the hydrogen superpower scenario more closely aligns with the Government of South Australia's aspirations for the role of hydrogen in the future energy system."

Further potential hydrogen developments in South Australia include Trafigura's Port Pirie Green Hydrogen Project. Starting at 20 tonnes per day of green hydrogen for export in the form of green ammonia, the full-scale plant would produce 100 tonnes per day of green hydrogen from a 440 MW electrolyser to meet both export and domestic supply needs.[32]

Given these and other potential hydrogen initiatives, we anticipate that developments in South Australia could track closer to *Hydrogen Superpower* scenario or even higher.

Using scenarios from 2022 ISP we have compared the amount of renewable generation forecast to be developed in each REZ by 2050 (Table 3). This shows that if the *Hydrogen Superpower* scenario eventuates, the scope of development to unlock the Mid-North SA, Eastern Eyre Peninsula and Western Eyre Peninsula REZs would need to far exceed the scope required in other scenarios.

In addition, it is likely that an additional very large increase of interconnection capability between South Australia and the rest of the NEM would be needed to assist generation and demand balancing across the NEM.

Demand forecasts for the *Hydrogen Superpower* scenario are discussed in Sections 3.3.1. The scope of the required REZ and future interconnector developments will depend greatly on the location of the new load centres to which the new generation will need access.

High-level potential scopes to unlock REZs to the extent required for the *Hydrogen Superpower* scenario are proposed in Section 4.4.

Table 3: Comparison by REZ of installed generation capacity in 2050 (2022 ISP results)

REZ	Generation Type	*Step Change*	*Hydrogen Superpower*	Comment
S1 South East SA	Solar Wind	0 MW 2,540 MW	100 MW 3,200 MW	Significant development of wind generation is forecast in the South East SA REZ for all scenarios.
S2 Riverland	Solar Wind	2,050 MW 0 MW	4,000 MW 0 MW	Forecast development of solar PV generation in the Riverland REZ for *Hydrogen Superpower* is about double the forecast for *Step Change*.
S3 Mid North SA	Solar Wind	0 MW 3,500 MW	1,300 MW 28,900 MW	Forecast development of wind in the Mid-North SA REZ for *Hydrogen Superpower* far exceeds the existing generation capacity of the South Australian grid. This would require an augmentation solution with much greater capacity than has been yet contemplated, with the scope depending on the location of the new load centres to which the new generation will need access.

[29] Office of Hydrogen Power South Australia | Hydrogen Jobs Plan

[30] Department of Energy & Mining, South Australia | Hydrogen in South Australia

[31] Department of Energy and Mining | South Australia's Green Paper on the energy transition

[32] Nyrstar | Port Pirie

Table 3: Comparison by REZ of installed generation capacity in 2050 (2022 ISP results) (Cont.)

REZ	Generation Type	*Step Change*	*Hydrogen Superpower*	Comment
S4 Yorke Peninsula	Solar Wind	0 MW 100 MW	0 MW 1,400 MW	Significant development of wind generation is forecast in *Hydrogen Superpower*.
S5 Northern SA	Solar Wind	2,450 MW 0 MW	2,900 MW 0 MW	Significant development of solar PV generation is forecast for all scenarios.
S6 Leigh Creek	Solar Wind	1,950 MW 1,950 MW	41,800 MW 17,200 MW	Forecast development of solar PV and wind generation in the Leigh Creek REZ for *Hydrogen Superpower* far exceeds the existing generation capacity of the South Australian grid. This would require an augmentation solution with much greater capacity than has been yet contemplated, with the scope depending on the location of the new load centres to which the new generation will need access.
S7 Roxby Downs	Solar Wind	700 MW 0 MW	3,400 MW 0 MW	Forecast development of solar PV generation in the Roxby Downs REZ for *Hydrogen Superpower* is about five times the forecast in *Step Change*.
S8 Eastern Eyre Peninsula	Solar Wind	0 MW 250 MW	5,000 MW 2,300 MW	Forecast development of solar PV and wind in the Eastern Eyre Peninsula for *Hydrogen Superpower* is approximately equivalent to the existing generation capacity of the South Australian grid. This would require an augmentation solution with much greater capacity than has been yet contemplated for the Eastern Eyre Peninsula, with the scope depending on the location of the new load centres to which the new generation will need access.
S9 Western Eyre Peninsula	Solar Wind	0 MW 0 MW	4,000 MW 1,750 MW	Forecast development of solar PV and wind generation in the Western Eyre Peninsula REZ for *Hydrogen Superpower* is approximately equivalent to the existing generation capacity of the South Australian grid. This would require an augmentation solution with much greater capacity than has been yet contemplated for the Eyre Peninsula, with the scope depending on the location of the new load centres to which the new generation will need access.
S10 Offshore South East SA Coast	Offshore wind	0 MW	0 MW	No development of offshore wind generation in South Australia is forecast in any scenario.

2.1.4 South Australia demand sensitivity

AEMO considers sensitivities in the ISP, to explore uncertainties pertaining to key assumptions. In the Draft 2024 ISP we expect AEMO to test the sensitivity of the Optimal Development Path for increases in Large Industrial Loads (LILs) in South Australia. We provide more information in Chapter 3 on why this is necessary.

This sensitivity can be used to analyse the effect of demand increases on the augmentation plan for South Australia. To this end, ElectraNet is proposing a sensitivity that includes those LILs we expect may commit by June 2024.

With the current forecasting regime LILs cannot be incorporated into the central or most likely scenario until they are committed. This tends to occur around 2 years before commercial operation. Large transmission projects cannot be delivered on the same timescale, typically taking five years from the time actionable status is declared and potentially longer. Unless this shortcoming can be addressed, it will ultimately lead to a greater cost solution where loads, generation and transmission fail to be coordinated.

2.2 2022 System Security Reports

AEMO published the 2022 System Security Reports in December 2022. 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 new system strength framework[33] implemented in the NEM, ElectraNet is required from 2 December 2025 to deliver an efficient level of system strength for South Australia on a forward-looking basis, to standards set by AEMO. 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.

AEMO published its 2022 System Strength report in December 2022, in which the first stage of the new system strength framework was implemented.

AEMO's review of system strength needs across the NEM identified that the present system strength in South Australia is sufficient until after 2024–25, given the four synchronous condensers operating since 2021 (two at Davenport, and two at Robertstown).

Our studies indicate that an increased efficient level of system strength at Robertstown and Para will be required from 2 December 2025. We are progressing a RIT-T to determine the best option to deliver the required efficient level of system strength services to the South Australian power system.

The required efficient level of system strength is forecast to continue to increase in future years. Potential solutions may include additional synchronous condensers, grid-forming static synchronous compensators (STATCOMs), hydrogen gas based synchronous generators, grid-forming inverter-based plants (e.g. batteries), and potentially other novel technologies.

2.2.2 Inertia

AEMO's review of inertia needs across the NEM confirmed the shortfall that was declared in 2020, for 200 MW of fast frequency response or equivalent inertia support activities, until 30 June 2023. We contracted with third parties for the provision of these required services, which have now ended.

AEMO also declared a new shortfall, equivalent to 360 MW of fast frequency response or equivalent inertia support activities, from 1 July 2023 until the expected completion of inter-network testing for Project EnergyConnect. We have again contracted with third parties for the provision of these required inertia services.

2.2.3 NSCAS

In its 2021 NSCAS report, AEMO declared a 40 Mvar reactive power absorption gap that will exist in South Australia when the requirement for the minimum number of synchronous generating units reduces from two to zero. AEMO's 2022 NSCAS report noted that the 40 MVar gap was likely to be resolved by newly committed and anticipated transmission, generation, and storage projects coupled with the commissioning of Project EnergyConnect.

However, voltage control continues to be a priority issue in South Australia, and AEMO is currently studying possible voltage control needs considering the most recent limits advice for system operation with less than two synchronous generator units in operation under certain demand and reactive power conditions.

We plan to install switched 275 kV reactors or equivalent services as part of EC.11645 Transmission Network Voltage Control (Section 7.4). The RIT-T for this identified need is progressing.

33 AEMO | ERC0300 System strength final determination

2.3 Power System Frequency Risk Review

AEMO published its final report for the 2022 Power System Frequency Risk Review (PSFRR) in July 2022. This was the last PSFRR as it has been replaced with the General Power System Risk Review (GPSRR). The purpose of the PSFRR was to review non-credible contingency events that could have the potential to have a marked effect on the system frequency and could lead to major disruptions or cascading outages.

The 2022 PSFRR included updates on key findings and recommendations from the 2020 PSFRR.

2.3.1 Recommendations and findings relating to South Australia

AEMO identified that further work is required to mitigate risks associated with the reduced effectiveness of under frequency load shedding (UFLS) schemes reported in the 2020 PSFRR. AEMO recommended that Network Service Providers (NSPs) regularly audit the availability of effective UFLS scheme considering the impact of distributed solar PV in their respective networks. The results should be regularly provided to AEMO for inclusion in risk assessments, UFLS reviews and planning studies.

AEMO also advised NSPs to immediately seek to identify and implement measures to restore emergency under-frequency response as close as possible to 60% of underlying load. Where this is not feasible, AEMO will collaborate with NSPs to develop an approach that identifies a level of emergency under-frequency response that is achievable, while delivering a significant reduction in power system security risks.

AEMO recommended that NSPs investigate measures to remediate the impacts of 'reverse' UFLS operation due to negative power flow on UFLS circuits and investigate arrangements to measure UFLS load availability in real time to inform power system operation and planning studies.

There is presently only one protected event declared by the Reliability Panel, being "the loss of multiple transmission elements causing generation disconnection in the South Australia region during periods where destructive wind conditions are forecast by the Bureau of Meteorology."[34] This protected event is currently managed as follows:

- AEMO imposes a 250 MW South Australian import limit on the Heywood interconnector during forecast destructive wind conditions in South Australia
- An emergency frequency control scheme (EFCS) called system integrity protection scheme (SIPS) is in place in South Australia to lower the risk of islanding due to trip of up to 500 MW of South Australian generation while South Australia is importing power.

AEMO reviewed the protected event and considered the impact of two committed upgrades:

- Upgrade of SIPS to a more effective Wide Area Protection Scheme (WAPS)
- Project EnergyConnect (PEC) Stage 1.

AEMO found that:

- Until PEC Stage 1 is delivered, it will be necessary to retain the 250 MW South Australian import limit on the Heywood interconnector during destructive wind conditions
- As part of the delivery of PEC Stage 1, AEMO recommended that:
  - The WAPS EFCS is modified to account for the change in network topology, acknowledging that ElectraNet is already progressing this
  - Based on thermal limits the existing 250 MW Heywood interconnector import limit is replaced by a 430 MW Heywood interconnector import and a 70 MW PEC stage 1 import limit during destructive wind conditions (PEC Stage 1's import limit under normal conditions is expected to be 150 MW).

The report states that AEMO will consider whether the existing protected event could be managed under the new National Electricity Rules (NER) reclassification framework (from March 2023)[35] and, if so, determine the applicable reclassification criteria and recommend revocation of the protected event.

AEMO identified that due to the penetration of distributed solar PV and transmission-connected inverter-based resources (IBR), South Australia is becoming more susceptible to large generation ramping events. Through analysis, AEMO identified ramping events in 2021 where the combined distributed solar PV and IBR generator output reduced by over 1,750 MW over 2.5 hours. AEMO is analysing historical ramping events to understand ramping risks and how changes in synchronous generator dispatch requirements could impact AEMO's ability to manage future ramping events. After its review is complete, AEMO plans to explore options to forecast and manage future NEM ramping events.

[34] Reliability Panel AEMC | Final Report AEMO Request for a Protected Event Declaration, 20 June 2019, p22.

[35] AEMC | National Electricity Amendment (Enhancing operational resilience in relation to indistinct events) Rule 2022 No. 1

2.4 General Power System Risk Review

AEMO published the final report for the 2023 General Power System Risk Review (GPSRR), in July 2023. This was the first GPSRR, which has replaced the Power System Frequency Risk Review. 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 to be completed annually and it has a broader scope to explore a wider 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.

This year's report concentrated mainly in the analysis of four priority risks/events, which none of them occurred in South Australia or had an impact on the SA network.

Additionally, the GPSRR examines other significant events that occurred since the 2022 PSFRR and provides a general idea of the adequacy of operational mitigation measures, such as Emergency Frequency Control Schemes, operational procedures, and capabilities. One of the events studied was the South Australian tower failure and trip of South East-Tailem Bend 275 kV lines, on November 2022.

Based on these further reviews AEMO recommended to:

- develop and coordinate adequate emergency reserve and fast to implement system security plans
- review the effectiveness of over frequency generation shedding schemes and the adequacy of under-frequency load shedding schemes
- maintain a high operational capability and adequate training
- continue considering non-credible contingency events which could adversely impact the stability of the power system and if necessary, implement mitigation controls.

We are assessing the impact that this will have on our planning processes and priorities.

A final recommendation was made for AEMO to review the protected event framework, given the updated contingency reclassification criteria and the limitations of the present framework.

2.4.1 Recommendations and findings for South Australia

As part of the selection and analysis of non-credible events that could lead to QNI (Queensland-NSW Interconnector) instability, AEMO confirmed a critical event reported in 2022 PSFRR, which could cause instability across several states. The event is the loss of the Moorabool Terminal Station lines, which could result in the South Australia Interconnector Trip Remedial Action Scheme (SAIT RAS) not being able to prevent a large power swing on Project EnergyConnect, This could lead to the tripping of Project EnergyConnect with the synchronous separation of South Australia, as well as tripping QNI with the synchronous separation of Queensland.

AEMO recommended that Powerlink and Transgrid design and implement a special protection scheme to mitigate the risk. Additionally, because of the potential for the Moorabool event to result into the separation of the NEM system into four islanded areas – Queensland, South Australia (separated at Heywood following EAPT operation), the network between Heywood and Moorabool (not a viable island) and the rest of New South Wales and Victoria – AEMO recommended that AEMO, AEMO Victorian Planning, ElectraNet and Transgrid continue cooperating as members of the Project EnergyConnect System Integration Committee to ensure the SAIT RAS operates successfully in conjunction with other NEM system protection schemes and generation tripping schemes.

As part of the review of significant events AEMO looked at whether events classified as protected events should continue under that classification, given recent changes to the way contingency events should be classified.[36] AEMO looked at two protected events related to South Australia, resulting in final recommendations to revoke their classification as protected events and refer to them as non credible contingencies. The two events are:

- South Australia destructive winds, derived from the event that cause a tower failure and trip of South East-Tailem Bend 275 kV lines, which occurred on 12th November 2022. AEMO concluded that suitable constraints can be implemented after Project EnergyConnect Stage 1 using the updated contingency reclassification criteria. Additionally, the implementation of an SPS to reduce the risk of non-credible loss of Project EnergyConnect can be done efficiently. AEMO recommends revising the constraint in Heywood associated with a similar event.
- South Australia separation. This was a proposed action from the 2020 PSFRR to manage the non credible synchronous separation of South Australia from the rest of the NEM. AEMO determined several measures that can be implemented before the full commissioning of Project EnergyConnect Stage 2 to reduce the risk. After the analysis and consultation with stakeholders was recommended not to continue classifying this as a protected event.

The report also details some of the work the AEMO has been doing to manage future NEM ramping events resulting from the increasing penetration of distributed solar PV generation and transmission connected inverter-based resources. Given the large penetration of distributed solar PV in South Australia, AEMO with the collaboration of ElectraNet is studying the behaviour of these events and possible mitigating actions.

[36] AEMC | Rule Determination National Electricity Amendment (Enhancing operational resilience in relation to indistinct events) Rule 2022

3 Electricity Demand

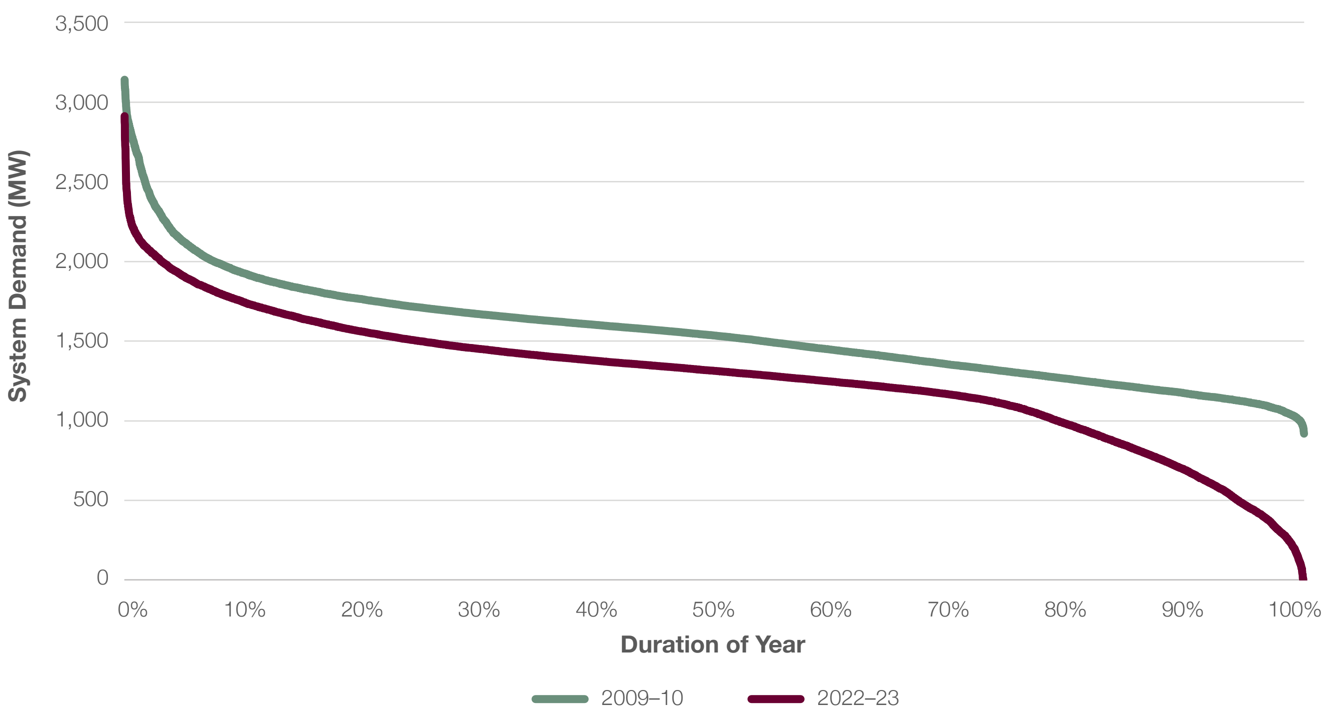
3.1 South Australian electricity demand

The South Australian demand profile is very 'peaky' in nature with relatively low energy content (Figure 10). 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 for some of those days.[37]

More than 90% of South Australian households have air conditioning and during these heatwave periods there is an extraordinary demand for cooling.[37] As a result, South Australia has a very "peaky" load duration curve. Even though demand can exceed 3000 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 markedly 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.

Figure 10: South Australian system wide load duration curves for 2009–2010 and 2022–2023



[37] SA Power Networks | Distribution Annual Planning Report 2022/23 to 2026/27

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' 2022/23–2026/27 Distribution Annual Planning Report.[38] 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 2023 Electricity Statement of Opportunities (ESOO).[39]

AEMO's *Step Change* forecast only includes large industrial loads (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.

As a result, core demand forecasts do not include the potential for near-to-medium term LIL customers as represented in ElectraNet's May 2023 TAPR Update. Alternatively, loads that have Government support via policies or plans such as with Hydrogen Jobs Plan may see their inclusion 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 2022. Details of the connection point forecasts can be found on ElectraNet's Transmission Annual Planning Report webpage.[40] SA Power Networks have provided draft forecasts for 2023 in September, updated based on the ESOO forecasts in August. Preliminary review of these forecasts indicates the updated forecasts will not have a material impact on our plans to support SA Power Networks over the 10-year planning horizon.

SA Power Networks developed ElectraNet's connection point forecasts by reconciling them with AEMO's State-level growth rate for the *Step Change* scenario forecast from the 2022 ESOO.

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

[38] SA Power Networks | Distribution Annual Planning Report 2022/23 to 2026/27

[39] AEMO | NEM 2023 Electricity Statement of Opportunities (ESOO)

[40] ElectraNet | ElectraNet Transmission Annual Planning Reports

3.3 Key drivers of demand

AEMO in its latest ESOO is forecasting an increase in demand compared to other recent forecasts. There are, however, four key potential developments that would significantly increase even further the maximum demands in South Australia. The level of this increase will depend on the number of projects brought to full commissioning and operation; however, given the large number and size of the proposals, even if just a few are successful it will represent a large amount of new load. These four key potential developments include:

- The development of hydrogen facilities near Whyalla and other large hydrogen hubs in accordance with the South Australian Government's hydrogen action plan[41]
- The development of large iron ore mining operations and the production of "green steel" in keeping with South Australian Government's Magnetite Strategy[42]
- The potential connection of large new customer loads such as new or expanded mining operations, new industrial loads, other energy-intensive opportunities such as data centres
- The widespread adoption of electric vehicles, and potential future policy settings that would drive the electrification of sectors that currently utilise other fuel sources.

We are actively engaged with a range of proponents from the mining sector, hydrogen industry, data centres and processing facilities seeking to connect to the transmission network. This could, in total, potentially exceed an additional 2,000 MW of demand, doubling South Australia's electrical energy usage by 2030. Figure 11 depicts the current new load connection interest.

South Australia remains at the global forefront of gigawatt-scale zero emission electrical systems. Discussions with customers are highlighting growing interest in developing new projects in South Australia and the importance of a renewable electrical grid in de-risking long-term investments and meeting their Environment, Social and Governance (ESG) objectives. This trend can be expected to continue to drive large-scale demand growth in the years to come.

Based on typical capacity factors of renewable generation projects, we expect that the ratio of new renewable energy capacity that will be needed to meet the new demand is about three to one, backed by energy storage.

[41] Department of Energy & Mining, South Australia | Hydrogen in South Australia

[42] Department of Energy & Mining, South Australia | Magnetite Strategy

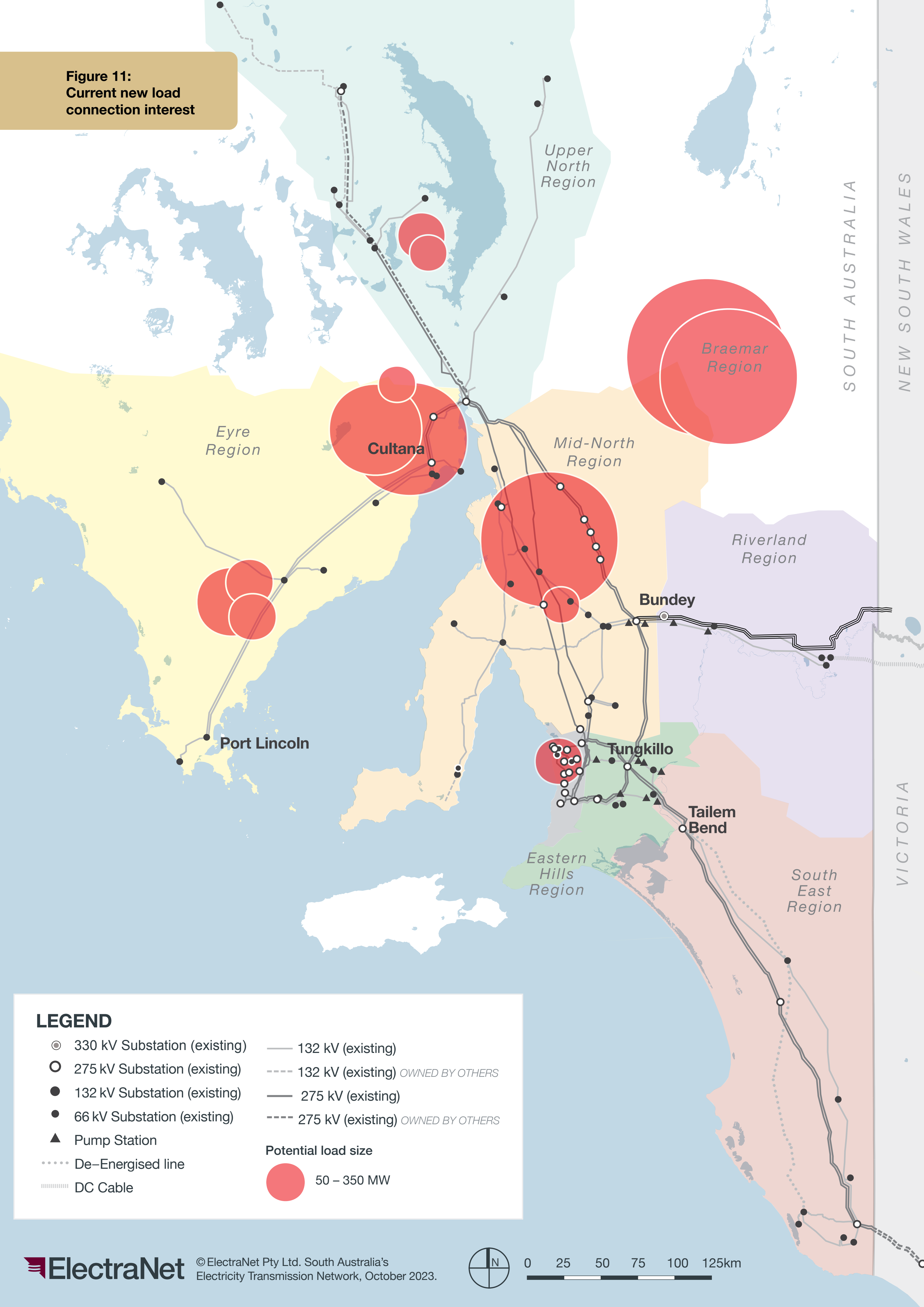


Figure 11: Current new load connection interest

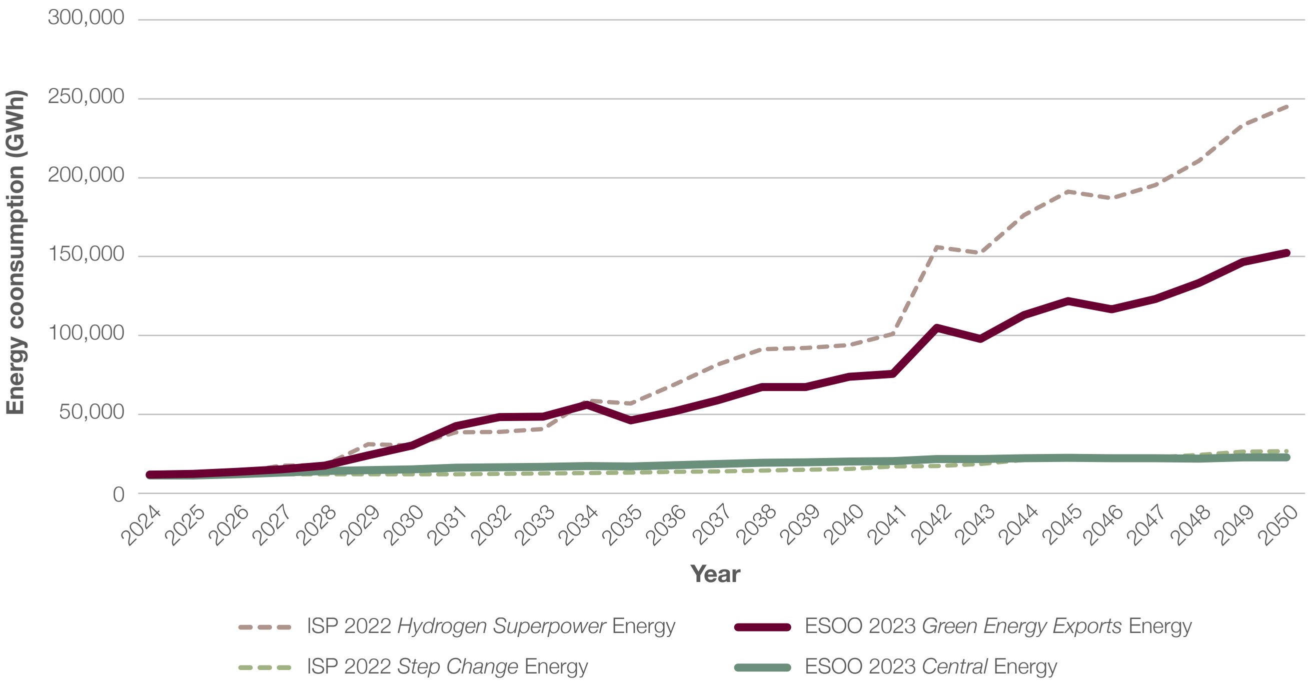
3.3.1. Large-scale hydrogen production

The South Australian Government has created the Hydrogen Jobs Plan[43] which will realise the construction of a world leading hydrogen power station, electrolyser, and storage facility within the Whyalla City Council area of South Australia. The proposed facilities are composed of 250 MW of electrolysers, 200 MW power generation and large storage for hydrogen and are expected to be operational by the early 2026.

The Hydrogen Jobs Plan, hydrogen export hubs[43] and other multiple hydrogen projects under consideration are setting up South Australia for an initial development of the hydrogen industry that is aligned with the Hydrogen Superpower scenario in the 2022 ISP.

Some of these other projects are the Port Bonython Hydrogen Hub, the Green Hydrogen Project at Port Pirie, Cape Hardy Hydrogen Hub, and others. Forecasts used for AEMO's 2022 Integrated System Planning studies show that energy consumption growth in the *Hydrogen Superpower* scenario far exceeds growth in the *Central* scenario. When compared with the energy consumption forecasts published in the recent 2023 ESOO, as shown in Figure 12, *Hydrogen Superpower* is comparable to the *Green Energy Exports* until the mid-thirties, after which *Hydrogen Superpower* grows at a higher rate than *Green Energy Exports*.

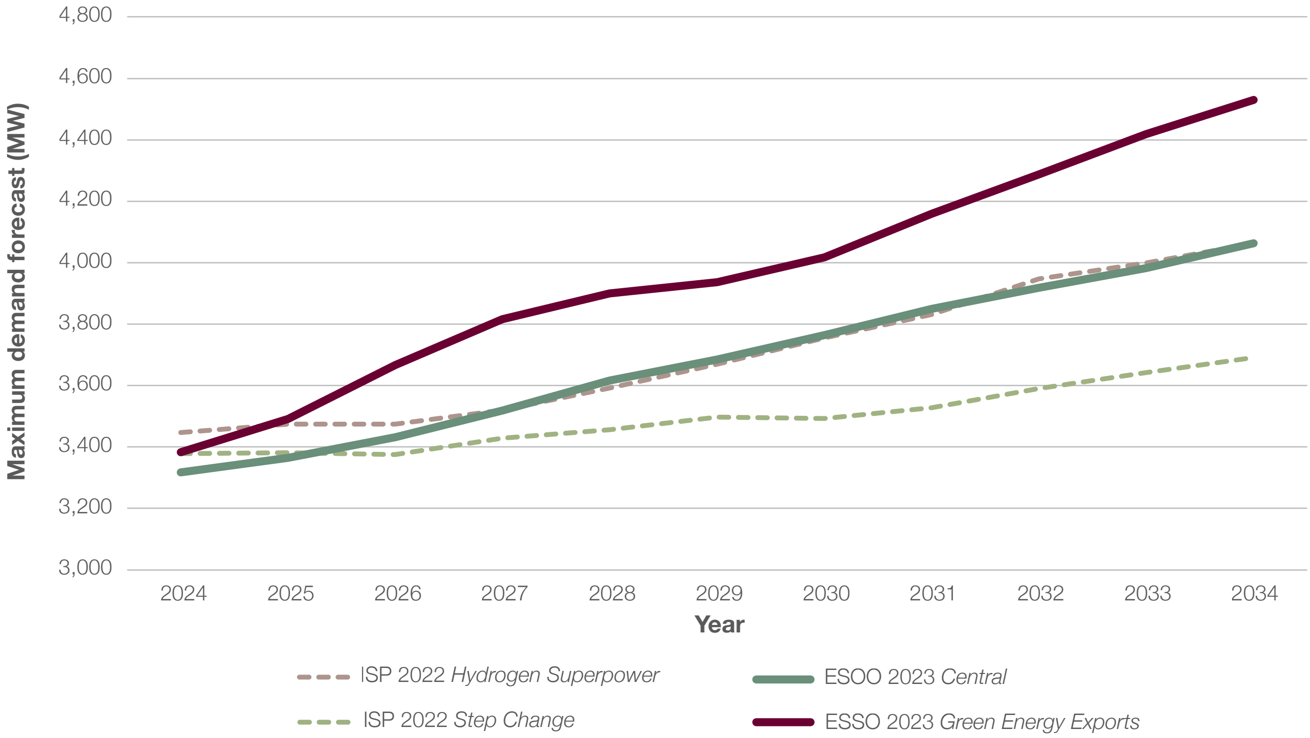
Figure 12: Comparison energy consumption forecasts between 2022 ISP and 2023 ESOO



43 Office of Hydrogen Power South Australia | Hydrogen Jobs Plan

A comparison of the maximum demand forecasts for the same scenarios is shown in Figure 13. On this figure the *Green Energy Exports* scenario shows the highest demand with a high and almost constant rate of increase. The ISP 2022 *Hydrogen Superpower* scenario very closely matches the 2023 ESOO *Central* scenario.

Figure 13: Comparison maximum demand forecasts between 2022 ISP and 2023 ESOO



We do not currently have specific hydrogen projects that comply with the definition of a committed project. However, given the number of interested developers that have contacted ElectraNet and the magnitude of some of these projects, just a small percentage of them becoming reality would increase the demand by hundreds of megawatts. Hence, we have determined that our forecast is closely aligned or even higher than AEMO's two hydrogen-related forecasts.

The extent of network expansion required to support the demand growth indicated by these hydrogen scenarios will depend on the number, timing, and locations of proposed major hydrogen industry developments. Network expansion to support a large-scale hydrogen industry will be most efficient if coordinated to ensure that major hydrogen demand centres are developed near major generation centres (e.g. REZs).

3.3.2 Mining and large industrial loads

South Australia is rich in the minerals the global economy increasingly requires as it decarbonises. This includes BHP's existing Olympic Dam facility, one of the world's most significant deposits of copper, gold, and uranium, along with other known copper and mineral resources throughout the state.

The South Australian government has created plans and policies to accelerate the exploration and technologies to increase the production of copper, gold, magnetite, and other minerals. The South Australia's Copper Strategy[44] seeks to more than triple South Australian copper production to 1 million tonnes per annum by 2030 and propel Australia to among the top three copper producing countries.

The South Australian Government's Magnetite Strategy[45] seeks to unlock 50 million tonnes of magnetite production per annum by 2030, with 90% of the resource located in the Braemar region and Eyre Peninsula.

South Australia also has the conditions required for the connection of other potential large flexible loads that benefit from connection to a renewable energy system, including data centres.

---

44 Department of Energy & Mining, South Australia | South Australia's Copper Strategy

45 Department of Energy & Mining, South Australia | Magnetite strategy

3.3.3 Electrification

Electrification of South Australia's transport, building and industrial sectors involves the replacement of fossil fuels with electricity. AEMO's 2023 IASR projects that South Australia's electricity sector will achieve net zero carbon operation before 2030.

AEMO's 2023 ESOO forecasts electrification (including Battery and Plug-in EVs) to increase electricity consumption in South Australia by 2053 by between 5.6 TWh and 17.4 TWh across the three future scenarios, representing an increase above 2025 operational demand levels of between 45% and 146%. The Central scenario considered the most likely by AEMO, forecasts demand to increase by 12 TWh (96%).

The South Australian Government is incentivising the adoption of electric vehicles by developing a state-wide EV charging network, providing a subsidy package for buyers, creating guidelines and standards for EVs and supporting EV fleet adoption by businesses. EV sales in 2023 for South Australia increased by 143% compared to the whole of 2022.[46]

AEMO's 2023 IASR included an analysis of the electric vehicle market. The forecast for South Australia for the *Step Change* scenario is a total of 17,800 of EVs by 2025, jumping to 215,000 by 2030 and 886,000 by 2040. The percentage of energy consumption is estimated just at 0.31% of the total for 2025, increasing to 3.7% by 2030 and 14.9% by 2040. These results indicate how EVs will consume and storage a large portion of the total consumed energy, making possible to use their batteries to help with the smooth operation of the network. This could be achieved using Virtual Power Plants (VPP) or some other mechanism via Vehicle to Grid (V2G) chargers.

Work commissioned by ElectraNet from consultant Energeia has estimated that electrification – a component of increasing electrical energy demand – could substantially exceed the levels estimated in the 2023 IASR and 2023 ESOO and occur more quickly. This may have a material impact on the speed and quantum of renewable developments and enabling transmission investments required in South Australia.

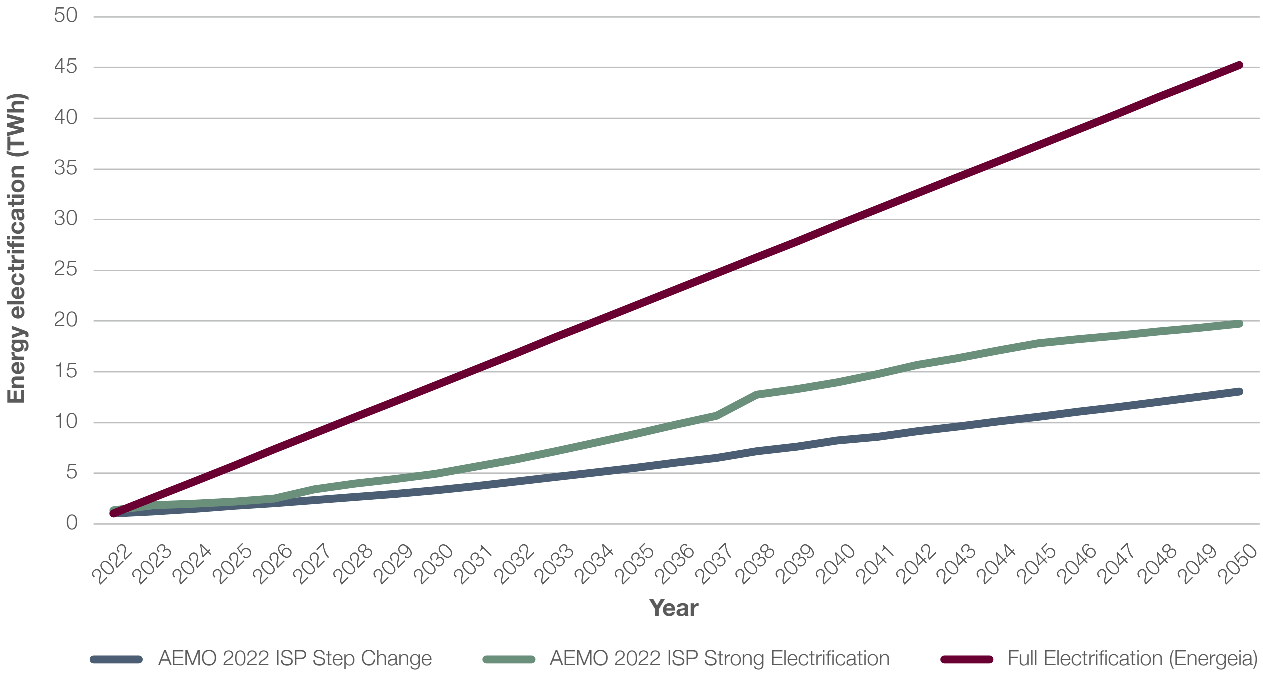
Energeia's indicative "full electrification" scenario reflects the following key inputs and assumptions:

- All consumption is steadily converted to electricity by 2050
- 2.5% year-on-year growth in energy demand to reflect long-term economic growth and energy efficiency improvements over time
- Electricity for transport is 300% more efficient than internal combustion on a tank to wheel basis
- Electricity for heat pumps is 300% more efficient than combustion.

[46] Electric Vehicle Council | State of Electric Vehicles

Energeia's forecast need for electrification significantly exceeds the quantum of electrification-related consumption that is in each of AEMO's ISP scenarios (Figure 14).

Figure 14: Scenarios of the increased component of demand due to electrification



The results show that electrification of the South Australian economy could occur faster than previously estimated, and with potentially much larger growth. We believe AEMO should include sensitivities that test much higher demand than currently included in their scenarios.

3.4. Demand forecasts

As reported in our 2022 TAPR and our 2022 TAPR Update, South Australia's energy transformation is impacting not only the supply of electricity but also the connection of new loads.

In our 2022 TAPR Update,[47] 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. Proponents 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.

Presently, there is a single direct connected customer load connected to the South Australian network that exceeds 100 MW in size. There are currently 8 proponents of load connections that exceed 100 MW undertaking prefeasibility studies.

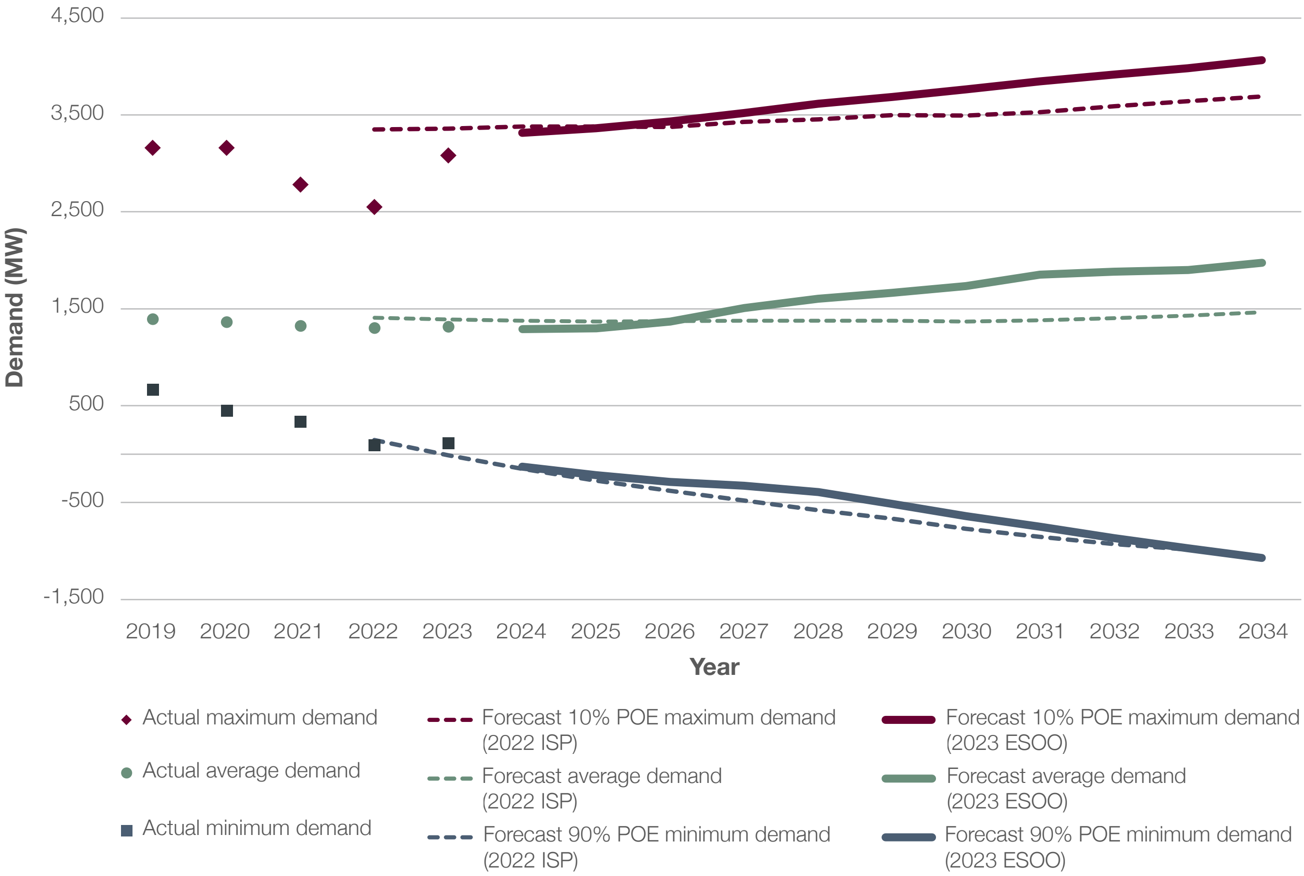
As mentioned before, SA Power Networks is also experiencing increased interest in connections to the distribution network. These new proposed connections includes residential, commercial and industrial loads, electric vehicle charging and small BESS connections.

The most recent update to AEMO's South Australian State-wide forecasts was published in August 2023, alongside AEMO's 2023 ESOO.

47 ElectraNet | 2023 Transmission Annual Planning Report Update

We have compared AEMO's August 2023 ESOO Central (*Step Change*) forecasts for South Australian maximum and minimum demands to the 2022 ISP forecasts that formed the basis of the plans presented in last Transmission Annual Planning Report, along with the previous five years and current year of actual maximum, average and minimum demands (Figure 15).

Figure 15: AEMO's 2023 ESOO *Central/Step Change* scenario forecasts differences with 2022 ISP



(AEMO's forecast data obtained from AEMO's forecast portal,[48] average values were derived from the forecast for energy consumption)

The 2023 ESOO forecast maximum and average demands show an increase for the eight years after 2025 as compared with the 2022 ISP. The 2023 ESOO maximum and average demands appear to grow with a similar rate across the years. The maximum demand forecast indicates that by earlies 2030s the load in the South Australia network could reach 4,000 MW.

The rate of decline in the 2023 ESOO minimum demand appears to be similar to the rate of decline in the 2022 ISP. The forecast indicates that by the early 2030s the minimum demand could reach a value of -1,000 MW. Figure 15 also shows that minimum demands are forecast to decrease at a similar rate as in the past.

[48] AEMO | National Electricity & Gas forecast portal

3.4.1 Integrated System Plan Sensitivity

AEMO's ISP demand forecasts are based on the forecasts developed for the 2023 IASR and used in the Electricity Statement of Opportunities (ESOO). As discussed in Section 2.1.4, these forecasts only include near term load connections that are considered committed.

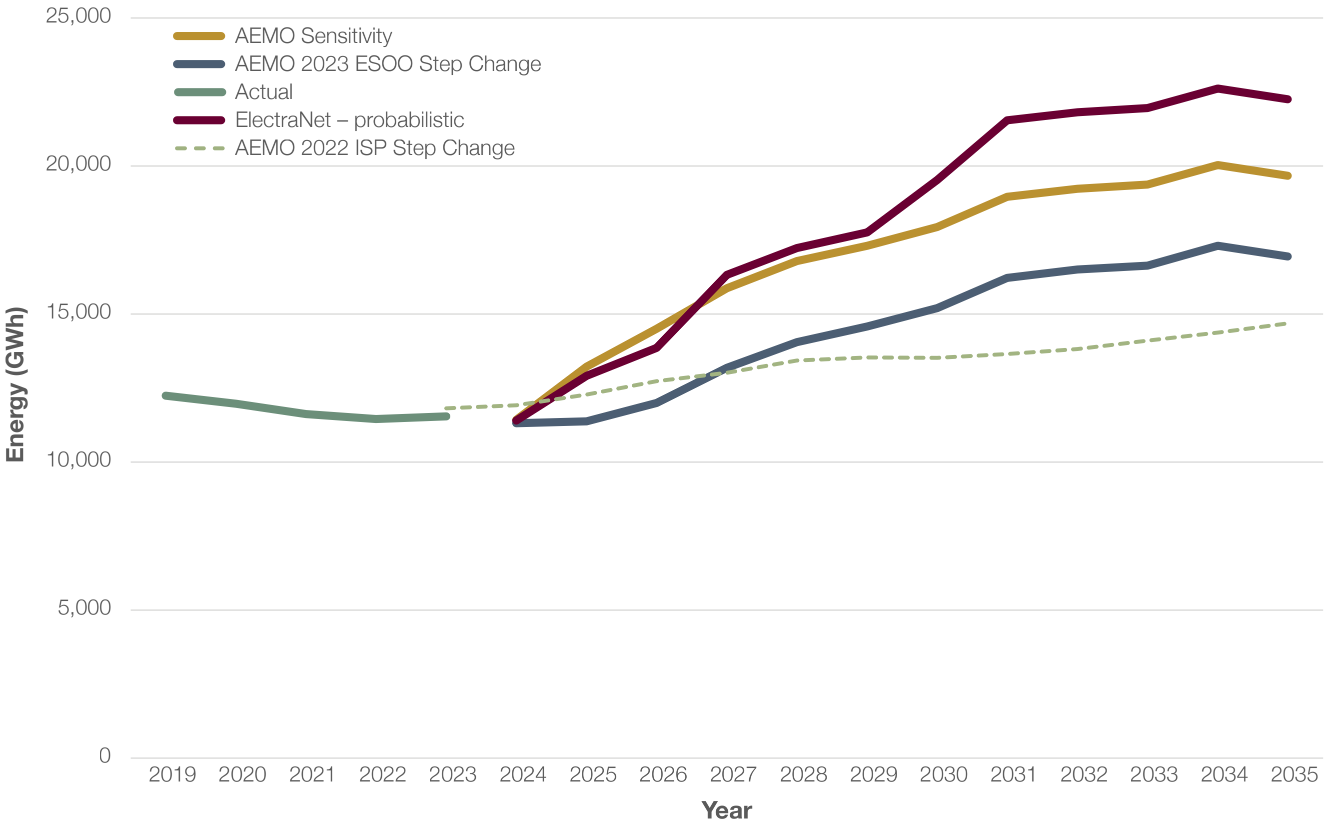
In an environment of a rapidly increasing demand outlook, AEMO has committed to modelling a South Australian demand forecast sensitivity case in its ISP. This sensitivity is limited to demands adding industrial loads that have a high likelihood of reaching committed status in the very near term, including those being driven by South Australia Government policy. This is shown in Figure 16 below as 'AEMO sensitivity'.

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.

Using this approach we have assessed the probability of potential loads proceeding and their likely timing to produce a probability weighted demand forecast. This forecast is shown in Figure 16 below as 'ElectraNet Probabilistic'. We believe this to be a more realistic and prudent outlook for planning purposes that takes a balanced view of expected demand. Importantly this does not include new loads that have yet to commence connection discussions with ElectraNet.

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. Further information on the transmission development priorities to meet this expected demand are discussed in the following sections.

Figure 16: Forecast energy – AEMO and ElectraNet Sensitivity



Sources: AEMO 2022 ISP and AEMO 2023 ESOO

3.5 Performance of 2022 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 2022–2023 at the Bureau of Meteorology's official Adelaide city site at West Terrace was 41.0°C on Tuesday 27 December (Table 4).

Table 4: 2022–23 Summer temperature data compared with long term trends[49]

	November		December		January		February		March	
	Long-term trend	2022–23	Long-term trend	2022–23	Long-term trend	2022–23	Long-term trend	2022–23	Long-term trend	2022–23
Max temp (C)	42.7	32.9	45.3	41	46.6	40.6	43.4	40.2	41.2	33.6
Date of max temp	30 Nov 1962	25 Nov 2022	19 Dec 2019	27 Dec 2022	24 Jan 2019	14 Jan 2023	1 Feb 1912	23 Feb 2023	3 Mar 1942	17 Mar 2023
Average max temp (C)	24.4	22.6	26.9	27.3	28.6	30	28.5	28.8	26.1	25
Days > 30	6	4	9.1	10	11.7	15	10.7	10	7	3
Days > 35	1.5	0	3.8	4	5.5	9	4.3	7	1.6	0
Days > 40	0.1	0	0.6	1	1.1	1	0.6	1	0.1	0
Difference between 2022–23 average max temp and long-term trend	-1.8		0.4		1.4		0.3		-1.1	

49 Bureau of Meteorology, Australian Government | South Australia Weather and Warnings

3.5.2 State-wide demand review

State-wide demand during 2022–23 reached a maximum of 3,141 MW on Thursday 23 February 2023. There were five days on which demand exceeded 2,500 MW during the 2022–23 summer as shown in Table 5.

Table 5: Highest demand days in summer 2022–23

Date	Maximum Demand (MW)	Maximum temperature (°C)	Preceding day maximum temperature (°C)	Preceding overnight minimum temperature (°C)
Thursday 23 February 2023	3,141	40.2	38.7	25.3
Tuesday 27 December 2022	2,834	41.0	39.0	27.0
Wednesday 22 February 2023	2,789	38.7	36.5	21.1
Thursday 16 February 2023	2,780	39.7	35.7	25.1
Friday 13 January 2023	2,525	37.2	35.3	18.5

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

Demand levels corresponding to a 10% Probability of Exceedance (POE) typically occur if such weather conditions occur midweek, before or after the traditional holiday period between Christmas Day and Australia Day. Such temperature patterns did not occur during the 2022–23 summer, consistent with the subdued maximum demand levels that were recorded during the 2022–23 summer.

Results at individual connection points are expected to vary due to local conditions. However, given that state-wide maximum demand was subdued, connection point maximum demands can be expected, on average, to also be low compared to expectations (Section 3.5.3).

Minimum demands were below 250 MW on 19 days between 1 October 2022 and 30 September 2023. Table 6 shows the five 30-minute average lowest maximum demands of these.

A record low 5-minute operational demand of -37 MW was observed on Sunday 1 October 2023.

Table 6: Five lowest demand days from 1 October 2022 to 30 September 2023 (30-minute average)

Date	Minimum Demand (MW)	Maximum temperature (°C)	Preceding over-night minimum temperature (°C)	Preceding day maximum temperature (°C)
Saturday 16 September 2023	37	24.9	7.9	20.9
Saturday 23 September 2023	52	23.6	12.8	20.5
Saturday 5 November 2022	106	26.4	13.5	20.7
Sunday 16 October 2022	118	20.9	6.9	18.9
Sunday 5 February 2023	120	23.2	10.8	21.7

Very low demand levels are typically characterised by mild Adelaide maximum temperatures between about 20°C and 30°C on a sunny day, preceded by a cool to mild overnight minimum temperature between about 5°C and 15°C. The lowest demand levels occur when these conditions coincide with a weekend or public holiday.

Overall, weather conditions that drive very low demands are more common and can occur throughout a longer period of the year, than weather conditions that drive very high demands.

It appears to be a tendency to get more events below 250 MW as years progress: there was 1 day reported in TAPR 2021, 5 days in TAPR 2022 and now 19 events in TAPR 2023. This is consistent with the installed capacity increase on distributed generation, mainly rooftop PV and batteries.

3.5.3 Connection point maximum demand review

As the need for transmission reinforcement is often localised, ElectraNet and SA Power Networks review each connection point on the transmission system.

During summer 2022–23, there were no connection points that recorded maximum demands that exceeded their forecast 10% POE maximum demand between 1 December 2022 and 31 March 2023.

Two of the four metropolitan bulk connection points each recorded maximum demands reached less than 77% and 88% of their 10% POE forecast. Four small (less than 2 MW) and 19 medium connection points failed to reach 85% of their 10% POE forecast. The high number of connection points with a maximum demand that was significantly below the 10% POE forecast level is consistent with the expectation that connection point maximum demands, on average, would be subdued along with the subdued statewide maximum demand (Section 3.5.2).

The November 2022 connection point forecasts are available in the connection point information published on our Transmission Annual Planning Report webpage.[50]

In September 2023 SA Power Networks provided their draft 2023 Connection Point demand forecasts. Our initial assessment of connection point capability to supply forecast maximum demand indicates that forecast maximum demand at Tailem Bend substation could exceed connection point capability within the next 5 years. We will investigate the nature and operating characteristic of the forecast load increases in the coming months to develop our understanding, assess the risks and identify options to manage these risks.

3.5.4 Connection point minimum demand review

In the year from September 2022 to September 2023, over three quarters of our connection points with SA Power Networks experienced negative power flows. These typically occurred on mild, sunny weekend or holiday days, when high distributed rooftop PV generation coincided with low underlying local demand.

With the increasing penetration of solar PV in South Australia, SA Power Networks recognised since 2019 the importance of producing minimum demand forecasts to enable early identification of any constraints or operating issues due to continuous reduction of the minimum demand and ultimately increasing reverse / export flows through its network.

SA Power Networks reported that between 1st January to 24th October 2022 their distribution network was a net exporter on twelve occasions. The longest and largest excursion was on 16th October 2022 when the distribution system operated with reverse flows for over five and half hours and experienced a peak negative demand of -236 MW.

SA Power Networks has forecast that only a few connection points will have reverse power flows exceeding their existing reverse power capability during this decade and it would occur around 2030 or later. We discuss potential actions to address these connection points in Section 7.5.

---

50 Electranet | Transmission Annual Planning Reports

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 17).

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 (Section 7.1).

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[51] for imports to South Australia, and 700 MW[52] for exports.

Emergency control schemes such as under frequency load shedding (UFLS), over frequency generator shedding (OFGS) and the System Integrity Protection Scheme (SIPS) (to be replaced by the Wide Area Protection Scheme (WAPS) in November 2023) 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

ElectraNet is required to report on designated network assets in South Australia.

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 currently no designated network assets within South Australia.

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

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

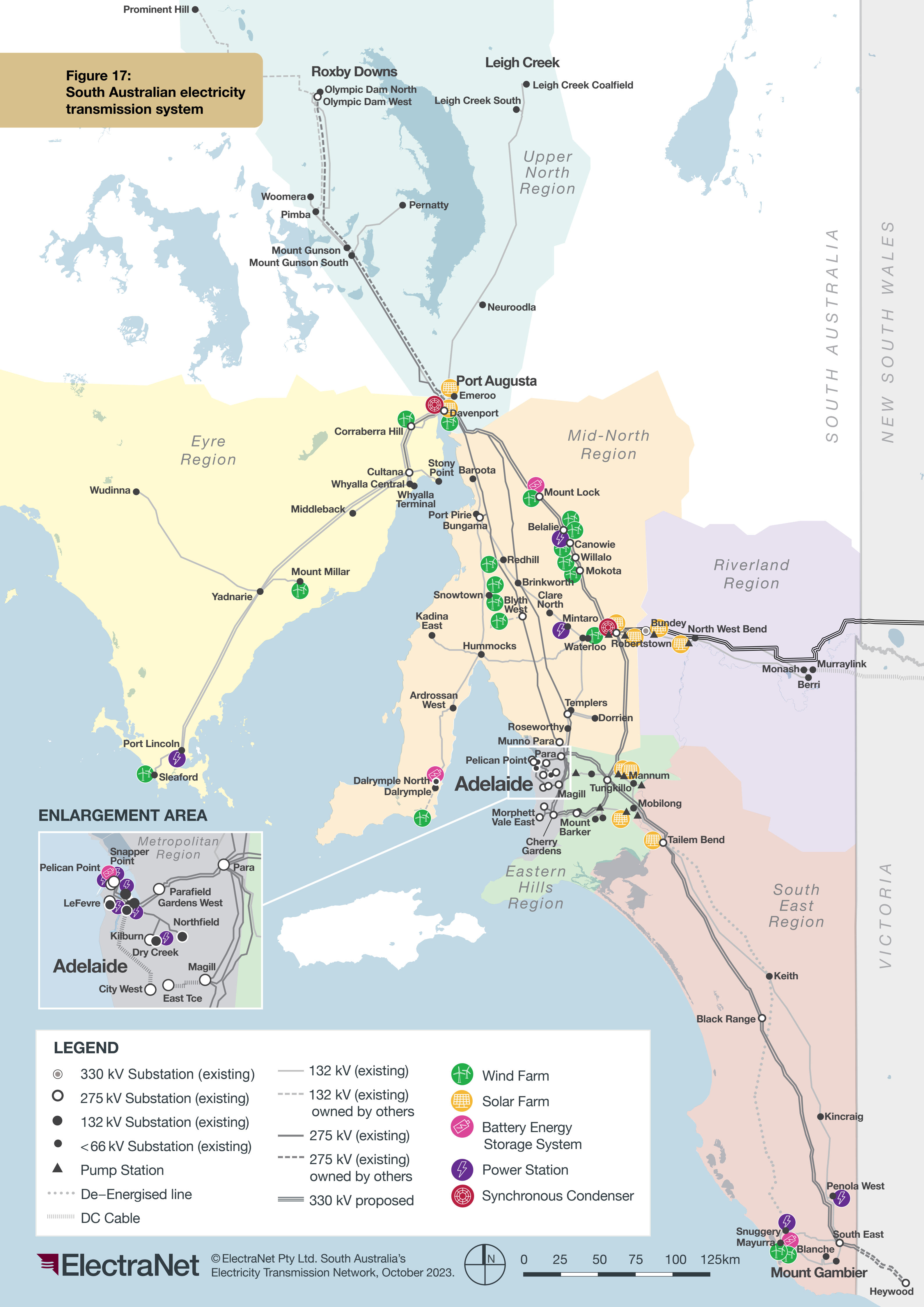


Figure 17: South Australian electricity transmission system

4.2 Transmission system constraints in 2022

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

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

We have assessed the top 20 network constraints in terms of their binding impact on transmission network and interconnector flows during the 2022 calendar year (Table 7) – each of these had a binding impact of at least $50,000 during 2022. Some constraints have been grouped as they manage the same network limit or operating condition. For example, two constraints might both manage the overload of the same network element for different contingency events.

Table 7: Constraint equations, descriptions, and impact in 2022

Network limitation	Binding impact in 2022 [$]	Binding duration in 2022 [hours]	Comments, with proposed and implemented actions
SVML_ROC_80 Keeps the rate of change of flow from South Australia to Victoria across Murraylink HVDC interconnector below 80 MW per 5 min	516,525,559.4	80.3	Constraint based on limit advice provided by Murraylink operator.
S_WATERLWF_RB Limits Waterloo Wind Farm output to its runback active power capability	174,407,938.9	17.6	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^NIL_CRK+MTM_95 Upper limit for Cathedral Rocks Wind Farm + Mt Millar Wind Farm <= 95 MW to maintain voltage stability limits	64,472,441.8	354.4	This constraint has been alleviated by the completion of Eyre Peninsula Link.
S>NIL_MHNW1_MHNW2 Avoid an overload of Monash – North West Bend 132 kV line No. 2 if the Monash – North West Bend 132 kV line No. 1 was to trip	40,088,214.0	1,562.8	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 Constrain Murraylink transfers from South Australia to Victoria to avoid voltage collapse at Monash	19,321,798.7	457.2	Proposed project EC.15175 Increase Murraylink transfer capacity will alleviate this constraint.
S>NIL_HUWT_STBG3 Limit Snowtown Wind Farm generation output to avoid overload of the Snowtown-Bungama 132 kV line if the Hummocks-Waterloo 132 kV line was to trip	17,919,481.3	382.5	We are monitoring this constraint to determine if the implementation of our proposed EC.15571 10-band rating NCIPAP project is likely to alleviate this constraint.

Table 7: Constraint equations, descriptions, and impact in 2022 (cont.)

Network limitation	Binding impact in 2022 [$]	Binding duration in 2022 [hours]	Comments, with proposed and implemented actions
S^NIL_PL_MAX Maximum generation at Port Lincoln due to voltage stability limit.	12,772,017.2	44.4	This constraint has been alleviated by the completion of Eyre Peninsula Link.
S>>NIL_TWPA_TPRS Avoid overload Templers-Roseworthy 132 kV line on trip of Templers West-Para 275 kV line	5,457,182.9	51.5	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 Mid North Expansion (Southern).
S>NIL_NWRB2_NWRB1 Avoid overload North West Bend–Roberstown #1 132 kV line on trip of North West Bend–Robertstown #2 132 kV line (this trips MWP1-3 SFs)	1,628,630.2	223.0	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.
V::S_NIL_MAXG_SECP_2 Vic to SA transient stability limit for loss of SA largest generator (South East Capacitor OOS or not available for switching)	560,900.7	9.2	The commissioning of Project EnergyConnect Stage 2 is expected to alleviate this constraint.
S>NIL_BWMP_HUWT Avoid overload of the Hummocks–Waterloo 132 kV line if a trip of the Blyth West–Munno Para 275 kV line was to occur	422,817.0	10.2	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.
S>NIL_NWRB1_MWP3RB Avoid overload Morgan Pipeline 3-Robertstown 132 kV line on trip of North West Bend–Roberstown 132 kV line	258,254.1	1.4	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_RBTU_WTTP Avoid overload Waterloo–Templers 132 kV on trip of Robertstown–Tungkillo 275 kV line	177,038.7	32.5	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 Mid North Expansion (Southern).
S^NIL_CRK_VCS_STATUS Upper limit for Cathedral Rocks Wind Farm based on Mt Millar Voltage Control System (VCS) availa-bility, [Note: CRK <=55 MW when VCS OFF; CRK<= 60 MW when VCS ON]	129,710.3	35.6	This constraint has been alleviated by the completion of Eyre Peninsula Link.

Table 7: Constraint equations, descriptions, and impact in 2022 (cont.)

Network limitation	Binding impact in 2022 [$]	Binding duration in 2022 [hours]	Comments, with proposed and implemented actions
S>>NIL_RBTU_WEWT Avoid overload Waterloo East–Waterloo 132 kV line on trip of Robertstown–Tungkillo 275 kV line	126,070.7	21.6	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 Mid North Expansion (Southern).
V::S_NIL_SETB_SECP_1 Vic to SA transient stability limit (South East Capacitor OOS or not available for switching) for loss of one South East–Tailem Bend 275 kV line. [NOTE: Assumed both Black Range series capacitors I/S]	119,514.3	5.2	AEMO invokes this constraint when needed to satisfactorily manage the transmission system. The commissioning of Project EnergyConnect Stage 2 is expected to alleviate this constraint.
S>NIL_NIL_NWMH2 Avoid an overload of North West Bend – Monash 132 kV line No. 2 during system normal conditions	82,669.4	0.1	The North West Bend to Monash No. 2 132 kV line was uprated from 80°C to 100°C ratings. Murraylink control upgrades to operationally implement the increased ratings occurred in October 2020, alleviating this constraint.
S>>NIL_BWMP_TWPA Avoid overload Templers West–Para 275 kV line on trip of Blyth West–Munno Para 275 kV line	79,183.7	7.8	This constraint would be alleviated by the implementation of the Mid North Expansion (Southern).
V_S_NIL_ROCOF 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. [NOTE: Switches based on ON/OFF status of Dalry Battery in Load Mode)]	72,951.8	22.0	The commissioning of Project EnergyConnect Stage 2 is expected to alleviate this constraint.
V::S_NIL_MAXG_1 Vic to SA Transient Stability limit for loss of the largest generation block in SA (South East Capacitor Available). [NOTE: Assumed both Black Range series capacitors I/S]	68,534.5	33.9	The commissioning of Project EnergyConnect Stage 2 is expected to alleviate this constraint.

4.3 Emerging and future network constraints and performance limitations

The implementation of Project EnergyConnect, establishing a new interconnector between South Australia and New South Wales, is expected to change dispatch patterns of existing generators and continue to support renewable energy generation connections in South Australia. In combination, this is expected to lead to changes in congestion patterns on the transmission network.

ElectraNet forecasts the emergence of congestion on the South Australian transmission network based on committed, anticipated and modelled expansion of generator investments in the state. There is inherent uncertainty in supply side forecasting where decisions are in large discrete blocks. Scenarios tested by AEMO in the 2022 ISP highlight diverging paths for the network. The *Hydrogen Superpower* scenario shows the potential need for massive transmission and generator developments in South Australia to accompany hydrogen exports on a global scale (Section 2.1.3).

Network limitations that may emerge under the *Step Change* scenario are highlighted in Table 8. These limitations are required to manage the increasing demand on the network to meet electrification.

Renewable energy developments in the South East zone could see congestion develop between Tailem Bend and the Adelaide metropolitan area beyond what is indicated below.

Renewable energy development in the northern parts of South Australia (including the Mid North, Eyre Peninsula, Yorke Peninsula and possibly Roxby Downs zones) together with imported flows from Project EnergyConnect could see congestion develop between Robertstown and the Adelaide metropolitan area.

These areas are consistent with the REZs identified for potential development in AEMO's 2022 ISP, requiring ElectraNet to undertake preparatory works for the South East and Mid-north REZs. The results of these preparatory works were presented to AEMO in July 2023.

A high volume of renewable energy developments on Eyre Peninsula could see congestion develop between Cultana and Davenport.

Considerable congestion is forecast to occur on Project EnergyConnect immediately after commissioning. In general, and across the South Australian network, congestion is forecast to grow substantially by late 2020s and 2030s.

We are investigating constraints applied to existing generators and potential new generation and battery connections output in the Western Suburbs and Northern Suburbs of the Adelaide metropolitan area. These constraints are applied to generators and battery output when any of the 275 kV transmission lines in the loop from Torrens Island – LeFevre – Pelican Point – Parafield Gardens West – Para are out of service; either due to planned works or following an unplanned event.

Where possible, references are provided to other chapters or sections of this report that contain information regarding projects or initiatives that would resolve or mitigate the forecast limitations.

Table 8: Forecast South Australian transmission network congestion

Limitation	Forecast binding hours 2025–2030	Forecast binding hours 2031–2040	Potential mitigating projects
Project EnergyConnect (NSW Thermal)	1,200	900	ElectraNet is examining the potential to expand Project EnergyConnect. Developments such as VNI West and upgrading of the Dinawan to Wagga-Wagga section to 500 kV may present a future expansion opportunity. Enhanced SPS expanding the combined interconnector limits.
Project EnergyConnect exports (800 MW)	1,200	3,900	
Project EnergyConnect imports (800 MW)	200	300	
Combined State-wide Import Limits	100	100	ElectraNet examination of Project EnergyConnect expansion. Enhanced SPS expanding the combined interconnector limits.
Combined State-wide Export Limits	700	1,500	
Heywood Corridor	<100	200	Preparatory works on South East REZ, focusing on the section of the interconnector between Tailem Bend and Adelaide that has low cost options. Future expansion of interconnection to Heywood or Bulgana may also be possible.
Heywood: Tailem Bend to Adelaide	200	400	
Loss of Mid-north 275 kV overloading parallel 132 kV corridor	500	2,700	Preparatory works on Mid-North REZ, focusing on the transfer corridor Project EnergyConnect and Adelaide as considerable generator interest is being registered in the area. Longer term, expansion between Project EnergyConnect and Whyalla may open up additional wind resources, reduce the cost of connecting mining loads in the North East of the state and supply a future hydrogen industry.
Robertstown to Tungkillo 275 kV	300	2,600	
Transmission capacity in Eyre Peninsula	300	600	Upgrade the Cultana-Yadanrie lines from 132 kV to operate at 275 kV and establish a new substation at Yadnarie.

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 of decarbonisation of 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 actual generator investment decisions are made or there is sufficient information available to proceed with a RIT-T. Project timings have not been proposed or presented because of this uncertainty.

We have identified high-level potential projects through constraint and planning analysis. 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 9 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 updated demand outlook for South Australia it is likely that the need for these projects will be brought forward from the timings indicated in AEMO's 2002 ISP. Additionally, we believe these projects should be considered for actionable status in the 2024 ISP.

Table 9: Near-term potential projects

Project options[53]	Options	Customer benefits	Proposed next steps
Eyre Peninsula Upgrade **Indicative cost: $80–150 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. Duplicate Davenport to Cultana at 275 kV or alternative supply to Cultana.	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.	Earlier this year 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 kV capable 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 will commence a RIT-T to investigate increasing the transmission networks capability to supply Eyre Peninsula including Eyre Peninsula link stage 2 upgrade between Cultana and Yadnarie. 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.[54]
Mid North Expansion (Southern) **Indicative cost:** **$300–600 million (depending on option)** **Timing: Mid to late 2020s** Construct new high capacity double-circuit twin conductor lines from Bundey to Para or to a new site between Parafield Gardens West and Torrens Island	• New lines to be 275 kV (rating at least 1100 MVA per circuit) or • New lines to be 330 kV (rating at least 1300 MVA per circuit) or • New lines to be 330 kV but operated initially at 275 kV Consider immediate incremental benefits of installing a second 275/132 kV transformer at Templers West and reconfiguring the Mid North 132 kV system to alleviate constraints caused by parallel operation of the Mid North 275 kV and 132 kV systems.	Enable higher transfers of low-cost renewable energy from the Mid North to the Adelaide Metropolitan load centre, unlocking potential for increased connection of renewables in the Mid North SA, Riverland and Northern SA REZs. Improve geographical diversification of transmission corridors to improve security of supply to customers in Adelaide, which will become increasingly important as Adelaide's dispatchable gas generation retires and as climate change increases bushfire risks to the transmission corridors in the Eastern Hills.	AEMO's 2022 ISP identified that this project would be needed by the late 2020s in the *Hydrogen Superpower* scenario and by the early 2030s in the *Step Change* scenario. Given the updated demand outlook it is likely that the need for this project will be brought forward, and we believe it should be considered for actionable status in the 2024 ISP. We have produced a report of Preparatory Activities to support AEMO's consideration of this project in the 2024 ISP. If identified as an actionable project in the 2024 ISP, we will undertake the applicable RIT-T and contingent project process.
South East Expansion (Stage 1) **Indicative cost: $30–50 million** **Timing: Mid to 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.	AEMO's 2022 ISP identified that this project would be needed by the mid-2020s in the *Hydrogen Superpower* scenario and by 2029 in the *Step Change* scenario. Given the updated demand outlook it is likely that the need for this project will be aligned with the earlier timing, and we believe it should be declared as an actionable project in AEMO's 2024 ISP. We have produced a report of Preparatory Activities to support AEMO's consideration of this project in the 2024 ISP. If identified as an actionable project in AEMO's 2024 ISP, we will undertake the applicable RIT-T and contingent project process.

53 Indicative cost ranges only, currently under review

54 AER | ElectraNet Determination 2023–28

Table 9: Near-term potential projects (cont.)

Project options[53]	Options	Customer benefits	Proposed next steps
Mid North Expansion (Northern) **Indicative cost: $300–1,500 million (depending on option)** **Timing: Mid 2020s to early 2030s** Construct new high capacity double-circuit twin conductor lines between Bundey and Cultana	• New lines to be 275 kV (rating at least 1,100 MVA per circuit) or • New lines to be 330 kV (rating at least 1,300 MVA per circuit) or • New lines to be 500 kV (rating at least 2,000 MVA per circuit) or • New lines to be 330 kV but operated initially at 275 kV or • New lines to be 500 kV but operated initially at 275 kV Consider further staging with an initial build from Bundey to Yunta, and a subsequent build from Yunta to Cultana Consider option of connecting the new lines at Wilmington or Davenport East in the Mid North or duplication of Cultana to Davenport	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. Unlock potential for increased connection of low-cost renewables in the Mid North SA, Northern SA, and Eastern Eyre Peninsula REZs. Provide capacity to supply developing iron ore deposits in the Braemar region (near Yunta) and the production of "green" steel. Provide a new high-capacity transmission path connecting the Adelaide 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 see this project as a priority option for further investigation given the extent of the higher potential electricity demand discussed in our TAPR Update and this TAPR. We are currently progressing these investigations to support AEMO's consideration of this project in its 2024 ISP.

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 should demand be higher than the ESOO Central forecast (Table 10). These projects would be required beyond the standard 10-year planning horizon. These options represent strategic expansions that would build on the immediate priorities by providing increased capacity for future large load and generation connections as they occur.

Table 10: Future potential needs

Project options	Description	Potential medium term development options
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 AC islanded 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, North SA, and Eyre Peninsula REZs to the Adelaide metropolitan and the proposed Eyre Peninsula hydrogen hub major load centres.
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 Under-Frequency Load Shedding (UFLS) scheme (Section 4.5.1)
- a distributed automatic Over-Frequency Generator Shedding (OFGS) scheme (Section 4.5.2)
- a System Integrity Protection Scheme (SIPS) (to be replaced by the Wide Area Protection Scheme (WAPS) in November 2023) (Section 4.5.3).

4.5.1 Automatic under-frequency load shedding

South Australia's existing level 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.[55]

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

AEMO most recently reviewed the design of the UFLS scheme for South Australia as part of the 2020 Power System Frequency Risk Review. AEMO's assessment indicated that:

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

Further, AEMO recommended that all transmission and distribution network service providers review the design of existing UFLS schemes with the aim of:

- ensuring that the amount and distribution of available load in the UFLS scheme is adequate to ensure its effectiveness, and make changes to optimise the performance of the scheme
- implementing improvements such as dynamic arming schemes that are designed to disarm UFLS relays when circuits are in reverse flow, so that back-feeding distribution feeders will not exacerbate any under frequency conditions by tripping due to UFLS.

AEMO has considered a declaration inadequate of a protected event to manage the risk of cascading failures and prevent a system blackout if a non-credible separation of South Australia from the NEM was to occur during periods where UFLS is inadequate. However, AEMO has decided not to further progress a request for declaration of the non-credible separation of South Australia as a protected event. All the recommended actions identified in AEMO studies can be implemented without declaration of a protected event and can be expected to minimise the identified power system risks associated with extreme under-frequency to non-material levels.

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 risk of cascading failures is reduced if non-credible separation of South Australia from the NEM was to occur.

ElectraNet is working with:

- transmission network direct-connect customers to ensure UFLS arrangements for each customer comply with Rules obligations
- implement "Frequency Recovery Mode" (FRM) on 400 MW of proportional resources, to assist frequency recovery and offset detrimental withdrawal as frequency recovers
- implement a new control scheme to trip Lake Bonney wind farms to prevent instability and tripping behaviour demonstrated in EMT models (provided to AEMO) following separation events when operating above thresholds.

[55] AEMO | Separation leading to under-frequency in South Australia

4.5.2 Automatic over-frequency generator shedding

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

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

AEMO has reviewed the OFGS scheme and made the following recommendations:

- increasing OFGS capacity by adding more 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.

4.5.3 System Integrity Protection Scheme (SIPS)

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

The Wide Area Protection System (WAPS) is replacing the existing System Integrity Protection Scheme (SIPS), but in general both follow the same protection principles. The WAPS and the SIPS are designed to rapidly identify conditions that could otherwise result in a loss of synchronism between South Australia and Victoria. Both schemes are designed to assist with the management of these conditions by rapidly injecting power from batteries or shedding some targeted loads, to assist in re-balancing supply and demand in South Australia, preventing a loss of the Heywood interconnector and subsequent islanding of South Australia from the NEM.

In consultation with AEMO we have deployed the new WAPS scheme using synchronised phasor technology and methods. The WAPS can differentiate between three different types of network stress: due to emerging angle stability event, due to power imbalance or due to large and fast frequency excursions. The new Wide Area Protection Scheme (WAPS) will utilise the same response mechanisms, but provide the following improvements compared to the SIPS scheme:

- triggering based on type and severity of the event
- more accurate detection and rapid triggering of battery energy storage systems and load response elements, minimising the risk of a trip of Heywood interconnector
- real time measurement of the available response
- response proportional to the type and magnitude of the event
- initiation of a proportionate load shedding response when triggered
- inherently adapts to changing conditions e.g. renewable generation mix or system loading.

WAPS is currently going through the Site Acceptance Testing, and it is expected to be in service by November 2023.

4.5.4 Project EnergyConnect Stage 1 Inter Trip Scheme

We are developing a new control scheme, the South Australian Interconnector Trip Remedial Action Scheme (SAIT RAS), to inter trip Project EnergyConnect's transmission line section between Bundey – Buronga in the event of non-credible loss of Heywood or Project EnergyConnect interconnector during the interim period when Project EnergyConnect Stage 1 is in service.

The SAIT RAS has been designed to detect the non-credible loss of either Heywood or Project EnergyConnect interconnector and take remedial action to prevent the tripping of the remaining interconnector due to power system instability. For South Australian import conditions, the remedial action will include tripping loads and fast active power increase from BESSs within South Australia. For South Australia export conditions, remedial action will include tripping of generators and rapid active power decrease from BESSs within South Australia.

As part of Project EnergyConnect, several existing protection schemes have been reviewed to assess their proper operation after Project EnergyConnect Stage 1 is commissioned. Some of these schemes are:

- **Tailem Bend reverse power emergency control scheme**

  This scheme will be replaced by a Tailem Bend 132 kV tripping scheme. This new scheme will directly inter-trip the Tailem Bend – Keith line in the event of double circuit trip of South East – Tailem Bend line. The scheme will also directly inter-trip the Tailem Bend – Mobilong line in the event of double circuit trip of South East – Tungkillo line.

- **Black Range fixed series capacitors bypass control scheme**

  This scheme has been modified to automatically bypass the fixed series capacitors via the Network Topology Control Scheme, in the event of any outages within the Victoria or South Australia 500 kV and 275 kV networks which increase the risk of the occurrence of sub-synchronous control interaction or sub-synchronous resonance.

- **Southeast Loss of Synchronism scheme**

  Out of step protection has been reviewed and existing settings have been identified as appropriate.

Photo:

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.[56] We encourage any potential new generators or customers to contact our Corporate Development Team.

connection@electranet.com.au

5.1 New connections and withdrawals

Several generators have connected or withdrawn since the publication of the 2022 Transmission Annual Planning Report, and other generators have committed to connect, or announced their intention to withdraw (Table 11).[57]

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

Table 11: Generators that have connected or withdrawn since 30 October 2022, or are committed to connect or withdraw

Generator	Type	Size	Location	Status
Blyth BESS – Neoen	Storage – battery	200 MW 400 MWh	Blyth West	Anticipated
Bolivar Power Station	Open Cycle Gas Turbine	123.2 MW	Parafield Gardens West	Commercial operation commenced December 2022
Bolivar Wastewater Treatment (Embedded in SA Power Networks' distribution network)	Storage – battery Solar PV	2.46 MW 5 MWh 11.25 MW	Northern Suburbs	Commercial operation commenced February 2023 and October 2022
Bungama BESS – Amp	Storage – battery	150 MW 300 MWh	Bungama	Anticipated
Christies Beach Wastewater Treatment (Embedded in SA Power Networks' distribution network)	Storage – battery Solar PV	2.09 MW 4.3 MWh 4.8 MW	Southern Suburbs	Commercial operation commenced January 2023 and October 2022
Cultana Solar Farm	Solar PV	357.4 MW	Cultana	Anticipated
Goyder South Wind Farm 1A	Wind Turbine	209 MW	Goyder	Committed
Goyder South Wind Farm 1B	Wind Turbine	203.5 MW	Goyder	Committed
Happy Valley Reservoir (Embedded in SA Power Networks' distribution network)	Storage – battery Solar PV	4.41 MW 8.8 MWh 8.3 MW	Southern Suburbs	Commercial operation commenced December 2022

56 ElectraNet | Connection Services

57 AEMO | NEM Generation Information

Table 11: Generators that have connected or withdrawn since 30 October 2022, or are committed to conect or withdraw (cont.)

Generator	Type	Size	Location	Status
Lincoln Gap Wind Farm — BESS	Storage – battery	10 MW 10 MWh	Lincoln Gap	Anticipated
Mannum — Adelaide Pumping Station No. 3	Solar PV	12.36 MW	Mannum – Adelaide	Commercial operation commenced January 2023
Mannum Solar Farm 2	Solar PV	30 MW	Mannum – Adelaide	Committed
Osborne	Gas Turbine – CCGT	118 MW	Osborne	Closure expected 2026
Port Augusta Renewable Energy Park — Solar	Solar PV	79.2 MW	Davenport	Commercial operation commenced January 2023
Tailem Bend Battery Project	Storage – battery	41.5 MW 84 MWh	Tailem Bend	Committed
Tailem Bend Stage 2 Solar	Solar PV	105 MW	Tailem Bend	Commercial operation commenced September 2023
Templers BESS	Storage – battery	111 MW 291 MWh	Templers	Anticipated
Torrens Island B	Gas Turbine	800 MW	Torrens island	Closure expected 2026
Torrens Island BESS	Storage – battery	250.7 MW 250 MWh	Torrens Island	Commercial operation commenced August 2023

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

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

5.2.1 Approach to generation opportunity calculations

We have assessed the anticipated thermal ability of the transmission network to accommodate additional generation after the full transfer capacity of Project EnergyConnect is anticipated to have been released, for two system conditions (Table 12). These represent dispatch conditions that may result in higher than usual intra-regional constraints on generator dispatch, at times when South Australian generation is not constrained by limits on export from South Australia to the rest of the NEM.

Table 12: 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)	SA system losses (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)
High summer demand sunny at noon	2,500	170	490 (import)	740 (import)	5%	50%	95%
High winter demand very windy and overcast	2,000	140	100 (export)	190 (import)	5%	90%	0

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

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

The indicative ability of the existing South Australian transmission network and connection points to accommodate new generation (in addition to any existing and committed generation) is summarised in Section 5.4.

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

We have incorporated the impact of committed projects (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, 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 expected to be a suitable site for proponents near Robertstown to connect once it has been established as part of Project EnergyConnect.

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 5.2.1. 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 level issues.[58]

For the last year ElectraNet has been 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 factories or mining.

5.2.3 Implications of South Australian system strength requirements

We installed synchronous condensers at Davenport and Robertstown in 2021. The installation of these synchronous condensers addressed the system strength and synchronous inertia needs that AEMO identified in 2018 for South Australia. 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-services.

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. However, other constraints such as for thermal capacity, stability or voltage limitations and interconnector transfer capacity might 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 or Systems Stability 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
- 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.

58 ElectraNet | Expected maximum and minimum fault levels for each connection point are available from our Transmission Annual Planning Reports

5.2.4 Opportunities to connect to Project EnergyConnect

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

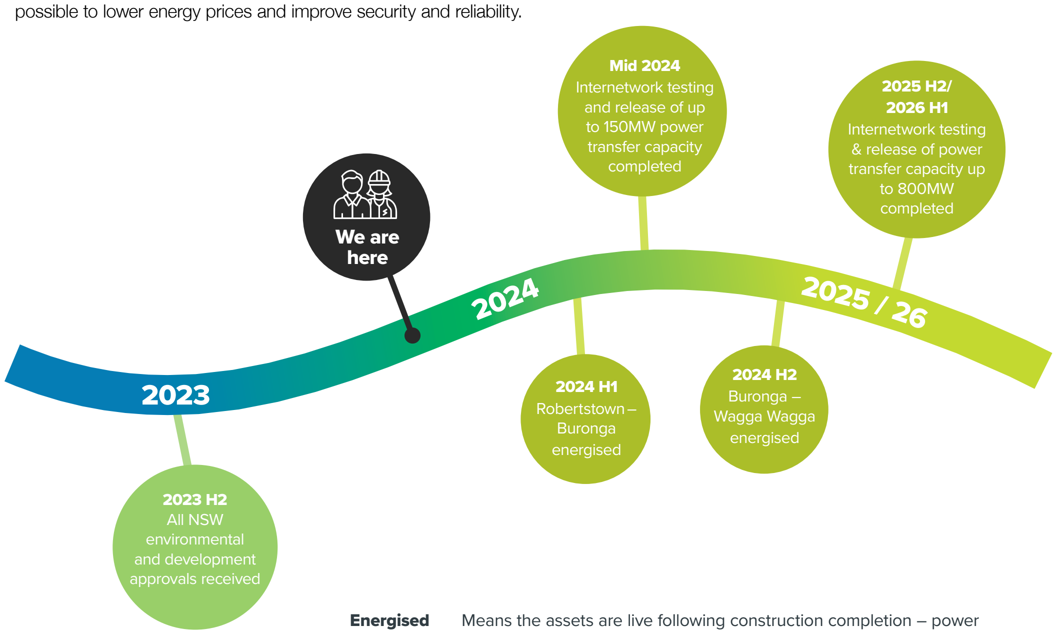
For proponents interested in connecting to Project EnergyConnect, the connection process is similar to the current process for connection to the transmission network. New connection enquiries can be formally lodged and progressed following ElectraNet's defined connection process.[59] Project EnergyConnect models have reached sufficient maturity to be used for planning purposes and are available to connection applicants via the normal AEMO data request process. Proponents need this modelling and information to prepare a formal Connection Application.

Currently, system integration activities are progressing to establish an agreed internetwork test program for Project EnergyConnect Stage 1 that is expected release up to 150 MW of transfer capability by July 2024.

The primary purpose of Project EnergyConnect is to increase transfer capability between NEM regions. While connection enquiries for proposed connections directly to Project EnergyConnect (cut-ins) can be lodged and processed, connections can only be physically facilitated once 500 MW of transfer capacity has been released across Project EnergyConnect. This is expected to be well into 2025. A South Australian Interconnector Trip Remedial Action Scheme (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 NEM. Any cut-in along Project EnergyConnect will likely require a significant amount of analysis and consequential redesign of the SAIT RAS.

Delivering Project EnergyConnect

We're working hard to ensure the project can be delivered as soon as possible to lower energy prices and improve security and reliability.



Energised Means the assets are live following construction completion – power transfer capability to be released subsequently following system testing

5.2.5 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,[60] 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.

---

59 ElectraNet | ElectraNet's Connection Process

60 AEMO | Power System Model Guidelines

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 are higher than 2022 demand forecasts. During the last year ElectraNet has been approached by an increasing number of potential customers interested in connecting large loads to the network, in most 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 2024-25 10% POE load at the time of early evening maximum demand, with:

- Conventional generators dispatched to 100% of capacity
- Wind farms dispatched to 2% of capacity
- Solar farms off
- Import of 600 MW across the Heywood interconnector and 300 MW across Project EnergyConnect.

5.4 Summary of connection opportunities

An indicative summary of the ability of the South Australian transmission network to accept generator or load connections in 2024–25 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 13: Indication of available capacity to connect generation and load in 2024–25

Connection point	Additional generation that could be connected (MW)		Additional load that could be connected (MW)	Prefeasibility or customer connection investigation in progress	Available exits
	High winter demand Very windy, overcast	High summer demand Sunny at noon	Very high summer demand Low wind, early evening		
Main Grid (275 kV)					
Belalie	300	400	300+	Yes	Yes
Blyth West	110	300	300+	Yes	Yes
Brinkworth	220	350	250	Yes	Yes
Bundey	460	530	300+		Yes
Bungama	110	400	300+	Yes	Yes
Canowie	290	400	300+		
Cherry Gardens	600+	600+	300+		Yes
City West	600+	530	180		
Corraberra Hill	240	350	300+		Yes
Cultana	290	430	300+	Yes	Yes (few)
Davenport	400	600+	300+	Yes	Yes (few)
Happy Valley	600+	600+	300+		
Kilburn	540	550	100		
Le Fevre	600+	600+	300+		
Magill	600+	600+	300+	Yes	Yes
Mokota	270	400	300+		Yes
Morphett Vale East	590	600+	180		Yes
Mount Barker South	600+	600+	300+		Yes
Mount Lock	290	380	300+		Yes
Mt Gunson South	270	230	30		Yes
Munno Para	280	280	100	Yes	Yes
Northfield	600+	600+	150		Yes
Para	600+	600+	300+	Yes	Yes
Parafield Gardens West	600+	380	300+	Yes	Yes
Pelican Point	600+	380	300+	Yes	
Robertstown	460	530	300+	Yes	Yes (few)
South East	600+	400	300+	Yes	Yes
Tailem Bend	600+	400	300+	Yes	Yes
Templers West	150	200	300+	Yes	Yes
Torrens Island	600+	600+	300+	Yes	

Table 13: Indication of available capacity to connect generation and load in 2024–25 (cont.)

Connection point	Additional generation that could be connected (MW)		Additional load that could be connected (MW)	Prefeasibility or customer connection investigation in progress	Available exits
	High winter demand Very windy, overcast	High summer demand Sunny at noon	Very high summer demand Low wind, early evening		
Tungkillo	600+	600+	300+	Yes	Yes
Willalo	280	400	300+		Yes
Upper North (132 kV)					
Leigh Creek South	5	5	0		
Mount Gunson	50	60	10		Yes
Mount Gunson South	210	230	30	Yes	Yes
Neuroodla	5	5	0		
Pimba	50	60	10		Yes
Eyre Peninsula (132 kV)					
Cultana	170	260	90	Yes	Yes
Port Lincoln Terminal	120	130	90		
Whyalla Central	150	180	5	Yes	Yes
Wudinna	70	80	20		
Yadnarie	120	130	90	Yes*	
Mid North and Riverland (132 kV)					
Ardrossan West	10	30	20		Yes
Baroota	50	10	0		Yes
Berri	40	110	5		
Brinkworth	20	230	80		Yes
Bungama	50	160	100		Yes
Clare North	20	160	30		Yes
Dalrymple	10	30	20		
Dorrien	10	110	20		
Hummocks	10	110	20		
Kadina East	10	110	20		Yes
Monash	40	180	5		Yes
Morgan–Whyalla Pump Station No 1	40	230	5		
Morgan–Whyalla Pump Station No 2	40	230	5		
Morgan–Whyalla Pump Station No 3	40	210	5		

Table 13: Indication of available capacity to connect generation and load in 2024–25 (cont.)

Connection point	Additional generation that could be connected (MW)		Additional load that could be connected (MW)	Prefeasibility or customer connection investigation in progress	Available exits
	High winter demand Very windy, overcast	High summer demand Sunny at noon	Very high summer demand Low wind, early evening		
Morgan–Whyalla Pump Station No 4	10	110	10		
North West Bend	40	180	5		Yes
Port Pirie	50	160	10		Yes
Roseworthy	90	130	90		
Templers	10	160	90		
Templers West	40	110	80	Yes	Yes
Waterloo	10	180	20		Yes
Eastern Hills (132 kV)					
Angas Creek	100	110	80		
Back Callington	50	60	0		
Cherry Gardens	120	130	100		
Kanmantoo	20	30	5		Yes
Mannum	120	110	80	Yes	Yes
Mannum–Adelaide Pump Station No 1	10	0	0		
Mannum–Adelaide Pump Station No 2	120	110	80		
Mannum–Adelaide Pump Station No 3	120	110	80		
Millbrook	5	0	0		
Mobilong	300	130	140		Yes
Mount Barker	220	180	100		
Murray Bridge–Hahndorf No 1	70	80	60		
Murray Bridge–Hahndorf No 2	160	160	140		
Murray Bridge–Hahndorf No 3	160	160	140		
Para	120	160	80	Yes	Yes
South East (132 kV)					
Blanche	10	80	40		Yes
Keith	70	30	80		Yes
Kincraig	70	80	80		Yes
Mt Gambier	10	80	40		

Table 13: Indication of available capacity to connect generation and load in 2024–25 (cont.)

Connection point	Additional generation that could be connected (MW)		Additional load that could be connected (MW)	Prefeasibility or customer connection investigation in progress	Available exits
	High winter demand Very windy, overcast	High summer demand Sunny at noon	Very high summer demand Low wind, early evening		
Penola West	50	110	160		
Snuggery	0	80	90		
South East	50	100	160		Yes
Tailem Bend	170	10	80		Yes

5.5 Proposed and committed new connection points

New connection points that have recently been energised, committed, or are proposed to enable the connection of new generators or loads as listed in Table 14.

In previous Transmission Annual Planning reports, a new load connection point had been proposed by SA Power Networks at Gawler East in the Mid North to meet localised growing demand. A Gawler East connection point is not currently proposed, as the expected development timeframes are unclear. However, it is possible that the need to develop a Gawler East connection could arise again at some point in the future, subject to actual developments in the local area.

Table 14: Proposed, committed, and recently energised new connection points for generators and customers

Connection Point	Planning Region	Project year	Connection Voltage	Scope of work
Snapper Point	Metropolitan Adelaide	2022	275 kV	Establish 275 kV connection point to facilitate connection of new generation.
Bundey	Mid North	2023	275 kV	Part of Project EnergyConnect – establish Bundey substation with 3 x 400 MVA 275/330 kV transformers to facilitate connection of South Australia via Robertstown 275 kV to the new interconnector.

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

There are four planned consultations for forecast limitations for which we plan to seek proposals for network support solutions (Table 15).

Future dates are indicative only. Reports will be published on ElectraNet's website,[61] with a summary on AEMO's website.[62] 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.[63]

We have entered into contracts for the provision of 360 MW of Fast Frequency Response services from 1 July 2023 until Project EnergyConnect is in operation.

Table 15: Planned consultations for which ElectraNet plans to seek proposals for network support solutions

RIT-T	Expected project commitment date	Consultation status
Transmission Network Voltage Control Refer to Section 7.4 of this report.	Early 2024	We commenced the application of the RIT-T with the publication of a Project Specification Consultation Report (PSCR) in December 2022. Proponents of potential options have submitted, and we are working on the technical-economic analysis of possible options to resolve the need. We plan to publish a Project Assessment Draft Report (PADR) by the end of 2023.
Eyre Peninsula Upgrade Refer to Section 7.5 of this report.	2024	We are preparing to commence the application of the RIT-T with the publication of a PSCR by the end of 2023.
System Strength Requirements in SA Refer to Section 7.4 of this report.	2024	We are preparing to commence the application of the RIT-T with the publication of a PSCR by the end of 2023.
Tailem Bend transformer upgrade Refer to Section 7.5 of this report.	2026	We are preparing to commence the application of the RIT-T with the publication of a PSCR in 2024.

61 ElectraNet | Regulatory Investment Test for Transmission

62 AEMO | Website

63 AEMO | Sign up for AEMO Communications Newsletter

Photo: Project EnergyConnect

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 16 and Figure 18).

Table 16: Network projects completed between 31 October 2022 and 31 October 2023 (inclusive)

Project Description	Region	Constraint driver and investment type	Asset in service
EC.14211 South East 275 kV Capacitor Bank Install an additional 100 Mvar capacitor bank and associated equipment at South East substation to enable power transfers from Victoria to be increased by 30 MW, to enable increased utilisation of the full capability of the Heywood interconnector.	South East	Market benefit (NCIPAP) Augmentation	November 2022
EC.14172 Eyre Peninsula Link Construct a new double-circuit line from Cultana to Yadnarie initially energised at 132 kV with a rating of about 300 MVA per circuit, with the option to be energised at 275 kV with a rating of about 600 MVA if required in the future. Construct a new double-circuit 132 kV line from Yadnarie to Port Lincoln, rated to about 240 MVA per circuit.	Eyre Peninsula	Reliability Augmentation	February 2023
EC.11002 Strengthen the Eastern Hills transmission corridor Connect the Tailem Bend to Cherry Gardens 275 kV line at Tungkillo.	Eastern Hills	Market Benefits (NCIPAP) Augmentation	June 2023
EC.14168 NCIPAP Smart Wires Power Guardian Technology Trial Install Smart Wires Power Guardian units on the Templers to Waterloo 132 kV line and uprate the Robertstown to Para 275 kV and the Robertstown to Tungkillo 275 kV lines to increase the transfer capacity of the transmission network in the Mid North region of South Australia.	Mid North	Market Benefit (NCI-PAP) Augmentation	June 2023
EC.14049 Leigh Creek South Transformer Replacement Replace the two existing 132/33 kV 5 MVA transformers, assessed to be at the end of their technical life with a corresponding high risk of failure, and the two SA Power Networks 33/11 kV transformers with a single new 5 MVA 132/11 kV transformer.	Upper North	Asset condition and performance Asset renewal	July 2023
EC.15322 Emergency Transmission Network Voltage Control. Install a 275 kV 50 Mvar reactor at Cherry Gardens substation to manage the high voltages at times of low or negative demand.	Metropolitan	Reactive support Augmentation	September 2023
EC.15320 Para SVC 2 Transformer Emergency Replacement Replace the Para SVC 2 transformer and auxiliary equipment that was damaged by a transformer fire in January 2022	Metropolitan	Asset condition and performance Asset renewal	September 2023

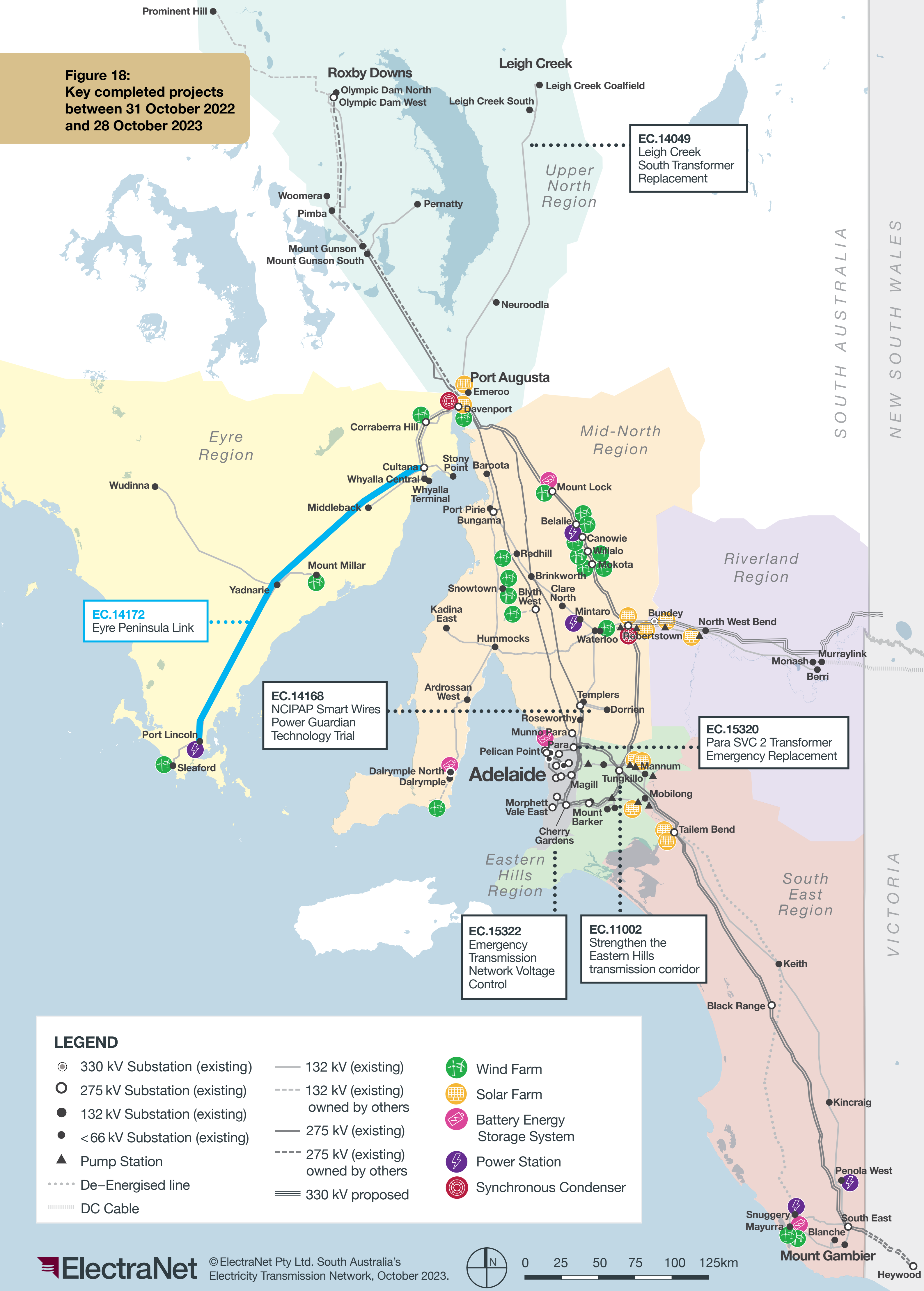


Figure 18:
Key completed projects between 31 October 2022 and 28 October 2023

ElectraNet

6.2 Committed projects

Committed projects are those projects for which the RIT-T has been completed (where required) and the ElectraNet Board has given approval. We are currently undertaking several committed projects which are expected to be completed between now and 2028 (Table 17 and Figure 19).

Table 17: Committed projects as of October 2023

Project Description	Region	Constraint driver and investment type	Asset in service
EC.14246 Wide Area Protection Scheme (WAPS) Implement a Wide Area Protection Scheme with the use of PMUs to real time monitor and process system parameters for event detection and include dynamic arming of participating loads and battery energy storage systems to enable a proportionate response to specific events to further enhance SA system security.	Various	Stability Operational	November 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 sub-stations that has been identified as a safety and operational issue.	Mid North	Asset condition and performance Asset renewal	October 2022 (Port Pirie) December 2023 (Bungama)
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	June 2024
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. The number of transformers requiring bushings to be replaced has increased from 16 to 20, as a result of detailed assessment of selected transformer bushings following the failure of similar bushings on other transformers.	Various	Asset condition and performance Asset renewal	May 2024
EC.14081 Line Insulator Systems Refurbishment 2018 – 2023 Refurbish transmission line support systems and extend the life of 18 transmission lines by renewing line asset components.	Various	Asset condition and performance Asset renewal	August 2024
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	December 2024

Table 17: Committed projects as of October 2023 (cont.)

Project Description	Region	Constraint driver and investment type	Asset in service
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	December 2024
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): July 2024 Stage 2 (Buronga to Wagga Wagga): late 2024
EC.14218 Spencer Gulf Emergency Bypass Preparation Undertake preparatory site works and procure spares to support a rapid restoration of Spencer Gulf high tower crossings for the Davenport – Cultana 275 kV transmission lines, which supply the entire Eyre Peninsula region.	Eyre Peninsula	Operational Operational	March 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	March 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	December 2023
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 2025
EC.14032 Instrument Transformer Unit Asset Replacement Replace instrument transformers at 19 substations which are at the end of their technical life, due to an increased risk of failure which may result in an increasing rate of explosive asset failure causing unpredictable damage resulting in potential substation failure and involuntary load shedding on parts of the network.	Various	Asset condition and performance Asset renewal	June 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 with consequential safety risks and the potential for involuntary load shedding on parts of the network.	Various	Asset condition and performance Asset renewal	March 2024

Table 17: Committed projects as of October 2023 (cont.)

<table>
<tr><th>Project Description</th><th>Region</th><th>Constraint driver and investment type</th><th>Asset in service</th></tr>
<tr><td>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.</td><td>Various</td><td>Asset condition and performance
Asset renewal</td><td>June 2025</td></tr>
<tr><td>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.</td><td>Various</td><td>Asset condition and performance
Asset renewal</td><td>June 2025</td></tr>
<tr><td>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.</td><td>Various</td><td>Asset condition and safety
Asset renewal</td><td>September 2025</td></tr>
<tr><td>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. 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 Customer Energy Resource (CER) Feed-in – monitoring will help understand the response of CER following-system disturbances for benchmarking power system models, network planning and accurate constraint development.
ElectraNet does not envisage that this project will impact inter-regional transfer.</td><td>All</td><td>Stability
Operational</td><td>March 2024</td></tr>
</table>

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 18 and Figure 19).

Table 18: Pending projects

Project Description	Region	Constraint driver and investment type	Asset in service
EC.14084 Line Conductor and Earthwire Refurbishment 2018–19 to 2022–23 **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: • Waterloo – Waterloo East • Waterloo East – Morgan Whyalla Pump Station #4 • Morgan Whyalla Pump Station #4 – Robertstown • Robertstown – Morgan Whyalla Pump Station #3 • Morgan Whyalla Pump Station #3 – Morgan Whyalla Pump Station #2 • Morgan Whyalla Pump Station #2 – Morgan Whyalla Pump Station #1 • Morgan Whyalla Pump Station #1 – North West Bend. The RIT-T for this project was completed in July 2023.	Mid North and Riverland	Asset condition and performance Asset renewal	June 2026
EC.15568 Northfield Transformer 7, 8 and 9 Interface Connection Requirement **Estimated cost: $14–16million** **Status: Pending** SA Power Networks are planning to replace their aging/failing 66 kV GIS switchgear at Northfield substation with a new AIS 66 kV switchyard. To support this replacement, we will need to upgrade the 66 kV GIS to AIS connection points to transformers #7, #8 and #9 at Northfield substation. SA Power Networks published the final Regulatory Investment Test for Transmission (RIT-D) document for Ensuring Reliable Supply for Adelaide's Eastern Suburbs in December 2022.	Metropolitan	Asset condition and performance Asset renewal	September 2026

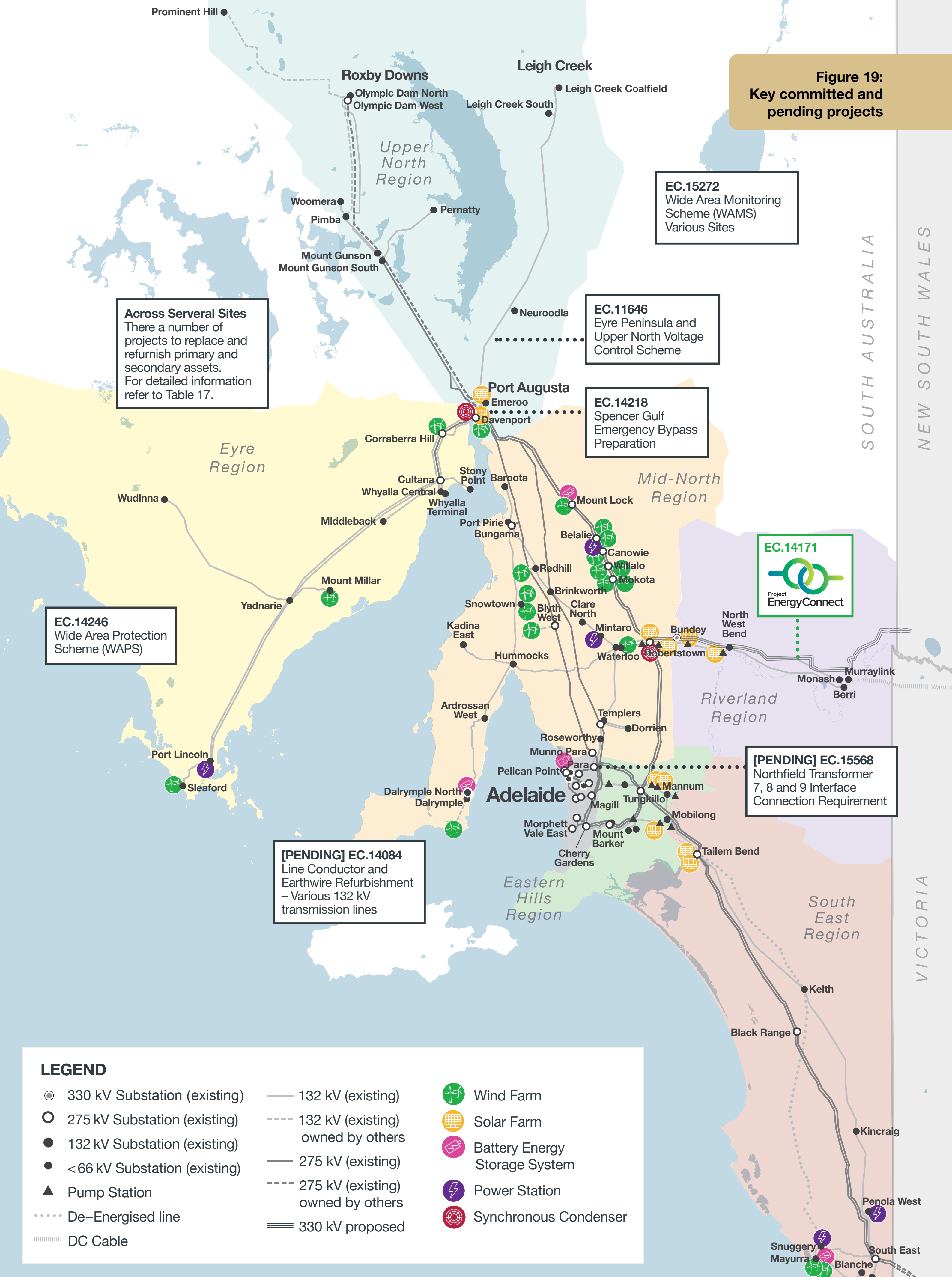


Figure 19: Key committed and pending projects

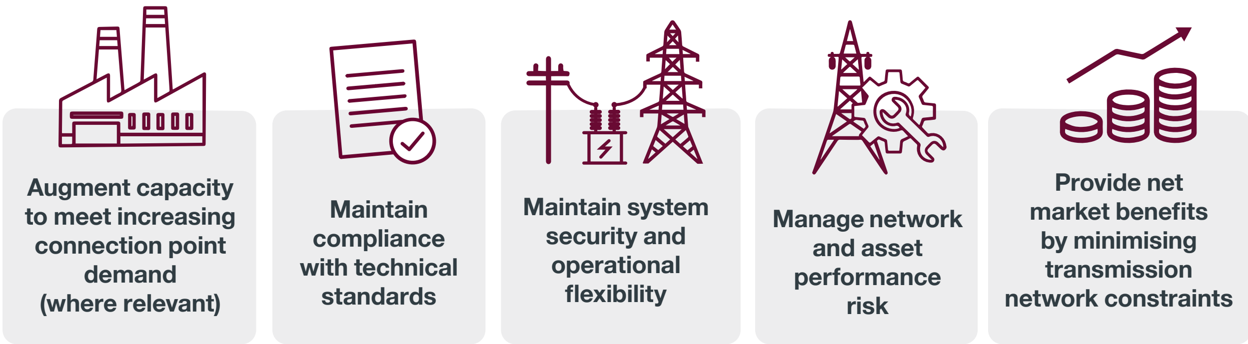
ElectraNet

Photo: Project EnergyConnect

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.

These developments include projects to meet various needs, such as to:



Estimated project costs quoted in this chapter are presented in 2023 dollar values. Cost estimates are provided as a range to reflect the variability of expected project costs. The estimated range for proposed projects is typically wider than for committed and pending projects, due to uncertainties about project scope, contingencies and risk, and the early stages of a project.

Our planning scenario is based on the *Step Change* scenario from AEMO's 2022 ISP. We believe the principles of our analysis and the proposed augmentation projects are still valid. However, because the rapid increase of enquiries and proposals from possible new loads and generators and the magnitude of some of them, we expect that augmentation needs will occur sooner and maybe even to a greater extent.

The scenario and assumptions have been characterised in the table below and a range of potential new generation connections over the next 10 years (generic, based on received enquiries and modelling outcomes) are graphically represented in Figure 20.

Characteristic	Planning scenario
Connection point demand forecasts	As published in the 2023 connection point data on our Transmission Annual Planning Report webpage.[64]
SA transmission system coincident demand forecasts	AEMO's 2023 ESOO 10% POE maximum demand forecast and 90% POE minimum demand forecast.
Potential new load connections	As shown in Figure 20 and Appendix F.
Potential new or retired conventional generators	
Potential new renewable generators	

[64] ElectraNet | Transmission Annual Planning Reports

Figure 20: Assumptions considered in ElectraNet's planning process

7.1 Summary of planning outcomes

Analysis of the planning scenario led to a range of high-level planning outcomes, project recommendations and development outcomes that are required for the scenario (Table 19).

Table 19: Summary of planning and development outcomes

<table>
<tr><th>Planning focus</th><th>Key outcomes</th></tr>
<tr><td>Interconnector and Smart Grid planning</td><td>
Project EnergyConnect
Project EnergyConnect involves the construction of a new 330 kV interconnector from Robertstown in South Australia to Wagga Wagga in New South Wales (NSW). Transfer capacity will be up to about 800 MW.
Once fully delivered, the full combined transfer limit across both the Heywood and Project EnergyConnect interconnectors will be 1,300 MW into South Australia and 1,450 MW export.
Project EnergyConnect remains an important project for the national electricity grid and a priority project for ElectraNet, AEMO and the federal and state governments.
Independent analysis shows Project EnergyConnect is expected to deliver additional net annual savings of around $100 for a typical household in South Australia and up to around $60 for a typical household in New South Wales. It will drive competition in the wholesale electricity market by connecting more, low-cost generation to the grid and support the ongoing transition to a lower carbon emissions future.
Project EnergyConnect construction commenced in May 2022 and remains on track to be delivered in two stages:
• The inter-network testing and release of initial transfer capability of the section from Robertstown in South Australia to Buronga in NSW are scheduled for the second quarter of 2024. The release of initial transfer capability up to 150 MW will be subjected to availability of suitable test conditions
• The completion of the second section from Buronga to Wagga Wagga in NSW, energisation and commissioning in late 2024, with inter-network testing and release of transfer capacity up to 800 MW over 12–18 months, subject to market demand.
Emergency Control Schemes
With the rapid evolution of the Power System, we expect that the need for emergency control schemes to manage both credible and non-credible system events will continue to grow.
Wide Area Protection Scheme
In collaboration with AEMO we are upgrading our old System Integrity Protection Scheme (SIPS) to a more sophisticated Wide Area Protection Scheme (WAPS). The final scheme will be commissioned in November 2023.
South Australian Interconnector Trip Remedial Action Scheme
As part of Project EnergyConnect a South Australian Interconnector Trip Remedial Action Scheme (SAIT RAS) is being implemented to cater for the non-credible loss of either Project EnergyConnect or Heywood. The WAPS and other SPSs will also be reviewed when Project EnergyConnect is implemented.
Wide Area Monitoring Scheme
We have rolled out a limited Wide Area Monitoring Scheme (WAMS) that uses phasor monitoring units to provide enhanced, high-resolution, time-synchronised wide area system monitoring access across the SA transmission network. We plan to enhance the existing WAMS by installing further phasor measurement units at candidate sites across the SA transmission network, which have been selected in collaboration with AEMO.
</td></tr>
</table>

Table 19: Summary of planning and development outcomes (cont.)

<table>
<tr><th>Planning focus</th><th>Key outcomes</th></tr>
<tr><td>System security, power quality and fault levels</td><td>System strength, inertia and fast frequency response
We installed synchronous condensers at Davenport and Robertstown in 2021, addressing the system strength and synchronous inertia needs that AEMO identified in 2018 for South Australia. They also contribute to the ongoing provision of adequate voltage control in the Mid North and Upper North of the South Australian transmission system including at times of low demand.
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 as well as significantly alleviating voltage limits in the Mid North.
The synchronous condensers have also enabled the SA system to be operated securely with only two large synchronous generator units in-service. Project EnergyConnect will facilitate the operation of the SA system with no synchronous units in service.
AEMO has not identified any system strength shortfall in South Australia in its 2022 AEMO System Strength Report, since the installation of the synchronous condensers at Davenport and Robertstown in 2021. However, based on AEM's forecasts of Inverter Based Renewables, there is a need to provide an increasing "efficient" level of system strength in South Australia from 2 December 2025. We are commencing a RIT-T to meet the efficient level.
AEMO confirmed the need for 360 MW of fast frequency response (FFR) or equivalent support activities from 1 July 2023, to maintain a secure operating level of inertia in South Australia until Project EnergyConnect is in operation. We engaged the market at the beginning of this year and secured the provision of the required FFR services.
Voltage control
We have identified a need to reduce the system's reliance on dynamic reactive power devices to satisfactorily manage steady-state voltage levels at times of low system demand. The identified need is supported by dynamic studies undertaken in early 2022. We are investigating options to resolve this need with project EC.11645 Transmission Network Voltage Control.
We are investigating this identified need and options to address it in the RIT-T process. We started the consultation process with the release of a PSCR in December 2022, followed by a request for additional information from proponents of non-network options. We are also considering network options such as the installation of a suite of 50–60 Mvar 275 kV reactors at various locations. We are progressing the economic assessment of the cost and benefits of the credible options, and plan to release a PADR before the end of 2023.
We expect the outcome of the project to enable continued satisfactory voltage control on the South Australian transmission system by maintaining an appropriate reserve of dynamic reactive power capability at times of low or negative net system demand.
In September 2023 we completed the installation of our spare 50 Mvar 275 kV reactor at Cherry Gardens, to provide additional voltage control capability for the Adelaide metropolitan area prior to completion of the Transmission Network Voltage Control RIT-T. Similarly, we are also considering the relocation to Para (for installation of a hot spare) of a reactor that has been installed at Bundey. At Para, it would provide additional voltage control capability for the Adelaide metropolitan area.
Power Quality
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 technical compliance limits. Further investigation is required to ensure appropriate levels of power quality performance for all network connected customers (load and generation).
Maximum fault levels
Fault levels are forecast to remain within design and equipment limits for the duration of the planning period.</td></tr>
<tr><td>Capacity and Renewable Energy Zone development</td><td>New connections
The South Australian transmission system continues to have capacity to connect new load, generators, and storage. Generation output may at times be limited by system constraints, particularly at times of very low system demand and at times of coincident high generation output of wind and solar farms.
We are aware of significant interest on large new generator and battery connections in the Mid North, Eyre Peninsula, Upper North and Riverland regions. There are also potential connections of batteries in metropolitan Adelaide.
We are working with South Australia's government to understand the impact of the emergence of Hydrogen production industry within our state. In addition to Hydrogen production, we continue to receive interests in load development in South Australia that would like to take advantage of our low-cost and low-emission electricity from renewable sources. Among these are large data centres and mine sites.
We are progressing some of the projects required to support these large generation and loads and which were signaled initially in the 2022 ISP. These include increasing power transfer capability between the South East, Mid North and metropolitan Adelaide and upgrade of Eyre Peninsula.</td></tr>
</table>

Table 19: Summary of planning and development outcomes (cont.)

Planning focus	Key outcomes
Capacity and Renewable Energy Zone development (cont.)	• **Eyre Peninsula Upgrade** Earlier this year 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 kV capable to enable it to be cost effectively upgraded to 275 kV operation when needed in the future. Depending on the load forecast it might be necessary to increase transfer capacity between Davenport and Cultana by construction of new 275 kV transmission lines. Based on the current level of customer interest on the Eyre Peninsula, we plan to commence a RIT-T before the end of 2023 to investigate increasing the capacity of the Cultana to Yadnarie section of Eyre Peninsula Link. • **South East Stage 1 Expansion** We completed preparatory activities for this potential expansion in June 2023. Network expansion would facilitate the connection of 400 MW to 600 MW of generation within this large REZ, such as wind generation near Mount Gambier or solar generation near Tailem Bend. The proposed scope is to string the vacant Tailem Bend to Tungkillo 275 kV circuit to enable increased transfers between the South East of South Australia and the Adelaide metropolitan load centre. AEMO's 2022 ISP identified that this project would be needed by the mid-2020s in the *Hydrogen Superpower* scenario and by 2029 in the *Step Change* scenario. Given the updated demand outlook it is likely that the need for this project will be aligned with the earlier timing, which would lead to it being declared as an actionable project in AEMO's 2024 ISP. If identified as an actionable project in AEMO's 2024 ISP, we will undertake the applicable RIT-T and contingent project processes. • **Mid North Expansion (Southern)** We completed preparatory activities for this potential expansion in June 2023. Network expansion would improve the power transfer from Bundey/Robertstown to the Adelaide load centre area to facilitate the transfer of generation in the North of South Australia to the main loads in the South. The proposed scope is to construct new high-capacity transmission lines from Bundey to either Para or a new location (between Torrens Island and Parafield Gardens West), along with a second 275/132 kV transformer at Templers West and 132 kV and 275 kV reconfiguration works in the Mid North. AEMO's 2022 ISP identified that this project would be needed by the late 2020s in the *Hydrogen Superpower* scenario and by the early 2030s in the *Step Change* scenario. Given the updated demand outlook it is likely that the need for this project will be brought forward, which may lead to it being considered for actionable status in AEMO's 2024 ISP. If identified as an actionable project in AEMO's 2024 ISP, we will undertake the applicable RIT-T and contingent project processes. • **Mid North Expansion (Northern)** Network expansion would unlock the 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, as well as further unlocking potential for increased connection of renewables in the Mid North SA, Northern SA, and Eastern Eyre Peninsula REZs. It would also provide capacity to supply developing iron ore deposits in the Braemar region (near Yunta), and provide a new high-capacity transmission path connecting the Adelaide load centre and emerging hydrogen hub major load centres on Eyre Peninsula with sources of renewable energy generation. The proposed scope is to construct new high-capacity transmission lines between Bundey and Cultana. We see this project as a priority option for further investigation given the extent of the higher potential electricity demand discussed in this Transmission Annual Planning Report. We are currently progressing these investigations to support AEMO's consideration of this project in its 2024 ISP. **Connection points** • **Tailem Bend** Based on the latest draft forecasts from SA Power Networks, loads at Tailem Bend are projected to exceed transformer ratings at Tailem Bend from about summer 2027-28. If this projection is confirmed by the final 2023 connection point forecast, we plan to commence a RIT-T for this identified need during 2024. • **Other connection points** Loads at all other connection points are forecast to remain within design and equipment limits for the duration of the planning period.

Table 19: Summary of planning and development outcomes (cont.)

<table>
<tr><th>Planning focus</th><th>Key outcomes</th></tr>
<tr><td>Market benefit opportunities</td><td>We have implemented projects that form ElectraNet's 2018–23 Network Capability Incentive Parameter Action Plan (NCIPAP) to reduce the impact of existing and forecast network constraints to deliver net market benefits. This includes the project to turn in the Tailem Bend to Cherry Gardens 275 kV line at Tungkillo which was delivered in June 2023.

We have included projects in our 2023–28 NCIPAP. These include projects to:
• 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
• 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
• Replace disconnector(s) and perform secondary system works (e.g. protection relay settings and CT ratio changes) to remove limitations that currently limit maximum flows on the 275 kV "East" circuit between Davenport and Para to 1250 A, enabling power flows of up to 645 MVA
• 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
• 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
• Alleviate forecast congestion on the Murraylink interconnector at times of high export by installing a 132 kV capacitor bank at Monash and upgrade the existing runback control scheme to include bi-directionality and allow it to run forward if required.</td></tr>
<tr><td>Network asset retirements and de-ratings</td><td>South Australia's transmission network is older than many others. Our replacement and refurbishment plans are based on our assessment of the condition, risk and performance of the relevant assets. We assess the condition of the various components of each transmission line and substation asset on an ongoing basis through routine inspections and patrols.

This information is used to assess how much longer the component can be expected to keep functioning before it fails. In doing this, we consider other information such as failure rates observed elsewhere and environmental conditions surrounding the assets.

Based on our assessment of asset condition, risk, cost and performance, we plan to address emerging condition needs for a range of assets on South Australia's electricity transmission network during the planning period.

Our major line refurbishment projects and substation asset replacement projects focus on the key components of these assets on the network. Our program includes current transformers, SVCs computer control systems, refurbishment of transmission lines and others.</td></tr>
<tr><td>Emergency control schemes</td><td>With the rapid evolution of the Power System, we expect that the need for emergency control schemes to manage both credible and non-credible system events will continue to grow.

In collaboration with AEMO we are upgrading our old System Integrity Protection Scheme (SIPS) to a more sophisticated Wide Area Protection Scheme (WAPS). The final scheme will be commissioned on November 2023. As part of Project EnergyConnect a Special Protection Scheme (SPS) will be implemented to cater for the non-credible loss of either Project EnergyConnect or Heywood. The WAPS and other SPSs will also be reviewed when Project EnergyConnect is implemented.

We have rolled out a limited Wide Area Monitoring Scheme (WAMS) that uses phasor monitoring units to provide enhanced, high-resolution, time-synchronised wide area system monitoring access across the SA transmission network. We plan to enhance the existing WAMS by installing further phasor measurement units at candidate sites across the SA transmission network, which have been selected in collaboration with AEMO.

AEMO published its final report for the 2022 Power System Frequency Risk Review (PSFRR) in July 2022. The 2022 PSFRR recommended revisions to constraints on the Heywood interconnector associated with the existing protected event for destructive wind conditions in South Australia. It also indicated AEMO's intention to explore options to forecast and manage future National Electricity Market ramping events (such as have been identified in South Australia during 2021) resulting from the increasing penetration of distributed solar PV generation and transmission-connected inverter-based resources.

In July 2023 AEMO published its first General Power System Risk Review (GPSRR), which replaced the Power System Frequency Risk Review (PSFRR). The GPSRR has a broader scope to explore a wider range of risks that could have adverse impacts on the power system. In this year the report examines the event of a tower failure and trip of South East-Tailem Bend 275 kV lines, which occurred on 12th November 2022. Based on this event and others in different states, AEMO recommended to develop and coordinate emergency reserve and system security plans, maintain a high operational capability and training and continue considering non-credible contingency events which could adversely impact the stability of the power system. We are assessing the impact that this will have on our planning processes and priorities.</td></tr>
</table>

7.2 Committed urgent and unforeseen investments

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

In January 2022 the Para SVC No.2 transformer and auxiliary equipment were damaged by a transformer fire. We have carried out project EC.15320 Para SVC No.2 Transformer Emergency Replacement to purchase and replace the damaged transformer and auxiliary equipment. Restoration of the SVC was completed in September 2023.

Iin September 2023 we installed our spare 275 kV 50 Mvar reactor at Cherry Gardens substation to assist with voltage control, especially for managing high voltage levels at times of low or negative demand. The project EC.15322 Emergency Transmission Network Voltage Control was created to facilitate this.

7.3 Interconnector and Smart Grid planning

ElectraNet is progressing projects and investigating opportunities to increase interconnector capacity between South Australia and the rest of the NEM, including the development of Project EnergyConnect and the deployment of "smart grid" technology such as wide area monitoring and protection schemes (Table 20 and Figure 21).

We are upgrading our old System Integrity Protection Scheme (SIPS) to a more sophisticated Wide Area Protection Scheme (WAPS), which will satisfy the requirements of AEMO's 2018 Power System Frequency Review. We will be further upgrading the WAPS to a more extensive Wide Area Monitoring Scheme (WAMS).

To meet supply requirements over the medium to long term, we are considering potential options for future additional interconnection. Options include a new 500 kV interconnector in the South East of South Australia and Victoria, and a new 500 kV interconnector to connect from either Bundey or near Yunta to New South Wales.

Table 20: 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.14246 Wide Area Protection Scheme (WAPS) Implement a Wide Area Protection Scheme with the use of PMUs to real time monitor and process system parameters for event detection and include dynamic arming of participating loads and battery energy storage systems to enable a proportionate response to specific events to further enhance SA system security.	Various	Stability Operational	November 2023
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): Second quarter 2024 Stage 2 (Buronga to Wagga Wagga): late 2024

Table 20: 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: $12–16 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 CER Feed-in – monitoring will help understand the response of CER 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	March 2024
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	Beyond 2028 (When or if shown to deliver net market benefits)
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 and 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 would impact inter-regional transfer.	Main Grid	Market benefit Augmentation	Beyond 2028 (When or if shown to deliver net market benefits)

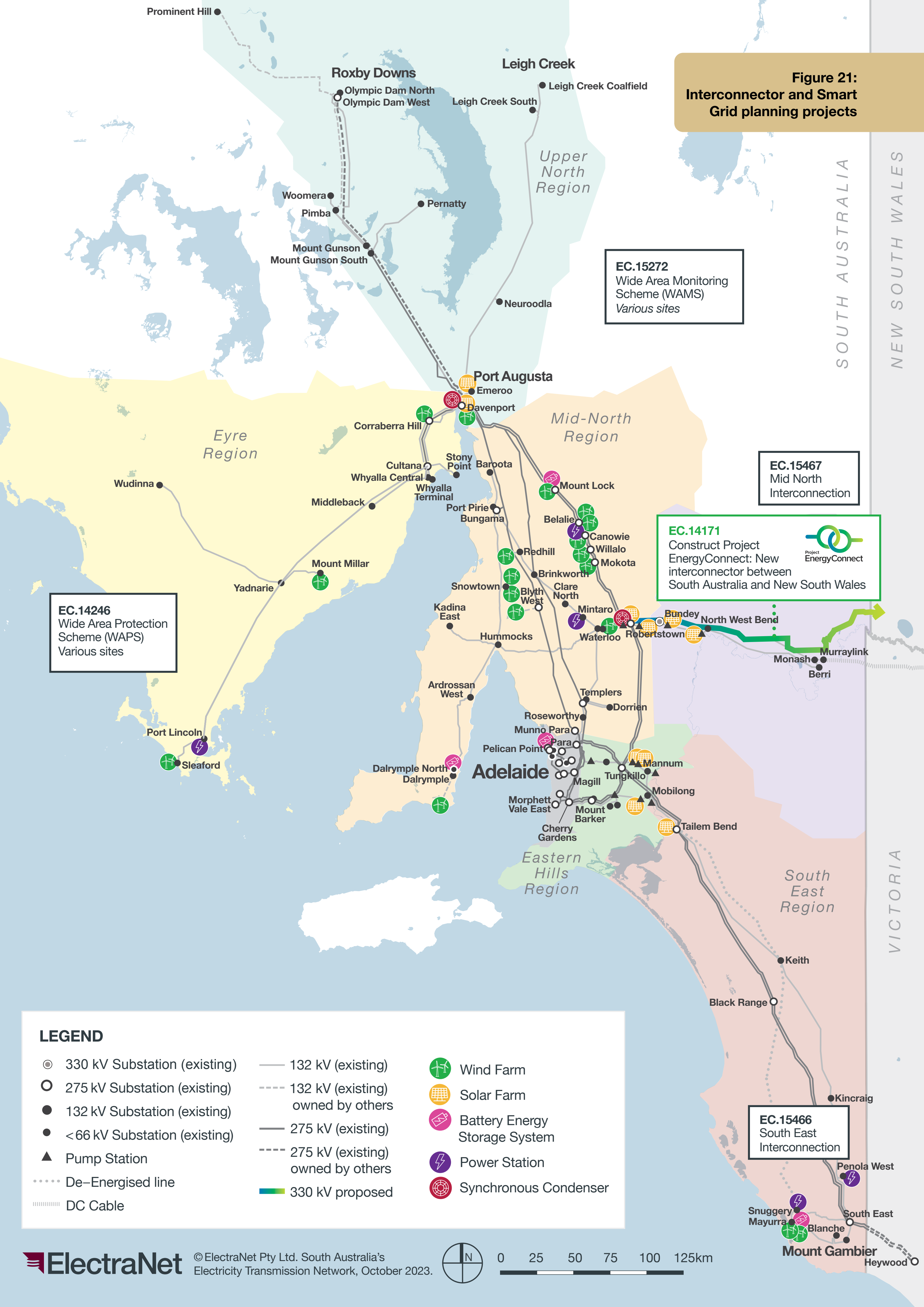


Figure 21: Interconnector and Smart Grid planning projects

7.4 System security, power quality and fault levels

A secure power system needs adequate levels of system strength, inertia, and voltage control, which in the past have been provided by synchronous power generation. We have proposed several projects to continue to provide an adequacy supply of system strength, inertia, and voltage control on South Australia's transmission network (Figure 22 and Table 21).

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

AEMO's most recent review of inertia declared a shortfall in ElectraNet's network, equivalent to 360 MW of fast frequency response or equivalent inertia support activities, from 1 July 2023 until the expected completion of inter-network testing for Project EnergyConnect. We engaged the market and contracted third parties for provision of the required services.

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

Based on the outcomes of AEMO's 2022 ISP and confirmed by our own modelling, the total of conventional generation in South Australia is expected to reduce over the next 10 years. Substation fault levels were assessed to ensure they will remain within design and equipment limits.

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

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

The installation of synchronous condensers at Davenport and Robertstown during 2021 has maintained and enhanced the ability to adequately control system voltage levels. Additional investment to increase inductive reactive power capability is forecast to be needed at times when there are no conventional generators online during minimum demand to maintain the ability of the system to control system voltage levels within equipment limits as the penetration of distributed solar PV generation continues to the extent that it delivers a net infeed to the transmission system.

The 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.[65]

[65] ElectraNet | Transmission Annual Planning Reports

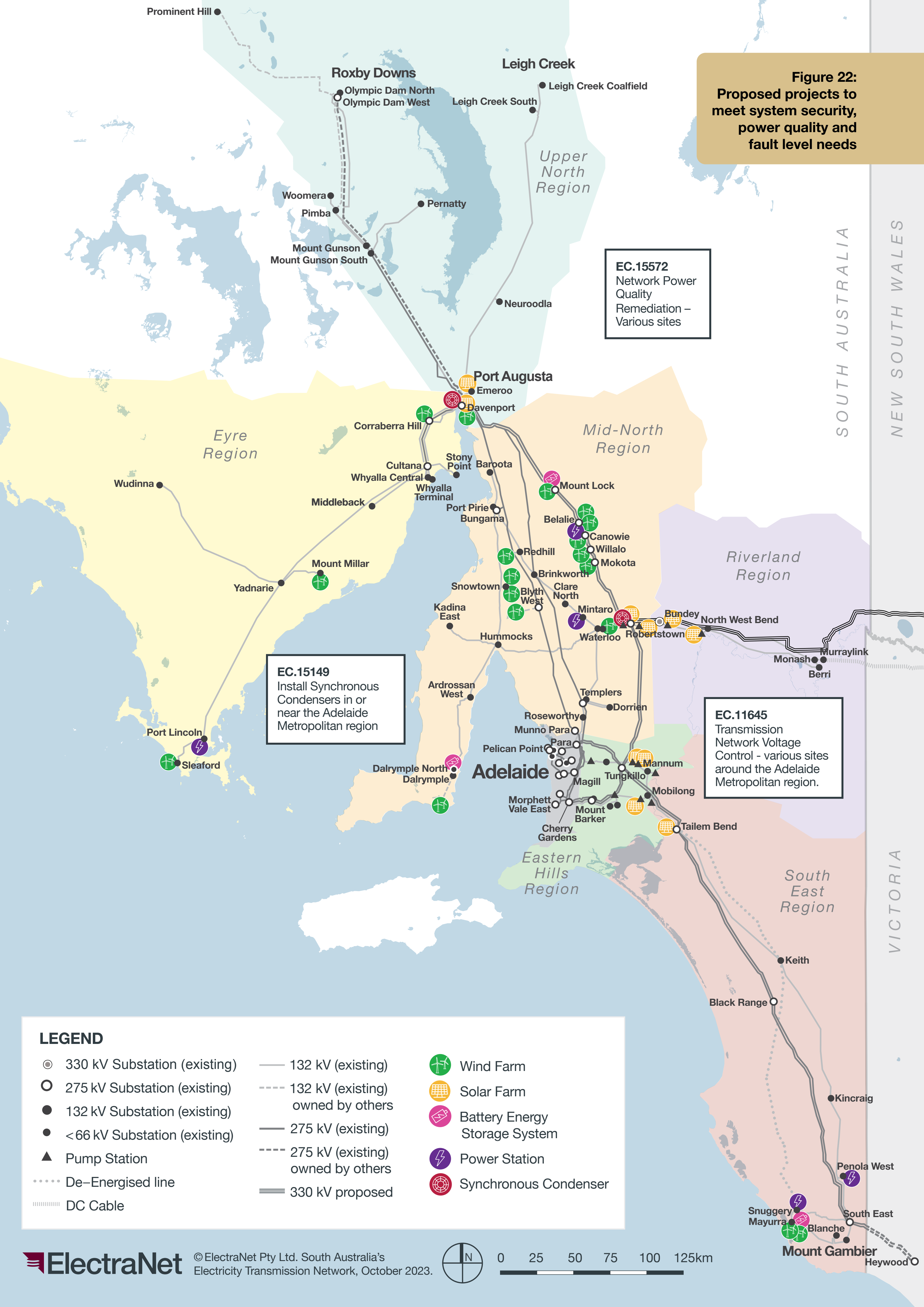


Figure 22: Proposed projects to meet system security, power quality and fault level needs

Table 21: 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: $50–60 million** **Status: Planned** Install a total of four 60 Mvar 275 kV reactors around the Adelaide metropolitan region at 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. We are progressing the RIT-T for this project. ElectraNet does not envisage that this project will impact inter-regional transfer.	Main Grid	Reactive support Augmentation	2026
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 inter-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 2025–2028 **Estimated cost: $300–450 million** **Status: Planned** Based on AEMO's forecast of Inverter Based Resources, there is a need to provide an increased "efficient" level of system strength in South Australia from 2 December 2025. To meet this need we propose to provide additional sources of system strength that will be equivalent to: • 2x 125 MVA synchronous condensers at Para and an additional 1x 125 MVA synchronous condenser at Robertstown or Bundey in 2025 • An additional 1x 125 MVA synchronous condenser at Para and an additional 1x 125 MVA synchronous condenser at Robertstown or Bundey in 2028. We are planning to commence the RIT-T process by the end of 2023. ElectraNet envisages that this project will impact inter-regional transfer.	Main Grid	Compliance Augmentation	2025–2028

7.5 Capacity and Renewable Energy Zone development

Early this year we completed Eyre Peninsula Link to continue efficiently meeting reliability standards on the Eyre Peninsula. We have also identified potential projects to provide capability for future new customers and generators (Table 22 and Figure 23).

ElectraNet annually compares connection capability against forecast connection point demand, considering the redundancy requirements specified for each connection point in the South Australian Electricity Transmission Code (ETC, redundancy requirements summarised in Appendix C Section C2.1). This is coordinated through joint planning with SA Power Networks, in which connection point projects are considered, proposed, and planned (Appendix B1.6).

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 plan to commence a RIT-T to investigate this possible upgrade before the end of 2023.

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. During last year, interest in large new load connections to the South Australian electricity transmission system has risen sharply. Proponents are 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. ElectraNet engaged consultant Energeia to undertake a prioritisation of REZs that considers development cost, delivery risk, and strategic leverage for State policy objectives. This prioritisation used key metrics and inputs to perform economic and strategic ranking assessments, which were combined into a composite ranking (Section 2.1.2). As an outcome of our REZs prioritisation work and our assessment to provide further insights on network investments, 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.

In the 2022 ISP,[66] the South East SA REZ expansion project and the Mid North SA REZ expansion project are required in the late 2020s in the *Hydrogen Superpower* scenario, and early 2030s in the *Step Change* scenario to facilitate the connection of generation within these REZs. Given the continuing high level of interest for connections in South Australia, we consider that the future developments identified could be needed much earlier than indicated.

We have identified a set of immediate priorities to manage this risk, which include:

- **Mid North Expansion (Southern)** – Timing: Mid to late 2020s. Construct new high capacity double-circuit twin conductor lines from Bundey to Para or to a new site between Parafield Gardens West and Torrens Island. Consider immediate incremental benefits of installing a second 275/132 kV transformer at Templers West and reconfiguring the Mid North 132 kV system to alleviate constraints caused by parallel operation of the Mid North 275 kV and 132 kV systems. We completed preparatory activities for this project in June 2023, to enable its consideration for actionable status in 2024 ISP.
- **South East Expansion (Stage 1)** – Timing: Mid to late 2020s. String the vacant circuit that exists on one of the Tailem Bend to Tungkillo 275 kV lines. We completed preparatory activities for this project in June 2023, to enable its consideration for actionable status in 2024 ISP.
- **Eyre Peninsula upgrade** – Timing: Mid to 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 are preparing to commence the RIT-T for this project.
- **Mid North Expansion (Northern)** – Timing: Mid 2020s to early 2030s. Construct new high capacity lines between Bundey and Cultana.

We will continue monitoring the requests for connection and we believe these projects should be declared as actionable projects in AEMO's 2024 ISP. We plan to commence RIT-Ts as soon as it is required.

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.

66 AEMO | 2022 Integrated System Plan (ISP)

Reverse power flows at only two connection points are forecast to possibly exceed their existing reverse power capability this decade. These include:

- Baroota – Reverse capability projected to be exceeded by 2029

  Potential solutions: require SA Power Networks to limit reverse power flows to no more than the existing limit of 10 MVA, and consider the feasibility of applying a reverse flow cyclic transformer ratings
- Mount Barker/Mount Barker South – Reverse capability during a prior outage of a single connection point transformer projected to be exceeded from 2026

  Potential solutions: require SA Power Networks to limit reverse power flows under prior transformer outage conditions, and consider the feasibility of applying reverse flow cyclic transformer ratings.

We monitor updates in reverse power flow forecasts for all connection points, enabling us to implement appropriate reverse power flow management by the time it is required at each connection point.

Table 22: 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: Not yet estimated** **Status: Proposed** Replace the existing 25 MVA 132/33 kV transformers at Tailem Bend with 60 MVA units. If SA Power Network's final 2023 connection point demand forecast confirms the project need for this project in 2027, we plan to commence the RIT-T process in 2024.	South East	Capacity Augmentation	2027
EC.15104 Eyre Peninsula Upgrade **Estimated cost: $50–150 million** **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 will commence a RIT-T to investigate increasing capacity of the Cultana to Yadnarie section of Eyre Peninsula Link. We are planning to commence the RIT-T process by the end of 2023. ElectraNet does not envisage that this project will impact inter-regional transfer.	Eyre Peninsula	Capacity Augmentation	2024 – 2028 (if required to facilitate large new customer connections on Eyre Peninsula)
EC.11011 Upper South East Network Augmentation **Estimated cost: $30–60 million** **Status: Planned** String the vacant third 275 kV circuit between Tailem Bend and Tungkillo and install static and dynamic reactive compensation if needed to increase transfer capability between the South East and the Adelaide metropolitan area. ElectraNet envisages that this project may impact inter-regional transfer.	Eastern Hills	Market benefits Augmentation	2024–2028 (if shown to deliver net market benefits)

Table 22: Projects proposed to meet capacity or REZ development needs (cont.)

Project Description	Region	Constraint driver and investment type	Asset in service
EC.15205 Mid North Expansion (Southern) **Estimated cost: $300–700 million (depending on option)** **Status: Planned** We completed preparatory activities for this project in June 2023, to enable its consideration for actionable status in 2024 ISP. This project will increase transfer capacity between Bundey and the Adelaide metropolitan load centre. Construct new high capacity double-circuit twin conductor 275 kV lines from Bundey to Para or to a new site between Parafield Gardens West and Torrens Island. Consider immediate incremental benefits of installing a second 275/132 kV transformer at Templers West and reconfiguring the Mid North 132 kV system to alleviate constraints caused by parallel operation of the Mid North 275 kV and 132 kV systems. Further project options are included in Section 4.4. We envisage that this project may impact inter-regional transfer.	Mid North	Market benefits Augmentation	2024 – 2030 (if shown to deliver net market benefits)
EC.15469 Mid North Expansion (Northern) **Estimated cost: $300–1,500 million (depending on option)** **Status: Planned** We have provided a high level scope for this project for AEMO's Transmission Expansion Options Report, to enable its consideration for actionable status in 2024 ISP. This project will increase transfer capacity between Bundey and the anticipated Cultana load centre. Construct new high capacity double-circuit twin conductor 330 kV or 500 kV lines from Bundey to Cultana or to a new site at Cultana East, with a line route that traverses a potential new wind and solar REZ near Yunta. Further project options are included in Section 4.4. We envisage that this project may impact inter-regional transfer. Uncertainty around the project's need and timing may result on it to be required for the Green Energy Export scenario.	Mid North	Market benefits Augmentation	2024 – 2030 (if shown to deliver net market benefits)
EC.14085 Gawler East Connection Point **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, 1 x 25 MVA transformer substation.	Mid North	Capacity Augmentation	2029 – 2033 (depending on local load growth)
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 (if shown to deliver net market benefits)

Table 22: Projects proposed to meet capacity or REZ development needs (cont.)

Project Description	Region	Constraint driver and investment type	Asset in service
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. Uncertainty around the project's need and timing may result on it to be required for the *Green Energy Export* scenario.	Main Grid	Market benefits Augmentation	2029–2033 (if shown to deliver net market benefits)
EC.15471 Eyre Peninsula Grid **Estimated cost: Not yet estimated** **Status: Being considered as an option for future development** Develop an HVDC link from Cultana to a new 500 kV HVAC system on the Eyre Peninsula that is AC islanded from the rest of the NEM, with double circuit 500 kV lines to connect new REZs and large loads. This project will 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. Uncertainty around the project's need and timing may result on it to be required for the *Green Energy Export* scenario.	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 between Torrens Island and Parafield Gardens West 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	2034 – 2038 (if shown to deliver net market benefits)

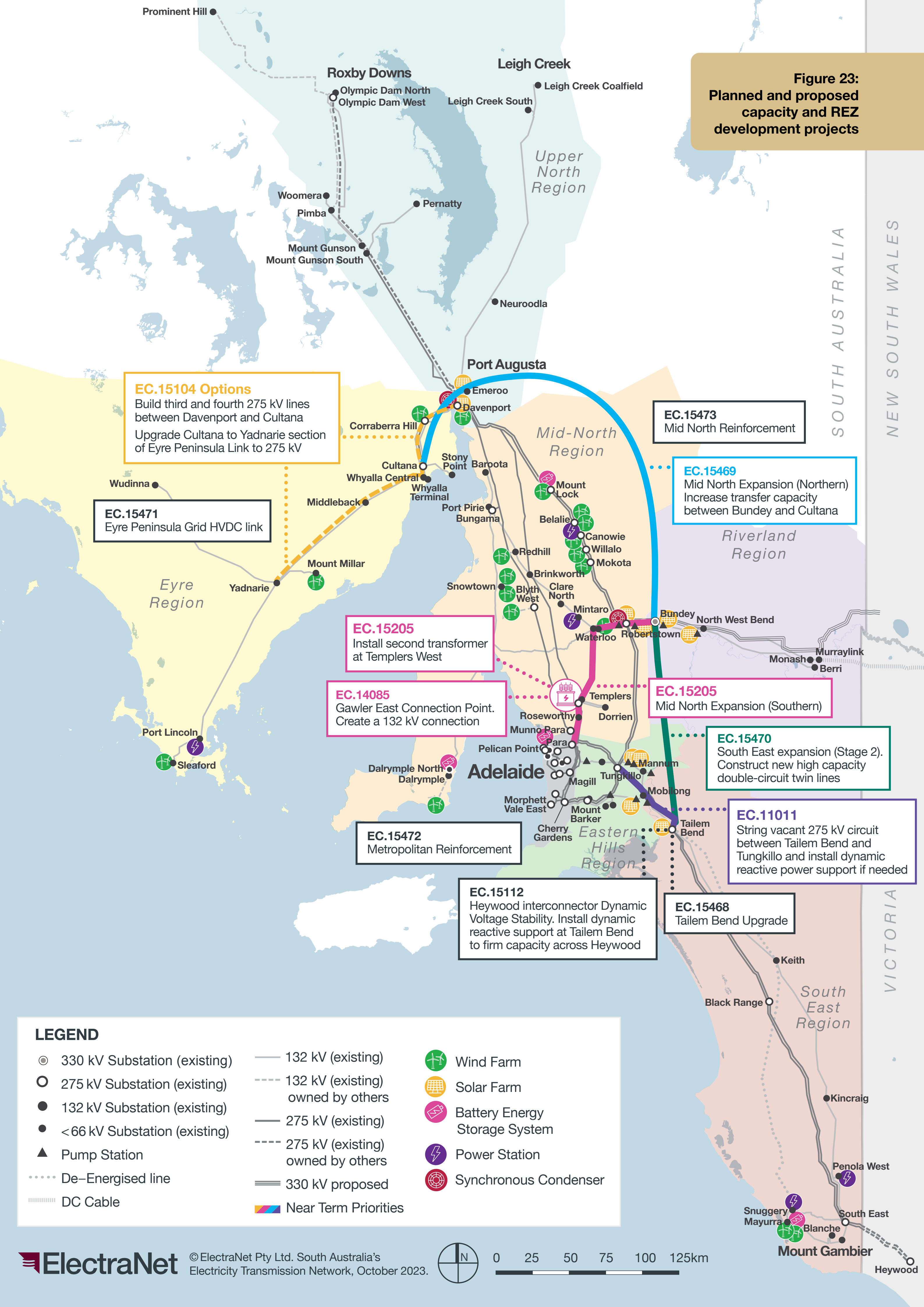


Figure 23: Planned and proposed capacity and REZ development projects

7.6 Market benefit opportunities

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

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 plan to complete projects that form part of our 2018–19 to 2022–23 NCIPAP and projects included in our 2023–24 to 2027–28 NCIPAP (Table 23 and Figure 24).

Table 23: Projects committed, planned and being considered to address market benefit opportunities

Project Description	Region	Constraint driver and investment type	Asset in service
EC.14065 Robertstown 132 kV Uprating **Estimated cost: $1–2 million** **Status: Planned** 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	December 2023
EC.15179 Robertstown to Tungkillo Line Uprating **Estimated cost: $2–3 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	2023–2024
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	2024–2025

Table 23: Projects committed, planned and being considered to address market benefit opportunities (cont.)

Project Description	Region	Constraint driver and investment type	Asset in service
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	2024–2025
EC.15175 Increase Murraylink Transfer Capacity **Estimated cost: $4–6 million** **Status: Proposed** *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 at 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	2025–2026

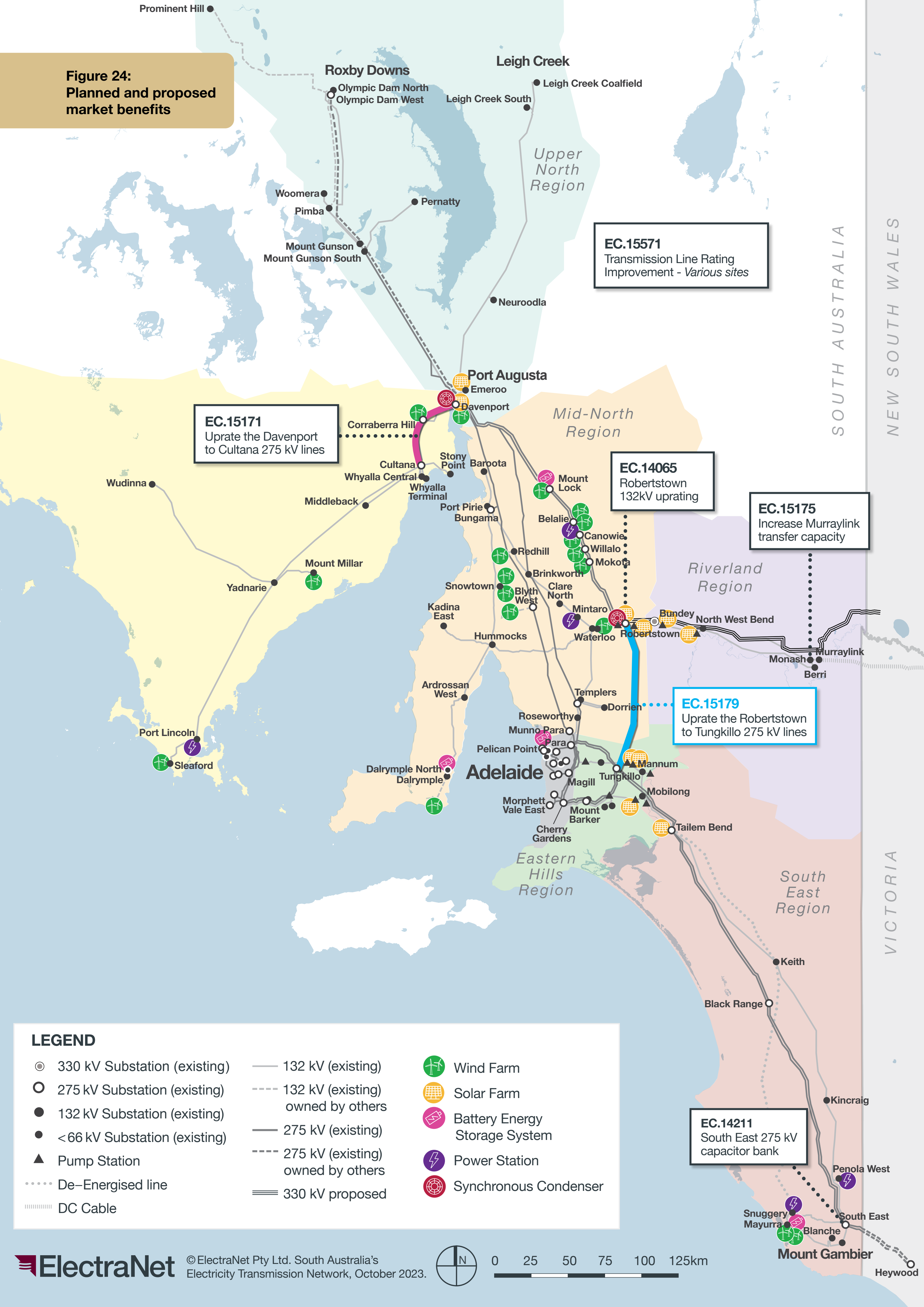


Figure 24: Planned and proposed market benefits

7.7 Network asset retirements and replacements

ElectraNet carries out projects that are planned to address needs that arise from planned retirements of assets, for example due to condition (Table 24).

Prior to 30 January 2018, projects to address replacement needs were not required to be subjected to the RIT-T.

The replacement of a power transformer based on condition provides an opportunity to review the appropriate size and need for any replacement transformer based on forecast demand. This can impact the capacity of the relevant substation. Because of this, projects that relate to the replacement of a power transformer are listed here even if their estimated cost is below the RIT-T threshold.

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

Table 24: 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 38 sets of current transformers at TIPS A and B switchyards that have been identified as high risk of failure.	Metro	Asset condition and performance Asset renewal	September 2025
EC.14077 Mannum Transformer #1 and Secondary System Replacement **Estimated cost: $6–8 million** **Status: Planned** Replace transformer #1 and secondary systems at Mannum substation that has been assessed to be at the end of their technical life 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	February 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 2023–24 to 2027–28 regulatory control period. We plan to initiate a RIT-T prior to commitment.	South East	Asset condition and performance Asset renewal	December 2026

Table 24: 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.15568 Northfield Transformer 7, 8 and 9 Interface Connection Requirement **Estimated Cost: $14–16 million** **Status: Pending** SA Power Networks are planning to replace their ageing and failing 66 kV GIS switchgear at Northfield substation with a new AIS 66 kV switchyard. To support this replacement, we will need to upgrade the 66 kV GIS to AIS connection points to transformers #7, #8 and #9 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	September 2026
EC.15239 F1803 Hummocks – Ardrossan West 132kV Line Refurbishment to 2023–28 **Estimated cost: $30–135 million** **Status: Planned** Replace line conductor, earthwire and insulator strings for the entire Hummocks to Ardrossan West 132 kV line, which has been assessed to be at end-of-life during the 2023–24 to 2027–28 regulatory control period, to renew line asset components and extend the asset life. We plan to initiate a RIT-T prior to commitment.	Mid North	Asset condition and performance Asset renewal	June 2028
EC.15432 F1802 Bungama – Port Pirie 132kV Line Refurbishment **Estimated cost: $5–110 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 2028–29 to 2023–33 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.14090 Mount Gambier Transformer 1 Replacement **Estimated cost: $4–16 million** **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 chosen to match the other 132/33 kV transformer at Mount Gambier, and provides capacity to meet the forecast demand at Mount Gambier connection point.	South East	Asset condition and performance Asset renewal	2029 – 2033

7.8 Network asset ratings

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

The framework proposes initial refinements to the application of static ratings, followed by a more widespread development of dynamic line ratings, which will be supported by improvements to the infrastructure (including weather stations) that is needed to apply and validate the dynamic line ratings.

The investment required to implement our Plant and Line Rating Framework is part of our 2023–24 to 2027–28 NCIPAP (EC.15571 Transmission Line Rating Improvement, Section 7.6).

ElectraNet continually reviews the condition of its network assets to ensure that they are suitable to support the forecast demand. We put a planned refurbishment or replacement program in place when condition assessment indicates that an asset's condition is declining to an unacceptable level.

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

7.9 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 25).

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

Table 25: 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 2018–19 to 2022–23 **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. The number of transformers requiring bushings to be replaced has increased from 16 to 20, as a result of detailed condition assessment of selected transformer bushings following the failure of similar transformer bushings. We published a PACR on 11 December 2018, concluding the RIT T for this program of work.[67]	Various	Asset condition and performance Asset renewal	May 2024
EC.14032 Instrument Transformer Unit Asset Replacement 2018–19 to 2022–23 **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. We published a PACR on 7 January 2020, concluding the RIT T for this program of work.[68]	Various	Asset condition and performance Asset renewal	June 2025

[67] ElectraNet | Managing the Risk of Transformer Bushing Failure PACR

[68] ElectraNet | Managing the Risk of Instrument Transformer Failure PACR

Table 25: 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.14031 Protection systems unit asset replacement 2018–19 to 2022–23 **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 RIT-T for this program of work.[69]	Various	Asset condition and performance Asset renewal	June 2025
EC.14033 Circuit Breaker Unit Asset Replacement 2018–2023 **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	December 2023
EC.14034 Isolator unit asset replacement 2018–19 to 2022–23 **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 RIT T for this program of work.[70]	Various	Asset condition and performance Asset renewal	June 2025
EC.14176 Surge Arrestor Unit Asset Replacement 2018–2023 **Estimated cost: $6–9 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	December 2024

69 ElectraNet | Managing the Risk of Protection Relay Failure PACR

70 ElectraNet | Managing the Risk of Isolator Failure PACR

Table 25: 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.14046 AC Board Replacement 2018–19 to 2022–23 **Estimated cost: $30–35 million** **Status: Committed** Program to replace and improve AC auxiliary supply equipment, switchboards and cabling at seventeen substations across the South Australian electricity transmission system that have been assessed to be at the end of their technical and economic lives. We completed a RIT-T for this program of work by publishing a PACR on 14 January 2020.	Various	Asset condition and performance Asset renewal	July 2026
EC.14081 Line Insulator Systems Refurbishment 2018–19 to 2022–23 **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	August 2024
EC.15043 AC Board Unit Asset Replacement 2023–24 to 2027–28 **Estimated cost: $8–14 million** **Status: Proposed** Replace and improve six AC auxiliary supply systems located at six substations across the South Australian electricity transmission system to be at end-of-life during the 2023–24 to 2027–28 regulatory control period due to increased risk of unsafe access, mal-operation and unplanned outages. We plan to initiate a RIT-T prior to commitment.	Various	Asset condition and performance Asset renewal	June 2028
EC.15060 Circuit Breakers Unit Asset Replacement 2023–24 to 2027–28 **Estimated cost: $15–17 million** **Status: Planned** Replace and improve 24 circuit breakers at 13 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 2023–24 to 2027–28 regulatory control period. We plan to initiate a RIT-T prior to commitment.	Various	Asset condition and performance Asset renewal	June 2028
EC.15120 Instrument Transformer Unit Asset Replacement 2023–24 to 2027–28 **Estimated cost: $16–20 million** **Status: Planned** Replace 25 voltage transformers and 75 current transformers at 14 substations across the South Australian electricity transmission system that have been assessed to be end-of-life during the 2023–24 to 2027–28 regulatory control period to address the increased risk of unsafe operation and poor performance. We plan to initiate a RIT-T prior to commitment.	Various	Asset condition and performance Asset renewal	June 2028

Table 25: 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.15189 Protection Relay Unit Asset Replacement 2023–24 to 2027–28 **Estimated cost: $8–12 million** **Status: Planned** Replace protection relays and associated components at five substations across the South Australian electricity transmission system that have been assessed to be end-of-life during the 2023–24 to 2027–28 regulatory control period. We plan to initiate a RIT-T prior to commitment.	Various	Asset condition and performance Asset renewal	June 2028
EC.15279 Emergency Unit Asset Replacement 2023–24 to 2027–28 **Estimated cost: $8–12 million** **Status: Planned** 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
EC.15233 Transmission Line Insulation System Replacement 2023–24 to 2027–28 **Estimated cost: $32–38 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 2023–24 to 2027–28 regulatory control period, to renew line asset components and extend line life. We plan to initiate a RIT-T prior to commitment	Various	Asset condition and performance Asset renewal	June 2028
EC.15242 Transformer Bushing Unit Asset Replacement 2023–24 to 2027–28 **Estimated cost: $8–12 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 2023–24 to 2027–28 regulatory control period. We plan to initiate a RIT-T prior to commitment.	Various	Asset condition and performance Asset renewal	June 2028
EC.15397 Isolator Unit Asset Replacement 2023–24 to 2027–28 **Estimated cost: $40–45 million** **Status: Planned** Replace 80 individual substation isolators at 12 substations across the South Australian electricity transmission system that have been assessed to be at end-of-life during the 2023–24 to 2027–28 regulatory control period. We plan to initiate a RIT-T prior to commitment.	Various	Asset condition and performance Asset renewal	June 2028

Table 25: 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.15237 Surge Arrestor Unit Asset Replacement 2014–2028 **Estimated cost: $5–7 million** **Status: Planned** Replace 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.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 2028
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
EC.15069 Circuit Breakers Unit Asset Replacement 2028–29 to 2032–33 **Estimated cost: $6–10 million** **Status: Proposed** Replace and improve circuit breakers across the South Australian electricity transmission system that will be assessed to be at the end of their technical and economic lives during the 2028–29 to 2032–33 regulatory control period. We plan to initiate a RIT-T prior to commitment.	Various	Asset condition and performance Asset renewal	2029–2033
EC.15042 AC Board Unit Asset Replacement 2028–29 to 2032–33 **Estimated cost: $8–15 million** **Status: Proposed** Replace and improve AC auxiliary supply equipment, switch boards and cabling at seventeen substations across the South Australian electricity transmission system that will be assessed to be at the end of their technical and economic lives during the 2028–29 to 2032–33 regulatory control period. We plan to initiate a RIT-T prior to commitment.	Various	Asset condition and performance Asset renewal	2029–2033

Table 25: 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.15123 Instrument Transformer Unit Asset Replacement 2028–29 to 2032–33 **Estimated cost: $50–80 million** **Status: Proposed** Replace voltage transformers and current transformers across the South Australian electricity transmission system that have reached the end of their technical or economic lives and have an increased likelihood of catastrophic explosion. This project will include the replacement of assets which will be determined based on asset needs. We plan to initiate a RIT-T prior to commitment.	Various	Asset condition and performance Asset renewal	2029–2033
EC.15244 Transformer Bushing Unit Asset Replacement 2028–29 to 2032–33 **Estimated cost: $5–10 million** **Status: Proposed** Replace individual transformer bushings that will be assessed to be at the end of their technical or economic lives during the 2028–29 to 2032–33 regulatory control period. This project will include the replacement of assets which will be determined based on asset needs. We plan to initiate a RIT-T prior to commitment.	Various	Asset condition and performance Asset renewal	2029 – 2033
EC.15211 Protection Relays Unit Asset Replacement 2028–29 to 2032–33 **Estimated cost: $8–15 million** **Status: Proposed** Replace protection relays and control schemes across the South Australian electricity transmission system that will be assessed to be at the end of their technical and economic lives during the 2028–29 to 2032–33 regulatory control period. We plan to initiate a RIT-T prior to commitment.	Various	Asset condition and performance Asset renewal	2029–2033
EC.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 2028–29 to 2032–33 regulatory control period. We plan to initiate a RIT-T prior to commitment.	Various	Asset condition and performance Asset renewal	2029–2033
EC.15251 Transmission Line Insulation Unit Asset Replacement 2028–29 to 2032–33 **Estimated cost: $12–20 million** **Status: Proposed** Refurbish transmission line insulator systems across the network that will be assessed to be at end-of-life during the 2028–29 to 2032–33 regulatory control period, to renew line asset components and extend line life. We plan to initiate a RIT-T prior to commitment.	Various	Asset condition and performance Asset renewal	2029 – 2033

Table 25: 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.15253 Transmission Line Conductor Unit Asset Replacement 2028–29 to 2032–33 **Estimated cost: $12–20 million** **Status: Proposed** Replace transmission line conductor and earthwire for components that will be assessed to be at end-of-life during the 2028–29 to 2032–33 regulatory control period, to renew line asset components and extend line life. We plan to initiate a RIT-T prior to commitment.	Various	Asset condition and performance Asset renewal	2029–2033
EC.15295 Emergency Unit Asset Replacement 2028–29 to 2032–33 **Estimated cost: $8–12 million** **Status: Proposed** Emergency replacement of individual assets is undertaken for assets that fail unexpectedly, to meet reliability standards. The average annual value of emergency replacement is about $2 million.	Various	Asset condition and performance Asset renewal	2029–2033

7.10 Security and compliance projects

There are a range of committed and planned projects that relate to the maintenance of our security and compliance for which planned expenditure exceeds $7 million (Table 26).

Table 26: Committed 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	December 2024
EC.11828 Substation Perimeter Intrusion and Motion Detection Security System **Estimated cost: $12–20 million** **Status: Proposed** Upgrade substation security systems across all 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	June 2028
EC.15220 Substation Security Fencing Replacement 2024–2028 **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	March 2027
EC.15235 Transmission Line Anti-Climb Installation 2023–24 to 2027–28 **Estimated cost: $20–25 million** **Status: Proposed** Install climbing deterrent devices and warning signage on 2,100 transmission towers located on 59 high voltage transmission lines that have been assessed as highly vulnerable to unauthorised access.	Various	Safety Asset renewal	June 2028
EC.15399 Substation Technology System Cybersecurity Uplift 2024–2028 **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 2028

Table 26: 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	June 2028
EC.15496 Substation LAN Replacement and Cybersecurity Uplift 2028–2033 **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 2023–2028 period.	Various	Security Asset Renewal	2029–2033
EC.15231 Transmission Line Anti-Climb 2028-29 to 2032-33 **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 2028–2033 **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: Summary of changes since the 2022 Transmission Annual Planning Report

In this appendix we provide an analysis and explanation of forecast demand, and other aspects of the 2023 Transmission Annual Planning Report (TAPR) that have changed significantly from the 2022 report. The following table includes a summary of the significant changes to our Transmission Annual Planning Report, which may be due to:

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

Table 27: Summary of changes since the 2022 Transmission Annual Planning Report

Section	Section Name	Significant changes between the 2022 and 2023 TAPR	Analysis and explanation for the significant change
1.1	South Australia's energy system transition: exceeding expectations	Figure 1 was updated based on the latest available figures and includes two new figures. Added Figure 2 to support narrative around the growing demand. Section 1.1 was updated to reflect current Federal and State government targets on net zero emission and renewable generation. The section describes the main possible drivers of load increase in South Australia and some of the network operational challenges. To provide a better view of the transition of the South Australian network, the infogram previously displayed after the executive summary has been moved to the end of this section.	Figures 1 and 2 used to describe the load evolution in South Australia. The section describes some of the operational risk challenges when the network operates at high levels of renewable energy. It briefly describes the demand and generation forecasts. This section has absorbed some of the information of the previous year 1.1.1, as that section has changed.
1.1.1	Customer interest	This is a new section explaining some of the reasons why to expect a very high increase in the demand forecast. Material under this numeral from last year document has been shifted to Section 1.1 and others.	This section and the following ones present some of the key drivers shaping the future of the network. This section briefly lists the main components that will shape the load forecast for South Australia.
1.1.2	New generation interest	This is a new section presenting some of the possible extremely large generators that could connect to the system.	This section briefly presents the possible type of generators that could connect to the network.
1.1.3	Distributed solar PV generation	This is a new section presenting the effect this generation component has in the system.	This section briefly discusses the effect distributed PV solar generation in the network.
1.1.4	Battery Energy Storage Systems	This is a new section briefly showing how BSEE are becoming an important component in the network explaining some of the reasons why to expect a very high increase in the demand forecast. Material under this numeral from last year document has been shifted to Section 1.1 and others	This section presents the present forecast for BSEEs in the South Australian Network.

Table 27: Summary of changes since the 2022 Transmission Annual Planning Report (cont.)

Section	Section Name	Significant changes between the 2022 and 2023 TAPR	Analysis and explanation for the significant change
1.2	Network Vision, future directions and key priorities	This section was updated with latest data and information. We summarised the themes on this section.	We updated the infographic in this section to reflect current figures and forecasts. We updated information on our current and planned projects. Each theme was summarised , presenting the information in a more compact way.
1.3	Network Transition Strategy	This is a new section introducing how ElectraNet is preparing to continue transitioning to 100% renewable.	ElectraNet's Network Transition Strategy is designed to enable the South Australian transmission system to continue 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.
1.4	How are our network vision and network transition strategy helping us prepare for the future?	Section renamed and assigned a new number.	We renamed this section to include our alignment with our network transition strategy in addition.
1.4.1	Interconnection	Section renumbered and updated.	We assigned a new number to the section and updated some of the information.
1.4.2	Managing asset condition	Section renumbered.	We assigned a new number to the section.
1.4.3	Planning for efficiently accommodate supply-side changes	This section was renumbered and updated with latest information.	We changed the number of this section and included more details about our plans to upgrade Eyre Peninsula Link and the preparation activities for some of projects connected to REZs.
1.4.4	Inertia and fast frequency response	This is a new section, replacing the inertia section from last TAPR.	We included information about our present network strength and how are we planning for the future.
1.4.5	System strength	This is a new section.	We included information about our present network strength and how are we planning for the future.
1.4.6	Challenges of increasing penetration of distributed energy resources on system security and voltage control	This section was renumbered and updated with latest information.	We changed the number of this section and included reference to AEMO's Engineering Roadmap to 100% Renewables).
1.4.7	Managing system security	This is a new section.	This section comments on the General Power System Risk Report.
1.4.8	Potential drivers of load	This section was renumbered and updated.	We changed the number of this section and introduced ElectraNet's position with respect to the demand forecast and its main drivers.
1.4.9	Climate Change	This section was renumbered and updated.	We introduce new information on how climate change can have a direct effect on ElectraNet and added graphs to illustrate.
2.1	Integrated System Plan	The information in this section was updated and includes data from ESOO 2023.	We updated the information on the projects and consolidated contents. Added the graph depicting ESOO 2023 scenarios.

Table 27: Summary of changes since the 2022 Transmission Annual Planning Report (cont.)

Section	Section Name	Significant changes between the 2022 and 2023 TAPR	Analysis and explanation for the significant change
2.1.2	Overview of all candidate REZs in South Australia	This section has been expanded with some of the work done to prioritize and understand the development of the REZs.	We included the results of our work, assisted by a consultant to prioritize the REZs. We updated the information on the potential projects.
2.1.4	South Australia demand sensitivity to replace core scenarios	This is a new section.	This section introduces the demand sensitivity analysis requested by ElectraNet in collaboration with AEMO.
2.2	2022 System Security Reports	The information in this section was updated and consolidated.	We updated the information and consolidated contents.
2.2.1	System strength	The information in this section was updated and extended.	We updated this section with information from AEMO's 2022 System Strength Report. We included our strength needs forecast and the plan to resolve them.
2.2.2	Inertia	The information in this section was updated.	We added some comments around batteries.
2.2.3	NSCAS	The information in this section was updated.	We included information on the progress of project EC.11645.
2.3	Power System Frequency Risk Review	The information in this section was updated.	We updated the information making reference to AEMO's 2022 Power System Frequency risk review (PSFRR).
2.3.1	Recommendations and findings relating to South Australia	The information in this section was updated.	Information presented on protected event and how this is managed, and ramping events associated with CER and renewables.
2.4	General Power System Risk Review	The information in this section was updated.	We updated the section with information from AEMO's 2023 General Power System Risk Review (GPSRR).
2..4.1	Recommendations and finds relating to South Australia	This is a new section.	We summarized the findings from the GPSRR relative to South Australia.
3.1	South Australian electricity demand	We updated the figure with new information.	We updated the figure to include data for 2022–23.
3.3	Potential key drivers of demand	This section was renumbered, updated and expanded with new information.	We changed the section number and updated information to describe potential drivers that could in future increase demand levels higher than the current forecasts.
3.3.1	Large-scale hydrogen production	This section was renumbered and renamed.	We included more detailed information about some of the publicly announced large hydrogen projects. Added some comments about level of connections enquires.
3.3.2	Mining and large industrial loads	This is a new section.	We included a brief commentary on the important influence on the demand forecast by this sector.
3.3.3	Electrification	This is a new section.	We included a commentary on the important influence on the demand forecast by this sector.

Table 27: Summary of changes since the 2022 Transmission Annual Planning Report (cont.)

Section	Section Name	Significant changes between the 2022 and 2023 TAPR	Analysis and explanation for the significant change
3.4	Demand forecasts	This section was renumbered and updated.	We updated this section to reflect the latest available information.
3.4.1	Integrated System Plan Sensitivity	This is a new section explaining ElectraNet's requested sensitivity.	We added a brief description of ElectraNet's requested sensitivity demand analysis.
3.5.1	Weather conditions during summer	This section was renumbered and updated.	We updated this section to reflect the latest available information.
3.5.2	State-wide demand review	The information in this section was updated.	We updated this section to reflect the latest available information. More days over 2,500 MW than previous year. Similarly, more days were under 250 MW.
3.5.3	Connection point maximum demand review	The information in this section was updated.	We updated this section to reflect the latest available information. We provided some insights on the 2022 Connection Point maximum demand forecast.
3.5.4	Connection point minimum demand review	This section was updated.	We updated the information.
4.2	Transmission system constraints in 2022	The information in this section was updated.	We updated this section to reflect the latest available information. We selected constraints for analysis if their impact was at least $50,000 during 2022.
4.3	Emerging and future network constraints and performance limitations	The information in this section was updated.	We updated this section to reflect forecast binding constraints and hours based on the 2022 ISP *Step Change* scenario We provided brief discussion on future constraints.
4.4	Potential projects to enable load growth	This section was updated.	We provided information on potential projects to address future constraints. We included new Eyre Peninsula Upgrade project, added new information and detail to projects included in TAPR 2022 and put them together on a table of near-term projects. We added a new table of future potential projects.
4.5	Frequency control schemes	This section was updated.	Replaced the System Integrity Protection Scheme with the Wide Area Protection Scheme.
4.5.1	Automatic under-frequency load shedding	This section was updated.	We included a brief paragraph about the declaration of protected event. We include some updated information about some of the additional measures ElectraNet is implementing to reinforce the UFLS.
4.5.2	Automatic over-frequency generator shedding	This section was updated.	We summarised the updated information.
4.5.3	System Integrity Protection Scheme (SIPS)	This section was updated.	We updated the section with a description of the new WAPS.

Table 27: Summary of changes since the 2022 Transmission Annual Planning Report (cont.)

Section	Section Name	Significant changes between the 2022 and 2023 TAPR	Analysis and explanation for the significant change
4.5.4	PEC Stage 1 Inter Trip Scheme	This is a new section.	We included a brief description of PEC's inter trip.
5	Connection opportunities and demand management	The information in this section was updated.	We updated this section based on AEMO's 2023 NEM Generation Information.
5.1	New connections and withdrawals	The information in this section was updated.	We provided information on new generation connections and withdrawals based on AEMO's generation information.
5.2.4	Opportunities to connect to Project EnergyConnect	The information in this section was updated.	We provided information and described the procedure to request a connection.
5.3	Connection opportunities for load customers	The information in this section was updated.	We updated our assumptions for the studies performed.
5.4	Summary of connection opportunities	The information in this section was updated.	We included additional information to help possible proponents.
5.6	Projects for which network support solutions are being sought or considered	The information in this section was updated.	We provided information on projects where we plan to seek proposals for network support solutions.
6.1	Recently completed projects	We updated the information to reflect the status of projects completed up until 31 October 2022. We updated the companion map.	There are five projects that were completed since we published the 2022 Transmission Annual Planning Report.
6.2	Committed projects	We updated the information to reflect the status of committed projects. We have updated the companion map.	We updated the list of committed projects. There are a total of 17 projects with majority of them proposing replacement or refurbishment of specific assets at several sites.
6.3	Pending projects	We have updated the information to reflect the of pending projects. We have updated the companion map.	We listed the two pending projects.
7	Transmission system development plan	Table and graph in this section were updated.	We updated the information related to possible future generation and projects.
7.1	Summary of planning outcomes	Table in this section was updated.	We updated the information related to projects and future expansion of the network.
7.2	Committed urgent and foreseen investments	A new project was included.	EC.15322 Emergency Transmission Network Voltage Control was completed in September 2023, to install a 275 kV 50 Mvar reactor at Cherry Gardens substation to manage the high voltages at times of low or negative demand.
7.3	Interconnector and Smart Grid planning	Table and graph in this section was updated.	EC.14246 was removed as it was completed in October.

Table 27: Summary of changes since the 2022 Transmission Annual Planning Report (cont.)

Section	Section Name	Significant changes between the 2022 and 2023 TAPR	Analysis and explanation for the significant change
7.4	System security, power quality and fault levels	Text and table in this section was updated. Some dates on the table were modified based on the present level of connection interest.	Remove Port Lincoln as a potential connection point where forecast could exceed its existing reverse power capability (Resolve by completion of Eyre Peninsula Link project) . Replace the Para SVC 2 transformer and auxiliary equipment that was damaged by a transformer fire in January 2022.
7.5	Capacity and Renewable Energy Zone Development	Text and table in this section was updated. Some dates on the table were modified based on the present level of connection requests.	We removed EC.14172 Eyre Peninsula Link project from the table (project completed), EC.14212 Upper North region eastern 132 kV line reinforcement and EC.14093 Upper North region western 132 kV line reinforcement (These two projects were cancelled. They were contingent projects based on customer load, that not materialise).
7.6	Market benefit opportunities	Table and graph was updated.	We removed EC.14168 NCIPAP Smart Wires Power Guardian Technology (installation has been completed), EC.11002 Strengthen the Eastern Hills transmission corridor (project completed), EC.14065 Robertstown Transformer Management Relay (project renamed), added EC.15179 Robertstown to Tungkillo Line Uprating (affect constraints around Roberstown).
7.7	Network asset retirements and replacements	Table and graph was updated.	We removed EC.14049 Leigh Creek South transformer replacement (project complete), EC.15320 Para SVC 2 Transformer Emergency Replacement (replacement completed) and added EC.15568 Northfield Transformer 7, 8 and 9 Interface Connection Requirement (SA PowerNetworks are planning to replace switchgear that will require updating ours). We removed several projects that are directed to groups of assets and transferred them to the more relevant Section 7.9.
7.9	Grouped network asset retirements, de-ratings and replacements	Table was updated.	We included projects targeting group of assets, that were previously under Section 7.7. Updated this information to reflect the latest status of these projects.
7.10	Security and compliance projects	Updated the table with the latest information.	We updated this information to reflect the latest results of our ongoing project and planning processes including the cost estimates and timings of projects.
Appendix E	Contingent projects	Updated this section to include the current status of each contingent project in our 2018–19 to 2022–23 regulatory control period, and added a summary of contingent projects that we proposed for the 2023–24 to 2027–28 regulatory control period.	This information was included to enable stakeholders to understand the status of each contingent project and the range of contingent projects currently being considered.


QTT072
QTT072

Appendix B: 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.

B1 National transmission planning working groups and regular engagement

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

- Executive Joint Planning Committee
- Joint Planning Committee
- 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.[71]

B1.1 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.

B1.2 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.

B1.3 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.

B1.4 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.

B1.5 Forecasting Reference Group

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

B1.6 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.

SA Energy Transition Steering Group

ElectraNet and SA Power Networks meet regularly with AEMO and the SA Government to coordinate key policy, planning and other developments impacting on ensuring successful energy transformation in South Australia.

[71] Energy Networks Australia | Website

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.

B1.7 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.

B1.8 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.

B2 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 1.4.1, 2.1.1, 5.2.4, 6.2, 7.1 and 7.3)

  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**
  (Sections 1.4.6, 2.2.3, 5.6, 7.1 and 7.4)

  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.

Appendix C: Asset Management Approach

C1 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.[72]

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.

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) as determined by the AER.[73] 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.

[72] NER clauses 6.5.6(a), 6.5.7(a), 6A.6.6 and 6A.6.7

[73] AER | Values of customer reliability final decision

C2 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.

C2.1 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.[74]

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[75]
- 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 28.[76]

[74] ESCOSA Licence/Exemption Register | Our transmission licence as currently in force (last varied 16 October 2019)

[75] South Australian Legislation | National Electricity (South Australia) Regulations

[76] ESCOSA | Electricity Transmission Code version TC/09.4

Table 28: 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.[77]

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

C2.2 Rules requirements

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

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

- consider public and worker safety paramount when planning, designing, constructing, operating and maintaining the network
- operate the network with sufficient capability to provide the minimum level of transmission network services required by customers
- comply with the technical and reliability standards contained in the Rules and jurisdictional instruments such as the ETC
- plan, develop and operate the network such that there is no need to shed load under normal and foreseeable operating conditions to achieve the quality and reliability standards within the Rules
- conduct joint planning with DNSPs and other TNSPs whose networks can impact the South Australian transmission network
- provide information to registered participants and interested parties on projected network limitations and the required timeframes for action
- develop recommendations to address projected network limitations through joint planning with DNSPs, and consultation with registered participants and interested parties.

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

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

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

- prepare and submit to ESCOSA for approval a SRMTMP dealing with the matters prescribed by regulation
- annually review, and if necessary update, the plan to ensure its efficient operation, and submit the updated plan to ESCOSA for approval
- not amend the plan without the approval of ESCOSA
- comply with the plan (as updated from time to time) as approved by ESCOSA
- 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.

---

77 ESCOSA | Electricity Transmission Code Review 2021 Final Decision

C3 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.[78]

Table 29: 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

78 AER | Transmission annual planning report guidelines

C4 Expenditure forecasting methodology

Our capital expenditure forecasting methodology is outlined below.

C4.1 Customer and stakeholder requirements

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

C4.2 Planning process

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

C4.3 Assessment of network limitations

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

- 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.

C4.4 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.

C4.5 Scope and estimate

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

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

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

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

C5 Key inputs and assumptions

This 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.

C5.1 Demand forecasts

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

C5.2 Asset health and condition assessments

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

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

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

C5.3 Planning and design standards

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

C5.4 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.

C5.5 Economic assessments

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

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

Inputs considered in these assessments include:

- capital and operating costs of alternative options
- reliability benefits – where unserved energy is measured by the Value of Customer Reliability (VCR) estimates published by AEMO[79]
- 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.

C5.6 Non-network alternatives

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

---

[79] AER | Values of Customer Reliability

C5.7 Risk assessments

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

This risk analysis considers:

- 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.

C5.8 Project cost estimation

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

C5.9 Project timing and delivery

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

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

Further information can be obtained from:

consultation@electranet.com.au

Appendix D: Compliance Checklist

This appendix sets out a compliance checklist which demonstrates the compliance of ElectraNet's 2023 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 30: Compliance Checklist

	Summary of requirements	Section
	The Transmission Annual Planning Report must be consistent with the TAPR Guidelines[80] 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 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[81]
(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 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, 7.7, 7.9 and our Transmission Annual Planning Report[81]
(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 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 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, 7.9 and our Transmission Annual Planning Report[81]
(2)	Planning proposals for future *connection points*.	Section 5.6

80 AER | Transmission annual planning report guidelines

81 ElectraNet | Transmission Annual Planning Reports

Table 30: Compliance Checklist (cont.)

Summary of requirements		Section
The Transmission Annual Planning Report must be consistent with the TAPR Guidelines[80] and set out:		
(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; the timing and likelihood of the constraints ii. 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 iii. sufficient information to enable an understanding of the constraints and how such forecasts were developed.	Chapter 7 and our Transmission Annual Planning Report[81]
(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 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 [81]
(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*) vi. other reasonable *network options* and *non-network options* considered to address the actual or potential *constraint* or inability to meet the *network* performance requirements identified in subparagraph (ii), if any. Other reasonable *network* and *non-network options* include, but are not limited to, *interconnectors*, *generation* options, demand side options, *market network service* options and options involving other *transmission and distribution networks*.	Sections 7.3 to 7.9
(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.	Sections 2.2, 2.3, 2.4 and 4.5.3
(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 30: Compliance Checklist (cont.)

Summary of requirements		Section
	The Transmission Annual Planning Report must be consistent with the TAPR Guidelines[80] 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* iii. information about where further information on the asset management strategy and methodology adopted by the *Transmission Network Service* Provider may be obtained.	Appendix C
(8)	Any information required to be included in 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 provide *inertia network services, inertia support activities* or *system strength services*.	Sections 1.3.4, 7.2 and 7.4
(9)	Emergency controls in place under clause S5.1.8, including the *Network Service Provider*'s assessment of the need for new or altered emergency controls under that clause.	Sections 4.5 and 7.3
(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* 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.	Section 4.5
(10)	Facilities in place under clause S5.1.10.	Sections 4.5 and 7.3
(11)	An analysis and explanation of any other aspects of the *Transmission Annual Planning Report* that have changed significantly from the preceding year's *Transmission Annual Planning Report*, including the reasons why the changes have occurred.	Appendix A
(12)	The results of joint planning (if any) undertaken with a *Transmission Network Service Provider* under clause 5.14.3 in the preceding year, including a summary of the process and methodology used by the *Transmission Network Service Providers* to undertake joint planning and the outcomes of that joint planning.	Appendix B

Appendix E: Contingent Projects

Table 31: Contingent projects for the 2024–28 regulatory control period

Project	Trigger[82]	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: c. Cultana 275/132 kV transformers to exceed their thermal limit of 200 MVA or d. Whyalla Central 132/33 kV transformers to exceed their thermal limit of 120 MVA or e. Whyalla Central to Cultana 132 kV lines to exceed their thermal limit of 117 MVA or f. Cultana to Stony Point 132kV line to exceed its thermal limit of 144 MVA or g. 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.	Proposed contingent	Section 7.5
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.	Proposed contingent	Section 7.4
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.	Proposed contingent	Section 7.3

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

Table 32: 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	Anticipated	Blyth West
Bolivar Wastewater Treatment BESS	2 MW	In service – Feb. 2023	Bolivar
Bungama BESS	150 MW	Anticipated	Bungama
Christies Beach Wastewater Treatment BESS	2 MW	In service – Jan. 2023	Christies Beach
Happy Valley Reservoir BESS	4 MW	In service – Dec. 2022	Happy Valley
Lincoln Gap WF BESS	10 MW	Anticipated	Corrabera Hill
Tailem Bend Battery Project	42 MW	Committed	Tailem Bend
Templers BESS	111 MW	Anticipated	Templers
Torrens Island BESS	250 MW	In service – Aug. 2023	Torrens Island
Potential New Solar Farm			
Bolivar Wastewater Treatment Solar	11 MW	In service – Oct. 2022	Bolivar
Christies Beach Wastewater Treatment Solar	5 MW	In service – Oct. 2022	Christies Beach
Cultana Solar Farm	357 MW	Anticipated	Cultana
Mannum – Adelaide Pumping Station No. 3	12 MW	In service – Jan. 2023	Mannum – Adelaide Pumping Station No. 3
Mannum Solar Farm 2	30 MW	Committed	Mannum
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			
Bolivar Power Station	123 MW	In service – December 2022	SA Power Networks Metro North – Parafield Gardens West
Retiring/Mothballed Generation			
Osborne (gas)	118 MW	In service – announced withdrawal 2026	New Osborne
TIPS B (gas)	800 MW	In service – announced withdrawal 2026	Torrens Island

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
OTR	Office of the Technical Regulator
POE	Probability of Exceedance
PACR	Project Assessment Conclusions Report
PADR	Project Assessment Draft Report

Abbreviations (cont.)

Abbreviation	Definition
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.

ElectraNet